



Quarterly Energy Dynamics

Q3 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 Q3 2018 (1 July to 30 September 2018). This quarterly report compares results for the quarter against other recent quarters, focussing on Q2 2018 and Q3 2017. 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.

DISCLAIMER

This document or the information in it may be subsequently updated or amended. This document does not constitute legal or business advice, and should not be relied on as a substitute for obtaining detailed advice about the National Electricity Law, the National Electricity Rules, the Wholesale Electricity Market Rules, the National Gas Law, the National Gas Rules, the Gas Services Information Regulations or any other applicable laws, procedures or policies. AEMO has made every effort to ensure the quality of the information in this document but cannot guarantee its accuracy or completeness.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this document:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this document; and
- are not liable (whether by reason of negligence or otherwise) for any statements or representations in this document, or any omissions from it, or for any use or reliance on the information in it.

VERSION CONTROL

Version	Release date	Changes
1	8/11/2018	Initial release
1a	15/11/2018	Minor correction: wind curtailment amount

Executive summary

Highlights for Q3 2018 include:

Mixed results for wholesale electricity prices, while wholesale gas prices increased across all markets

- Wholesale gas prices increased across all markets compared to Q3 2017 despite a year-on-year reduction in demand (largely due to reduced gas-powered generation (GPG) demand). Average quarterly gas prices in the Declared Wholesale Gas Market (DWGM) in Victoria and Brisbane's Short-Term Trading Market (STTM) were the second highest on record.
 - The price changes have coincided with: reduced supply from Longford compared to Q3 2017 (-19%); an increase in pipeline deliveries to Curtis Island for LNG export (+2.3%); and increasing international oil and gas prices. These changes were manifested in a shift in the price of gas injection offers across the DWGM and STTMs in Sydney, Adelaide and Brisbane: the quantity priced below \$8/GJ fell by 20% compared to Q3 2017.
- Mixed results for wholesale electricity prices compared to Q2 2018, with small increases in New South Wales, Queensland and Western Australia, and small decreases in Victoria and South Australia.
- 2019 electricity futures prices rallied over the quarter, particularly in Victoria and New South Wales. This coincided with: a reduction in hydro dam levels in mainland Australia; relatively high gas prices (coupled with some expectation of this continuing into 2019); forecasts of a hot and dry start to 2019;¹ and concerns over the potential delays to the connection of new renewable projects to the grid.

Record quarterly hydro output from Hydro Tasmania

- The quarter recorded the highest NEM hydro generation since 2013, underpinned by record quarterly hydro output from Hydro Tasmania, which contributed to:
 - Tasmania's wholesale electricity price reducing substantially (to \$43/MWh) as Hydro Tasmania changed its market offers to increase output. Practically, the change in bidding translated to an additional 1,000 MW offered below \$50/MWh compared to previous quarters – an 88% increase.
 - Comparatively high levels of inter-regional transfers north on Basslink and the Victoria to New South Wales interconnector. Total inter-regional transfers during the quarter were 18% higher than in Q2 2018, and were at their highest level since Q4 2016.

Increased penetration of variable renewable energy

- Over 1,200 MW of new large-scale solar and wind capacity began generating during the quarter. The amount of large-scale solar capacity that commenced generation during the quarter is higher than the NEM's entire large-scale solar capacity at the start of the year. This, coupled with favourable wind conditions, led to record quarterly variable renewable energy (VRE) output which contributed to:
 - GPG continuing its downward trend in 2018: year-to-date GPG at the end of Q3 2018 was at its lowest level since 2006 and 21% lower than in 2017. Q3 2018 was the first quarter on record in which wind output has exceeded GPG.
 - Quarterly NEM emissions reaching their lowest level on record, both in terms of total emissions and average emissions intensity.
 - An increased requirement for AEMO to intervene in the South Australian market in order to maintain the power system in a secure operating state, with around 10% of VRE output in the region curtailed over the quarter.

Other highlights included:

- NEM operational demand was flat compared to Q3 2017, with small shifts in industrial loads as well as significant small-scale PV capacity additions (which are increasingly influencing the demand profile).
- Separation of Queensland and South Australia from the rest of the NEM following a trip of the Queensland to New South Wales interconnector (QNI) on 25 August 2018. This event resulted in: approximately 1,110 MW of under-frequency load shedding in New South Wales, Victoria and Tasmania; and more than \$10 million in Frequency Control Ancillary Service (FCAS) costs on a single day, which was a key contributor to the highest quarterly FCAS costs since 2008.
- Record volumes were traded through the Gas Support Hub (HSH) during the quarter – an increase of 100% compared to the same period last year and a 61% increase on the next highest quarter.
- The South West Interconnected System (SWIS) reached over 1 GW of rooftop PV and solar farm capacity installed. High amounts of small-scale PV are resulting in falling minimum daytime demands as well as an increase in the occurrence of negative prices.

¹ Bureau of Meteorology 2018, *Climate outlook for October to December*. [online] www.bom.gov.au/climate/ahead/outlooks/archive/20180927-outlook.shtml

Contents

Executive summary	3
Highlights for Q3 2018 include:	3
1. Electricity market dynamics	5
1.1 Weather	5
1.2 Electricity demand	6
1.3 Electricity generation	8
1.4 Wholesale electricity prices	12
1.5 Inter-regional transfers	17
2. WEM market dynamics	19
2.1 Electricity demand	19
2.2 Wholesale electricity prices	21
3. Gas market dynamics	23
3.1 Gas demand	23
3.2 Wholesale gas prices	24
3.3 Gas supply	26
3.4 Pipeline flows	27
3.5 Gas Supply Hub	28
3.6 Gas – Western Australia	28
Abbreviations	30

1. Electricity market dynamics

1.1 Weather

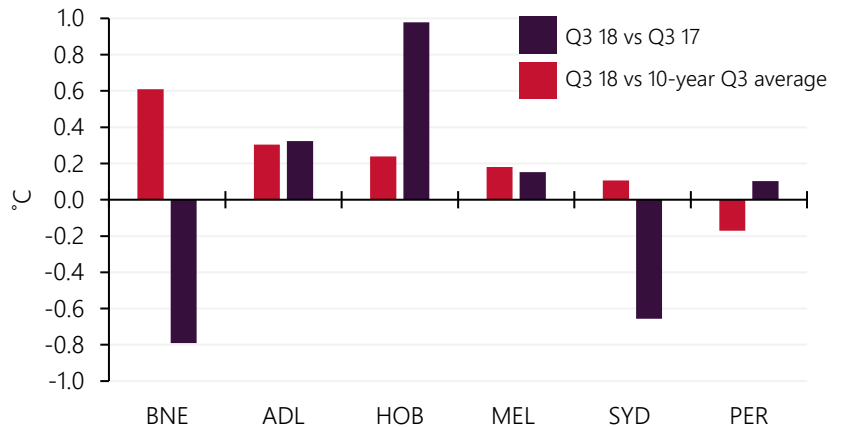
Temperature

The 2018 winter was the fifth warmest on record for Australia representing a continuation of warm weather trends seen over the past 12 months.²

Daytime temperatures were above the 10-year average across almost all of Australia, particularly in Queensland and New South Wales where average maximum temperatures ranked in the top 10% of historical observations. This was due in part to July 2018 being the second warmest July nationally with temperatures around 2°C warmer than the long-term average.

The end of the quarter saw a cold finish for parts of Eastern Australia, including some very cold overnight temperatures in Victoria and South Australia, which recorded their coolest average minima for September on record.

Figure 1 Average maximum temperature variance by capital city – Q3 2018 vs Q3 2017 and 10-year Q3 average



Source: Bureau of Meteorology

Compared to Q3 2017, the variation between cities was mixed. Average maxima fell in Brisbane and Sydney from the warmest on record in Q3 2017 but remained comparatively higher than the 10-year average. Hobart experienced warmer conditions this quarter than Q3 2017, which was comparatively cooler than the 10-year average (Figure 1).

Rainfall

Rainfall totals for the months of July and September were the lowest on record², representing a continuation of the dry conditions experienced across Australia for most of the year (Figure 2). A majority of the east coast experienced rainfall deficits in Q3 2018 with New South Wales significantly below average and in some parts of the state, the lowest on record (Figure 3). Tasmania, unlike the mainland, recorded above average rainfall in Q3 2018, particularly in western Tasmania.

Figure 2 Rainfall Deciles – January to September 2018

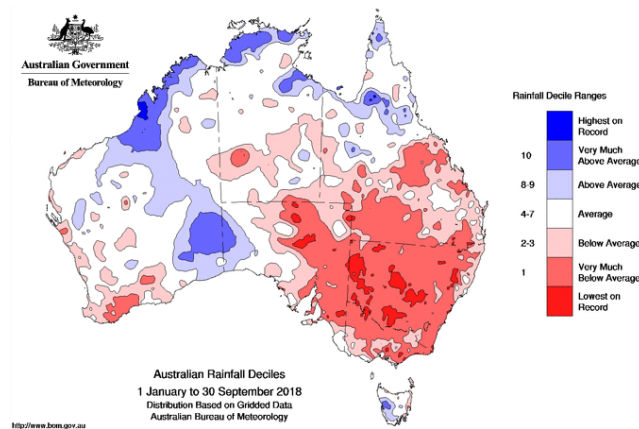
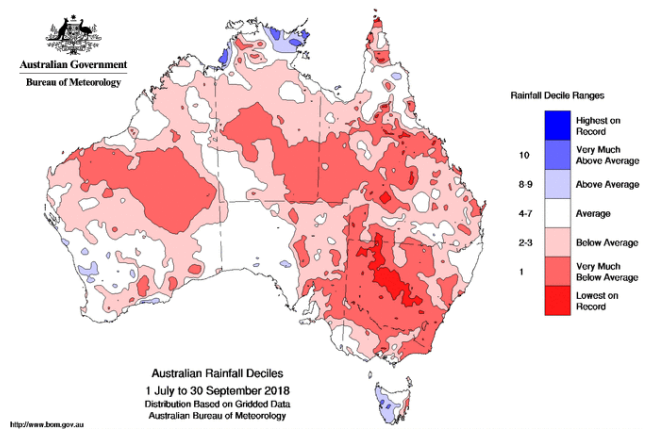


Figure 3 Rainfall Deciles – Q3 2018

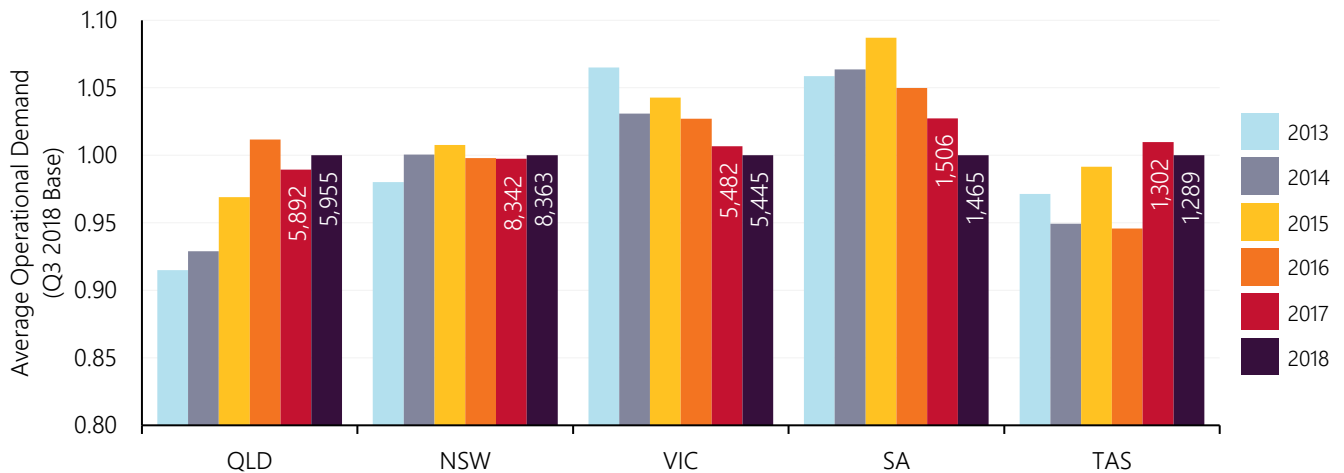


² BOM Climate summaries can be found at this link, click on the relevant month for more details: http://www.bom.gov.au/climate/current/statement_archives.shtml

1.2 Electricity demand

Electricity demand in Q3 2018 was flat in the NEM compared to Q3 2017 with small increases in average operational demand in the northern regions offset by decreases in the southern regions (Figure 4). Temperatures across the NEM this quarter compared to Q3 2017 were relatively similar, with warmer than average daytime temperatures and cooler overnight temperatures. Therefore, the overall changes in average demand across quarters were primarily a function of shifts in industrial loads, new connections and increasing small-scale PV generation.

Figure 4 Average operational demand for Q3 (2013 to 2018)



Note: Demand by region has been normalised with Q3 2018 as the base. Values greater than 1 indicate that demand was higher than in Q3 2018 while values less than one represent the opposite. Units within the columns are in MW.

From a regional perspective, average operational demand increased in Queensland (+64 MW) and New South Wales (+21 MW) due to more industrial load. Victoria’s average operational demand decreased (-37 MW) despite increased load from Portland Aluminium Smelter compared to Q3 2017³, highlighting the significant increase in PV generation over the quarter. In South Australia, plant issues at Olympic Dam⁴ and additional PV generation were factors in decreasing operational demand by 40 MW compared to Q3 2017.

While the overall movement in average demand varied geographically, one element was consistent across all NEM regions – the impact of small-scale PV in reducing operational demand in the middle of the day. Increased small-scale generation has the effect of offsetting consumption, thereby lowering the overall grid demand for electricity. This is a trend that has been increasing over time as the level of installed small-scale PV capacity continues to rise (see Section 1.3.4).

Maximum and minimum demand

Once again, South Australia’s quarterly minimum demand record was broken and equalled the all-time record low. The lowest Q3 operational demand occurred on 30 September 2018 at 1430hrs when operational demand reached 661 MW, 132 MW lower than the previous Q3 record of 793 MW. Drivers of this new record included increased uptake of small-scale PV in South Australia (see Section 1.3.4) as well as reductions in industrial load. Table 1 outlines the maximum and minimum demands observed during Q3 2018 and the respective regional records.

Table 1 Maximum and minimum demand (MW) by region – Q3 2018 vs records⁵

	QLD		NSW		VIC		SA		TAS	
	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min
Q3 2018	7,749	4,647	12,039	5,961	7,377	3,752	2,299	661	1,678	904
All Q3	8,212	2,972	14,289	4,636	8,351	3,601	2,530	793	1,790	792
All-time	9,798	2,894	14,744	4,636	10,576	3,217	3,399	661*	1,790	552

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

³ In Q3 2017, Portland Aluminium Smelter was in the final stages of restoring capacity that was lost following a power outage in December 2016. See: www.premier.vic.gov.au/portland-smelter-completes-restart/

⁴ www.abc.net.au/news/2018-08-20/technical-issues-at-bhp-olympic-dam-mine/10144692

⁵ Table records refer to those prior to the commencement of Q3 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.

1.2.1 Power system management

Queensland and South Australia system separation

On Saturday 25 August 2018, at 1311 hrs, the NSW-QLD interconnector (QNI) tripped, separating Queensland from the rest of the NEM.⁶ This also resulted in activation of the Heywood Emergency Control Scheme⁶ and separation of South Australia from the rest of the NEM. There was also approximately 1,110 MW of under-frequency load shedding in New South Wales, Victoria, and Tasmania. Market impacts included:

- The South Australia spot electricity price reduced to around -\$450/MWh, due to the loss of export to Victoria which caused a temporary excess of supply in South Australia. Prices rapidly recovered to pre-event levels.
- Queensland’s energy price increased to around \$1,400/MWh for a single dispatch interval.
- More than \$10 million in frequency control ancillary service (FCAS) costs incurred– all mainland regions recorded FCAS prices at the price cap of \$14,500/MWh (see Section 1.4.5).

Following the event, AEMO added QNI to its Vulnerable Transmission List with this status a matter of ongoing investigation.⁶ Practically, addition to the list means the transmission line is eligible to be reclassified as a credible contingency event during a lightning storm, which can reduce transfer limits and flows on the interconnector.

System strength

Over the quarter, AEMO intervened on multiple occasions to direct synchronous generation to remain online to ensure adequate system strength in South Australia and thereby maintain the grid in a secure operating state.⁷ On average, directions were in place for around 40% of the time during the quarter (Figure 5), with a cost⁸ of \$7.4 million, which was \$0.35 million higher than the prior quarter. This compares with directions in place for 50% of the time in Q2 2018 and 30% in the period since the system strength unit combinations were introduced in September 2017. Key drivers of system strength directions during the quarter included periods of relatively low prices (<\$50/MWh) and high wind output (>1,100 MW) which resulted in synchronous generators seeking to decommit from the market for commercial reasons.

During Q3 2018, total curtailments⁹ of non-synchronous generation (large-scale wind and solar farms) in South Australia increased to around 150 GWh (or 10% of South Australian non-synchronous generation) (Figure 6), with curtailment occurring for 26% of the time during the quarter. This was the highest amount on record and around 70 GWh higher than the next highest quarter (Q3 2017). Key drivers were record high wind generation (Section 1.3.4) and insufficient synchronous generators being available to meet system strength requirements.

Figure 5 Directions for system strength in South Australia

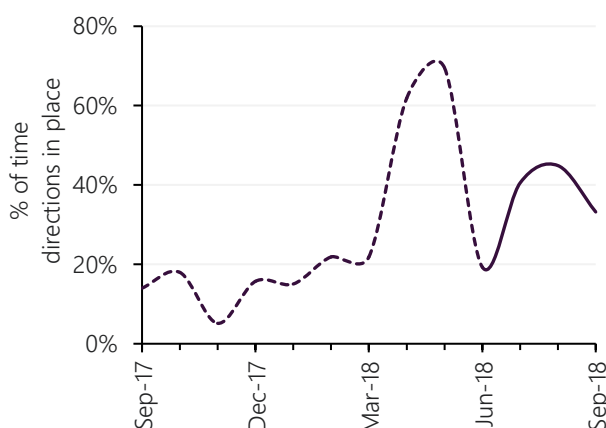
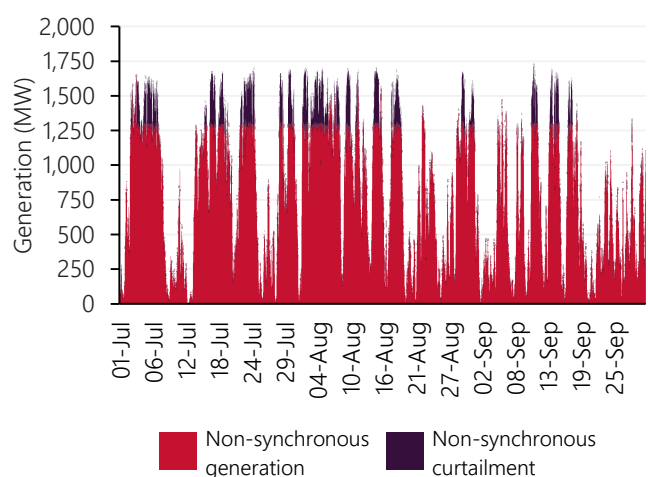


Figure 6 Generation and curtailment of non-synchronous units in South Australia



⁶ For further details see: AEMO 2018, *Preliminary Report – Queensland and South Australia system separation on 25 August 2018*. [online] www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2018/Preliminary-report-QLD-SA-System-Separation-25-August-2018.pdf

⁷ AEMO has specified combinations of synchronous generation units that would provide sufficient system strength. This is available at: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Limits-advice>

⁸ Based on Compensation Recovery Amount (provisional amount)

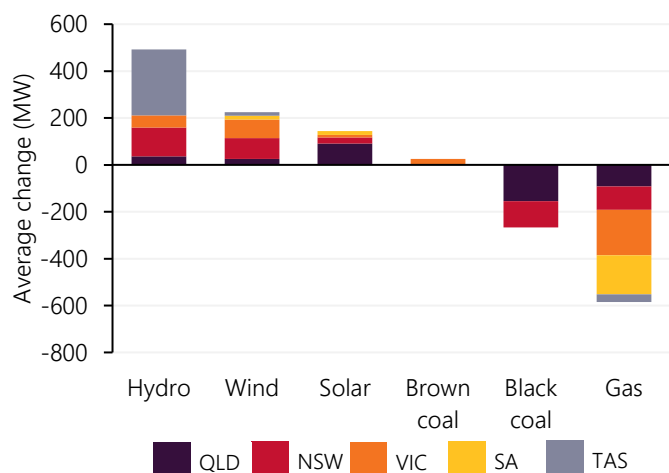
⁹ Based on the unconstrained intermittent generation forecast (UIGF). AEMO is required to prepare forecasts of the available capacity of semi-scheduled generators, in order to schedule sufficient generation in the dispatch process. This is known as the as the UIGF. AEMO estimates UIGF based on the outputs of the Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS). Further information is available at: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Solar-and-wind-energy-forecasting>

1.3 Electricity generation

In Q3 2018, renewable generation in the NEM reached record quarterly levels, comprising more than 20% of the supply mix for the first time on record. Compared to Q3 2017, combined hydro, wind and large-scale solar increased by approximately 850 MW on average, driven by new wind and solar capacity commissioned, as well as a continuation of comparatively high hydro output, particularly in Tasmania (Figure 7).

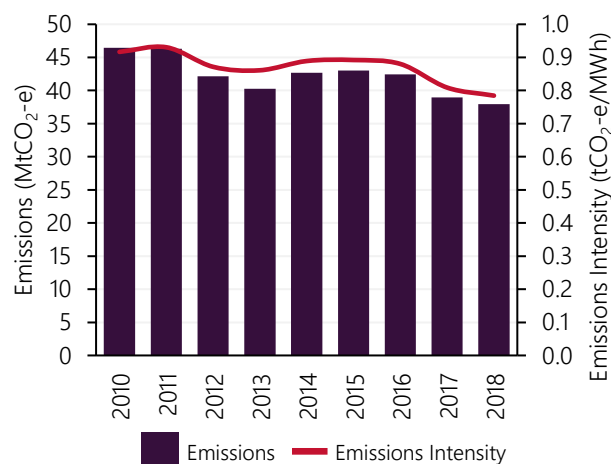
High renewable output contributed to a 584 MW reduction in GPG on average compared to Q3 2017, with quarterly wind output exceeding GPG for the first time. Due to the record renewable output, quarterly NEM emissions reached their lowest level on record, both in terms of emissions and emissions intensity (Figure 8).¹⁰

Figure 7 Change in supply – Q3 2018 vs Q3 2017



Note: Solar only includes large-scale solar

Figure 8 NEM Q3 emissions and emissions intensities



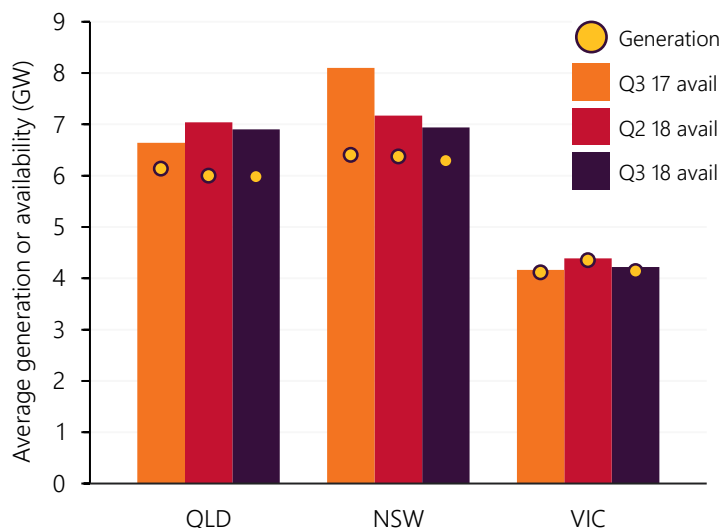
1.3.1 Coal-fired generation

During the quarter, average black coal-fired generation declined to its lowest level since Q4 2016, driven by:

- A comparatively high level of outages in the black coal fleet in New South Wales (Figure 9).
- Periods of lower spot electricity prices in Queensland leading to lower output from price-sensitive generators on these occasions.

The New South Wales fleet recorded its lowest availability since Q2 2016, largely due to extended unit outages at Bayswater and Vales Point power stations. Despite a 1,160 MW decrease in availability of New South Wales coal-fired generation, there was only a 110 MW reduction in actual output. This was achieved by in-service plant running comparatively harder – with over 700 MW of generation shifted from \$80-\$100/MWh price bands to \$60-80/MWh price bands.

Figure 9 Coal average availability and generation



Average generation from Queensland’s black coal-fired fleet reduced by 155 MW compared to Q3 2017 despite a 265 MW increase in average availability. The reduction in output was due to an increase in the duration of lower priced periods: Queensland’s wholesale price was below \$60/MWh 36% of the time during the quarter, compared to 15% of the time in Q3 2017. This contributed to reductions in average output at price sensitive generators including Tarong and Stanwell power stations (-249 MW and -160 MW, respectively), with Millmerran Power Station reducing average output by 268 MW due to lower availability.

Brown coal-fired generation was steady compared to Q3 2017, but reduced by 216 MW when compared to Q2 2018, largely due to reduce availability and output from Loy Yang A Power Station.

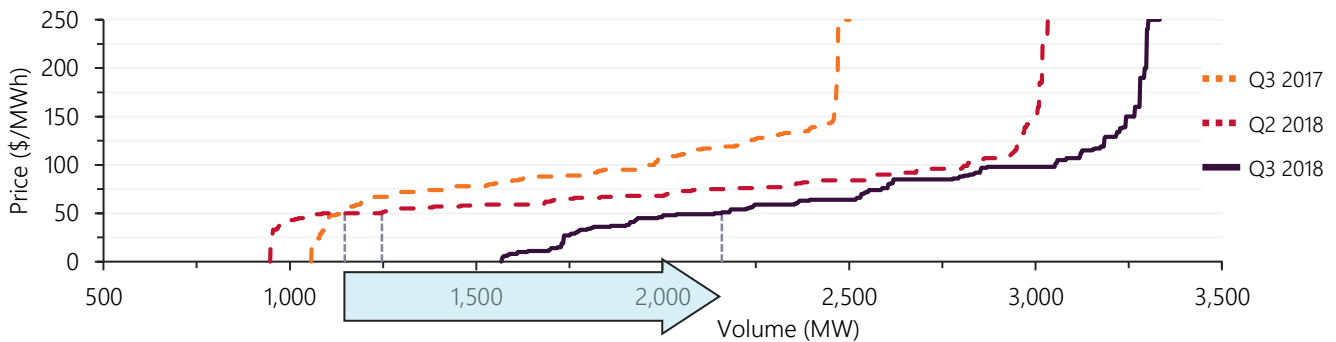
¹⁰ Based on AEMO’s Carbon Dioxide Equivalent Intensity Index. [online] www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Settlements-and-payments/Settlements/Carbon-Dioxide-Equivalent-Intensity-Index

1.3.2 Hydro generation

Q3 2018 represented the third highest quarterly hydro generation output since NEM start, with average output of 2,387 MW. This represented a substantial increase of 492 MW (+26%) on Q3 2017 output as well as a 164 MW increase on Q2 2018.

The largest increase in hydro generation occurred in Tasmania, which recorded its highest quarterly hydro output since joining the NEM. Cumulative hydro generation from Hydro Tasmania in 2018 to date is only 9% behind 2013 levels – a year of record generation from Hydro Tasmania where they created approximately 2.5 million Large-scale Generation Certificates (LGCs).¹¹ Above average Tasmanian rainfall in recent months resulted in some storage being close to capacity (Figure 11), contributing to Hydro Tasmania reducing the price of its energy offers in order to increase generation output. This translated to an additional 1,000 MW offered below \$50/MWh compared to previous quarters – representing an 88% increase (Figure 10).

Figure 10 Bid supply curve – NEM Hydro



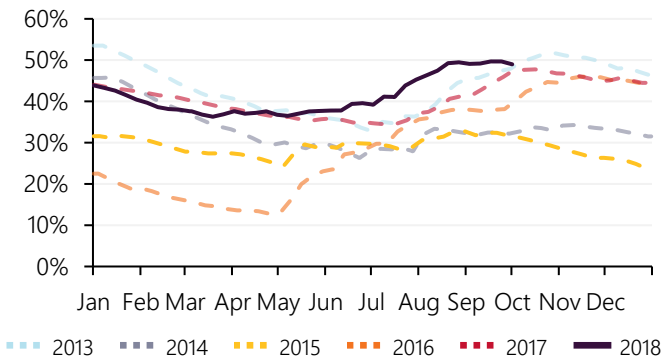
Hydro Tasmania’s increase in relatively low-priced generation also led to:

- Significant inter-regional transfer into Victoria via the Basslink interconnector (see Section 1.5).
- Reduced local wholesale electricity prices – in Q3 prices averaged \$43/MWh, well below other NEM regions (see Section 1.4).
- Changed offers into the FCAS market, with Hydro Tasmania prioritising dispatch in the energy market rather than the FCAS markets (see Section 1.4.5).

New South Wales and Victoria’s average hydro output remained comparatively high compared to Q3 2017 but was slightly down on the prior quarter. High levels of generation and below average rainfall this winter has depleted storage levels at Lake Eucumbene (the Snowy scheme’s main storage) to the lowest levels for this time of year since the Millennium Drought (Figure 12).

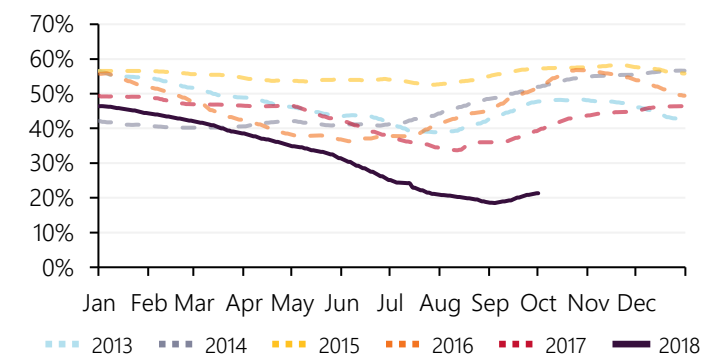
From September, there was a noticeable change in Snowy Hydro’s electricity offers where they increased the price of offers and thereby reduced output. The change in behaviour comes as the latest Spring outlook¹² suggests a possible El Niño event occurring in 2018 which, coupled with the relatively low storage levels at the end of this quarter, point to Lake Eucumbene likely starting 2019 from a below average level. Potential impacts of lower start of year storage levels include reduced Snowy generation in 2019 – this will most likely impact average generation levels (as opposed to reducing generation on an extreme day) and could be manifested in comparatively higher energy prices in 2019 (see Section 1.4.2).

Figure 11 Hydro Tasmania – Total Storage levels¹³



Source: Hydro Tasmania website

Figure 12 Snowy Hydro – Lake Eucumbene Storage level



Source: Snowy Hydro website

¹¹ www.parliament.tas.gov.au/ctee/Joint/Transcripts/PAC%20Energy%20Hearing%20QoN/Hydro%20-%20hearing%20of%2015%20August%202016%20QON%20responses.pdf

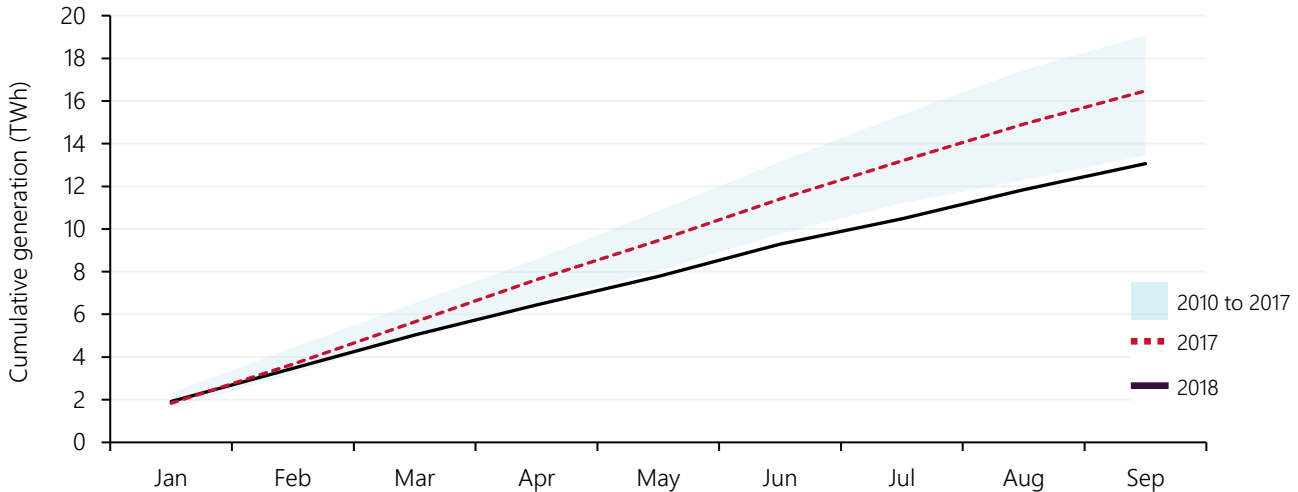
¹² Bureau of Meteorology 2018, *Climate outlook for October to December*. [online] www.bom.gov.au/climate/ahead/outlooks/archive/20180927-outlook.shtml

¹³ More detailed storage information can be found on the Hydro Tasmania website: <https://www.hydro.com.au/water>

1.3.3 Gas-powered generation

GPG continued its downward trend in 2018, with Q3 2018 representing the first quarter in which the NEM’s GPG was lower than wind output. Year-to-date GPG at the end of Q3 2018 was at its lowest level since 2006¹⁴ and 3.41 TWh (21%) lower than at the same time in 2017 (Figure 13).

Figure 13 Gas-powered generation | Q1 to Q3 cumulative generation | 2010 to 2018



Compared to Q3 2017, GPG reduced by approximately 584 MW on average, with reductions occurring in all NEM regions (Table 2). Drivers of reduced GPG included:

- Increased variable renewable energy (VRE) output, with Figure 14 illustrating the historical relationship between GPG and VRE output. Large-scale solar and wind farms typically bid in at prices at or below \$0/MWh (to ensure dispatch), which displaces the highest priced generator in the bid stack (which is frequently GPG).
- Comparatively high hydro output (Section 1.3.2), which can typically play a similar role in the merit stack to GPG (and thus displace GPG when operating at high levels).
- Higher wholesale gas prices across all east coast domestic markets (see Section Figure 36) which may influence GPG offers into the market. In Q3 2018, there was a 561 MW reduction in GPG offers priced below \$100/MWh on average when compared to Q3 2017.

Figure 14 Relationship between GPG and VRE output



Table 2 Average GPG output – Q3 18 vs Q3 17

Region	Q3 2017 (MW)	Q3 2018 (MW)	Change (MW)
QLD	575	483	▼ 92
NSW	339	239	▼ 100
VIC	414	221	▼ 193
SA	916	749	▼ 167
TAS	50	19	▼ 32
TOTAL	2,295	1,711	▼ 584

¹⁴ Made more significant by the fact there was a lot less GPG capacity in the NEM in 2006. GPGs that had yet to be commissioned in 2006 include: Braemar 2 (519 MW); Colongra (724 MW); Darling Downs (663 MW); Mortlake (584 MW); Tallawarra (440 MW); Uranquinty (664 MW).

1.3.4 Wind and solar generation

Compared to Q3 2017, average large-scale¹⁵ wind and solar generation in Q3 2018 increased from 1,887 to 2,255 MW (+20%), making up 10% of the supply mix over the quarter compared to 8% in Q3 2017 (Figure 15).

Average wind generation was up 224 MW and average large-scale solar generation increased by 144 MW as additional capacity was brought online. Since Q3 2017, 1,270 MW of large-scale solar capacity has commenced generation, with 697 MW starting generation in Q3 2018 alone (Table 3). The amount of large-scale solar capacity that commenced generation during the quarter is higher than the NEM's entire large-scale solar capacity at the start of the year. In addition, 500 MW of new wind capacity commenced generation in Q3 2018 – 41% in New South Wales, 35% in Queensland and 24% in South Australia.

Figure 15 Average wind and solar generation by region

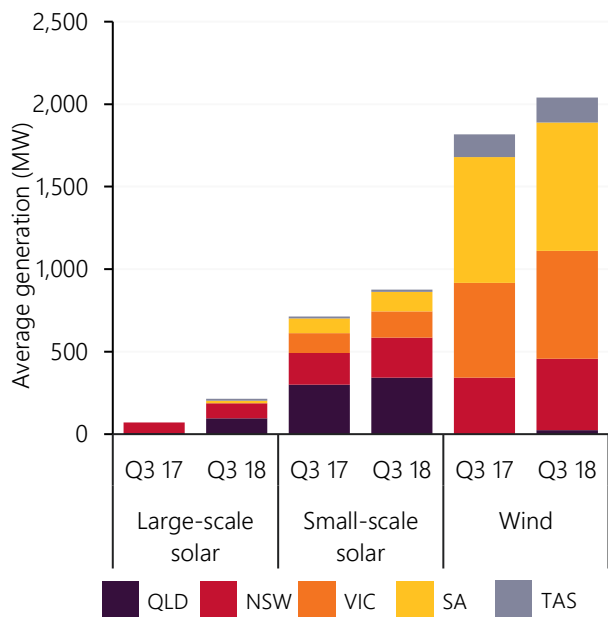
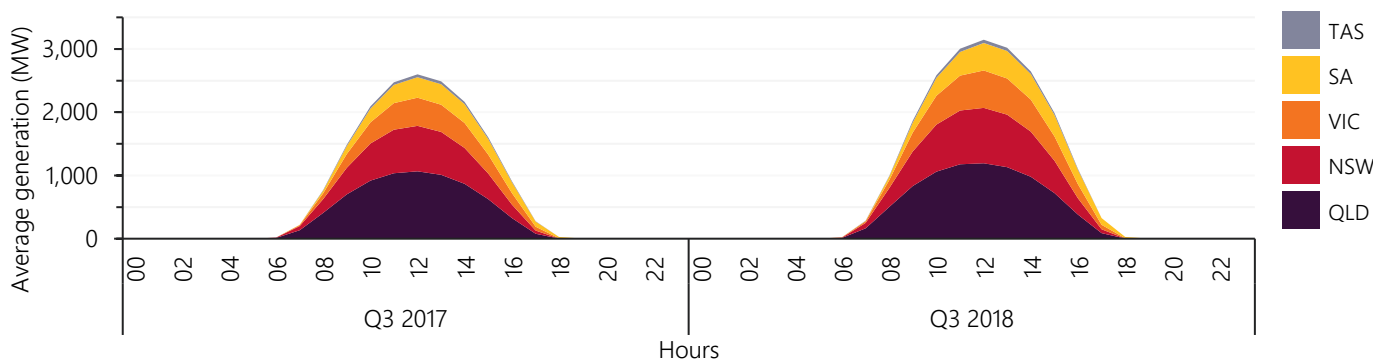


Table 3 New entrants¹⁶ in the NEM in Q3 2018

Region	New entrant	Capacity (MW)	Fuel Source
NSW	Bodangora	113	Wind
	Crookwell 2 Wind Farm	96	Wind
	Coleambally Solar Farm	150	Solar
QLD	Mount Emerald Wind Farm	178	Wind
	Collinsville Solar PV	40	Solar
	Darling Downs Solar Farm	108	
	Emerald Solar Park	72	
	Hamilton Solar Farm	56	
	Ross River Solar Farm	116	
SA	Whitsunday Solar Farm	56	Solar
	Willogeleche Wind Farm	119	
VIC	Bannerton Solar Park	99	Solar

Average Q3 2018 small-scale PV generation increased from 713 MW to 875 MW (+23%) when compared to Q3 2017. The largest increase was in South Australia and Victoria (+32%), with large increases also occurring in New South Wales (+25%), Tasmania (+18%) and Queensland (+15%). The average daily peak generation of small-scale PV¹⁷ increased from 2,714 MW to 3,285 MW (+21%) between Q3 2017 and Q3 2018 (Figure 16). Increases in generation correspond with a record amount of installed small-scale PV capacity over 2018, with the Clean Energy Regulator estimating that 1,600 MW will be installed by the end of the year, a 45% increase on the record capacity installed in 2017 (1,100 MW).¹⁸

Figure 16 Average daily small-scale solar generation profile



¹⁵ Large-scale generation includes market generators (a generator which sells all of its sent-out electricity through AEMO's market) and non-market generators with registered capacity equal to or greater than 30 MW.

¹⁶ Table includes new entrants that began generating during the quarter. Several of these projects are still undergoing testing and have yet to commence generating at full capacity.

¹⁷ The maximum small-scale PV generated across a 30-minute trading interval each day averaged across the quarter.

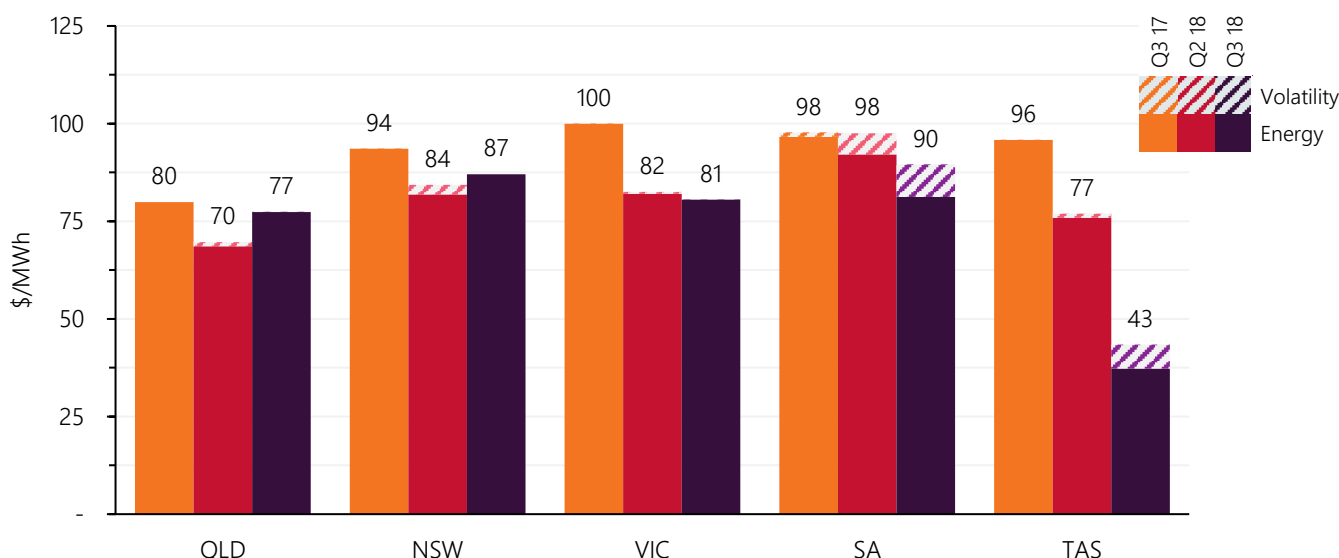
¹⁸ CER 2018, *Small-scale technology certificate market update - October 2018* [online] <http://www.cleanenergyregulator.gov.au/RET/Pages/About%20the%20Renewable%20Energy%20Target/How%20the%20scheme%20works/Small-scale%20technology%20certificate%20market%20updates%20by%20month/Small-scale-technology-certificate-market-update-%E2%80%93-October-2018.aspx>

1.4 Wholesale electricity prices

Apart from in Tasmania, there were relatively small movements in spot wholesale electricity prices in Q3 2018 compared to Q2 2018 (Figure 17). Queensland and New South Wales recorded price increases of \$7 and \$3/MWh respectively, with Victoria and South Australia decreasing by \$1 and \$8/MWh respectively. At \$43/MWh, Tasmania was the lowest priced region in the NEM by a significant margin.

Further to the changes noted above, average wholesale electricity prices were lower in all regions than in the corresponding period last year (Q3 2017). On the mainland, the two largest decreases were in Victoria (-\$19/MWh) and South Australia (-\$8/MWh). Lower prices in these regions were a function of temporal factors such as higher hydro output, as well as more persistent factors such as new supply from large-scale solar and wind coming online.

Figure 17 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.

Wholesale electricity price drivers in Q3 2018 compared to Q2 2018

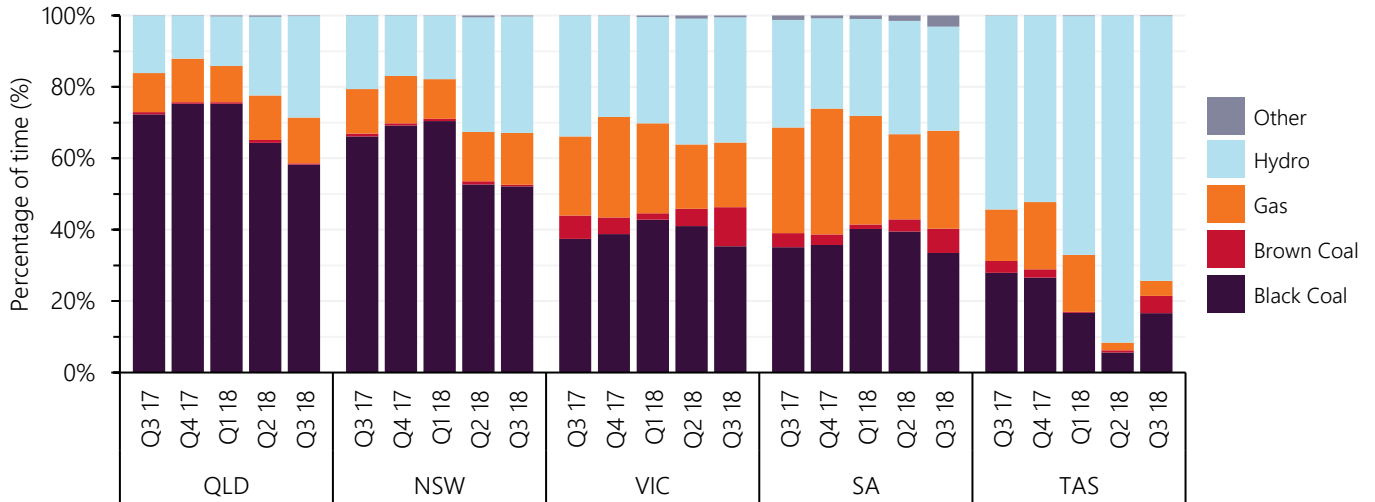
<p>Small price increase in Queensland and New South Wales</p>	<ul style="list-style-type: none"> • Reduced availability and generation from the black coal-fired fleet – see Section 1.3.1 for further details. • A shift in Queensland GPG offers into higher priced bands, as well as reduced availability. There was a 407 MW reduction in Queensland GPG price below \$100/MWh when compared to Q2 2018. This coincided with higher Queensland gas prices – see Section 3.2 for further details.
<p>Small price decrease in Victoria and South Australia</p>	<ul style="list-style-type: none"> • Record high wind output – see Section 1.3.4 for further details. • Increased imports into Victoria from Tasmania via Basslink due to high hydro generation – See section 1.5 for further details. <p>In South Australia, these factors were offset by increased price volatility over the quarter, with cap returns increasing from \$5/MWh to \$8/MWh. Most of the price volatility occurred during transmission network outages in July, which restricted flows on the Heywood interconnector in both directions, resulting in South Australia being increasingly reliant on local generation to meet demand.</p>
<p>Substantial price decrease in Tasmania¹⁹</p>	<ul style="list-style-type: none"> • Changed market offers from Hydro Tasmania to manage storage levels as well as inter-regional transfers on Basslink – see Section 1.3.2 for further details. • Basslink binding at its export limit for majority of the quarter, which resulted in the Tasmanian wholesale being set locally – see Section 1.5 for further details.

¹⁹ In Tasmania, the spot wholesale electricity price has less influence on wholesale electricity price pass through to retail prices than in other regions. This is due to regulation of Tasmanian wholesale electricity prices via Hydro Tasmania's wholesale contracts and application of Victorian wholesale prices. For further details see: www.economicregulator.tas.gov.au/electricity/pricing/wholesale-pricing/wholesale-pricing-history-and-overview

1.4.1 Price-setting trends

The wholesale price-setting dynamics in Q3 2018 were similar to those observed in Q2 2018 with the exception of Tasmania. Figure 18 highlights the changes in price setting outcomes of this quarter compared to Q2 2018 and Q3 2017.

Figure 18 Price-setting by fuel type – Q3 2018 vs prior quarters

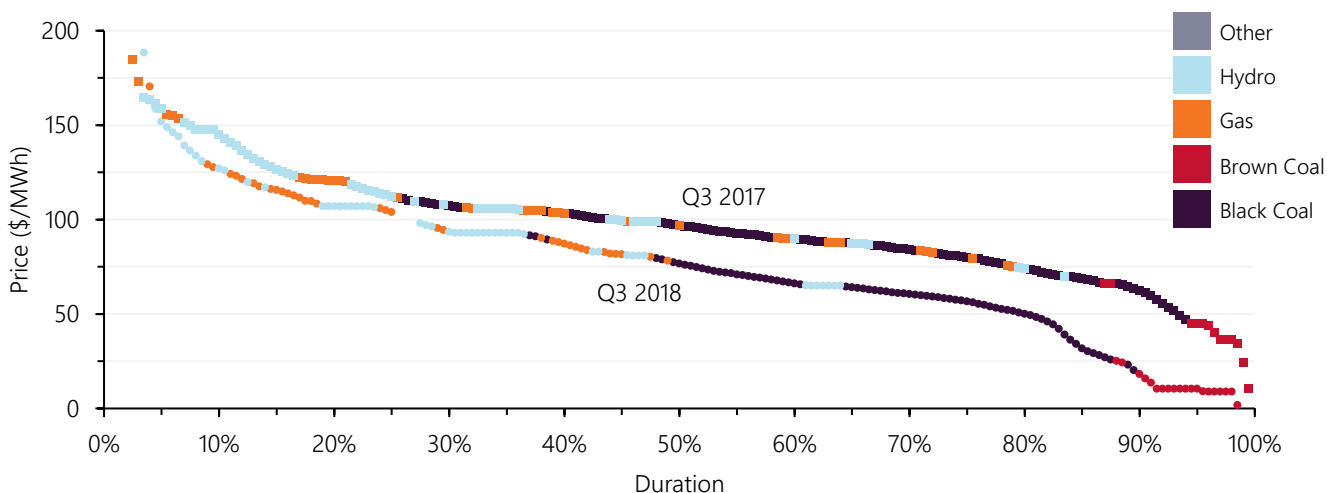


Note: Price setting can occur inter-regionally: for example, Victoria's price can be set by generators in other NEM regions.

On a regional basis:

- **Queensland and New South Wales** – black coal remained the dominant price setting fuel type in these regions where it set the price 52-58% of the time, but had a reduced price-setting role compared to recent quarters. Hydro continued to have an increased role in price-setting (around 30% of the time) with Snowy Hydro's Murray unit setting the price most frequently.
- **Victoria and South Australia** – compared to Q3 2017, Victoria's average price decreased from \$100/MWh to \$81/MWh. Most notably, prices were below \$25/MWh around 13% of the time compared to 1% in Q3 2017 (Figure 19). This was largely due to increased flows of lower priced generation from Tasmania effectively displacing comparatively higher priced offers from gas generators. This, coupled with periods of high wind output, contributed to brown coal units setting the price 11% of the time, the highest level since the closure of Hazelwood in Q1 2017. This increased price-setting role also extended to a lesser extent in South Australia and Tasmania. Whilst the frequency of hydro generation setting the price in the mainland NEM has remained consistent at around 34%, in Q3 2018 hydro set the price at lower levels than prior comparable quarters.
- **Tasmania** – with Basslink returning to service, the frequency of local price setting in Tasmania decreased by 20% when compared to Q2 2018. Despite this reduction, local generation in Q3 2018 still set Tasmania's price more often than in Q2-Q4 2017 due to Basslink binding north for the majority of the quarter (Section 1.5). In addition, due to Hydro Tasmania's shift in offers to lower prices, Tasmanian generation units played a reduced role in setting other regions' prices. In previous quarters, Tasmania set the Victorian and South Australian price around 15% of the time, however this quarter the percentage decreased to 3%.

Figure 19 Price duration curve by fuel type – Victoria – Q3 2018 vs Q3 2017



1.4.2 Electricity futures markets

In Q3 2018, the price of electricity futures contracts traded on the ASX rebounded strongly from the reductions that occurred in the first half of 2018 (Figure 20). The price increases occurred across both calendar year (Cal) 2019 and 2020 swap products, with the largest increases for Cal 2019 occurring in New South Wales (+14%) and Victoria (+13%, Table 4).

These price increases coincided with:

- A reduction in hydro storage levels on the mainland – dry conditions as well as Snowy Hydro’s comparatively high output year-to-date has resulted in reduced storage levels which has the potential to limit Snowy Hydro’s output in 2019 (see Section 1.3.2)
- Relatively high wholesale gas prices, coupled with some expectation of this continuing into 2019 (see Section 3.2.1).
- Concerns over the speed of connection of new renewable projects to the grid²⁰, which has the potential to slow deployment of the large pipeline of projects expected to come online in the coming years.
- Forecasts of hot and dry conditions for the start of 2019²¹ which could lead to hotter and drier conditions, intensifying the high demand periods over the peak summer period.

Figure 20 ASX energy – Calendar year 2019 swap prices by region

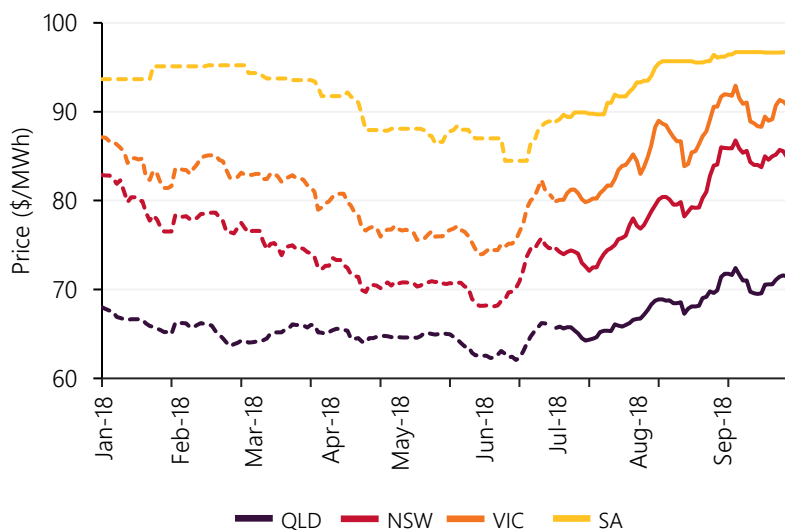


Table 4 Change over Q3 2018 for Cal 2019 and Cal 2020 swap prices

Region	Cal 19	Cal 20
QLD	+\$5.80 (9%)	+\$3.58 (7%)
NSW	+\$10.59 (14%)	+\$8.31 (14%)
VIC	+\$10.58 (13%)	+\$5.60 (9%)
SA	+\$7.76 (9%)	+\$0.74 (1%)

Q1 2019 cap prices were also up in Victoria (+31%), New South Wales (+25%) and South Australia (+13%), reflecting market sentiment regarding the heightened risk of price volatility over the upcoming summer. This is emphasised by the following comparison: Q1 2019 cap prices at the end of Q3 2018 were trading at a higher price than Q1 2018 prices in the lead up to summer last year.

1.4.3 International coal prices

The average Q3 2018 Australian dollar spot price for high quality Australian Newcastle thermal coal (6000 kcal) rose 15% compared to the previous quarter, averaging approximately \$160/tonne, its highest level since early 2011. This increase continues a longer-term trend with average quarterly prices up 50% since the beginning of 2017 and 130% since the beginning of 2016. More recent increases have been due to a depreciation of the Australian dollar relative the US dollar with the underlying US dollar 6000 kcal spot price flat over the quarter (-1%) with prices softening since highs reached at the end of July 2018. Strong underlying demand is displayed in the forward market, where coal futures prices remain above \$120 per tonne beyond 2018.²² The primary cause of maintained high prices appears to be ongoing strong power station demand from Asia coupled with the depreciation of the Australian dollar against the US dollar.²³ The price increase of premium coal contrasted with the price of lower quality coal (5500 kcal) which fell 4% over the quarter (Figure 21). 5500 kcal is the quality of coal used by Australian black coal generators in the NEM.

²⁰ RenewEconomy 2018, *AEMO’s Zibelman admits “hiccup” in new solar and wind connections*. [online] <https://reneweconomy.com.au/aemos-zibelman-admits-hiccup-in-new-solar-and-wind-connections-53241/>

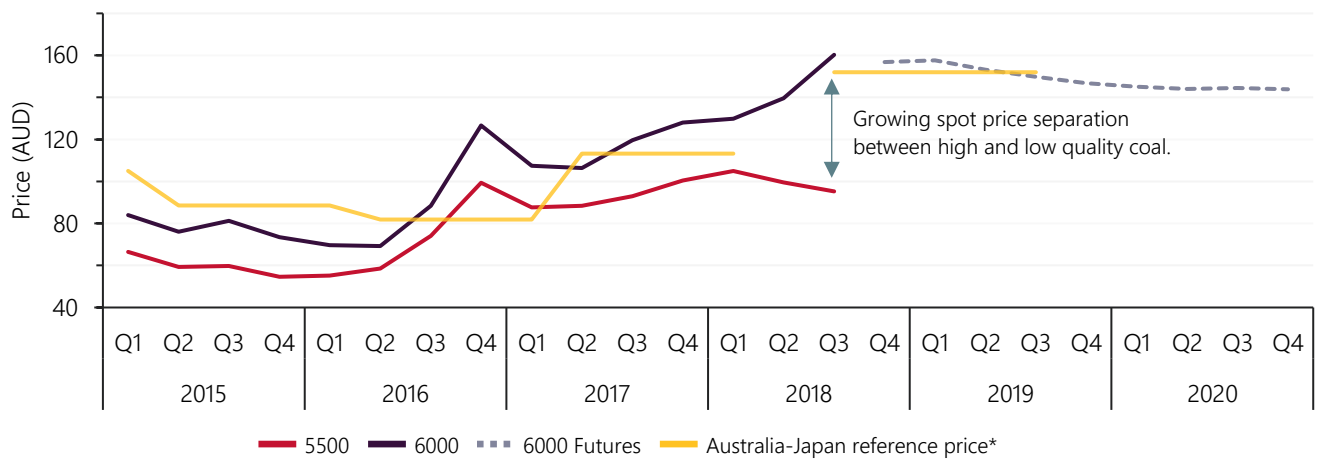
²¹ Bureau of Meteorology 2018, *Climate outlook for October to December*. [online] www.bom.gov.au/climate/ahead/outlooks/archive/20180927-outlook.shtml

²² Assuming the exchange rate at the end of Q3 2018 remains constant – AUD/USD: 0.7222

²³ Forbes 2018, *The Inconvenient Truth Of Rising Coal Prices*, [online] www.forbes.com/sites/timreadgold/2018/09/20/the-inconvenient-truth-of-rising-coal-prices/#1336b9c6b55c

While high international coal prices did not appear to directly affect operation of the majority of Australia’s coal-fired fleet over Q3 2018, continued high prices over the short to medium term have the potential to affect generation costs into the future. While much of Australia’s coal-fleet remain on legacy fuel contracts, any requirement for incremental coal (for example, due to contract expiration or support higher levels of production) will be potentially difficult to obtain due to rail congestion. High spot prices typically result in increased export volumes out of the Newcastle coal export terminals and an increase in the utilisation of the Hunter Valley rail network that connects coal mines with the terminal. Any black coal generator that relies on the Hunter Valley rail network for delivery of incremental coal will be doing so on a more constrained network.

Figure 21 Quarterly average international black coal spot, futures and contract prices



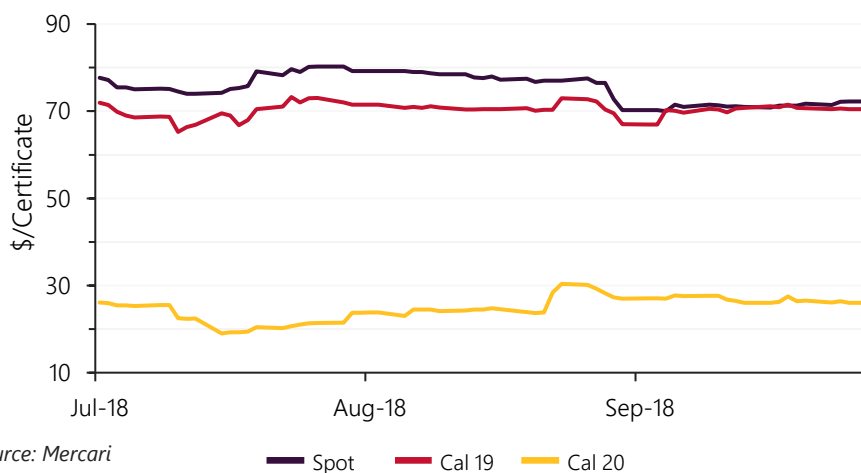
Source for Newcastle thermal spot and futures prices: Bloomberg

* Australia-Japan reference price refers to 12 month contracted price between Glencore and Tohoku Electric Power Co.

1.4.4 Environmental Markets

The LGC spot price fell 7% over Q3 2018 finishing the quarter just above \$70 per certificate. This continues the trend over 2018 to date – down 16% since January and likely reflects growing sources of LGC supply as new renewable generation commences (Section 1.3.4). Cal 18 and 19 contracts also fell slightly, and Cal 20 prices were flat over the quarter having already fallen 56% since January. The falling forward prices likely reflect growing market confidence that financed large-scale renewable projects will result in enough additional LGC supply for the 2020 Large-scale Renewable Energy Target to be met.²⁴ Q3 2018 average Small-scale Technology Certificate (STC) prices were down \$3, finishing the quarter at \$34.35 as record roof-top PV installations continue in 2018.²⁵

Figure 22 LGC spot and forward prices over Q3 2018



Source: Mercari

Table 5 LGC prices

Product	Change over Q3 18
Spot	▼ \$5.43 (7%)
Cal 18	▼ \$4.22 (5.5%)
Cal 19	▼ \$1.48 (2%)
Cal 20	▼ \$0.07 (0.29%)

²⁴ CER 2018, Large-scale Renewable Energy Target market data [online] <http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/Large-scale-Renewable-Energy-Target-market-data>

²⁵ CER 2018, Small-scale technology certificate market update - October 2018 [online] www.cleanenergyregulator.gov.au/RET/Pages/About%20the%20Renewable%20Energy%20Target/How%20the%20scheme%20works/Small-scale%20technology%20certificate%20market%20updates%20by%20month/Small-scale-technology-certificate-market-update-%e2%80%93-October-2018.aspx

1.4.5 Frequency control ancillary services

In Q3 2018 frequency control ancillary services (FCAS) costs were \$73 million²⁶ – the highest quarter since 2008 (Figure 23). Compared to Q2 2018:

- Regulation FCAS costs increased by \$2.8 million.
- Contingency Raise FCAS costs increased by \$1 million.
- Contingency Lower FCAS costs increased by \$4.8 million.

The increase in costs occurred despite a 17% reduction in FCAS demand compared to Q2 2018. Contributors to the increase in FCAS costs compared to Q2 2018 include:

- **Reduced hydro supply** – In Q3 2018 hydro generators such as Hydro Tasmania made offers to optimise energy dispatch rather than FCAS dispatch. In addition, the Jindabyne pump at Guthega and Wivenhoe Power Station (historically, two of the largest providers of Raise FCAS) did not provide any FCAS supply during the quarter. These factors led to a halving of Raise FCAS supply from hydro generators (Figure 24), erasing the effect of additional supply that came online in late 2017 and early 2018 (Hornsedale Power Reserve and demand response).
- **High priced event** – more than \$10 million in FCAS costs accumulated on 25 August 2018 due to the trip of the QNI interconnector and subsequent separation of Queensland and South Australia from the rest of the NEM (Section 1.2.1). During this period, AEMO required provision of local FCAS in Queensland and South Australia: due to the limited local FCAS providers on this day, very high prices and costs occurred in all NEM regions (particularly in Queensland).

Figure 23 Quarterly FCAS costs by service

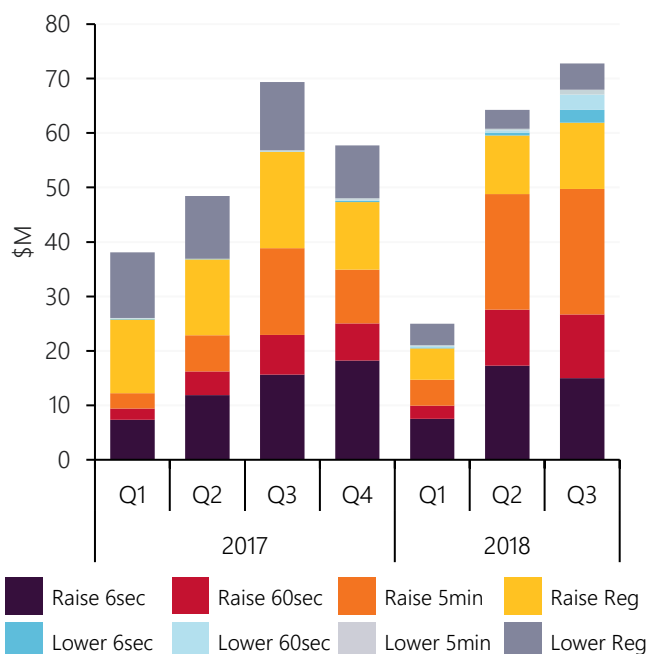
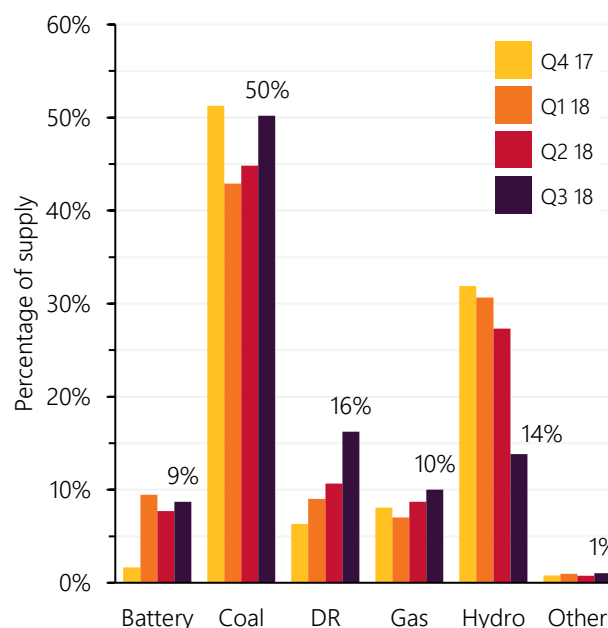


Figure 24 Raise FCAS enabled by fuel type



Of note, during the quarter AEMO announced that the South Australian 35 MW FCAS constraint²⁷ would no longer be applied from 12 October 2018 onwards.

Historically, during times of local requirements, South Australian FCAS prices have been very high due to the limited number of suppliers of these services in the region. AEMO estimates that the 35 MW FCAS constraint added more than \$100 million in FCAS costs over 2016 and 2017, with reduced impact in 2018 following entry of Hornsdale Power Reserve into the FCAS markets, as well as a reduction in the time in which the constraint has been applied.²⁸

²⁶ Represents preliminary data and subject to minor revisions.

²⁷ For system security purposes, AEMO required 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.

²⁸ AEMO 2018, *Quarterly Energy Dynamics – Q1 2018*. [online] www.aemo.com.au/Media-Centre/AEMO-publishes-Quarter-Energy-Dynamics---Q1-2018

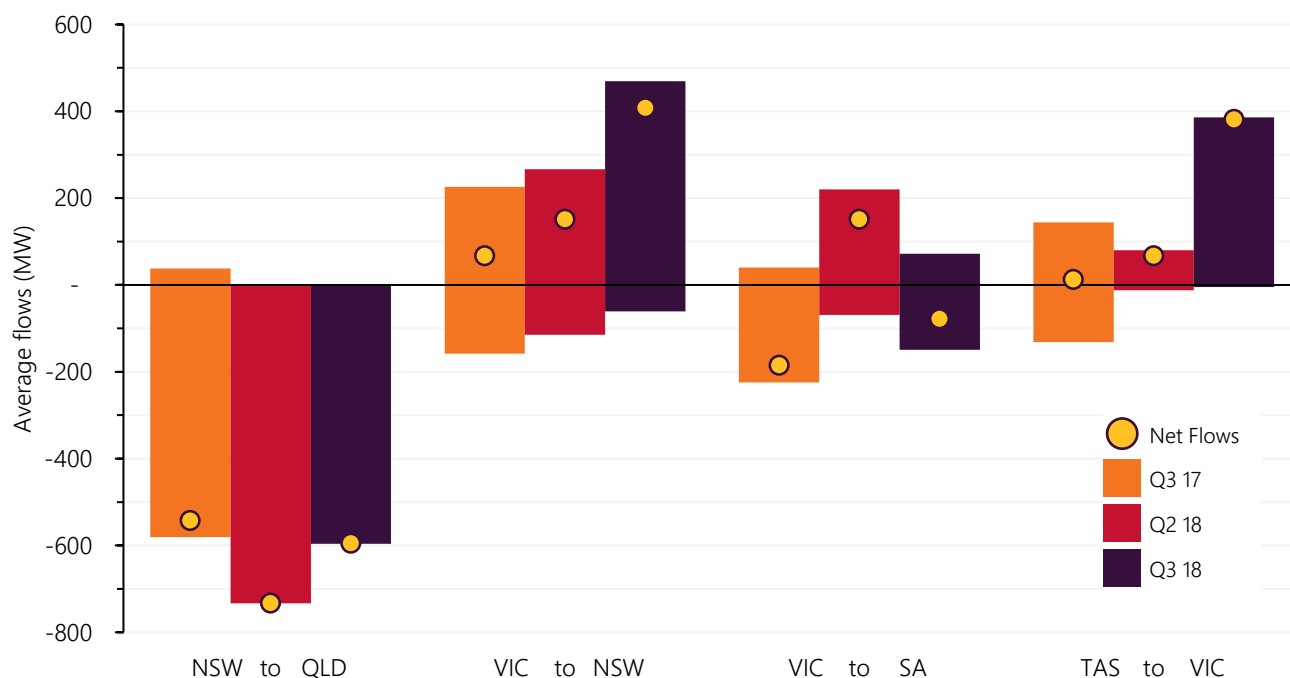
1.5 Inter-regional transfers

Total inter-regional flows during the quarter increased to 3.9 TWh (+18% compared to Q2 2018), representing the highest level since Q4 2016. This was primarily a function of: increased interconnector availability; strong flows north on Basslink; and significant imports into New South Wales.

By regional interconnector²⁹ (Figure 25):

- Tasmania to Victoria (Basslink)** – with Basslink returning to service for the entire quarter and record output from Hydro Tasmania, Basslink flowed almost exclusively north into Victoria at near record levels (net 382 MW on average). Flows north reached the export limit for the majority of the quarter, contributing to electricity price separation between Tasmania and Victoria (see Section 1.4), with Tasmania’s price set locally 68% of the time.
- New South Wales to Queensland** – Inter-regional transfer was almost exclusively south into New South Wales at relatively high levels (net 581 MW on average), although reduced by 137 MW against Q2 2018 levels, due to a reduction in Queensland GPG (see Section 1.3.3). Average QNI import limits for southerly flows were slightly higher (+39 MW) than in Q2 2018, and there was a 66% reduction in time in which flows south reached or exceeded the import limit, contributing to reduced price separation between the regions (Section 1.4). This is illustrated in inter-regional price setting: Queensland’s price setting by local generators fell to 35% (from 47% in Q2 2018) due in part to QNI reaching its transfer limit less frequently.
- Victoria to New South Wales** – with record high wind output, as well as record hydro output in Tasmania, prevailing inter-regional transfer was north into New South Wales at the highest levels (net 412 MW on average) since the closure of Hazelwood Power Station. These flows were also a function of reduction black-coal fired power station availability in New South Wales (see Section 1.3.1). Flows north on the interconnector reached the export limit 21% of the time during the quarter, up from 9% of the time in Q2 2018.
- Victoria to South Australia** – quarterly electricity transfers between these two regions reduced by 24% compared to Q2 2018, largely due to transmission network constraints affecting the Heywood Interconnector. Transmission network constraints (mostly in July and August) reduced the average export and import limits by around 20-30% for the quarter, with flows on the interconnector reaching these limits for 27% of the time (up from 10% in Q2 2018). The prevailing flow for the quarter was 78 MW into Victoria, largely driven by high South Australian wind output.

Figure 25 Quarterly inter-regional transfers in the NEM³⁰



²⁹ For simplicity, where there are multiple interconnectors between two regions results for these interconnectors are taken in aggregate.

³⁰ Positive transfers are denoted for: New South Wales transfers into Queensland; Victorian transfers into New South Wales and South Australia; Tasmanian transfers into Victoria.

1.5.1 Inter-regional settlement residue and settlement residue auctions

Inter-regional settlement residue (IRSR) is the product of the difference in the wholesale electricity prices between two regions and the quantity of electricity flowing over an interconnector between those two regions.³¹ IRSR is generally:

- **Positive** when electricity flows from a lower-priced region to a higher-priced region (which is typical). Settlement Residue Auctions (SRAs) provide participants access to positive IRSR by enabling them to bid for entitlements to a proportion of the total IRSR in advance. Participants can use these units to hedge against high prices on an inter-regional basis, however unlike conventional financial products (such as swap or cap contracts) they do not provide a firm hedge.
- **Negative** when electricity flows from a higher-priced region to a lower-priced region (also known as counter price flow). Consumers in the lower-priced region, which is importing electricity, pay for the negative IRSRs through their network charges.

Despite the comparatively high levels of inter-regional transfers noted in Section 1.5, the IRSR value this quarter was only slightly higher than recent quarters (Figure 26). This was driven by: a narrowing of the electricity price spread between regions (due in part to limited price volatility); reduced returns on the NSW-QLD interconnectors due to lower flows and price separation; and Basslink not being included in IRSR value.³²

AEMO estimates that more than \$40 million of residue accrued on Basslink, due to the comparatively high transfers as well as significant price separation between Tasmania and Victoria (see Section 1.4). Under current arrangements, this residue is allocated to Hydro Tasmania.

Figure 27 shows net returns for holders of SRA units in recent quarters. In general, participants have paid a higher price for these units than the eventuating quarterly IRSR returns, resulting in net losses for these units.³³ This occurred in Q3 2018, with net losses of \$6.9 million, largely due to losses associated with units that were purchased for VIC-SA flows prior to the closure of Hazelwood. Participants holding units for Q3 2018 VIC-NSW flows made net returns of \$12.5 million, most likely due to larger than expected flows into New South Wales.

Figure 26 Quarterly positive IRSR value³²

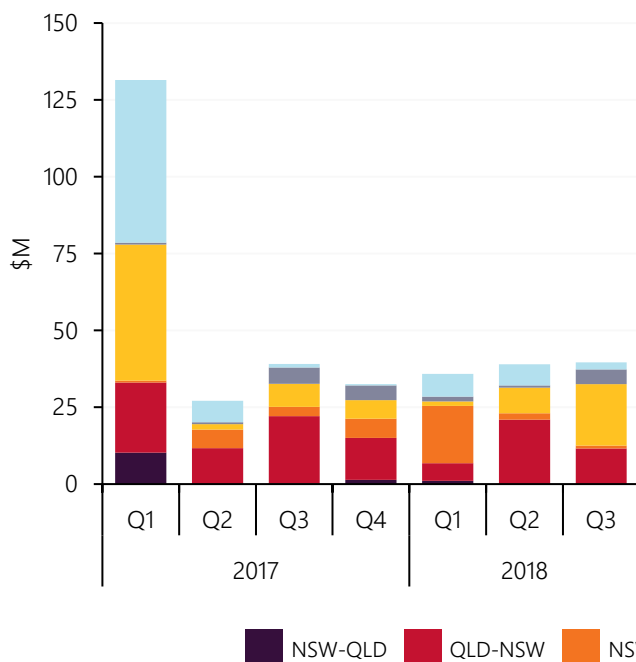
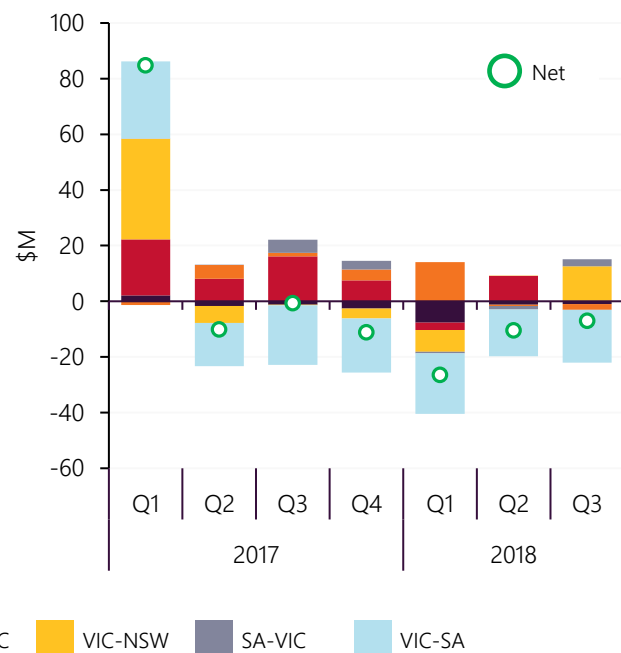


Figure 27 Quarterly SRA unit returns³⁴



³¹ For further details on IRSR and SRA units see: AEMO 2018, *Guide to the Settlements Residue Auction*. [online] www.aemo.com.au/-/media/Files/Electricity/NEM/Settlements_and_Payments/Settlements/2018/Guide-to-the-Settlements-Residue-Auction.pdf

³² All interconnectors, except for Basslink are regulated interconnector. Positive IRSR from regulated interconnectors is distributed to holders of SRA units purchased prior to the quarter. Under current arrangements residue from Basslink is allocated to Hydro Tasmania.

³³ Noting that SRA units may be used in a broad portfolio of risk management products, so SRA unit losses may be made up by gains from other futures products.

³⁴ Unit returns based on the weighted average cost per unit. The cost for units will vary across the twelve separate SRA tranches sold per quarter.

2. WEM market dynamics

2.1 Electricity demand

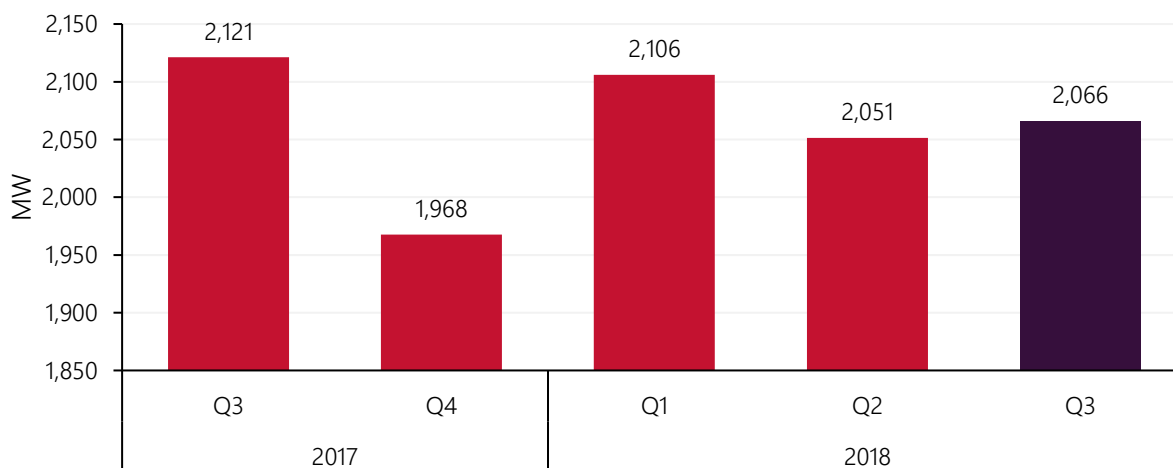
2.1.1 Weather

Average maximum temperatures in Perth during Q3 2018 were on par with Q3 2017 (+0.1°C). The average solar exposure in Q3 2018 was higher than in Q3 2017 (+0.7 MJ/m²) and the long-term Q3 average (+0.4 MJ/m²), contributing to increased generation from solar capacity.

2.1.2 Average demand

In Q3 2018, average demand³⁵ in the WEM remained relatively stable compared to Q2 2018 (15 MW increase or +0.7%) but decreased by 55 MW (or -3%) relative to Q3 2017 (Figure 28). The main driver for this decrease has been the rapid and significant increase in installed solar photovoltaic (PV) capacity in the WEM which has reduced the underlying system demand (see Section 2.1.4).

Figure 28 WEM average operational demand



2.1.3 Maximum and minimum demand

During Q3 2018, the WEM experienced its lowest year-to-date demand, with demand decreasing to 1,275 MW at 1230hrs on 30 September 2018 (Table 6). This was the lowest Q3 demand since 2009 and was only 102 MW higher than the all-time minimum demand since WEM commencement, driven by the increase in small-scale PV capacity.³⁶

Table 6 WEM maximum and minimum demand (MW) – Q3 2018 vs records³⁷

MAXIMUM DEMAND (MW)			MINIMUM DEMAND (MW)		
Q3 2018	All-time	All Q3	Q3 2018	All-time	All Q3
3,251	4,006	3,418	1,275	1,173	1,177

³⁵ 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 recorded since WEM commencement.

³⁶ The Wholesale Electricity Market of Western Australia commenced on 21 September 2006.

³⁷ Table records refer to those prior to the commencement of Q3 2018. Instances where the previous record has been broken are shown with red text. The records go back to when the WEM commenced.

2.1.4 Increasing small-scale PV capacity

In August 2018, the SWIS reached approximately 1 GW of installed solar photovoltaic (PV), both small- and large-scale (Figure 29). Installed solar PV capacity increased by 198 MW (or 25%) in the 12 months from Q3 2017 to Q3 2018. This increase in solar PV has reduced the underlying system demand during the daytime driving changes to WEM minimum demand trends.

The WEM has historically experienced minimum demand overnight in the off-peak period. In Q3 2018 however, the WEM saw an increase in the occurrence of minimum demand occurring during the daytime on-peak period 0800hrs to 2200 hrs. There were 24 days in Q3 2018 with daytime minimums compared to 19 days in Q2 2018 and 12 days in Q3 2017 (Figure 30).

Figure 29 WEM small-scale PV installed³⁸

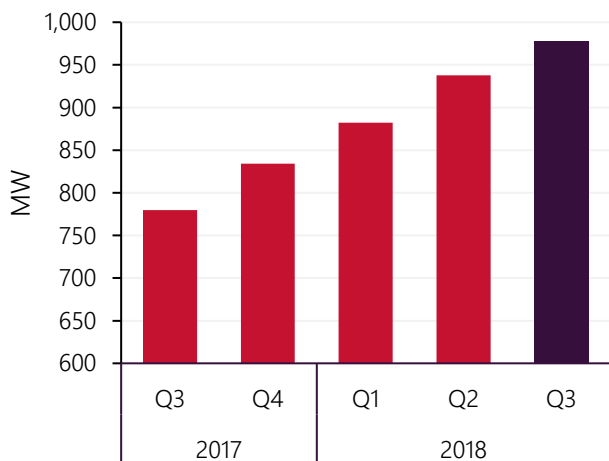
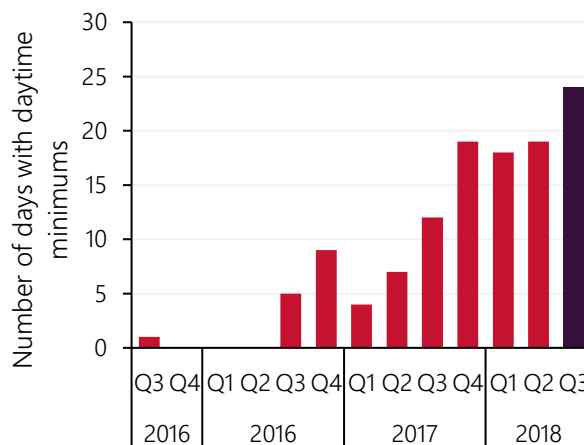


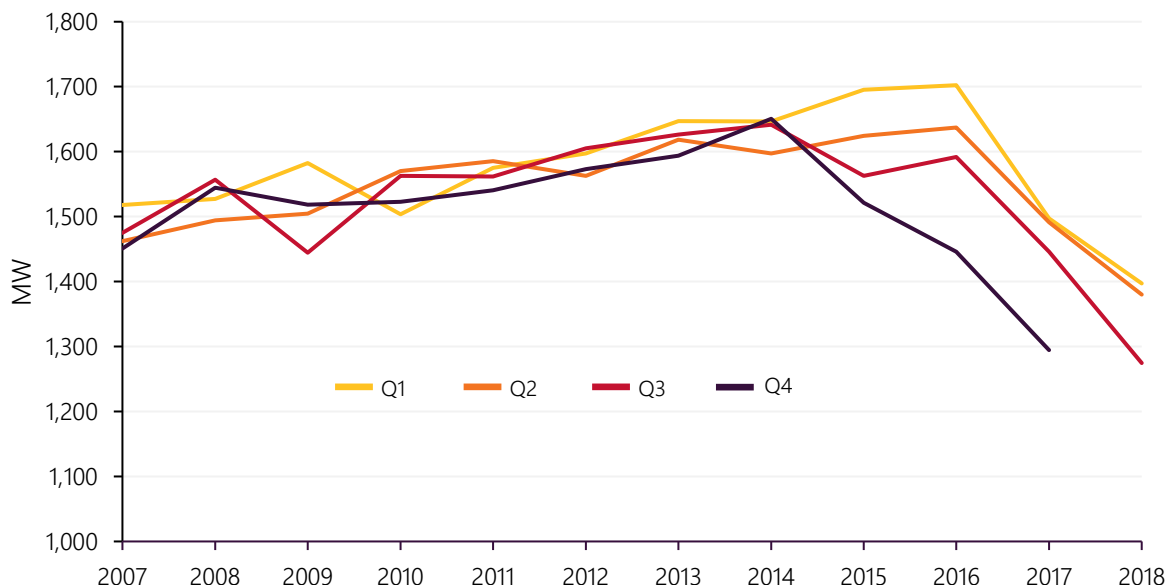
Figure 30 WEM – daytime minimum demand trends



Source: Clean Energy Regulator

Q3 2018 marked a continuation of falling minimum daytime demand across all quarters, which has been occurring since 2016 (Figure 31). During the quarter, the increase in small-scale PV capacity, combined with an above average solar exposure (Section 2.1.1) resulted in the minimum daytime demand falling by 171 MW compared to the same period last year. Variations in underlying demand across the quarters are due to steadily increasing solar PV capacity quarter to quarter, the seasonal changes in solar irradiance and associated solar PV output.

Figure 31 WEM trend of minimum daytime demand



³⁸ Based on data from the Clean Energy Regulator as at 30 October 2018.

2.2 Wholesale electricity prices

The average wholesale electricity prices in both the Balancing Market and Short Term Energy Market (STEM) increased by 9% in Q3 2018 compared to Q2 2018 (Figure 32). With stable average demand between quarters (Section 2.1.2), the main contributor to higher prices in Q3 2018 was a decrease in the availability of baseload coal-fired power stations due to a higher number of planned outages. Availability of baseload generation in Q3 2018 was 87% compared to 92% in Q2 2018 (Figure 33).

Conversely, average prices in both the Balancing Market and STEM decreased significantly in Q3 2018 compared to the same time last year, reducing by \$12.7/MWh (or 19%) and \$11.2/MWh (or 18%) respectively. This was a function of lower average demand (-56 MW or -3%) and higher availability of mid-merit generation facilities during that quarter.

The Synergy Balancing Portfolio, which has majority market share, set the Balancing Market price for 74% of trading intervals in Q3 2018 compared to 79% of trading intervals in Q3 2017.

Figure 32 WEM wholesale electricity prices

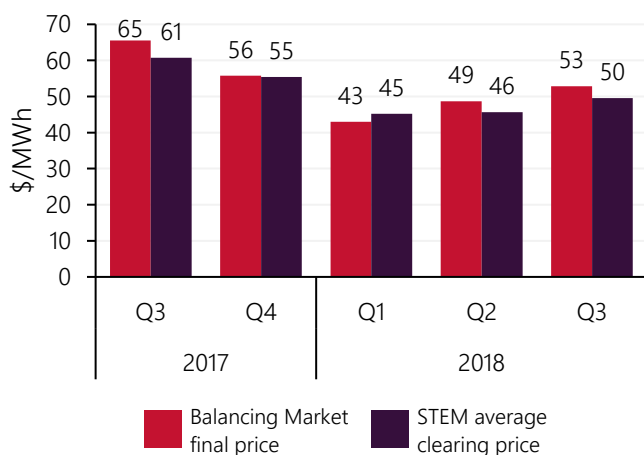
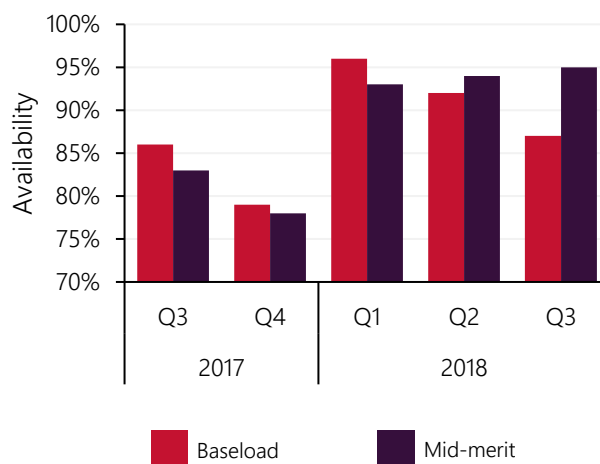


Figure 33 WEM generation availability by class³⁹



In Q3 2018, the WEM reached the maximum STEM Price of \$302/MWh for the first time since Q2 2017. On 6 August 2018 there were three intervals where the Balancing Price reached the maximum price limit, which all occurred during the on-peak period between 1300 hrs to 1430 hrs. Contributors to the event included:

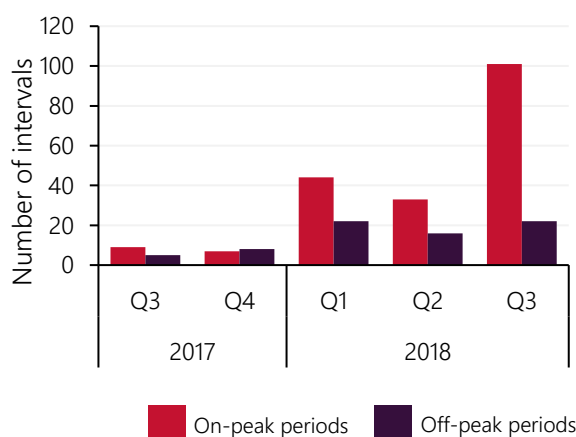
- A minor cloud event that decreased small-scale PV generation and therefore increased system operational demand by about 50-100 MW.
- Very low generation from the wind farms (between 1% and 5% of capacity).
- Outages of some large coal-fired generation facilities (COLLIE_G1 and MUJA_G7).
- Participant bidding behaviour.

2.2.1 Negative prices

Q3 2018 recorded the highest number of trading intervals with a negative Balancing Price since the Balancing Market commenced. There were 101 negative price intervals (or 2.8%) in Q3 2018 compared to the next highest quarter of Q1 2018 which had 44 negative price intervals (or 1.5%) (Figure 34).

The average Balancing Price during these intervals was approximately -\$30/MWh and the majority (82%) occurred during the daytime on-peak period (08:00 to 22:00hrs), compared to 67% in Q2 2018 and 64% in Q3 2017. The increased occurrence of negative prices is linked to falling daytime minimum demands, driven by increased small-scale PV capacity.

Figure 34 WEM negative Balancing Prices



³⁹ In the [2018 WEM Electricity Statement of Opportunities](#), AEMO has classified baseload, mid-merit, and peaking facilities as follows (a) Baseload relates to facilities that operate more than 70% of the time; (b) Mid-Merit relates to facilities that operate between 10% and 70% of the time; and (c) Peaking relates to facilities that operate less than 10% of the time.

2.2.2 Constrained compensation

Contrasting Q2 2018 results,⁴⁰ in Q3 2018 there was no constrained off compensation paid to Non-Scheduled Generators and accordingly, there was a significant decrease (-91%) in total constrained compensation in Q3 2018 compared to Q2 2018 (Table 7). The largest portion of constrained compensation was paid to Scheduled Generators for being dispatched down to maintain security. The main driver for the total decrease in constrained compensation was fewer and smaller network outages in the South West Interconnected System.

Table 7 WEM constrained compensation

Payment	Q3 2017	Q2 2018	Q3 2018	Q3 vs Q2	2018 vs 2017
Scheduled Generator constrained on	\$77k	\$118k	\$84k	-29%	-8%
Scheduled Generator constrained off	\$253k	\$330k	\$175k	-47%	-31%
Non-Scheduled Generator constrained off*	\$30k	\$2.4M	0	-100%	-100%
Total	\$360k	\$2.8M	\$259k	-91%	-28%

*Non-Scheduled Generators are not able to be constrained on.

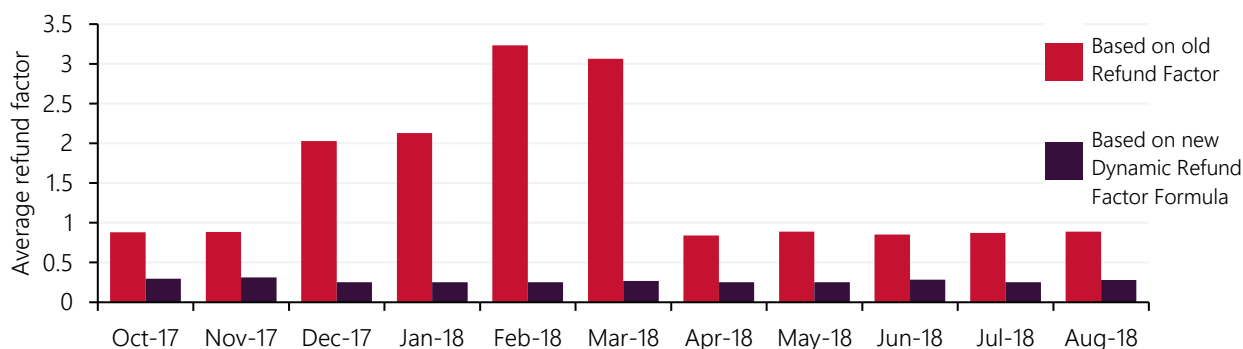
2.2.3 Refund factor for spare capacity

Under the Reserve Capacity Mechanism⁴¹ (RCM) a facility holding capacity credits may be subject to paying refunds if they fail to comply with their reserve capacity obligations. These refunds vary throughout the year and are calculated per trading interval based on the size of the outage, the Reserve Capacity Price and a refund factor. The refund factor is intended to act as a disincentive to facilities going on outage during periods where the amount of spare capacity available is low.

From 1 October 2017, the static refund factor was replaced with a new Dynamic Refund Factor (DRF)⁴² which is determined based on the amount of spare capacity available in a given trading interval. Q3 2018 marks one year since the introduction of the DRF and it is interesting to see how it compares to the previous refund factor.

Figure 35 shows the monthly average DRF over the last year compared to what the monthly average refund factor would have been using the previous static method. The previous method resulted in much higher refund factors, and therefore higher refund charges to generators on forced outage, than the new DRF method.

Figure 35 WEM comparison between the old and new Refund Factor methods for spare capacity



Note: Data as at 31st August 2018

Although Figure 35 shows that the DRF sits close to its floor value of 0.2543 for most of the year, there are some periods where the DRF spikes to a higher value. In general, DRF spikes have occurred during periods of high demand such as the summer peak, or periods where large numbers of facilities are on planned outage for maintenance, such as in the low demand shoulder seasons. In general, high DRF events have been relatively short in duration, so have not had much influence when considered on average over a given month.

⁴⁰ AEMO 2018, *Quarterly Energy Dynamics – Q2 2018*. [online]

⁴¹ The RCM ensures that there is adequate capacity available each year to meet peak system requirements including a reserve margin. Providers of capacity are allocated capacity credits by AEMO and each Market Customer is required to contract for capacity credits to cover their share of capacity. Uncontracted capacity credits are settled by AEMO at the Reserve Capacity Price which was \$111,752.53 in the 2017-18 Capacity Year.

⁴² These changes were introduced in the Wholesale Electricity Market Amending Rules 2016 made by the Minister under regulation 7(4) of the Electricity Industry (Wholesale Electricity Market) Regulations 2004. The previous refund factor was based a static table of values that specified a different value at different times of the day, week, and year, with higher values at times that were historically high demand periods.

⁴³ Note that this DRF floor is a facility specific value. Facilities that have been on forced outage over the previous 90 days will have a higher Refund Factor Floor than 0.25. Refer to Clause 4.26.1(f) of the WEM Rules for details of how the Refund Factor Floor is calculated.

3. Gas market dynamics

3.1 Gas demand

Total gas demand⁴⁴ decreased by 6 PJ during the quarter compared to Q3 2017, primarily because of a 25% reduction in GPG demand (Table 8). Table 9 provides a summary of the drivers of demand changes.

Table 8 Gas demand – quarterly comparison

Demand	Q3 2018 (PJ)	Q2 2018 (PJ)	Q3 2017 (PJ)	Percentage change from Q3 2017
AEMO Markets *	114	95	117	▼ 2.7%
GPG **	34	38	45	▼ -25%
QLD LNG	309	292	300	▲ 2.9%
TOTAL	456	426	462	▼ -1.3%

* 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 Power Station.

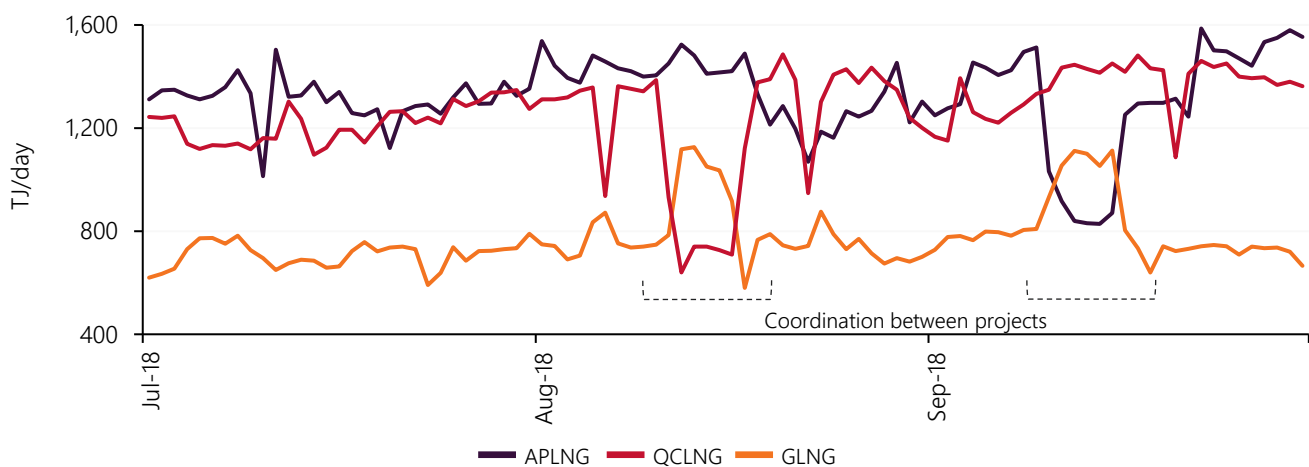
Table 9 Changes in gas demand

Demand decreases against Q3 2017	9 PJ decrease in GPG demand, offset by an increase in hydro, solar and wind output (Section 1.3).
	<ul style="list-style-type: none"> A slight decrease in residential, commercial and industrial demand, down 3 PJ. This fall is consistent with expectations published in recent AEMO forecasting reports, which have noted that (in the short term) demand reductions from energy efficiency improvements and fuel switching to electricity would be greater than increases in demand from new connections.⁴⁵
	The above reductions were somewhat offset by a 7 PJ increase in pipeline deliveries for export LNG.

3.1.1 LNG demand

Average daily pipeline deliveries of 3,354 TJ/d flowed to Curtis Island during Q3 2018, an increase of 76 TJ/d compared to Q3 2017 and an increase of 145 TJ/d compared to the prior quarter. A reduced duration of planned outages over Q3 2018 at QCLNG and APLNG contributed to the volume of LNG exports increasing by 16.5 PJ (or 6%) when compared to the previous quarter. (Figure 36).

Figure 36 Pipeline deliveries to Curtis Island over Q3 2018



⁴⁴ 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.

⁴⁵ AEMO 2018, *2018 Gas Statement of Opportunities*. [online] www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2018/2018-Gas-Statement-Of-Opportunities.pdf

During the quarter, there was a continuation of arrangements between the LNG consortia relating to the delivery of gas during train outages: GLNG pipeline deliveries to Curtis Island increased during periods of planned maintenance at QCLNG and APLNG. An additional 4 LNG cargoes (77 in total) were exported during Q3 2018 compared to the previous quarter, although this was consistent with Q3 2017 exports. Four of the Curtis Island cargoes were reported as spot priced between \$12 and \$14/GJ.⁴⁶ The increase in LNG exports over Q3 2018 coincided with higher international oil and gas prices (Section 3.2.1).

3.2 Wholesale gas prices

During Q3 2018 there were significant increases in average wholesale gas prices compared to recent quarters, with broadly similar price outcomes across the AEMO-operated east coast gas markets (Figure 37). The DWGM and Brisbane STTM recorded their second highest average price on record (and were up +11% and +41% respectively compared to Q3 2017), and the Adelaide and Sydney STTM average gas prices were the third highest on record (up +13% and 5% respectively). Price changes between Q2 and Q3 2018 correspond with increases in Victorian demand over winter and increased LNG Curtis Island demand as production increased following a reduction in plant maintenance over Q2 2018 (Table 9).

Between Q3 2017 and Q3 2018 there was an increase in the price of gas injection bids in all markets – in Q3 2018 the quantity of gas priced below \$8/GJ reduced by 20% (to 1.1 PJ/day), with an equivalent volume being offered at higher prices (\$9 to \$11/GJ) (Figure 37). Key changes between Q3 2017 and Q3 2018 that may have influenced higher priced offers include:

- Reduced supply from Longford (-19%, Figure 42);
- An increase in pipeline deliveries to Curtis Island for export (+2.3%); and
- Increasing international oil and LNG prices (Section 3.2.1).

Figure 37 GSH, DWGM and STTM average quarterly prices

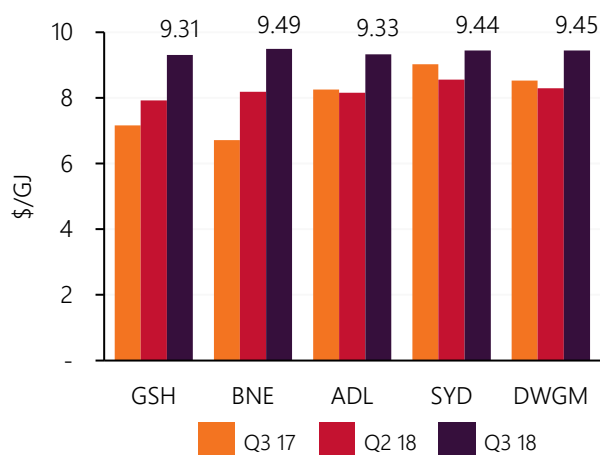
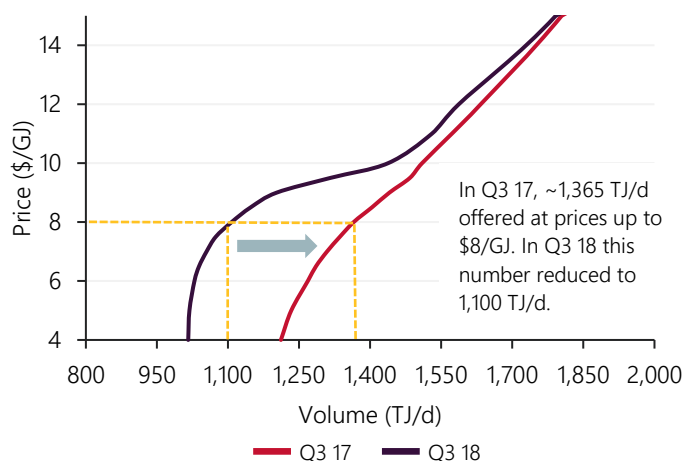


Figure 38 DWGM and STTM injection bid supply curve



3.2.1 International gas and oil prices

The price for domestic gas on the east coast is increasingly 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':

"The presence of oil-linked mechanisms in gas supply agreements (GSAs) 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.⁴⁷

International oil and gas prices continued to increase over Q3 2018. Brent Spot traded at \$105/bbl at the start of Q3 2018 and ended the quarter at \$115/bbl (Figure 31), an increase of 9% and the highest price recorded since the end of 2014. Price rises were driven by strong northern hemisphere demand and the impending U.S. led sanctions on Iran.⁴⁸

⁴⁶ Information provided by Argus Direct.

⁴⁷ ACCC 2016, *Inquiry into the east coast gas market*, April 2016. [online] www.accc.gov.au/system/files/1074_Gas%20enquiry%20report_FA_21April.pdf

⁴⁸ Thomson Reuters 2018. *Oil eases, but Iran sanctions keep Brent above \$80 a barrel*. [online] www.reuters.com/article/us-global-oil/brent-oil-trades-near-four-year-high-but-u-s-crude-retreats-idUSKCN1M602C

Figure 39 ICE Brent futures price – monthly average (AU\$)



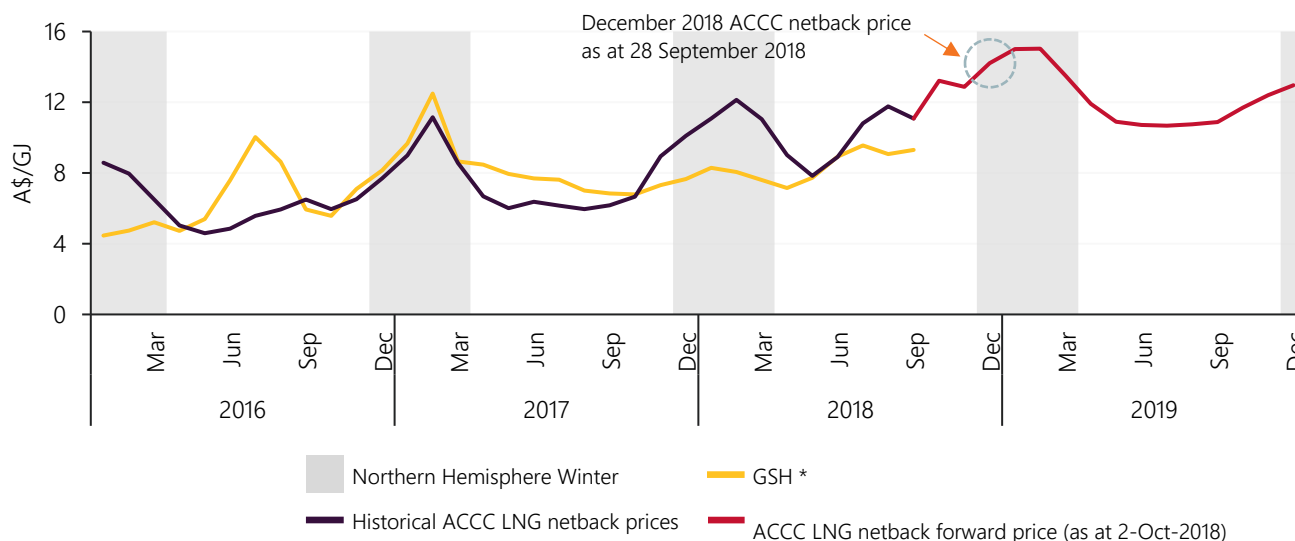
Source: Bloomberg

In Q3 2018 the ACCC commenced the publication of a historic and forward LNG netback price – a theoretical export parity price that a gas supplier can expect to receive for exporting its gas. The price is calculated by taking the delivered price of LNG and subtracting the costs of liquefying natural gas and shipping it to the destination port.⁴⁹

The Gladstone LNG consortia have agreed to an undertaking⁵⁰ to offer any ‘excess’ gas (i.e. that above long-term contracts) to the domestic market to “help achieve parity between local and international prices.”⁵¹ The ACCC’s publication of a netback price recognises that it has the potential to play a role in domestic price formulation. A high LNG Netback forward price could challenge domestic industrial gas consumers in procuring volumes under the auspices of the undertaking of the LNG consortia to offer gas to the domestic market.

Figure 40 shows the first ACCC LNG netback price as of 28 September 2018 and the daily delivered volume weighted average GSH price. The historic ACCC LNG netback price increases in line with growing heating requirements during the northern hemisphere winter months. Note the LNG netback forward price for December 2018 in Figure 40, indicating possible tight supply over the northern hemisphere winter.⁵²

Figure 40 Historic and forward monthly average ACCC LNG netback and Gas Supply Hub prices



*GSH price: daily delivered volume weighted average price
Source: ACCC and AEMO

⁴⁹ ACCC 2018, LNG netback price series. [online] www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2020/lng-netback-price-series

⁵⁰ Australian Government 2017, Heads of Agreement – The Australian East Coast Domestic Gas Supply Commitment. [online] www.industry.gov.au/sites/g/files/net3906/f/heads_of_agreement_-_the_australian_east_coast_domestic_gas_supply_commitment.pdf

⁵¹ Minister for Resources and Northern Australia 2017, Australian Domestic Gas Security Mechanism to safeguard supply. [online] www.minister.industry.gov.au/ministers/canavan/media-releases/australian-domestic-gas-security-mechanism-safeguard-supply

⁵² It should be noted that the ACCC LNG netback forward price is subject to change and will be updated by the ACCC twice a month.

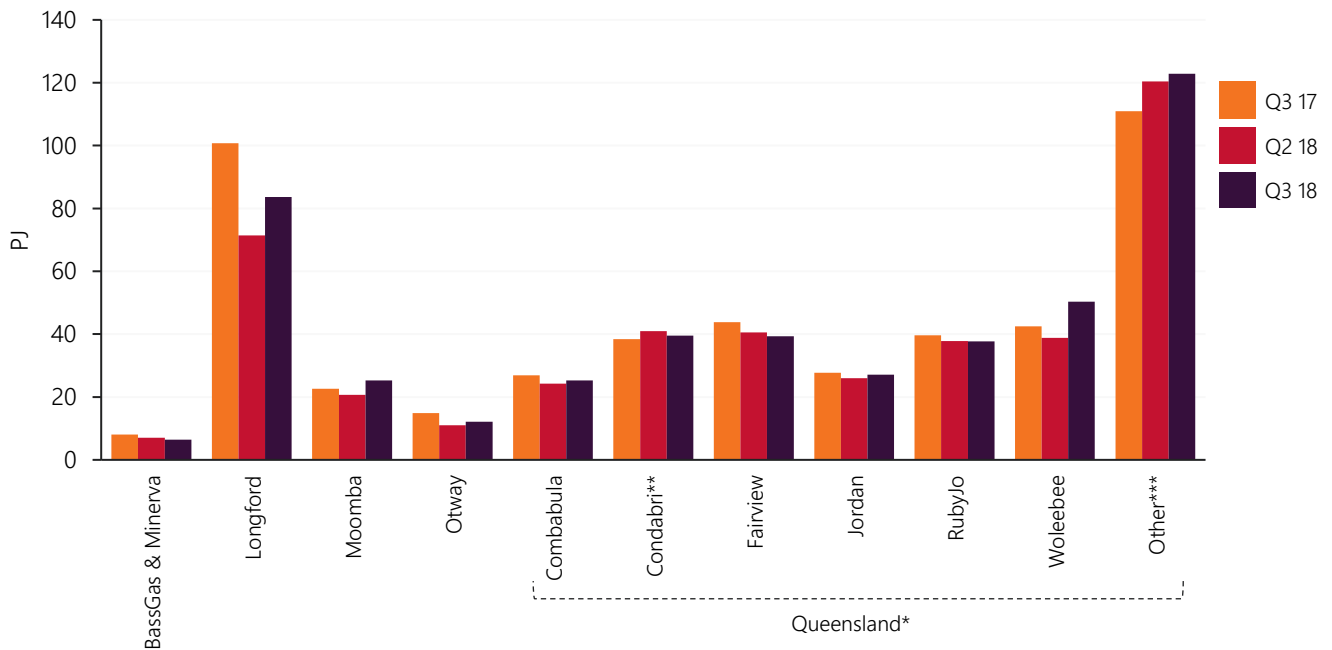
3.3 Gas supply

3.3.1 Gas production

East coast gas production of 470 PJ was recorded during Q3 2018, a 31 PJ (or 7%) increase when compared to the prior quarter (Figure 41). A 13 PJ increase in Victorian production from the Otway and Longford gas facilities and a 5 PJ increase in Moomba production in South Australia compared to Q2 2018 was likely driven by seasonal demand profiles and were in line with winter heating load requirements. Whilst Longford production was 17 PJ (17%) lower than record high Q3 2017 production, Q3 2018 output of 83 PJ was toward the top level of long-term Q3 production (Figure 42), with the relative reduction in production somewhat offset by reduced GPG demand.

Increased Victorian and South Australian production was supported by a 13 PJ increase in Queensland production, primarily sourced from Woleebee (+11 PJ) due to a reduction in planned maintenance that occurred during Q2 2018. Increased Queensland production facilitated increased southward flows on the South West Queensland Pipeline to meet increased Victorian demand (Section 3.4).

Figure 41 Quarterly gas production by plant

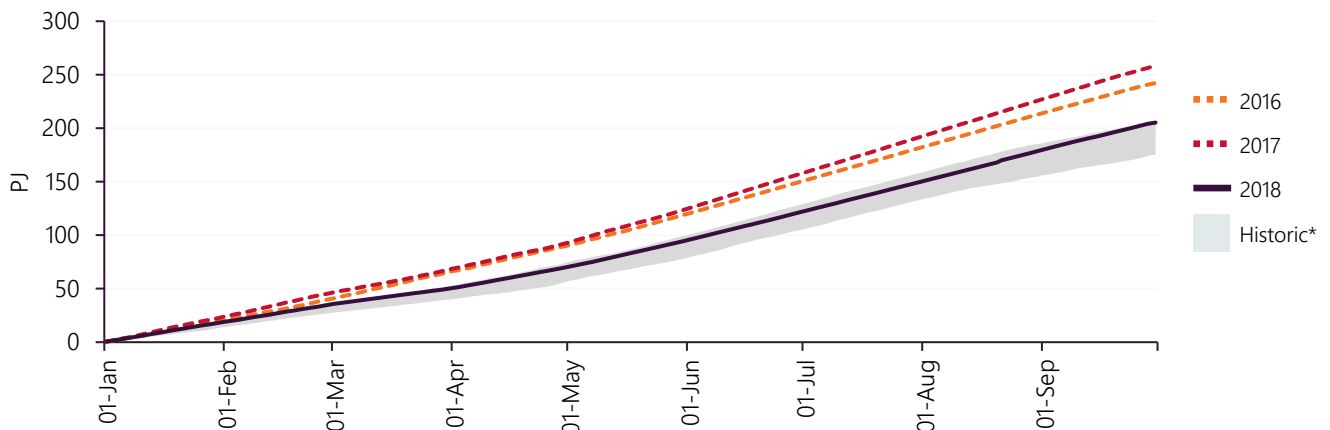


* Queensland production is based on grouping all Gas Bulletin Board production facilities in the Roma Zone of the Gas Bulletin Board

** Condabri is the grouping of North, Central and South production facilities.

*** Plant not explicitly stated are grouped as "Other".

Figure 42 Longford Gas Plant | Q1 to Q3 cumulative production | 2009 to 2018



*The shaded series represents the highest and lowest cumulative production levels occurring between 2009 and 2015

3.3.2 Gas storage

A gas balance of 9.3 PJ was recorded at the Iona Underground Storage Facility (Victoria) as at 30 September 2018. Gas withdrawals exceeded gas injections ('net withdrawals') by 5.5 PJ during the quarter, compared to net withdrawals of 2.3 PJ during Q3 2017 (Figure 43). Reduced Q3 2018 gas production from Otway and Longford compared to Q3 2017 contributed to an increased reliance on gas from Iona Underground Storage and southerly flows from Queensland to meet quarterly gas demand (Figure 44).

Figure 43 Iona Daily Injections & Withdrawals

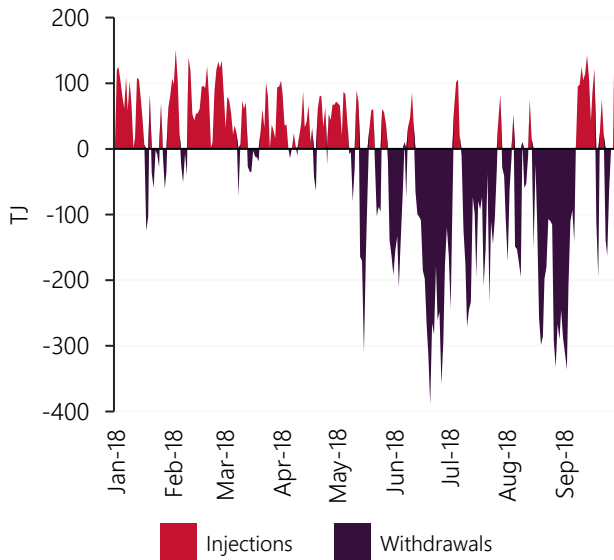
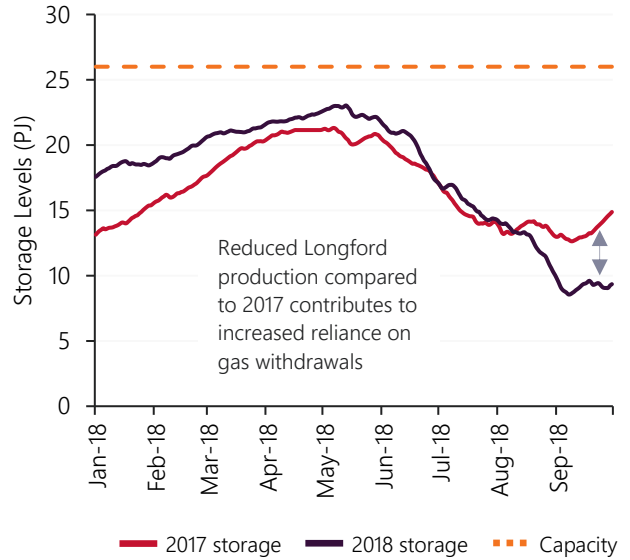


Figure 44 Iona Underground Storage Facility – storage levels



3.4 Pipeline flows

Quarterly gas delivery from Victoria to other states totalled 33 PJ, consistent with exports during Q1 and Q2 2018 (Figure 45). Following record production in 2017, decreased output from the Otway and Longford gas facilities during 2018 (Figure 41 and Figure 42) has contributed to a 10 PJ (or 23%) reduction in Victorian exports when compared to Q3 2017.

Reduced Victorian deliveries to other states compared to 2017, likely due to the reduction in Longford production, has been somewhat offset by reduced GPG demand, increased Iona withdrawals and increased net southerly flows along the South West Queensland Pipeline (Figure 46). For the first time, net daily southerly flows along the South West Queensland Pipeline were recorded for the entire period during the quarter.

Figure 45 Victorian gas exports to other states

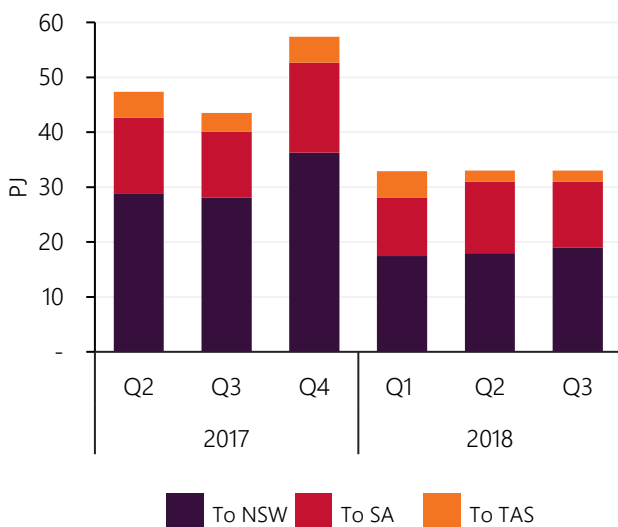
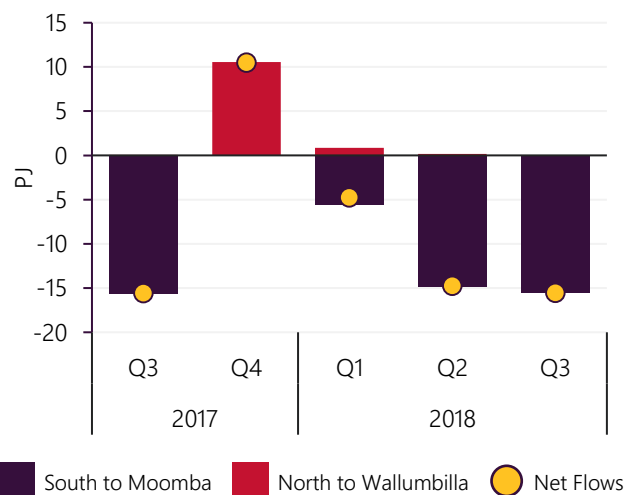


Figure 46 South West Queensland Pipeline at Wallumbilla



3.5 Gas Supply Hub

Record volumes were traded through the GSH during Q3 2018 – an increase of 100% compared to the same period last year and a 61% increase on the next highest quarter (Q3 2016, Figure 47). The highest ever monthly volume was traded in September 2018 with four of the ten highest daily volumes taking place during the month (Figure 48).

Figure 47 GSH traded volumes – record quarters

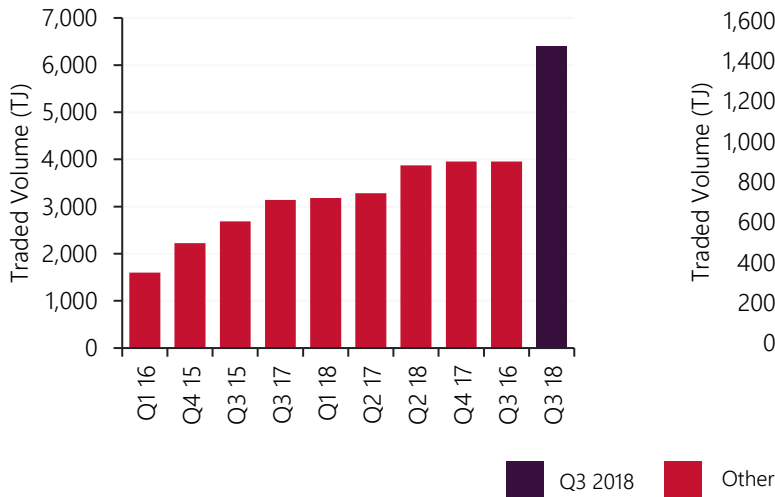
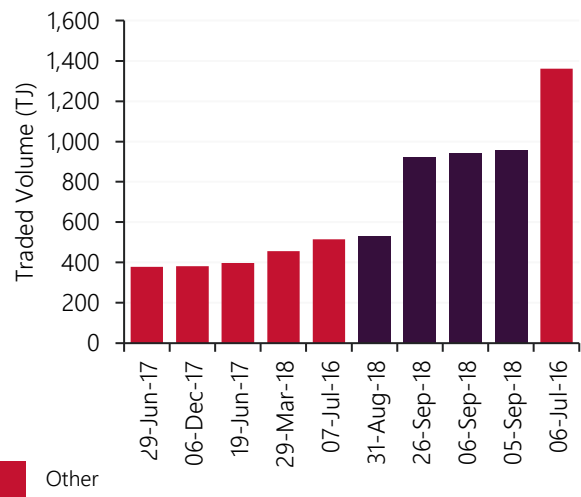


Figure 48 GSH traded volume – record days



Commercial motives (such as standardised prudential arrangements trading limits) are potentially incentivising participants to increasingly trade through the GSH, as opposed to more traditional off market bi-lateral agreements. Over half of all Q3 2018 traded volumes were for delivery in Q4 2018. The volumes traded for December delivery were settled at \$10.08/GJ – an indication of what the market is expecting to pay for gas towards the end of 2018 as at the end of Q3 2018. In comparison:

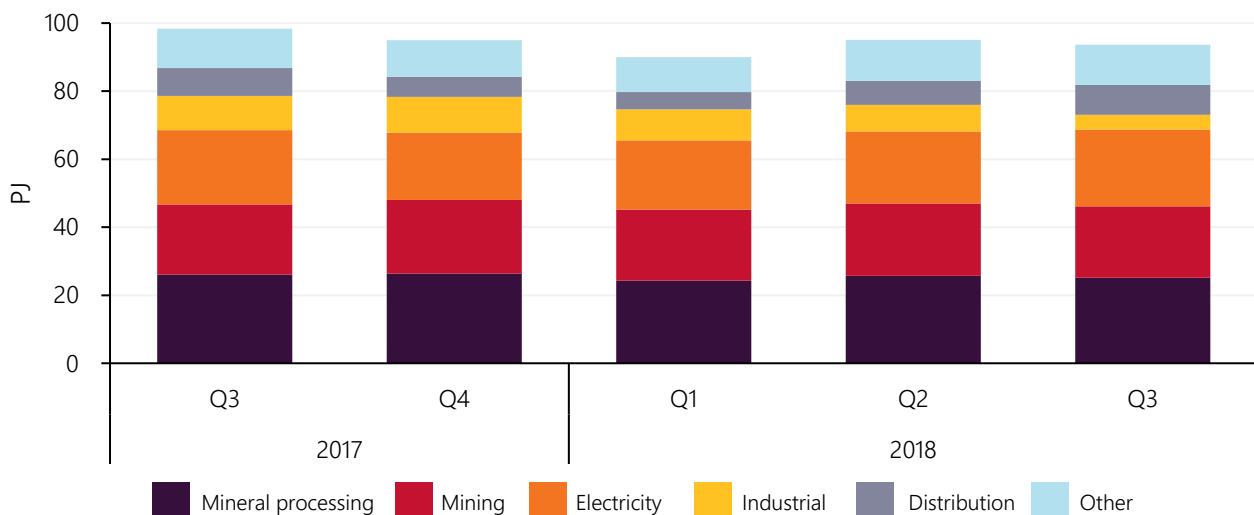
- The volume weighted average price traded on the GSH in December 2017 was \$7.66/GJ.
- ACCC forward LNG netback price as at 28 September 2018 for December 2018 was \$14.20/GJ (Section 3.2.1).

3.6 Gas – Western Australia

3.6.1 Gas demand

Total gas consumption in Q3 2018 was 2% lower than in Q2 2018 and 5% lower than Q3 2017. This was largely driven by a decrease in consumption by users in the industrial sector (Figure 49). Specifically, the Yara Pilbara Liquid Ammonia Plant – one of the largest gas consumers in the state – which normally consumes on average 2,500 TJ/month (8% of total consumption) decreased its consumption during Q3 2018 to an average 877 TJ/month (3% of total consumption). The facility had been undertaking its largest turnaround since construction started in 2003.

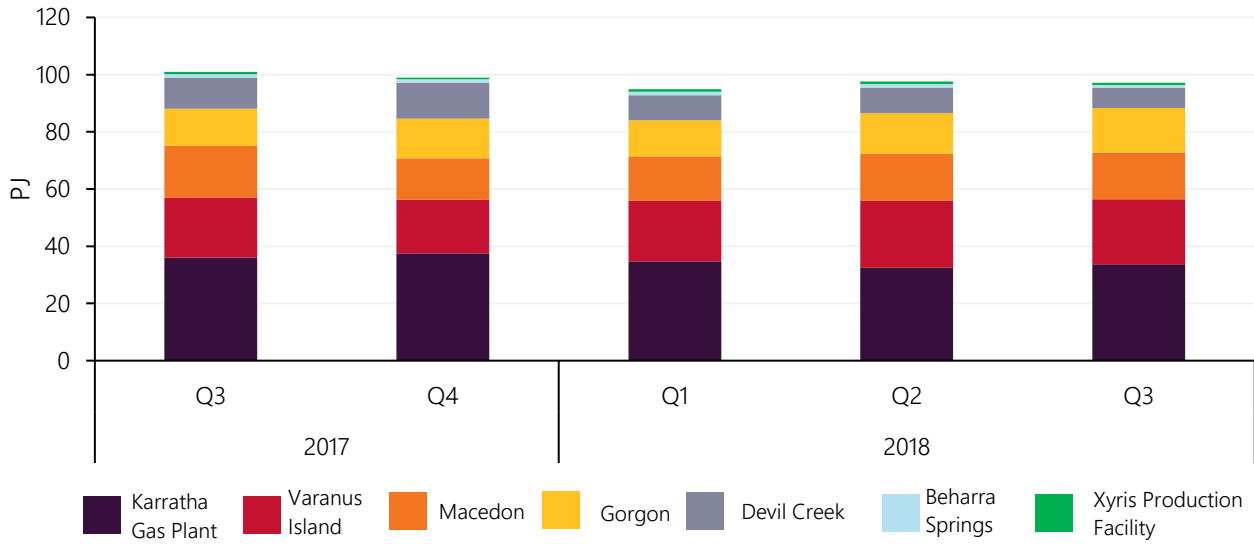
Figure 49 WA gas demand



3.6.2 Gas supply

Gas supply in WA over the Q3 2018 period has remained constant (Figure 50). Overall production in Q3 2018 was 97.1 PJ compared to 97.6 PJ in Q2 2018. Gorgon increased production by 10% (from 14 PJ to 15.6 PJ) with decreases in production from Devil Creek by 22% (from 9 PJ to 7 PJ) and Varanus Island by 3% (from 23.5 PJ to 22.7 PJ).

Figure 50 WA gas supply



Abbreviations

Abbreviation	Expanded name
AEMO	Australian Energy Market Operator
BBL	Barrel
CER	Clean Energy Regulator
CCGT	Combined cycle gas turbine
DRF	Dynamic Refund Factor
DWGM	Declared Wholesale Gas Market
FCAS	Frequency control ancillary services
GJ	GigaJoule
GPG	Gas-powered generation
GSH	Gas Supply Hub
IRSR	Inter-regional settlement residue
LFAS	Load Following Ancillary Services
LGC	Large-scale Generation Certificates
LNG	Liquefied natural gas
MW	MegaWatt
MWh	MegaWatt hour
NEM	National Electricity Market
PJ	PetaJoule
PV	Photovoltaic
QNI	New South Wales to Queensland interconnector
RCM	Reserve Capacity Mechanism
SRA	Settlement Residue Auction
STC	Small-scale technology certificate
STEM	Short Term Energy Market
STTM	Short Term Trading Market
SWIS	South West Interconnected System
SWQP	South West Queensland Pipeline
TJ	TeraJoule
USD	United States dollars
VRE	Variable renewable energy
WEM	Wholesale Electricity Market