AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Quarterly Energy Dynamics

Q1 2018

May 2018

Author: Market Insights | Markets

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 2018 (1 January to 31 March 2018). This quarterly report compares results for the quarter against other recent quarters, focussing on Q1 2017 and Q4 2017. Geographically, the report covers the National Electricity Market – which includes Queensland New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania – and the gas markets operating in the same states (except Tasmania).

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Executive Summary

Highlights for Q1 2018 include:

- Australia experienced its second hottest summer on record but compared to Q1 2017 the impact was mixed. In Sydney and Brisbane the weather was less hot than the record heat experienced in Q1 2017. In Adelaide, it was hotter than in Q1 2017, while in Melbourne it was warmer than average and unchanged year-on-year. The above contributed to a 1.5% reduction in average electricity demand. Victoria was the one region to increase electricity demand compared to Q1 2017, driven by warm summer conditions and increased industrial load.

  Mixed results for wholesale electricity prices, with relatively higher prices in the southern states (Victoria, South Australia and Tasmania, at $102, $117 and $91/MWh, respectively) when compared to the northern states (Queensland and New South Wales, at $70 and $72/MWh, respectively).

  – Queensland and New South Wales experienced very low price volatility[1] despite record high demand in Queensland on 14 February 2018. Drivers of limited price volatility compared to Q1 2017 included: the return to service of Swanbank E (385 MW); increased generation from black coal-fired power stations (by 382 MW); and fewer periods of coincident hot weather and high demand in the contiguous regions.

  – The key driver of comparatively higher prices in Victoria and South Australia was the return of weather-driven price volatility: almost all price volatility in these regions occurred on three days of coincident hot weather, high demand and low wind output.

- Electricity Futures prices generally decreased and remained in backwardation, indicating a market expectation that wholesale electricity prices will continue to fall over the next two years. For example, the Victorian 2018 price fell by 17% to $86.70/MWh as Q1 prices came in lower than expectations and the 2019 price declined by 8.5% ending at $79.71/MWh. Over Q1, the large-scale generation certificate (LGC) forward prices for 2020 fell sharply by 42% ($59 to $34), as the market factored in growing supply of renewable generation and an expectation that the Large-scale Renewable Energy Target (LRET) will be met.

- Key changes in the electricity supply mix compared to Q1 2017 included:

  – The current coal fleet[2] generated at its highest level since Q3 2008. Whilst there was less brown coal-fired generation on an absolute basis due to the retirement of Hazelwood, the remaining brown coal-fired plant increased average output by 198 MW and black coal-fired generation increased by 382 MW on average.

  – Hydro generation increased by 335 MW (30%) when compared to Q1 2017 and wind output increased by 239 MW.

  – Continued growth in rooftop PV generation, with the amount of rooftop PV generated during the daily maximum increasing from 2,794 to 3,240 (+16%) between Q1 2017 and Q1 2018. Over 2017 more than 1 GW of rooftop capacity was installed.

- Gas prices across AEMO's gas markets rebounded from Q4 2017, with the largest increase recorded in the Victorian DWGM from $6.36/GJ to $8.98/GJ. Oil prices continued to climb during the quarter with Brent ending the quarter at A$89.25/bbl.

- Longford gas production decreased to its lowest Q1 levels since 2015 which contributed to a change in net gas flows, with prevailing flows south from Queensland.

- Power System issues included: periods of low demand and high wind resulted in operational issues and directions in South Australia. In total, there were 19 separate unit direction notices for a total of 476 hours, with the majority of these occurring in March 2018.

  – High demand on 19 January 2018 led to capacity being dispatched under the Reliability and Emergency Reserve Trader (RERT) mechanism.

- Frequency control ancillary service (FCAS) market costs were 57% ($32.7 million) lower than in Q4 2017, with a key driver being the introduction of new technology (Hornsdale Power Reserve and demand-side response).

[1] Price volatility measured as cap returns for electricity prices above $300/MWh

[2] Historical data adjusted to exclude power stations that have closed, such as Hazelwood Power Station.

Contents

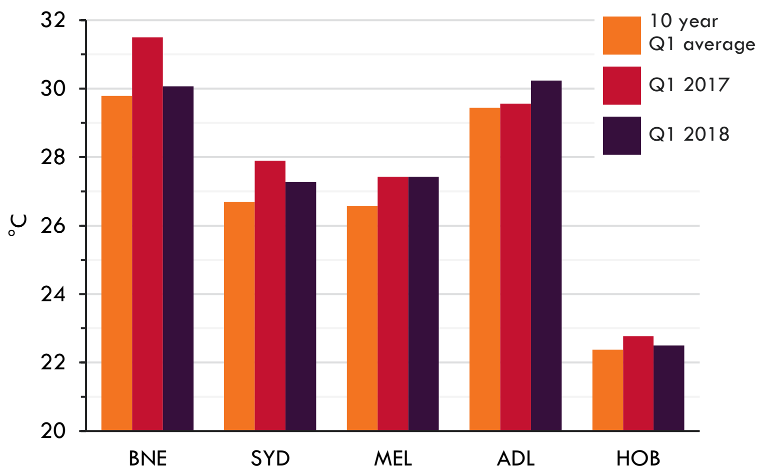
1. Electricity market dynamics

1.1 Weather

The 2018 summer was the second hottest on record for Australia as a whole, but compared to Q1 2017 the results were mixed (Figure 1). Q1 2018 temperatures in Sydney and Brisbane were warmer than average, but lower than the record highs for those cities experienced in Q1 2017. In Adelaide, the average temperature was warmer than in Q1 2017, while in Melbourne it was warmer than average and unchanged year-on-year. Overall, these temperature movements contributed to a 1.5% reduction in average electricity demand year on year (see Section 1.2.)

It was a dry quarter in most regions, with lower than average rainfalls recorded in New South Wales (-43%), Victoria (-42%), and South Australia (-31%). Tasmania and Queensland recorded quarterly rainfalls slightly higher than the long term average.

Figure 1 Q1 Average maximum temperature by region

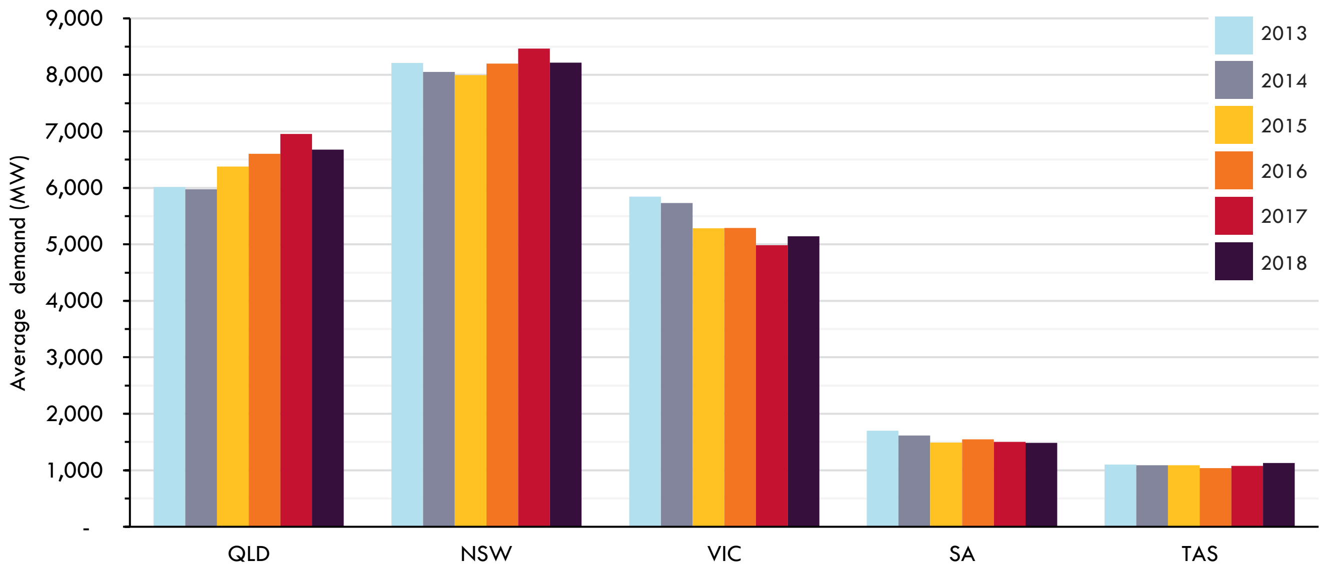


Source: Bureau of Meteorology

1.2 Electricity demand

In Q1 2018, average electricity operational demand[3] across the NEM was down (-334 MW or -1.5%) relative to Q1 2017 (Figure 2). From a regional perspective, the largest reductions in average operational demand were seen in Queensland (-277 MW) and New South Wales (-246 MW), driven by less hot summer conditions, industrial load reductions[4] and continued growth in new rooftop PV installations (see Section 1.3.2). Average operational demand increased in Victoria by 158 MW (+3.2%) compared to Q1 2017, with the main driver being the much lower Portland Aluminium Smelter load seen in Q1 2017.[5] Average operational demand was up slightly in Tasmania (+49 MW) and slightly down in South Australia (-19 MW).

Figure 2 Average operational demand for Q1 (2013 to 2018)



[3] Operational demand refers to the electricity used by residential, commercial and large industrial consumers, as supplied by the scheduled, semi-scheduled and significant non-scheduled generating units.

[4] Boyne Island Aluminium Smelter announced they were reducing load in Q1 2017: http://www.boynesmelters.com.au/17/News-and-Publications/view/94/BSL-forced-to-reduce-production-for-the-second-time-in-three-years

[5] During Q1 2017, the plant was operating at reduced levels after a power outage in December 2016 curtailed their capacity. A media release from Alcoa referring to the restart of capacity can be found here: http://news.alcoa.com/press-release/corporate/portland-aluminium-smelter-victoria-australia-restart-capacity-lost-after

1.2.1 Maximum and minimum demand

Table 1 outlines the maximum and minimum demands observed during the quarter. Notable events included:

- Queensland set a new all-time record for maximum operational demand during a prolonged heatwave where four days exceeded the previous record. The new record of 9,796 MW occurred on 14 February 2018 at 1700hrs, exceeding the previous record by 384 MW.
- South Australia recorded its lowest Q1 demand on 1 January 2018 at 1300hrs when operational demand fell to 720 MW, 105 MW (-13%) below the previous Q1 record.[6]

Table 1 Maximum and minimum demand by region – Q1 2018 vs records

Region	Maximum Demand (MW)			Minimum Demand (MW)		
	Q1 2018	All-time	All Q1	Q1 2018	All-time	All Q1
Queensland	**9,796**	9,412	9,412	5,121	2,894	3,098
New South Wales	13,027	14,744	14,744	5,826	4,636	4,642
Victoria	9,153	10,576	10,576	3,636	3,217	3,311
South Australia	2,960	3,399	3,399	**720**	584 *	825
Tasmania	1,344	1,790	1,499	890	552	552

Note: Table records refer those prior to the commencement of Q1 2018. 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 from May 2005.
* Excluding system black event in South Australia (28th September 2016)

1.2.2 Power system management

During Q1 2018, AEMO intervened to direct units in South Australia in order to manage system strength, issuing 19 separate unit direction notices for a total of 476 hours (relative to 13 unit direction notices across 288 hours in Q4 2017). Key drivers included low operational demand combined with periods of high wind resulting in insufficient synchronous units being online for the purposes of system strength. Interventions were required in order to keep the system in a secure operating state over the period. Around 1.2% of wind generation was curtailed during Q1 2018, down from 2.3% in Q4 2017 and 5.9% in Q3 2017 (Figure 4).

On 19th January AEMO intervened in the market to activate Reliability and Emergency Reserve Trader (RERT) reserves in response to a LOR2 condition being forecast in Victoria as a result of high demand and projected reserve shortfalls.

Figure 3 Directions for SA system strength (duration)

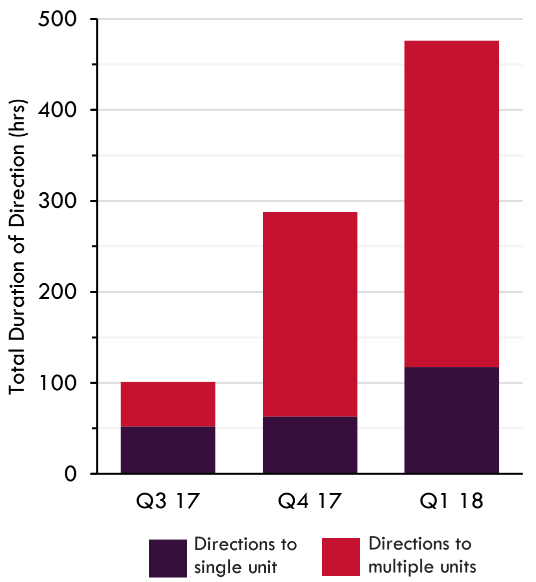
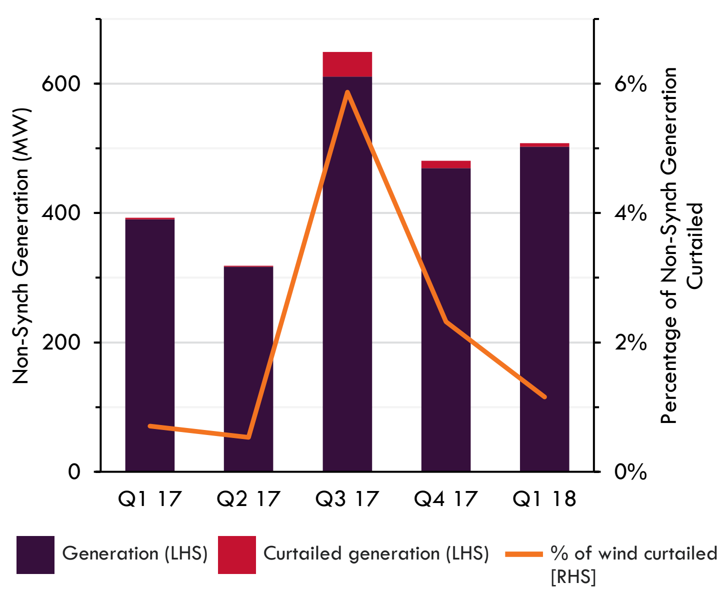


Figure 4 Curtailed SA wind generation



[6] More discussion on the changing demand profile can be found in the AEMO observations: http://www.aemo.com.au/-/media/Files/Media_Centre/2018/AEMO-observations.pdf

1.3 Electricity generation

The Q1 2018 NEM supply mix was marked by increased output from renewable generation and the remaining coal-fired fleet (accounting for Hazelwood's closure) compared to Q1 2017, which meant less gas-powered generation (GPG) was required to serve demand (Figure 5 and Figure 6). This result contrasts with outcomes for most of 2017, in which black coal-fired generation and GPG replaced the majority of Hazelwood's output.[7]

Figure 5 Quarterly electricity supply mix

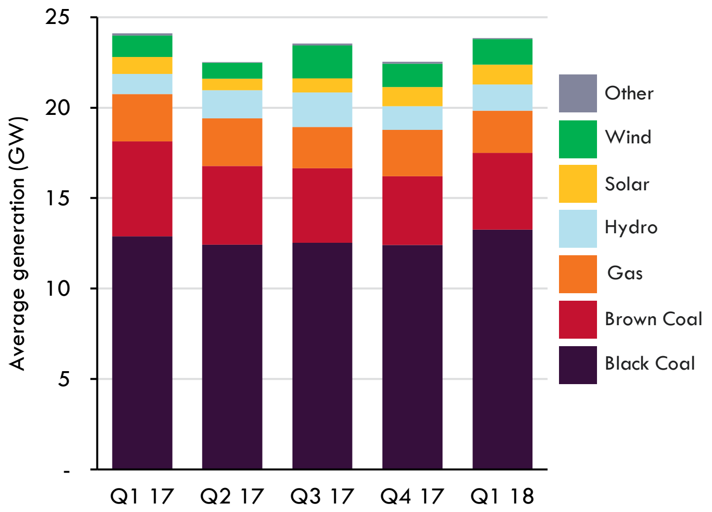
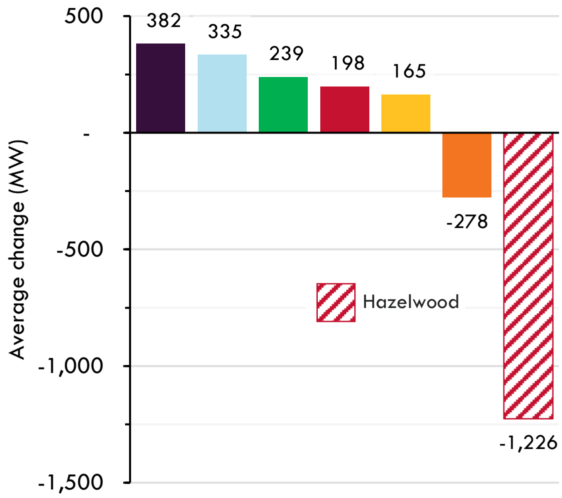


Figure 6 Change in supply – Q1 18 vs Q1 17



Note: Brown Coal does not include Hazelwood in Figure 6. Solar includes large-scale and rooftop PV.

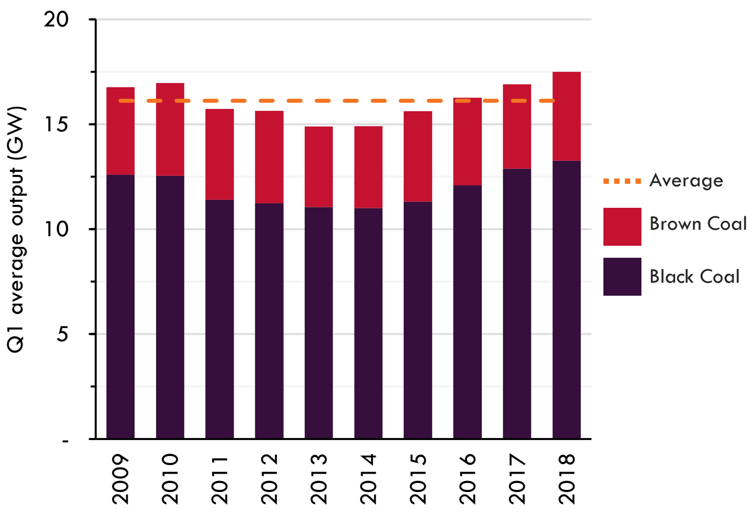
1.3.1 Coal

During Q1 2018 the current NEM coal fleet[8] generated at its highest level since Q3 2008 and increased average output by 580 MW when compared to Q1 2017

- The current coal fleet recorded its fourth highest quarterly availability in the last 10 years
- The number of unplanned outages dropped by 12% compared to Q1 2017 (and was slightly higher than 2015 and 2016 levels).

While average brown coal-fired generation decreased by 1,028 MW compared to Q1 2017 (due to the closure of Hazelwood), output from the remaining brown coal fleet increased by 198 MW on average (Figure 6). This was largely a function of increased availability of Loy Yang A Power Station.

Figure 7 Q1 average output from current coal fleet



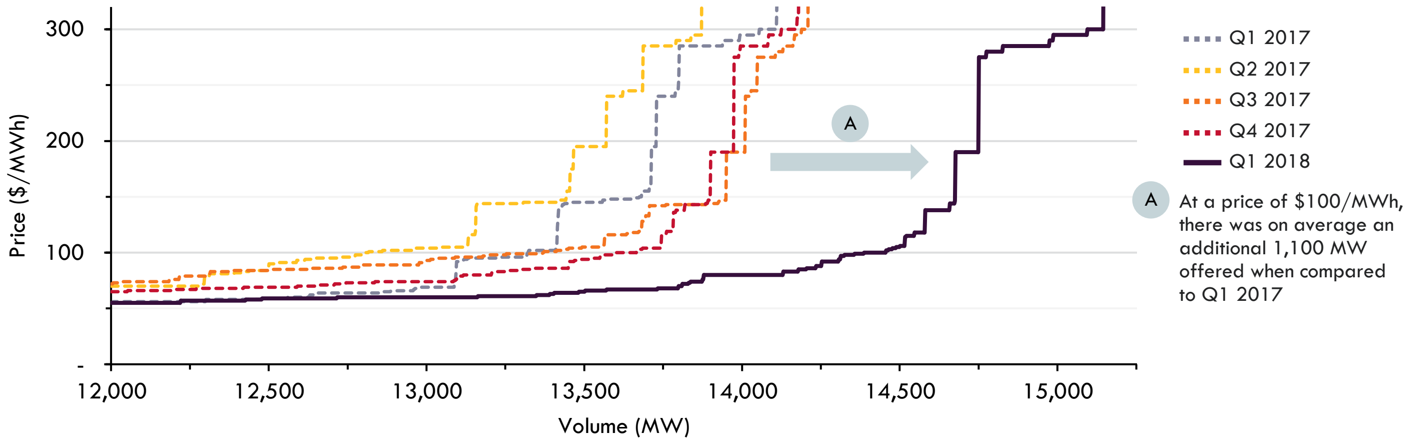
Black coal-fired generation increased output by 382 MW on average, reaching its highest level since Q1 2010, as it continued to play a key role in replacing Hazelwood's generation. A reduction in the price at which generation volume was offered led to a shift in the bid supply curve from the current black coal fleet (Figure 8). This was partly driven by the Queensland Government's instructions to its state-owned[9] generators and an easing of coal supply concerns for black coal-fired generators in New South Wales. In particular, Mt Piper, Callide and Gladstone power stations generated at higher levels than in Q1 2017 (+82 MW, +110 MW, and +72 MW respectively).

[7] AEMO 2018. Quarterly Energy Dynamics – Q4 2017. www.aemo.com.au/Media-Centre/AEMO-publishes-Quarter-Energy-Dynamics---Q4-2017

[8] Historical data adjusted to exclude power stations that have closed, such as Hazelwood Power Station.

[9] More details on the Queensland instruction can be found here: https://www.dnrme.qld.gov.au/energy/initiatives/powering-queensland

Figure 8 Bid supply curve – NEM black coal



1.3.2 Renewables

Compared to Q1 2017, average renewable generation in Q1 2018 increased by 734 MW, making up 17% of the supply mix during the quarter.

The largest increase in renewable output was from hydro generation, which increased by 30% (+335 MW) compared to Q1 2017. By region, hydro output in Tasmania increased by 213 MW (40%), New South Wales by 120 MW (50%), with a smaller increase in Victoria (42 MW). Increased hydro generation was a function of increased hydro capacity offered at lower priced bands: the average amount of hydro generation in the NEM priced below $120/MWh increased by about 750 MW. Increased output from hydro generators in Tasmania had the effect of reducing net flows into Tasmania when compared to Q1 2017.

Large-scale solar and wind output increased by 263 MW, which was primarily a function of new capacity coming online (Table 2) and improved wind conditions.

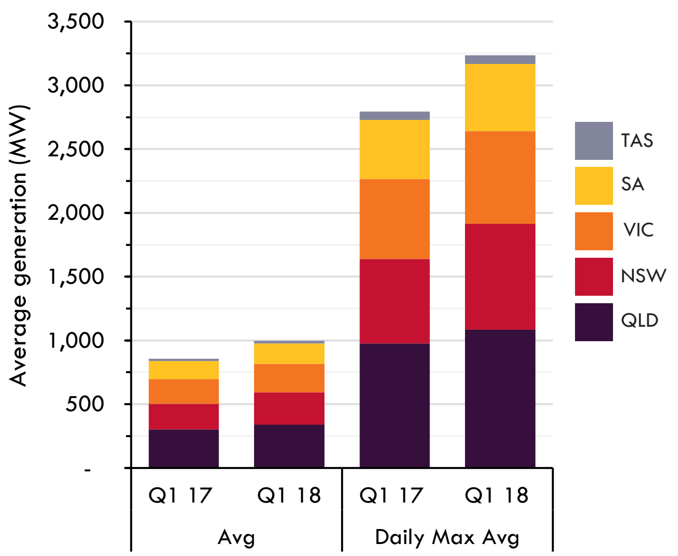
Table 2 New entrants in the NEM in Q1 2018

New entrant	Capacity (Region)	Fuel Source
Sapphire Windfarm	270 MW (NSW)	Wind
Parkes Solar Farm	55 MW (NSW)	Solar
Hughenden Solar Farm	18 MW (QLD)	Solar

Note: Table includes new entrants that began generating during the quarter

Average Q1 2018 rooftop PV generation increased from 857 MW to 997 MW (+16%) when compared to Q1 2017 (Figure 9), resulting in Q1 2018 recording the highest level of PV generation on record. The largest rise was in New South Wales (+27%), with Victoria (+15%), Queensland (+12%), and South Australia (13%) also experiencing large increases. The daily maximum average generation [10] increased from 2,794 MW to 3,240 MW (+16%) between quarters. These increases correspond with a record amount of installed rooftop PV capacity over 2017 (+1.06 GW).[11]

Figure 9 Average rooftop PV generation by region



Note: Daily maximum much higher than average because average incorporates periods in which rooftop PV is not generating

1.3.3 Gas-powered generation

With increased dispatch of other fuel types during the quarter and reduced wholesale electricity prices in New South Wales and Queensland (see Section 1.4), average GPG decreased by 278 MW (-11%) compared to Q1 2017. In Queensland,

[10] The maximum rooftop PV generated across a 30 minute trading interval each day averaged across the quarter.

[11] CER. 2018. Household solar capacity through the roof in 2017. [online]. http://www.cleanenergyregulator.gov.au/RET/Pages/News%20and%20updates/NewsItem.aspx?ListId=19b4efbb-6f5d-4637-94c4-121c1f96fcfe&ItemId=480

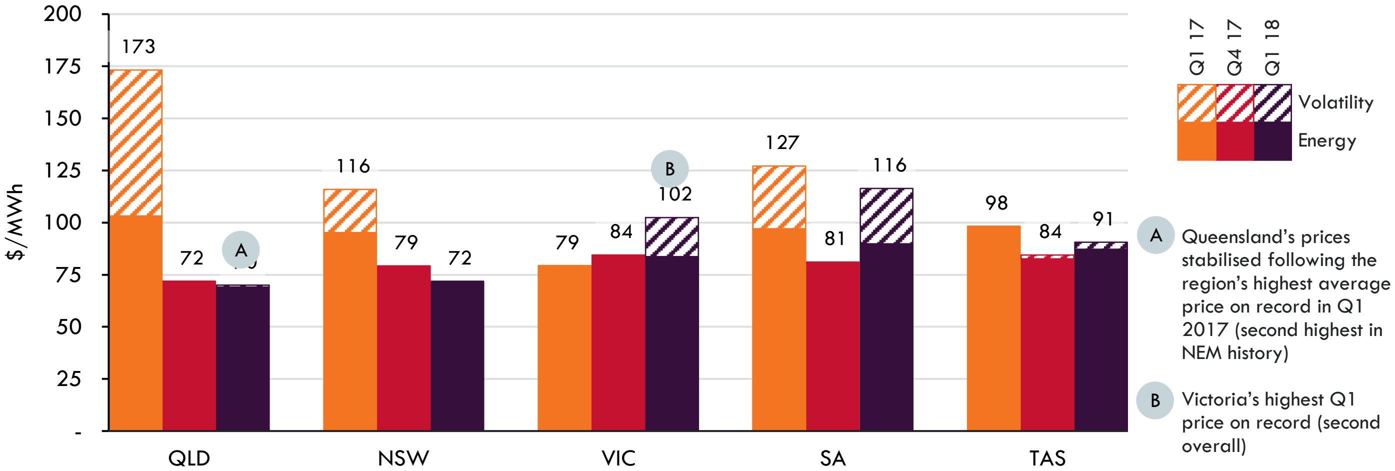
Swanbank E operated for its first full quarter since it was mothballed[12] in 2015 (it returned to service in November 2017), adding 237 MW of supply on average to the region. However, this increase was offset by reductions at Darling Downs and Braemar power stations (-183 MW and -139 MW, respectively), with Queensland's overall GPG output reducing by 216 MW (-18%).

Similar GPG reductions occurred in New South Wales, where output fell by 224 MW (-66%), making Q1 2018 the lowest GPG recorded in New South Wales since 2009. This was driven by the changed operating regime of Smithfield Energy Facility[13] as well as significant reductions in generation from Uranquinty (-101 MW). South Australia experienced an increase in average GPG of 138 MW due to Pelican Point operating at full capacity[14] when compared to Q1 2017, while Victoria's and Tasmania's GPG output remained steady.

1.4 Wholesale electricity prices

During Q1 2018, average wholesale electricity prices were comparatively higher in Victoria, South Australia and Tasmania ($102, $116 and $91/MWh, respectively) than in Queensland and New South Wales ($70 and $72/MWh, respectively) (Figure 10). Overall, average prices were generally higher than Q4 2017, but lower than Q1 2017. Table 3 provides a summary of price drivers during the quarter.

Figure 10 Average wholesale electricity price by region



Note: The average quarterly price is broken up into two parts, energy and volatility. Volatility refers to the contribution of high priced events (above $300/MWh) to the average price more commonly known as cap returns. Energy is therefore the remainder.

Table 3 Wholesale electricity price drivers in Q1 2018

Lower prices in QLD and NSW	• Lower electricity demand – milder summer conditions in Queensland and New South Wales compared to Q1 2017 contributed to a total 523 MW reduction in electricity demand (see Section 1.2). • Increased black coal-fired generation and availability – see Figure 5 for further details. • Greater availability of lower priced hydro capacity – compared to Q4 2017, the average amount of hydro generation in New South Wales priced below $120/MWh increased by 394 MW. • Return of Swanbank E in Queensland – an additional 237 MW of supply was provided by Swanbank E, which returned to service after being mothballed for three years.
Higher prices in VIC and SA	• Weather driven price volatility – see Section 1.4.1 for further details. • Physical limits on importing lower price electricity from New South Wales into Victoria. Over the quarter, Victoria's wholesale electricity price was 43% higher than New South Wales' and physical flows south on the VIC-NSW interconnector were constrained 30% of the time (averaging 527 MW over these periods). • A shift of the supply curve in Victoria – Q1 2018 represents the first summer since closure of Hazelwood Power Station, which provided an average 1,225 MW of low-priced capacity in Q1 2017.

[12] Press Release on Swanbank E return to service can be found here: http://www.stanwell.com/news/press-releases/swanbank-e-power-station-return-service/

[13] It closed in July 2017, but was brought back into service with up to 109 MW of capacity available. Despite this, it has only generated at very low levels since July 2017.

[14] Press release on Pelican Point return to full capacity can be found here: http://www.gdfsuezau.com/media/newsitem/Pelican-Point-to-return-to-full-capacity

1.4.1 Price volatility

During Q1 2018 there was high wholesale electricity price volatility in Victoria and South Australia, but low price volatility in New South Wales and Queensland (Table 4).

Low volatility in QLD and NSW	• Combined Q1 2018 quarterly cap returns[15] for New South Wales and Queensland were only $0.85/MWh, compared to $90.78/MWh in Q1 2017. Prices in Queensland and New South Wales were above $300/MWh for two hours during the quarter compared to around 100 hours in Q1 2017, driven by: – Fewer periods of coincident hot weather and high operational demand in the two regions. In Q1 2018 there were only eight hours where the combined demand exceeded 21,500 MW, compared to 32.5 hours in Q1 2017. – The Queensland Government's instruction to its state-owned generators to "undertake strategies to place downward pressure on wholesale prices".[16]
High volatility in VIC and SA	• Combined Q1 2018 cap returns for Victoria and South Australia increased to $45.89/MWh from $30.70/MWh in Q1 2017. This volatility largely occurred on three days of coincident hot weather, high demand and low wind output in the two regions. – On 18 January, 19 January and 7 February 2018 the maximum temperature in both regions exceeded 37 °C and combined demand exceeded 11,800 MW, while wind capacity factors were low (less than 20% during peak, compared to typical capacity factors of 30-40%). – An unplanned outage of one unit at Loy Yang B Power Station on 18 January 2018 contributed to price volatility – high prices on this day made up 41% of total cap returns in these regions for the quarter.

Table 4 Quarterly cap returns by region ($/MWh)

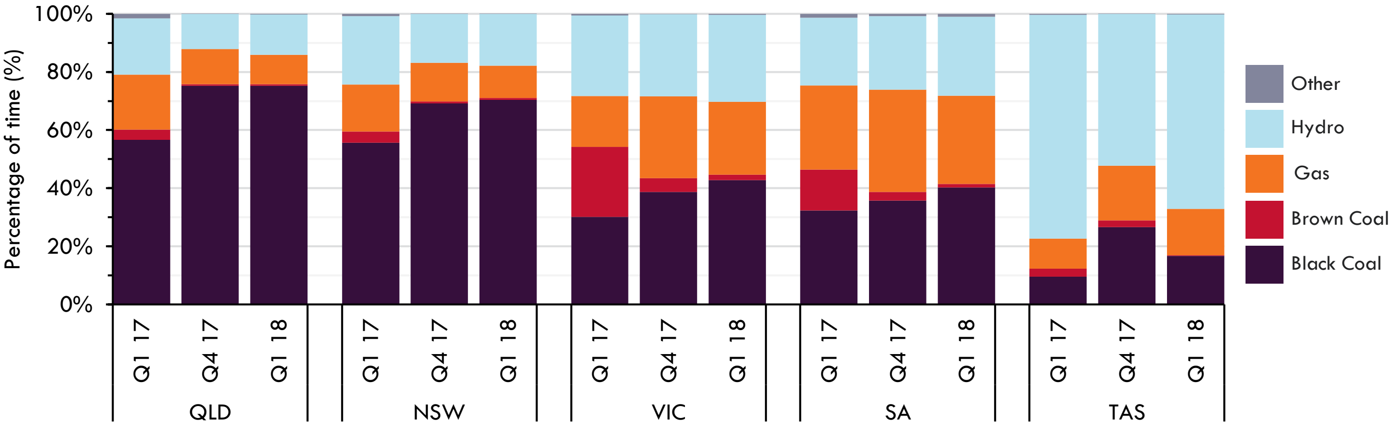
Quarter	Queensland	New South Wales	Victoria	South Australia	Tasmania
Q1 2017	$70.06	$20.72	$0.59	$30.11	$0.25
Q4 2017	$0.11	$0.00	$0.27	$0.47	$1.83
Q1 2018	$0.85	$0.00	$18.76	$26.68	$3.37

Note: Cap returns are expressed as $/MWh.

1.4.2 Price setting trends

As previously discussed[17], the closure of Hazelwood has led to shifts in wholesale price dynamics in the NEM. Figure 11 highlights the significant changes in price setting trends compared to 12 months ago as well as the adjustments from the previous quarter.

Figure 11 Price setting duration by fuel type – Q1 2018 vs previous quarters



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

[15] A measure of volatility in electricity prices is the presence of high price events – prices above $300/MWh. Often represented as 'quarterly cap returns' which is the sum of the NEM half hourly 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] https://dnrme.qld.gov.au/energy/initiatives/powering-queensland

[17] AEMO 2018. Quarterly Energy Dynamics – Q4 2017. www.aemo.com.au/Media-Centre/AEMO-publishes-Quarter-Energy-Dynamics---Q4-2017

Compared to Q1 2017, the significant reduction of brown coal-fired generation since Hazelwood's closure has diminished the role of brown coal in price setting – most evident in Victoria where brown coal price-setting decreased from around 24% of the time to 1.8% this quarter. This has corresponded with black coal-fired generation setting the price more often in every NEM region, particularly in Queensland and New South Wales where the percentage of time increased from around 56% to greater than 70% this quarter. This was a product of increased black coal-fired generation and availability at lower prices.

Compared to Q4 2017, there were only small movements in price setting roles in Q1 2018. The trend of brown coal playing a minor part in price setting continued. Lower GPG output and availability saw a decrease in its price setting role in all mainland regions, most notably in South Australia where price setting fell from 35.2% to 30.4% this quarter. GPG's price-setting role was replaced by black coal and hydro due to increased availability and generation of these fuel sources.

1.4.3 Electricity futures markets

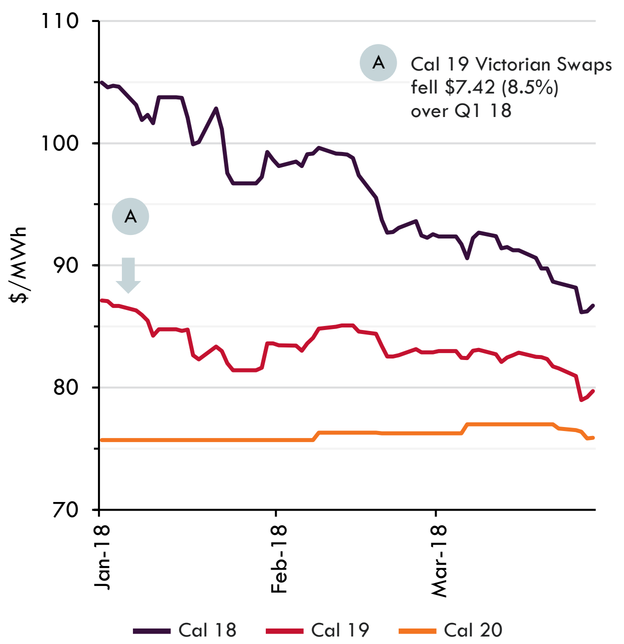
Over the quarter ASX Energy calendar swap prices for Victorian calendar 2018 and 2019 products fell by 17% and 8.5% respectively. The forward curve remained in backwardation, as illustrated in Figure 12, which shows that the market expects falling Victorian wholesale prices out to 2020. Similar trends were observed in New South Wales and Queensland.

As discussed in Section 1.4.1 there has been an observed reduction in volatility in New South Wales and Queensland between Q1 2017 and Q1 2018 with lower cap returns during Q1 2018. Ongoing market sentiment of reduced future volatility is shown in the price of ASX Energy cap products with Q1 2019 prices reducing an average of 20% across New South Wales, Queensland and Victoria over the quarter (Figure 13).

Table 5 ASX Energy Q1 19 cap prices

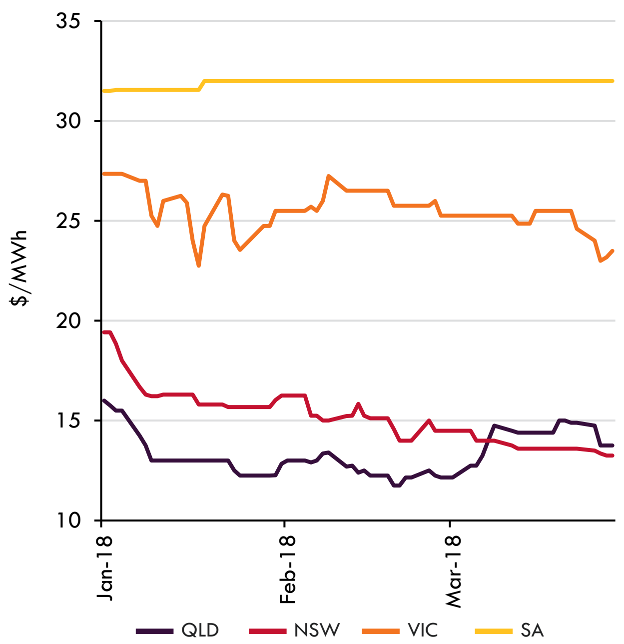
Region	Change over Q1 18
Queensland	▼ $2.25 (14%)
New South Wales	▼ $6.17 (32%)
Victoria	▼ $3.85 (14%)
South Australia	▲ $0.5 (2%)

Figure 12 ASX Energy Victorian Cal swap prices 2018-20



Source: ASX Energy

Figure 13 ASX Energy Q1 19 cap prices



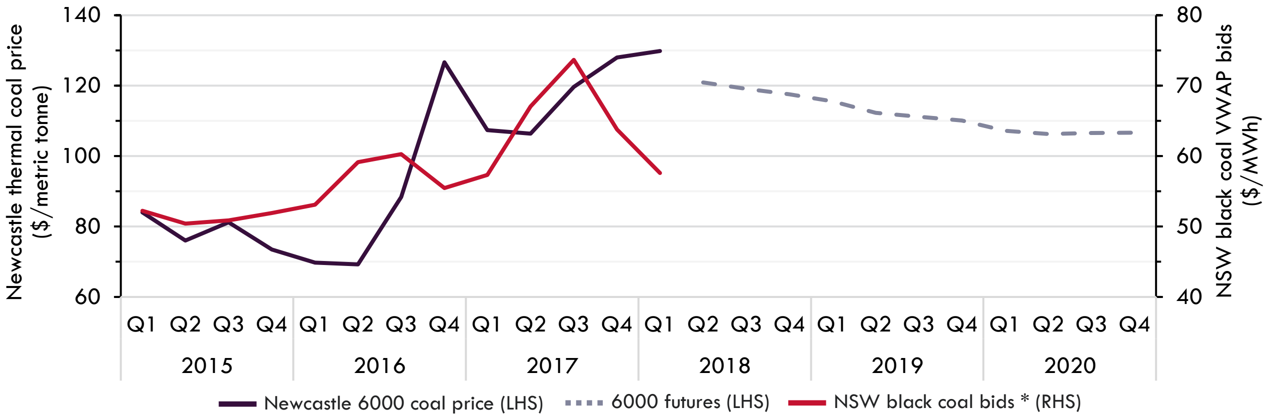
Source: ASX Energy

1.4.4 International coal and prices

The average spot price for Australian Newcastle thermal coal remains at comparatively high levels, averaging over $130 per tonne in Q1 2018. Relatively high prices were driven by strong Chinese demand following the easing of import restrictions, however prices began to fall toward the end of the month following the end of the Chinese winter (Chinese winter typically sees an increase in demand for coal).[18] Strong underlying demand in China also showed in the forward market, where coal futures prices remain above $100 per tonne beyond 2018 (Figure 14).

High international coal prices do not appear to be directly impacting recent domestic black-coal fired generators electricity price offers with the quarter recording a continuation of Q4 2017 lower electricity offers (Figure 14). This drop reflects a reversal of trends throughout most of 2017, where an increase in the price of offers from New South Wales black-coal fired generators coincided with rising international coal prices.

Figure 14 Quarterly average international black coal spot and futures prices and domestic coal-fired generators' offers



Source for Newcastle thermal spot and futures prices: Bloomberg
* Black coal bids are the volume-weighted average price of bids priced between $40-$120/MWh

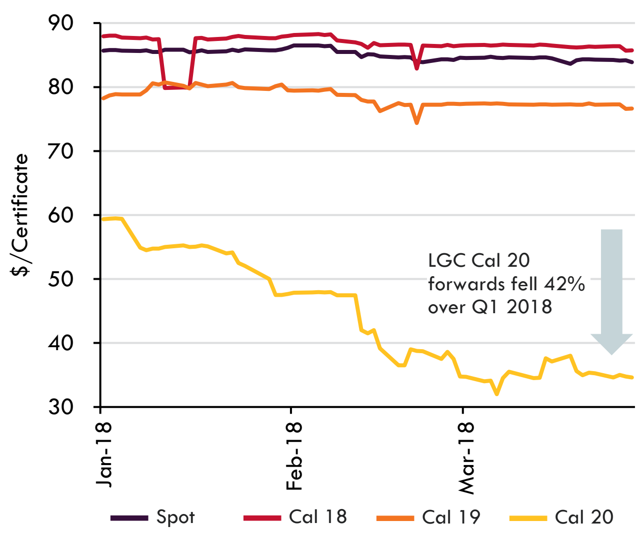
1.4.5 Environmentals

Over the quarter, the price for calendar year 20 forward contracts fell 42% ($59 to $35), suggesting market participants are expecting increased supply of renewable generation and that they are increasingly confident that the LRET will be met in 2020 (Figure 15).[19]

In February 2018 electricity retailers liable under the Large-scale Renewable Energy Target (LRET) were required to surrender large-scale generation certificates (LGCs) proportional to their energy purchases over the 2017 calendar year. Non-compliance with the LRET in 2017 was just under 7% with a total shortfall of 1.65 million LGCs. This compared to 11% in 2016.

Following the 2017 LRET surrender, the Clean Energy Regulator (CER) stated that 'there will be a more than adequate surplus of certificates through to 2020'.[20] The CER's statement is supported by expected new LGC supply sourced from about 7 GW of large-scale renewable projects constructed or firmly announced since 2016.[21]

Figure 15 LGC spot and forward prices



Source: Mercari

[18] Bloomberg 2018. www.bloomberg.com/news/articles/2018-03-13/winter-s-over-in-china-these-commodities-will-feel-the-heat

[19] The forward price curve is based on a 'Mid-Point Index' - the mid-point between a recorded bid and offer.

[20] CER. *Surplus of large-scale generation certificates after final surrender*. [Online] http://www.cleanenergyregulator.gov.au/RET/Pages/News%20and%20updates/NewsItem.aspx?ListId=19b4efbb-6f5d-4637-94c4-121c1f96fcfe&ItemId=478

[21] CER. *Large-scale generation certificate market update - February 2018*. [Online] http://www.cleanenergyregulator.gov.au/RET/Pages/About%20the%20Renewable%20Energy%20Target/How%20the%20scheme%20works/Large-scale%20generation%20certificate%20market%20update%20by%20month/Large-scale-generation-certificate-market-update-February-2018.aspx

1.4.6 Frequency control ancillary services

In the NEM, frequency control ancillary services (FCAS) are market mechanisms employed to correct frequency deviations arising from imbalances between supply and demand.[22] In Q1 2018, FCAS costs were $25 million[23], representing a $32.7 million (57%) decrease on Q4 2017 levels (Figure 16).

AEMO's FCAS requirements were steady compared to Q4 2017, so decreases in FCAS prices were the main driver of lower costs. Contributors to lower FCAS prices included:

- **Additional supply from new technologies** – towards the end of 2017 two participants (Hornsdale Power Reserve and EnerNOC) entered the FCAS markets. These participants provided FCAS supply from a large-scale battery and aggregated demand response, representing an Australian first for these technologies. During Q1 2018 these new technologies captured a larger share of FCAS markets: they supplied about 20% of Raise FCAS, compared to 8% in Q4 2017, displacing higher-priced supply from existing technologies (largely coal, Figure 17).
  - In addition, increased competition through two new FCAS providers has coincided with a reduction in the price of offers from some existing providers. For example, in the Raise 5min FCAS market an additional 110 MW was offered to the market at prices below $5/MWh in Q1 2018 compared to Q4 2017. Of this additional supply of lower-priced FCAS, about 50 MW came from HPR and EnerNOC, with the remaining coming from existing providers such as CS Energy and Hydro Tasmania.
- Reduced pricing impact of the South Australian 35 MW FCAS constraint[24] – in Q1 2018, the constraint had less of an impact on FCAS prices than in Q4 2017, due to fewer binding events[25] and increased supply during these events (see Section 1.4.7).

Figure 16 Quarterly FCAS cost by service

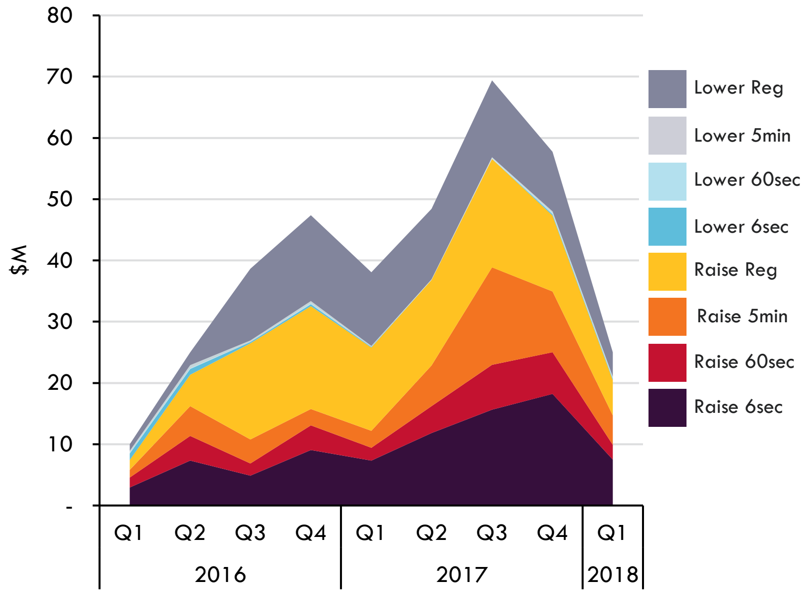
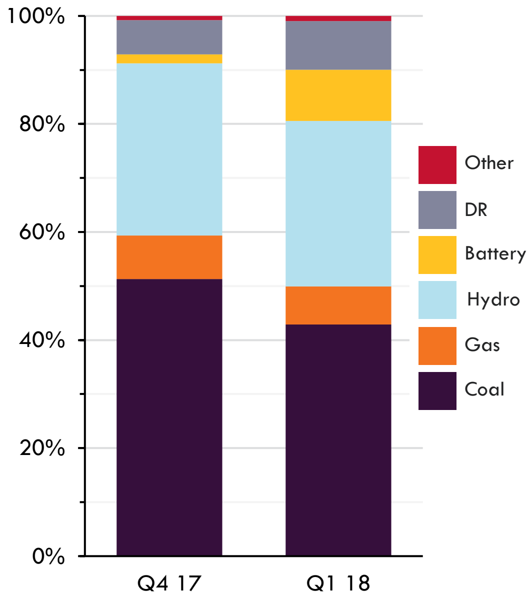


Figure 17 Raise FCAS supply by fuel type



1.4.7 Hornsdale Power Reserve

This section is focussed on the Hornsdale Power Reserve (HPR), the first scheduled battery in the NEM and currently[26] the largest lithium-ion battery in the world. The end of Q1 2018 marked the first full quarter of HPR operation since its commissioning in December 2017.

In the energy market, HPR was dispatched as a load for 38% of the quarter and charged with 11 GWh of energy, while it was dispatched as a generator for 32% of the quarter, discharging 8.9 GWh of energy. HPR typically charged in the early hours of

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[22] AEMO. *Guide to ancillary services in the National Electricity Market*. [ONLINE] Available at www.aemo.com.au/-/media/Files/PDF/Guide-to-Ancillary-Services-in-the-National-Electricity-Market.ashx Accessed.

[23] Represents preliminary data and subject to minor revisions.

[24] For system security purposes, AEMO requires the local procurement of 35 MW of regulation FCAS in South Australia at times when the separation of the region at the Heywood Interconnector is a credible contingency. During these times of local requirements, FCAS prices have been very high due to the limited number of suppliers of these services.

[25] It bound for 13 hours in Q1 2018, representing a 7 hour reduction on Q4 2017 levels.

[26] As at 19 April 2018.

the morning, corresponding with lower energy prices, and typically discharged in the late afternoon, corresponding with higher energy prices (Figure 18). A comparison of the average charge and discharge price reveals an average price arbitrage of $90.56/MWh (Figure 19). This spread is in a large part due to three days of price volatility in South Australia (18 January, 19 January and 7 February 2018) during which the South Australia price settled above $5,000/MWh for nine trading intervals.

Figure 18 Average Q1 daily dispatch for HPR

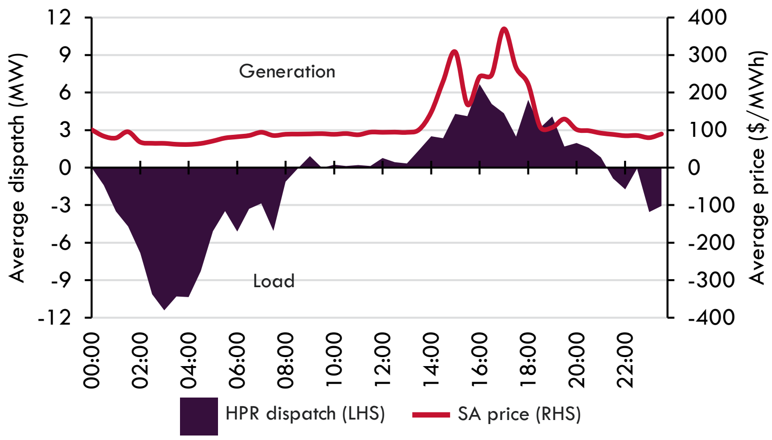
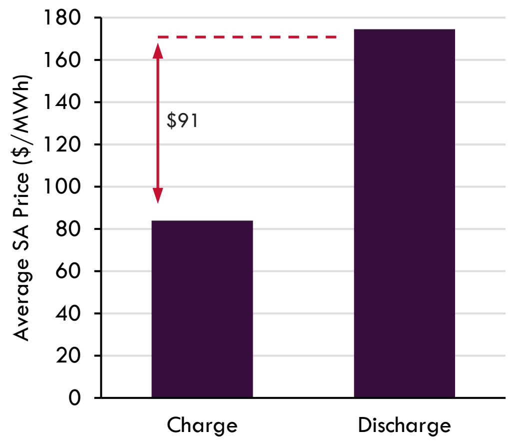


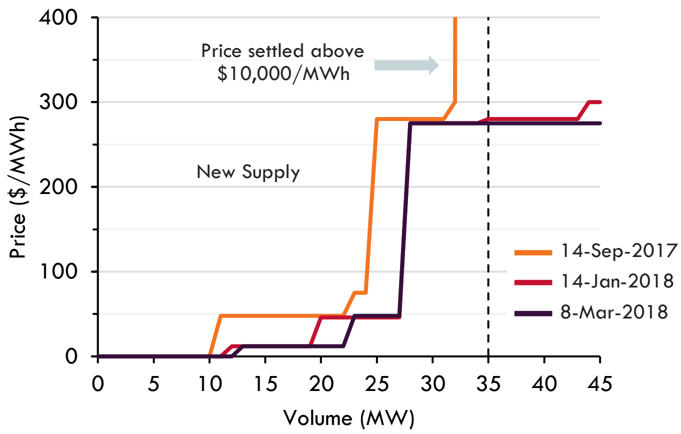
Figure 19 Average Q1 HPR charge and discharge price



In the FCAS markets, HPR was enabled to provide regulation and contingency FCAS for 71% and 99% of the time, respectively.

HPR also provided regulation FCAS to South Australia during the activation of the 35 MW FCAS constraint on 14 January and 8 March 2018. Historically, during the times that this constraint has bound, regulation FCAS prices in South Australia have typically exceeded $9,000/MWh due to the limited number of suppliers of these services in the region. However, on 14th January, HPR provided additional supply into FCAS regulation markets (Figure 20), and average Raise and Lower Regulation prices were $248/MWh during the event. AEMO estimates that this reduced the cost of regulation services by about $3.5 million during the five hour period in which the constraint bound.

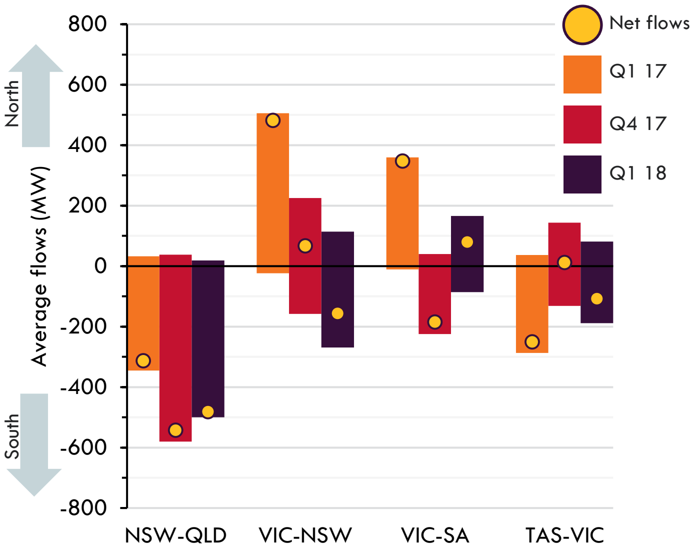
Figure 20 Supply curves for raise regulation FCAS in SA during time of 35MW local regulation constraint with and without HPR



1.5 Inter-regional flows

- Average interregional flows from Queensland to New South Wales in Q1 2018 increased by 168 MW (54%) compared to Q1 2017, whilst a marginal reduction (11%) was recorded against the prior quarter.
- A significant (132%) swing in transfers from Victoria to New South Wales was recorded in Q1 2018 when compared to Q1 2017, with average flow shifting from 482 MW into New South Wales to an average flow of 156 MW into Victoria.
- In Q1 2018 average flow was from Victoria to South Australia, which reflects prevailing flow in Q1 2017. Average flow reduced by 77%.
- Prevailing flow on the Basslink interconnector was southerly, with a 57% reduction when compared to Q1 2017, primarily driven by increased output from hydro generation in Tasmania.

Figure 21 Quarterly interconnector flows in the NEM



2. Gas market dynamics

2.1 Gas demand

Total gas demand[27] increased by 4 PJ during the quarter compared to Q1 2017, driven by a 9 PJ increase in pipeline deliveries for export LNG (Table 6). This increase was partially offset by a 5 PJ (11%) decrease in GPG, influenced by the ongoing supply-side evolution in the NEM. The largest reductions in GPG demand occurred in Queensland (4.5 PJ or 23%) and New South Wales (2.7 PJ or 58%) (Section 1.3.3).

Residential, commercial and industrial demand for gas from AEMO's wholesale gas markets remained consistent at 54 PJ, with minor quarterly variances between each of the markets.

Table 6 Total Gas Demand – Q1 2018 vs Q1 2017

Total Demand	Q1 2017 (PJ)	Q1 2018 (PJ)	Volume Change (PJ)
AEMO Markets *	54	54	-
GPG **	47	42	▼ 5
QLD LNG	298	307	▲ 9
TOTAL	**399**	**403**	▲ **4**

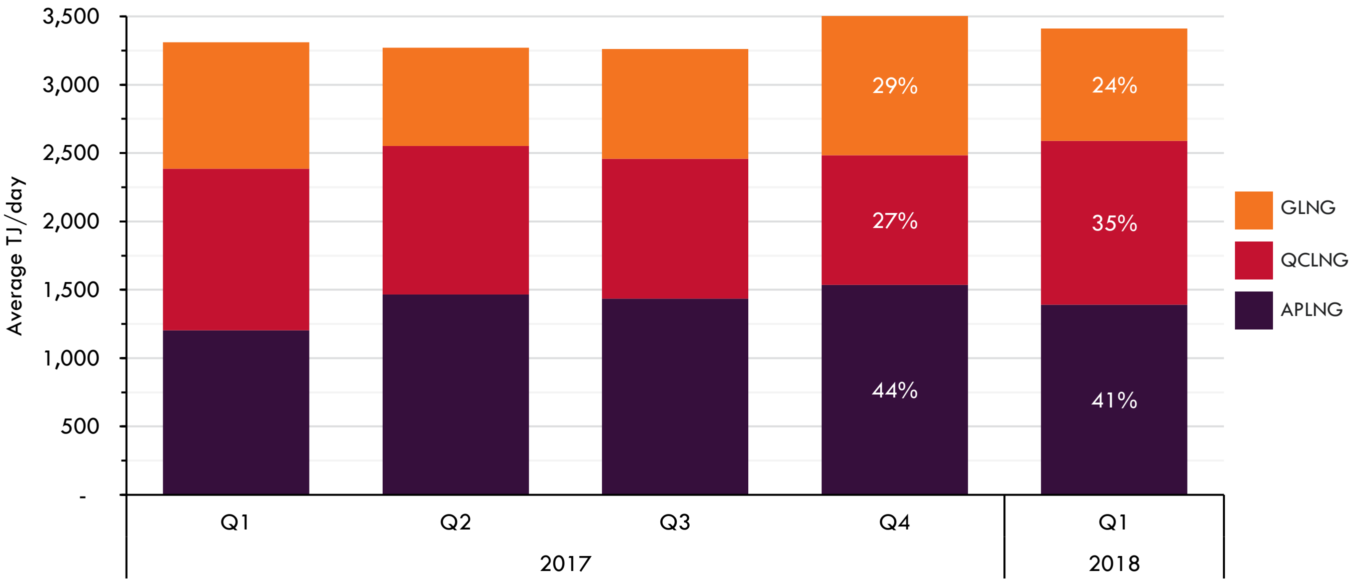
* AEMO Markets demand is the sum of customer demand in each of the Short Term Trading Markets (STTMs) and the Declared Wholesale Gas Market (DWGM).
** Includes demand for GPG usually captured as part of total DWGM demand. Excludes Yabulu as not connected to main gas pipelines.

2.1.1 LNG

Average daily pipeline deliveries remained at comparatively high levels at above 3,400 TJ/d during Q1 2018, but were slightly down on Q4 2017 levels.

APLNG's contribution to pipeline deliveries decreased to 41% during Q1 2018, due to planned maintenance to their LNG plant in March. This decrease was mostly offset as pipeline deliveries from QCLNG increased to 35% during Q1 2018 following a total LNG plant outage as a result of a major planned maintenance program in the previous quarter.

Figure 22 Pipeline deliveries to Curtis Island



[27] AEMO's wholesale gas markets, gas demand for gas-powered generation and pipeline deliveries to the Curtis Island LNG projects. Total demand does not include regional demand i.e. demand that is not captured by one of the markets.

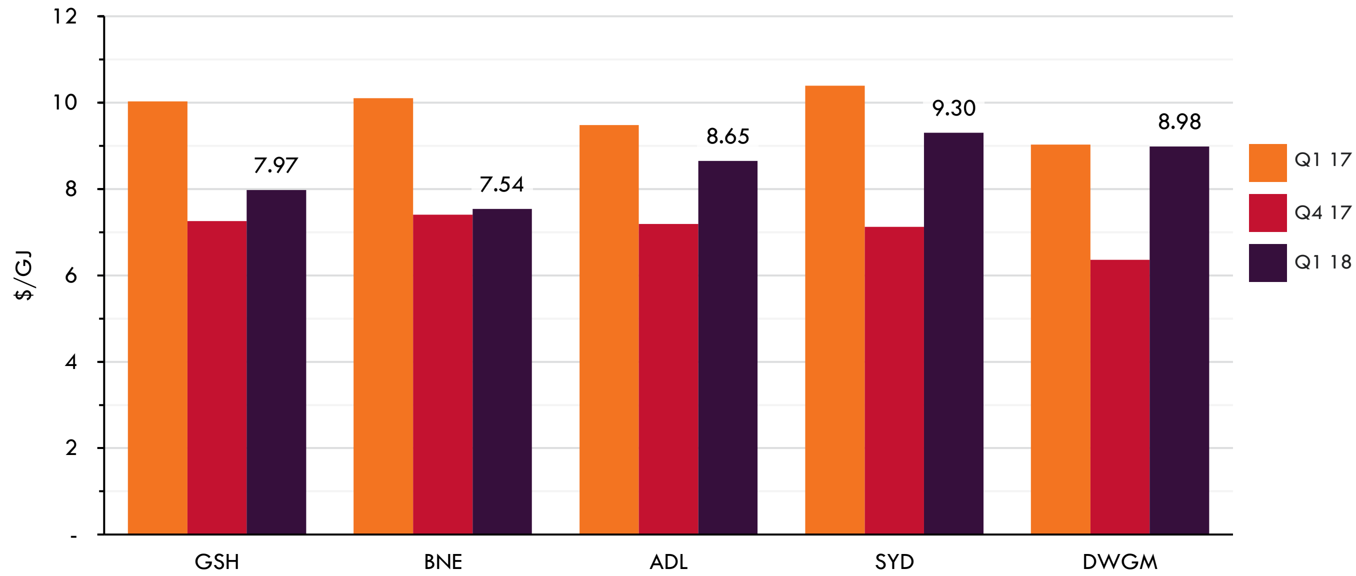
2.2 Wholesale gas prices

Average quarterly prices increased across all AEMO gas markets during Q1 2018 when compared to Q4 2017 and decreased in all gas markets compared with Q1 2017 (Table 7 and Figure 23).

Table 7 Wholesale gas price in Q1 2018

Price *increases* against Q4 2017 in all gas markets	• All of AEMO's gas markets recorded average quarterly price increases, with the largest variations recorded in the Victorian DWGM and Sydney STTM which have increased \$2.62/GJ and \$2.18/GJ respectively. • Adelaide's STTM average quarterly prices also increased by \$1.47/GJ. – The gas price increases were influenced by less gas flowing along the Eastern Gas Pipeline and the SEAGas pipeline to the Sydney and Adelaide markets respectively as a result of lower quarterly production from Longford (Figure 26).
Price *decreases* against Q1 2017 in all gas markets	• All of AEMO's gas markets recorded average quarterly price decreases, with the largest variations recorded in the Gas Supply Hub and Brisbane STTM (both > \$2/GJ) and Sydney STTM (> \$1/GJ), driven by: – Additional gas supplied into the market from Queensland during the quarter, specifically from Combabula, Condabri and Woleebee Creek. – An increase in black coal-fired generation and lower electricity prices in Queensland and New South Wales during the quarter, which contributed to lower gas consumption in GPG in these regions.

Figure 23 Average wholesale gas price per market



2.2.1 International gas prices

The price for domestic gas on the east coast is increasingly being influenced by the global price for oil, as noted by the Australian Competition and Consumer Commission (ACCC) in their *Inquiry into the east coast gas market*[28]:

> *"The presence of oil-linked mechanisms in GSAs[29] means that the prices paid by the gas buyers under those GSAs will adjust quite rapidly in response to the changing oil prices."*

Specifically, some gas contracts on the east coast include price formulas that are 100% oil linked and some have a combination of an oil-linked component and a commodity gas component indexed to inflation. Oil indexing of gas contracts is often based on Brent Crude or Japanese Customs-cleared Crude (JCC) prices.[30]

[28] Page 32, *Inquiry into the east coast gas market*, April 2016 https://www.accc.gov.au/system/files/1074_Gas%20enquiry%20report_FA_21April.pdf

[29] Gas Supply Agreements

[30] Page 33, *Inquiry into the east coast gas market*, April 2016 https://www.accc.gov.au/system/files/1074_Gas%20enquiry%20report_FA_21April.pdf

During Q1 2018, the 2-month lagged price for Brent oil increased, closing more than AUD10/bbl higher than the previous quarter-close to AUD89.25/bbl. Increasing Brent prices were driven by stronger global demand which contributed to the unwinding of surplus oil stocks and the lifting of suppressed oil prices relative to mid-2017.

Figure 24 Brent oil price

Source: EIA for Brent oil price (USD/bbl). WM/Reuters FX Benchmarks for USD:AUD exchange rates

2.3 Gas supply

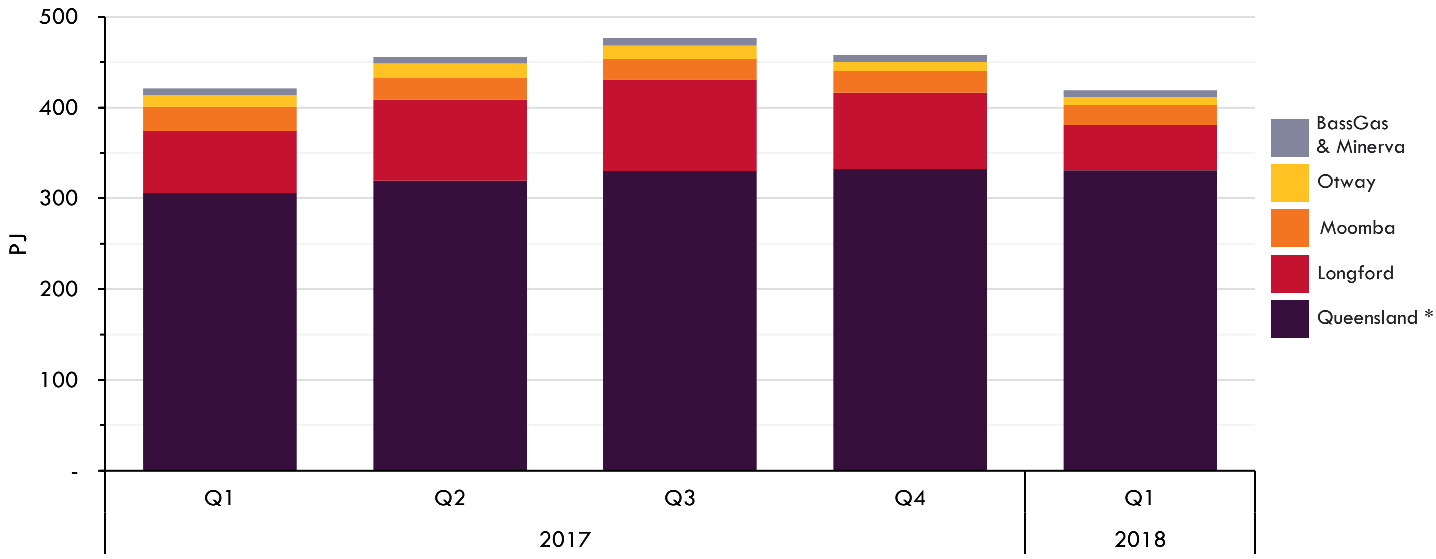
2.3.1 Gas production

East coast gas production of 419 PJ was recorded during Q1 2018 (Figure 25), the lowest quarterly production total since 2016.

Total production decreased 39 PJ when compared with Q4 2017, driven by:

- 40% reduction (-34 PJ) in production from Longford (Figure 26).
- A minor percentage reduction in Queensland production (-0.6%) however this still equates to a decrease of 2 PJ for the quarter.
- 14% reduction (1 PJ) in production from BassGas and Minerva.

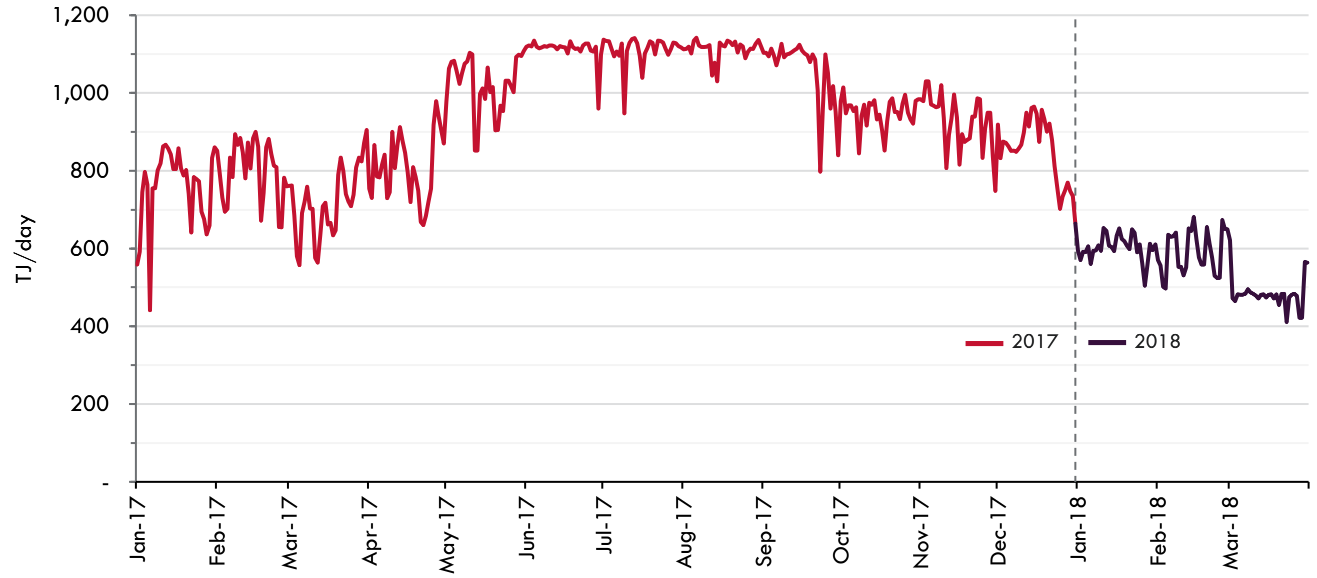
Figure 25 Production by gas plant



* The Queensland production is based on grouping all Gas Bulletin Board production facilities in the Roma Zone of the Gas Bulletin Board.

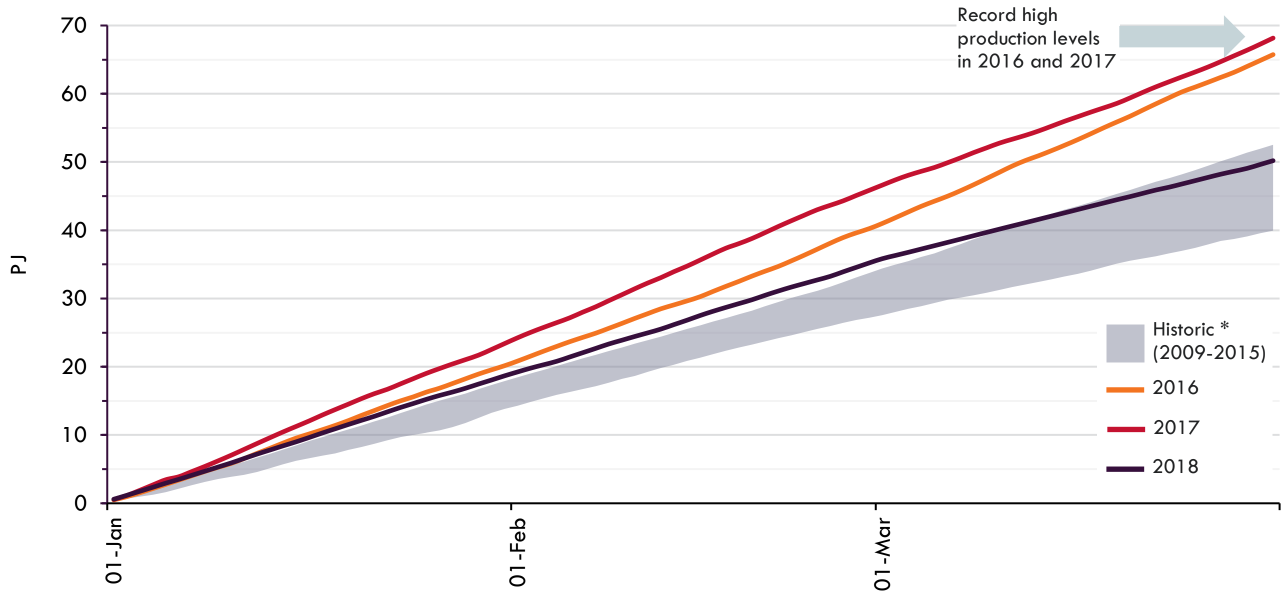
As foreshadowed by the ACCC Gas Inquiry[31] gas production from Longford decreased from Q4 2017 levels, averaging 558 TJ/d during Q1 2018, the lowest quarterly production total from Longford since 2015. Scheduled maintenance at Longford for the duration of March 2018 contributed to the lower production: production capacity was reduced to less than 500 TJ/d, a reduction of more than 50% from Longford's Gas Bulletin Board-listed capacity of 1,030 TJ/d.

Figure 26 Longford Gas Plant daily production



The step change in Longford gas production since 1 January 2018 appears significant in comparison to the record production years of 2016 and 2017. However production for Q1 2018 is consistent with the historical pre-record production years of 2009 to 2015.

Figure 27 Longford Gas Plant | Quarter 1 cumulative production | 2009 to 2018



* This series represents the highest and lowest cumulative production levels observed between 2009 and 2015

[31] ACCC, 2017-2020 Gas Inquiry: Interim report, p. 30, available at https://www.accc.gov.au/publications .

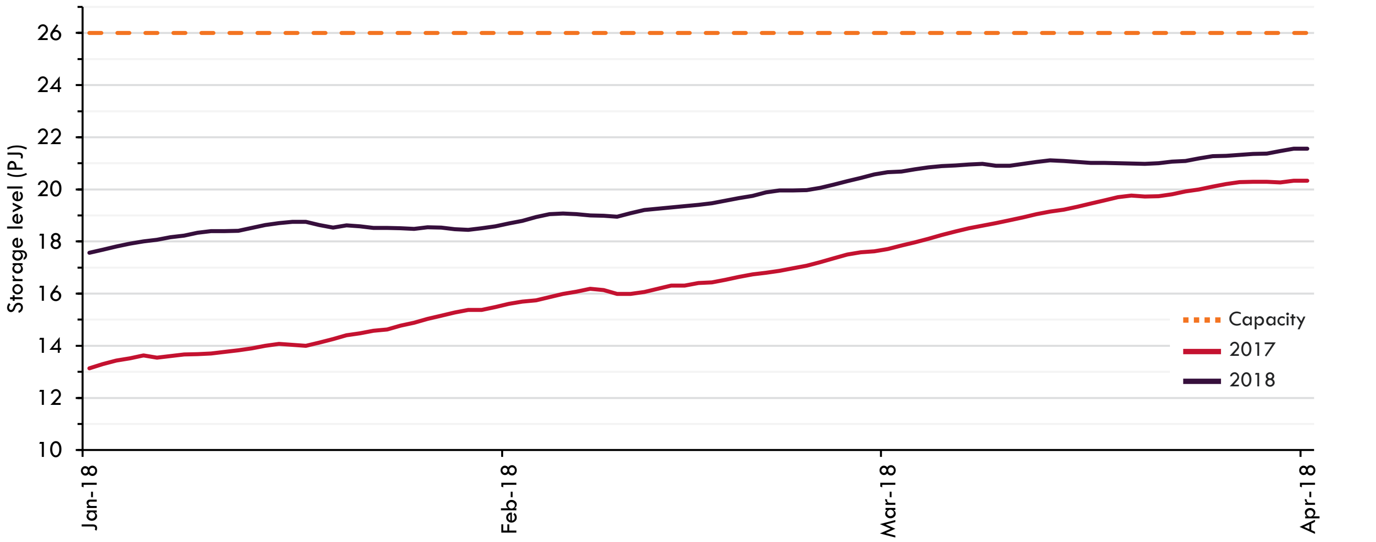
2.3.2 Gas storage

A gas inventory of 18 PJ was recorded at the Iona Underground Storage Facility (in Victoria) at the commencement of 2018. Net-injections into Iona of 4 PJ during the quarter were lower than Q1 2017 (by 3 PJ), driven by:

- Reduced Q1 2018 production from Longford and Otway.
- Volatility in wholesale electricity prices (see 1.4.1 above).

This resulted in a closing inventory of 21 PJ at the end of Q1 2018, a 1 PJ increase compared to 31 March 2017.

Figure 28 Iona Underground Storage Facility – storage levels

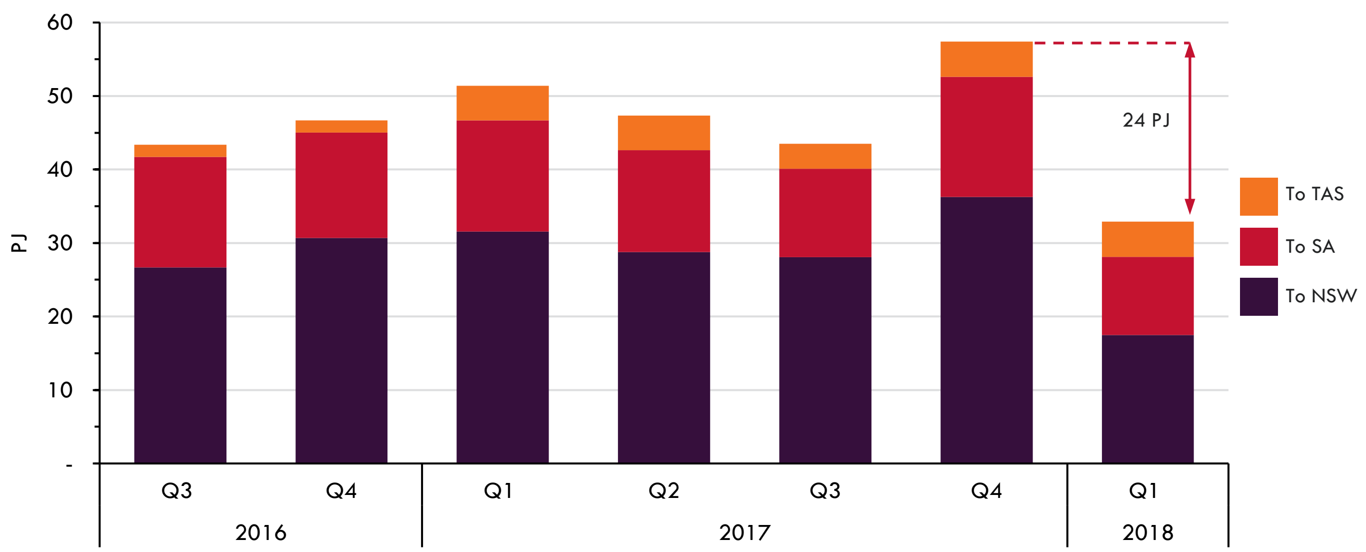


2.4 Pipeline flows

2.4.1 Reduced gas exports from Victoria to other states

Decreased Longford gas production has driven reduced Q1 2018 gas exports from Victoria to other states by 24 PJ (43%) when compared to Q4 2017 (Figure 29). Whilst quarterly deliveries along the Tasmanian Gas Pipeline remained consistent at 5 PJ, exports via the SEAGas pipeline to South Australia reduced by 53% to 11 PJ. Gas flows to the New South Wales STTM recorded the greatest decrease from Q4 2017, as deliveries along the Longford-sourced Eastern Gas Pipeline more than halved, contributing to a quarterly export total to New South Wales of 18 PJ.

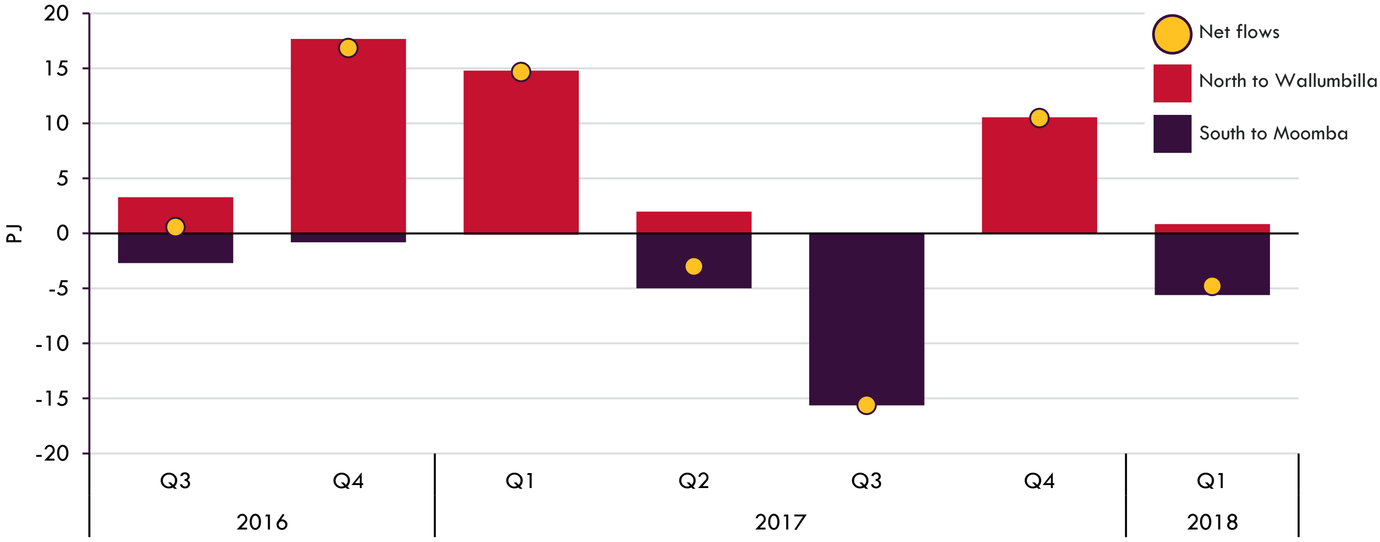
Figure 29 Victorian gas exports to other states



2.4.2 Changing net-directional flow along the SWQP

Recent seasonal trends of gas flowing north on the South West Queensland Pipeline (SWQP) towards Wallumbilla during summer and south towards Moomba during winter ended in Q1 2018 with a reversion to more normal north to south flows from Moomba. Quarterly net deliveries of 5 PJ flowed south on the SWQP to support southern markets coinciding with lower quarterly production from Longford (Figure 26).

Figure 30 South West Queensland Pipeline at Wallumbilla



Abbreviations

Abbreviation	Expanded name
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
BBL	Barrel
BNEF	Bloomberg New Energy Finance
CER	Clean Energy Regulator
CCGT	Combined cycle gas turbine
DWGM	Declared Wholesale Gas Market
FCAS	Frequency control ancillary services
FID	Final investment decision
GJ	GigaJoule
GPG	Gas-powered generation
GSH	Gas Supply Hub
HPR	Hornsdale Power Reserve (Tesla battery)
LGC	Large-scale Generation Certificates
LNG	Liquefied natural gas
MW	MegaWatt
MWh	MegaWatt hour
NEM	National Electricity Market
PJ	PetaJoule
PPA	Power purchase agreement
PV	Photovoltaic
RERT	Reliability and Emergency Reserve Trader
STTM	Short Term Trading Market
SWQP	South West Queensland Pipeline
TJ	TeraJoule
USD	United States dollars