Report to the Minister for Energy on the Effectiveness of the Wholesale Electricity Market 2018

Final Report

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Economic Regulation Authority
WESTERN AUSTRALIA

D200441

Economic Regulation Authority

4th Floor Albert Facey House
469 Wellington Street, Perth

Mail to:
Perth BC, PO Box 8469
PERTH WA 6849

T: 08 6557 7900

F: 08 6557 7999

E: info@erawa.com.au

W: www.erawa.com.au

National Relay Service TTY: 13 36 77
(to assist people with hearing and voice impairment)

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Executive summary

Each year, the ERA reviews how effectively the Wholesale Electricity Market is meeting its objectives and provides a report to the Minister for Energy with recommendations for improvements in the market.

Current conditions

This year the ERA finds that the Wholesale Electricity Market is failing to meet an important market objective. It is not minimising the long-term cost of electricity for consumers.

Three observations lead the ERA to reach this conclusion.

First, wholesale electricity prices have increased by more than 20 per cent in the past four years despite an absence of underlying cost drivers in fuel costs or scarcity of generation capacity. There has been excess generation capacity, there have been decreases in demand and reduced gas prices, and there have been only modest increases in coal prices. The ERA has examined whether other factors such as the increased share of renewable energy in the market have caused an increase in prices and concluded that up to 2017/18 it may have increased costs and reduced profits for some generators. However, these generators rarely set the market price and so their higher costs should not have influenced wholesale prices.

Second, Western Australia has the highest prices for ancillary services in Australia. Ancillary services are provided by generation businesses to provide a secure and stable electricity supply, for example by balancing the supply of and demand for electricity in real time. These services have been effective in ensuring system security in the South West Interconnected System, but their cost is high.

Third, the ERA has conducted a formal investigation of Synergy's pricing behaviour and concluded that Synergy has been bidding wholesale energy into the market at values that are higher than the market rules permit. The market rules specify that a generator cannot charge prices that exceed its reasonable expectation of the short run marginal cost of producing electricity if that behaviour relates to market power. The ERA has concluded that Synergy has breached this rule, and is taking action through the Electricity Review Board.

In past Wholesale Electricity Market reports, the ERA has argued that restructuring Synergy to reduce its market power would help to contain costs in the wholesale market and position the industry to respond flexibly and efficiently to changing market conditions. The ERA still holds this view. However, this report focuses on other measures that government can take to help the market develop to better meet the market objective of minimising long-term costs for consumers.

Emerging challenges

In addition to the current problems of the Wholesale Electricity Market identified above, the ERA has identified several emerging challenges.

Western Australia's electricity market is changing and will change further over the coming decade. Large-scale renewable energy, such as wind farms, is contributing a growing share of electricity generation, and an increasing number of households and small businesses generate their own electricity using rooftop solar panels. This is changing the profile of electricity demand and supply and presenting challenges to the operation of the electricity system and Wholesale Electricity Market.

New technologies such as batteries offer opportunities both to help match increasingly variable demand and supply, and to provide the ancillary services necessary to keep the electricity

system stable. However, current regulatory and market arrangements do not support the integration of large-scale battery technology into the electricity system.

The excess generation capacity that has been a feature of the Western Australian electricity market for many years may no longer prevail after Synergy's coal generators are retired. In this changing and unpredictable environment, government decisions made over the next few years will have long-lasting effects on Western Australia's electricity market.

Retiring generation

Western Australia has had excess generation capacity for many years, and there is currently sufficient capacity available to maintain the reliability of the electricity system. However, some of Synergy's generators are reaching the end of their expected life, and in time will need to be replaced. These plant retirements are an opportunity for new businesses and new technologies to participate in the Wholesale Electricity Market and create a more diverse market that disciplines the pricing behaviour of market participants.

If private investment is not forthcoming, the Government will have to fund investment to replace Synergy's ageing plant to maintain the reliability of the electricity system. Government would retain the cost and risk of investing in new generation and Synergy would continue to dominate the Wholesale Electricity Market, reducing business activity and innovation and risking higher prices and less choice for consumers.

Large engineering projects take time to develop, finance and build. Investors need to be able to assess available opportunities well in advance. Government can assist private investors to assess future opportunities by clarifying Synergy's future role in the Wholesale Electricity Market, and in particular by signalling that Synergy will not itself replace ageing generation plant.

Storage and renewable generation

By the end of 2018, just over 1,000 MW of small-scale solar generation had been installed on household rooftops. The market operator forecasts that this will more than double over the next 10 years. Two major wind farm projects, Yandin and Warradarge, are projected to substantially increase the contribution of wind to the market.

The output from wind and solar generation is intermittent and depends on weather conditions. This can cause significant and rapid peaks and troughs in electricity demand and supply. Flexible generators, and other technologies such as battery storage, will be needed to ensure reliable electricity supplies in the future.

Batteries can also be an extremely cost-effective technology for provision of ancillary services that are currently supplied by thermal generators.

Large-scale battery storage is being used in other jurisdictions, including South Australia and California. Western Australia's Wholesale Electricity Market cannot currently benefit from battery technologies because there is no provision in the market rules for batteries to participate in the market. In the Wholesale Electricity Market, investors in batteries need clarity on what services batteries may provide, and the basis on which they are provided. Battery owners can then assess the investment opportunity available and respond appropriately.

The Government's reform program

The Government's reform program for the Wholesale Electricity Market includes proposals for significant changes to the market: constrained network access, security constrained and optimised dispatch of both energy and ancillary services, and facility bidding for Synergy. The Government proposes that the new market design will be operational in October 2022.

While the broad intent of these initiatives is to improve the market, there appears to have been very limited progress and market participants are poorly informed on the proposals. The information released on the reform proposals has been high level, and the timing and detail of particular reforms are not clear. The detail of the reform program is only just beginning to emerge through discussions in the two Market Advisory Committee Working Groups: one led by the Public Utilities Office that is providing advice on market design and operation, and the other led by AEMO that is providing advice on the technical operation of the power system.

Without more detail, market participants will find it hard to assess whether and when new investment opportunities exist and whether the reforms will adequately cover existing market deficiencies and future challenges. New businesses may miss opportunities to invest in the market, reducing business activity and limiting choice for consumers.

Tariff reform

The market reform program focusses on the supply of electricity. Another wholesale market objective is to influence when, and how much, electricity is consumed. Tariff reform that changes consumers' behaviour could help to reduce costs in the wholesale market.

Wholesale electricity prices vary by time of day to reflect the different cost of supplying electricity as demand peaks and troughs. Also, the reserve capacity mechanism provides incentives for major users of electricity to limit demand in peak demand periods. The Wholesale Electricity Market therefore contains effective mechanisms to manage demand.

However, the price signals to manage demand do not effectively pass through to small-use customers. Most small-use consumers are not charged prices that reflect time-of-day and seasonal variation in the cost of generation, instead paying a flat rate for energy.

As a result, small-use customers have no incentive to manage their use of electricity in a manner that will reduce electricity supply costs across the market. In particular, there are no incentives to reduce demand in the early morning and late afternoon when the supply cost of electricity in the South West Interconnected system is highest; or to switch demand to off-peak periods when costs are low. As batteries become increasingly prevalent elsewhere there will be little financial incentive to use them in Western Australia if the existing tariff structure continues. The higher-than-necessary costs of wholesale electricity and ancillary services are eventually passed through to consumers, resulting in higher prices and lower affordability.

Customer education programs and time of use tariffs that reflect costs in the wholesale market can encourage customers to move consumption into periods when wholesale prices are low, and to lower the overall cost of wholesale electricity.

Summary of Recommendations

Recommendations:

1. Synergy's market power needs to be reduced to lower the cost of wholesale electricity. In the absence of structural reform, the government can reduce Synergy's market power by:

    a. Signalling to the market that the Synergy will not itself replace ageing thermal generation plant as that plant is retired.

    b. Making changes to the regulatory scheme that constrain Synergy's market power, as recommended by the ERA in its separate report on this matter.

2. Current market rules and technical standards are silent on, or prevent, the uptake of some new technologies. These should change to allow for large-scale batteries to be integrated into the electricity system and participate in the Wholesale Electricity Market.

3. Retail tariff reforms and/or public education programs should be pursued to provide electricity customers with the knowledge and incentives to adjust their electricity consumption in a way that will reduce costs of supply across the market. A review of regulated retail tariffs for small use electricity customers is urgently needed.

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 Act requires the ERA to provide recommendations as to how they could be achieved.

1.1 Regulatory requirements

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 and System Management carry out their 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.

1 Section 128 of the Electricity Industry Act 2004

2 Rule Change Panel, 2018, Wholesale Electricity Market Rules (11 January 2019). clause 2.16.12 (online)

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.
- Encourage competition among generators and retailers in the South West Interconnected System, including by facilitating the efficient entry of new competitors.
- Avoid discrimination in that 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.

1.2 Report structure

This WEM report has three major elements: identifying why the WEM is not meeting the WEM objectives, identifying emerging challenges, and discussing opportunities available to government to enable the WEM to better achieve the WEM objectives.

Section 2 explores how market conditions influence the achievement of the market objectives and outlines the circumstances of wholesale energy price increases in the WEM.

Section 3 on emerging challenges explores some of the operational effects of the energy sector transformation on the electricity market: the ongoing effects of rooftop solar on the load profile served by the electricity market, and the retirement of aging thermal generation capacity over the next ten years.

Section 4 covers opportunities for the government to improve how effectively the WEM meets WEM objectives. These include limiting Synergy's market power, supporting private sector investment in the electricity market in existing and emerging technologies, and improving price signals for retail electricity customers.

The appendices to this report provide:

- the reporting requirements
- a commentary on the effective operation of main market processes and procedures
- information on the WEM market dynamics as reported in the discussion paper
- a summary of the submissions received in response to the discussion paper
- a summary of international experience integrating batteries into energy markets.

[3] Ibid. clause 1.2.1

1.3 Consultation

The ERA held a stakeholder workshop including market participants in April 2018.

On 21 December 2018, the ERA released a discussion paper seeking public submissions on matters influencing the effectiveness of the WEM. It also presented to the Market Advisory Committee on 5 February 2019.

The ERA received 11 submissions in response to the discussion paper. Stakeholder comments are included and addressed throughout this report, and the public submissions are available on the ERA website.[4]

[4] Economic Regulation Authority, 2019, Annual Wholesale Electricity Market Effectiveness review.

2. The Wholesale Electricity Market is not meeting its objectives effectively

Electricity retailers buy electricity from the balancing market or bilateral contracts with generators. Retailers also pay for the cost of generation capacity, network and ancillary services through separate mechanisms. Retailers recover their costs through the sale of electricity to consumers.

One of the objectives of the Wholesale Electricity Market (WEM) is to minimise the long-term cost of electricity supply to consumers. The ERA has found that the WEM is failing to meet this objective. Three observations inform this conclusion:

- WEM prices have increased in real terms by more than 20 per cent in the last four years, despite low fuel costs and only limited excess generation capacity.
- Western Australia has the highest prices in Australia for ancillary services, used to provide a secure and reliable electricity supply.
- An ERA investigation into Synergy's pricing behaviour has concluded that Synergy has been bidding wholesale energy into the market at values that are higher than the market rules permit.

Each of these observations is examined in more detail below.

2.1 Wholesale electricity price increases

The stack of electricity supply costs in the South West Interconnected System (SWIS) in the past four years is shown in Figure 1. The cost stack for each year shows the combined costs of wholesale electricity: wholesale electricity market balancing prices, capacity costs, and ancillary services.

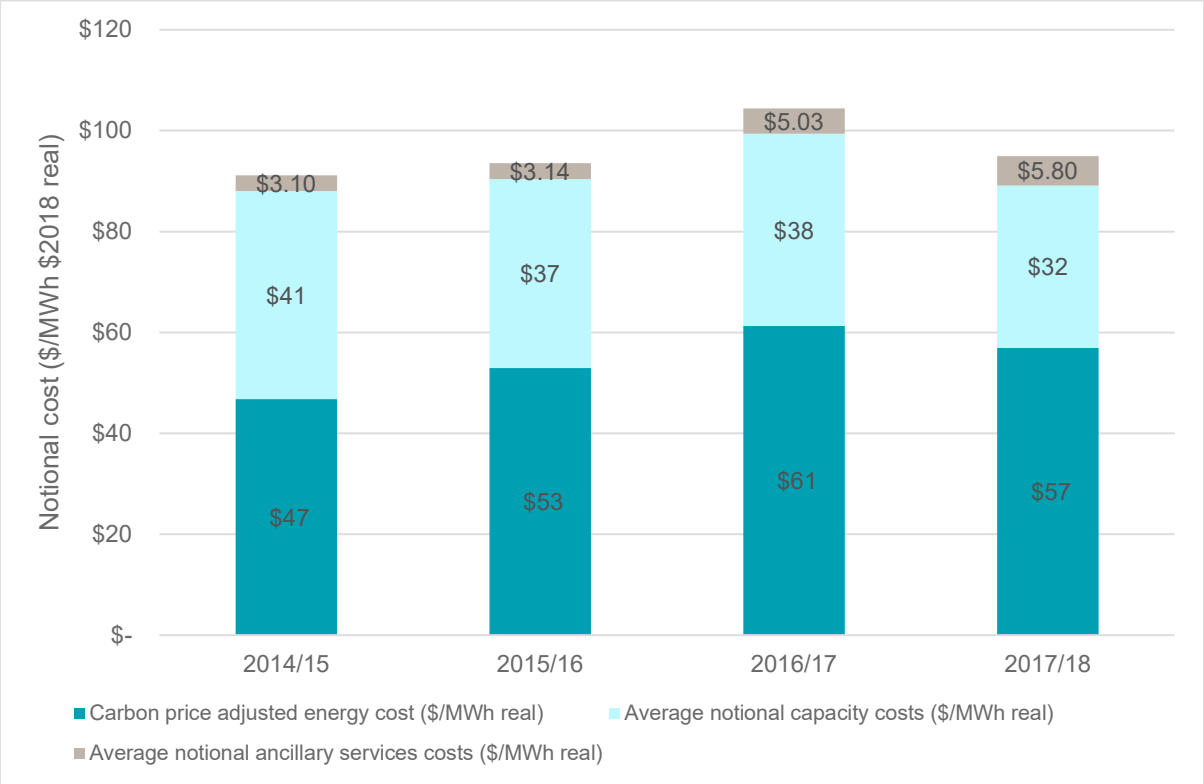
From 2014/15 to 2017/18, the combined costs of energy, capacity and ancillary services, increased by 4 per cent in real terms.

Since 2014/15, volume-weighted average wholesale electricity costs in the balancing market have increased by approximately 23 per cent in real terms. Ancillary service costs, many of which are linked to the balancing market, have also increased. Capacity costs have decreased by over 20 per cent.

The decrease in the cost of capacity[5] has been more than offset by increases in the cost of energy and ancillary services.

[5] ERA, 2013, *Consultation Paper: Review of methodology for setting the Maximum Reserve Capacity Price and the Energy Price Limits in the Wholesale Electricity Market*, p. 27-28. online

Figure 1 Notional costs of wholesale electricity supply per unit of energy consumed (real $2017/18)



Source: ERA analysis of Australian Energy Market Operator (AEMO) data

The increase in balancing prices does not appear to have been driven by changes in the main input costs for generating electricity: gas prices have decreased, and coal prices have remained constant. Moreover, energy demand has declined, both in total and at times of peak demand.

2.1.1 Gas and coal prices

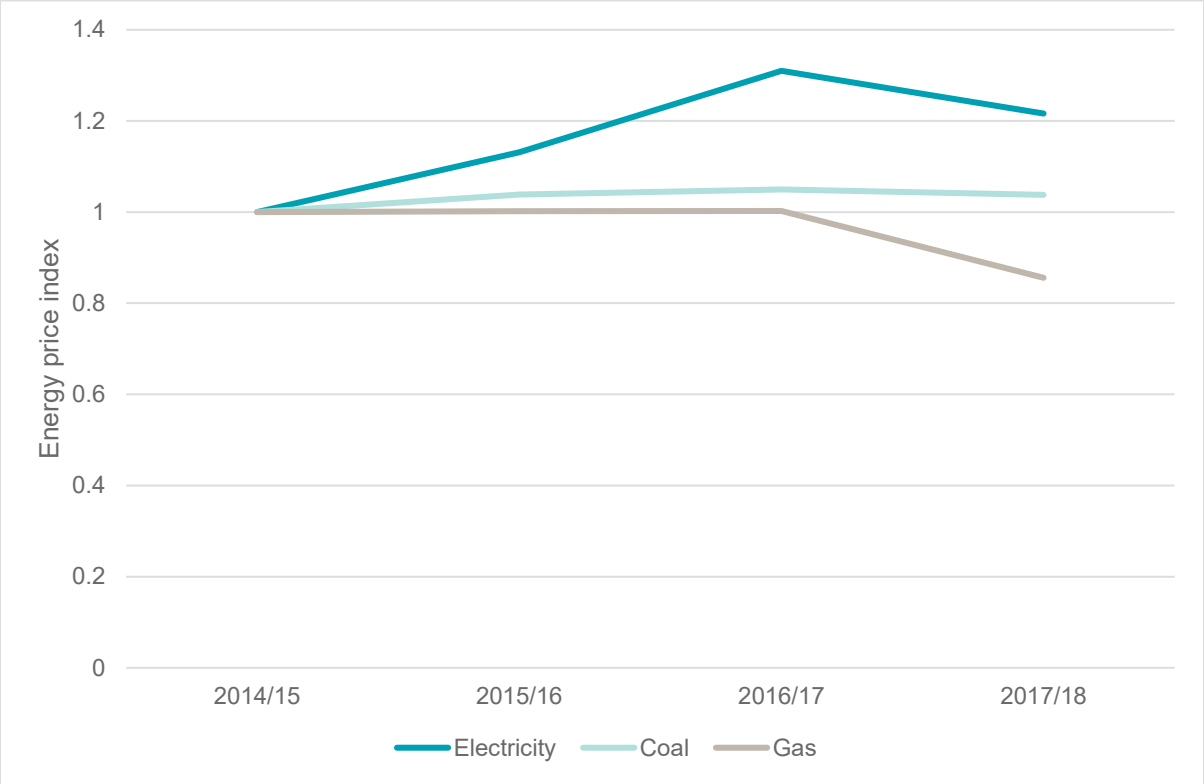
Balancing market bids are made up of start-up costs, fuel costs, and variable operation and maintenance costs.[6] Fuel costs typically comprise the largest component of the operational costs used to prepare a balancing market bid, consistent with a generator's short-run marginal cost.

Publicly available[7] data on fuel prices is shown in Figure 2. This shows the volume-weighted average gas price for domestic gas production and domestic coal sales against average balancing prices.

6 For more information on balancing market bidding refer to the ERA's guideline (online)

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

Figure 2: Quarterly average fuel prices and weighted quarterly average balancing market prices ($2018 real)



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.[8] 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.

Coal prices have remained approximately constant in real terms over recent years.

The ERA has analysed both publicly available gas price information and confidential information made available to the ERA in its market monitoring role. Most sources suggest gas prices have been trending lower, with gas prices falling in real terms last financial year. The quarterly average contract prices for domestic gas[9] appear to be converging on the quarterly average gas spot market prices.[10] Between 2016/17 and 2017/18, gas spot market prices have reduced, and analysis undertaken by the ERA on gas market spot prices indicates that the trading price range is relatively insensitive to the volumes traded.[11]

The 20 per cent increase in average balancing market prices over the last four years therefore does not appear to have been driven by increases in primary fuel costs.

8 DMIRS, 2018, Major Commodities Resources File, (online)

9 AEMO, 2017, *Gas Statement of Opportunities for Western Australia*, p. 33. (online)

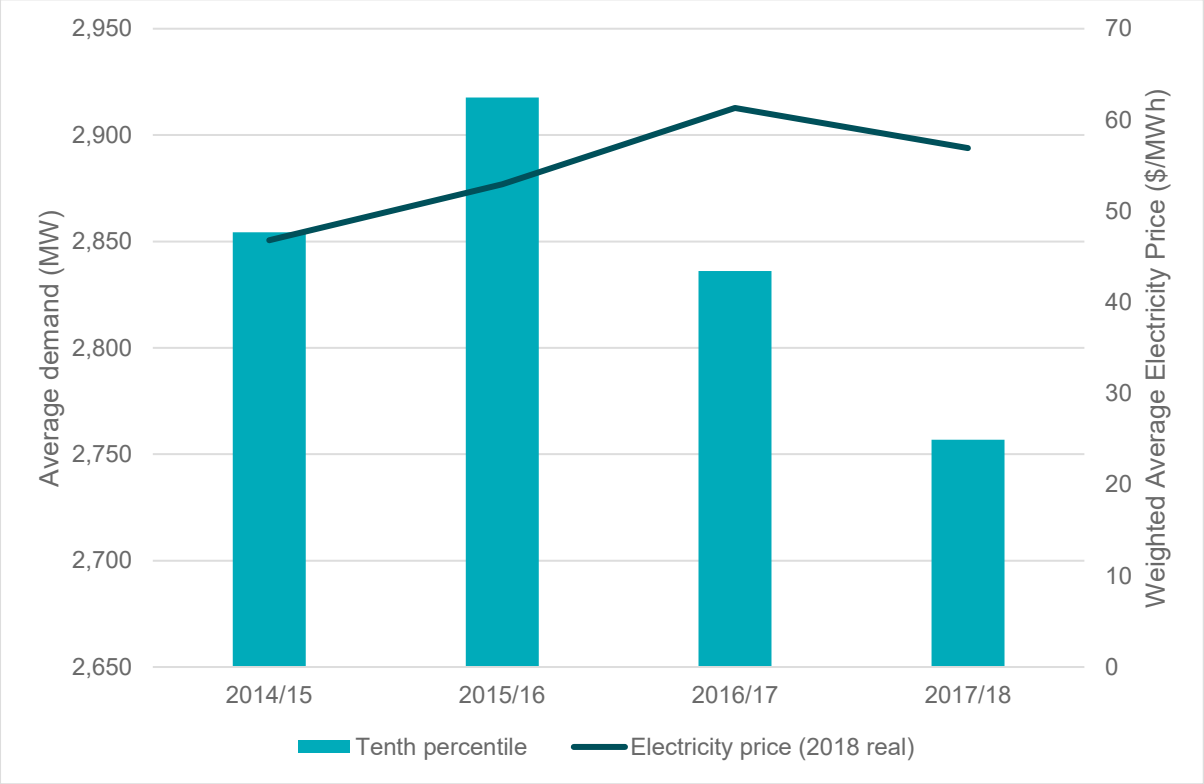
10 gasTrading, 2019, Spot market – Historical prices and volume (online)

11 gasTrading. 2019, Spot market – Bid information and scheduled gas (online)

2.1.2 Changes in the level and profile of demand

The last two summers have been relatively mild.[12] With temperature-dependent demand weak, the WEM should have recorded lower wholesale prices. However, this did not occur. In 2017/18, although demand was low, balancing market prices were the second highest on average since the market began in July 2012.

Figure 3: Average top ten per cent of demand and weighted average balancing prices over the last four years



Source: ERA analysis of AEMO data

The reduced demand from mild summers in the last two years is illustrated in Figure 3 along with average balancing prices over the last four years. The two columns on the figure show the declining average demand for the tenth per cent of intervals.

Low demand in and of itself should not place upward pressure on balancing prices. However, changes in the demand profile could have driven balancing prices to increase. This is considered below.

Changing load profile

The sustained high level of installation of behind-the-meter rooftop solar has changed network demand. Rooftop solar installation has reduced:

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

[12] Bureau of Meteorology, 2019, Current climate 2017/18 (online) and 2016/17 (online)

Rooftop solar dampens network demand in the middle of the day. When rooftop solar is not generating, customer demand from the network peaks in the morning as consumers prepare for the day ahead, and in the evening as they arrive home.

Generator costs can increase if the generators are dispatched more often, ramped up and down more frequently, or run for shorter periods to meet these changes in demand. Generators' increased costs would tend to be reflected in higher bids into the balancing market. If there is a change in the costs of those generators that typically set the balancing price, this could drive up wholesale electricity prices.

The ERA has investigated whether the presence of high levels of rooftop solar generation has increased wholesale electricity market balancing prices over the four years up to and including 2017/18.

2.1.2.1 Thermal generator run times

Thermal generators, such as coal plants and to a lesser extent, combined cycle gas turbines, are relatively inflexible compared with open cycle gas turbines. Starting a thermal generator and "ramping" the generator up and down causes wear and tear.[13] A higher number of starts and fast ramping means that major maintenance may be needed sooner than expected.[14] If a generator is required to start more frequently, or increase or decrease its output over a shorter period of time, its variable operating costs can increase, such as needing parts refurbished or replaced more often. It is also possible that, after starting, the generator runs for a shorter period in response to transitory increases in demand. The higher start-up cost must then be amortised over the shorter run duration, increasing the start-up cost of the machine further. However, these increased costs will increase the balancing price only if this is the marginal generator for the trading interval.

Synergy owns half the accredited generation capacity in the WEM and sets prices in most trading intervals. To determine whether generator run times may be influencing bids into the balancing market, the ERA examined the average run duration of Synergy's largest generators.[15]

Most of the generators' average run times appear to have changed little between years (see Figure 12 in Appendix 3). Only the Cockburn closed-cycle gas turbine showed a change in average run time large enough that it might indicate a need for higher bids into the market to recover costs.

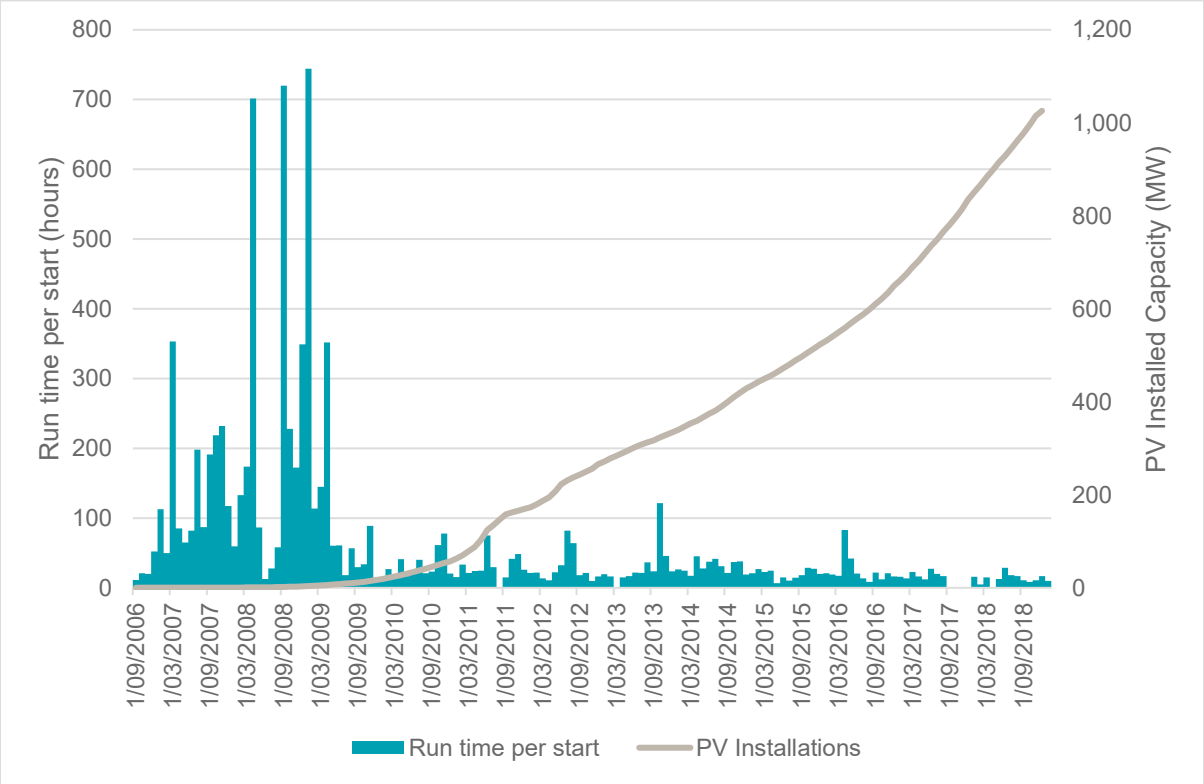
The ERA reviewed Cockburn's operational pattern since 2006 to identify whether it was influenced by increasing levels of rooftop solar. This is illustrated in Figure 4 below.

[13] Eggart, J, Merine, M, Sasser, J & Thompson, C, 2017, *Heavy-Duty Gas Turbine Operating and Maintenance Considerations*, p. 10, (online)

[14] These are commonly referred to as 'factored starts which have a penalty weighting for fast start-ups. Equipment manufacturers use factored starts, rather actual number of starts, to estimate the timing of maintenance outages. Factored starts are estimated based on how severe starts and trips by the machine are relative to a normal start.

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

Figure 4 **Cockburn closed-cycle gas turbine 1 monthly starts and installed distributed PV generation capacity**



Source: ERA analysis of AEMO and Clean Energy Regulator data

Before June 2009, Cockburn used to run for multiple days after every start up. Most of the starts occurred in off-peak periods, and most shut downs occurred after 9:00pm. From June 2009, the number of starts increased and the run durations dropped.

There has been a further reduction in run time per start over the last few years, but this reduction has been modest when compared to the large reductions after June 2009. The operational pattern of lower run times per start observed mid-2009 commenced at least two years before the growth in rooftop solar generation began to escalate in 2011. The ERA takes the view that, although Cockburn's run time per start has changed, this does not appear to have been a result of increased rooftop solar. Also, Cockburn's capacity factor is diminishing over time and, at around 5 per cent, it would rarely be the price setting generator in the market.

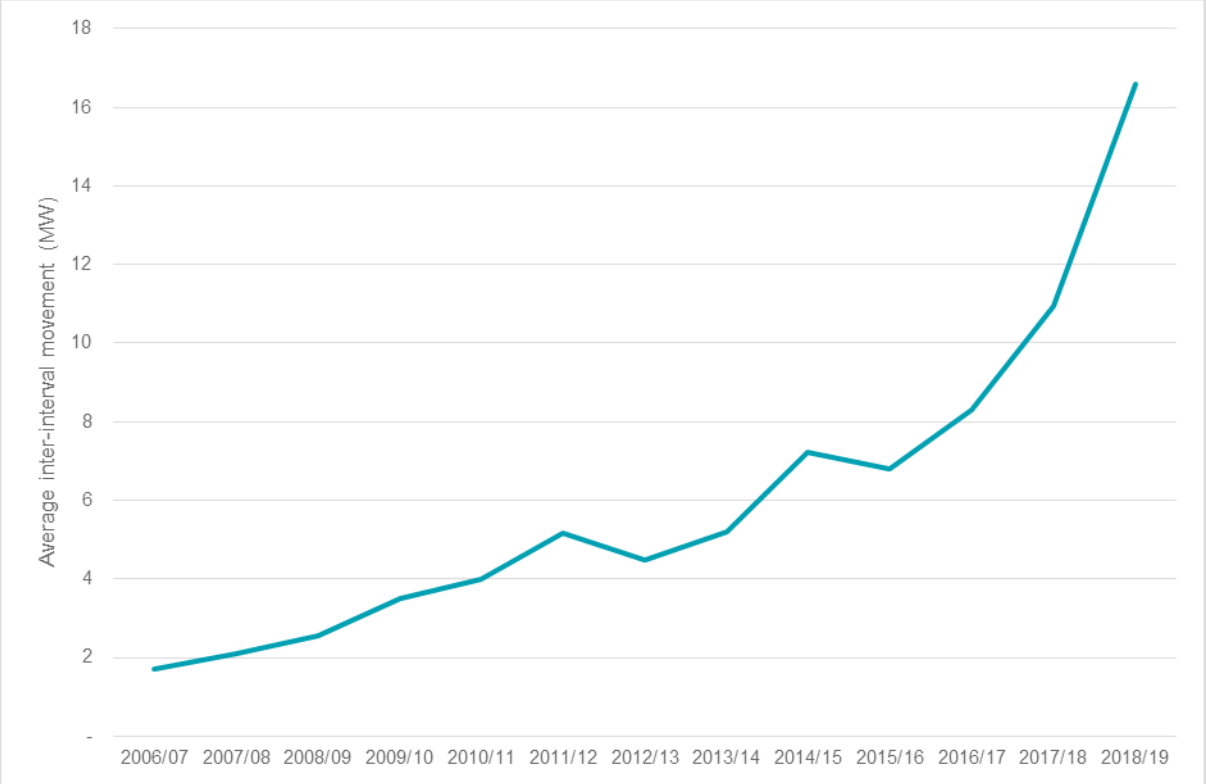
Examination of run-time data for Synergy's other generators (aggregated into classes) indicated that the number of generator starts has not materially changed nor has the run time per start. This would not have driven an increase in thermal generator costs.

Accordingly, at least until the end of the 2017/18 financial year, the increasing penetration of rooftop solar does not appear to have materially changed generator run times to the point where this would increase balancing market bids and prices.

Notwithstanding the absence of changes in run times, thermal generators have had to move their output over a wider range from interval to interval. This is most apparent in Synergy's coal-fired generators, which are more sensitive to such movement compared to other types of

generation.[16] This wider operational range has occurred predominantly during peak hours. This observation was supported by the Australian Energy Market Operator (AEMO) in its submission to the WEM discussion paper.[17]

Figure 5 Average annual inter-interval movement for Collie Power Station from 1:00pm to 6:00pm



Source: ERA analysis of AEMO data

Figure 5 above shows the average movement between trading intervals for the Collie power station from 1:00pm to 6:00pm when generators begin to increase their output ready to meet evening peak demand.[18] These changes may create operational challenges for the generators, more frequent maintenance and an increase in costs.

However, notwithstanding the possible increase in costs, coal plant do not usually set the balancing price. Coal incurs substantial start-up and shut down costs. Once running, coal plant needs to stay on to remain economic and so their bids fall towards the lower end of the bid stack. The increase in costs for coal plant in the short term would not have driven up balancing prices over the period. The same operational trends are not seen in the output of Synergy's gas turbines or in the output of privately-owned coal fired power stations.

2.1.3 Conclusion

Average wholesale electricity balancing prices have increased by more than 20 per cent over the last four years. The ERA has investigated the main drivers of balancing market price increases - fuel prices and demand - and found coal prices have remained relatively flat and

[16] AEMO, 2019, *Integrating Utility scale Renewables and Distributed Energy Resources in the SWIS*, p. 30. (online)

[17] A summary of AEMO's submission in response to the discussion paper is provided in Appendix 4.

[18] The figure for 2018/19 includes data up to 27 January 2019.

gas prices are decreasing. Two mild summers have also reduced peak demand. None of these factors have driven increases in the price of wholesale electricity in the balancing market.

Wholesale prices are set by the operating costs of the most expensive generator needed to meet demand, usually gas-fired generators. While there is some evidence that the operating costs of coal plants may have increased due to solar and wind generation, the same does not appear to be the case for the price-setting gas units. An increase in the operating costs of a less expensive (non-price setting) generator, such as a coal plant, may reduce the owner's profits because its operating costs have increased, but not its revenue. However, this will not alter the wholesale price.

Therefore, a factor other that costs seems to be driving these price increases.

The ERA is concerned that the increase in costs could be a result of Synergy exercising its market power in the balancing market.

The ERA has conducted a formal investigation of Synergy's pricing behaviour and concluded that Synergy has been bidding wholesale energy into the market at values that are higher than the market rules permit. The market rules specify that a generator cannot charge prices that exceed its reasonable expectation of the short run marginal cost of producing electricity if that behaviour relates to market power. The ERA has concluded that Synergy has breached this rule and is taking action through the Electricity Review Board. More information on this investigation can be found in the notice published on the ERA's website.

2.2 Ancillary services price increases

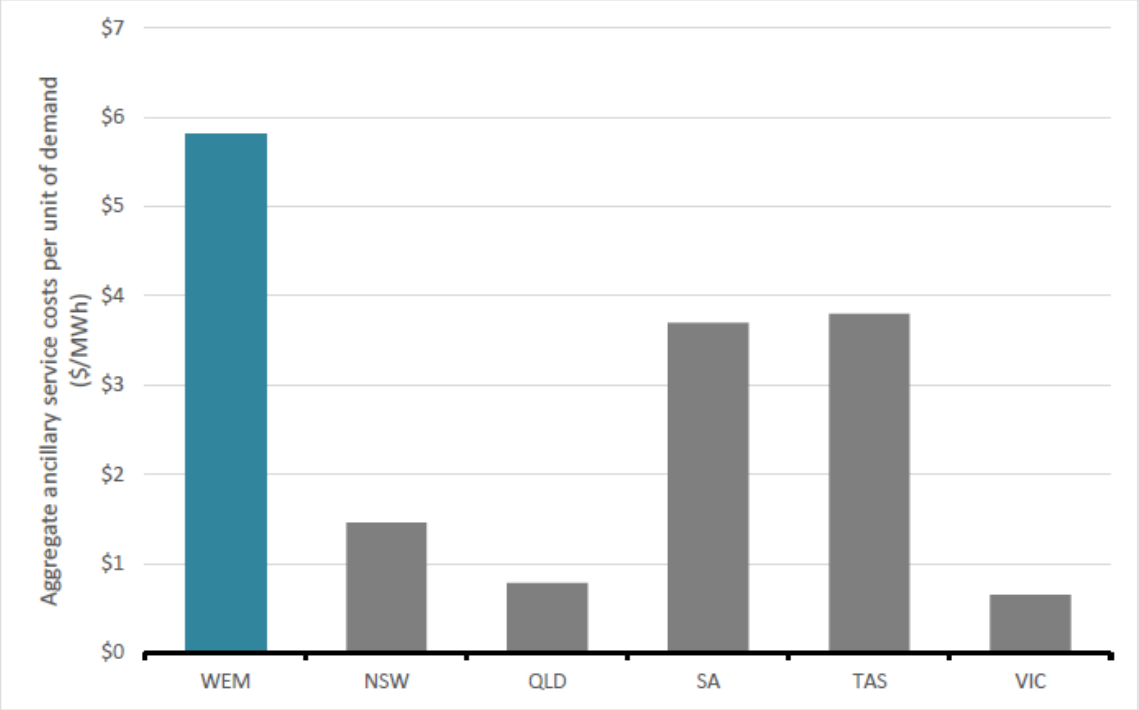
Electricity supply can become more variable as the penetration of intermittent generators, wind and solar farms, increases. Households that install rooftop solar consume some of the electricity they generate, which reduces their demand for electricity from the network. Rooftop solar is weather dependent and variability in the output of rooftop solar translates into variability in network demand. For example, when it is cloudy in Perth, the output from rooftop solar reduces and demand for electricity from the network can increase rapidly.[19]

In an electricity system, variability in the supply of and demand for electricity is managed through use of ancillary services. In the WEM, there are several ancillary services: load following, spinning reserve, load rejection reserve and system restart. The Load Following Ancillary Service helps to balance the supply and demand for electricity in real time. Spinning reserve and load rejection reserve are opposite ancillary services and respond to the loss of a generator and loss of a major load respectively. System restart, commonly known as 'black start', is used to re-energise the electricity system after a large-scale power outage.

The WEM has the highest ancillary services cost in the country, as shown in Figure 6 below.

[19] In its presentation to Western Australia Electricity Forum on 11 December 2018, System Management showed some of the large load fluctuations of 100 MW to 200 MW that it must manage within half hour trading intervals caused by the variable output of rooftop solar generation.

Figure 6 Australian ancillary services unit costs by jurisdiction (2017/18)



Source: ERA analysis of AEMO data

The total cost of ancillary services is driven by the quantity and price of the services required. To review the total cost of ancillary services, the ERA has investigated whether and how ancillary service quantities and prices have changed.

Each year, AEMO determines the requirement for ancillary services in the WEM. The quantity of Load Following Ancillary Service has remained stable at 72 MW for several years. There has been no change in the volume of ancillary services required despite increased volatility in demand driven by rooftop solar installations, or increased volatility in the electricity supply from a greater penetration of renewable generation such as wind farms. Therefore, the increase in ancillary service costs is not due to higher quantities of ancillary services and must be driven by other factors.

The ERA has recommended that AEMO investigates options to improve Load Following Ancillary Service measurement as both supply and demand are expected to become more variable as more intermittent generation enters the market.[20]

Excessive balancing prices are passed through to ancillary services prices: a higher balancing price contributes to higher costs for Load Following Ancillary Service and spinning reserve. Facilities providing Load Following Ancillary Service may forego energy sales in the balancing market if they are dispatched to support system security. Their ancillary service offers might reasonably be priced to reflect possible foregone high-priced energy sales in the balancing market.

Most of the ancillary services cost increases are attributable to the Load Following Ancillary Service market, (refer to Figure 24 in Appendix 3). Since the Load Following Ancillary Service

[20] ERA, 2018, *Decision on the Australian Energy Market Operator's 2018-19 Ancillary Services Requirements*, p. 4. (online)

market began in 2014, prices for this service have increased substantially and reflect increases in balancing market prices. The step-change in Load Following Ancillary Service costs noted in the 2016/17 WEM report has persisted through the 2017/18 financial year.[21]

Up to the end of 2017/18 there were three participants cleared to participate in the Load Following Ancillary Service market. However, the market is dominated by Synergy, which sets the price for all but a handful of intervals. There is not enough non-Synergy capacity cleared to participate in the market that can meet the service requirements and apply competitive pressure by undercutting Synergy on price.

Where ancillary service costs are determined through an administered process, cost increases have been lower. 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, spinning reserve costs remain sensitive to balancing market prices. Therefore, as balancing prices have increased, so have spinning reserve costs.

[21] ERA, 2018, *2016–17 Wholesale Electricity Market Report to the Minister for Energy Appendices*, p. 10, (online)

3. Emerging challenges

Over the review period, the ERA has concluded that the Wholesale Electricity Market (WEM) is not meeting the WEM objectives effectively. The ERA has also identified two emerging challenges that, unless addressed, will further impede the effective operation of the WEM:

- The increase in small-scale solar generation and its effects on daily patterns of electricity demand from the network.
- The aging fleet of thermal generators in the market and the likely need for new generation investment.

These are discussed in turn below.

3.1 Increasing rooftop solar

Up to the end of June 2018, the end of the review period for this report, the ERA has found that rooftop solar generation has not changed the operation of thermal generators in a way that placed upward pressure on wholesale electricity prices.

However, this may not be the case in the future.

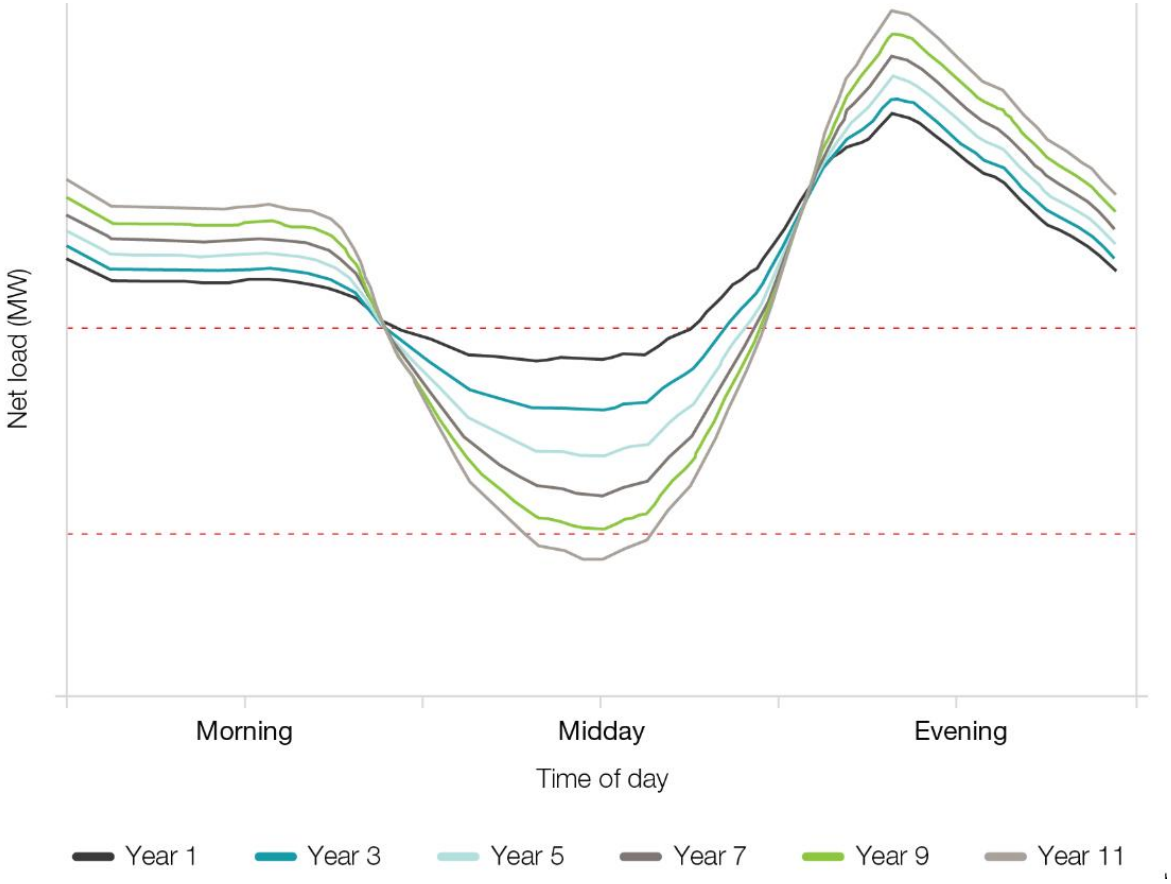
Households have made substantial investments in rooftop solar. At of the end of 2018, installed rooftop generation capacity exceeded 1,000 MW, which was comparable to the combined capacity of all Synergy's coal generators. The Australian Energy Market Operator (AEMO) forecasts that rooftop solar installations will continue to grow by 8.7 per cent a year, equivalent to an annual average increase of 134 MW of new rooftop solar generation. For the first time, in late 2018 the output from rooftop solar was a net exporter[22] of energy into the balancing market. This means that in several peak demand intervals, the output from rooftop solar more than exceeded the consumption of all households and some small businesses.[23]

As households install rooftop solar, the output from these units will continue to substitute demand from the network, also called operational demand, during the middle of the day. As the sun sets, output from rooftop solar reduces and, over two or three hours all consumer load, previously substituted by rooftop solar, must be met by the network. Over time, increasing levels of rooftop solar will substitute more network demand and network-connected generators will have to ramp up their output more quickly to supply the steep increase in operational demand in the early evening. Figure 7 illustrates how the sustained penetration of rooftop solar photovoltaics over time is expected to reduce net load in the middle of the day. As the net load crosses the higher red dotted line across the chart the market becomes more inefficient: the market inefficiency threshold. As net load crosses the lower red dotted line the electricity system becomes increasingly unstable: the system instability threshold. This is explained further below.

[22] This is output from rooftop solar as measured by the notional meter. "The Notional Wholesale Meter is a term used to define the aggregate quantity of all customers without interval meters" AEMO, 2019, *AEMO Quarterly Energy Dynamics Report Q4 2018*, p. 29. (online)

[23] The net solar generation exported to the balancing market is resold by Synergy to other customers.

Figure 7 Illustrative net load over time with increasing levels of rooftop solar



Source: ERA

Typically, coal facilities in the WEM have been regarded as low-cost, baseload thermal generation once they are running. However, coal plants are large and slow to ramp their output up and down and cannot safely operate below a given output level. Therefore, they are inflexible and less able to respond to the increasing variability in demand. Faster moving gas plant is available to respond to peaks in demand but is typically higher cost than coal plant.

Coal plant may choose to bid below their short run marginal cost in some market intervals, just to stay running, particularly overnight and in the middle of the day. This may not be sustainable and so coal plants may choose to turn on and off for periods of time. The increased penetration of rooftop solar and grid connected renewable generators is expected to place operational challenges on, and increases financial risks to owners and operators of inflexible generators.

When less coal plant is available, operational demand will be met by higher cost gas plant and renewable generators such as solar and wind farms, leading to market inefficiencies and increasing costs. This is when the downturn in net load from rooftop PV in Figure 7 above crosses the market inefficiency threshold, in year 1.

A paper by AEMO on utility-scale renewables and distributed energy references increasing system security risks as consumers continue to install rooftop solar units and:

> All new utility-scale generation in the SWIS for the last five years has been renewable. All 790 MW of new large-scale generation forecast by AEMO to connect to the SWIS by 2021 is expected to be renewable.[24]

The output from renewable generation depends on the weather and is therefore variable. This makes maintaining system reliability and security more complex. This is illustrated by the downturn in net load from rooftop PV in Figure 7 above crossing the system instability threshold in year 11.

The large rotating turbines present in thermal plant can resist fluctuations in frequency and help to maintain the security of the electricity system. This support reduces when coal plant does not participate in the market. To maintain system security, AEMO will need to procure more ancillary services and/or turn down variable generators, such as wind farms. Both actions will increase costs in the electricity system. These costs are met by electricity generators and retailers and so eventually will be passed through to consumers. An increase in the quantity of ancillary services will increase costs as will constraining the output from renewable generation.

The rate of take-up of rooftop solar is largely driven by customers responding to the price signals they receive. The current price signals for residential consumers are flat and do not indicate the costs of supplying electricity at different times of the day. This is important because managing demand can minimise the long-term cost of electricity supply to consumers and enhance system reliability. However, there are no demand management measures included in the market reform program. This is addressed further in section 4.4.

Large-scale batteries are flexible and could cost-effectively address increasing variability in demand and supply. Deployed appropriately, batteries can dampen the variability of renewable generators' output and provide ancillary services. In addition, batteries can relieve network congestion and so delay expenditure on network augmentation. Batteries can also provide price arbitrage between low-cost and high-cost periods and so change the profile of demand. Many of these services can be deployed simultaneously. Other jurisdictions, such as South Australia and Great Britain, have already provided for the successful integration of battery storage into their electricity markets.

Large-scale batteries do not currently participate in the WEM. This is because it is difficult for investors to fully assess the costs of installing and running a battery against possible revenue streams. For example, a charged battery can provide generation capacity and contribute to reliability in the South West Interconnected System (SWIS). However, once discharged that capacity is no longer available. Batteries may be able to enter the market under similar conditions as other intermittent generators, such as wind and solar farms, where the capacity payments to the batteries are reflective of its availability. However, the market rules do not provide a mechanism to value the capacity contribution of a battery and award capacity credits. This creates a barrier to large-scale batteries entering the WEM. Investment could be encouraged by clearly signalling how batteries can be entitled to capacity payments under the current market rules or by proposing changes to the market rules that explicitly recognise the contribution of a large-scale battery to available capacity in the SWIS. The ERA discusses this further in section 4.3.

[24] AEMO, 2019, *Integrating Utility-scale Renewables and Distributed Energy Resources in the SWIS*, p. 29. (online)

3.2 Aging thermal generation capacity

Some large generators in the WEM, including Muja C and D and the smaller Pinjar units, are probably approaching the end of their expected lives. Statements in budget estimate hearings indicated Muja C and D would be retiring from 2025.[25] Retiring generation capacity will need to be replaced to meet demand and to provide ancillary services to maintain the reliability and security of the electricity system.

How re-investment occurs to replace Muja or other retiring plant can either improve or maintain pricing discipline in the WEM. As noted in section 3.1, batteries do not currently participate in the WEM although they could replace some of the retiring capacity. Without reform the most cost-effective technologies, such as batteries, may not be adopted, increasing costs in the wholesale market.

There may be problems in attracting private investment to replace aging capacity. As the dominant supplier in the WEM, Synergy owns much of the retiring plant. Without a clear statement of Synergy's future role in the market, third parties cannot assess the viability of any future investment. Also, if the information provided on when generators are going to retire 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 long lead-times because of the need to secure funding, approvals, network connection, and fuel supply arrangements.

Government can avoid some of the costs and risks it faces from investing directly and indirectly in generation through state-owned Synergy by enabling third parties to invest and replace Synergy's generation plant when it retires. The ERA makes recommendations on how the government could enable third party investment in section 4.2 below.

[25] Western Australia Parliament, 2016, *Assembly Estimates Committee B*, *Budget Estimates*, p. 7. (online)

4. Capturing opportunities

The Wholesale Electricity Market (WEM) is not minimising the long-term cost of electricity for consumers. Achieving this will require further competitive pressure on market participants and, where this is not possible, more effective regulation to curb opportunities to exercise market power.

There are opportunities to improve diversity in the market. Generators have multi-year lead times to develop projects and then operate over decades. Capturing opportunities presented by plant retirements and establishing niches for emerging technologies such as batteries provide the greatest opportunities for investors to enter the WEM and provide sufficient pricing discipline for the market to operate more effectively and reduce long term costs for consumers.

4.1 Improving current arrangements

Structural disaggregation of Synergy would reduce Synergy's market dominance. The ERA has discussed the benefits of structural separation of Synergy in previous reports to the Minister.[26] However, even without structural reform there are measures the government can take to help the market better meet the market objectives.

Greater diversity and effectiveness in the WEM can be achieved by attracting new generation businesses, and enhancing the participation of existing ones.

One way to increase market participation and activity is to improve access to forward electricity contracts so participants can manage their exposure to price and volume risks in the wholesale market.[27] Retailers hedge to avoid prices they are unable to pass through to their customers. Hedge products also reduce risks for new retailers wishing to enter the WEM.[28] Generators hedge to mitigate the risk that low balancing market prices limit their earnings. Higher levels of business activity in the retail market can help stimulate pricing discipline in the wholesale electricity market. Retailers seeking lower priced supplies will help drive wholesale electricity costs down to the efficient long-term cost of supply. The effectiveness of competition in each market is dependent upon the other.

Synergy's dominance in the wholesale electricity market is mitigated by a regulatory scheme designed to limit its market power. The ERA reviews this scheme annually and has recommended ways Synergy can be better regulated and constrained in its obligations to offer and price bilateral energy contracts to competing retailers.[29] The main recommendation in the most recent review was to reduce the spread between the buy and sell prices of Synergy's standard products. Improvements to Synergy's regulatory scheme were supported by Kleenheat and ERM Power in their submissions to the WEM discussion paper.[30]

The regulatory scheme constrains Synergy from exploiting market power and setting standard product sell prices too high by requiring Synergy to publish the price at which it must buy standard products. However, if the spread between the buy and sell price is too wide, Synergy can use its market power to set too high a price for standard products, limiting their usefulness

[26] ERA, 2018, *2016–17 Wholesale Electricity Market Report to the Minister for Energy*, p. 22. (online)

[27] ACCC, 2018, *Retail Electricity Pricing Inquiry – Final Report*, p.105. (online)

[28] AEMC, 2010, *Review into the role of hedging contracts in the existing NEM prudential framework Final Report*, p. 19. (online)

[29] ERA, 2017, *2016 Report to the Minister on the Effectiveness of the Electricity Generation and Retail Corporation Regulatory Scheme*, p. 17-22. (online)

[30] A summary of Kleenheat's and ERM Power's responses to the WEM discussion paper is provided in Appendix 4.

as a hedging tool. The ERA has recommended that the spread between the buy and sell prices of standard products be reduced from 20 per cent to 10 per cent.

4.2 Enabling competition to develop

There are options for Government to increase the effectiveness of the WEM by encouraging greater private sector participation in the market.

With little or no growth in demand, the best opportunities to improve private sector participation in the WEM will come when generators exit the market and need replacing. Generation projects take years to develop, connect to the network, finance, construct and commission. As noted in section 3.2 above, one of the oldest generators in the market, Muja CD, is expected to be the next generator to exit the market.[31] If, as has been indicated to Parliament, Muja C is to retire by the mid 2020's, planning for its replacement should commence shortly given the three to five year lead-time to design, finance and build new generation plant.

Recent retirements of Synergy's generation capacity could provide the government with the opportunity to release some of this network capacity for use by existing or new market participants to invest in generation in the WEM.

There are changes to the capacity pricing mechanism under way currently that affect plant retirements. The Public Utilities Office has recommended that all generators provide three years' notice ahead of plant closure.[32] This could provide greater advance notice to investors and was supported by the Australian Energy Market Operator (AEMO), Community Electricity and Kleenheat in their responses to the WEM discussion paper.[33]

Greater private-sector participation in the wholesale market may be encouraged by a clear retirement schedule, and clarity on whether or not Synergy intends to, or is permitted to, replace its retiring generation. This point was supported by Summit Southern Cross Power, the Australian Energy Council and ATCO Gas Australia in their submissions to the WEM discussion paper.[34]

Once an investment opportunity is identified a prospective new entrant must access the network. The market reform program proposes to introduce constrained network access, where any generator connected to the South West Interconnected System (SWIS) joins in the knowledge that its output can be constrained in response to congestion or faults on the network. Constrained network access will improve access to Western Power's network while avoiding network augmentation. More generators will be able to connect to the WEM, increasing activity and pricing discipline. Until then, an interim access arrangement is in place that enables new generators to connect on a constrained basis. The quantity of new generation that can enter the market through the interim arrangement is limited to 900 MW. While the interim arrangement is in place existing generators are generally connected on an unconstrained basis and new generators can have their output constrained. Most new entrants

31 Western Australia, 23 May 2018, *Hansard Reference to Muja retirement estimates committee A,* p. 8. (online)

32 Department of Treasury, 2018, *Improving Reserve Capacity pricing signals – a proposed capacity pricing model Draft Recommendations Report*, p. viii. (online)

33 A summary of the AEMO, Community Electricity and Kleenheat submission received in response to the WEM discussion paper is provided in Appendix 4.

34 Summaries of the submissions provided by Summit Southern Cross Power, the Australian Energy Council and ATCO Gas Australia are provided in Appendix 4.

have been low cost renewable generators such as wind farms. If a new entrant is constrained off, it cannot bid into the market. This undermines economically efficient generation dispatch.

Despite interim restrictions on the quantity of new generation able to connect to the WEM, existing generators can retain network capacity beyond the retirement of their plants. This ties up capacity that could otherwise be used by other generators.[35]

Since the commencement of the market in 2006, around 1,150 MW of generation plant capacity (as measured by capacity credits) has retired. Approximately 97 per cent of this was from Synergy's portfolio (excluding West Kalgoorlie and Mungarra which are retained on network control service contracts).[36]

The network access contracts between Synergy and Western Power are confidential and it is not known whether Synergy has maintained the network access for retired generators. However, if Synergy is maintaining its network access after retiring substantial facilities, such as Kwinana Power Station (789 MW of capacity credits) and Muja AB (220 MW of capacity credits), this represents:

- An avoidable cost burden to its shareholders as Synergy pays network charges for this network access.
- A barrier to private sector generators accessing the network.

If Synergy did release network capacity after plant retirement, this would allow other generators to connect to the network.

Closing a generator does not necessarily mean that its full capacity would be available to other generators (this is subject to network topography), but implies some capacity would be released. If new businesses and new technologies can more easily connect to the network, they can provide network services that may defer costly network augmentation. If they also participate in the WEM, they can create a more competitive market that disciplines the pricing behaviour of market participants.

Recommendation 1

Synergy's market power needs to be reduced to lower the cost of wholesale electricity. In the absence of structural reform, the government can reduce Synergy's market power by:

a. Signaling to the market that the Synergy will not itself replace ageing thermal generation plant as that plant is retired.

b. Making changes to the regulatory scheme that is intended to constrain Synergy's market power, as recommended by the ERA in its separate report on this matter.

4.3 Incorporating storage technologies

Energy storage allows pricing arbitrage. Batteries can store supply generated during periods of low prices and discharge it for use later when prices are higher. Typically, prices are at their

[35] Western Power, 2017, *Submission to ERA Discussion Paper on 2016/17 Wholesale Electricity Market Report for the Minister*, pp. 5-6. (online)

[36] Department of Treasury, 2018, *Arrangements for continued power supply reliability in the North Country and Eastern Goldfields regions*, p. 2. (online)

highest in the late afternoon and early evening. Depending upon how much capacity is available, batteries can reduced demand on the network at peak periods, leading to lower costs and prices.

Many forms of energy storage have been used in the energy sector for some time, including hydro power, compressed air energy storage and fly-wheels. Horizon Power's Denham power station had a fly-wheel installed to manage intermittency from a wind turbine,[37] and compressed air storage is in use in Texas and Iowa.[38] The Tumut 3 Power Station in New South Wales operated by Snowy Hydro incorporates pumped storage.[39]

Electrochemical and solar thermal are newer storage technologies. Other jurisdictions are already exploring ways to use these to provide capacity, energy, ancillary services, and network support services.

Different types of storage have different physical properties, including how quickly they can charge and discharge, and how long they can store electricity. These physical properties will determine when and where they can deliver one or more network or market services.

Markets where batteries can participate and provide several services will generate several income streams and make batteries a more attractive investment. However, these markets must also be able to accommodate the flexibility of battery services as a source of both energy supply and demand and allow them to switch between states of charge and discharge.

Storage technologies do not currently participate in the SWIS. AEMO is currently considering how to register a utility-scale battery to participate commercially in the WEM. The market rules do not provide clear guidance on whether and how batteries can receive capacity credits or if they can provide both energy and ancillary services. The technical rules may need to be reviewed to clarify the technical standards batteries must meet to participate in the WEM.

The rapid adoption of storage in other markets means these integration challenges have already been considered, and resolved, elsewhere. Other markets provide models that can be adapted and adopted for the WEM.

Enabling batteries to participate in the WEM, supported in ERM Power's submission to the WEM discussion paper, could help reduce ancillary service costs, as has been observed in South Australia.[40] The introduction of the Hornsdale Power Reserve (the TESLA Big Battery) increased the pool of local generators able to provide ancillary services in South Australia and it undercut bids from existing generators in periods of transitory market power.[41] It was the introduction of new generating capacity, and not the superior performance of the battery, that altered ancillary service prices during the battery's trial period.

The ERA has reviewed how batteries can participate in wholesale markets in other jurisdictions, the problems they encountered and how these have been overcome. This participation is summarised in Appendix 5.

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37 EPRI, 2004, EPRI-DOE Handbook Supplement of Energy Storage for Grid Connected Wind Generation Applications, Report 1008703, Technical Update, p. 13-1. (online)

38 Ibid p15-1

39 Snowyhydro, 2019, Power Station (online)

40 Submissions from other stakeholders commented more generally that third parties should be able to participate in new technology trials, such as battery trials. A summary of all submissions received in response to the WEM discussion paper is provided in Appendix 4.

41 AEMO, 2018, *Hornsdale Wind Farm 2 FCAS Trial, Knowledge Sharing Paper*, pp. 4-35. (online)

Recommendation 2

Current market rules and technical standards are silent on, or prevent, the uptake of some new technologies. These should be changed to allow for large-scale batteries to be integrated into the electricity system and participate in the wholesale electricity market.

4.4 Improving price signals

Electricity consumers' demand determines the supply cost of electricity. Generally, increased demand for electricity increases balancing prices. This is because supplies of electricity from more costly generators are needed to cover higher levels of demand. More generation and network capacity is developed to make sure enough capacity is available to meet the highest level of demand in the system, even if the market only reaches the highest level of demand for infrequent, short periods. Increased variability of demand also increases the need for ancillary services that maintain the balance of supply and demand.

Taking "measures to manage the amount of electricity used and when it is used" is important because managing demand can minimise the long-term cost of electricity supply to consumers and enhance system reliability.[42]

The rapid uptake of rooftop solar is partly in response to the flat price signals consumers receive through residential electricity tariffs. This does not meet the market objective of managing how and when electricity is being consumed, nor is it minimising the long-term costs of electricity to all consumers.

If households receive electricity prices that reflect wholesale supply costs, including network costs, and the time of day when they are consuming, some consumers will respond by voluntarily decreasing their electricity usage in high-cost periods and perhaps shifting demand to lower cost periods. This in turn could lower wholesale electricity supply costs for all households.

Some large market customers have already altered their demand to reduce costs.[43] Under the market rules, large market customers fund the procurement of capacity in proportion to their contribution to peak demand. AEMO estimates that, during the peak demand periods in the past seven years, large market customers reduced their consumption and lowered total load from 41 MW to 77 MW during peak demand periods. Over time, this reduces the amount of capacity needed in the system and lowers the cost of supply for all electricity consumers.

Households invest in rooftop solar for many reasons, including economic considerations and environmental concerns. Research in Queensland demonstrated that current electricity prices and expectations of future electricity prices were two of the most important motives for investment in rooftop solar.[44] Research in the United States indicated that over 85 per cent of rooftop solar adopters used some form of financial analysis to guide their decision-making.[45]

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42 RCP, 2019, *Wholesale Electricity Market Rules*, clause 1.2 (online)

43 AEMO, 2018, *Electricity Statement of Opportunities*, p. 36. (online)

44 Bondio S., Shanahzari M, McHugh A., 2018 *The technology of the middle class: Understanding the fulfilment of adoption intentions in Queensland's rapid uptake residential solar photovoltaics market*, In Renewable and Sustainable Energy Reviews, Volume 93, pp. 642-651.

45 Rai V., McAndrews K, 2012, *Decision Making and behaviour change in residential adopters of Solar PV*, In Proceedigns of the World Renewable Energy Forum, (online)

Changing the tariffs used to calculate household electricity bills is one tool government can use to reflect the actual cost of supplying electricity at different times of the day. Customer education programs are another.

The greater the difference between average demand and maximum demand, the more expensive the demand profile is to serve. Both network and generation investment must be sufficient to supply typically short and infrequent periods of maximum demand. The cost to supply electricity also changes across the day. Wholesale electricity prices in the late afternoon peak can be expected to increase as generators recover their start-up costs over shorter run times. The feedback between system demand and consumer price and hence consumer behaviour is missing.

Tariffs that reflect actual electricity supply costs will influence consumers' decisions on when to consume electricity and whether to invest in rooftop solar and/or battery storage. This could help to lower the variability of demand, reducing generation costs and improving system reliability. For example, the California Independent System Operator considers household batteries to be valuable in improving system reliability.[46]

Getting price signals right is a complex task. Electricity pricing that does not reflect the cost of supply can result in consumption and investment decisions that increase the cost of supply, and transfer costs unfairly from one group of customers to another. Customer education programs are another means of influencing when and how much electricity households consume. Encouraging consumers to reduce or defer their consumption from the late afternoon to periods when overall demand is lower, such as during the middle of the day or overnight will help reduce the difference between average and maximum demand. The types of electricity usage that can be moved to other times includes running pool pumps, dishwashers, and washing machines and dryers.

While retail tariffs are separate from the WEM, electricity usage choices affected by retail prices flow back to the wholesale market. Reform is needed to improve the ability of consumers to make informed decisions about their electricity use and invest in technology such as batteries and solar panels.

Recommendation 3

Retail tariff reforms and/or public education programs should be considered and pursued in parallel with the existing reform process to provide electricity customers with the knowledge and incentives to adjust their electricity usage in a way that will reduce costs of supply across the market. A review of regulated retail tariffs for small use electricity customers is needed, otherwise the consequences of the blunt price signals will continue.

[46] Californian Independent System Operator, 2018, *Letter from the Californian Independent System Operator to FERC re compliance with Order No. 841*, Filing for Order No. 841, (online)

Appendix 1 Reporting requirements

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, and annually under the Wholesale Electricity Market Rules. This year, both reviews are 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:

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

Appendix 2 Market processes and procedures

Effectiveness of the Rule Change Proposal process

The ERA is required to report on the effectiveness of the market rule change process and procedure change process.

The independent Rule Change Panel was created under the Energy Industry (Rule Change Panel) Regulations 2016 (WA) (Regulations) and is responsible for the rule change process. The Regulations require the ERA to provide an Executive Officer and other staff, services and facilities to the Rule Change Panel (Panel). Governance arrangements[47] are in place to mitigate against any perceived or actual conflict of interest and perceptions of bias from the ERA providing staff and services to the Panel.

The Panel undertook a stakeholder satisfaction survey for 2017/18. The results were mostly positive although stakeholders expressed some dissatisfaction on the timeliness of the rule change process.[48] This concern was reinforced by the Rule Change Support team's advice to the ERA.

The Panel has encountered two complications in administering the rule change process that it has sought to address:

- Establishing a prioritised list of rule change proposals that will be actively supported by AEMO.
- Obtaining timely, accurate and public estimates of AEMO's cost and time to implement rule change proposals.

The Panel sets priorities for processing rule change proposals using a prioritisation framework that has been reviewed and endorsed by the Market Advisory Committee. At the beginning of 2019, the Panel had 13 open rule change proposals. Of the top six prioritised proposals, the first two were classified as having a high urgency rating and the remaining four proposals had a medium priority rating.[49] However, AEMO has not provided support to the Panel in accordance with these priorities. Delays in receiving advice requested from AEMO caused over a year's delay in progressing the highest priority rule change proposal, citing resource constraints as the reason for the delay.

The WEM reform program has incorporated some of the Panels priority rule change proposals, including the two high urgency proposals. Although AEMO has provided support to some of the rule changes transferred into the reform program, it has still not provided support on the two high urgency proposals. The Panel and the Rule Change Support team are continuing to work directly with AEMO and through the Market Advisory Committee to progress the rule change proposals in line with the agreed priority ranking.

The Rule Change Support team requires reasonably accurate assessments from AEMO of the cost and practicality of implementing rule change proposals for inclusion in draft rule change reports, which are released for public consultation. AEMO's estimates were initially not timely and were lacking in accuracy. Since then, the Rule Change Support team and AEMO have discussed and come to a common understanding of AEMO's contribution to draft

47 ERA, 2018, *Governance arrangements for staff supporting the ERA and Rule Change Panel,* (online)

48 RCP, 2018, *Rule Change Panel Annual Activities Report 2017/18*, p. 30. (online)

49 A high urgency rating means "compelling proposal, and either large net benefit or else necessary to avoid serious perverse market outcomes" and a medium urgency rating means "the net benefit to the market may be large but needs more analysis to determine or is material but not large enough to warrant a high rating".

rule change reports. The timeliness of AEMO's cost estimates has been addressed but the accuracy of estimates remains under review.

AEMO and System Management

The ERA became responsible for the compliance and enforcement functions in the Market Rules on 1 July 2016. The ERA is also required to report on the effectiveness of AEMO including in its capacity as System Management) in carrying out its functions.

On 13 February 2019, the ERA provided an annual report to the Minister for Energy on AEMO's compliance with the Market Rules over the 2017/18 financial year.[50] The report included the audit reports of AEMO's compliance with the Market Rules as well as the results of nine investigations carried out on AEMO's compliance with the Market Rules and Market Procedures in this report.

The ERA found that, of the 50 compliance incidents, 30 were instances of non-compliance with the Market Rules for Gas Service Information Rules and that 27 of these were low risk. The audit identified 18 instances that posed a compliance risk, these were divided evenly into low and medium risk assessments. There were two minor compliance issues.

The audit report stated that AEMO had made significant progress in addressing System Management risks following the transfer of the function to AEMO on 1 July 2016. However, there were some repeated non-compliances in 2017/18, including failures with legacy Information Technology systems that remain at Western Power. The failures resulting in AEMO dispatching generators from an earlier Balancing Merit Order that may not be least cost at the time and could trigger 'out-of-merit' payments to some generators. Overall, this could result in higher costs to electricity customers.

There were two matters of concern to the ERA during 2017/18, these were:

- A compliance risk from the introduction of a new reserve capacity settlement system. There were several defects in the interface between the new system and an existing system.
  - AEMO has implemented measures to reduce the risk of future non-compliance and the ERA will continue to monitor the effectiveness of these measures.
- A compliance risk from the shortfall of ancillary services required to maintain power system security and reliability.
  - AEMO explained that these service shortfalls emerged because of the greater penetration of renewable resources. The ERA is satisfied that none of the shortfall events identified threatened the security of the power system.

ERA's compliance with the Market Rules

As part of its compliance and enforcement responsibilities under clause 2.14.5A of the Market Rules, the ERA provides the Minister for Energy with an annual report on its own compliance with the Market Rules and Market Procedures.

[50] ERA, 2019, *Report to the Minister for Energy on the Australian Energy Market Operator's Compliance 2017/18*, pp. 1-11. (online)

To assess its compliance, the ERA engaged consultants 2020 Global to independently audit its compliance during 2017/18.

The audit concluded that the ERA had "complied in all material respects" and made one recommendation for improvement. The auditor found that "compliance monitoring methods using market data remain *ad-hoc"* but noted that the ERA was in the process of developing compliance monitoring tools. The auditor's recommendation was that the ERA "finalise the development and implementation of these monitoring tools".

The ERA identified one of its own non-compliances in June 2018. It investigated the reasons and published the outcomes.[51] Between 26 November 2016 and 24 April 2018, the published versions of the Market Rules on the ERA's website did not contain the exact text of gazetted rule amendments made by the Minister for Energy. This means the Market Rules published were not the 'in-force' versions of the rules. This contravenes rule 151 of the Gas Services Information (GSI) rules, regulation 9(1) of the GSI regulations 2012 and regulation 8 of the Electricity Industry (Wholesale Electricity Market) Regulations 2004. The errors were mostly punctuation related or the incorrect text was used. There were no significant risks created by the non-compliance. The ERA has now implemented processes to ensure gazetted amendments are correctly updated in the rules prior to publishing.

Investigations into bidding behaviour

On 26 July 2017, the ERA notified Synergy that it had commenced an investigation into price-quantity offers submitted by Synergy into the Balancing Market. The investigation is pursuant to clause 2.16.9B(aA) of the Market Rules and the ERA is investigating whether Synergy's market offers have exceeded its reasonable expectation of the short-run marginal cost of generating the electricity and whether this behaviour relates to Synergy's market power.

In response, Synergy denied that it had "engaged in any inappropriate or anomalous market behaviour in relation to the pricing of offers in its Balancing Submissions".

The ERA has concluded that Synergy has breached this rule and is taking action through the Electricity Review Board. More information on this investigation can be found in the notice published on the ERA's website.[52]

Market administration and market fees

In its submission, ERM Power raised the question of how market costs are passed onto market participants, stating:[53]

> With the increasing penetration of rooftop solar PVs and the spill of electricity into the market by non-registered market participants, there appears to be increasing inequity whereby Market Participants are paying for systems and process to maintain a secure and stable system that is continually being disrupted and made more volatile by the non-registered entities.

[51] ERA, 2018, *Disclosure of non-compliance by the Economic Regulation Authority with requirements to publish in-force versions of market rules*, p. 1. (online)

[52] ERA, 2017, *ERA starts investigation into Synergy's pricing behaviour*, p. 1, (online)

[53] ERM Power, 2019, *Submission to Report to the Minister for Energy on the Effectiveness of the Wholesale Electricity Market 2017/18 Discussion paper*, pp. 2-3. (online)

ERM Power then recommended the ERA investigate and make recommendations on other possible market fee recovery mechanisms that ensure more equity such that fees are recovered from all users.

Consumers that substitute part of their demand, remain connected to the electricity network and will pay the costs passed to them by their retailers. There is no case to charge consumers who receive no service from the market. Consumers can and should be able to choose how they meet their energy needs. There should be no distinction between consumers who buy less from the market because they bought a more energy efficient appliance, replace an electric oven with a gas oven, or install rooftop solar. The level of disruption resulting from consumer choices result from the blunt price signals they receive; this is discussed further in section 4.4. If, however, the question is one of allocation of costs for ancillary services, the Market Advisory Committee may be the most appropriate forum to explore this further.

The Australian Energy Council's submission[54] noted that "On an energy basis, the WEM is 10% of the size of the NEM [National Energy Market] yet market fees are approximately twice that of the NEM". The submission acknowledged that:

> The AEC believes that participant fees should relate to recovering costs of operating the market and accordingly market participants should not pay for government led market reform.

Summit Southern Cross Power's submission commented that:[55]

> The WEM's market fees are too high. At what point is the question asked: Is the current market design – and evolution of that design, the most appropriate one for the WEM?
>
> AEMO's expected revenue requirements for the next (AR5) period are alarming and will again substantially increase the costs of operating the market. These costs are generally attributed to introducing further complexity to the market design.
>
> Much of the benefit of the complex competitive structures will not be realised until there is some form of disaggregation of Synergy. However, this does not appear to be likely in the short or medium-term future.

Summit Southern Cross Power also stated that "Western Power has an obligation under its own access arrangements to enable customers to connect to its network. Implementing constrained access, to this end, should be a cost to Western Power in exercising its core functions. At the least, implementing constrained network access is a deferral of the capex that would need to be spent by Western Power to meet its access arrangement obligations."

54 AEC, 2019, *Submission to Report to the Minister for Energy on the Effectiveness of the Wholesale Electricity Market 2017/18 Discussion paper*, p. 6. (online)

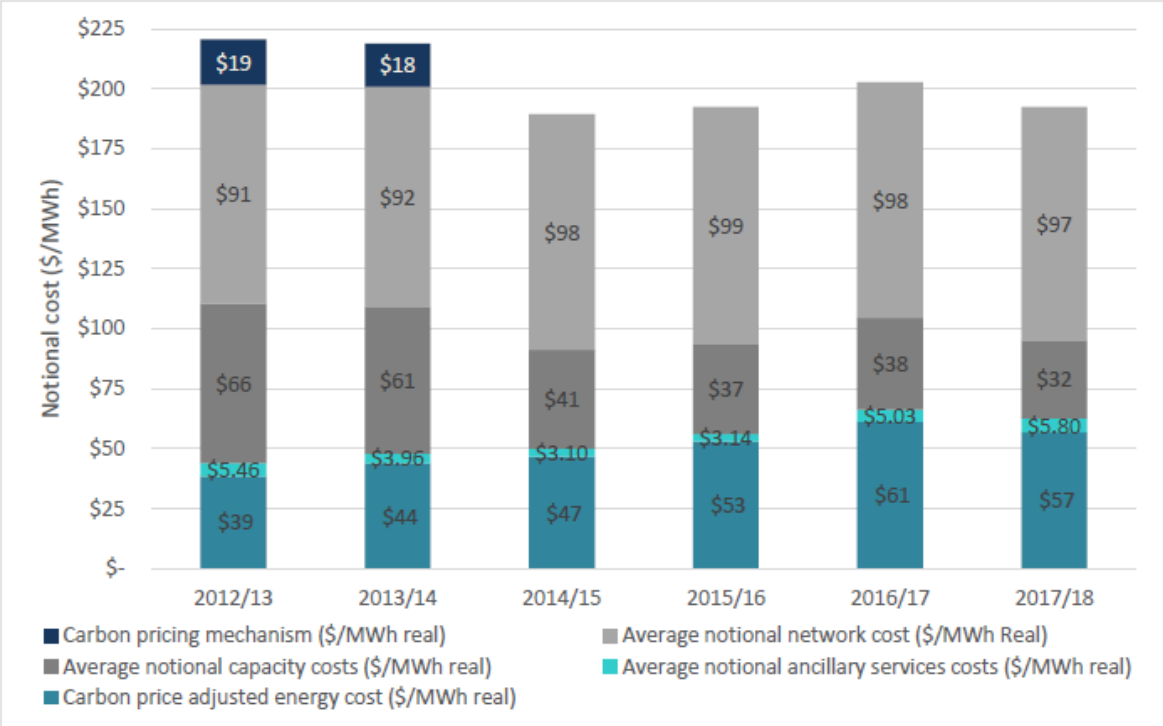
55 SSCP, 2019, *Submission to Report to the Minister for Energy on the Effectiveness of the Wholesale Electricity Market 2017/18 Discussion paper*, p. 7. (online)

Appendix 3 Market data and commentary

Notional wholesale electricity unit costs

Figure 8 shows the notional unit cost of wholesale electricity[56] 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 8 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 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).

[56] 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.

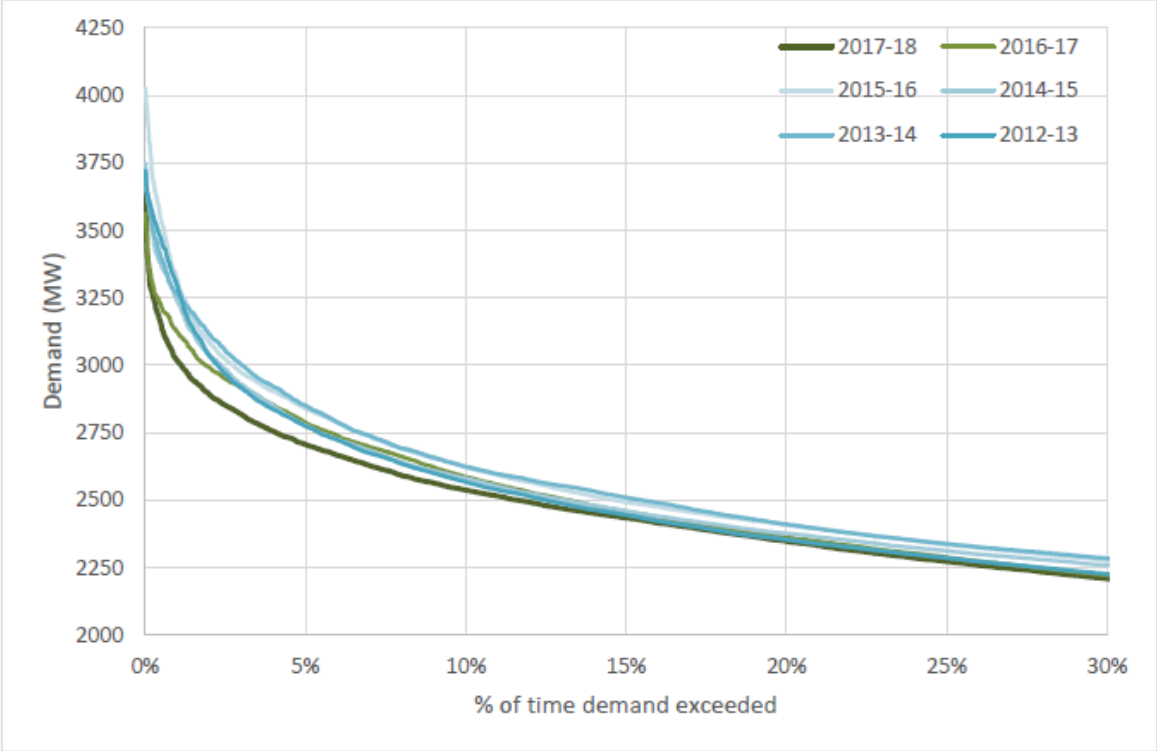
The increases in the cost of wholesale electricity and LFAS has absorbed any savings made in administered segments of the market.

Demand

The reduced demand in the last two years can be illustrated in Figure 9. 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 9 Load duration curve – top 30 per cent of intervals



Source: ERA analysis of AEMO data

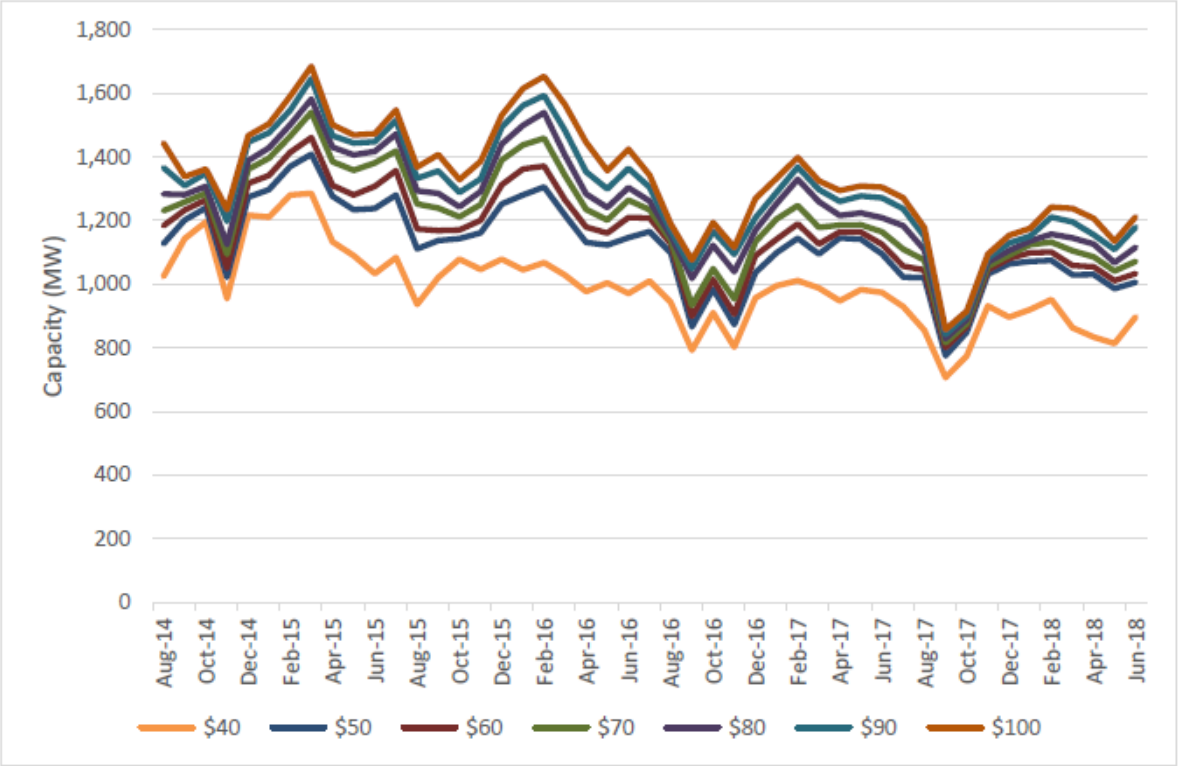
The change in the relationship between demand and balancing market prices occurred in late 2016. This coincided with a change in offers into the wholesale electricity market, primarily from Synergy.

Since the repeal of the carbon pricing mechanism, Synergy's offers have become more expensive. Figure 10 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 10 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 A 1 below 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 1,250 MW 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 1,500 MW has doubled from $90-100 to $190-200.

Table A 1 Synergy's average price of balancing market bids in January Price of 1,000 MW supply Price of 1,250 MW of supply Price of 1,500 MW of supply

	Price of 1,000 MW supply	Price of 1,250 MW of supply	Price of 1,500 MW 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

	Price of 1,000 MW supply	Price of 1,250 MW of supply	Price of 1,500 MW of supply
January 2018	$40-50	$130-140	$190-200

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 section). However, temperatures will not stay mild indefinitely, and current forecasts indicate summer 2019 temperatures will be above average.[57] When temperatures increase, demand will increase, and electricity prices will follow.

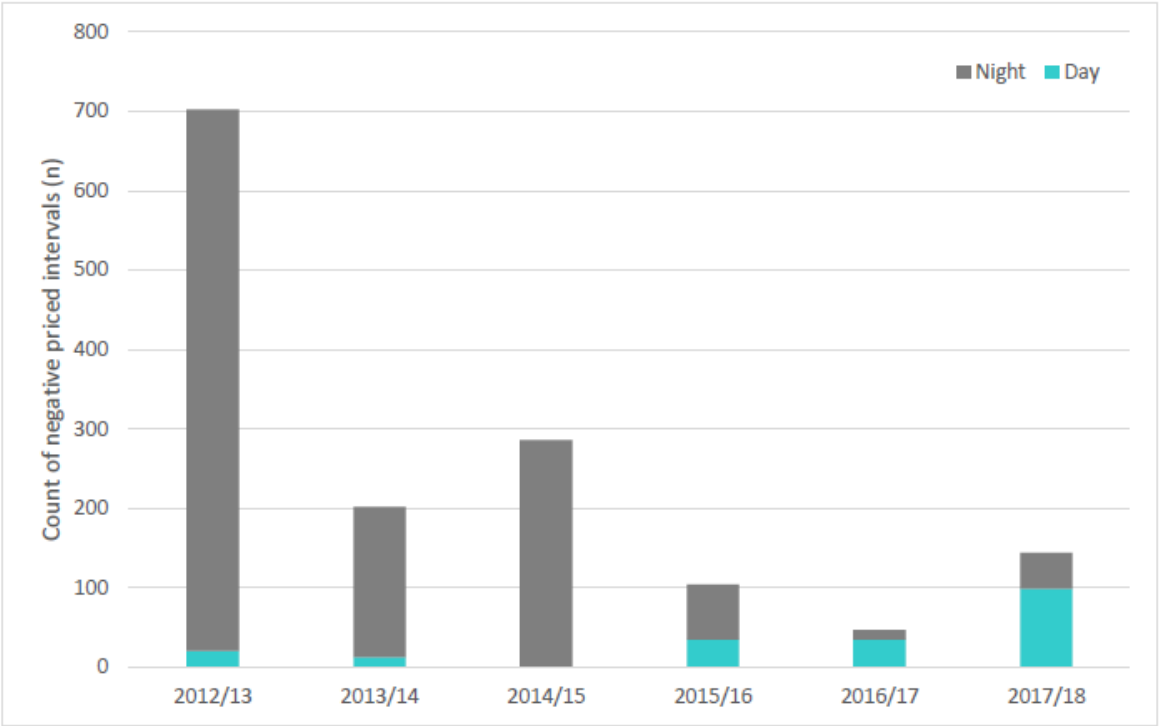
The increased penetration of behind-the-meter generation, such as rooftop photovoltaics (PV) has affected consumer demand (refer to section 3).

Negative pricing incidents

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 11).

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.

Figure 11 Incidence of daytime and night time negative pricing



[57] Bureau of Meteorology, 2018, *Climate Outlook for December to February*, (online)

Source: ERA Analysis of AEMO data

Aside from one niche product with limited application,[58] 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.

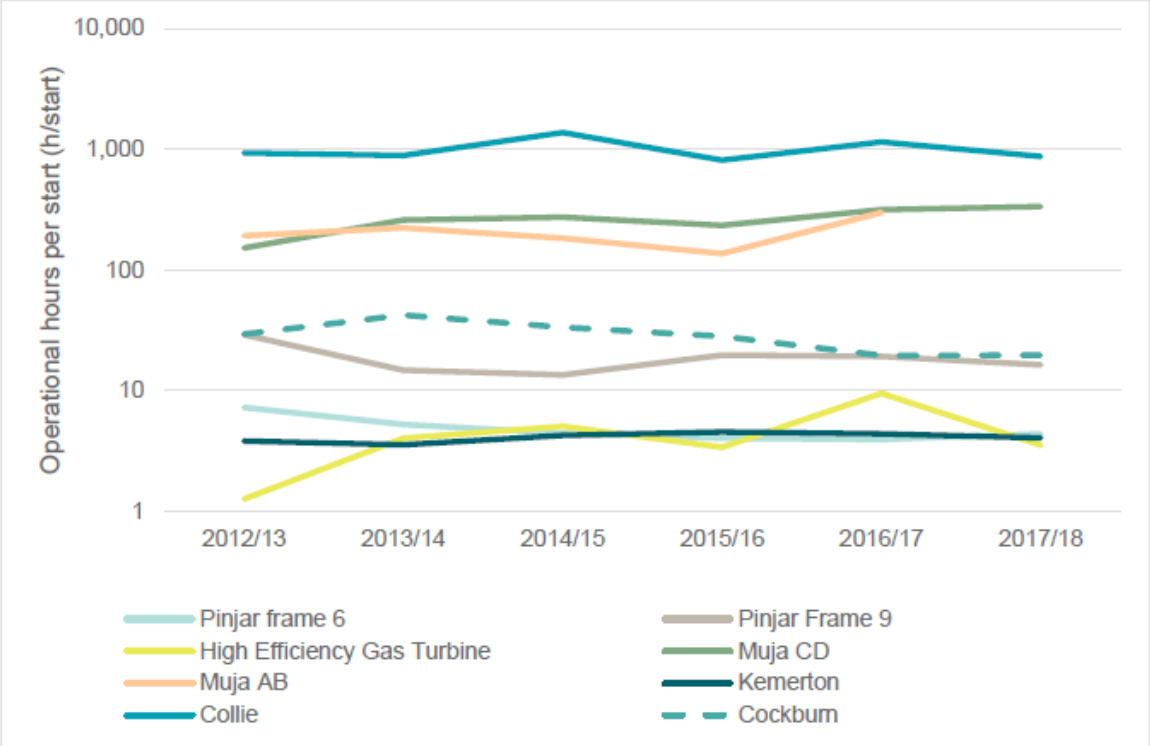
Generator run times

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 Wholesale Electricity Market (WEM) and sets prices in around 80 per cent of trading intervals. Figure 12 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.

Figure 12 Average run hours per start cycle major Synergy generators



Source: ERA analysis of AEMO data

[58] Synergy, 2019, *Electric Vehicle Home Plan*, (online)

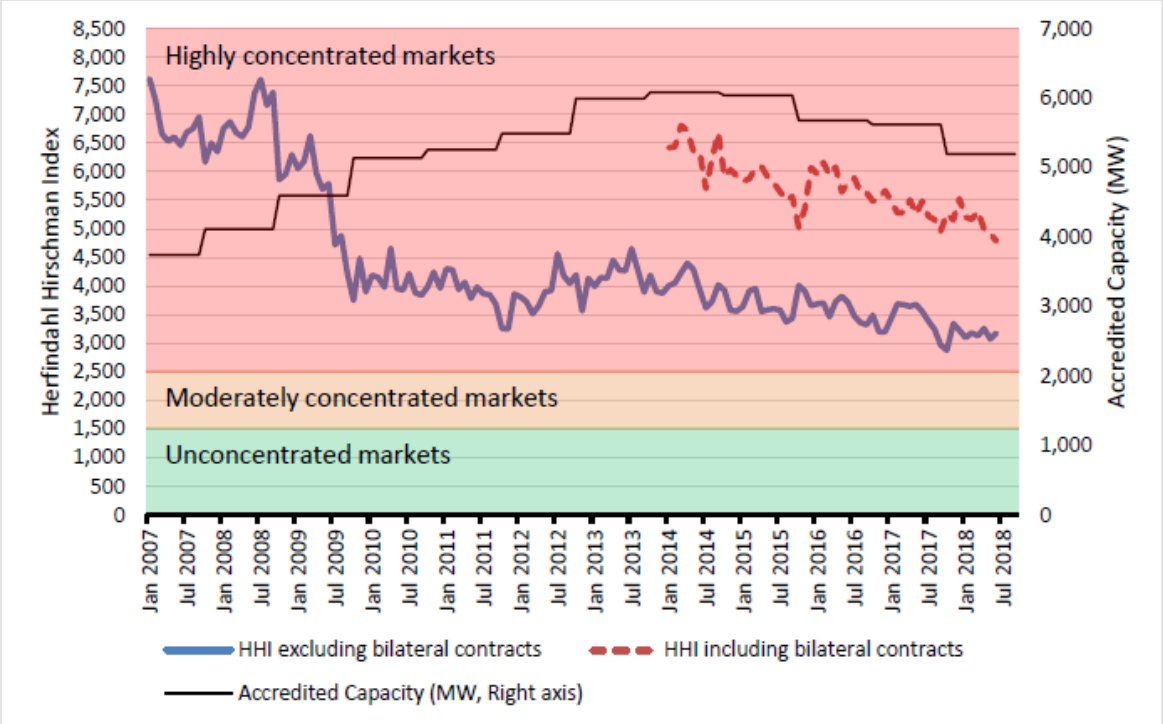
Since their installation, the high efficiency gas turbine run times have increased. They tend to run for three to five hours.

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 five per cent, it cannot account for price setting in most intervals.

Who sets the price

The WEM remains highly concentrated as illustrated by the Herfindahl-Hirschman Index (HHI) shown in Figure 13.[59] 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.

Figure 13 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.

[59] 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*, pp. 18-19. (online)

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 14 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.

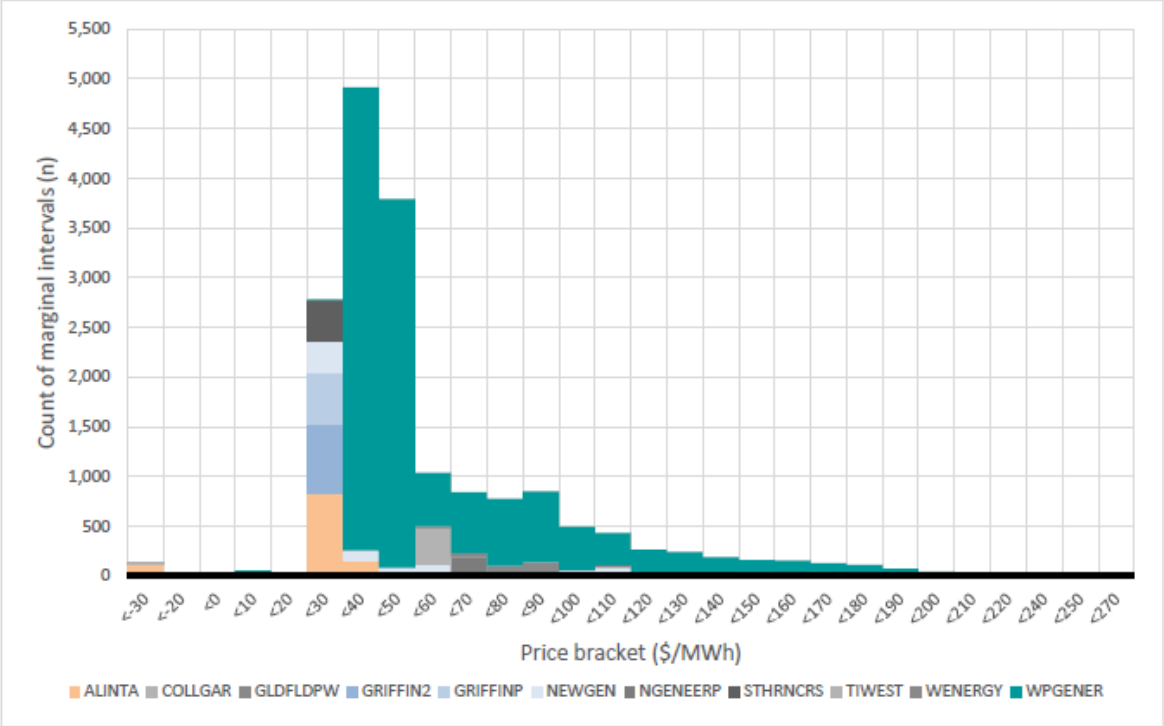
Synergy, with half the accredited capacity in the wholesale market, sets prices in around 80 per cent of intervals.

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 15).

Figure 14 Who set the price and at what price 2017/18



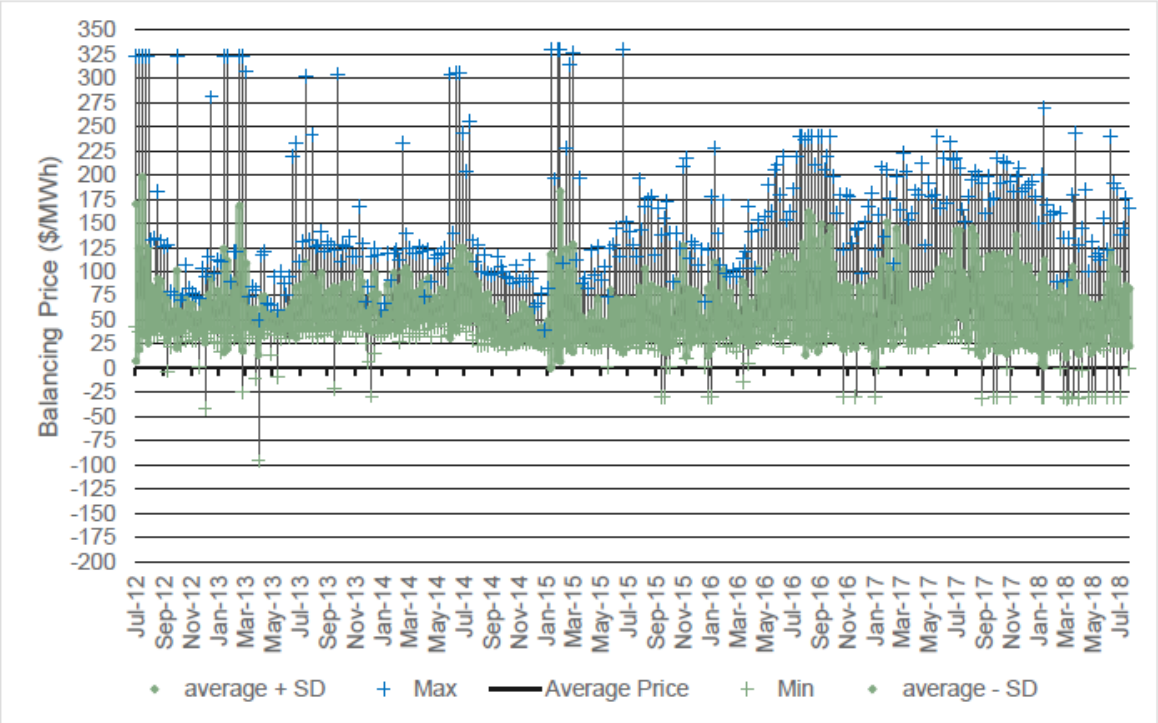
Source: ERA analysis of AEMO data

Balancing market

Figure 15 and Figure 16 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.

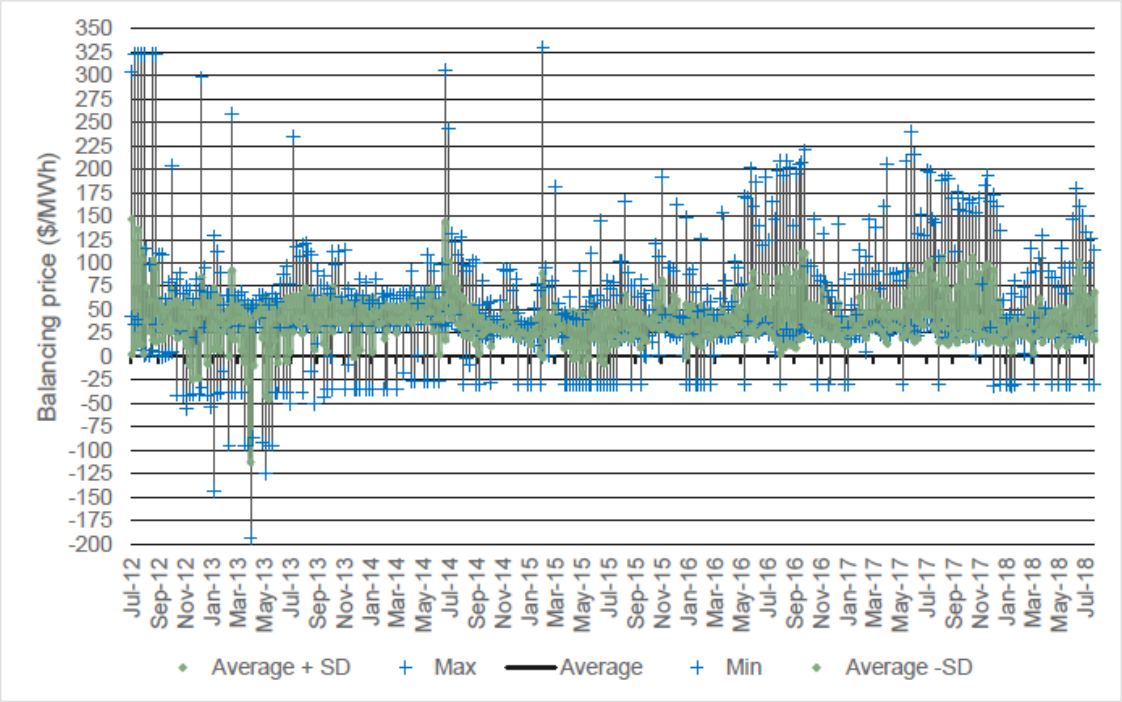
Figure 15 Weekly balancing market summary data– peak intervals



Source: ERA analysis of AEMO data

The frequency of negative prices during off-peak periods (Figure 16) has fallen since the start of the balancing market. However, during peak periods (Figure 15) 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.

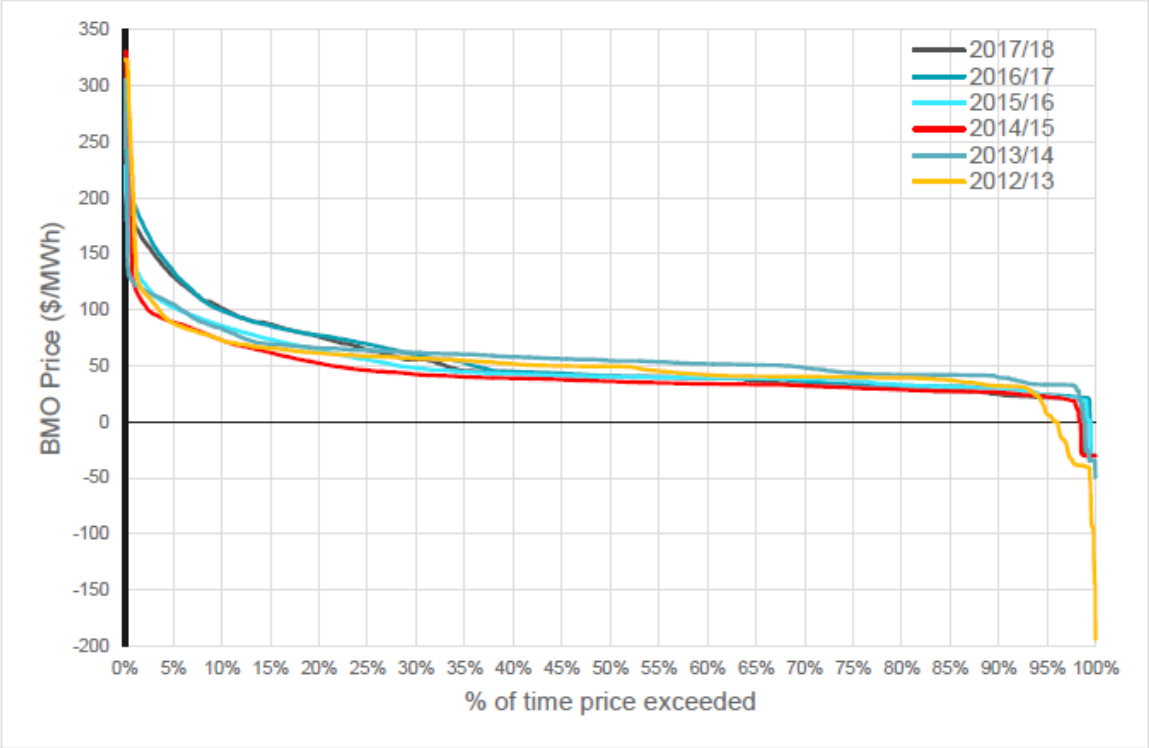
Figure 16 Weekly balancing market summary data– off-peak intervals



Source: ERA analysis of AEMO data

Figure 17, 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.

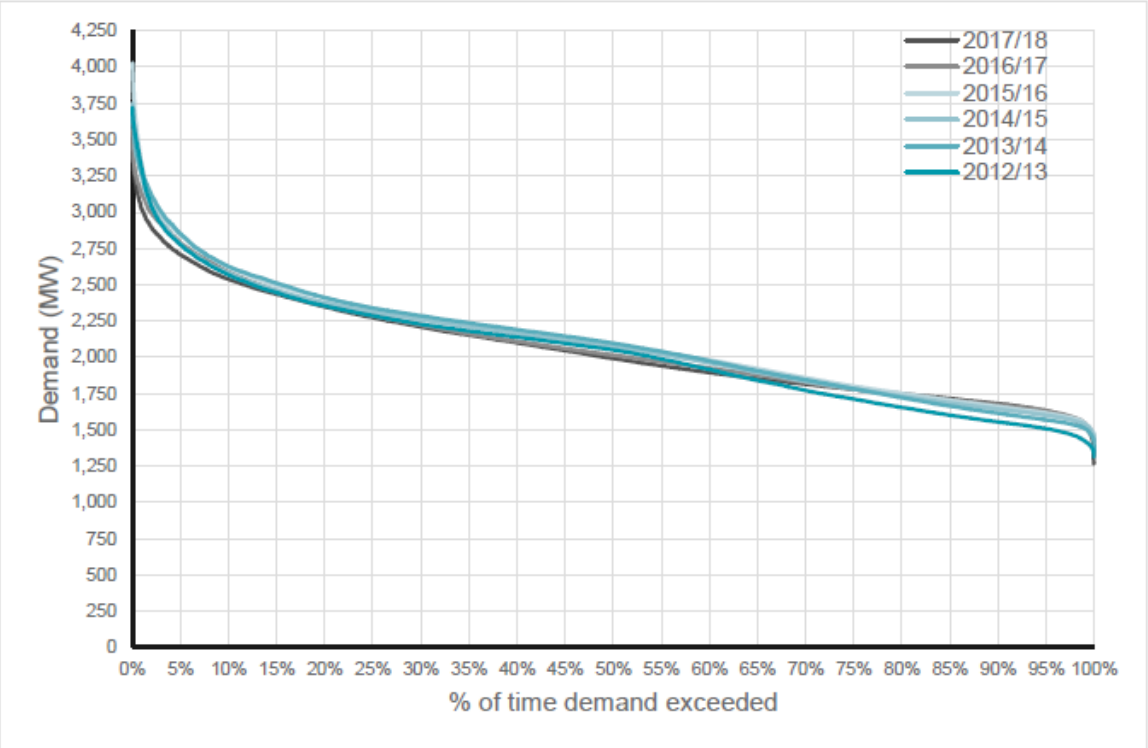
Figure 17 Price duration curve 2012/13 to 2017/18



Source: ERA analysis of AEMO data

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

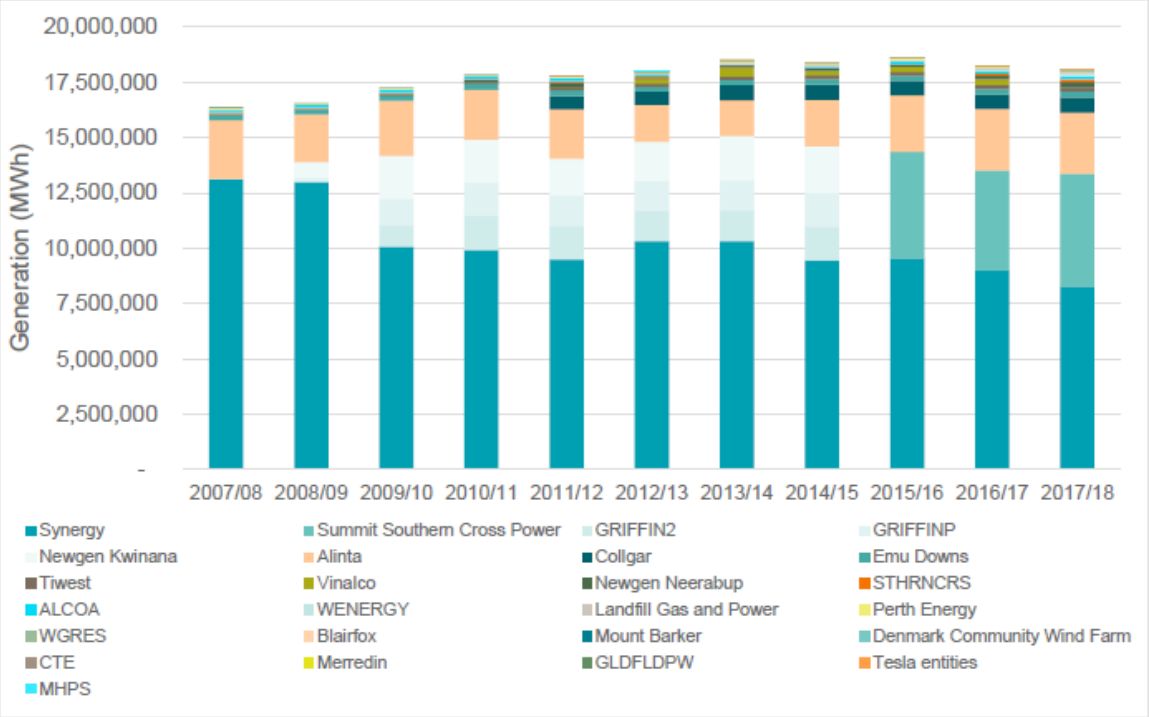
Figure 18 Load duration curve 2012/13 to 2017/18



Source: ERA analysis of AEMO data

Figure 19 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 19 Generation sent out by market participant from 2007/08 to 2017/18

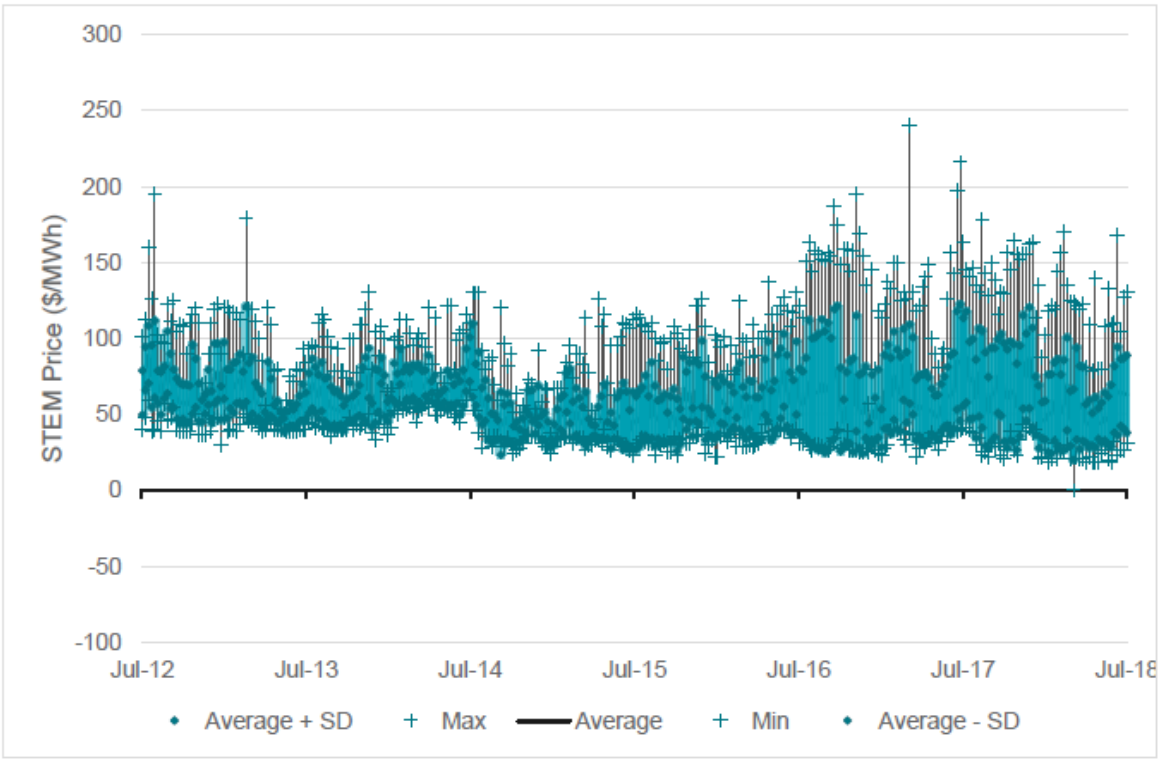


Source: ERA analysis of AEMO data

Short term energy market

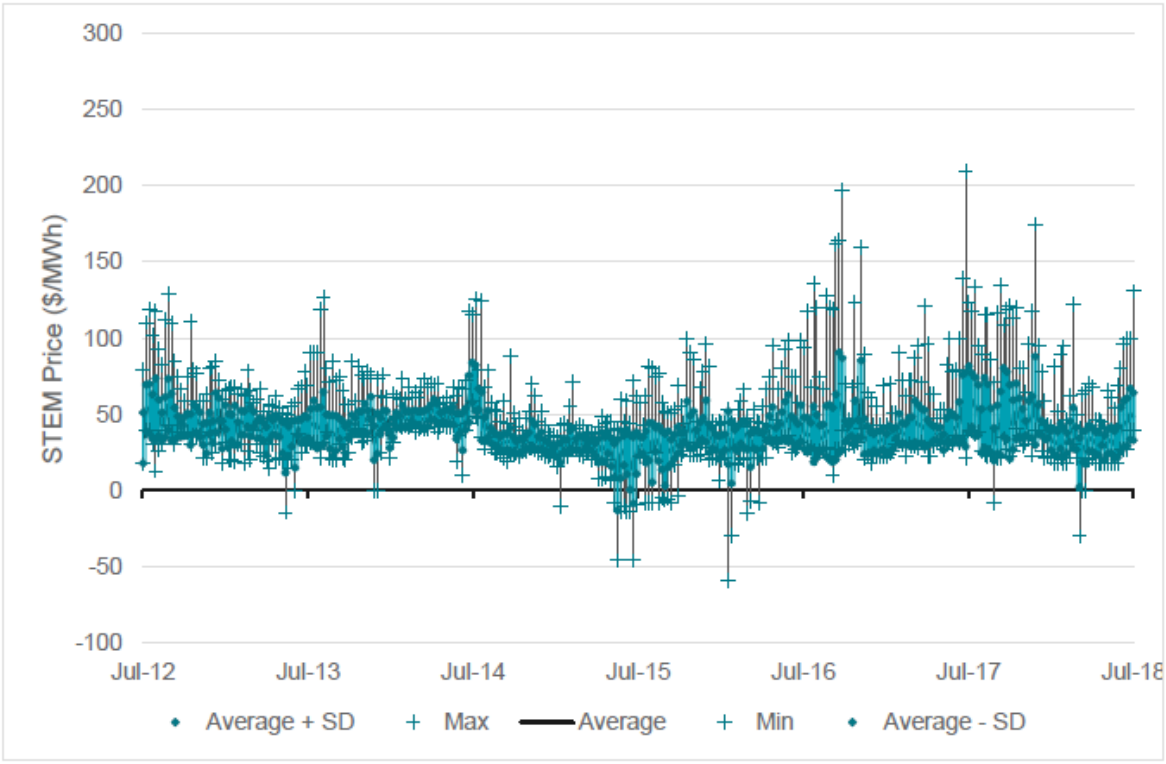
Figure 20 and Figure 20 show peak and off-peak weekly summary data for the Short Term Energy Market (STEM). The patterns show comparable trends to the balancing market but in the STEM are more muted. Volatility during peak periods remains high although prices moderated in the last six months of 2017/18.

Figure 20 STEM Weekly summary data – peak intervals



Source: ERA analysis of AEMO data

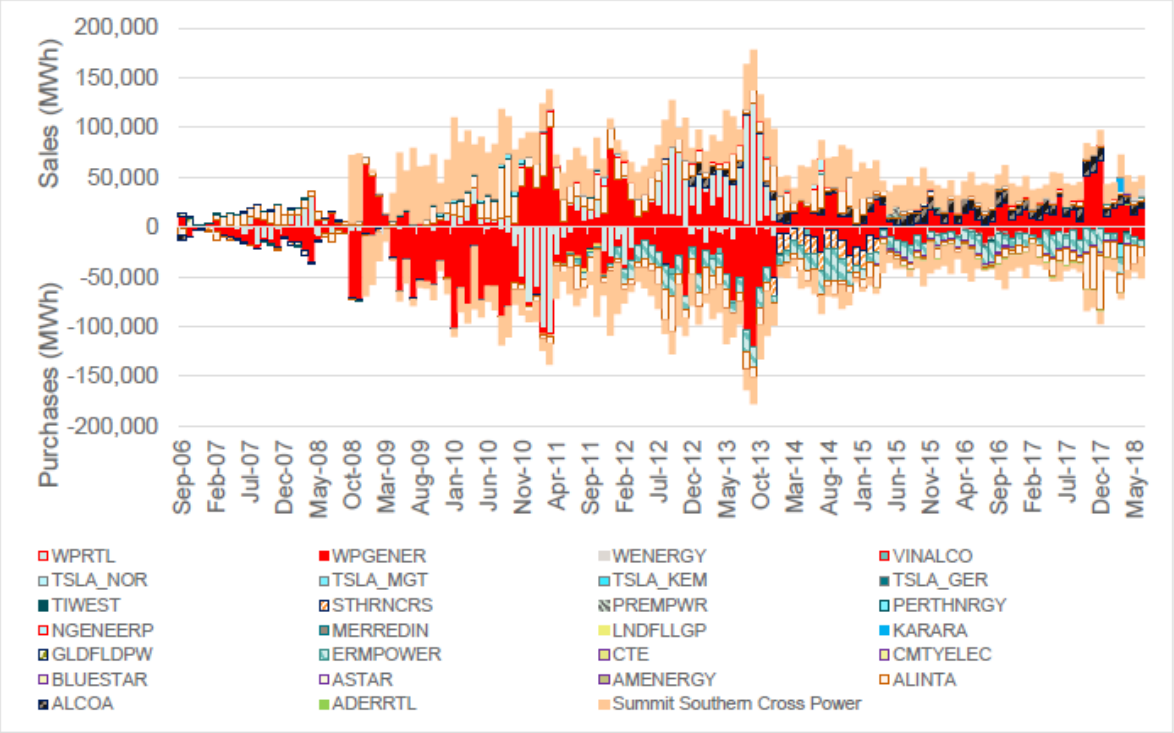
Figure 21 STEM Weekly summary data – off-peak intervals



Source: ERA analysis of AEMO data

Figure 22 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 22 Monthly STEM activity by market participant

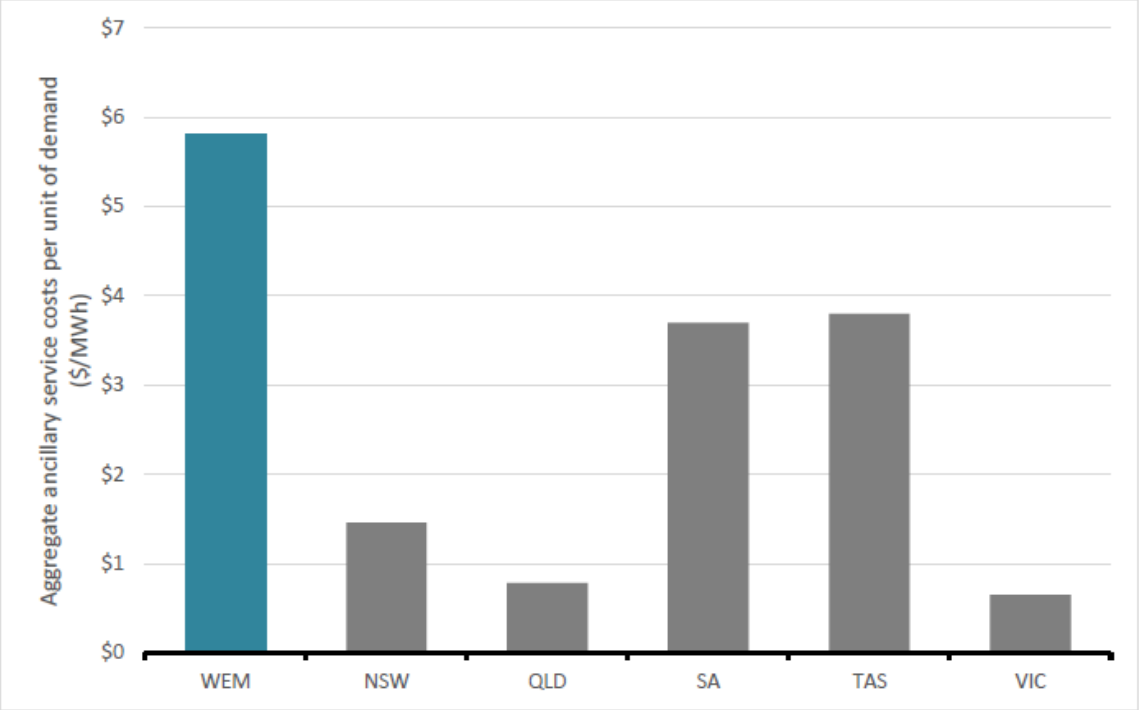


Source: ERA analysis of AEMO data

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 23).

Figure 23 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 several years.[60] 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.[61] 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.

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

60 Frequency controlling ancillary services are upward and downward load following ancillary services, spinning and load rejection reserves.

61 ERA, 2018, *Decision on AEMO's 2018-19 Ancillary Services Requirements*, p. 4. (online)

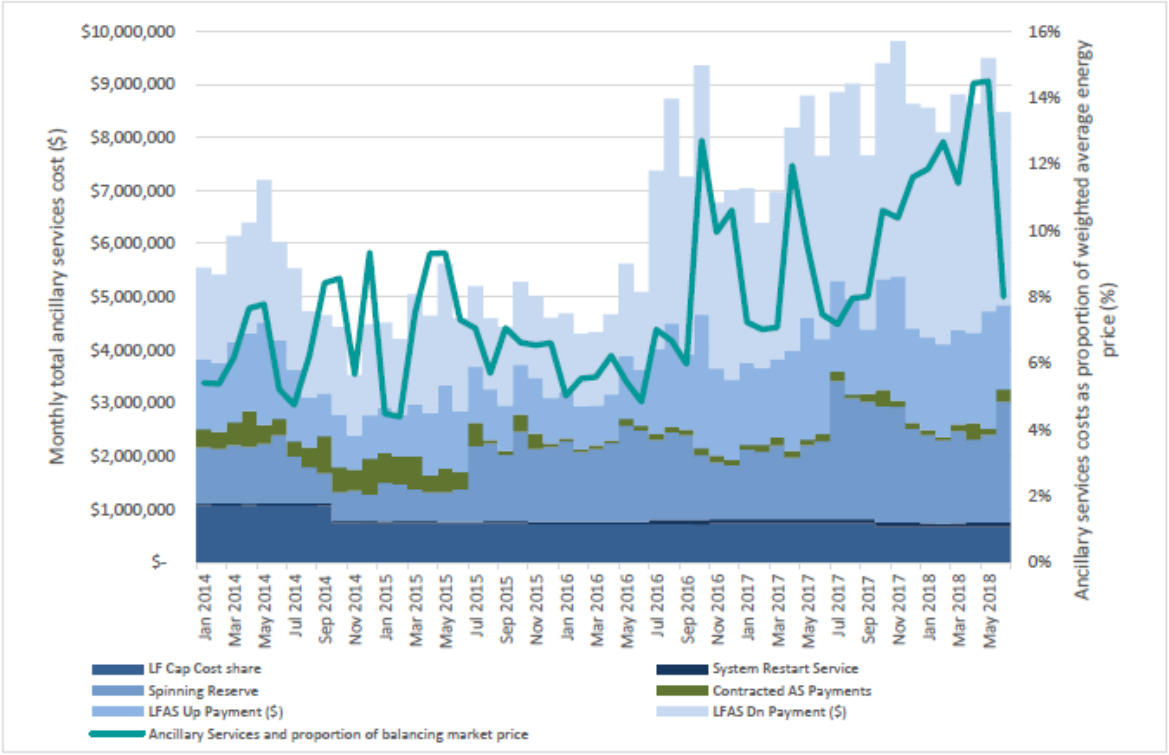
penetration of renewable generation. Therefore, the increase in ancillary service costs cannot easily be attributed to these changes and may be driven by other factors.

Most of the ancillary services cost increases are attributable to the LFAS market (Figure 24). 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 enough capacity to meet the LFAS requirements and undercut Synergy on price.

Figure 24 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 and the opportunity to reduce spinning reserve costs. These requirements include:[62]

- generators to be available for 95 per cent of intervals[63]
- contracts that have a minimum limit of 8 MW and a maximum limit of 26 MW
- fixed, 12-month contracts.[64]

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.[65] [66]

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.[67] This has continued in 2017/18. No new participants have entered the LFAS market and Synergy remains a pivotal supplier.

62 AEMO, 2018, *Request for Expression of Interest for Provision of Spinning Reserve and Load Rejection Reserve in the WEM*, (online).

63 Few plants 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.

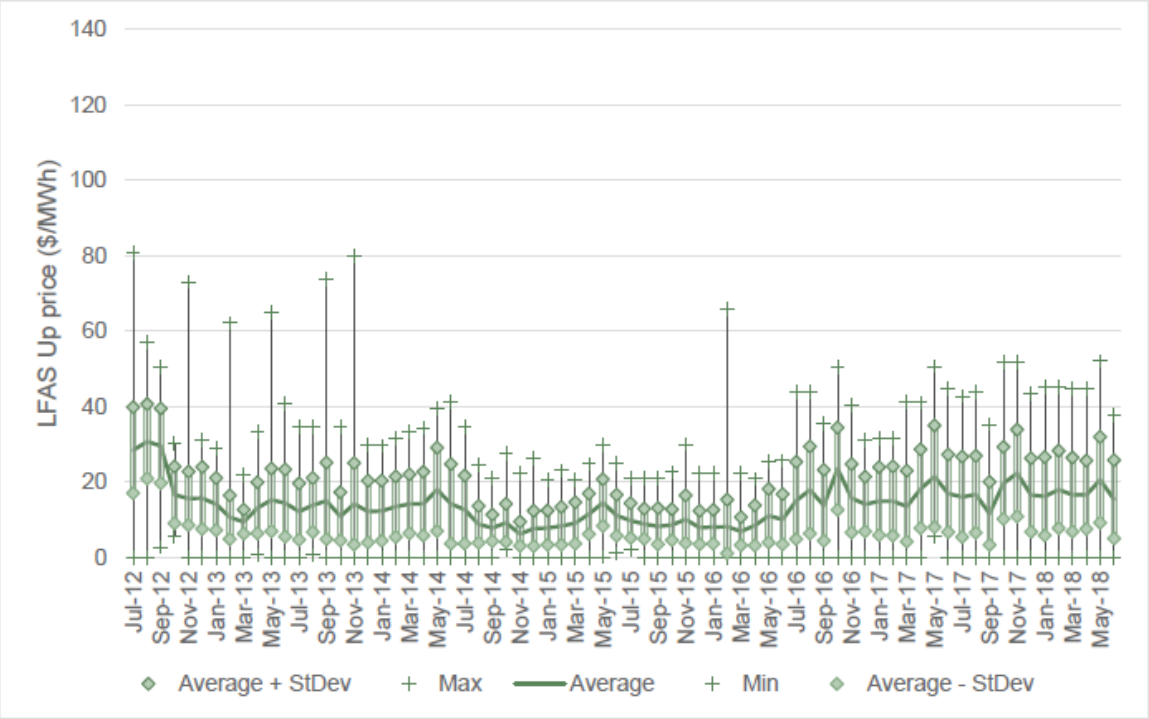
64 One possible provider has informally indicated a single year contract term made it difficult to justify the investment required to provide a competitive bid.

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

66 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.

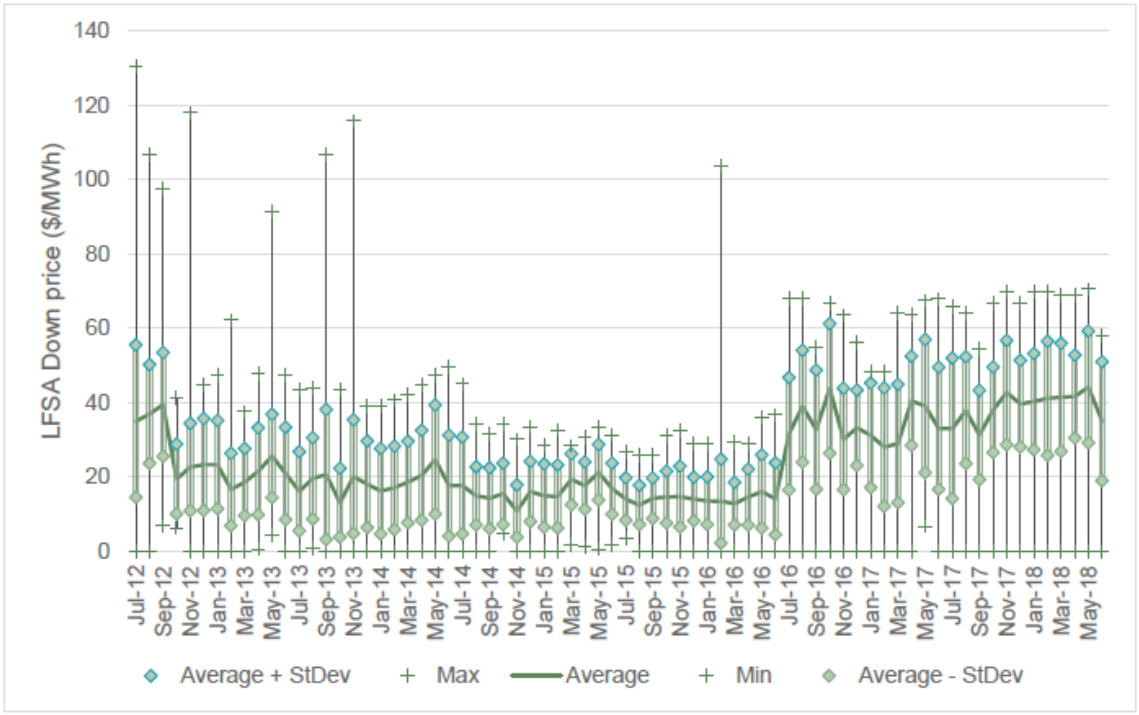
67 ERA, *2016/17 WEM Report to the Minister for Energy – Technical Appendix*, p. 10. (online)

Figure 25 Load Following Ancillary Services Up summary pricing statistics



Source: ERA analysis of AEMO data

Figure 26 Load Following Ancillary Services Down summary pricing statistics



Source: ERA analysis of AEMO data

Outages

Table A 2 below 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 A 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

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_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	-	-	-
	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

Appendix 4 Stakeholder feedback

Table A 3 Stakeholder feedback in response to WEM issues paper 2017/18

Submission	Comments	Addressed in the report
AEMO	The changing profile of the operational demand is resulting in greater movement of the output of scheduled generators, including coal generators. Sustained levels of negative pricing may also be unsustainable in the longer term as: • Generators may be compensated below their short run marginal cost. • This can compromise the availability of ancillary services needed to ensure system security and reliability. Improved distributed energy resources (DER) visibility and options for the direct or aggregated control of DER or participation of DER in the WEM is needed. This would allow AEMO to manage these generation sources to maintain system security and reliability reducing the need for ancillary services and provide alternate resources for the provision of system security services. A range of measures are needed to support short term forecasting such as: • Increased automation to support later gate closure and five-minute dispatch cycles. • Stronger incentives for market participants to assist in managing variability including pricing and cost allocation for ancillary services. • Improved visibility of DER through a comprehensive register of these resources. • New opportunities and incentives for end user consumers with DER to participate in the WEM and operate in a "predictable" way to achieve reliability and security standards and improved market outcomes. The Public Utilities Office (PUO) WEM reform program is the best opportunity to implement these measures in the short term. The PUO's proposed new obligation for market participants to provide at least three years notice prior to the retirement of generation facilities will provide valuable confirmation of retirement intentions. There would be additional benefit if market participants had to advise AEMO of the expected closure year for each of their generation facilities larger than a given threshold, and for AEMO to publish these closure years. This would also strengthen long term investment signals by providing earlier notice of retirement intentions.	Section 2.1.2.1 suggests that to the end of 2017/18, rooftop solar has not increased generator costs to the point where this has increased balancing prices. However, section 3.1 acknowledges that this may not be the case in the future. The report does not comment on direct participation of DER in the WEM, other than to recognise the need for improved price signals for consumers in section 4.4. The report does not cover the market reform program in any detail. The Executive Summary acknowledges the limited progress on reform to date and that clarity provided through the reform program will assist third parties to assess future investments. The retirement of aging thermal capacity is covered in section 3.2 and the requirement for clarity on Synergy's role in replacing generation capacity is addressed in section 4.2.

	Q15 response: The market operation, administration and development expenditure is prudent given the size and complexity of the WEM. There is merit in ex-post project reviews, particularly for projects relating to changes to the market or regulatory arrangements to ensure lessons are learnt and benefits are achieved.	Refer to Appendix 2.
Community Electricity	Western Power and Synergy legitimately need some confidentiality to operate responsibly, effectively and efficiently, but their right to conceal information enables them to avoid accountability and manipulate the market and their shareholder. Rule Change RC-2014-09 (Managing Market Information) should be resurrected. Trial results should be made public and the process of selecting private sector partners should be regulated, transparent and on commercial terms. Western Power obstructs initiatives to innovate, which are barriers to third parties participating in the behind-the-meter market despite proven expertise and track record in doing so. The PUO's draft recommendation that require generators to provide at least 3 years' notice prior to retirement of generation facilities is supported with an additional suggestion that penalties should be incurred for non-compliance with the notice period. Synergy can arbitrarily and spontaneously control the capacity price to any level it chooses up to the cap by retiring selected generating units. Network access is critical to generator development but has been tangled in the uncertainty and confusion of the market reform process for the last five years. The reforms are misplaced and should focus on issuing price signals to optimise the replacement of institutional capital by private, behind-the-meter capital. Supports for fit-for-purpose constrained network access and the corresponding fit-for-purpose security-constrained dispatch of energy. The constrained network access aspects of the electricity market reforms are the central strategy for promoting new generation investment and they are plainly ill-considered, dysfunctional and do not support development of an efficient and effective wholesale market.	The retirement of aging thermal capacity is covered in section 3.2 and the requirement for clarity on Synergy's role in replacing generation capacity is addressed in section 4.2. The report does not comment on the appropriateness of the market reform program.
Australian Energy Council (AEC)	Tariff reform must be considered to encourage efficient use of distributed energy resources, and to ensure visibility of these resources to the broader market. Participant fees should relate to costs of operating the market and accordingly market participants should not pay for government-led market reform.	This is addressed in section 4.4. Refer to Appendix 2

	The falling generation cost (energy plus capacity) and decline in Synergy's market share is a positive sign of improving competitive discipline.	Section 2.1 disagrees with this conclusion.
	Supports innovative products and services in pursuit of improvements to market and system efficiency and ultimately to support lowest prices for consumers. Regulatory barriers currently exist that restrict open participation in innovative trials; in particular restricted retail access to residential customers and business customers who consume less than 50 MWh per annum.	
	Trials should be open to all market participants and that care should be taken not to inadvertently provide any participant with a competitive first mover advantage.	
	It is reasonable that generators flag plant retirement three years in advance, but should not be bound by a date, as generators are subject to unforeseeable events, which can affect their ongoing operability.	The retirement of aging thermal capacity is covered in section 3.2 and the requirement for clarity on Synergy's role in replacing generation capacity is addressed in section 4.2.
	There is a need for policy and regulatory flexibility to allow the market to best meet the market objectives, in short to supply affordable reliable electricity.	
	State Government investment in generation reduces private sector investment and in the long-run reduces the benefits obtained from a competitive market.	This is addressed in part by section 4.3 on incorporating storage technologies.
	Q14 response: There needs to be policy and regulatory certainty, and flexibility to adapt to new technologies and supply models that may be more efficient and offer superior consumer experience.	
Kleenheat	At present it is increasingly unattractive to offer electricity to its gas customers. Kleenheat relies on the WEM and Synergy to source its electricity and suggests that Synergy's back-to-back and standard products are not a viable option for sourcing wholesale electricity, as evidenced by the lack of liquidity in them.	These points are addressed in section 4.1. This section supports improvements to the regulatory scheme in place to mitigate Synergy's market power.
	Close the bid-ask spread on Synergy standard products to improve liquidity of both buy and sell products and enforce price discipline.	
	Facility bidding for Synergy to improve transparency of price drivers and how competitive or otherwise individual generators are.	The report does not comment on the appropriateness of the market reform program.
	Shorter re-nomination time frames for generator bids with facility bidding creates more dynamic and competitive generation market.	
	Kleenheat also supports the removal of Synergy's wholesale business unit offering wholesale electricity to Synergy's retail business unit on terms more favourable to other retailers in any circumstance.	

	Innovation trials are not sufficiently open with private industry currently unable to participate in these trials. Kleenheat suggests it would participate and invest in these markets if they were open to them. Q8 response: Market participants should be required to signal intended plant retirements at least three years in advance. The lack of clarity around when or if existing capacity will retire hinders the ability of private industry to make investment decisions to add new capacity and continues to entrench Synergy's market dominance. Q11 response: Support for full retail contestability with competition possibly delivering similar improvements to the electricity market that have been seen in the WA residential natural gas market. To improve the investment environment in the WEM Synergy's market dominance needs to be reduced. Improved transparency through facility budding, road map of policy reform and implementation of regulatory change to increase competition are all necessary to reduce Synergy's market dominance.	The retirement of aging thermal capacity is covered in section 3.2 and the requirement for clarity on Synergy's role in replacing generation capacity is addressed in section 4.2.
ERM Power	A market is only effective if there is wholesale price transparency, liquidity and enough supplier competition in all markets. The WEM cannot be an effective market without meaningful competition and with one dominant generator/retailer in the market. The regulatory measures introduced to keep Synergy in check are necessary to ensure the viability of the WEM while Synergy continues to have market power. The market must be further improved with the implementation of the recommendations made by the ERA to the Minister on the Electricity Generation and Retail Corporation (EGRC) regulations and improvements to the Standard Products regime. It is important to maintain appropriate segregation of Synergy's Wholesale and Retail businesses which would provide some degree of transparency and stability for a retailer to access appropriately priced wholesale electricity products to enable a functioning WEM. It is an opportune time to revisit the question as to whether the SRMC pricing principles and dual price cap regimes are still fit for purpose. With less periods during the daytime to recover costs due to increased daytime minimum demand and negative pricing, SRMC pricing may not be enough to recover the cost of being dispatched. It may be time to explore the issue of having one market price cap. The combination of a lower number of intervals to recover cost with an increase in gas prices could result in non-liquid units having to breach the non-liquid price cap, while being unable to bid higher due to the limitation of the non-liquid cap.	These points are addressed in section 4.1. This section supports improvements to the regulatory scheme in place to mitigate Synergy's market power. Not addressed in the report although this has been identified for consideration as part of the market reform program.

	A large-scale battery achieving a combination of a capacity price and returns from the energy and ancillary services markets, may be the most economically efficient reliable technology to reduce long term cost of production of electricity supplied to customers which will achieve the objectives in the Market Rules better that current practises.	The participation of batteries is addressed in section 4.3.
	There appears to be increasing inequity whereby registered market participants are paying for systems and process to maintain a secure and stable system that is continually being disrupted and made more volatile by the non-registered entities.	Refer to Appendix 2.
	The ERA could investigate and make recommendation on other possible market fees recover mechanism that ensure greater equity and that fees are recovered from all users which could result in the lowering of market fees for consumers.	
Stephen Davidson	A percentage of the aggregate cost of the WEM should be used to fund public advocacy of consumer rights in the SWIS. This would allow small business consumers who do not have powerful industry associations, to lobby the government on behalf of the interests of their members.	
	Thermal generators in the WEM do extra balancing work to cover the additional mis-match caused by unpredictable aggregated MW output from intermittent generators having a free run and generate as much electricity as its intermittent primary energy source allows. This can increase WEM costs.	This is discussed in section 3.1.
	The discussion paper is silent on the control requirements of the SWIS power system and ability of the SWIS generation to meet them.	This is not within the scope of the WEM report.
	The disaggregation of Synergy would not help because it will not change the structure of the generating units nor improve their manoeuvring capabilities. Disaggregation could only increase costs due to more executives, corporate overheads and boards.	The report recognises that disaggregating Synergy is not government policy (section 4.1)
	More efficient operation of the SWIS could be improved by: • reactive power from the inductance of transformers and transmission and distribution lines • more frequent calculation of loss factors • enforce equal droop action on all generators and penalise failure to provide full droop response.	
	Q6 response: Microgrids have negligible effect on the WEM because they are micro consumer solutions and therefore no reference to microgrids should have been included in the paper.	
	Three years advance notification before plant retirement is better than having no notification.	

	Performance requirements for batteries and rooftop PV should be established and implemented.	These last two points are addressed by sections 4.2 and 4.3 respectively.
ATCO	It is imperative that there is policy and regulatory certainty and clarity around the future role of government utilities to encourage investment in the WEM by private sector and to deliver improved choice and more efficient cost of service outcomes for consumers.	This point is addressed in section 4.2.
	Supports the current government initiatives to reform the WEM.	These points are covered in section 3 on emerging challenges.
	The emerging driver for increasing WEM costs has arisen from the importance of 'security of supply' and 'grid stability' which is driven by increasing market penetration of non-scheduled generators.	
	The current Synergy portfolio bidding arrangements are not reflective of the current market and can possibly reduce competition as other generators are not subject of the same portfolio benefit in setting a bid price. Transition to facility bidding would provide greater transparency of increases in wholesale electricity prices.	The report does not comment on the appropriateness of the market reform program.
	Is supportive of opportunities to participate in the 'Inquiry into Microgrids and Associated Technology's in WA' and regards this as a positive step towards removing barriers and improving the investment environment.	
	The Electricity Statement of Opportunities report provides valuable insights for possible investment decisions and AEMO should continue to consult with industry on the development of the report and the assumptions that underpin it.	These points are addressed in the report in section 4.2 on enabling competition.
	Supports the forewarning of generating plant closures around three years in advance but also acknowledges that forecast retirement is only an indicator and generators should not be bound by an anticipated retirement date.	
	Commonwealth and State governments need to provide clear policy certainty to support reform in the WEM which will assist in facilitating the private sector's ability to make decisions to invest in generation assets within the WEM.	
	A coordinated investment in distributed generation technology between Government-owned utilities and the private sector will deliver innovative and valued solutions which are in the long-term interests of consumers.	
Noel Schubert	There are several factors explaining the observed increase in balancing prices in the WEM including generators operating at lower MW output levels due to increased wind and solar PV generation which increases short-run marginal costs. Another factor is Synergy's long-term fuel	These points are covered in section 2.1.

	contracts and bilateral contracts for the purchase of energy could mean that Synergy's generators do not follow shorter term fuel market price trends.	
	Generation and network wholesale electricity supply costs are higher due to very blunt or improperly focussed network and retail tariff price signals. The existing energy-based tariffs cause substantial cross-subsidies to rooftop PV and air-conditioners and both cause the significant and increasing variability in system demand that the network and generators must cope with adding to supply costs.	The comments on price signals are addressed in section 4.4.
	The network demand-based tariffs do not effectively incentivise customers to move demand away from network and system-wide peak demand periods into low demand periods.	
	There is very little work being done on influencing the 'demand-side' issues - customers' use of electricity and new technologies like solar PV, batteries and electric vehicles, as well as the usual appliances and loads.	
	There is capacity already available in the SWIS, which is not being made available to the capacity market that could defer the need for some replacement generation. For example, past demand response (DSM) capacity that could be made available under terms that are lower cost than new conventional generation capacity, and both the Mungarra and Kalgoorlie gas turbines are currently restricted to network support roles.	
	It would be possible to economically contain peak demand growth through tariff reform, demand management and adoption of new technologies so that no new thermal generation capacity is required for some time even if Muja C is retired.	
	The Individual Reserve Capacity Requirement (IRCR) will vary in future. This is due to the predictability of when the 12 IRCR peak intervals are likely to occur, IRCR responders can act to reduce demand for those intervals which will affect responders' participation and the overall level of demand reduction.	
Western Power	Network constraints are present when large generators want to connect in the same area. Investors may need to wait for network augmentation to occur and contribute to the cost of network augmentation as part of the network connection cost. Introducing a constrained market in the WEM may address these network constraints.	The report does not comment on the appropriateness of the market reform program.
	There is no consolidated central source of information available to investors that holistically considers network investment information and generation forecast information for the SWIS.	
	There are limited incentives for investors to locate loads or generators in unconstrained areas.	

	Western Power suggest that correct and early market signals may promote investment in new and efficient generation in the WEM. Advanced notice of plant retirements in the WEM is necessary to signal investment opportunities to the market. A lead time of more than three years is often required to design and build new generation, carry out network augmentation and complete connections works. An advanced notice period of at least five years would be beneficial. The future network will be more modular as behind-the-meter generation continues to increase. Transition to a modular network would require removal of the current legislative limitations, development of a data collection framework and a review of technological barriers such as current voltage operating ranges.	The retirement of aging thermal capacity is covered in section 3.2 and the requirement for clarity on Synergy's role in replacing generation capacity is addressed in section 4.2.
Southern Cross Power Holdings Pty Ltd (SCPH)	The WEM's generation mix is ill-equipped to manage the changes in demand profile it is experiencing. The ageing base load generation is becoming less viable and gas turbines are too big or incur high penalties for short-duration ruins, and so are not suited for the type of flexible operation that is becoming more important to the grid. A significant barrier for non-government entities participating in trials is that existing legislation and historic structures specifically preclude third parties from accessing customers, such as the laws around retailing to Synergy's franchise customers; or accessing the regulatory 'opportunity cost' of Western Power obligations to service network customers. Implementing more competitive frameworks to run innovation trials, where other service delivery proponents can tender to offer services at a lower price than the state-owned entities would be highly beneficial. Q9 response: A dedicated 'replacement tender' process could be used to manage the orderly exit older generation and more importantly, an orderly entry of new generation that is suitable to the ongoing requirements of the market. The investment environment will be likely to worsen over the short-to-medium term. The major factors influencing this are that the market will be in a state of 'reform' for an extended period, there is no clear understanding whether Synergy will replace its aging fleet, and uncertainty around future renewable policy. The WEM's market fees are too high. Recent information regarding AEMO's expected revenue requirements for the next (AR5) period are alarming and will again substantially increase the costs of operating the market. Both consumption and demand are expected to decline out to 2022 and the increasing costs of operating, administering and regulating the WEM will need to be recovered from a decreasing supply base.	These points are addressed in section 3 on emerging challenges. The retirement of aging thermal capacity is covered in section 3.2 and the requirement for clarity on Synergy's role in replacing generation capacity is addressed in section 4.2. Refer to Appendix 2.

Appendix 5 Batteries

Deployed appropriately, batteries could relieve network congestion and delay expenditure on network augmentation, provide price arbitrage between low-cost and high-cost periods, change the profile of demand, dampen the variability of renewable generators' output (which would also reduce market volatility) and provide ancillary services. Many of these services can be deployed simultaneously.

Other jurisdictions, such as South Australia and Great Britain, have already provided for the successful integration of battery storage into their electricity markets. The ERA has researched the current and prospective use of batteries in other jurisdictions as summarised below.

Batteries and market power

Other markets have considered the capacity for batteries to participate in markets and developed rules to prevent the inappropriate exercise of market power.

Participation in the National Electricity Market (NEM) has demonstrated how batteries are able to address transitory market power. In South Australia, faults on the power line linking to Victoria created a reduced, localised pool of generators providing the fast frequency response ancillary service. This smaller group of generators had transitory market power enabling them to offer or rebid their capacity at prices far exceeding the prevailing energy price.[68] The introduction of the Hornsdale Power Reserve (the TESLA Big Battery) increased the pool of local generators able to provide ancillary services and it undercut bids from existing generators in periods of transitory market power.[69] It was the introduction of new generating capacity, and not the superior performance of the battery, that altered ancillary service prices during the battery's trial period.

The Wholesale Electricity Market (WEM) load following ancillary services (LFAS) market has similar market power issues to the South Australian ancillary services market, where market power in South Australia was transitory and linked to particular circumstances, it persists in the WEM for longer periods. The technical and market rule changes needed to integrate the Hornsdale Power Reserve in South Australia could inform the introduction of storage in the WEM.

Substantial differences between the WEM and the NEM will influence how batteries are adopted in each market. The WEM is a smaller market, and its energy prices are capped between - $1,000/MWh and $302/MWh.[70] Batteries participating in the WEM could arbitrage prices, but it would be over a smaller range than the NEM. The market trading range between the minimum and maximum price in the NEM is nearly 12 times that of the WEM.

The smaller arbitrage opportunity and demand range in the WEM suggests that the opportunity for batteries to participate in the WEM may be limited. A sufficiently sized storage facility entering the WEM could have a substantial first-mover advantage. The entry of such a battery has the capacity to mitigate or exacerbate market power in the WEM. This has implications for the definitions of market power and implications for market power mitigation measures.

The New York Independent System Operator (NYISO) has already considered how batteries could exert market power. It recently proposed revisions to its market rules to provide

68 AER, 2018, *Report into market ancillary service prices above $5000/MW. South Australia 13 and 14 October 2017*, p. 5. (online)

69 AEMO, 2018, *Hornsdale Wind Farm 2 FCAS Trial, Knowledge Sharing Paper*, pp. 4-35. (online)

70 ERA, 2018, *2018 Energy Price Limits Decision*, p. 2. (online)

definitions of physical and economic withholding for energy storage resources, such as batteries.[71] A generator that deliberately withholds its physical generation capacity to drive energy prices higher can be defined as exercising market power. As batteries can be both a load and a supply of electricity, NYISO is proposing that a battery refusing to withdraw energy, or charge when it has transitory market power may also constitute physical withholding. There could be lessons for the WEM from how the NYISO has approached batteries and market power.

Batteries and capacity valuation

Batteries, and more traditional forms of energy storage such as pumped hydro, already participate in the Great Britain capacity market.[72]

Great Britain's market rules initially allowed batteries to participate in the same markets as pumped storage. The capacity provided by both types of storage was equally valued and the de-rating factor of 96 per cent applied to pumped hydro was also assigned to batteries.[73] The de-rating factor indicates the quantity of capacity that can be relied upon to be available, and paid for, when required. The de-rating factor, and high number of capacity credits this represented attracted many batteries to quickly enter the Great Britain capacity market.

Market participants were concerned that much of the new battery storage was of short duration; batteries that could release their charge and supply electricity for only half an hour. In response, the National Grid, the market operator in Great Britain, investigated the duration of system 'stress events', or periods when the electricity market was only just able to maintain a reliable electricity supply. On average, these events lasted approximately two hours.[74] Unlike pumped hydro, short duration batteries cannot discharge and supply electricity over the whole two hours of a system stress event. The National Grid suggested that if the short duration batteries could not provide the same service as pumped hydro, they should not be assigned the same de-rating factor as a pumped hydro plant, or an equivalent number of capacity credits.

In the latter part of 2017, the National Grid revised the method for estimating the de-rating of short duration batteries.[75] They were de-rated to the lowest rating of just under 18 per cent. Other battery technologies that could discharge for up to four hours (flow batteries) retained the 96 per cent de-rating factor.

In the WEM, the pricing model for the Reserve Capacity Mechanism is still being designed and it is unclear whether consideration has been given to whether and how batteries will be remunerated under this design.[76] Experience from the Great Britain capacity market can help inform the inclusion and remuneration of batteries into the reserve capacity market in the WEM.

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71 New York Independent System Operator, 2018, *Filing for Order No. 841, Letter from the New York Independent System Operator to the Federal Energy Regulatory Commission*

72 Pumped hydro is a type of hydroelectric energy storage. Water is pumped from a lower reservoir into a higher reservoir. During periods of high demand, water from the higher reservoir is released through turbines to produce electricity and collects afterwards back in the lower reservoir.

73 De-rating is a process of reflecting operational constraints or limitations as a function of nameplate capacity.

74 National Grid Electricity Transmission, 2017*, Duration-Limited Storage De-Rating Factor Assessment – Final Report*, p. 3. (online)

75 The National Grid statistically derived 'equivalent firm capacity' that a short duration battery could displace during periods of system stress.

76 Department of Treasury, 2018, *Improving Reserve Capacity pricing signals – a proposed capacity pricing model Draft Recommendations Report*, p. viii. (online)

Batteries and network benefits

Great Britain's Office of Gas and Electricity Markets (Ofgem) expects that network companies and system operators will increasingly rely on flexible resources, such as batteries, as alternatives to traditional network reinforcement. The removal of barriers to batteries and other storage technologies can enable more participants to provide flexibility and help deliver cost savings and security of supply for consumers by creating competition for grid services.[77]

Ofgem considers that allowing monopoly entities such as network licensees to own and operate batteries could risk the competitive deployment of storage and inhibit its uptake in the system. Network licensees have competitive advantages over third-party storage providers.[78] For example, network licensees control the network infrastructure, and because of this, they can restrict, impede or deny third party access to the network, preventing them from offering competing network or market services.

In December 2018, Ofgem introduced a new condition in its Electricity Distribution Licence to prevent distribution network operators from owning and operating generation assets, of which battery technology is a subset.[79] [80] If a network operator wishes to own and operate a battery it must separate the organisational, legal and decision-making activities of the network and generation businesses. This aims to ensure that protections are in place to manage possible conflicts of interest as markets for flexible resources, such as batteries, develop.

Instead of owning batteries themselves, network operators in Great Britain can enable and benefit whole system innovation by signalling their flexibility needs to the market, through publication of future network requirements and by engaging extensively with stakeholders in planning future network investments. Network operators do not need to operate storage to benefit from the services that storage can provide.

The WEM has similar rules to Great Britain, prohibiting network operators from generating. Despite this, the government-owned Western Power is gradually expanding its involvement in operating batteries as part of a series of trials of the technology and its integration into the SWIS. The sharing of the knowledge gained from such trials to support third-party participation in new markets for flexible technologies such as batteries is discussed in section 4.2.

A summary of the various applications for storage technologies in the transmission and distribution system, in the market, and behind the meter is provided in Table A 4 below.

[77] Ofgem, 2018, *Decision on enabling the competitive deployment of storage in a flexible energy system: Changes to the electricity distribution licence*, p. 4. (online)

[78] Such as access to a lower cost of capital.

[79] Ofgem, 2018, *Decision on enabling the competitive deployment of storage in a flexible energy system: Changes to the electricity distribution licence*, p. 1. (online)

[80] Ofgem considers that generation and storage share similar characteristics and perform similar functions in terms of generating and exporting electricity to the grid.

Table A 4 Storage technology applications in electricity systems.

Position	Application	Storage System	Operational use
Grid	Transmission	Large scale facility used to improve grid performance and assist integration of utility scale renewables.	Voltage support and grid stabilization, decrease transmission losses, diminish congestion, increase system reliability, support local grid during upstream outages, defer/substitute transmission investment, optimise renewable-related transmission.
	Distribution	Facility located at substation or distribution feeder, controlled by utility, integrated distribution into utility management systems. Can be mobile.	Substation - flexible peaking capacity while also mitigating stability problems. Feeder – mitigate stability problems and enhance system reliability and resiliency.
	Microgrid	Facility that supports small power systems that can 'island' eg farm at edge of grid.	Ramping support to enhance system stability and increase reliability. Smooth and firm customer-sited solar or wind. Support islanded microgrid operation for critical services during grid outage. Provides short term power output.
	Island grid	Facility that supports physically isolated electricity systems eg isolated mining operation - scale can vary widely by use.	Supporting stability and reliability, in addition to smoothing and firming renewables. May provide balancing and fast ramping. Provides enduring output.
Market	Hybrid generation	Large scale storage facility collocated with renewable energy	Wind and solar firming, smoothing and dispatch. Can shift renewable generation output to meet market needs and/or energy arbitrage. Capacity and resource adequacy.
	Peaker replacement	Large-scale energy storage system designed to replace peaking gas turbine and other facilities. Fast and responsive.	Capacity, energy sales (eg time-shift/arbitrage), spinning reserve. Can be brought online quickly to meet rapidly increasing demand at peak and quickly taken offline as demand diminishes.
	Frequency regulation	Energy storage system with parameters designed to reflect system requirements. Fast and responsive.	Balances power by raising or lowering output to follow real time changes in load to maintain frequency to be held within a tolerance band.
Behind the meter	Residential	System for residential home use	Back-up power, power quality improvements eg regulates power supply and smooths the quantity of electricity sold back to the grid from PV and extends the utility of solar generation.
	Commercial and industrial (C&I)	System sized to have enough power and energy to support multiple C&I energy management strategies.	Behind the meter peak shaving and demand reduction ie time shift energy from grid or from customer-sited solar, to manage energy use under a time-of-use retail rate. May provide option of providing grid services to utility or wholesale market.
	Commercial appliance	System that contains limited energy and power.	Provides behind the meter demand reduction.

Source Table 1 is adapted from the DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA (online) *and Lazard's Levelised cost of Storage – version 2* (online)

Appendix 6 List of Figures