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Quarterly Energy Dynamics – Q4 2017

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Purpose

AEMO has prepared this new report to provide energy market participants and governments with information on the market dynamics, trends and outcomes during Q4 2017 (1 October to 31 December 2017). It is intended that AEMO will produce this report quarterly on an ongoing basis as part of its regular market monitoring and reporting activities.

This quarterly report provides a summary on the electricity and gas market dynamics, trends and outcomes during Q4 2017. It also compares results for the quarter against other recent quarters, focussing on Q3 2017 and Q4 2016. 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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Summary

Highlights for Q4 2017 include:

- Wholesale electricity and gas prices fell compared to Q3 2017, but remained high compared to historical levels. The key drivers of comparatively lower wholesale electricity and gas prices were reduced demand associated with seasonal temperature increases and some generators lowering the price of their offers (in electricity).
 - Wholesale electricity prices averaged close to \$80/MWh across the National Electricity Market (NEM), with Victoria the highest region at \$84.45/MWh and Queensland the lowest at \$71.71/MWh. Whilst electricity prices for the quarter were generally the lowest quarter in 2017, they remained high compared to historical levels, with Q4 2017 the highest Q4 on record in all NEM regions except South Australia.
 - There was a greater amount of gas-powered generation (GPG) and black coal-fired generation offered at prices below \$100/MWh, despite high international gas and coal prices.
 - Wholesale gas prices were also generally lower compared to Q3 2017, particularly in the Declared Wholesale Gas Market in Victoria (DWGM, down \$2.17/GJ) and the Short Term Trading Market in Sydney (STTM, down \$1.90/GJ).
- Weather was warm compared to the long-term average in Sydney and Melbourne. This contributed to small reductions in demand in AEMO's electricity and gas markets compared to Q4 2016.¹
 - However, total gas demand (consisting of demand from AEMO's markets, GPG demand and deliveries to the LNG projects on Curtis Island) increased by 9% compared with Q4 2016, driven by a rise in GPG demand and record gas deliveries to Curtis Island.
- Key changes in the electricity supply mix included:
 - Outages at Loy Yang A and Yallourn power stations, which – in addition to closure of Hazelwood in March 2017 – led to brown coal-fired generation reaching its lowest quarterly average since commencement of the NEM. This contributed to the second lowest quarterly level of emissions since NEM-start.
 - A significant reduction in hydro generation, which was about 25% lower than in Q3 2017 and down 40% from Q4 2016 levels, as hydro generators conserved water in the lead up to 2018.
 - GPG increasing output compared to Q3 2017 despite lower demand, reflecting higher availability at Darling Downs, Tamar Valley CCGT and Tallawarra power stations.
- Operational issues included:
 - Periods of low demand and high wind which resulted in operational issues and directions in South Australia.
 - High demand on the 30 November 2017, which led to an early test of AEMO's summer readiness program, with capacity dispatched under the Reliability and Emergency Reserve Trader (RERT) mechanism.
- Frequency control ancillary service (FCAS) market costs were \$58 million, the second highest quarter on record, with record high annual FCAS costs of over \$200 million. The entry of two new participants (Hornsedale Power Reserve and EnerNOC) into the FCAS markets contributed to a \$13 million reduction in FCAS costs compared to Q3 2017.
- Approximately 900 MW of large-scale renewable projects receiving a final investment decision or announcing power purchase agreements, bringing the total announced since October 2016 to over 5,000 MW.

¹ AEMO gas markets demand is the sum of customer demand in each of the STTM's and the DWGM

CONTENTS

Purpose	2
Disclaimer	2
Copyright	2
Summary	3
1. ELECTRICITY MARKET DYNAMICS – Q4 2017	5
1.1 Weather	5
1.2 Electricity demand	5
1.2.1 System management issues and summer readiness	6
1.3 Generation in the National Electricity Market	7
1.3.1 New entrants during the quarter	8
1.3.2 Large-scale Renewable pipeline	9
1.4 Wholesale electricity prices	9
1.4.1 Wholesale electricity price drivers	9
1.4.2 International coal and prices	11
1.4.3 Frequency control ancillary services	11
1.4.4 Electricity futures markets	12
1.5 Electricity flows	12
2. GAS MARKET DYNAMICS – Q4 2017	14
2.1 Gas demand	14
2.1.1 LNG	14
2.2 Gas supply	14
2.2.1 Gas storage	15
2.3 Wholesale gas prices	16
2.3.1 International gas prices	16
2.4 Pipeline flows	16
APPENDIX A. ABBREVIATIONS	18

1. ELECTRICITY MARKET DYNAMICS – Q4 2017

1.1 Weather

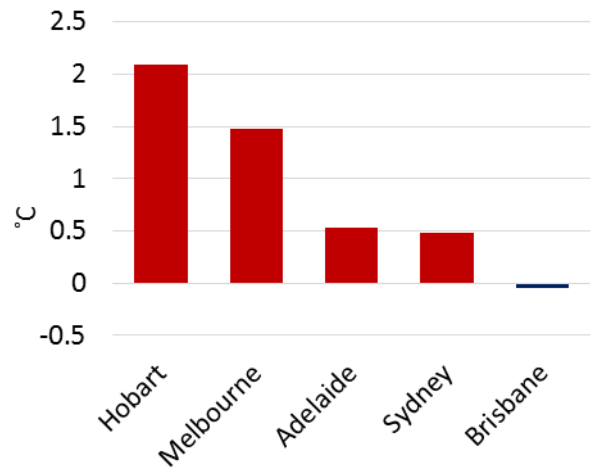
Quarterly average maximum temperatures were above the ten year average in Melbourne, Sydney, Adelaide and Hobart (Figure 1), following Australia’s sixth-warmest spring on record.

A prolonged warm spell occurred in Victoria during the quarter as Melbourne experienced the highest number of spring days above 30°C on record (15 days). Average maximum temperatures in Melbourne across the quarter were up 0.7°C on the 10-year average. Wind conditions were slightly lower than average, leading to a reduction in wind generation.

In Sydney, average maximum temperatures for the quarter were 0.5°C warmer than the 10-year average. Rainfall across New South Wales was 16% higher than the long-term average.

Tasmania experienced an exceptionally warm Q4, with average maximum temperatures in Hobart up 2.1°C from the 10-year average. It was also a dry quarter, with rainfall across the state down 28% from the long-term average.

Figure 1 Variance between 10-year average Q4 and Q4 2017 average maximum temperature

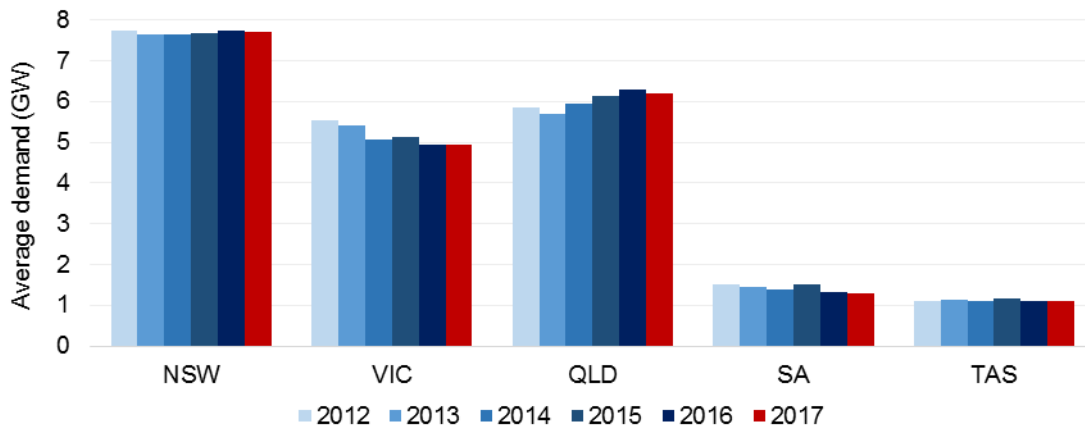


Source: Bureau of Meteorology

1.2 Electricity demand

In Q4 2017, average electricity operational demand² across the NEM was slightly down (-121 MW or -0.6%) relative to Q4 2016 (Figure 2), driven by increased rooftop PV generation (+64 MW) and reduced underlying demand. From a regional perspective, the largest reduction in average operational demand was observed in Queensland, where average operational demand was 86 MW lower than that in Q4 2016 driven by new rooftop solar PV installations and milder summer conditions. Average operational demand was marginally down in New South Wales, Victoria and South Australia and marginally up in Tasmania.

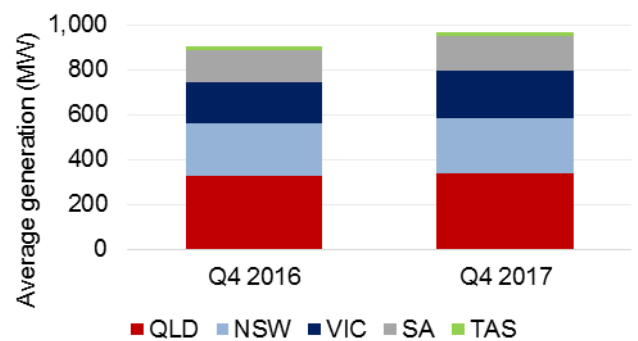
Figure 2 Average operational demand for Q4, 2012 to 2017



² 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.

Average rooftop PV generation in Q4 2017 increased from 905 MW to 969 MW (+7%) when compared to Q4 2016 (Figure 3). The largest increases were in Victoria (+15%) and South Australia (+8%). These increases correspond with an increase in rooftop PV capacity reported by the Clean Energy Regulator³ and higher than average sunshine across all capital cities except Adelaide.⁴

Figure 3 Average rooftop PV generation by region



1.2.1 System management issues and summer readiness

Electricity

During the quarter, several system security and reliability issues occurred, including:

- Low reserve conditions occurred across Victoria and South Australia in late November as a result of extreme heat, unit outages and low wind. On 30 November 2017, AEMO intervened to dispatch 32 MW of Reliability and Emergency Reserve Trader (RERT)⁵ demand response reserves to assist in maintaining reliable operation of the system.⁶
- During periods of high wind conditions combined with low operational demand in South Australia, AEMO issued multiple sets of directions over Q4 2017 to synchronous units in order to maintain system strength.⁷ In total, there were 12 sets of directions during the quarter. These measures contributed to maintaining the system in a secure and reliable operating state.

AEMO also released its summer readiness report, which outlined the actions taken to prepare the NEM to meet requirements for summer 2017-18.⁸ Notable milestones during the quarter included:

- In October, the Australian Renewable Energy Agency and AEMO announced 10 pilot projects had been successful in the competitive round under the demand response trial. Participation ranged across network providers, retailers, aggregators, direct energy users, and technology providers such as smart thermostat developers.
- Finalising contracts for 1,150 MW to be available for via RERT for summer 2017-18: 884 MW of demand response and 266 MW of generation.
- The return to service of the 385 MW Swanbank E Power Station in December, as mandated by the Queensland Government.
- The connection of Australia’s first utility-scale battery at Hornsdale Power Reserve to the north of Adelaide at the end of November. The Hornsdale battery is the world’s largest lithium ion battery (100 MW/129 MWh).

³ Clean Energy Regulator. *Small-scale technology certificate market update*. [ONLINE] Available at <http://www.cleanenergyregulator.gov.au/About/Pages/News%20and%20updates/NewsItem.aspx?ListId=19b4efbb-6f5d-4637-94c4-121c1f96fcef&ItemId=463> Accessed 8th January 2018.

⁴ Measured using global solar exposure - the total amount of solar energy falling on a horizontal surface. The daily global solar exposure is the total solar energy for a day, and is typically between 1 and 35 MJ/m² (megajoules per square metre). Bureau of Meteorology. *Climate Data Online*. [ONLINE] available at <http://www.bom.gov.au/climate/data/index.shtml> Accessed 9th January 2018.

⁵ RERT is a mechanism AEMO uses to maintain power system reliability and system security via reserve contracts. Further information is available at: AEMO 2017, *Summer operations 2017-18*. Available at: https://www.aemo.com.au/-/media/Files/Media_Centre/2017/AEMO_Summer-operations-2017-18-report_FINAL.pdf and <https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Reliability-And-Emergency-Reserve-Trader---External-Procedure-Amendment>

⁶ AEMO previously contracted under RERT 2005, 2006 and 2014, but on each of these occasions it was not activated or dispatched.

⁷ AEMO, *South Australia System Strength Assessment*, September 2017. Document available at: https://www.aemo.com.au/-/media/Files/Media_Centre/2017/South_Australia_System_Strength_Assessment.pdf and AEMO, *Transfer Limit Advice – South Australia System Strength*, December 2017. Document available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2017/Transfer-Limit-Advice---South-Australian-System-Strength.pdf

⁸ AEMO 2017, *Summer operations 2017-18*. Available at: https://www.aemo.com.au/-/media/Files/Media_Centre/2017/AEMO_Summer-operations-2017-18-report_FINAL.pdf

Gas

On 30 November 2017, AEMO issued a notice of a threat to system security in the Victorian Declared Wholesale Gas Market (DWGM) due to an unplanned outage of the Longford production plant, and the resulting risk of breaching the minimum pressure at Sale. During this event, AEMO scheduled out-of-merit-order injections through an ad hoc schedule. This resulted in approximately \$266,000 of ancillary and uplift payments.

1.3 Generation in the National Electricity Market

Q4 2017 provided further insight on the supply mix replacing Hazelwood since its closure in March 2017, with black coal-fired generation and GPG providing the majority of the replacement energy to date (Figure 4).

Average brown coal-fired generation during Q4 2017 was 3,799 MW, representing the lowest quarterly average since the commencement of the NEM. This was a function of the closure of Hazelwood Power Station in March 2017 and extended outages at Yallourn and Loy Yang A power stations during the quarter.⁹ Compared to Q3 2017, output at Loy Yang A Power Station dropped by 272 MW. Record low brown coal output contributed to Q4 2017 recording the second lowest quarterly level since the beginning of the NEM (37.7 MtCO₂-e).¹⁰ Annual NEM emissions for 2017 also reached their second lowest levels since NEM start, driven by the progressive closure of coal-fired power stations since 2012 and relatively low demand.

There was also a significant reduction in hydro generation, which averaged 1,321 MW in Q4 2017, about 25% lower than in Q3 2017 and down 40% from Q4 2016 levels (Figure 5). In New South Wales, Snowy Hydro reduced output and replenished hydro storage levels. This resulted in net storage levels at Lake Eucumbene (the principal Snowy Scheme storage) increasing by 7.4% over the quarter, with Lake Eucumbene finishing the year at 46.4% compared to 49.5% at the end of 2016.¹¹ Snowy’s hydro generation in 2017 was 46% lower than in 2016 – a year of record generation for Snowy where it received 1.9 million LGCs for generating above baseline levels.¹²

In Tasmania, average hydro generation in Q4 2017 reduced against Q3 2017 due to the dispatch of Tamar Valley Combined Cycle Gas Turbine (CCGT) at relatively high levels in November and December (it did not run for most of Q3 2017). The dispatch of Tamar Valley CCGT coincided with dry conditions in Tasmania.

Figure 4 Change in generation by fuel type (Q2-Q4 2017 versus Q2-Q4 2016)

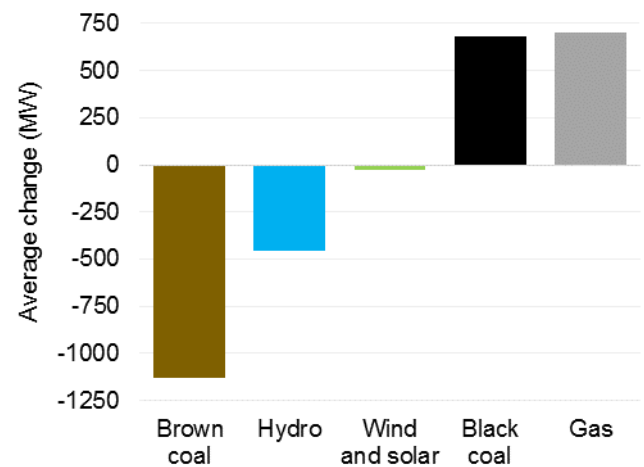
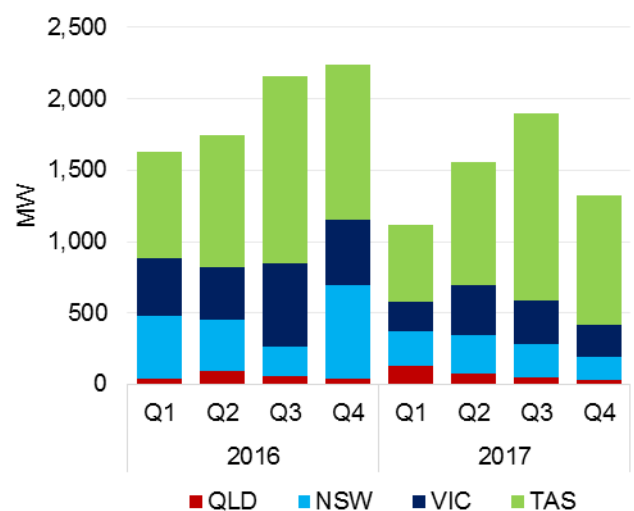


Figure 5 NEM quarterly hydro generation by region



⁹ The drop in availability was due to planned and unplanned outages.

¹⁰ Unadjusted emissions. Department of the Environment and Energy 2018. *Quarterly Update of Australia’s National Greenhouse Gas Inventory: September 2017 (incorporating December 2017 quarter emissions from the National Electricity Market)*. <http://www.environment.gov.au/climate-change/climate-science-data/greenhouse-gas-measurement/publications/quarterly-update-australias-national-greenhouse-gas-inventory-sep-2017>

¹¹ Snowy Hydro. *Lake Levels*. Available at: <http://www.snowyhydro.com.au/our-energy/water/storages/lake-levels-calculator/>. Accessed on 12 January 2017.

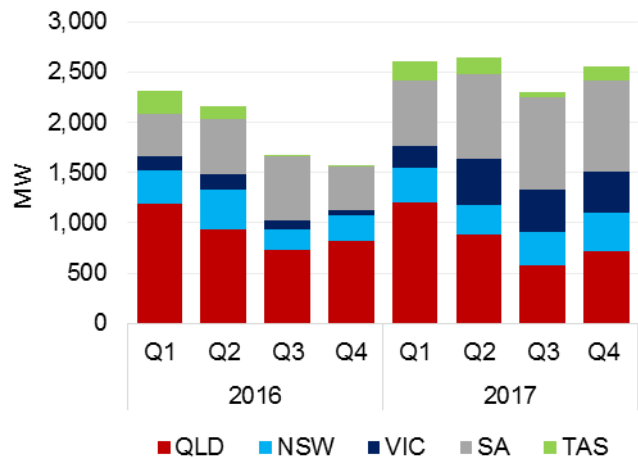
¹² Snowy Hydro 2017. *Annual Report*. Available at: https://drive.google.com/file/d/0B4c54AAM_BVvQy1iODU5dTrWGQ2Y1VBOGQ4aWd1YXhlSnE4/view

Average black coal-fired generation during Q4 2017 recorded a slight decrease compared to Q3 2017 (-125 MW on average) due to reduced electricity demand. However, in Queensland black coal-fired generation maintained the trend of progressively increasing output, with average Q4 2017 generation of 6,083 MW, the second highest quarterly average since Q1 2016. This was due to increased availability of Callide, Stanwell and Tarong North power stations compared to Q3 2017.

In New South Wales, black coal-fired generation was relatively flat compared to Q3 2017 (-75 MW), with an increase in the amount of capacity priced below \$80/MWh offsetting the impact of lower demand (-632 MW on Q3 2017). Output increased at Bayswater (+258 MW) and Vales Point (+68 MW) power stations, but reduced at Mt Piper (-249 MW) and Liddell (-83 MW) power stations.

GPG was the only major fuel type to increase average generation between Q3 2017 and Q4 2017 (+263 MW) (Figure 6). This was influenced by higher GPG availability and some generators reducing their market offers (see Section 1.4.1). The main increases in GPG compared to Q3 2017 were at Darling Downs (+191 MW), Tallawarra (+107 MW) and Tamar Valley CCGT (+77 MW). In 2017, comparatively high wholesale electricity prices have encouraged the return to service of over 833 MW of GPG capacity, including Swanbank E, Tamar Valley CCGT and Pelican Point (from half to full capacity).

Figure 6 NEM quarterly GPG by region



1.3.1 New entrants during the quarter

During the quarter, there were several new entrants in the electricity market (Table 1), including:

- The commissioning of the Tesla battery at Hornsdale Wind Farm. The Hornsdale Power Reserve (HPR) commenced commercial operations in the NEM during November 2017. During December, HPR was active in all NEM markets.
- A new demand-response project entering the FCAS markets. In October 2017, EnerNOC entered the FCAS markets through aggregated demand response – a first in the history of the NEM. This was enabled by approval of the ancillary services unbundling rule change by the Australian Energy Market Commission (AEMC) earlier in the year.¹³
- Connection of two sets of non-market diesel-gas hybrid generators in South Australia to assist with reliability over summer peak conditions as part of the South Australian Government’s energy plan.
- The return to service of Swanbank E as instructed by the Queensland Government.

Table 1 New entrants in the NEM in Q4 2017¹⁴

New entrant	Capacity and Region	Technology	Markets
Hornsdale Power Reserve Unit 1 (Tesla Battery)	100 MW; 129 MWh (SA)	Battery Storage	Energy; FCAS (all)
SA Diesel Generators	276 MW (SA)	Diesel	Energy (RERT)
Swanbank E	385 MW (QLD)	CCGT	Energy
EnerNOC Demand Response	160 MW (NSW and VIC)	Demand response	FCAS (contingency raise services)
Kidston Solar Stage 1	50 MW (QLD)	Solar	Energy
Kiata Wind Farm	31 MW (VIC)	Wind	Energy
Yaloak South Wind Farm	29 MW (VIC)	Wind	Energy

¹³ AEMC 2016 Demand Response Mechanism and Ancillary Services Unbundling. <http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism>

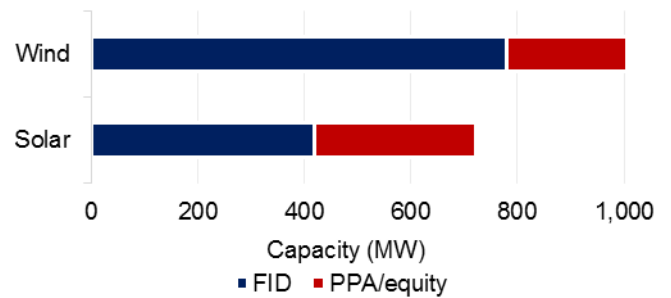
¹⁴ Includes mothballed power stations returning to service.

1.3.2 Large-scale Renewable pipeline

According to Bloomberg New Energy Finance (BNEF), nine projects with a total capacity of 1,200 MW obtained a Final Investment Decision¹⁵ (FID) in Q4 2017 (Figure 7). A further 533 MW capacity of projects announced the signing of a power-purchase agreement¹⁶ (PPA).

The projects announced in Q4 2017 are a continuation of a strong trend. Since October 2016 over 5,000 MW of new renewable energy projects have received a FID or PPA.

Figure 7 Q4 2017 announced renewable capacity by fuel source

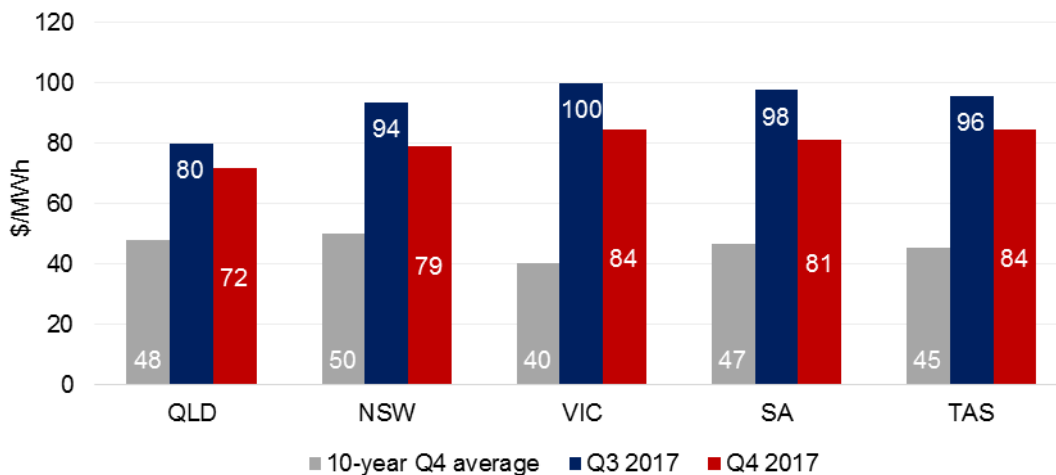


Source: BNEF and publicly available information

1.4 Wholesale electricity prices

Wholesale electricity prices averaged close to \$80/MWh across the NEM, with Victoria the highest region at \$84.45/MWh and Queensland the lowest at \$71.71/MWh (Figure 8). Whilst electricity prices for the quarter were generally the lowest quarter in 2017 they remained high compared to historical levels, with Q4 2017 the highest Q4 on record in all NEM regions except for South Australia.

Figure 8 Average wholesale electricity price by region



Note: Prices represented as simple average, not volume-weighted.

1.4.1 Wholesale electricity price drivers

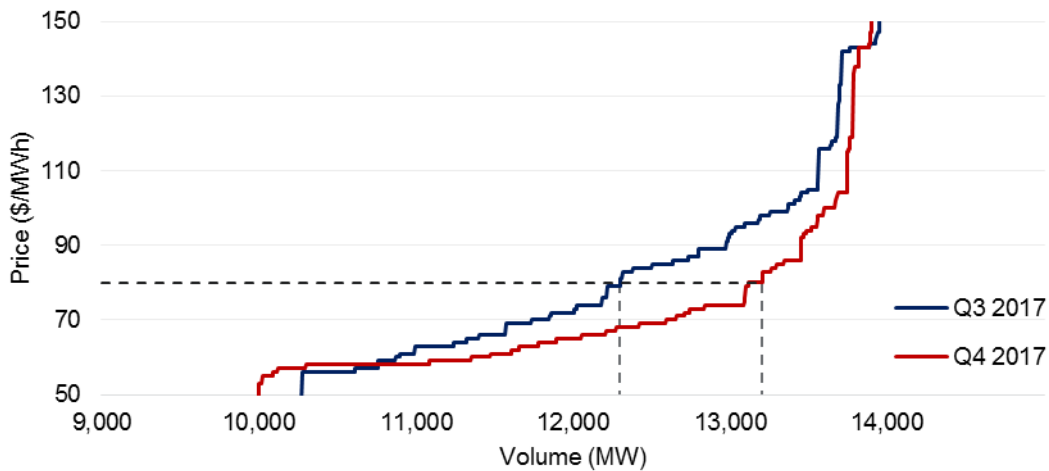
Factors contributing to lower wholesale electricity prices during Q4 2017 compared to Q3 2017 included:

1. Lower operational demand – average operational demand reduced across the NEM by 1,261 MW compared to Q3 2017. This change in demand is typical for the seasonal variation occurring between Q3 and Q4.
2. Greater availability of lower-priced black coal capacity (Figure 9) – between Q3 2017 and Q4 2017, the average amount of black coal-fired generation in the NEM priced below \$80/MWh increased from 12.3 GW to 13.2 GW (+7%, see Section 1.3).

¹⁵ **FID:** Made by company directors / management when a final decision is made on when, where and how much capital will be spent on a project. A project that has reached FID indicates a higher level of certainty that a company will attempt to proceed with construction in the near future.

¹⁶ **PPA:** A contract between two parties, one which generates (electricity and LGCs) and one who purchases. A project with a PPA indicates a level of certainty that a project will proceed. However, there may be a lengthy delay between when a project signs a PPA and when a project commences construction.

Figure 9 NEM Black coal bid supply curve



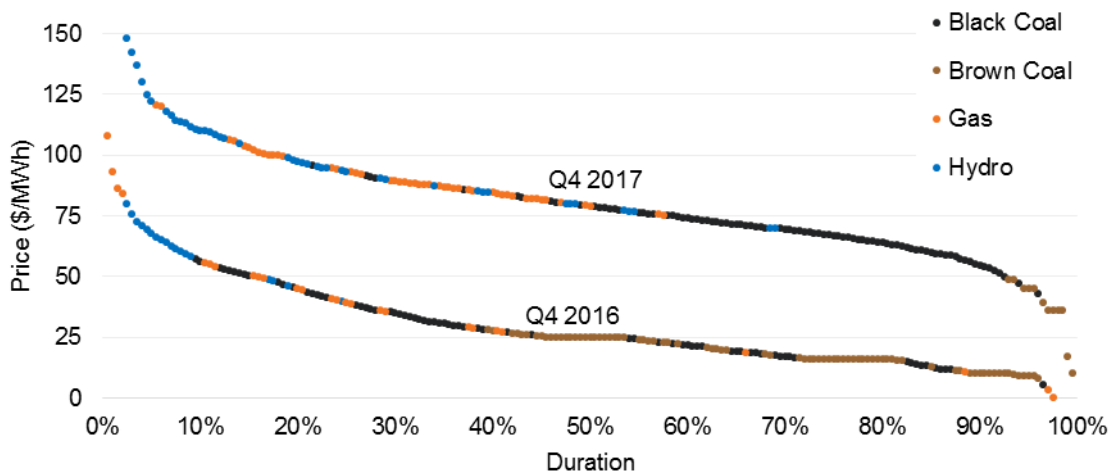
3. Greater availability of lower-priced GPG capacity – between Q3 2017 and Q4 2017, the average amount of GPG priced below \$100/MWh increased from 2,243 MW to 2,694 MW (+451 MW). This coincided with a reduction in gas prices in domestic markets compared to Q3 2017 (see Section 2.3)

Shifting wholesale electricity price dynamics in the NEM

Since Hazelwood retired in March 2017, all NEM regions have experienced relatively high wholesale electricity prices, driven by the reduction in low-priced capacity historically offered by Hazelwood, coupled to an increase in the price of offers by some generation types.

This change is most apparent in Victoria, where large shifts in generation mix and pricing have led to a 153% increase in electricity prices between Q4 2016 and Q4 2017, illustrated in its price duration curve (Figure 10). In Q4 2017, black coal set the price 39% of the time (up from 30%), brown coal at 5% (down from 40%), gas at 28% (up from 10%) and hydro at 28% (up from 20%). These changing dynamics resulted in the price for Q4 2017 being above \$50/MWh more than 94% of the time compared to only 22% of the time in Q4 2016.

Figure 10 Wholesale electricity price setting duration curve by fuel type (Victoria)

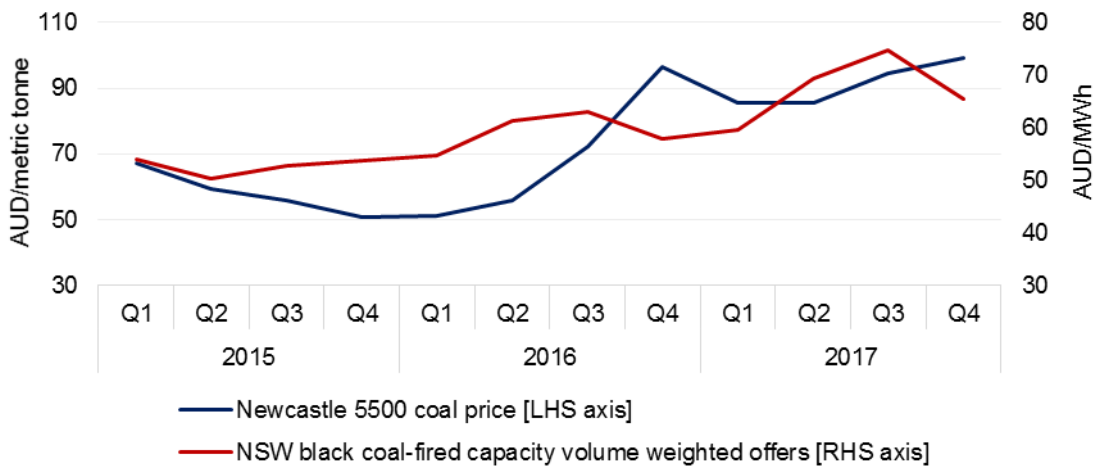


Note: Figure only shows wholesale electricity prices between \$0 and \$150/MWh, but all prices included in the analysis. Price-setting can occur inter-regionally, that is, Victoria’s price can be set by generators in other NEM regions.

1.4.2 International coal and prices

The monthly average spot price for Australian Newcastle thermal coal hit a 2017 high of over USD100 per tonne in December, driven by strong Chinese demand following the easing of import restrictions. The strong physical market in China also showed in the forward market, where coal futures see sustained prices above USD80 per tonne beyond 2018. Despite the high international coal prices, during the quarter domestic black-coal fired generators lowered the price of their wholesale electricity offers compared to Q3 2017 (see Section 1.4.1). This reflects a reversal of recent trends, where an increase in the price of offers from New South Wales black-coal fired generators has coincided with rising international coal prices (Figure 11).

Figure 11 Quarterly average international black coal price and domestic coal-fired generators' offers



Source: Bloomberg (for coal price). Note: Volume-weighted offer electricity price limited to offers between \$40/MWh and \$120/MWh.

1.4.3 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.¹⁷ In Q4 2017, FCAS costs were \$58 million¹⁸ – the second highest quarter on record (Figure 12), with record high annual FCAS costs of over \$200 million.

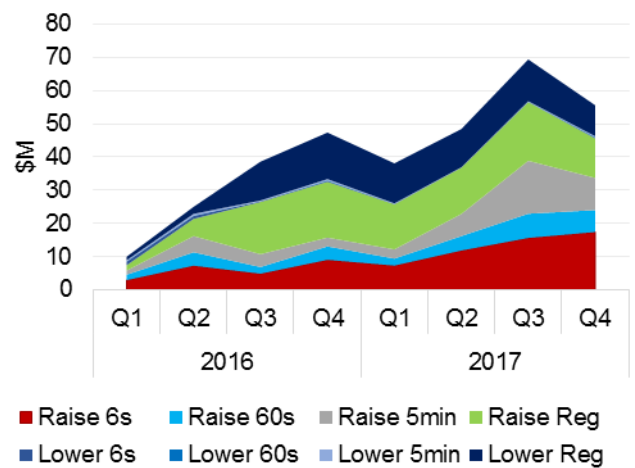
Despite this, in Q4 2017 FCAS costs were \$13 million lower than Q3 2017 (the highest quarter on record). Compared to Q3 2017:

- Regulation FCAS costs declined by \$9.1 million.
- Contingency Raise FCAS costs decreased by \$5.2 million.
- Contingency Lower FCAS costs increased by \$0.4 million.

Contributors to the decline in FCAS costs compared to Q3 2017 include:

- New supply – as mentioned in Section 1.3.1, two new participants (Hornsedale Power Reserve and EnerNOC) entered the FCAS markets during the quarter. The Hornsdale Power Reserve was enabled for FCAS in all eight

Figure 12 Quarterly FCAS costs by service



¹⁷ 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.

¹⁸ Represents preliminary data and subject to minor revisions.

FCAS markets, while demand response provider EnerNOC was enabled for FCAS in the Contingency Raise Services (mostly 60sec and 5min markets).

- Reduced pricing impact of the South Australian 35 MW FCAS constraint¹⁹ – in Q4 2017, the constraint had less of an impact on FCAS prices than in Q3 2017, due to fewer binding events, contributing to a 37% reduction in South Australian Regulation FCAS prices.

1.4.4 Electricity futures markets

During Q4 2017, the electricity futures recorded only minor changes for Calendar Year 2018 products (Figure 13). New South Wales and South Australia Calendar Year 2018 products traded up 2.0% and 2.1% respectively over the period, while Queensland and Victoria cleared prices declined by 1.6% and 0.9% respectively.

In contrast to Calendar Year products, swaps and caps for Q1 2018 and Q3 2018 recorded significant changes:

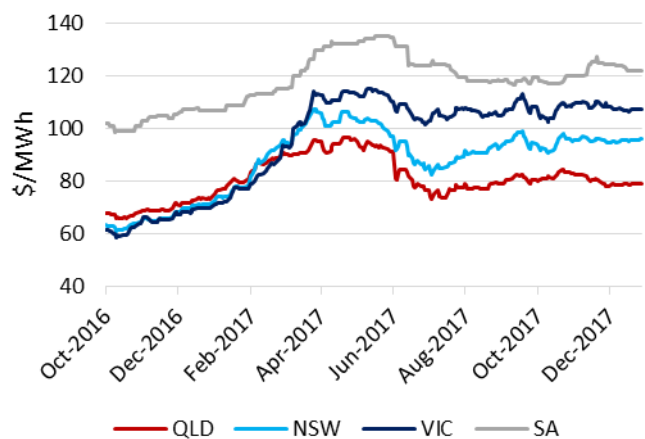
- **New South Wales:** Q1 Swap traded up 5.0% over Q4 whilst Cap recorded a 9.0% increase.
- **Queensland:** Q1 2018 Cap traded down 16.7%.
- **Victoria:** Q1 2018 Cap traded up 1.6% in Q4 2017.
- **South Australia:** Q1 2018 Cap traded up 20.3% whilst Q3 2018 traded down 31.7%.

1.5 Electricity flows

In Q4 2017, total flows across interconnectors in the NEM were significantly lower than in Q4 2016 (-1.7 TWh, -26%), particularly on the VIC-NSW interconnector (-2.2 TWh). Drivers of this reduction include:

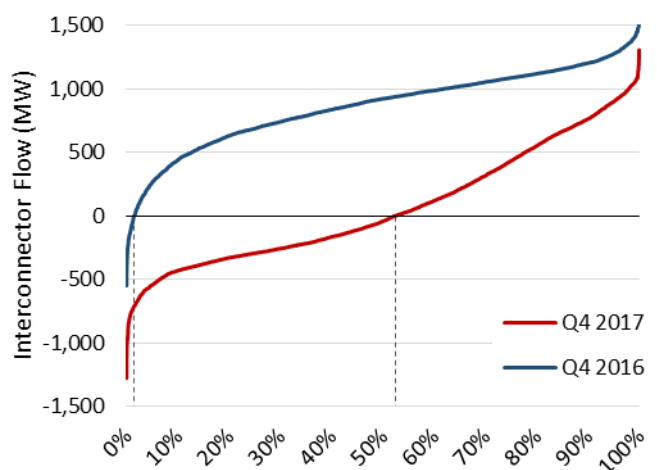
- Closure of Hazelwood Power Station – prior to the closure of Hazelwood, there were typically high levels of flows north on the VIC-NSW interconnector, due to a greater amount of lower-priced capacity in Victoria. Since Hazelwood’s closure, the marginal generators in each of the two regions have moved closer in price, reducing the requirement for flows between the regions (Figure 14).

Figure 13 CAL2018 Electricity futures price by region



Source: ASX Energy

Figure 14 Flow duration curve (VIC-NSW interconnector)



Note: Flows above zero are towards New South Wales, negative flows are towards Victoria.

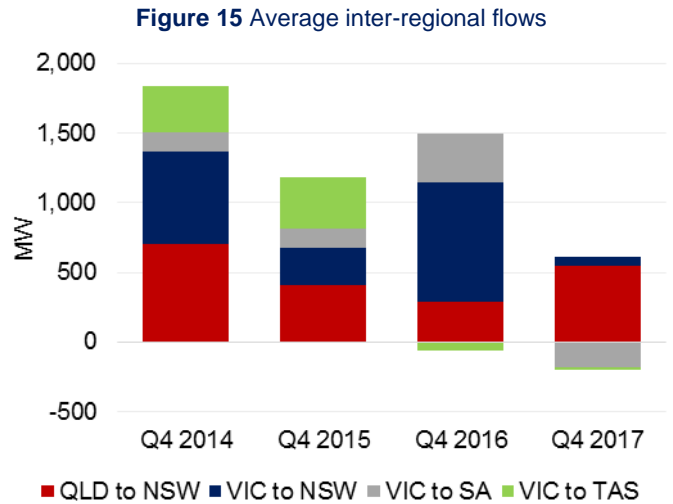
¹⁹ For system security purposes, AEMO requires the local procurement of 35 MW of regulation FCAS in South Australia at times when the separation of the region at the Heywood Interconnector is a credible contingency. During these times of local requirements, FCAS prices have been very high due to the limited number of suppliers of these services.

- Constraints on the VIC-NSW interconnector – flows south on the interconnector were limited by the N^{AV}_NIL_1 constraint²⁰, which bound more for 4.7% of the time in Q4 2017 (compared to never binding in Q4 2016). The constraint is mainly eased by generation from Upper Tumut and then Lower Tumut and Uranquinty in New South Wales; it is exacerbated by generation at Murray in Victoria. A 90% drop in generation from Tumut compared to Q4 2016 has contributed to limited flows south on the interconnector.

These factors also contributed to interregional settlement residue reducing from \$89 million to \$32 million between Q4 2016 and Q4 2017, largely on the VIC-NSW and VIC-SA interconnectors.

Figure 15 shows the year-on-year quarterly averages of net inter-regional flows for each directional interconnector. On average, New South Wales and Victoria were net importers of electricity (609 MW and 130 MW respectively) while Queensland, Tasmania and South Australia were net exporters.

During the quarter Victoria was a net importer of electricity and South Australia was a net exporter, with an average of 185 MW flowing from South Australia to Victoria (representing a net change of 531 MW compared to Q4 2016).²¹ This outcome is a function of significant thermal power station closures coupled with ongoing investment in renewable generation. For example, due to the large amount of wind capacity in South Australia and Victoria, wind conditions strongly influence interconnector flows in those regions. In Q4, net electricity exports from Victoria to New South Wales reduced significantly, decreasing from 861 MW in Q4 2016 to 67 MW in Q4 2017. This contributed to a quarter-on-quarter increase in flows from Queensland to New South Wales (256 MW).



²⁰ To avoid collapse for loss of the largest Victorian generating unit.

²¹ Interconnector flows are bi-directional. That is, at times during the quarter electricity flowed from Victoria to South Australia and vice versa.

2. GAS MARKET DYNAMICS – Q4 2017

2.1 Gas demand

Total gas demand (consisting of demand from AEMO’s markets, GPG demand and deliveries to the LNG projects on Curtis Island) increased by 35 PJ during Q4 2017 compared to Q4 2016, driven by increases in deliveries to Curtis Island (see Section 2.1.1) and GPG demand. (Table 2).

GPG demand increased 21 PJ compared to Q4 2016. The largest increases occurred in Victoria (10 PJ up from 1 PJ) and South Australia (18 PJ up from 10 PJ), driven by lower brown coal-fired generation (through the retirement of Hazelwood in March and unplanned outages at Yallourn and Loy Yang A) and lower hydro generation (see Section 1.3).

Demand in AEMO’s markets was 7 PJ lower than Q4 2017, driven by a 6 PJ reduction in demand in the DWGM²². A two degree increase in average daily temperatures in Melbourne, compared to Q4 2016 contributed to the reduction in residential and commercial demand in the DWGM.

Table 2 Total gas demand²³

Total Demand	Q4 2016 (PJ)	Q4 2017 (PJ)	Volume Change (PJ)
AEMO Markets²⁴	73	66	(7)
GPG²⁵	28	49	21
LNG	303	323	20
Total	403	438	35

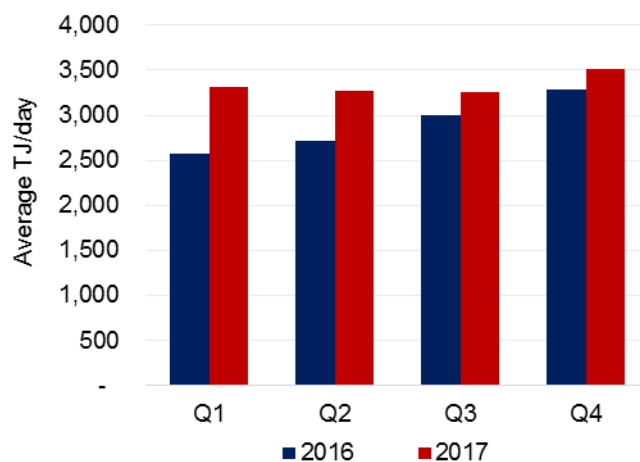
2.1.1 LNG

Record flows to Curtis Island were set during Q4 2017 where quarterly average deliveries exceeded 3,500 TJ/d for the first time (Figure 16).

Average flows for Q4 2017 increased by 250 TJ/d compared to Q3 2017, driven by increased equity production and greater pipeline deliveries from Victoria and Moomba compared to the previous quarter.

Brent oil also reached its highest price since December 2014 (67.02USD/bbl on 26th December 2017), therefore increasing the oil-linked price for LNG and incentivising additional sales of LNG.

Figure 16 Gas deliveries to Curtis Island



2.2 Gas supply

Greater gas production from Queensland²⁶ and Longford during Q4 2017 has driven total supply to increase by 35 PJ compared to Q4 2016.

Driven by an increase in deliveries to Curtis Island (or ‘LNG demand’) Queensland supply increased by 29 PJ compared to Q4 2016 (Figure 17). Overall, 2017 was a record year for Queensland gas production.

²² DWGM demand in this instance refers to residential, commercial and industrial loads only. *GPG demand* ordinarily included as part of the DWGM has been excluded and is instead reported separately as part of *GPG demand*.

²³ The total demand does not include regional demand i.e. demand that is not captured by one of the markets.

²⁴ AEMO Markets demand is the sum of customer demand in each of the STTM’s and the DWGM.

²⁵ Includes demand for GPG usually captured as part of total DWGM demand.

²⁶ The Queensland production is based on grouping all Gas Bulletin Board production facilities in the Roma Zone of the Gas Bulletin Board.

A quarterly production increase of 10 PJ compared to Q4 2016 contributed to record annual production volumes at the Longford and Otway gas plants for the second consecutive year (Figure 18). This trend is unlikely to continue as production at Longford is forecast to return to historical levels of between 230 PJ/yr and 260 PJ/yr.

Figure 17 Production by gas plant (Queensland is grouped)

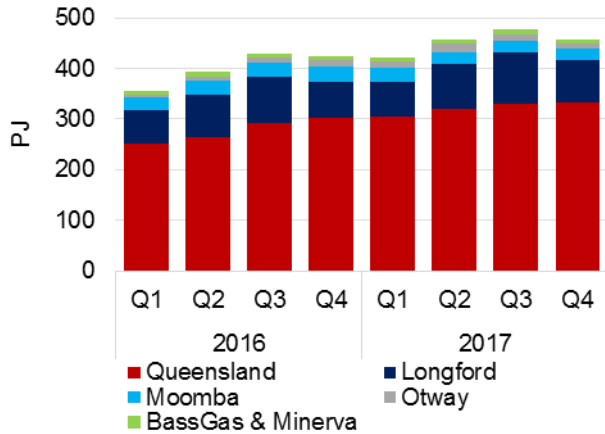
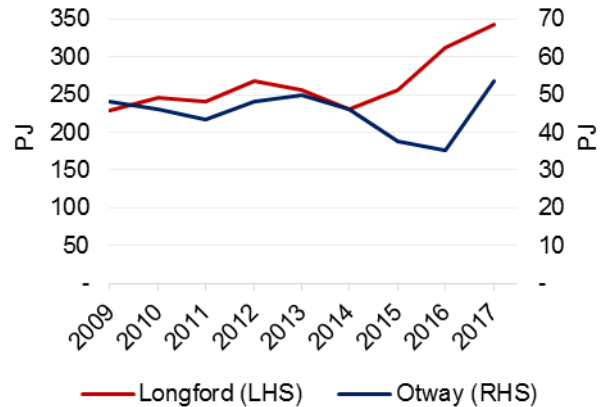


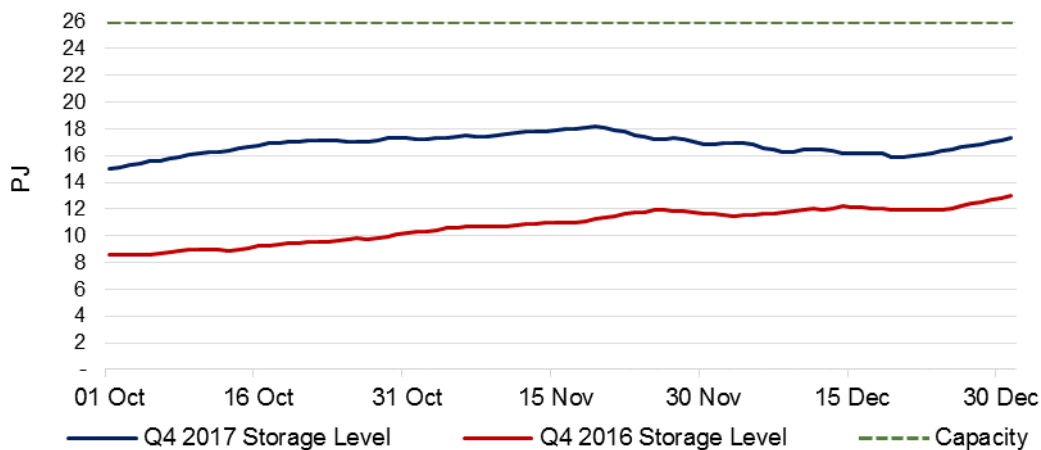
Figure 18 Longford and Otway gas plants long-term production



2.2.1 Gas storage

Iona Underground Storage levels ended the year 4 PJ higher than at the end of 2016 (Figure 19), primarily because storage levels were impacted by supply issues in 2016. Despite this, Iona only filled 2.4 PJ during the quarter compared to 4.4 PJ in Q4 2016. Contributing factors to this were higher GPG demand and Victorian gas exports (despite Longford producing at record levels).

Figure 19 Iona Underground Storage Facility - Storage Levels

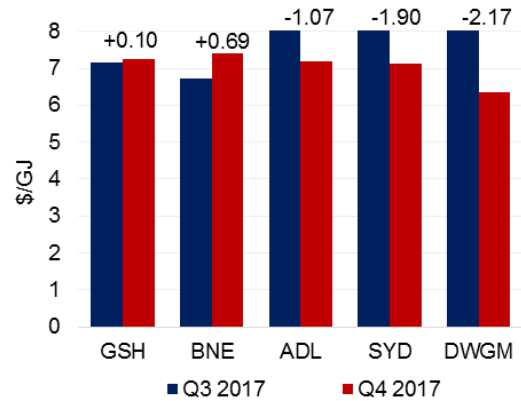


2.3 Wholesale gas prices

Seasonal temperature increases during Q4 2017 in Adelaide, Sydney and Melbourne resulted in reduced demand and a reduction in average quarterly wholesale gas prices when compared to Q3 2017 (Figure 20).

- The average quarterly price in the DWGM decreased by \$2.17/GJ to \$6.36/GJ during Q4 2017. This 25% decrease in gas prices was primarily caused by milder weather compared to Q3 2017 leading to less heating demand for gas.
- In the Sydney STTM, an average quarterly price of \$7.12/GJ was recorded during Q4 2017, a reduction of \$1.90/GJ compared to Q3 2017.
- In the Adelaide STTM, an average quarterly price of \$7.19/GJ was recorded during Q4 2017, a reduction of \$1.07/GJ from the previous quarter.

Figure 20 Average wholesale gas price per market



2.3.1 International gas prices

During the quarter, a disparity emerged between the indicative LNG contract price and the price of wholesale gas on the domestic market (Figure 21). Increased LNG prices were driven by:

- Delay of nuclear restarts in Japan.
- Reduced LNG exports from Indonesia.
- Strong northern hemisphere winter demand.
- China’s shift away from domestic coal-fired generation towards imported LNG.
- Brent Crude (to which the price of LNG is linked) has increased by about AU\$13.00 per barrel between 01 July 2017 and 31 December 2017.

Figure 21 Domestic versus international gas prices



Note: LNG export price based on Brent Spot Price (sourced from Reuters) with 14% slope.

2.4 Pipeline flows

Quarterly increases in supply from Victoria’s production facilities (+12 PJ compared with Q4 2016) has contributed to greater gas exports to neighbouring states (Figure 23). An additional 10 PJ was exported during Q4 2017 from Victoria compared to Q4 2016. Increased exports were driven by increased Longford production (see Section 2.2) resulting in greater Eastern Gas Pipeline deliveries to New South Wales, and increased deliveries to Tasmania along the Tasmanian Gas Pipeline to meet greater GPG demand from Tamar Valley.

Net deliveries along the South West Queensland Pipeline (SWQP) flowed northerly towards Wallumbilla during Q4 2017 (Figure 22). Net quarterly deliveries to Wallumbilla were 8 PJ less than Q4 2016 and this reflects increased native Queensland production as average daily deliveries to Curtis Island reached record levels in advance of the northern hemisphere winter.

Figure 22 SWQP at Wallumbilla

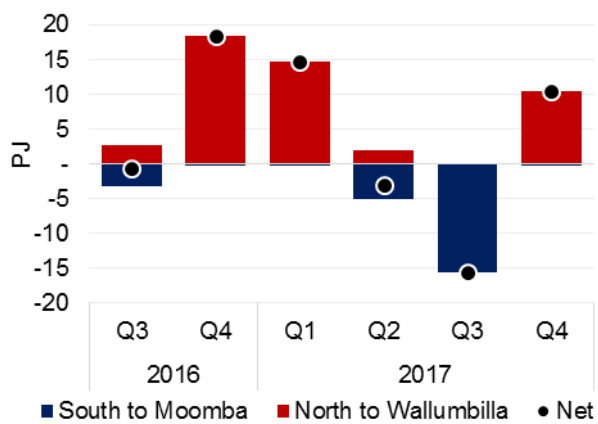
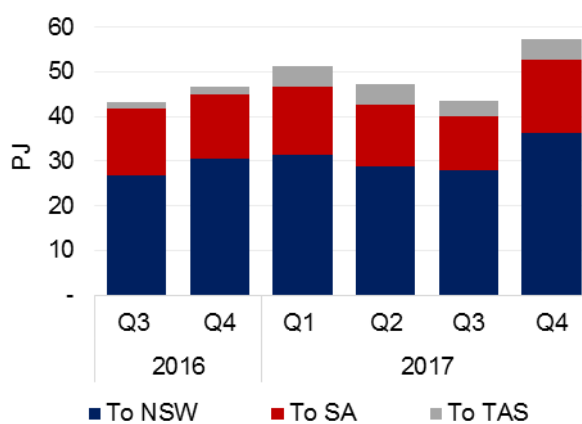


Figure 23 Victorian gas exports to other states



APPENDIX A. ABBREVIATIONS

Abbreviation	Expanded name
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
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