Report to the Minister for Energy on the Effectiveness of the Wholesale Electricity Market 2017/18

Discussion paper

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Economic Regulation Authority
WESTERN AUSTRALIA

DMS196819

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Invitation to make submissions

Submissions are due by 4:00 pm WST, Friday, 8 February 2018

The ERA invites comment on this paper and encourages all interested parties to provide comment on the matters discussed in this paper and any other issues or concerns not already raised in this paper.

We would prefer to receive your comments via our online submission form https://www.erawa.com.au/consultation

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Please note that submissions provided electronically do not need to be provided separately in hard copy.

All submissions will be made available on our website unless arrangements are made in advance between the author and the ERA. This is because it is preferable that all submissions be publicly available to facilitate an informed and transparent consultative process. Parties wishing to submit confidential information are requested to contact us at info@erawa.com.au.

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1. Introduction

The ERA is required to review and prepare a report for the Minister for Energy on how effectively the Wholesale Electricity Market (WEM) meets its objectives:

- every three years under the *Electricity Industry Act 2004*[1]
- annually under the Wholesale Electricity Market Rules.[2]

This year, both reviews will be combined into a single report.

The Act requires the ERA to review the operation of the WEM and consider the extent to which the market objectives are being achieved. Where they are not achieved, the ERA is required to provide recommendations on how they could be achieved.

The annual review under the Market Rules requires the report to the Minister to contain the following:

- A summary of the information and data listed in Market Rule 2.16.1. This is the data the Australian Energy Market Operator (AEMO) must provide to the ERA in the Market Surveillance Data Catalogue.
- The ERA's assessment of the effectiveness of the market, including how effectively AEMO carries out its functions, with discussion of the following:
    - Reserve Capacity Market
    - market for bilateral contracts for capacity and energy
    - Short Term Energy Market
    - Balancing Market
    - dispatch processes
    - planning processes
    - administration of the market, including the Market Rule change process
    - ancillary services.
- An assessment of any events or behaviour that influenced the effectiveness of the market.
- Any recommended measures to increase how effectively the market meets the market objectives for the Minister for Energy to consider.

The ERA may also choose to address other issues not included above.

The WEM objectives are to:[3]

- Promote the economically efficient, safe and reliable production and supply of electricity and electricity-related services in the South West Interconnected System.

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1 Section 128 of the Electricity Industry Act

2 Clause 2.16.12 of the Market Rules

- Encourage competition among generators and retailers in the South West Interconnected System, including by facilitating the efficient entry of new competitors.
- Avoid discrimination in market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or reduce overall greenhouse gas emissions.
- Minimise the long-term cost of electricity supplied to customers from the South West Interconnected System.
- Encourage the taking of measures to manage the amount of electricity used and when it is used.

1.1 Purpose of this discussion paper

To prepare for the review, the ERA has analysed market data, considered information provided in discussions with market participants, and collected evidence from past reviews of the market. This discussion paper combines this analysis and outlines the ERA's initial observations and inferences on:

- how well the WEM is achieving its objectives
- what may be driving these market outcomes.

Market observations from the 2017/18 financial year are provided in Appendix 1.

This discussion paper presents an opportunity for participants to respond to the information presented and the inferences drawn from them. The ERA encourages interested parties to make submissions during the consultation period, providing evidence or practical examples where possible.

Information received during the consultation process will inform the ERA's preparation of the final report to the Minister for Energy.

1.2 Reporting context

An extensive market reform program is currently under way in the WEM. This is being managed and co-ordinated by the Public Utilities Office (PUO), with support from AEMO. The reform process provides forums for market participants to have their say.[4]

Many of the reforms identified in the program aim to address known shortcomings within market mechanisms, such as those that exist within ancillary services and network access.

At the time of writing, the details of the reform are still under consideration and so are not addressed in this paper. Instead, the paper will:

- Document matters highlighted by the data the ERA reports on, such as rising wholesale electricity prices. This is covered in chapter 2.
- Look beyond the implementation of market reforms to identify future problems that may impede the effective operation of the WEM, including the future investment environment. This is covered in chapter 3.

[4] http://www.treasury.wa.gov.au/Public-Utilities-Office/Industry-reform/Wholesale-Electricity-Market-reform-work-program/

2. Pricing trends in the WEM and potential drivers

Wholesale electricity prices in the Wholesale Electricity Market (WEM) have increased by just under 50 per cent in the last six years.

After adjusting prices to account for the effect of the carbon pricing mechanism,[5] annual average balancing prices have increased by approximately 46 per cent in real terms since the balancing market commenced in 2012/13.[6] Balancing market prices have persistently increased during both peak and off-peak periods.[7]

The ERA has examined changes in demand and trends in underlying costs. These elements do not appear to account for the wholesale price increases as indicated by the preliminary findings outlined in sections 2.1 and 2.2. There are other factors that could be influencing wholesale prices, such as an increase in how frequently gas-fired generation sets the balancing price.

The ERA is interested in exploring what else may be driving up wholesale electricity prices.

Synergy has significant market power in a highly concentrated wholesale electricity market. No other generator in the WEM has a sufficiently large market presence to be able to exert competitive discipline on Synergy, and downward pressure on wholesale prices. The ERA has explored the potential for market power to drive up wholesale prices in section 2.3.

2.1 Changes in demand

In 2017/18, demand was low but balancing market prices were the second highest on average since the market began in July 2012. Low demand would normally result in lower prices. However, this did not occur.

The last two summers have been relatively mild.[8] With temperature-dependent demand weak, the WEM should not have recorded higher wholesale prices. **Figure 1** in the next section shows that balancing prices reduced slightly between 2016/17 and 2017/18. The lower demand in 2017/18 has likely influenced this reduction as bids into the market over the same period remained high. This is addressed later in the paper.

5 The carbon pricing mechanism commenced in July 2012 and was repealed in July 2014.

6 Carbon price adjustments are the product of the average emissions intensity for the South West Interconnected System for scope 2 emissions reported in the National Greenhouse and Energy Reporting System (DCCEE, 2012) and (DCCEE, 2013), and the regulated carbon price in effect for the period in question. Additional information is available from:

http://www.cleanenergyregulator.gov.au/Infohub/CPM/About-the-mechanism

http://www.environment.gov.au/climate-change/climate-science-data/greenhouse-gas-measurement/publications/nger-technical-guidelines-2013

http://www.environment.gov.au/climate-change/climate-science-data/greenhouse-gas-measurement/publications/nger-technical-guidelines-2012

7 Refer to Figure 10 and 11 in the Appendix.

8 http://www.bom.gov.au/climate/current/season/wa/archive/201802.perth.shtml and http://www.bom.gov.au/climate/current/season/wa/archive/201702.perth.shtml

Current forecasts indicate that summer 2019 temperatures will be above average.[9] When the temperature increases demand will increase, and electricity prices can be expected to rise further.

While the current low level of demand appears to be putting downward pressure on wholesale electricity prices, a change in the profile of demand could drive balancing prices in the opposite direction.

The sustained high level of installation of behind-the-meter rooftop photovoltaics (PV) has changed network demand. Rooftop PV installation has:

- suppressed demand from the network in the middle of the day
- suppressed day-time prices on weekends.

By dampening network demand in the middle of the day, rooftop PV creates peaks in the morning as consumers prepare for the day ahead, and in the evening as they arrive home.

Generator costs can increase if they are dispatched more often, ramped up and down more frequently, or run for shorter periods to meet these changes in demand. Generators' increased costs need to be recovered through higher bids into the balancing market. If there is a change in how generators are dispatched, this could drive up wholesale electricity prices.

Synergy owns half the accredited generation capacity in the WEM and sets prices in the majority of trading intervals. To determine if generator run times may be influencing bids into the balancing market, the ERA examined the average run duration of Synergy's largest generators.[10]

The majority of average run times appear to have changed little between years.[11] Only the Cockburn closed-cycle gas turbine showed a material enough change in average run time that might indicate a need for higher bids into the market to recover costs. However, Cockburn's output is diminishing. Cockburn's capacity factor (the ratio of its actual output to potential output over time) is currently low at around 5 per cent. Therefore, it cannot account for price setting in the majority of intervals.

From analysis of Synergy's generators, the ERA has not found any strong evidence to suggest that behind-the-meter solar generation is causing widespread changes to generator run time durations or start up frequencies. However, if the changes in network demand persist, and generators are dispatched differently in response, this could affect future balancing market prices.

2.2 Input fuel costs

Balancing market bids are made up of start-up costs, fuel costs, and variable operation and maintenance costs.[12] Typically, fuel costs comprise the largest component of the

9 Bureau of Meteorology (2018) Climate Outlook for December to February, Issued 29 November 2018, Bureau of Meteorology, Canberra, http://www.bom.gov.au/climate/ahead/outlooks/archive/20181129-outlook.shtml

10 These were Pinjar, Kemerton, Kwinana High Efficiency Gas Turbines, Cockburn, Collie and the eight Muja units.

11 Refer to Figure 7 in the Appendix.

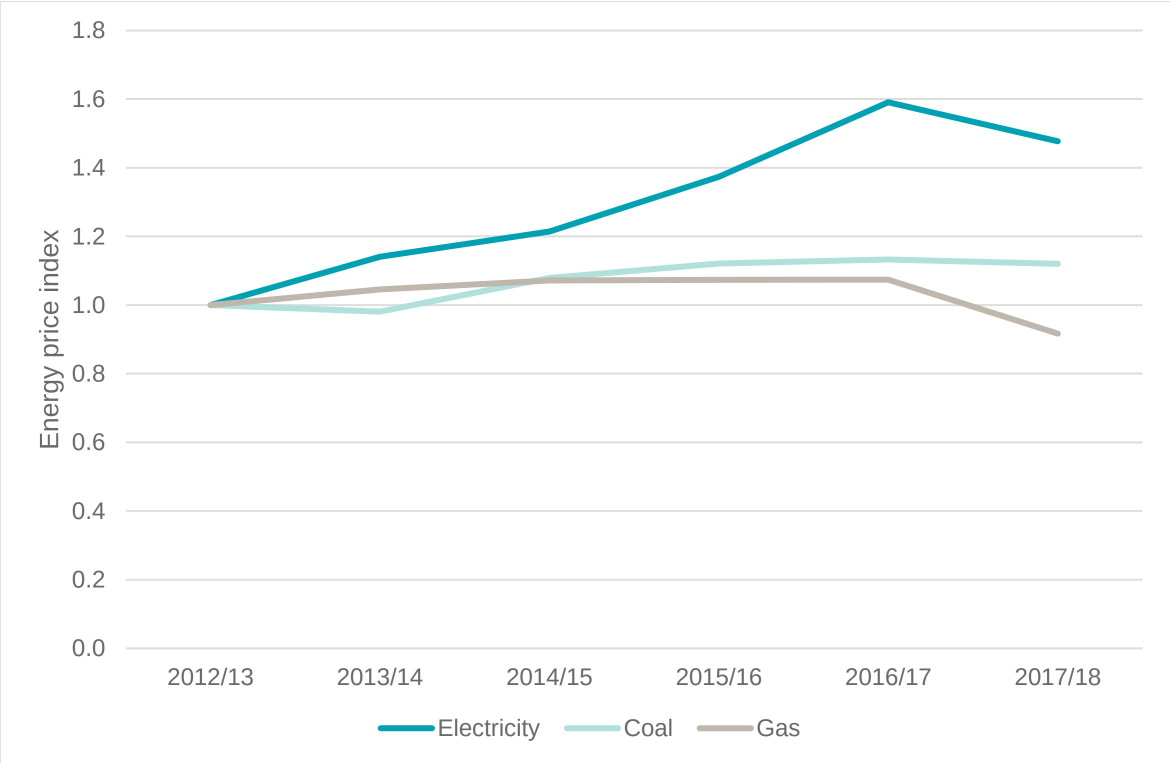
12 McHugh A, (2008) Portfolio Short Run Marginal Cost of Electricity Supply in Half Hour Trading Intervals, Technical Paper, Economic Regulation Authority, Perth

operational costs used to prepare a balancing market bid, consistent with a generator's short-run marginal cost.

The ERA has graphed publically available[13] data on fuel prices in Figure 1. This shows the volume-weighted average gas price for domestic gas production and domestic coal sales against average balancing prices.

Gas and coal prices have been subject to relatively modest price increases in recent years, with gas falling in real terms last financial year. This is in contrast to the average balancing market price for electricity.

Figure 1: Quarterly average fuel and weighted quarterly average balancing market electricity prices[14] [15]



Source: ERA analysis of Department of Mines, Industry, Regulation and Safety (DMIRS), AEMO and Gas Trading data

Note: DMIRS publishes a time series of gas and coal production values compiled from royalty collections.[16] This data provides a volume-weighted average price of gas sales from producers into the domestic market. Downstream trades between non-producers, such as swaps and most spot sales, are not captured in this data set. Nevertheless, it provides information on fuel price trends in the market. Coal sales values are also derived from royalty returns and provide comparable contracted pricing data.

13 Western Australian fuel supply contracts are typically confidential but some data on fuel prices is publicly available

14 Weighted average producer fuel cost data is for arms-length sales from commodity producers reported to the Department of Mines, Industry Regulation and Safety for their royalty determination. Gas prices also include variable transport charge for T1 tariff.

15 Prices are indexed against 2012/13 values in real terms against $2018.

16 DMIRS (2018) Major Commodities Resources File, DMIRS, Perth, http://dmp.wa.gov.au/Documents/Investors/Major-Commodities-2017-2018.xlsx

The quarterly average contract prices for domestic gas[17] appear to be converging on the quarterly average gas spot market prices.[18] Between 2016/17 and 2017/18, gas spot market prices have reduced, and analysis undertaken by the ERA suggests the trading price range appears relatively insensitive to the volumes traded.[19]

In conclusion, the ERA's preliminary analysis suggests that the low level of demand and flat or declining fuel input prices have not suppressed wholesale electricity prices.

Issue

Wholesale electricity prices have continued to rise in spite of downward pressure from demand and fuel prices.

Question

1. What other factors may be driving up wholesale electricity prices if not demand or fuel costs?

Although demand is only growing slowly, the profile of demand has changed with the penetration of rooftop solar.[20] Greater use of gas-fired generation to provide the rapid ramp-up in generation output to meet the afternoon peak could be driving higher input costs. The ERA's initial findings on run times for Synergy's major generators suggests this is not the case. However, Synergy's portfolio bidding masks the identity of price setting units within a tranche of generation. This makes it difficult to determine whether a coal or gas generator is setting the balancing price in each interval.[21] The ERA is continuing to research this issue.

Issue

As the penetration of renewable energy behind the meter increases, it is altering the load profile serviced by generators in the WEM. This alteration has the potential to increase costs.

Question

2. Do market participants consider generators are changing their bids into the balancing market to recover higher start-up and shut down costs over shorter run times?

2.3 Market power

Synergy controls around 80 per cent of generation in the WEM through its own fleet of generators and through power purchase agreements. Collectively, the three largest

[17] AEMO (2017) Gas Statement of Opportunities for Western Australia, Australian Energy Market Operator, Perth, p33, https://aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/WA_GSOO/2017/2017-WA-GSOO.pdf

[18] http://www.gastrading.com.au/spot-market/historical-prices-and-volume/13-historical-prices-and-volume/27-price-history-table

[19] http://www.gastrading.com.au/spot-market/historical-prices-and-volume/13-historical-prices-and-volume/25-bid-information-scheduled-gas

[20] AEMO (2018) Electricity Statement of Opportunities, Australian Energy Market Operator, Perth, Perth, p37

[21] A portfolio generation tranche or bid may reflect part of the output from a single generator or a composite of multiple generators.

generators in the market (Synergy, Summit Southern Cross Power, and Alinta) have a market share of 90 per cent of generation sent out.

The ERA is concerned that Synergy's dominance and the lack of competition in the WEM could enable Synergy to exercise market power and push up wholesale electricity prices. At the time of writing, Synergy was under investigation into its pricing behaviour.[22]

High wholesale prices are ultimately passed through to consumers, who may be charged more for electricity than would be the case in a competitive market. Competitive pressure also creates efficiency as firms seek ways to reduce their costs of production to remain competitive.

There are regulations that place restrictions on Synergy to mitigate the potential for it to misuse market power.

Non-discrimination requirements in the Electricity Generation and Retail Corporation (EGRC) scheme ensure that Synergy must not offer wholesale supplies of electricity to its retail business unit on terms and conditions that are more favourable than those offered to retail or generation competitors. So if Synergy did use its market power to inflate wholesale prices, then its own retail business unit would also buy wholesale supplies at the inflated prices. This non-discrimination requirement exists to restrict Synergy's retail business unit from having a competitive advantage in the contestable retail sector.

There are five other retailers actively competing with Synergy in the retail market, and Synergy's contestable retail market share, measured by consumption has declined over time.

As a vertically integrated company with market power, Synergy could potentially increase wholesale electricity prices and profit in the wholesale sector, while being unconcerned about a loss of retail market share or a reduced profit in its retail business unit.[23] The retail business unit's reduced profit will be offset by gains by the wholesale business unit from the price mark-up. The wholesale business unit will also collect a price mark-up from the third party generators and retailers contracting for supply with Synergy. This is demonstrated by the example in the box below.

[22] https://www.erawa.com.au/electricity/wholesale-electricity-market/market-behaviour-investigations/2017-investigation-into-synergys-pricing-behaviour

[23] See page 7 of the Parliamentary transcript from the Assembly Estimates Committee meeting held on 19 September 2017. Regardless of the RBU reporting a loss of $273 million, by combining the WBU and the RBU results, Synergy made an overall profit, an outcome that was a function of the internal transfer price.

Western Australia, Assembly Estimates Committee A, p7, 19 September 2017, Budget Estimates, http://www.parliament.wa.gov.au/hansard/hansard.nsf/0/0c4ff5c8fe13b7c1482581ae00222869/$FILE/A40+S1+20170919+p78b-86a.pdf

The requirements for transfer pricing and for Synergy to set non-discriminatory wholesale prices do not eliminate the opportunity for Synergy to charge price mark-ups above efficient levels. If Synergy marks-up its wholesale prices, there is no effect of this mark-up on Synergy's overall profit from supplying to its own retail business unit at the marked-up price. Combining, the wholesale and retail business units' profits cancels out the quantity bought by the retail business unit at the marked-up wholesale price.

Synergy's profit is determined by the quantities sold to third-party generators and retailers at the marked-up price, combined with the quantity sold by the retail business unit at its retail price, minus the Synergy's wholesale costs. A simple mathematical explanation of how this is possible is provided below:

$$Wholesale\ profit = (Retail\ quantity\ bought\ \times wholesale\ price) + (third\ party\ quantities\ \times wholesale\ price) - wholesale\ cost$$

$$Retail\ profit = (Retail\ quantity\ sold\ \times Retail\ price) - (Retail\ quantity\ bought \times wholesale\ price)$$

$$Synergy\ profit = Wholesale\ business\ unit\ profit + Retail\ Business\ Unit\ profit$$

$$Synergy\ profit = (\cancel{RBU\ quantity\ bought\ \times wholesale\ price}) + (third\ party\ quantities\ \times wholesale\ price) - wholesale\ cost + (Retail\ quantity\ sold\ \times Retail\ price) - (\cancel{RBU\ quantity\ bought \times wholesale\ price})$$

$$Synergy\ profit = (third\ party\ quantities\ \times wholesale\ price) - wholesale\ cost + (Retail\ quantity\ sold\ \times Retail\ price)$$

Synergy's profit is therefore not dependent on the Retail Business Unit's wholesale supply costs.

If Synergy is misusing its market power to inflate wholesale contract prices, the wholesale supply arm of Synergy's business could earn additional income over and above what it would earn in a competitive market. Where consumer demand is insensitive to changes in price, consumers will pay for the inefficient pricing in the long term.

Market power is not always transitionary and can endure in the WEM given the existing barriers to entry for new generators: long lead times on project approvals and development, and delays obtaining network access.

Synergy's market power may also have implications for the contestable retail market.

Although this retail market appears competitive, as noted above, there has been no change in the number or market share of small, standalone retailers.

Not all retailers have their own generation to supply customers. Those that do are not always perfectly hedged, and do not always generate electricity in quantities that exactly match their retail obligations. Small, standalone retailers mostly procure electricity from the balancing market and short term energy market.

Retailers that want to hedge against volatility in wholesale electricity market spot prices have limited options other than to contract with Synergy for a wholesale supply. Typically, this contracting is through mandated standard products or customised contract arrangements.

If Synergy were to use its market power to inflate wholesale contract prices, this could undermine the use of standard and customised products as hedging tools, and limit the development of further competition in the contestable retail market. In its reports to the Minister for Energy on the effectiveness of the EGRC scheme, the ERA has made recommendations on how to improve access to standard products as a hedging tool that would not adversely affect Synergy's legitimate commercial interests.

The ERA is concerned that Synergy has market power, and that there is insufficient competitive discipline on Synergy in the WEM to keep wholesale prices down.

Synergy's dominance in the WEM is likely to persist for the foreseeable future. In the absence of competitive pressure, Synergy's market power needs to be reduced to limit the extent to which Synergy can misuse its market power to push up wholesale prices. Only when Synergy's market power is curtailed will market participants have confidence that wholesale prices are efficient and reflective of underlying market characteristics, such as: changes in demand and supply costs.

The ERA is still of the view that restructuring Synergy remains the best way to curtail Synergy's market power in the wholesale or retail markets. However, restructuring Synergy has not been government policy. In the absence of restructuring, other measures should be considered to curtail Synergy's use of its market power.

In the National Electricity Market, the Australian Competition and Consumer Commission (ACCC) concluded that "high and entrenched levels of concentration in the market", coupled with changes to fuel prices, elevated electricity prices.[24] Measures recommended by the ACCC that could be relevant to addressing limited competition in the WEM include:

- Generation ownership - amending the market rules to prevent acquisitions or other arrangements that would enable a market participant to own or control more than 20 per cent of dispatch.[25]
- Market-making - introduce mechanisms to require generators to make hedging products available.[26]

The Minister for Energy has directed Synergy to reduce its generation cap.[27] The reduction in capacity resulted in plant retiring from the market, but the capacity retired rarely ran and the change to the cap is unlikely to result in any material difference in market dominance. Synergy's joint venture green fund, through which it is developing new renewable energy projects, allows it to maintain its dominance by capturing opportunities for new projects.[28] With the change in cost of renewable generation projects, their exemption from Synergy's generation cap warrants consideration.

24 ACCC (2018) Restoring Electricity Affordability and Australia's Competitive Advantage: Retail Electricity Pricing Inquiry – Final Report, ACCC, Canberra, p xviii

25 ACCC (2018) Restoring Electricity Affordability and Australia's Competitive Advantage: Retail Electricity Pricing Inquiry – Final Report, ACCC, Canberra, p xvii

26 ACCC (2018) Restoring Electricity Affordability and Australia's Competitive Advantage: Retail Electricity Pricing Inquiry – Final Report, ACCC, Canberra, pp129-130

27 Government of Western Australia, Electricity Corporations Act, Ministerial Direction, 17 November 2016 http://www.parliament.wa.gov.au/publications/tabledpapers.nsf/displaypaper/3914913c260ae23260b839a74825807400138d6b/$file/tp-4913.pdf

28 Western Australia, Media Statements, New Renewables Projects in WA given 'green light', https://www.mediastatements.wa.gov.au/Pages/McGowan/2018/04/New-renewables-projects-in-WA-given-green-light.aspx, accessed on 118 December 2018

The EGRC regulations contain a 'market making mechanism,' the standard product regime which obligates Synergy to make mandated standard products available to its competitors. These are fixed quantities of energy that Synergy must advertise for sale and purchase at published prices. However, the efficacy of the EGRC regulations appears hampered by the size of the spread between the standard product sell price and buy price.[29] The standard product buy-sell spread was intended to constrain Synergy from raising its standard product prices too high. If it did, then Synergy risks having to purchase standard products at published prices that may be above the balancing price, especially if the balancing price is volatile, as it has been in the WEM over the last two financial years. Synergy will avoid purchasing additional electricity as it already has more than enough from existing generation output and contracts to meet its retail obligations. If there is no risk that Synergy will be obligated to purchase energy, the buy price is not an effective anchor for the sell price.

The Energy Security Board also recommended a market liquidity obligation as part of the National Energy Guarantee with an introductory spread of five percent for its proposed market making mechanism in the National Electricity Market (NEM). This is much lower than the 20 percent spread set in the EGRC regulations.[30] The ERA recommends the standard product spread be reduced to 10 per cent. If the Minister implements a reduced spread and demand for standard products fails to materialise, then the spread could be tightened further or, as has happened in New Zealand, the standard product quantities and terms could be reconsidered.[31]

Financial reporting obligations are another way to expose gains resulting from excessive pricing. In the United Kingdom, electricity generation licensees have financial performance reporting obligations.[32] The requirements followed a review of transfer pricing practice within vertically integrated entities in the electricity market.

The guidelines standardised the reporting conditions and format preventing generators from aggregating electricity market activities with those outside national borders or in different markets (such as gas retail) thereby obscuring activity in the electricity market. Since the introduction of standardised segmented financial reporting guidelines in 2015, market concentration has reduced and lower generator margins have been reported.[33]

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29 ERA (2017) 2016 Report to the Minister on the Effectiveness of the EGRC Regulatory Scheme, ERA, Perth, pp 17-22

30 Energy Security Board (2018) National Energy Guarantee Technical Working Paper – Qualifying Contracts, COAG Energy Council, Canberra, p16, http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/TWP%20-%20Qualifying%20Contracts%20-%20June%202018.pdf#page=16&zoom=100,0,536

31 ASX (2017) ASX New Zealand Electricity Derivatives Market – Market Development, ASX, Sydney, pp1

https://www.asx.com.au/documents/products/NZ_Electricity_Market_Development_May_2017.pdf

32 OFGEM (2015) Guidelines for Preparing Consolidated Segmental Statements, OFGEM, London, https://www.ofgem.gov.uk/sites/default/files/docs/2015/05/css_guidelines_jan_2015.pdf

33 OFGEM (2018) State of the Energy Market – 2018 Report, OFGEM, London, pp 49-56 https://www.ofgem.gov.uk/system/files/docs/2018/10/state_of_the_energy_market_report_2018.pdf

Issue

The WEM is highly concentrated. Synergy is dominant through its own generation plant and power purchase agreements with other generators. There is insufficient competitive discipline on Synergy to keep wholesale prices down.

Infra-marginal generators, which are dispatched with bids below the balancing price, benefit from these higher balancing prices.

Questions

3. Is the market applying sufficient pricing discipline on generators in light of the high level of concentration in the WEM?
4. Aside from disaggregation, what other measures could improve competitive discipline in the WEM? How would these measures work?

2.4 Conclusion

The ERA's analysis suggests that neither demand nor fuel prices are driving wholesale prices higher. Increased penetration of intermittent generation, particularly behind-the-meter, is dampening network demand during the middle of the day. However, analysis of Synergy's largest generators shows that this has not yet begun to shorten generator average run duration; or, at least, not to the point where it needs to substantially increase bids to recover start-up and shut down costs over shorter run times.

Synergy's market power and a lack of competitive pressure in the WEM could be behind the upward trend in balancing prices, or gas-fired generation could be setting the balancing price in more intervals over the last six years. The ERA is continuing to investigate these last two possible causes.

Question

5. What other factors should the ERA consider that may underlie wholesale price increases in the WEM?

3. Future risks and the investment environment

Much of the scheduled generation capacity in the Wholesale Electricity Market (WEM) is approaching end of life, and so existing generation plant will need to be replaced at some point in the future.

The accuracy of demand forecasts and the need for early investment signals for new generation capacity to enter the market are critical to maintain a secure and reliable electricity supply for consumers in the future.

The ERA suggests the future investment environment may be challenging if investors do not receive appropriate and timely signals to alert them to new investment opportunities. There is a lead time from designing and building new generation plant to it participating in the market and contributing to the provision of secure and reliable electricity supplies. Therefore, attention is needed soon to ensure the new, future design of the WEM will be an attractive environment for the private sector to invest in new generation. If not, the government may decide that it must underwrite future generation investment, extending the duration of Synergy's dominance in the market.

3.1 Demand is changing

The 2018 Electricity Statement of Opportunities (ESOO) report shows demand is forecast to increase very slowly, at an average annual rate of 0.6 per cent to 2027/28.[34]

The supply forecasts in the report indicate no future generation plant retirements,[35] but assume continued uptake of behind-the-meter photovoltaic (PV) generation and growing battery installations.[36]

Consumers' behaviour is changing (refer to section 2.1) as they invest in rooftop PV and battery storage. This may happen more quickly than forecast, particularly as new financing models, such as solar leasing, can enable more households to benefit from rooftop PV. Consumer investment is changing traditional demand profiles and without appropriate data, demand will become more difficult to forecast.

Currently, there is publicly-available information on rooftop PV, but it is limited to aggregated information, by postcode, on PV systems installed behind the meter.[37]

To generate more accurate demand forecasts, comprehensive and more frequent data will be needed on how PV systems, and increasingly on how storage systems, affect demand. This was recognised in the 2017 Independent Review into the Future Security of the National Electricity Market (commonly known as the Finkel report). This review recognised the importance of "a clear need for greater visibility of [distributed energy resources]". One of the recommendations from the review was to "develop a data collection framework …to provide static and real-time data for all forms of distributed energy resources".[38]

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34 AEMO, (2018) Electricity Statement of Opportunities, AEMO, Perth, p3

35 Ibid. p48

36 Ibid. p23-29

37 http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations

38 Finkel A., Moses K., Munro C., Effeney T., O'Kane M., (2017) Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, Commonwealth of Australia, Canberra, p58-59

Demand and energy supply forecasts are compared to identify reliability risks in an electricity system that trigger mechanisms for capacity investment and procurement. Accurate demand forecasts help investors to make decisions about future electricity generation investments.

3.2 Lack of early, system-wide signals for new investment

Some scheduled generators in the WEM, such as Collie, may be mid-life. However, other assets, including Muja CD and the smaller Pinjar units, are likely approaching end of life. Statements in budget estimate hearings indicated Muja C and D would be retiring from 2025.[39] Synergy has since moved away from this position suggesting a much longer outlook, beyond ten years for Muja Stage D.[40] Despite this, the current ESOO covering the period from 2018/19 to 2027/28 does not signal any future generation plant retirements.

Synergy is the dominant supplier in the WEM. As the single largest holder of capacity and with the oldest capacity in the market, Synergy has robust information on the remaining operational life of its generators. However, there is no requirement for Synergy to share this information with the market.

If the forward capacity signal is inadequate, there may be insufficient time for a project to meet all the conditions necessary to be operational in time to mitigate a projected capacity shortfall. Depending in part on their technology, new projects can have a long lead-time because of the need to secure funding, approvals, network connection, and fuel supply arrangements or resource monitoring.

The modelling for the ESOO relies on information provided to it by market participants. Individual generation owners undertake analysis to identify when their generation plant should retire. The Finkel Review recommended obligating substantial generators in the NEM to provide advance notice to the market of plans to retire plants.[41]

In the WEM, information in advance of a generation facility closing could be provided by the owner to the Australian Energy Market Operator (AEMO), which makes the information available to the market. Potential investors would then have more information on investment opportunities.

3.3 Lack of a clear carbon policy

Renewable generators are supported by the renewable energy target, one of the few long-term elements of national climate change policy. The Federal Government has signalled its intention not to extend the renewable energy target beyond 2020. However, there is no explicit federal climate change policy covering the energy sector. The National Energy Guarantee sought to combine electricity reliability and emissions reduction in a single

[39] Western Australia, *Assembly Estimates Committee B*, *Budget Estimates*, p 7, (2016) http://parliament.wa.gov.au/Hansard/hansard.nsf/0/ef292507bcd0ef3848257fc7002449cf/$FILE/A39+S1+20160524+p199b-209a.pdf

[40] Western Australia, *Assembly Estimates Committee A*, *Budget Estimates*, p 8, (2018) http://www.parliament.wa.gov.au/Hansard/hansard.nsf/0/3d3ce9dc4437f7114825829f00221255/$FILE/A40+S1+20180523+p263b-273a.pdf

[41] Finkel A., Moses K., Munro C., Effeney T., O'Kane M., (2017) Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, Commonwealth of Australia, Canberra, p23

mechanism, but this has been abandoned. The lack of a clear and comprehensive carbon policy makes it difficult to anticipate implications for energy policy and the energy sector.

While the Western Australian Government has committed to revising its climate change policy,[42] policy uncertainty remains as the electricity sector works through the current market reform process. There are few details on how a Western Australian climate change policy would interact with energy policy.

This policy uncertainty is creating investment uncertainty for fossil fuelled generators. Investors in the WEM have previously commented on their difficulties raising finance or extending financing arrangements in their submissions to previous annual WEM reports.[43]

The lack of a clear national carbon policy, coupled with the extended reform process at the State level, increases investment risk.

3.4 The development of new technologies

Globally, the electricity sector is becoming more complex as it assesses and adopts new technologies.

In the WEM, the renewable energy policy and consumers' pursuit of lower energy bills has increased the integration of renewable generation both behind the meter and on the network.

Electricity consumers have lowered their use of the network (if not their maximum demand) by investing in their own generation assets, and increasingly in storage. In the 2018 ESOO, AEMO noted that actual rooftop PV in 2017/18 was higher than previously forecast,[44] and predicted that rooftop PV installations will grow at an annual average of 8.7 per cent, with 134 MW installed on average each year. For small-scale battery installations, AEMO forecasts:

> "Under the expected growth scenario, the installed capacity of battery systems in the SWIS was projected to increase at an average growth rate of 28 per cent from 47 MWh in June 2019 to 436 MWh in June 2028. This rate of growth is primarily attributed to the expected reduction in the cost of battery systems over the forecast period."[45]

Behind the meter investment can affect the electricity system in a numbers of ways, some beneficial, some detrimental.

Consumers with their own generation (and storage) have more control over their electricity bills. This reduces demand on the network, which can delay network augmentation. For some customers at the edge of the grid, rooftop PV combined with a battery and in some cases a diesel generator backup can significantly improve the security of their supply.[46] If combined with peer-to-peer trading, rooftop PV and storage could enable consumers to

42 Western Australia Government, Media Statements, McGowan Government to develop new climate change policy, https://www.mediastatements.wa.gov.au/Pages/McGowan/2018/12/McGowan-Government-to-develop-new-climate-change-policy.aspx, Accessed 18 December 2018

43 Merredin Energy, (2017), Submission in relation to 2016/17 WEM report, p3 and Bluewaters, (2017), Response to discussion paper – 2016/17 WEM report, p1

44 AEMO, (2018), Electricity Statement of Opportunities, AEMO, Perth, p7

45 Ibid p 29

46 Western Power, Stand Alone Power Systems – Stage 1, https://westernpower.com.au/energy-solutions/projects-and-trials/stand-alone-power-systems-stage-1/, accessed 18 December 2018

trade with their (non-solar) neighbours. This may reduce or delay the need for investment in capacity at the network level.

However, localised over-generation from rooftop PV could, in some areas, complicate network operations and impair network security. Western Power has acknowledged the future network will be more “modular” as more generation is distributed on consumers’ rooftops.[47] Without appropriate network planning, network assets could become stranded.

Increasing rooftop generation, combined with increased penetration of renewables, can reduce the need for investment in traditional generation plant and the system support services, such as inertia, that coal and gas turbines provide naturally. Therefore, a higher penetration of renewables may increase the need for ancillary services to maintain system reliability and security. The PUO is exploring the future generation mix in the WEM, to determine system risks.[48]

Investors in the generation sector are having to assess the potential future role of different technologies, while those technologies are still developing. How the different rates of development of new technologies affects the risk of investment being stranding is not well understood. However, it is possible that the changes to the load profile resulting from investment in distributed generation could strand assets.

New and low short-run marginal cost generation, such as that provided by renewable generators, would lower prices in the balancing market, and also have implications for ancillary services markets. However, once the renewable energy target is withdrawn, it is unclear whether investment in wind and solar generation will continue at the same level.

Residential consumers are making investment decisions based on blunt price signals and will make consumption decisions based on those same price signals. The volatility in demand resulting from investments behind the meter and in renewable generation could be offset by many of those same investments, if appropriate price signals were available. For example, battery storage could help dampen afternoon demand peaks, provide some ancillary services, alleviate network congestion, or improve network load factors.

3.5 Strategic positioning for new technologies

The opportunity to integrate investments in new technologies installed behind the meter into the electricity market is limited. There is a first-mover advantage for entities that manage to capture that opportunity.

Western Power has conducted trials of a number of new technologies including micro grids, battery storage and stand-alone power systems.[49] The residential sector leads distributed generation investment, and Synergy’s legislated monopoly over small use customers places it in a dominant position to test and implement new technologies for these customers. [50]

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47 Western Power (2018), Response to the Economics and Industry Standing Committee Inquiry into electricity microgrids, Western Power, Perth

48 Department of Treasury, SWIS Generation mix modelling, http://www.treasury.wa.gov.au/Public-Utilities-Office/Industry-reform/SWIS-Generation-Mix-Modelling/, accessed 18 December 2018

49 Western Power, Projects and Trials, https://westernpower.com.au/energy-solutions/projects-and-trials/, , accessed 18 December 2018

50 Western Australian Government, Electricity Corporations Act 2005, Electricity Corporations (Prescribed Customers) Order 2007, available from https://www.slp.wa.gov.au/gazette/gg.nsf/gen/79C7EB2D066A6068C825730800169C52

Western Power's knowledge of customer consumption patterns and system locations also gives it an advantage over prospective entrants to the market.

New network services for residential customers, such as peer-to-peer trading, have developed recently and will probably continue to emerge in future. For some of these technologies, there may be barriers to entry for the private sector. For example, the market rules do not currently accommodate the entry of battery technologies.[51] Removing barriers to private sector investment in these technologies may serve the long-term interests of consumers better than extending the technologies and services offered by incumbent government-owned monopolies.

3.5.1 Investors with innovative products may provide more cost-effective outcomes for the market

Batteries could smooth the demand profile, shift peaks and improve network load factors. At present, large-scale batteries cannot register as stand-alone market facilities in the WEM, although the reform process is examining how batteries can be brought into the market.[52]

When large-scale batteries can participate in the WEM, there will need to be clear guidance on how they do so to prevent the misuse of market power. Batteries enable generators to influence demand and hence price. Ideally, a battery is used to arbitrage between low and high prices thereby smoothing demand. However, a battery could also be used to increase prices or extend the duration of peaks and high prices if it is charged instead of discharging during peaks.

Tariff incentives or regulatory intervention may be needed for the potential benefits of battery storage to be realised in the SWIS. Either tariffs or regulation may be required to ensure consumers discharge (rather than charge) their batteries during evening peak periods to dampen network load and mitigate the need for rapid ramps in generation output.

The potential influence of batteries in the electricity market is best illustrated with reference to the building and operation of a large battery in the South Australian electricity market as shown in the box below.

51 Clause 2.29.2 of the Market rules does not allow a facility to be registered both as generation and load. This creates a barrier for the entry of storage technologies.

52 Public Utilities Office (2018) Wholesale Electricity Market Reform Program – Industry Forum, Department of Treasury, Perth, p20, http://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Industry_reform/WEM-Reform-Program-Industry-Forum-September-2018.pdf

Case Study

The Australian Energy Regulator (AER) investigates all instances where the price of ancillary services in the National Electricity Market:

- significantly exceeds the relevant spot price for energy
- exceeds $5000/MW for a number of trading intervals.

During 2017, there were price spikes in the frequency control ancillary services in South Australia. The AER investigated and found these high prices coincided with outages on one of the two transmission lines between Victoria and South Australia. The outage of the transmission line electrically isolated South Australia from the rest of the NEM. In these periods the frequency control ancillary services needed to be provided from generators within South Australia. The pool of generators able to provide frequency control was reduced, which enabled them to offer or rebid capacity at prices far exceeding the prevailing energy price.[53]

The introduction of the Hornsdale Power Reserve (the TESLA 'Big Battery') in 2018 increased the pool of participants that were able to bid energy and ancillary services into the NEM. This applied competitive pressure on bids to provide the frequency control ancillary service.[54]

It was the introduction of new capacity and not the superior performance of the battery that altered ancillary service prices during the battery's trial period.[55]

It is uncertain whether the market reform program will include guidance on how battery storage participates in the WEM or will explore if or how other price signals such as tariffs could be used to incentivise consumers to operate their batteries at certain times. This should become clearer as more detail is released on the scope of individual market reform projects.

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53 AER (2018) Report into market ancillary service prices above $5000/MW. South Australia 13 and 14 October 2017, AER, Melbourne, https://www.aer.gov.au/system/files/FCAS%20prices%20above%205000MW%20-%2013%20and%2014%20October%202017.pdf

AER (2018) Report into market ancillary service prices above $5000/MW. South Australia 24 October 2017, AER, Melbourne, https://www.aer.gov.au/system/files/FCAS%20prices%20above%205000MW%20-%2024%20October%202017.pdf

AER (2017) Report into market ancillary service prices above $5000/MW. South Australia 14 September 2017, AER, Melbourne, https://www.aer.gov.au/system/files/MW%2014%20September%202017.pdf

AER (2017) Report into market ancillary service prices above $5000/MW. South Australia 28 August 2017, AER, Melbourne, https://www.aer.gov.au/system/files/20170828%20FCAS%20%245000%20report%20%28SA%29.pdf

AER (2017) Report into market ancillary service prices above $5000/MW. South Australia 22 May 2017, AER, Melbourne, https://www.aer.gov.au/system/files/20170522%20sa%20fcas%20%245000.pdf

AER (2017) Report into market ancillary service prices above $5000/MW. South Australia 18 April 2017, AER, Melbourne, https://www.aer.gov.au/system/files/FCAS%20prices%20above%20%245000MW%20-%2018%20April%202017%20%28SA%29_2.pdf

54 AEMO (2018) Hornsdale Wind Farm 2 FCAS Trial, Knowledge Sharing Paper, AEMO, Melbourne, p4

55 *Ibid*. p35

3.6 Conclusions

Existing generation in the WEM will need to be replaced at some point in the future. The ERA suggests that the future investment environment will be challenging for the private sector without:

- More accurate demand forecasts.
- Early signalling of when existing capacity will exit the market.
- Greater certainty about carbon policy.
- Technical requirements for new technologies to connect to the network that support market objectives of security and reliability.
- Market guidelines, to support participation of battery storage in the WEM.
- Consideration of tariff reform to encourage consumers with behind-the-meter PV and storage to operate their systems in ways that not only benefits them, in lower bills, but also reduces costs across the WEM.[56]

If private investment is not forthcoming, either because the environment is too risky or the notice was too short, consumers will expect government to make the investments itself or take responsibility for the outcomes of an investment shortfall. This could have consequences for the state budget and for the persistence of market power in the WEM.

[56] For example, flat tariff products and buyback tariffs provide inefficient price signals. Consumers may over or under invest in system capacity or complementary technologies such as control systems and batteries that may allow a better optimisation of the assets and hence allow better investment decisions. Similarly, curtailing output to protect incumbent investments (such as conventional generators or network assets) from competition will not deliver efficient outcomes.

Issue

The future investment environment in the WEM may not be conducive to continued third-party investment. This may leave the State Government responsible for funding or underwriting future generation investments.

Questions

6. Are market participants satisfied that innovation trials are sufficiently open to participation from entities independent of government?
7. To what extent do market participants rely on, or derive benefit from, the electricity statements of opportunity in planning and investment decisions?
8. Should market participants signal intended or probable plant retirements at least three years in advance, as has been suggested in the National Electricity Market; or, should the market operator undertake its own analysis of the probable plant exit dates?
9. If not advanced notice of plant retirements, what other mechanisms could be used to signal investment opportunities and improve the operation of the capacity mechanism?
10. To what extent do policy uncertainty and behind-the-meter changes in generation and storage influence decisions to develop projects in the WEM?
11. Do market participants consider the investment environment in the WEM is challenging? If so, why?
12. Do market participants consider the investment environment in the WEM will improve or worsen over the short to medium term? If so, what factors will drive this change?
13. What is the likelihood that the State Government will need to invest to replace generation assets?
14. What could organisations such as the ERA, AEMO, Western Power and the State Government reasonably do to improve the investment environment?

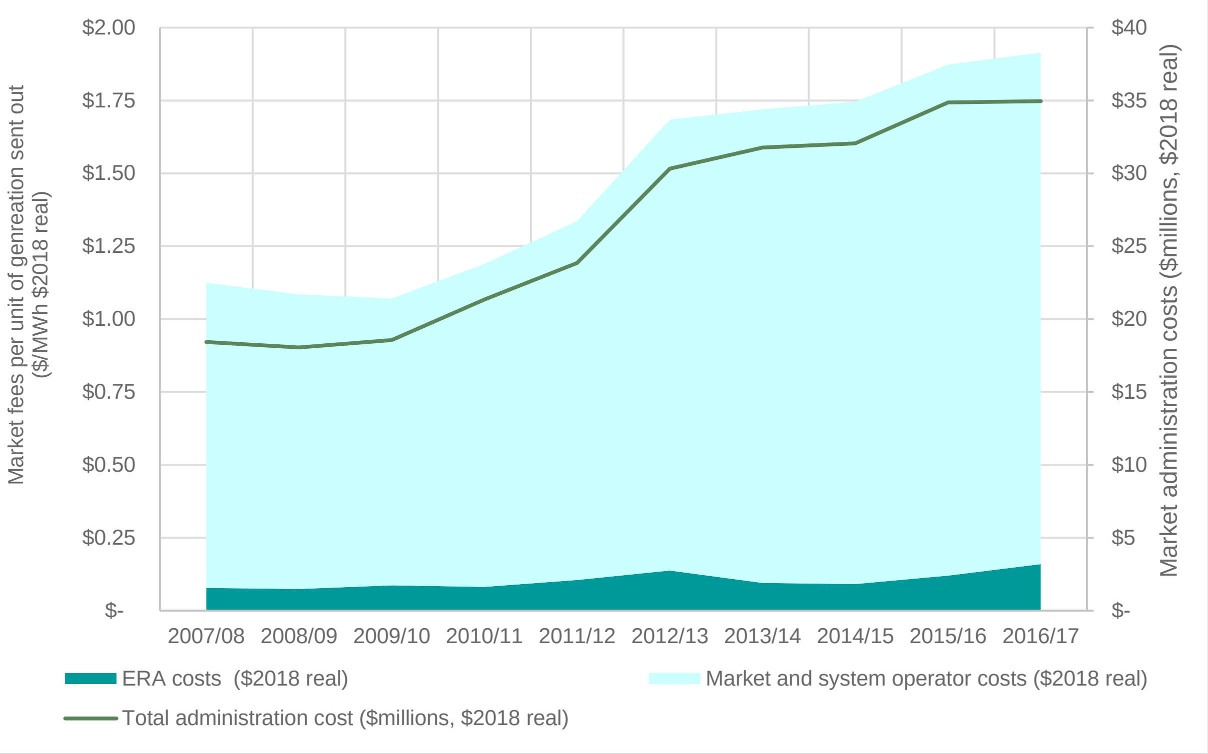
4. Market administration, governance, and reform

Although a relatively small element of the total cost of electricity to consumers, the cost of market administration and regulation has almost doubled in the 10 years to 2016/17, from $18.4 million to $35 million. On a cost per unit basis, market administration is now around a quarter of the total ancillary services cost to the market.

Figure 2 aggregates the costs of market administration for the Independent Market Operator, the Australian Energy Market Operator (AEMO) and System Management, and market regulatory costs for the ERA.

For a relatively small market like the WEM, the market fees are substantial. This is partly a function of scale, as the fixed costs are recovered from a smaller base.

Figure 2: Market administration costs



Source: ERA Analysis of AEMO, Western Power and ERA annual reports

The market objectives are in tension; meeting one objective may come at the cost of others. For example, the cost to increase reliability increases the cost to consumers. The gains of reforms must be balanced against the cost to implement, maintain, and regulate the reforms. Ultimately, consumers will pay for administrative inefficiency through elevated electricity prices.

The market and system operator costs are predominantly recovered through market fees. The ERA must review and approve AEMO's allowable revenue and forecast capital expenditure for three-year periods. The fourth allowable revenue period (AR4) ends on 30 June 2019. The next allowable revenue period (AR5) extends to 30 June 2022. The ERA must only approve proposed expenditure that is prudent, efficient and the lowest practicably sustainable cost.[57]

57 Market rule 2.22.A.11 (b)

In June 2018, the Minister for Energy extended AEMO's functions to include preparation for and implementation of WEM reforms, including the move to constrained network access. This move increases the scope of activities for which AEMO can recover costs through market fees. This has transferred a proportion of the cost of market reform directly to market participants.

Most of AEMO's anticipated costs for its new reform functions will be included in AEMO's funding proposal for AR5. This has to be provided to the ERA by 15 March 2019. The ERA must review and approve any expenditure by 14 June 2019. The ERA's review process will include publishing a discussion paper and asking for submissions from stakeholders.

As noted above, the funding approval requirements for AEMO's allowable revenue and forecast capital expenditure are stated in the Market Rules. However, there is no requirement for the ERA to undertake an *ex post* review of projects undertaken by AEMO. There is no mechanism to consider whether:

- The projects undertaken delivered the anticipated benefits.
- The costs incurred in undertaking projects and recovered from market participants were greater or less than the anticipated project benefits.

There is a mechanism to manage under and over recovery of AEMO's expenditure between years. If AEMO spends more than its budget for a financial year, the overspent amount is deducted from the following year's budget.[58]

The costs and benefits of proposed rule changes are captured in the rule change process and help inform decisions by the independent Rule Change Panel, such as the rule change to amend prudential exposure that will commence on 1 June 2019.[59] AEMO will incur $2.7 million in additional costs to make the necessary changes to its IT systems to implement the rule change but the financial burden, in the form of lower credit support provided by market participants, reduces by $69 million.

The process to establish the costs and benefits of planned market reforms is less transparent. The former market reform program released information on the high level cost and benefits.[60] On 1 October 2018, the PUO released results for consultation on the costs and benefits of moving to constrained network access.[61] At the time of writing, the PUO had not indicated that it was preparing any additional cost benefit analysis on other aspects of market reform.

58 Market Rules, Rule 2.22A.7

59 ERA website, 2018, Rule Change RC_2017-06, Final Rule Change report, p101

60 PUO website, July 2016, Final Report: Design recommendations for wholesale market and ancillary service reforms, p33

61 PUO website, Oct 2018, Information paper – Modelling the impacts of constrained access

Issue

The cost of operating, administering and regulating the WEM has doubled in real terms over the last 10 years in response to increasing market complexity. The current market reform program will increase market fees further in real terms.

Questions

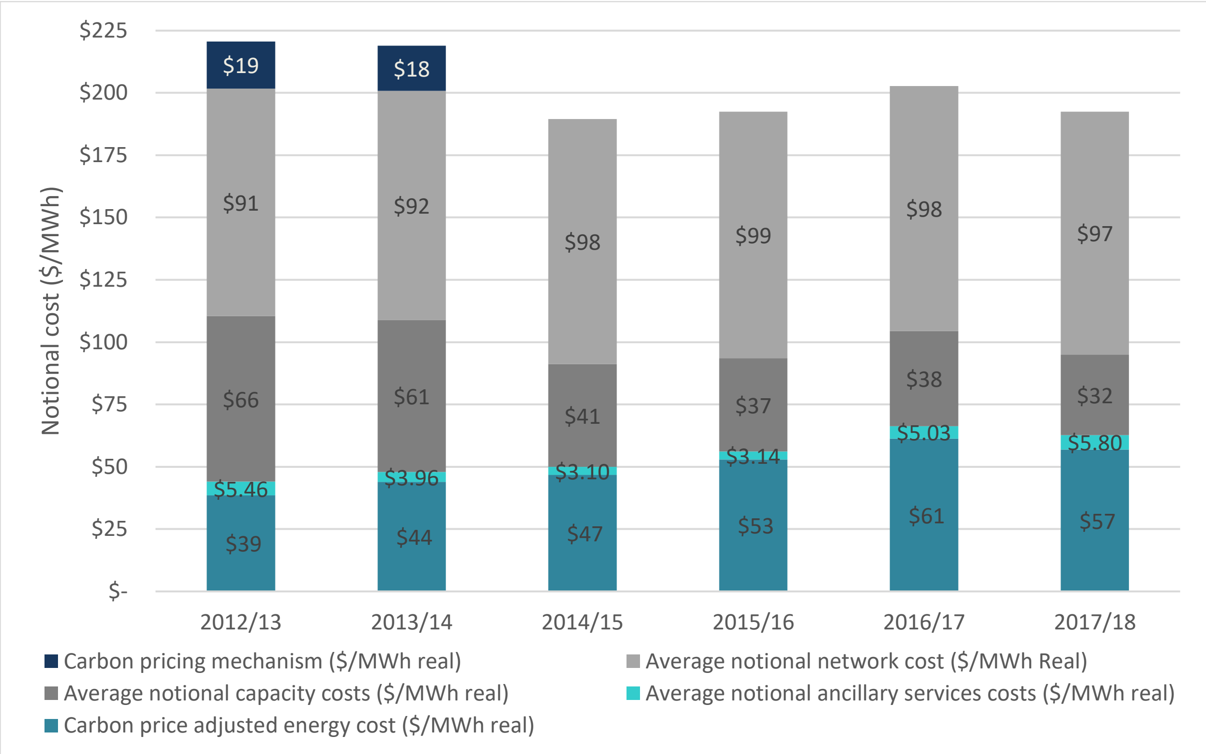
15. Do market participants consider that market operation, administration and development expenditure is delivering the benefits anticipated? If not, is the market and its electricity consumers failing to secure the benefits because of structure, governance, lack of competition, or scale?

Appendix 1 Market Data

Notional wholesale electricity unit costs

Figure 3 shows the notional unit cost of wholesale electricity[62] supplied from 2012/13 to 2017/18. This aggregates the costs of wholesale electricity, capacity, network, ancillary services and carbon, and calculates a unit cost by dividing by the quantity of electricity consumed. Retail costs and market administration fees have been excluded.

Figure 3: Notional costs of wholesale electricity supply per unit of energy consumed (real $2017/18)



Source: ERA analysis of AEMO and Clean Energy Regulator data.

Since the repeal of the carbon pricing mechanism in August 2014, notional wholesale unit costs have remained fairly stable in real terms. They have ranged from $189/MWh in 2014/15 to $202/MWh in 2016/17. On the surface, notional wholesale unit costs appear contained.

The individual elements within the notional wholesale unit cost are managed differently, as follows:

- Some elements, such as capacity costs, network costs, and some ancillary service costs (spinning reserve and load rejection reserve) are managed through administered mechanisms.
- Market-based mechanisms determine wholesale electricity prices and the cost of the load following ancillary service (LFAS).

62 Wholesale notional electricity costs are the product of balancing market prices and generation. It costs bilaterally traded volumes at the balancing market price.

Reviewing the individual cost elements demonstrates that costs determined by market-based mechanisms have increased substantially.

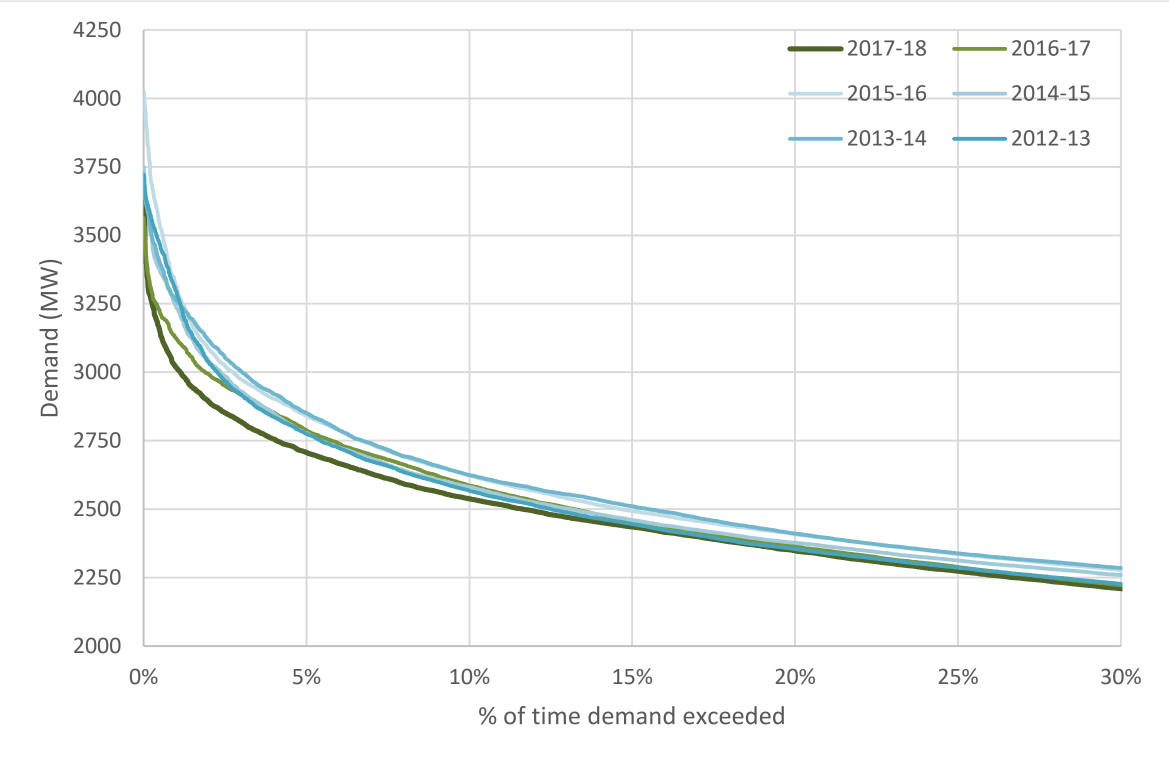
The increases in the cost of wholesale electricity and LFAS has absorbed any savings made in administered segments of the market.

Demand

The reduced demand in the last two years can be illustrated in **Figure 4**. This shows the load duration curve over the 30 highest load periods from 2012/13 to 2017/18. Load duration in these intervals is lowest in 2017/18. Load duration in 2016/17 is also low in the top two to three per cent of intervals.

While the relationship between price and demand is a function of many things, the last two years showed markedly higher prices in the top 25 per cent of trading intervals relative to other years. For example, the fifteenth percentile of prices in 2017/18 was $87/MWh whereas in 2014/15 it was $61/MWh.

Figure 4: Load duration curve – top 30 per cent of intervals



Source: ERA analysis of AEMO data

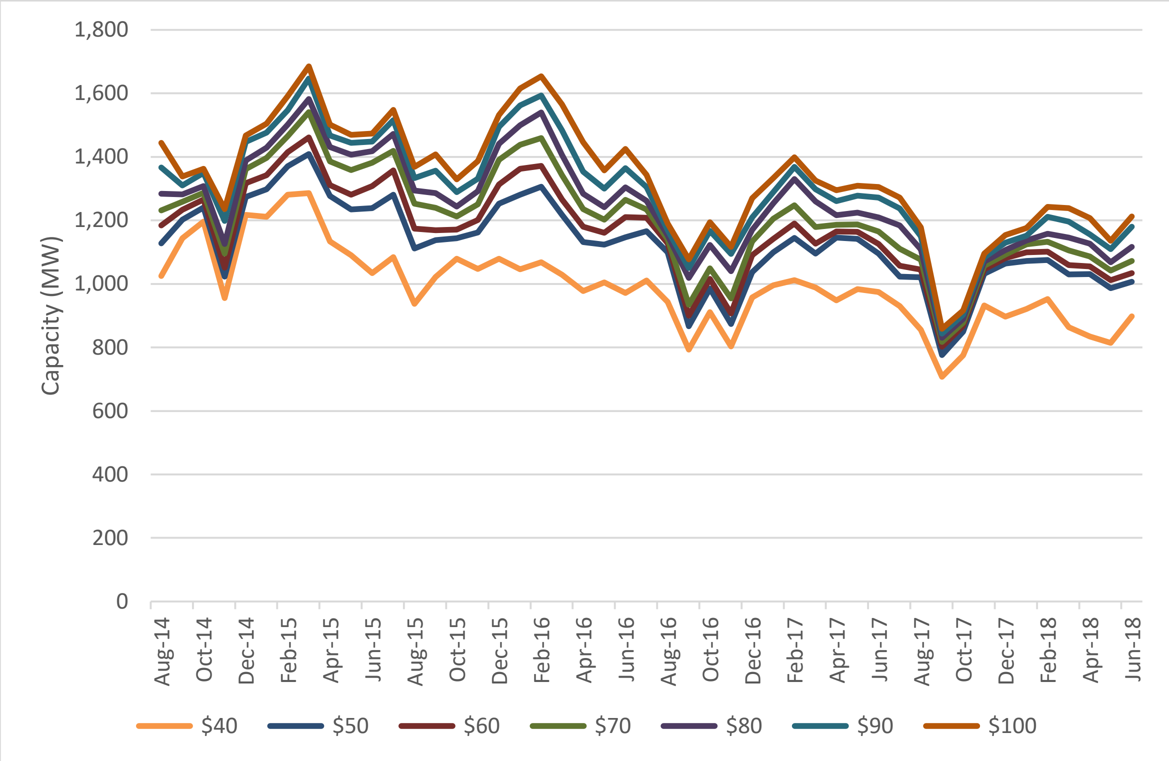
The change in the relationship between demand and balancing market prices occurred in late 2016. This coincided with a change in offers into the wholesale electricity market, primarily from Synergy.

Since the repeal of the carbon pricing mechanism, Synergy's offers have become more expensive. **Figure 5** shows the availability of capacity from Synergy's portfolio at increasing price thresholds between $40/MWh and $100/MWh. The lines show the quantity of capacity offered within price bands.

The dips in available capacity, for example in November 2014 and November 2017, reflect generation capacity taken offline for outages.

The peak capacity available is generally shown in January in each year, in preparation for the onset of the hot season. This is after the annual maintenance cycles have been completed.

Figure 5: Synergy's available capacity at different price thresholds



Source: ERA analysis of AEMO data

Synergy's available capacity at each price threshold has reduced over time, as shown by the overall downward trend.

Capacity normally offered above $30/MWh has become increasingly expensive. Table 1 shows the average price range for given quantities, in megawatts, of generation supplied from Synergy's generation portfolio in January each year.

The average price of 1,250MW of capacity from Synergy's portfolio in January has increased from $40-50/MWh in 2015 to $130-140 in 2018, and the price of 1,500MW has doubled from $90-100 to $190-200.

Table 1: Synergy's average price of balancing market bids in January

	Price of 1,000MW supply	Price of 1,250MW of supply	Price of 1,500MW of supply
January 2015	$30-40	$40-50	$90-100
January 2016	$30-40	$40-50	$70-80
January 2017	$40-50	$70-80	$120-130
January 2018	$40-50	$130-140	$190-200

Synergy's bids into the balancing market are currently under investigation by the ERA.[63]

Consumers have benefited from mild temperatures and avoided higher wholesale electricity costs. This has also masked the full extent of supply cost increases (see the next chapter). However, temperatures will not stay mild indefinitely, and current forecasts indicate summer 2019 temperatures will be above average.[64] When temperatures increase, demand will increase, and electricity prices will follow.

The increased penetration of behind-the-meter generation, such as rooftop photovoltaics (PV) has affected consumer demand, and could be affecting wholesale electricity prices (refer to section 2.1).

Incidents of negative pricing

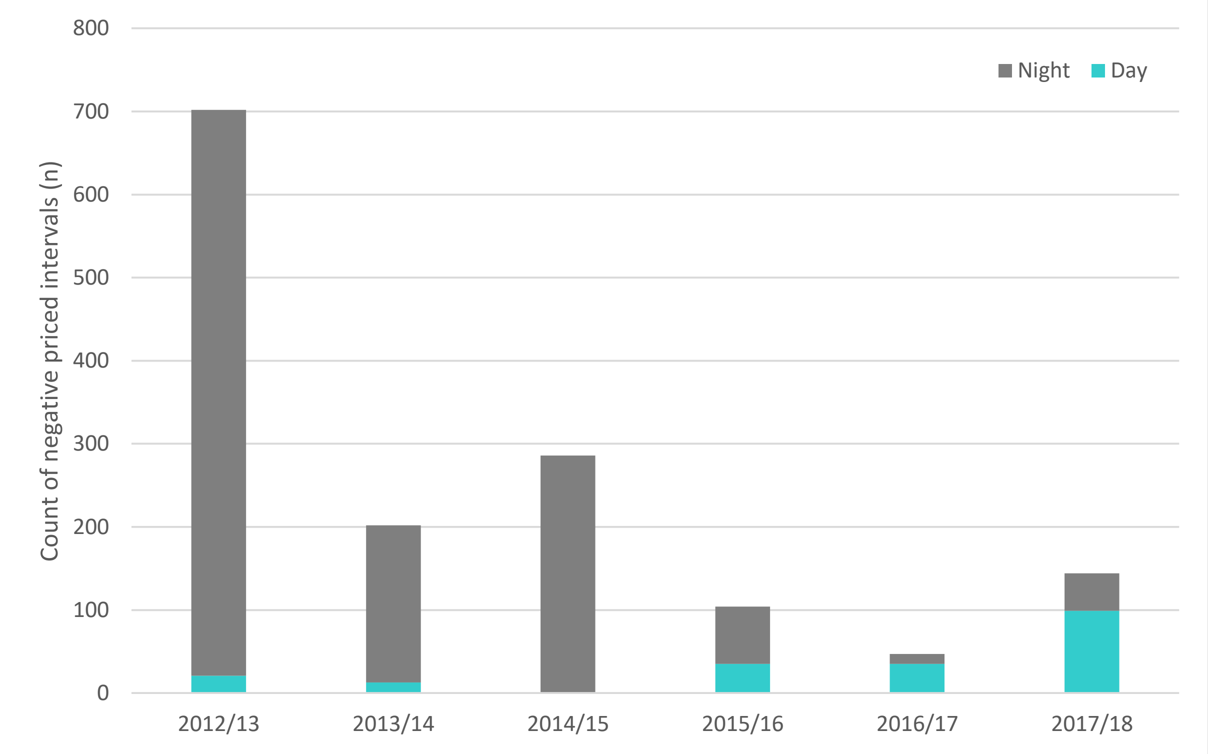
The distribution of negative pricing has changed. Following the retirement of the South West Cogen Joint Venture in March 2016, the frequency of overnight negative prices has reduced. Over the same period, the incidence of negative pricing has increased during daylight hours, mainly on weekends and public holidays (Figure 6).

Despite the change in distribution of negative pricing incidents, the number of incidents is small and balancing market prices have persistently increased during peak and off-peak periods.

63 https://www.erawa.com.au/electricity/wholesale-electricity-market/market-behaviour-investigations/2017-investigation-into-synergys-pricing-behaviour

64 Bureau of Meteorology (2018) Climate Outlook for December to February, Issued 29 November 2018, Bureau of Meteorology, Canberra, http://www.bom.gov.au/climate/ahead/outlooks/archive/20181129-outlook.shtml

Figure 6: Incidence of daytime and night time negative pricing



Source: ERA Analysis of AEMO data

Aside from one niche product with limited application,[65] Synergy has not developed any new residential retail tariffs that suggest it is responding to competition from residential rooftop solar. Synergy obtains generation spilt into the network from rooftop solar which it then retails to other consumers through the notional wholesale meter and has entered the solar retail market.

Generator run times

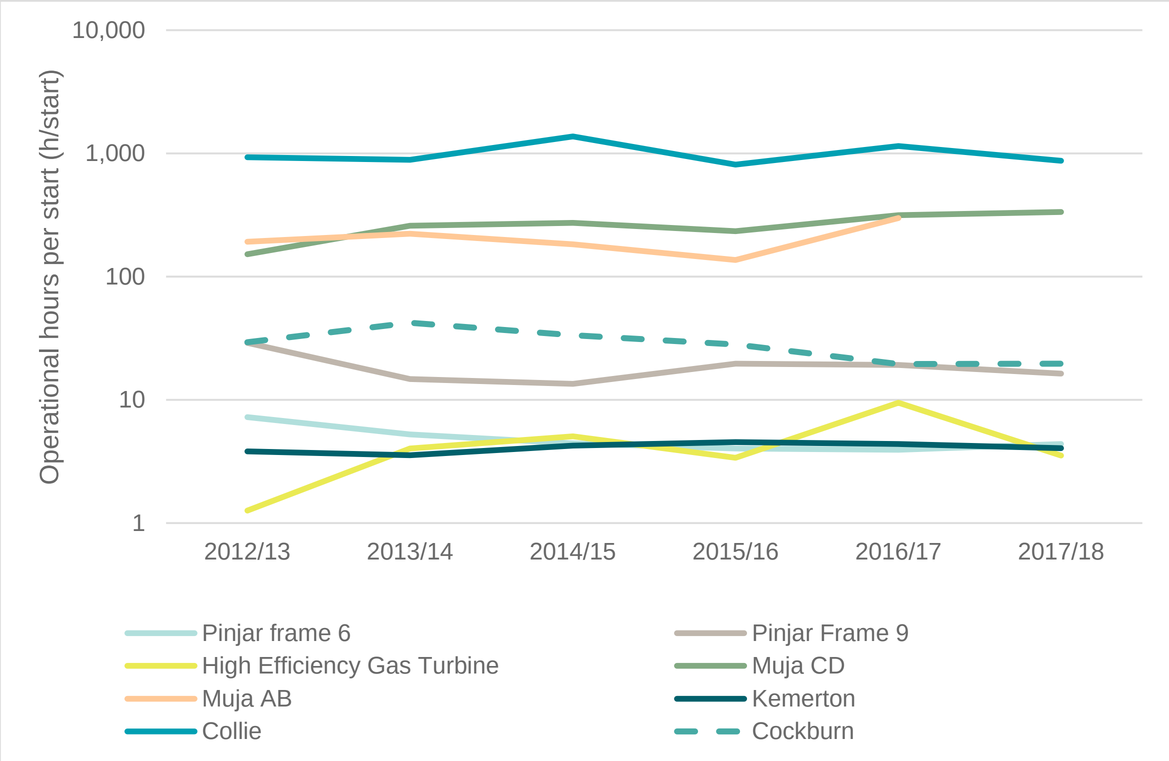
A change in the frequency of starts and stops and the average run duration of generation facilities could increase wholesale prices. Start-up costs are amortised over a generator's run duration. Shorter run times mean fewer intervals over which to recover start-up and shut-down costs. This means a higher bid is necessary to recover costs.

The extent to which start-up and shut-down costs may have influenced pricing can be inferred from publicly available generation sent out data.

Synergy's dispatch is the obvious generator to examine. Synergy owns half the accredited generation capacity in the WEM and sets prices in around 80 per cent of trading intervals. **Figure 7** shows the average run times for Synergy's major generating facilities, these are: Pinjar, Kemerton, Kwinana High Efficiency Gas Turbines, Cockburn, Collie and the eight Muja units.

[65] Refer to Synergy's Electric Vehicle Home Plan tariff in Synergy, Electric Vehicle Home Plan, https://www.synergy.net.au/Your-home/Energy-plans/Electric-Vehicle-Home-Plan?tid=Energy-plans:side_nav:Electric%20Vehicle%20Home%20Plan, accessed 18 December 2018.

Figure 7: Average run hours per start cycle major Synergy generators



Source: ERA analysis of AEMO data

Since their installation, the high efficiency gas turbine run times have increased. They tend to run for three to five hours.

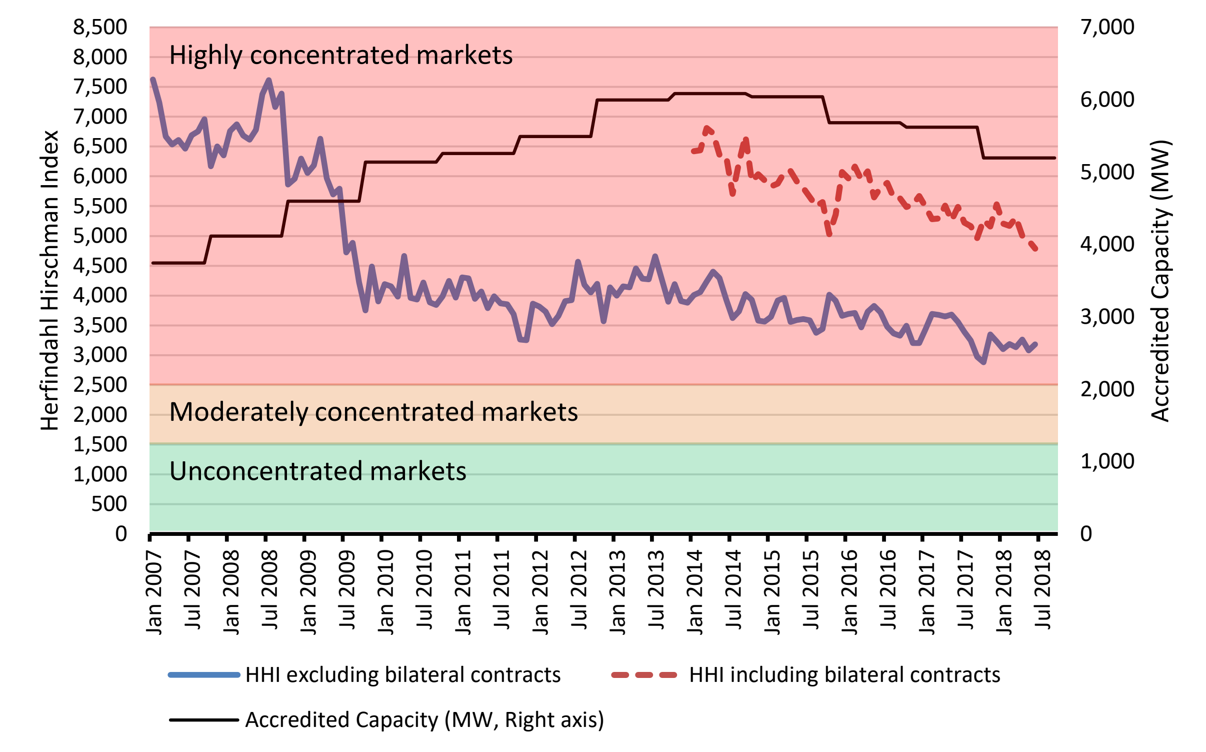
Only the Cockburn closed-cycle gas turbine (the downward-trending dashed line on the graph above) showed a change in average run time that might indicate that the change in dispatch duration has driven higher offer prices. However, Cockburn's capacity factor is diminishing over time and at around 5 per cent, it cannot account for price setting in the majority of intervals.

Who is setting the price?

The WEM remains highly concentrated as illustrated by the Herfindahl-Hirschman Index (HHI) shown in **Figure 8.** [66] While the level of concentration has trended downwards since 2010 it remains well within the highly concentrated area of the graph, particularly when bilateral contracts are added.

[66] The Herfindahl-Hirschman Index is a competition and market concentration indicator calculated by summing the squares of market participants' market shares. The results are weighted towards those with higher market share. Un-concentrated markets are those with an index below 1,500, moderately concentrated markets between 1,500 and 2,500 and highly concentrated above 2,500. US Dept. of Justice and Federal Trade Commission (2010) Horizontal Merger Guidelines, US Dept. of Justice, Washington, pp 18-19, https://www.justice.gov/sites/default/files/atr/legacy/2010/08/19/hmg-2010.pdf

Figure 8: Herfindahl Hirschman Index with bilateral contracts



Source: ERA analysis of AEMO data

The HHI index is often considered an indicator of competition in a market. Less concentrated markets are considered more competitive when there is a greater number of participants with similar market shares.

In the WEM, the market is dominated by Synergy who owns or controls around 80 per cent of generation. The three largest generators, Synergy, Summit Southern Cross Power and Alinta collectively contribute around 90 per cent of generation.

Observing that the wholesale electricity market is concentrated is not definitive evidence that it is also uncompetitive. The ERA has also considered which generators are setting the price in trading intervals, and at what level. **Figure 9** shows which generators are setting the marginal price, at different price bands. Where there are several marginal generators in a price band, this indicates some competition is occurring.

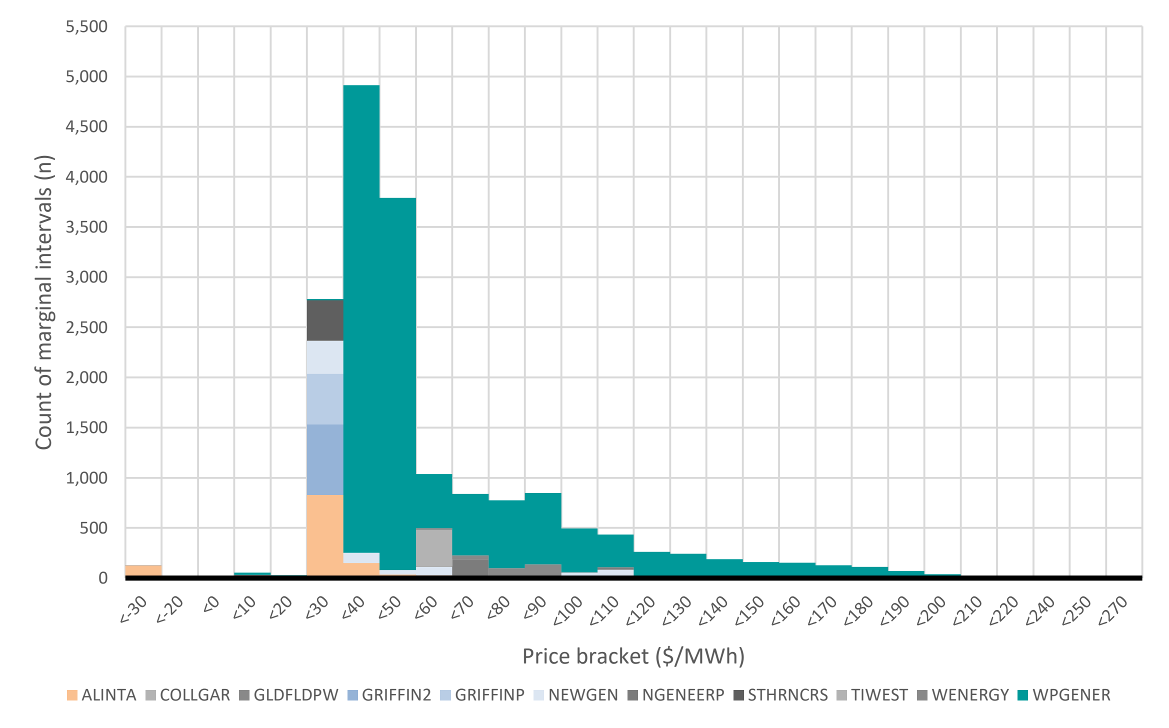
Synergy, with half the accredited capacity in the wholesale market, sets prices in around 80 per cent of intervals.

During 2017/18, there were at least five generators competing to set the balancing price between $20/MWh and $30/MWh. Above this level, Synergy predominantly sets the price and appears to have few competitors.

While new generation capacity has entered the wholesale market, in recent years that has typically been smaller-scale renewable plant.

Overall, new generation plant entering the market has not materially affected the wholesale market concentration since 2009. This could be because the new capacity investments have been made by existing participants which has left market concentration unaffected, and or the capacity investments did not materially affect dispatch (as indicated in Figure 10).

Figure 9: Who set the price and at what price 2017/18



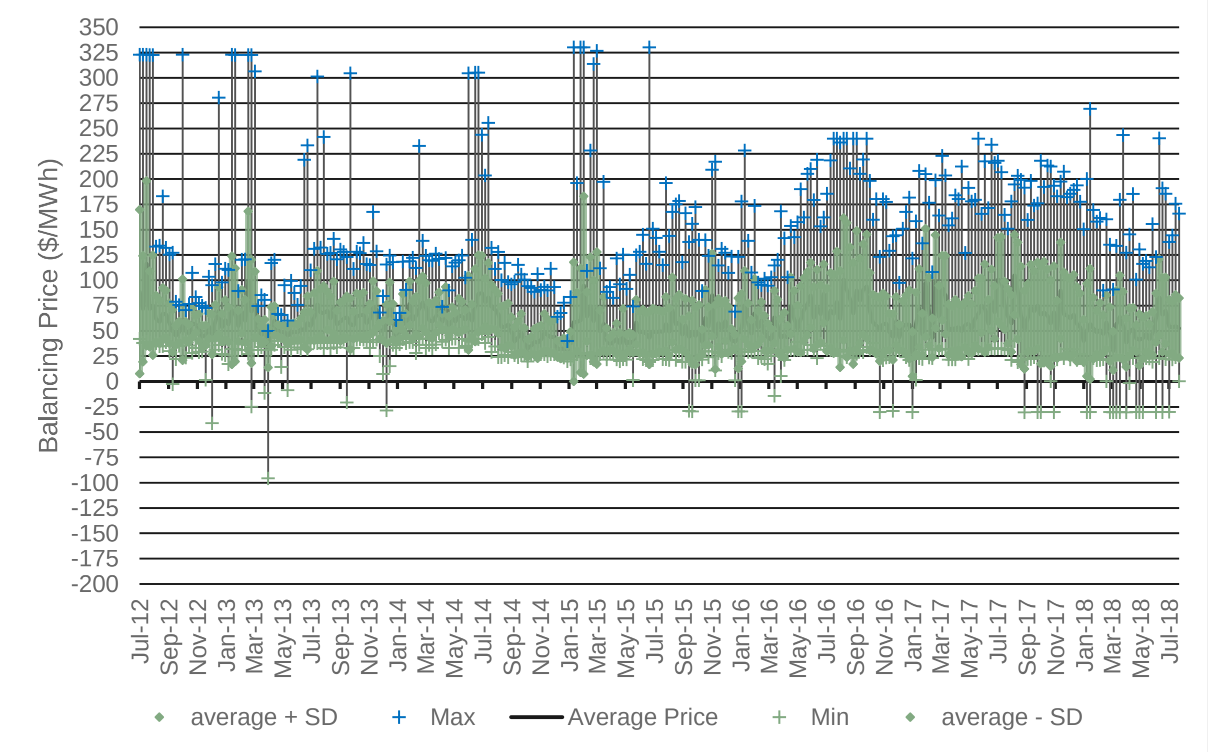
Source: ERA analysis of AEMO data

Balancing Market

Figure 10 and **Figure 11** show the average balancing market prices from market start.

Wholesale electricity prices have remained volatile throughout 2017/18. This is despite relatively low prices in the final quarter of 2017, primarily due to a mild summer and low demand.

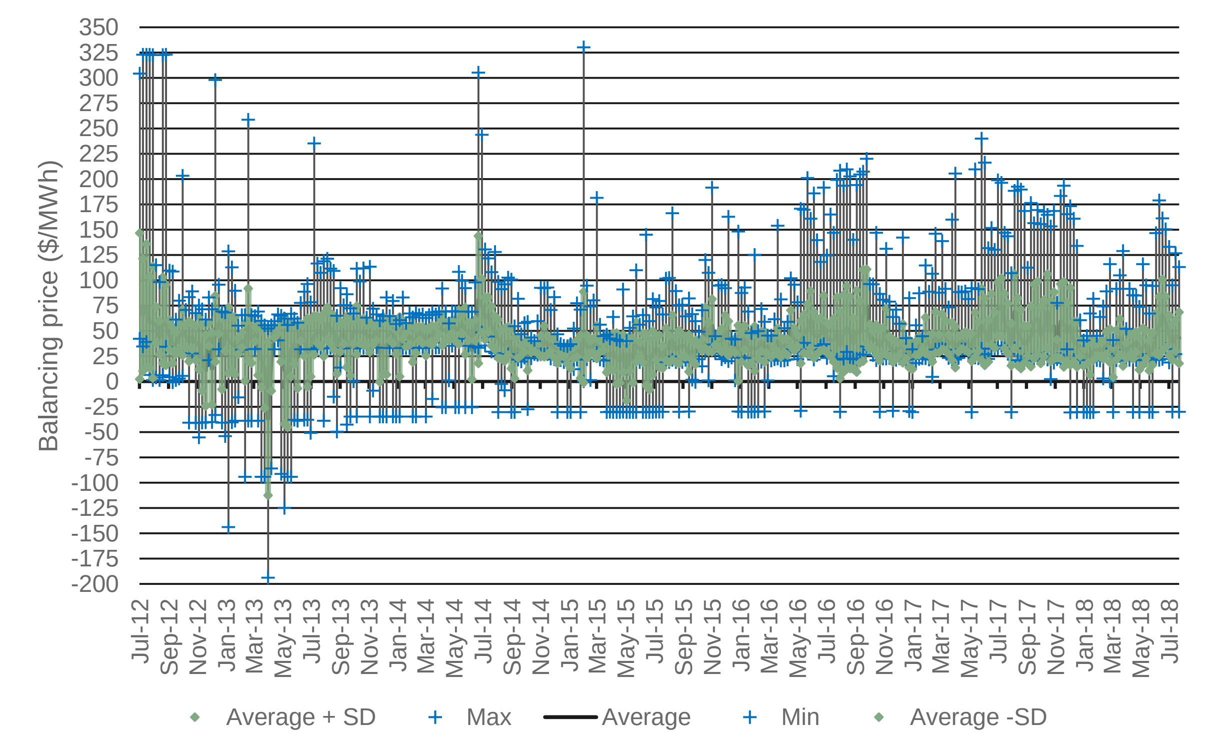
Figure 10: Weekly balancing market summary data– peak intervals



Source: ERA analysis of AEMO data

The frequency of negative prices during off-peak periods (**Figure 11**) has fallen since the start of the balancing market. However, during peak periods (**Figure 10**) the incidence of negative pricing increased, predominantly on weekends when solar output is reducing overall demand, pushing the balancing price into the negative range of the offer curves.

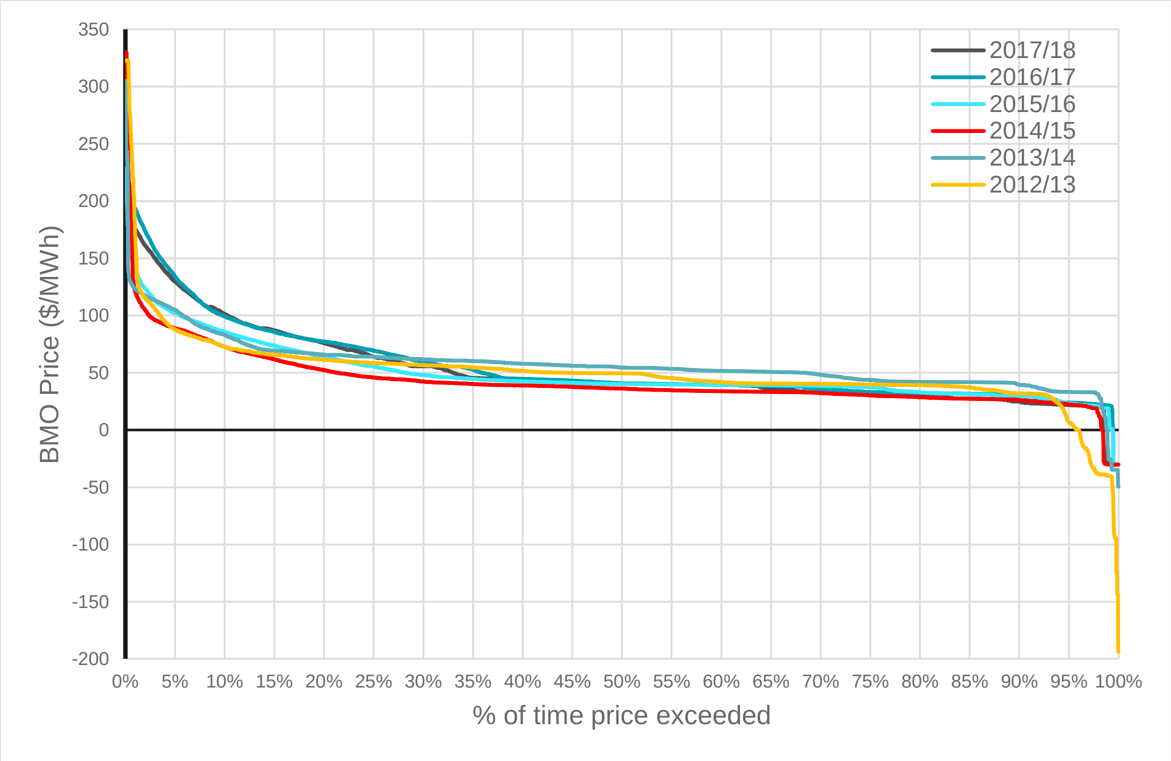
Figure 11: Weekly balancing market summary data– off-peak intervals



Source: ERA analysis of AEMO data

Figure 12, shows the price duration curves from the start of the balancing market. As outlined in chapter 2.1, the most notable feature is the uplift in pricing for the top 25 per cent of intervals for 2016/17 and 2017/18. This uplift means the incidence of pricing above $50/MWh has been substantially higher in the last two financial years than in previous years.

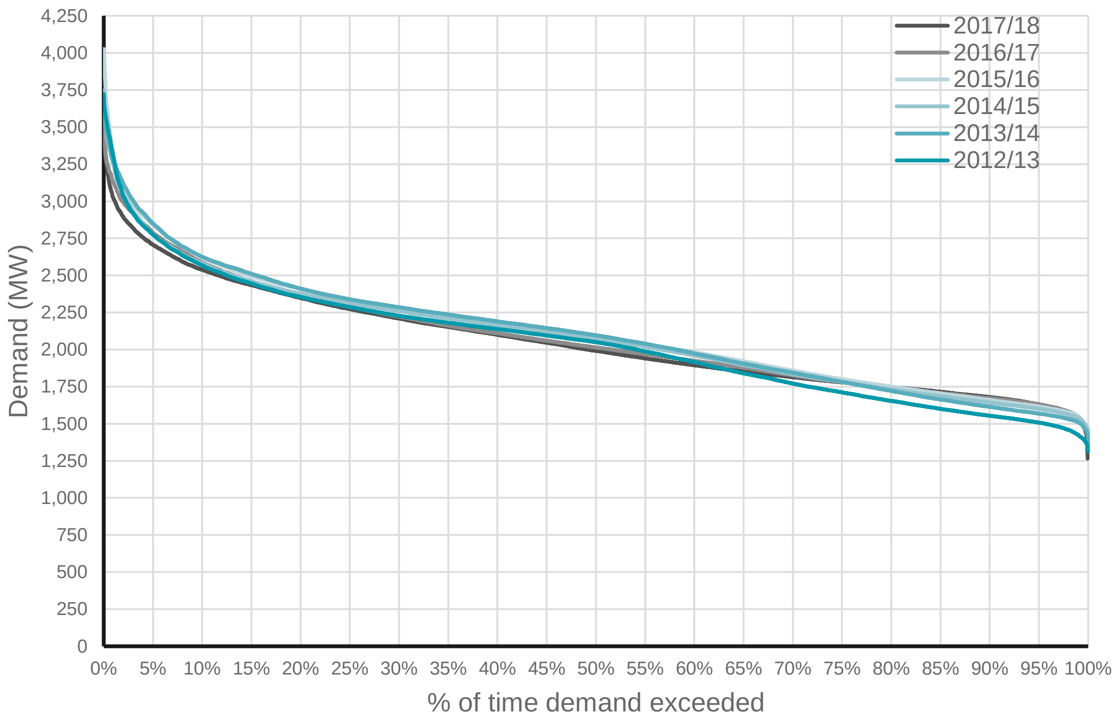
Figure 12: Price duration curve 2012/13 to 2017/18



Source: ERA analysis of AEMO data

Demand in 2017/18, similar to that in 2016/17 was relatively low compared to previous years. (**Figure 13**).

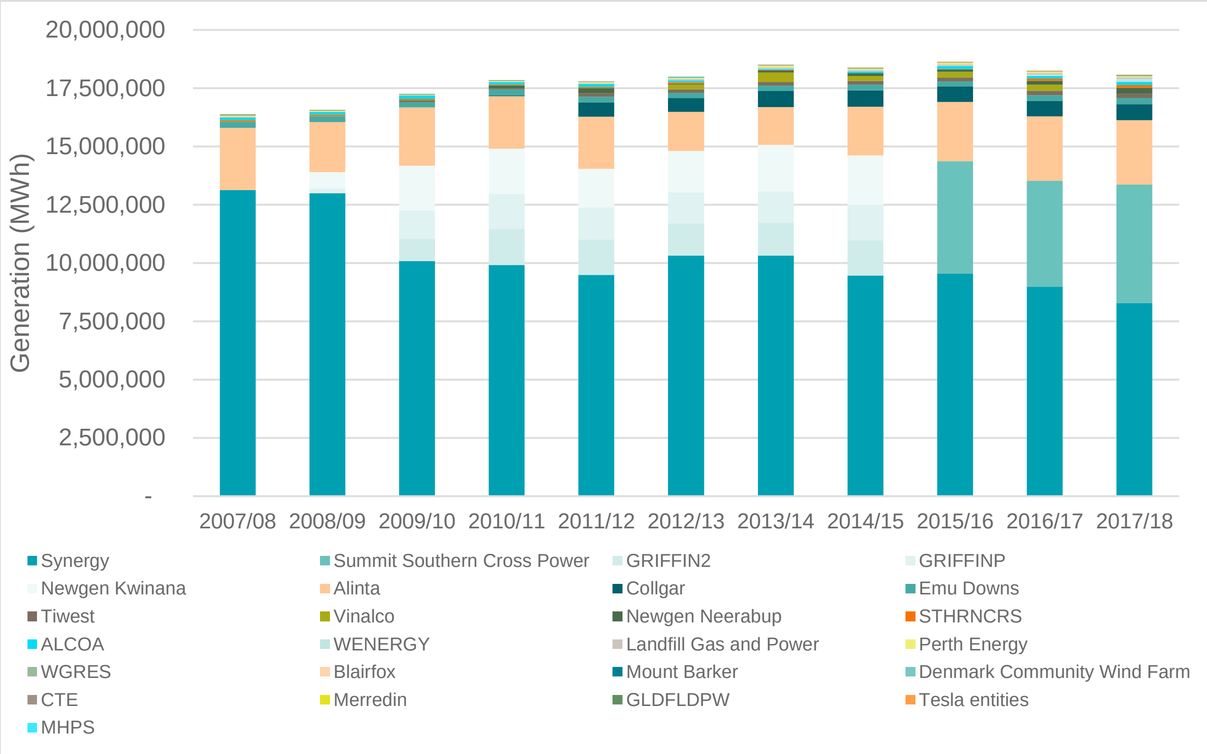
Figure 13: Load duration curve 2012/13 to 2017/18



Source: ERA analysis of AEMO data

Figure 14 shows electricity generation sent out by market participant. Synergy's generation sent out has reduced. Summit Southern Cross Power generators' output increased and Alinta's generation output was comparable to that in 2016/17. Synergy's share of generation sent out reduced to around 45 per cent in 2017/18. The three largest generators collectively contribute around 90 per cent of generation.

Figure 14: Generation sent out by market participant from 2007/08 to 2017/18

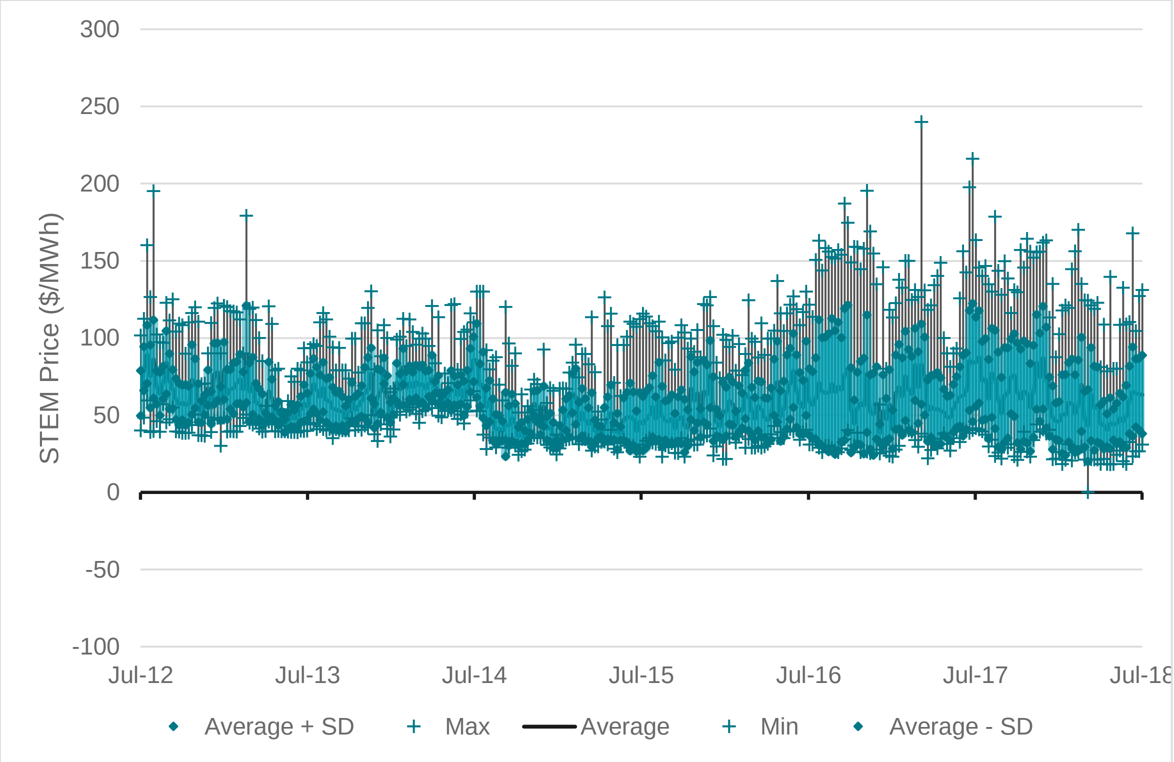


Source: ERA analysis of AEMO data

Short term energy market

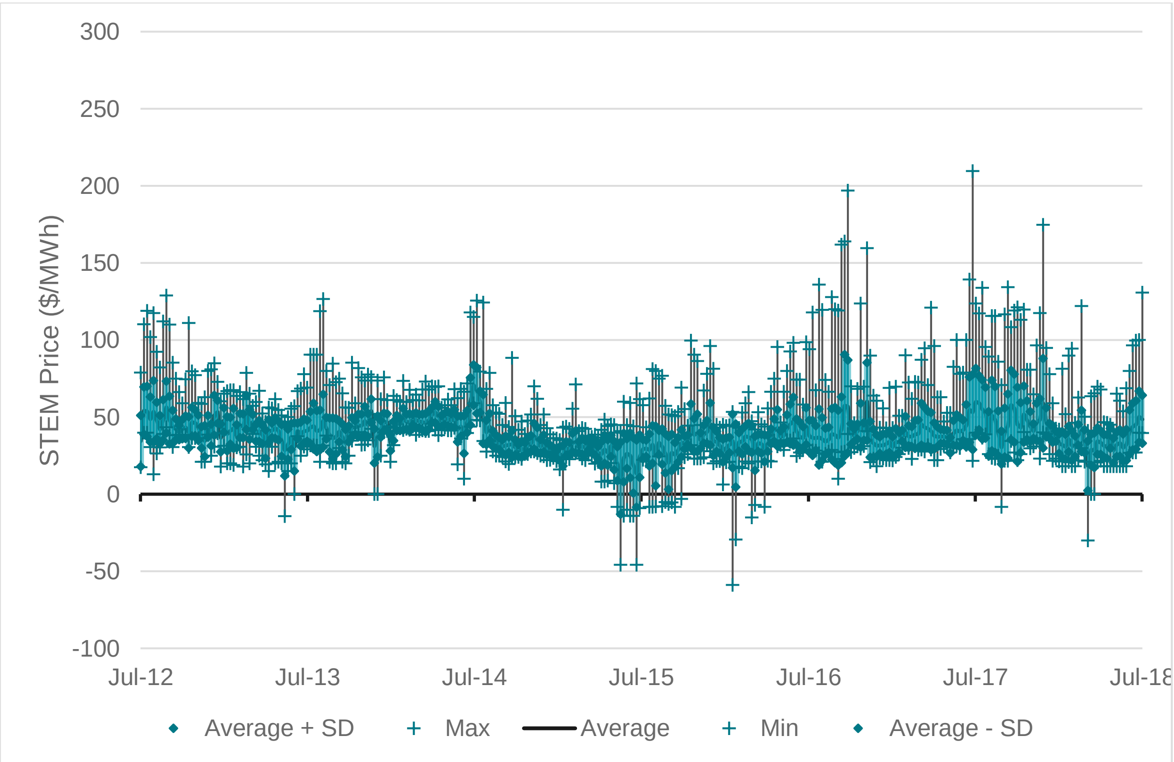
Figure 15 and **Figure 16** show peak and off peak weekly summary data for the Short Term Energy Market (STEM). The patterns show comparable trends to the balancing market but in the STEM are more muted. Volatility during peak periods remains high although prices moderated in the last six months of 2017/18.

Figure 15: STEM Weekly summary data – peak intervals



Source: ERA analysis of AEMO data

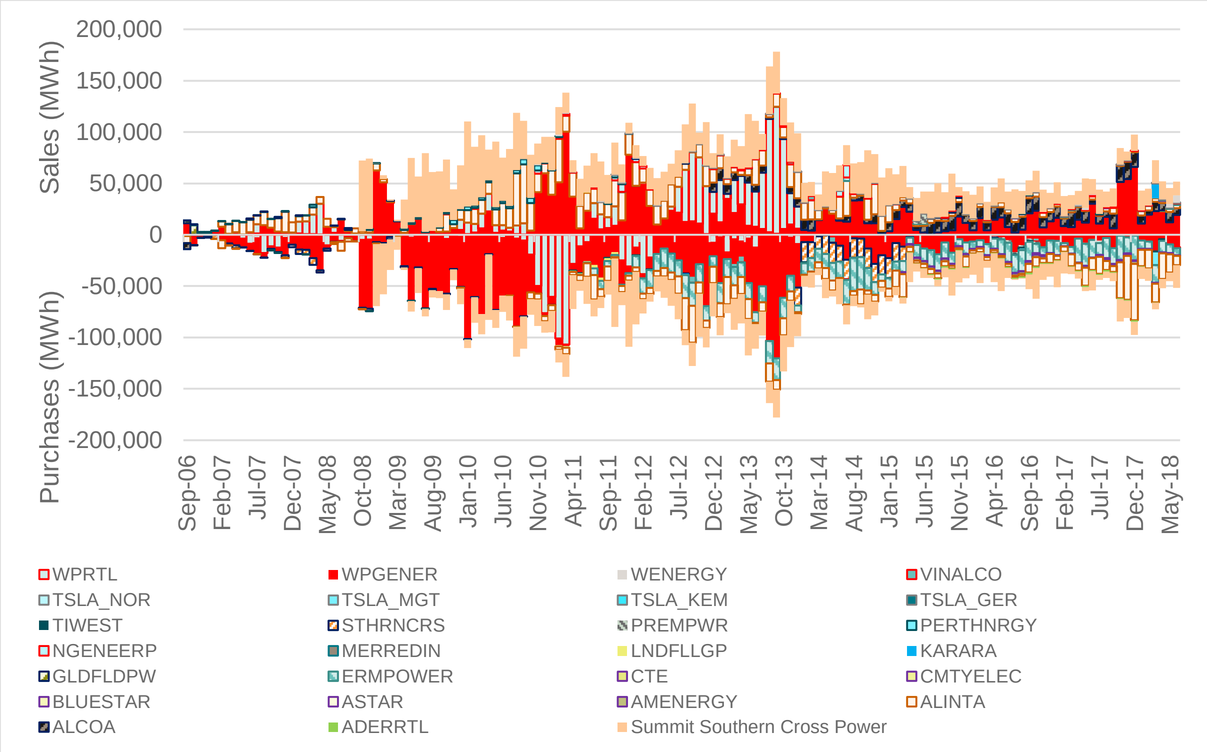
Figure 16: STEM Weekly summary data – off-peak intervals



Source: ERA analysis of AEMO data

Figure 17 shows the monthly STEM activity by market participant. The quantity of STEM trades increased from September to November 2017 with an increase in sales from Synergy and an increase in purchases from Alinta that coincided with a series of outages.

Figure 17: Monthly STEM activity by market participant

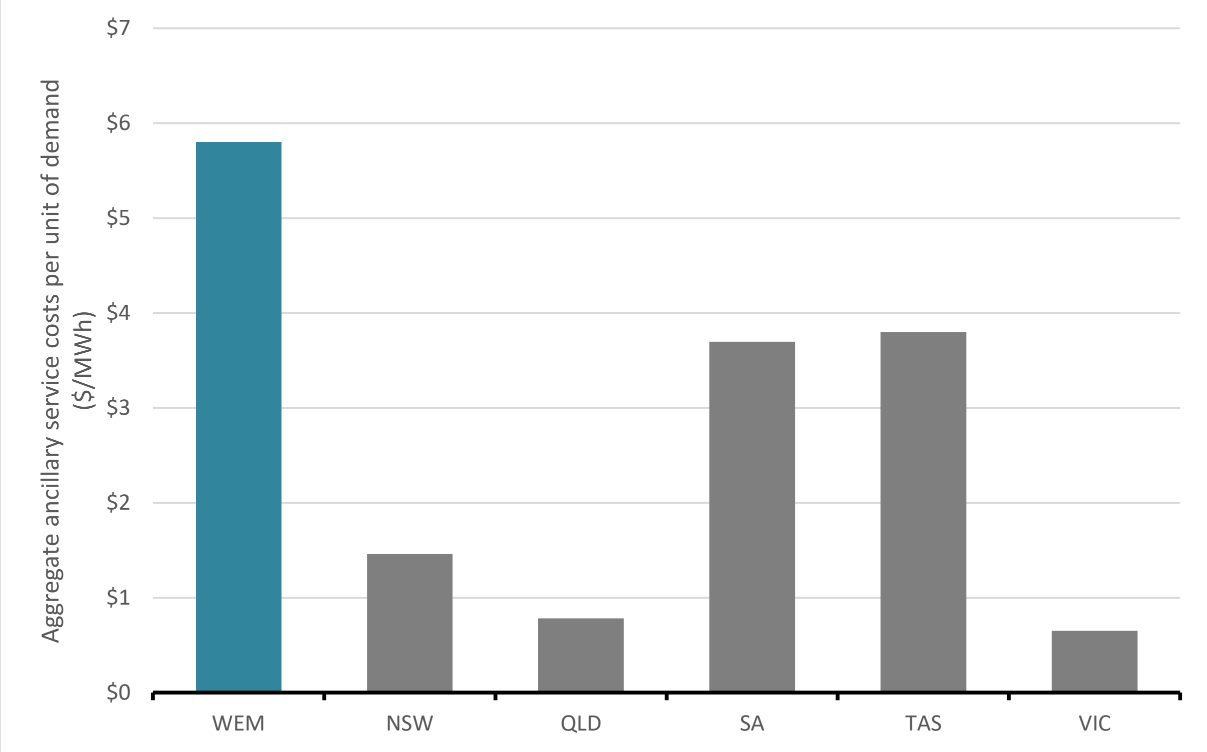


Source: ERA analysis of AEMO data

Ancillary Services

Ancillary services provide an example of poor market competition. The WEM has the highest ancillary services cost in the country by a large margin (**Figure 18**).

Figure 18: Australian ancillary services unit costs by jurisdiction



Source: ERA analysis of AEMO data

In the WEM, the ancillary services requirements for frequency control have remained stable at 72 MW for a number of years.[67] Annually, AEMO determines the requirement for ancillary services in the WEM. AEMO did not increase its ancillary services requirement in its 2018/19 report despite the ERA:

- Commenting that in the previous year, AEMO's requirement was 72 MW for raise and lower services, whereas the average actual quantity enabled was 110 MW raise and 111 MW lower.
- Recommending that AEMO investigate options to improve LFAS measurement.

AEMO's 2018/19 ancillary services requirement report provided greater clarity on the measurement issue, and confirmed that AEMO is making some improvements to better anticipate ancillary service requirements.[68] There are still limitations in how ancillary service requirements are determined. For example, AEMO's:

- Systems do not allow operators to record the actual use of resources for ancillary services from within Synergy's generation portfolio, even though the units providing the service are known.
- Processes are backward-looking, with limited foresight on when the ancillary service requirements may prove inadequate.

[67] Frequency controlling ancillary services are upward and downward load following ancillary services, spinning and load rejection reserves.

[68] ERA, (2018), Decision on AEMO's 2018-19 Ancillary Services Requirements, Economic Regulation Authority, Perth, p4, https://www.erawa.com.au/cproot/19328/2/AEMO%20Ancillary%20Services%20Requirements%20decision%202018-19.PDF

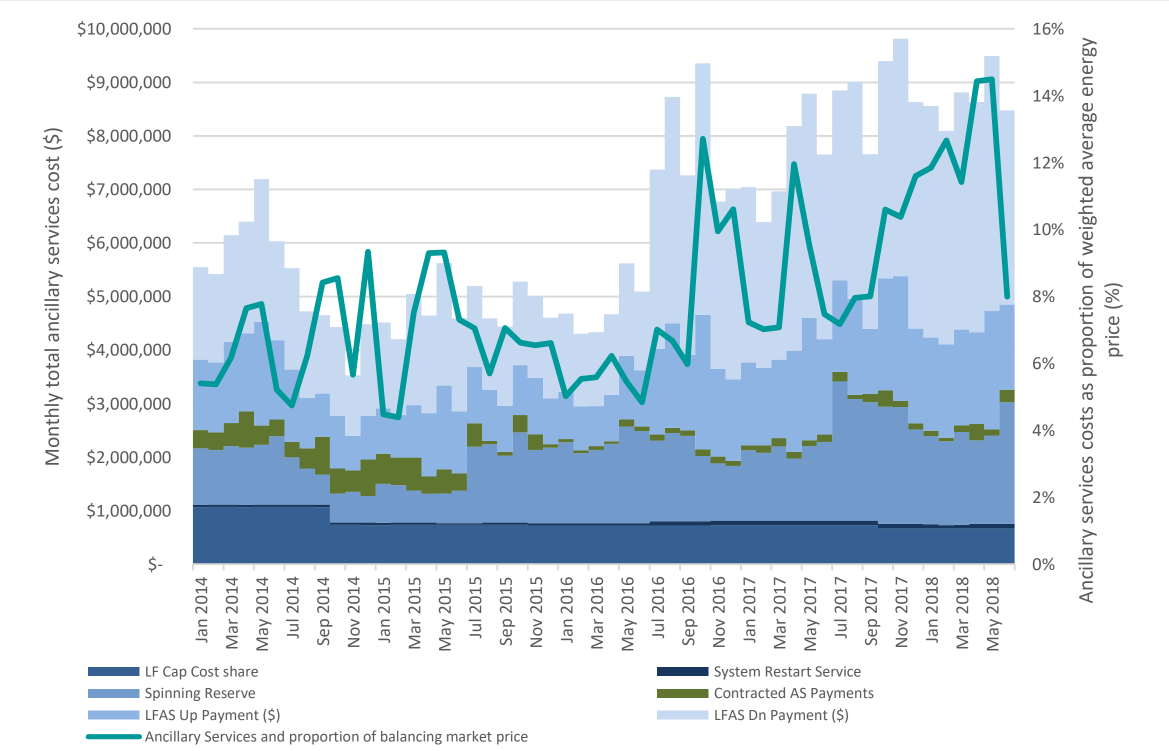
There has been no change in the volume of ancillary services required in response to increased volatility in demand from rooftop solar, or increased volatility in supply from a greater penetration of renewable generation. Therefore, the increase in ancillary service costs cannot easily be attributed to these changes and may be driven by other factors.

Most of the ancillary services cost increases are attributable to the LFAS market (**Figure 19**). Since the LFAS market began, LFAS prices have increased substantially, and have coincided with increases in balancing market prices.

There are just three participants cleared to participate in the market, with Synergy the pivotal supplier. There has been limited competition in the LFAS market, and the anticipated competitive discipline on prices in the market has failed to materialise.

The market is dominated by a single supplier, Synergy, which sets the price for all but a handful of intervals. Other suppliers lack sufficient capacity to meet the LFAS requirements and undercut Synergy on price.

Figure 19: Ancillary services costs and proportion of ancillary service costs of balancing market prices



Source: ERA analysis of AEMO data. The increase in ancillary service costs late in 2016, corresponds to a change in Synergy's bidding behaviour.

In contrast to the LFAS market, there have been more limited cost increases in administered ancillary services processes. The market rules allow AEMO to contract with third parties where this would deliver a lower cost for the market. The costing of spinning reserve has an administrative element; the ERA approves the margin value percentages included in the calculation of payments for providing spinning reserve. However, the magnitude of spinning reserve costs is sensitive to balancing market prices.

AEMO's procurement process has not increased the participation of third-party spinning reserve, and it has never run a procurement process for third-party load rejection provision.

The spinning reserve procurement terms are likely to have limited third-party participation with the potential to reduce spinning reserve costs. These requirements include:[69]

- generators to be available for 95 per cent of intervals[70]
- contracts that have a minimum limit of 8 MW and a maximum limit of 26 MW
- fixed, 12-month contracts. [71]

The interpretation and application of technical requirements in the provision of spinning reserve services may also constitute a barrier to participation from plant that might otherwise reduce ancillary services costs. Of the plant capable of meeting the spinning reserve availability requirement, AEMO has excluded capacity that could provide some response.[72] [73]

The market reform program is reviewing the technical requirements for ancillary services. If the technical requirements for ancillary service provision remain unchanged, market participants will continue to be ineligible to participate and compete in a future co-optimised market for electricity and ancillary services. If this happens, the anticipated benefits from having a co-optimised market will be limited.

The 2016/17 WEM report noted a step change in LFAS.[74] This has continued in 2017/18. No new participants have entered the LFAS market and Synergy remains a pivotal supplier.

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69 AEMO invitation to tender pp 2 and 9, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/Ancillary-Services/2018/Invitation-to-Tender---WEM-Spinning-Updated-Submission-Date.pdf

70 Few plant have operational hours approaching 95 per cent. Neither the peaking nor mid merit generators, likely to have the lowest marginal spinning reserve cost, would be eligible to participate. The minimum and maximum contract quantities are not explained and reflect a synthetic constraint on the market that would increase the cost to provide spinning reserve during peak intervals.

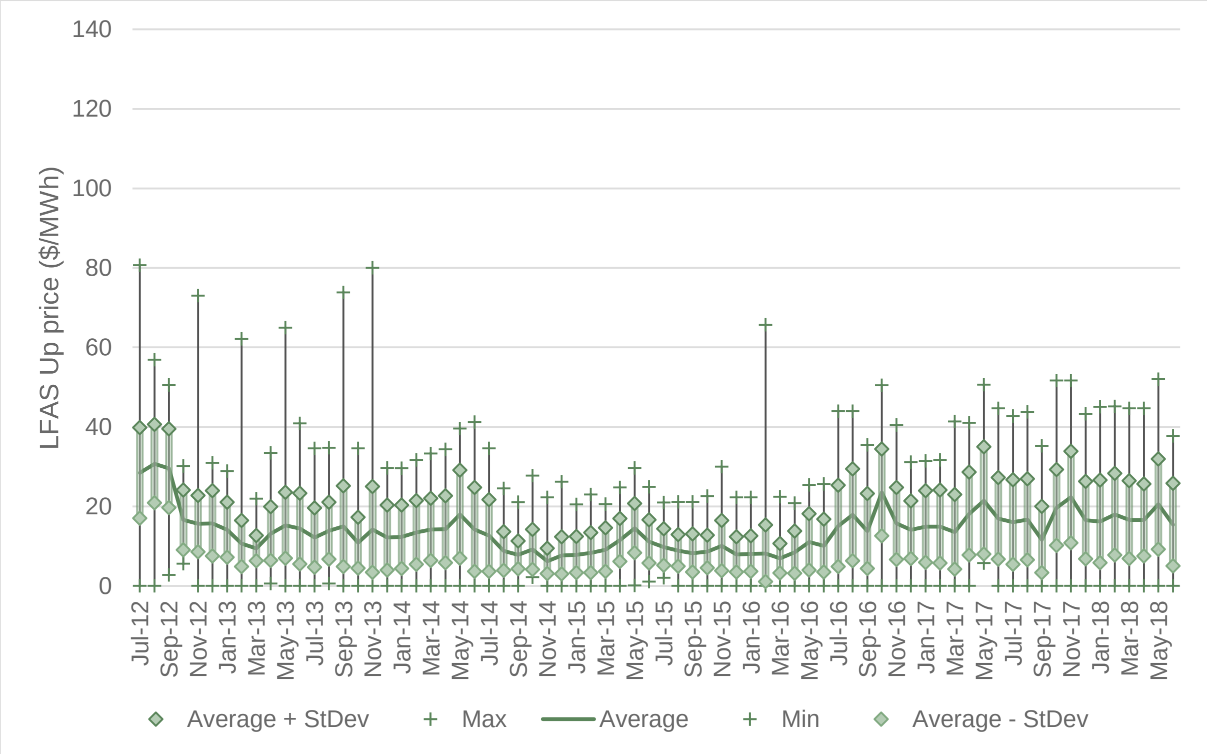
71 One possible provider has informally indicated a single year contract term made it difficult to justify the investment required to provide a competitive bid.

72 Email from Brendan Clarke of System Management dated 9/02/2017

73 The quantity of spinning reserve required is the net of 70 per cent of the single largest generation or network contingency less LFAS_UP. Thus the contribution of generators to providing spinning reserve can be directly (via eligibility to contract with AEMO to provide a service) or by reducing the quantity of spinning reserve required through frequency keeping services.

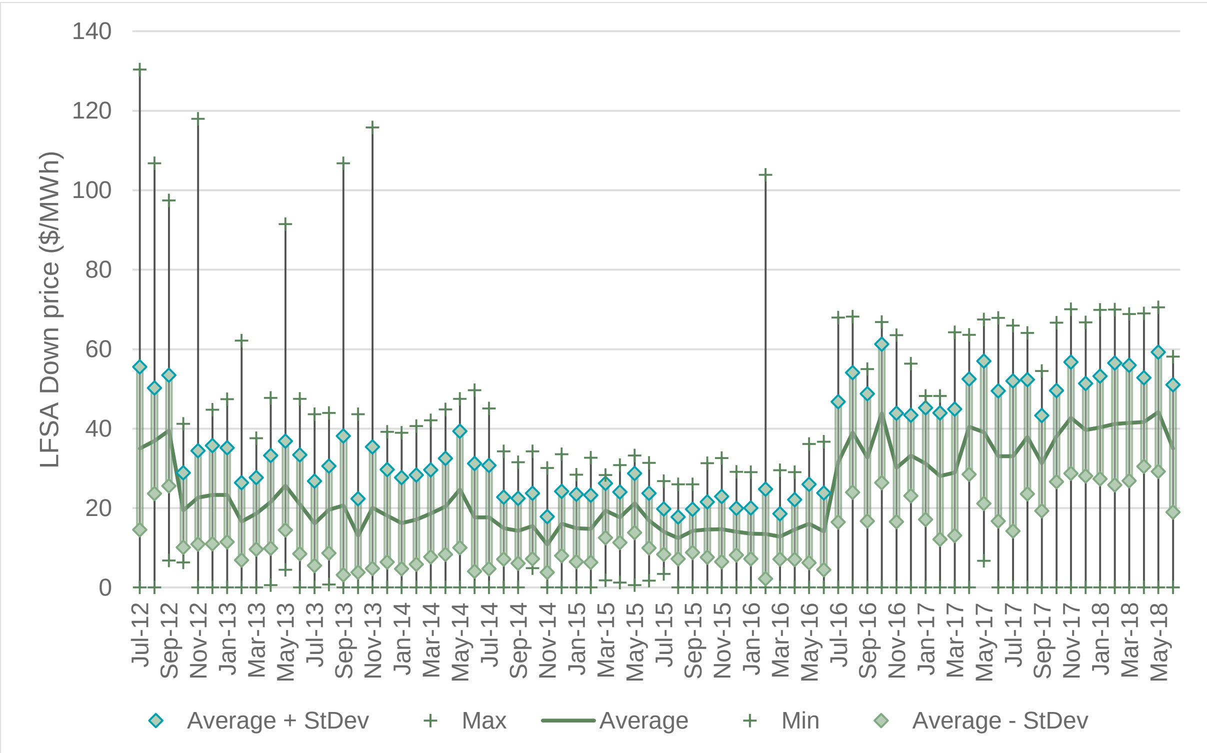
74 ERA website, 2016/17 WEM Report to the Minister for Energy – Technical Appendix, p10

Figure 20: Load Following Ancillary Services Up summary pricing statistics



Source: ERA analysis of AEMO data

Figure 21: Load Following Ancillary Services Down summary pricing statistics



Source: ERA analysis of AEMO data

Outages

Table 2 summarises outage data since the start of the balancing market. Cockburn_CCG1, Muja G5, Muja G6, Pinjar GT10 and Kwinana GT3 had the largest outages overall with outages exceeding 15%. Cockburn CCG1 had the largest forced outage rate with the Muja G1 through to G4 with forced outage rates of around 8%. Planned outages for Cockburn CCG1, Muja G5 and Muja G6 and Pinjar GT10 each had planned outages exceeding 20%.

Table 2: Outages by type, participant and facility from 2012/13 to 2017/18

PARTICIPANT	FACILITY NAME	INSTALLED CAPACITY (MW)	FORCED OUTAGES (%)						PLANNED OUTAGES (%)						EQUIVALENT UNAVAILABILITY FACTOR (%)						AVERAGE UNAVAILABLE CAPACITY (MW)					
			2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
ALCOA	ALCOA_WGP	25	4%	25%	1%	2%	3%	6%	30%	9%	3%	1%	0%	10%	33%	34%	5%	3%	3%	16%	8.3	8.6	1.2	0.9	0.9	3.9
ALINTA	ALINTA_PNJ_U1	143	0%	0%	0%	0%	0%	0%	5%	14%	9%	7%	3%	12%	5%	14%	9%	7%	3%	12%	7.8	20.3	13.1	9.6	3.7	17.6
	ALINTA_PNJ_U2	143	0%	0%	0%	0%	0%	2%	13%	13%	6%	9%	2%	4%	13%	13%	6%	10%	3%	6%	18.3	18.8	9.0	13.6	3.7	9.2
	ALINTA_WGP_GT	190	0%	0%	0%	0%	1%	0%	2%	6%	7%	4%	6%	4%	3%	7%	7%	5%	7%	4%	4.9	12.4	13.4	9.3	12.5	7.4
	ALINTA_WGP_U2	190	1%	1%	0%	0%	0%	0%	2%	7%	7%	3%	6%	4%	3%	7%	7%	4%	7%	4%	5.6	13.7	13.5	7.3	12.5	7.7
	ALINTA_WWF	89.1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-	0.0	0.2	0.1	0.0	-
COLLGAR	INVESTEC_COLLGAR_WF1	206	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1.0	0.3	0.5	0.0	-	-
EDWFMAN	EDWFMAN_WF1	80	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0.3	0.1	-	0.0	0.0	-
GLDFLDPW	PRK_AG	68	0%	0%	0%	1%	1%	0%	0%	0%	0%	1%	1%	1%	0%	0%	1%	2%	2%	1%	0.2	0.2	0.4	1.6	1.6	0.5
Summit Southern Cross Power	BW2_BLUEWATERS_G1	217	0%	0%	1%	1%	46%	5%	11%	9%	8%	11%	10%	1%	12%	10%	9%	12%	56%	6%	25.7	21.3	20.6	26.8	122.4	13.8
	BW1_BLUEWATERS_G2	217	5%	2%	0%	0%	1%	0%	9%	13%	9%	16%	2%	14%	14%	15%	9%	16%	3%	14%	30.1	32.4	20.5	35.5	7.1	29.7
	NEWGEN_KWINANA_CCG1	335	0%	1%	0%	1%	0%	0%	3%	2%	3%	14%	6%	5%	4%	3%	3%	15%	6%	5%	12.2	8.7	9.0	50.8	21.3	18.1
MERREDIN	NAMKKN_MERR_SG1	82	1%	1%	0%	1%	1%	1%	3%	3%	9%	7%	2%	1%	4%	5%	9%	8%	3%	2%	3.2	3.8	7.7	6.7	2.5	1.3
NGENEERP	NEWGEN_NEERABUP_GT1	342	0%	0%	0%	0%	0%	0%	5%	5%	1%	2%	1%	1%	5%	6%	1%	2%	1%	1%	17.1	20.1	4.2	6.8	3.6	4.2
STHRNCRS	STHRNCRS_EG	23	3%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%	6%	0%	0%	0%	0%	0%	1.3	0.1	-	-	-	-
TIWEST	TIWEST_COG1	42.1	1%	6%	2%	1%	1%	2%	2%	7%	1%	1%	9%	2%	3%	13%	3%	2%	10%	4%	1.2	5.5	1.3	0.9	4.3	1.7
TSLA_GER	TESLA_GERALDTON_G1	9.9	0%	0%	0%	0%	0%	0%	25%	4%	2%	1%	2%	3%	25%	4%	4%	1%	3%	4%	2.5	0.3	0.4	0.1	0.3	0.4
TSLA_KEM	TESLA_KEMERTON_G1	9.9	0%	0%	0%	0%	0%	0%	9%	1%	1%	1%	1%	0%	10%	1%	1%	1%	2%	0%	1.0	0.1	0.1	0.1	0.2	0.0
TSLA_MGT	TESLA_PICTON_G1	9.9	0%	0%	0%	0%	0%	0%	2%	2%	1%	0%	1%	1%	2%	2%	1%	2%	1%	2%	0.2	0.2	0.1	0.2	0.1	0.2
TSLA_NOR	TESLA_NORTHAM_G1	9.9	0%	0%	0%	0%	0%	0%	5%	1%	1%	5%	2%	1%	5%	2%	1%	5%	3%	2%	0.5	0.2	0.1	0.5	0.3	0.1
WENERGY	PERTHENERGY_KWINANA_GT1	116	0%	0%	0%	0%	3%	2%	2%	1%	1%	9%	7%	6%	3%	1%	1%	9%	10%	9%	3.2	1.7	1.3	10.4	11.2	9.9
Synergy	ALBANY_WF1	21.6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0.0	0.0	-	0.0	0.0	-
	COCKBURN_CCG1	236.6	0%	0%	0%	0%	1%	8%	3%	8%	6%	13%	18%	37%	4%	9%	7%	13%	18%	45%	9.4	20.2	15.7	30.8	43.4	107.6
	COLLIE_G1	318	1%	2%	1%	1%	0%	2%	3%	16%	5%	7%	8%	8%	4%	18%	6%	8%	9%	10%	12.8	56.5	19.5	25.3	28.0	31.1
	GERALDTON_GT1	15.9	0%	1%	57%	16%	0%	0%	15%	3%	1%	0%	0%	0%	15%	6%	59%	16%	0%	0%	2.4	0.9	9.3	2.6	-	-
	GRASMERE_WF1	13.8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0.0	0.0	-	0.0	0.0	-
	KEMERTON_GT11	154	0%	0%	0%	0%	0%	1%	13%	1%	5%	3%	14%	1%	13%	1%	5%	3%	14%	2%	19.8	2.1	8.0	5.3	21.6	2.5
	KEMERTON_GT12	154	0%	0%	0%	0%	0%	0%	1%	16%	1%	3%	16%	1%	2%	16%	1%	3%	16%	1%	2.8	24.6	1.5	5.2	24.5	1.3
	KWINANA_G5	177.5	5%	5%	2%	0%	0%	0%	8%	8%	0%	0%	0%	0%	12%	14%	2%	0%	0%	0%	22.2	25.7	2.9	-	-	-

PARTICIPANT	FACILITY NAME	INSTALLED CAPACITY (MW)	FORCED OUTAGES (%)						PLANNED OUTAGES (%)						EQUIVALENT UNAVAILABILITY FACTOR (%)						AVERAGE UNAVAILABLE CAPACITY (MW)					
			2012 /13	2013 /14	2014 /15	2015 /16	2016 /17	2017 /18	2012 /13	2013 /14	2014 /15	2015 /16	2016 /17	2017 /18	2012 /13	2013 /14	2014 /15	2015 /16	2016 /17	2017 /18	2012 /13	2013 /14	2014 /15	2015 /16	2016 /17	2017 /18
	KWINANA_G6	184	3%	2%	2%	0%	0%	0%	13%	19%	10%	0%	0%	0%	16%	22%	12%	0%	0%	0%	30.0	39.7	21.6	-	-	-
	KWINANA_GT1	20.8	0%	1%	4%	0%	3%	0%	16%	4%	7%	8%	1%	1%	16%	5%	11%	8%	5%	1%	3.3	1.1	2.2	1.6	1.0	0.3
	KWINANA_GT2	100.1	2%	1%	1%	2%	2%	0%	7%	24%	17%	18%	16%	9%	9%	25%	18%	20%	19%	11%	9.1	24.5	17.7	20.3	18.6	11.1
	KWINANA_GT3	100.1	3%	1%	4%	3%	1%	6%	5%	19%	13%	12%	18%	9%	9%	20%	18%	15%	19%	17%	8.7	19.6	17.8	15.4	19.0	17.1
	MUJA_G5	195.7	1%	2%	2%	8%	0%	5%	14%	23%	5%	14%	4%	30%	15%	24%	7%	23%	5%	35%	29.5	47.4	14.0	45.1	9.1	68.8
	MUJA_G6	190.75	1%	1%	21%	2%	1%	3%	47%	5%	2%	22%	4%	23%	47%	6%	23%	24%	5%	26%	90.3	10.9	43.9	46.2	10.2	49.7
	MUJA_G7	211	3%	0%	23%	1%	0%	0%	3%	9%	21%	14%	14%	5%	6%	9%	44%	15%	14%	6%	11.8	19.8	91.9	31.2	30.2	11.7
	MUJA_G8	211	2%	2%	6%	1%	0%	2%	7%	2%	31%	11%	17%	3%	9%	5%	36%	12%	17%	5%	19.9	10.0	77.0	25.1	35.5	10.1
	MUNGARRA_GT1	37.2	0%	1%	0%	2%	0%	0%	9%	9%	14%	0%	3%	0%	9%	10%	14%	2%	3%	0%	3.3	3.6	5.2	0.8	1.2	0.2
	MUNGARRA_GT2	37.2	0%	0%	0%	1%	1%	0%	0%	9%	1%	0%	2%	0%	1%	9%	1%	1%	3%	1%	0.2	3.4	0.5	0.3	1.1	0.2
	MUNGARRA_GT3	38.2	0%	2%	1%	0%	0%	0%	17%	1%	10%	6%	3%	0%	17%	2%	11%	6%	3%	0%	6.6	0.8	4.2	2.3	1.0	0.2
	PINJAR_GT1	37.2	0%	0%	1%	0%	0%	0%	1%	4%	0%	6%	0%	11%	1%	4%	1%	6%	0%	11%	0.5	1.6	0.3	2.4	0.0	4.2
	PINJAR_GT10	116	0%	1%	1%	1%	1%	2%	9%	37%	0%	7%	9%	23%	9%	37%	1%	7%	9%	25%	10.4	43.3	1.3	8.6	10.6	29.0
	PINJAR_GT11	123	0%	0%	6%	1%	1%	1%	6%	11%	8%	10%	18%	1%	6%	11%	14%	11%	19%	2%	7.5	13.8	17.7	13.2	23.9	2.4
	PINJAR_GT2	37.2	0%	0%	1%	0%	0%	0%	6%	5%	0%	6%	0%	3%	6%	6%	1%	6%	0%	3%	2.1	2.1	0.2	2.2	0.1	1.2
	PINJAR_GT3	38.2	0%	0%	0%	1%	1%	1%	13%	0%	10%	3%	0%	2%	13%	0%	10%	5%	1%	4%	5.0	0.1	3.9	1.9	0.4	1.4
	PINJAR_GT4	38.2	0%	0%	0%	0%	0%	0%	7%	0%	21%	3%	0%	2%	7%	1%	22%	3%	1%	2%	2.7	0.2	8.3	1.3	0.3	0.8
	PINJAR_GT5	38.2	0%	0%	0%	0%	0%	0%	6%	0%	0%	9%	0%	3%	6%	1%	0%	9%	0%	3%	2.3	0.2	0.1	3.5	0.1	1.3
	PINJAR_GT7	38.2	0%	0%	0%	0%	0%	0%	1%	10%	0%	0%	4%	8%	1%	10%	0%	1%	4%	8%	0.5	3.7	0.1	0.3	1.4	3.0
	PINJAR_GT9	116	0%	0%	3%	3%	1%	2%	19%	1%	21%	2%	35%	7%	19%	1%	24%	4%	36%	9%	22.5	1.3	27.8	4.8	41.3	10.4
	PPP_KCP_EG1	85.7	1%	0%	2%	0%	0%	0%	9%	6%	5%	4%	2%	2%	10%	6%	7%	4%	2%	2%	8.3	4.9	6.0	3.1	2.0	1.8
	SWCJV_WORSLEY_COGEN_COG1	116.4	0%	0%	1%	0%			3%	7%	2%	2%			3%	7%	3%	2%	0%	0%	3.9	8.0	3.1	2.9		
	WEST_KALGOORLIE_GT2	38.2	0%	2%	1%	0%	0%	1%	9%	9%	3%	0%	0%	3%	9%	11%	4%	3%	1%	4%	3.6	4.4	1.6	1.0	0.2	1.6
	WEST_KALGOORLIE_GT3	24.6	0%	1%	0%	1%	2%	0%	23%	2%	3%	0%	3%	0%	23%	3%	4%	2%	6%	0%	5.7	0.8	1.0	0.6	1.4	0.0
VINALCO	MUJA_G1	55	74%	68%	5%	0%	0%	8%	0%	0%	5%	2%	42%	1%	74%	68%	11%	2%	42%	9%	40.8	37.2	5.8	0.9	23.1	4.9
	MUJA_G2	55	74%	59%	2%	2%	2%	8%	0%	0%	3%	0%	7%	1%	74%	59%	10%	2%	8%	9%	40.8	32.2	5.3	0.8	4.5	4.9
	MUJA_G3	55	50%	5%	2%	0%	0%	8%	4%	10%	4%	2%	12%	1%	54%	14%	5%	2%	13%	9%	29.8	7.9	2.9	1.0	7.1	4.9
	MUJA_G4	55	38%	5%	1%	0%	1%	8%	7%	5%	2%	9%	7%	1%	45%	10%	3%	9%	8%	9%	25.0	5.2	1.6	5.2	4.3	4.9
GRNOUGH	GREENOUGH_RIVER_PV1	10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-	0.0	0.0	0.0	-	-
MUMBIDA	MWF_MUMBIDA_WF1	55	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-	-	0.3	0.1	-	-

Source: ERA analysis of AEMO data

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