Ancillary service parameters: spinning reserve margins, load rejection reserve and system restart costs for 2020/21

Determination

31 March 2020

Economic Regulation Authority

WESTERN AUSTRALIA

D213041

Economic Regulation Authority

Level 4, Albert Facey House

469 Wellington Street, Perth WA 6000

Telephone 08 6557 7900

Email info@erawa.com.au

Website www.erawa.com.au

This document can also be made available in alternative formats on request.

National Relay Service TTY: 13 36 77

Contents

List of appendices

1. Overview

The Australian Energy Market Operator (AEMO) uses ancillary services to maintain the security of the South West Interconnected System. AEMO uses an administered mechanism in the market rules to calculate costs for three ancillary services: spinning reserve, load rejection reserve and system restart. The cost of the load following service, which AEMO uses to balance supply and demand in real time, is determined through a market.

Spinning reserve and load rejection reserve are complementary but opposite ancillary services. AEMO uses them to maintain system frequency when there is a sudden loss of supply or demand. Spinning reserve provides a rapid increase in generation to compensate for the sudden loss of a large generator. Load rejection provides a rapid decrease in generation if a large load is lost. A generator providing system restart can energise the electricity system after a total system blackout.

Synergy is the largest generator in the Wholesale Electricity Market (WEM), and the default provider of ancillary services including spinning reserve and load rejection reserve.[1] Payments to Synergy for providing these services are based on settlement formulas prescribed in the market rules using parameters determined by the Economic Regulation Authority.[2] AEMO bases its proposals for system restart on its contracted costs with generators providing system restart services.

On 30 November 2019, AEMO proposed new margin values to calculate spinning reserve payments and new costs for load rejection reserve and system restart payments (referred to as Cost_LR) for 2020/21.[3]

The ERA published an issues paper on 16 December 2019 and invited stakeholders to comment on that paper and AEMO's proposed values. The ERA received four submissions in response.[4,5]

The ERA has considered AEMO's proposal, stakeholders' comments and the WEM objectives to make its determination.

AEMO's modelling and stakeholder comments

AEMO's approach to the modelling of spinning reserve and load rejection reserve costs has improved from previous years. The modelling incorporated most of the ERA's previous recommendations and recent changes in the WEM. For example, the modelling included:

- Changes in the spinning reserve requirement due to the connection, mid-2020, of two new wind farms on the same line in the northern part of the electricity network.
- Outcomes from AEMO's trial use of dynamic load rejection reserve quantities.
- Dispatch of generators to meet all ancillary service requirements simultaneously instead of using separate models as in the past.

---

1 Rule Change Panel, 2020, *Wholesale Electricity Market Rules (22 February 2020)*, clause 3.11.7A (online)

2 Rule Change Panel, 2020, *Wholesale Electricity Market Rules (22 February 2020)*, clause 9.9.2 (online)

3 AEMO, 2019, *Margin values and Cost_LR proposals for 2020/21*, (online)

4 ERA issues paper, *Spinning Reserve, Load Rejection Reserve and System Restart Costs: Margin Values and Cost_LR Ancillary Services parameters for 2020/21, December 2019* (online)

5 Stakeholder public submissions, ERA website, 12 December 2019 (online)

AEMO also conducted a rigorous quality assurance process, resulting in a deeper review of the modelling outputs as they were produced and iterative adjustments to ensure the dispatch results were reasonable.

Synergy's fuel price assumptions were a critical input to the model. The gas price is required for calculating Synergy's costs to provide ancillary services and the market clearing price in the model.

AEMO used back-casting to derive Synergy's gas price because Synergy did not provide fuel price information to AEMO. The back-casting exercise derived a gas price for Synergy of $3.50/GJ delivered (including transport costs) and reduced fuel costs for other market participants by up to 40 per cent, compared to the values submitted or provided in previous years. This formed the base case underlying AEMO's proposal.

Back-casting is the comparison of modelled outputs with actual outputs. Using back-casting to identify specific inputs, in this case fuel costs, is problematic. This pre-supposes that the model is already valid, and that differences between real world outcomes and modelled outcomes based on known fuel prices are predominantly due to wrong input assumptions rather than, for example, market inefficiencies, model inaccuracy, or any exercise of market power.

While validating input assumptions may be reasonable, determining input assumptions through back-casting is not. AEMO's consultant, Ernst and Young, acknowledged the limits of back-casting for the purpose of deriving gas price inputs in its final report.[6]

Two stakeholders, Perth Energy and Bluewaters Power, were generally supportive of AEMO's modelling approach.[7] Synergy's submission considered that AEMO's modelling and its derivation of a $3.50/GJ gas price was flawed but supported the margin values derived by the modelling.

Determination

To make its determination on margin values and Cost_LR, the ERA must ensure that Synergy is compensated for the efficient and reasonable costs of providing ancillary services, while still meeting the WEM market objective of minimising long-term costs to consumers.

The ERA has concerns about AEMO using back-casting to derive Synergy's gas price, which resulted in fuel price assumptions and balancing price forecasts that were not supported by available evidence. Instead, the ERA has based its determination on margin values and load rejection reserve costs on the modelled scenario that assumes a Synergy gas price of $5.25/GJ delivered.

The ERA has used publicly available information on gas prices to help inform its decision. The Department of Mines, Industry Regulation and Safety publishes a weighted average domestic gas price. This data is collected from the producers and reflects a weighted average contract price. The weighted average gas price from the suppliers has been trending downwards from $4.96/GJ in 2016/17 to $4.05/GJ in 2018/19. The ERA also reviewed spot market prices; in January 2020 the average market spot price was $2.43/GJ.[8]

6 AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version),* (online), Pp. 68, 69

7 However, Perth Energy's view was based on the $3.50/GJ gas price being a reasonable 'supplier price' prior to transport, whereas the $3.50/GJ assumption is a delivered gas price including transport costs.

8 Gas Trading, Historical Prices and Volumes webpage, online, accessed 26 February 2019.

AEMO's sensitivity scenario, which used a gas price of $5.25/GJ delivered, equated to a supplier gas price of $3.90/GJ - relatively close to the weighted average supply price for 2018/19. This price is consistent with gas price and transport information provided to AEMO by the market participants for their generators in this review.

AEMO's proposal, which was based on a Synergy gas price of $3.50/GJ delivered, equated to a supplier gas price of around $2.15/GJ. This is much lower than the weighted average domestic gas supply price (excluding transport) for 2018/19 and the January 2020 market spot price. A second AEMO scenario used a Synergy gas price of $7.00/GJ delivered, which equated to a supplier price of $5.65/GJ; well above the spot and weighted average domestic gas supply prices.

The ERA has based its determination on margin values and load rejection reserve costs on the sensitivity study results from the scenario where Synergy's delivered gas price was set at $5.25/GJ delivered because this gas price is both supported by publicly available information and consistent with gas price information provided by other market participants.

System restart costs are based on the contracted costs of providing the service. AEMO's new proposed system restart cost of $3,277,661 for 2020/21 is not materially different to its previous proposal for that year of $3,293,000. The new cost is based on more recently published revised forecast CPI escalation rates. In 2019 the ERA did not approve AEMO's proposed cost of providing system restart in the North Metropolitan network sub-area for 2020/21 and for the same reasons does not approve the new proposed cost for 2020/21. Consistent with its determination last year, the ERA has:

- Applied the consumer price index to the previous contract value for system restart in the North Metropolitan sub-region.
- Approved contract costs for the South Metropolitan and South Country network sub-areas, inflated by the consumer price index in line with contract terms.

The ERA acknowledges that AEMO is taking the ERA's past recommendations into consideration when tendering for new system restart services for the North and South Metropolitan network sub areas, as current contracts expire on 30 June 2021.

In accordance with clauses 3.13.3A and 3.13.3B of the WEM Rules, the ERA determines that:

- The value of margin peak and margin-off peak parameters for 2020/21 are 25.46 per cent and 21.42 per cent respectively.
- The value of the Cost_LR parameter (combined costs for load rejection $1,167,000 and system restart $2,868,473) is $4,035,473 for 2020/21.

2. Introduction

The South West Interconnected System uses ancillary services to maintain the balance of supply and demand at all times. This determination covers three ancillary services:

- Spinning reserve provides a rapid increase in generation following a sudden shortfall in electricity supply resulting from the loss of a large capacity generator or main transmission equipment disconnecting generation.[9]
- Load rejection reserve provides a rapid decrease in generation output where a large load is lost, such as when a transmission line trips. This service, and spinning reserve, are required to maintain system frequency within acceptable limits.
- The system restart service provides the capability of starting up in total system blackout conditions and can energise the power system to enable other generators to be started up.

AEMO undertakes a review of the costs of these ancillary services and proposes peak and off-peak margin value percentages, used to calculate spinning reserve costs, and forecasts costs for providing load rejection reserve and system restart services, together called Cost_LR.

The ERA is responsible for determining margin values and Cost_LR, and must consider:

- the Wholesale Electricity Market objectives[10]
- AEMO's proposal
- submissions received in response to the public consultation process.[11]

Once determined, the costs based on these values are allocated to market participants according to the market rules.

A summary of the feedback on the ERA's issues paper is included in Appendix 2. Specific feedback is included where relevant in the sections that follow.

This year, the ERA is conducting its determination of margin values and Cost_LR together. This is because AEMO has proposed new values for:

- Margin peak and margin off-peak values for financial year 2020/21, annually as usual.
- Cost_LR for the single year of 2020/21 rather than for the usual three years.

The WEM rules allow AEMO to resubmit Cost_LR values if it calculates values materially different to those determined by the ERA for the three-year period (2019/20 to 2021/22).[12]

All annual values in this paper refer to the financial year unless otherwise indicated.

---

9 The market rules define spinning reserve as capacity held in reserve from synchronised scheduled generators, and dispatchable or interruptible loads to support system frequency in the event of network or generator outages.

10 Rule Change Panel, 2020, *Wholesale Electricity Market Rules (22 February 2020)*, clause 1.2 (online)

11 Rule Change Panel, 2020, *Wholesale Electricity Market Rules (22 February 2020)*, clause 3.13.3A (online)

12 For any year within the normal 3-year review period for Cost_LR, the market rules require AEMO to propose and the ERA to determine revised Cost_LR values if System Management (part of AEMO) determines Cost_LR to be materially different than the costs provided for the normal 3-year review period. Rule Change Panel, 2020, *Wholesale Electricity Market Rules (22 February 2020)*, clause 3.13.3C (online)

3. AEMO's ancillary services proposal

On 30 November 2019, AEMO submitted its proposal to the ERA for margin values and Cost_LR for 2020/21.

AEMO reserves Synergy's generation capacity to provide the spinning reserve ancillary service. AEMO's proposal must consider the margin that Synergy could reasonably have expected to earn on energy sales foregone due to the supply of spinning reserve and the loss in efficiency of Synergy's scheduled generators resulting from the provision of the spinning reserve service.

AEMO engaged Ernst & Young (EY) to assist calculating the spinning reserve margin values and cost of providing the load rejection reserve service. The ERA published AEMO's proposal and EY's supporting information on 13 December 2019.[13] [14] AEMO also provided results of several sensitivity analysis scenarios for spinning reserve margin values and load rejection reserve service cost estimates, in the EY report.[15]

AEMO contracts with generators able to provide system restart services. Restart costs are based on pricing from these contracts.

AEMO proposed the values for ancillary services in Table 1.

Table 1: AEMO's proposed values to apply in 2020/21

Service	Approved 2019/20	Proposed 2020/21
Margin Value peak (%)	17.32	39.65
Margin Value off-peak (%)	12.92	23.24
Load rejection reserve ($)	1,400,444	721,000
System restart ($)	2,899,148	3,277,661

Source: AEMO, Margin Values and Cost_LR proposals for the 2020/21 financial year

AEMO has improved the process and modelling for this proposal, when compared to those in previous years. AEMO has endeavoured to implement the ERA's recommendations from its last determination and has incorporated other modelling changes to capture material changes in the market. These have combined to make AEMO's modelling more complex.

13 AEMO, 2019, *Margin values and Cost_LR proposals for 2020/21*, (online)

14 AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version) and supporting spreadsheets*, (online)

15 AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version),* (online), P. 56

4. Market modelling

The modelling of spinning reserve margin values and load rejection reserve costs requires forecasting generator dispatch, balancing prices and spinning reserve requirements in 2020/21 through a simulation of the WEM. Such modelling inevitably requires a degree of simplification and it is impractical to perfectly reflect the market in a model.

AEMO's modelling seeks to identify the costs of delivering spinning reserve and load rejection reserve ancillary services that would be incurred in an efficient market given existing generation plant in the WEM. In doing so, it supports the WEM objective of minimising the cost of electricity supply across both energy and ancillary services markets. The model simulates future market outcomes and forecasts the spinning and load rejection reserve requirements and estimates the amount necessary to compensate Synergy for providing the services. These values also inform AEMO's spinning reserve contracts with other providers.

AEMO made material changes to the modelling this year. These changes were in response to the ERA's recommendations in the 2019 determination and to changes in the market as outlined below.

This section discusses aspects of the modelling shared by both spinning reserve margin values and load rejection reserve services. Stakeholder feedback on AEMO's modelling approach is included.

Matters more specific to the spinning reserve margin values, load rejection reserve service and system restart costs are discussed in their respective chapters.

4.1 ERA's past recommendations

The ERA has previously recommended improvements to the calculation of Synergy's opportunity cost of providing spinning reserve. AEMO has developed models consistent with these recommendations. The ERA's recommendations also influenced the calculation of load rejection reserve costs.

In its last determination (published March 2019), the ERA recommended that for all future reviews of ancillary services, AEMO should:[16]

- Ensure that all accompanying documentation (such as consultant reports) underlying its proposals contained a detailed discussion of the results, including reconciling modelled results with observed practice.
- Ensure that its consultants conducted sensitivity analyses with the modelling and included a detailed discussion of the results in the draft assumptions report.
- Rigorously test input assumptions for the model with market participants including using blank forms to collect modelling input data prior to conducting a back-casting analysis.
- Ensure that its consultants conducted back-casting analysis and used the results to validate the input assumptions.
- Ensure that its consultants included detailed discussion of results, and possible limitations of the modelling in the final assumptions report.

[16] ERA, 2019, *Ancillary service parameters: spinning reserve margin (for 2019/20) and load rejection reserve and system restart costs (for 2019/20 to 2021/22)*, (online), P. 12

- Submit all supporting information, including modelling output workbooks, together with its proposal, by 30 November each year.
- Ensure that a proper quality assurance process was conducted on the proposals and their supporting documentation, with supporting statements on how the quality assurance was conducted and any issues identified.

4.2 Modelling changes

There are technical changes underway or on trial in the WEM, and AEMO has incorporated these into its assumptions and modelling. The main changes are outlined below:

- Spinning reserve - Mid-2020, two new wind farms (Yandin and Warradarge) will connect on the same 330kV transmission line in the North Country. At times, this will become the single largest contingency for spinning reserve. AEMO could manage the contingency by constraining down the wind farms, which would increase balancing prices. Alternatively, AEMO could increase the spinning reserve requirement to cover the contingency. While a resolution to this problem is being investigated through the Market Advisory Committee and reform work, AEMO's modelling dispatched more spinning reserve to cover the larger contingency whenever it could be covered.
- Load rejection reserve - AEMO is testing a dynamic load rejection reserve requirement based on need in real time. This dynamic load rejection reserve trial aims to reduce the quantity, and therefore the cost, of load rejection reserve. The trial results so far have informed the modelling assumptions for 2020/21.
- Load following ancillary services (LFAS) - AEMO is changing how it models LFAS, which will affect the amount of spinning reserve and load rejection reserve provided by Synergy. Two new providers entered the LFAS market in 2019 and AEMO introduced a new LFAS requirement of 85MW from 5:30am to 7:30pm and 50MW at all other times. For 2020/21, AEMO modelled increased requirements of 116MW and 70MW respectively to allow for the expected increase in the variability of demand and intermittent generation.

The modelling also co-optimised spinning reserve and load rejection reserve within the same model. This was an important modelling refinement and better represents AEMO's actual practice.[17] In previous years, these services have been modelled separately and independently of one another.

The modelling changes influence how generators are dispatched in the model, which in turn influences the forecast quantity and cost of spinning reserve and load rejection reserve.

Other modelling changes are outlined in Appendix 1.

[17] In practice, AEMO will seek to find a scheduling solution that provides LFAS, spinning reserve and load rejection reserve. As circumstances change, AEMO will actively monitor changes in supply and demand and determine whether it must reschedule generators to maintain supply of all ancillary services. This can mean allowing the quantity of load rejection reserve to reduce due to scheduling decisions for other reasons if the amount required isn't needed. The modelling approach this year ensures that the modelled dispatch will also ensure ancillary services requirements are also met.

4.3 AEMO's modelling approach

AEMO undertook a four-stage modelling process: data collection, model revision, and back-casting followed by a thorough quality assurance review of the outcomes.

AEMO followed the ERA's suggestions to collect data from market participants for the modelling exercise. While most market participants provided information, Synergy did not provide fuel cost input assumptions.

EY revised the model so that it simultaneously modelled the least-cost solution to provide spinning reserve, load rejection reserve, and LFAS. EY also revised the model to incorporate several market changes occurring during the forecast period. These changes are outlined in Appendix 1.

AEMO and EY undertook a back-casting exercise to validate the model and refine Synergy's fuel cost input assumptions. The process resulted in very low Synergy fuel prices and low input fuel cost assumptions for several non-Synergy generators before the modelled dispatch schedules and market balancing prices reasonably aligned with the actual 2018/19 balancing market outcomes.[18] This is discussed in section 4.4.1.

Synergy's fuel price assumptions are a critical input to the model. The gas price identifies Synergy's costs to provide ancillary services and the market clearing price in the model. Sensitivity analyses were conducted on Synergy's gas price. Modelled balancing market prices are also sensitive to the quantity of low-cost generation in the market.

AEMO has substantially improved its quality assurance processes. This resulted in an iterative model development process identifying refinements to more closely reflect market outcomes and more credible dispatch solutions.[19]

4.3.1 Stakeholder comments

Perth Energy and Bluewaters Power were generally supportive of AEMO's modelling approach. Bluewaters Power noted that "the modelling and back casting exercise by EY had provided rigor around the model assumptions to ensure appropriate forecasting".[20] Follow-up discussions to clarify Perth Energy's submission confirmed that they had supported a $3.50/GJ 'supplier' gas price (excluding transport costs), whereas the $3.50/GJ assumption is a delivered price.

Synergy's submission noted that the balancing price outcomes from the modelling prior to any back-casting exercise were "materially higher than historical outcomes" and considered this was indicative of a flawed model.[21] Synergy also considered AEMO modelling and its derivation of $3.50/GJ gas to be flawed, but supported the margin values derived by the modelling.

---

18 AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version) and supporting spreadsheets*, (online)

19 For example, EY applied rules to prevent generators from decommitting for infeasibly short periods of time and operating below their minimum generation levels.

20 Bluewaters, 2020, *Response to issues paper – Margin Values and Cost_LR Ancillary Service parameters for the 2020/21 financial year*, (online) P.1

21 Synergy, 2020, response to *Spinning Reserve, Load Rejection Reserve and System Restart Costs: Margin Values and Cost_LR Ancillary Services Parameters for 2020/21 Issues Paper*, (online), P. 6

4.4 ERA consideration

The ERA acknowledges the challenges in a modelling exercise of this nature and AEMO's improvements to its modelling and quality assurance processes. The 2020/21 forecast period will be subject to substantial changes, still to be realised, for which no comparative time series data exists.[22] This made AEMO's modelling task more complex and limited the feasibility of year-on-year comparisons.

AEMO conducted a more rigorous quality assurance process than in previous years, resulting in a deeper review of the modelling outputs as they were produced and modelling interventions or refinements to ensure the dispatch results were reasonable. However, the ERA has concerns about the method used to derive fuel cost input assumptions through back-casting. The reasoning is explained below.

4.4.1 Modelling assumptions and back-casting

AEMO sought to accommodate the ERA's recommendation to collect up-to-date input assumptions using blank response forms but was only partially successful.[23] Synergy did not provide AEMO with its fuel costs. This meant that AEMO had to estimate Synergy's fuel costs; one of the primary model inputs.

Models simulate the real-world electricity market. Back-casting is a means of validating a model – even where an optimised model is modelling a non-optimised market. Back-casting is used to identify points of model divergence from observation and identify reasons for the difference. Such differences may result from simplifications inherent to a model's design, the crafting of its algorithms, or indicate material flaws in a model's structure. Back-casting enables modellers to determine the materiality of differences and 'tune' the model by adjusting the treatment of parameters within the model to more correctly resemble actual outcomes.

AEMO simultaneously sought to validate the model and identify primary input assumptions. Using a starting point from a media report, AEMO adjusted Synergy's and other generators' fuel prices through an iterative calibration process to arrive at modelled outcomes resembling real world market outcomes for the 2018/19 financial year.[24]

This process set Synergy's delivered gas cost to $3.50/GJ and reduced gas and coal prices provided by other major market generators by 40 per cent, compared to the values submitted or provided in previous years.[25] The process also set the load-independent variable operation and maintenance cost to zero for Cockburn, Kwinana GTs, Muja, and Collie generators.

All modelling scenarios and sensitivities set Synergy's non-energy-related variable operating and maintenance costs to zero and so it is difficult to estimate the materiality of this change. However, because fuel prices tend to dominate operating costs, reducing the non-variable operating and maintenance costs to zero is expected to have had a substantially smaller

---

22 These changes are outlined in appendix 1

23 Past practice had been to send workbooks pre-filled with the previous year's assumptions. The ERA was concerned that the generators were not reviewing and updating the major assumptions for their generators.

24 Mercer D., 2019, "Synergy Pushes for Bargain in Gorgon Gas Deal, In "The West Australian", online, 22 April, 2019

25 Gas fuel prices were reduced by 40% for NewGen Kwinana and Alinta Pinjarra generators. Coal fuel prices were reduced for Bluewaters Power and Synergy's coal-fired generators. AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version),* (online), P. 34

influence on the forecast balancing prices than the fuel cost input assumptions adjusted through back-casting.

4.4.1.1 Stakeholder comments

Synergy noted the iterations undertaken to calibrate the model but, given the lack of detail provided in AEMO and EY's documentation, Synergy was unable to determine the reasonableness of the modelling approach, particularly as:

> There are a multitude of combinations of cost parameters, operating parameters and/or other input assumptions that can lead to the same results.[26]

Synergy identified what it considered were deficiencies in the model and stated:

> These apparent deficiencies in the modelling stem primarily from inappropriate fuel price assumptions and removal of [load-independent] variable operating and maintenance costs which, despite a potential underestimation of balancing prices, will result in the undervaluation of Synergy's cost of providing the relevant services.[27]

While validating input assumptions through back-casting may be reasonable, the ERA considers that determining input assumptions is possibly not. EY acknowledged the limits of back-casting for this purpose in its final report, stating:

> This can lead to input cost assumptions that do not appear to match historical observations. To mitigate these limitations, the sensitivity analyses [discussed in section 4.4.3] … are offered to provide insights on the relative impact of changing the input cost assumptions.[28]

4.4.1.2 Conclusion

The ERA's recommendation that AEMO should undertake back-casting was intended to provide comfort to market participants that the model reasonably reflected an efficient market. Any differences between the model's output and real-world outcomes could be explained in terms of differences between the market and the model's design - for example, differences that might result from facility bidding in a model compared to portfolio bidding for Synergy's generators in the market.[29] Adjustments could be made to the model where appropriate.

Where differences could not be explained, an assessment could be made on the validity of input assumptions while also considering the inherent differences between real-world and simulated outcomes. For example, where a generator provided exceptionally low input costs, but was never dispatched, a modeller might discuss the assumption with its source.

Using back-casting to identify specific inputs, in this case fuel costs, is problematic. This pre-supposes that the model is already valid and that differences are predominantly due to incorrect input assumptions. Instead of validating the model through back-casting, there is a

---

26 Synergy, 2020, *Spinning Reserve, Load Rejection Reserve and System Restart Costs: Margin Values and Cost_LR Ancillary Services Parameters for 2020/21 Issues Paper submission*, (online), P. 6

27 Ibid, P. 1

28 AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version),* (online), P. 69

29 In the case of this modelling cycle, adjustments were made to the minimum generation of some coal generators to prevent them being decommitted for short durations. In practice, the output of Synergy's generators would likely be adjusted to accommodate the coal generator's minimum stable generation to prevent decommitment for short periods. This might have a relatively small effect on Synergy's costs, but this is not expected to be material in aggregate.

risk that market inefficiencies, model inaccuracy, or any exercise of market power, for example, are being quantified by changing the input fuel price assumptions.

The ERA has concerns about the validity of AEMO's base case. Consequently, the ERA has assessed the base case and the alternative fuel price scenarios against a notional, ideal scenario. This is discussed further in section 4.4.2 below.

4.4.2 An ideal modelling scenario

An ideal modelling scenario would use credible inputs, including fuel prices, and use a suitably validated model. It would use the best available information (provided by the market participants subject to validation) as inputs to the model.

Fuel is the largest input to a generator's short run marginal cost and therefore its costs to supply energy and ancillary services. Synergy's fuel price is particularly important due to the size of its generation portfolio, and its market significance. Also, the purpose of this exercise is to identify Synergy's reasonable and efficient ancillary services costs consistent with the market objectives. The fuel costs can be validated by comparing them with alternative information sources, such as publicly available data sources (spot market prices and gas prices published by the Department of Mines, Industry Regulation and Safety). Generation costs should also broadly align with generators' offers into the market.

Gas pricing in the model should be based on the market cost of gas and include the full gas transport cost. A market participant buying from the spot market may be assumed not to have pipeline capacity available and would need to contract transport. Participants selling gas would also seek to recover the transport component of the gas where they can. The alternative cost to obtain gas would therefore be the supplier gas price plus the total transport cost of around $1.35/GJ.[30]

The ERA has doubts about the credibility of the primary input assumptions to the base case of AEMO's proposal. Synergy did not support the modelling or the derived gas price of $3.50/GJ. EY noted the risks that its approach could yield results that were ultimately unrealistic and presented alternative fuel price sensitivities to assess the effects of different fuel prices on the outputs.[31]

Given the timeframe for the determination, it was not possible for the ERA to replicate, consult, and quality assure supplementary modelling of an ideal scenario. Nor has the ERA sought to estimate the current market cost of gas. Without a reliable forecast based on an ideal scenario, the ERA has evaluated the pricing scenarios presented in the proposal (base case and the four sensitivities) against a hypothetical ideal scenario. This evaluation was to assess the best fit among the options presented. The ERA has considered alternative views on the fuel price assumptions and Synergy's electricity price forecast. This includes considering the effect of fuel price and constraints on new wind farms.

4.4.3 The effect of alternative fuel prices

AEMO modelled two sensitivities for Synergy delivered gas prices of $5.25/GJ and $7.00/GJ to compare against the results for the base case that used a $3.50/GJ delivered gas price. Other parameters were kept the same in each case, including coal prices, and gas prices for other market participants' generators. The modelling results are shown in Table 2.

30 DBNGP (WA) Transmission Pty Limited Full Haul T1 reference tariff, 1 January 2020, ERA website (online)

31 AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version),* (online), P.69, 56

Table 2: Spinning reserve and load rejection reserve modelled results - base case and fuel price sensitivities - for 2020/21 financial year

	Base case $3.50/GJ Synergy gas	Sensitivity 1A $5.25/GJ Synergy gas	Sensitivity 1B $7.00/GJ Synergy gas
Margin value parameters (%)			
Spinning reserve margin peak	39.65	25.46	20.60
Spinning reserve margin off-peak	23.24	21.42	20.24
Modelled balancing market price ($/MWh)			
Average balancing price - peak	35.15	40.47	43.63
Average balancing price off-peak	31.16	37.36	40.87
Spinning reserve ($ million)			
Synergy's availability cost - peak	5.06	5.04	4.92
Synergy's availability cost - off-peak	2.42	3.35	3.80
Synergy's total availability cost	7.48	8.40	8.72
Load rejection reserve ($ million)			
Load rejection reserve availability cost – peak	0.175	0.274	0.430
Load rejection reserve availability cost – off-peak	0.546	0.893	1.349
Total annualised load rejection cost	0.721	1.167	1.779

Sources: AEMO's proposal for 2020/21 and Table 10 of Ernst & Young's Ancillary services parameter review 2019 final report, public version, 6 December 2019

4.4.3.1 Stakeholder comments

Synergy stated the $3.50/GJ gas price assumption failed to consider Synergy's obligation as the default provider of ancillary services. Synergy could not rely on there being enough gas available in the spot market and so it:

> Must enter into firm, take-or-pay long term gas supply arrangements (GSAs). The different conditions of demand and supply for gas mean that prices under long term GSAs cannot be expected to be, and in practice are not, the same as those in the spot market.[32]

Synergy also suggested that the combination of increased supply from Wheatstone and Gorgon gas fields and reduced demand for gas from the mining sector had contributed to low spot prices for gas. Synergy predicted stagnant or increasing gas prices in the future and so concluded:

32 Synergy, 2020, *Spinning Reserve, Load Rejection Reserve and System Restart Costs: Margin Values and Cost_LR Ancillary Services Parameters for 2020/21 Issues Paper submission*, (online), P. 3

> A gas price of $3.50/GJ is inappropriate, unsubstantiated and not supported by shifting microeconomic dynamics.[33]

4.4.3.2 Conclusion

There is publicly available information on gas prices to help inform the ERA's determination. The Department of Mines, Industry Regulation and Safety regularly publishes a weighted average domestic gas price.[34] This information is collected from the producers and reflects a weighted average contract value. The price does not include downstream markets such as the spot market (except for small volumes that may be sold by suppliers into these markets). The weighted average gas price from the suppliers has been trending downwards from $4.96/GJ in 2016/17 to $4.05/GJ in 2018/19.

A price of $3.50/GJ delivered (including transport) equates to a supplier gas price of around $2.15/GJ. This is substantially lower than the weighted average domestic gas supply price (excluding transport) for 2018/19 of $4.05/GJ, and the January 2020 market spot price of $2.43/GJ.[35,36]

A gas price of $5.25/GJ delivered equates to a supplier gas price of $3.90/GJ, relatively close to the weighted average supply price for 2018/19. This price is consistent with gas price and transport information provided to AEMO by the market participants for their generators in this review.

A gas price of $7.00/GJ delivered, equates to a supplier price of $5.65/GJ – well above the spot and weighted average domestic gas supply prices.

AEMO conducted two sensitivity analyses on constraining the new wind farms which influence the balancing price.[37] In the base case, the model would flag instances where it could not schedule sufficient spinning reserve to cover the larger contingency when driven by the wind farms' combined output.[38] In the first sensitivity case, Yandin and Warradarge wind farms' output was reduced by 20 per cent for all intervals. In the second sensitivity case, the combined output from Yandin and Warradarge wind farms was constrained to the largest output from a single generator in the prior interval.

Constraining the output of these wind farms increased the balancing price in peak and off-peak periods by one to two dollars per MWh.[39] These constraints also increased the margin values by up to five per cent for peak periods and two per cent in off-peak periods.

Badgingarra wind farm has often been constrained down by Western Power since commissioning and it is expected that the new North Country wind farms will also be constrained more than has been modelled. Western Power declined to provide guidance to AEMO on the extent to which the wind farms could be constrained. Also, these sensitivity cases used the same fuel price inputs for all coal and non-Synergy gas as the base case.

---

33 Synergy, 2020, *Spinning Reserve, Load Rejection Reserve and System Restart Costs: Margin Values and Cost_LR Ancillary Services Parameters for 2020/21 Issues Paper submission*, (online), P. 4

34 DMIRS, 2019, Major Commodities Resources File, (online), "Petroleum – Gas Prices" tab

35 This price is calculated by the Department of Mines, Industry Regulation and Safety from gas producer royalty returns to government. It is derived from the sum of domestic gas sales revenue collected by producers and divided by the domestic gas production.
Department of Mines, Industry Regulation and Safety (2019) 2018-19 Major Commodities Resources File, DMIRS, Perth, online, Petroleum – Gas Prices tab.

36 Gas Trading, Historical Prices and Volumes webpage, online, accessed 26 February 2019.

37 AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version),* (online), P.53-63

38 Ibid. P. 15

39 Ibid. P. 56

While it is expected the new wind farms will be constrained, perhaps materially, the effect this would have on the balancing price under a higher Synergy gas price scenario is unknown.

In making its determination on margin values and Cost_LR, the ERA seeks to ensure that Synergy is appropriately compensated for its cost of providing these ancillary services while meeting the WEM market objective of minimising long-term costs to consumers. Stakeholder feedback and publicly available gas price information does not support using a Synergy gas price of $3.50/GJ delivered for the modelling of spinning reserve and load rejection reserve costs. Therefore, the proposal based on a delivered Synergy gas price of $3.50/GJ delivered is not a sound basis on which the ERA can make its determination.

The ERA supports basing its determination on the sensitivity study results from the scenario where Synergy's delivered gas price was set at $5.25/GJ because this gas price is supported by publicly available information and is consistent with gas price information provided by other market participants.

4.4.4 Alternative balancing price forecasts

The spinning reserve costs are recovered from the balancing price via the margin values. The balancing price is multiplied by the quantity of spinning reserve required after deducting quantities of contracted services and LFAS raise capacity. Therefore, forecast balancing market outcomes are a relevant factor in determining which Synergy gas price assumption to choose.

The cost of gas affects the cost of generation, the availability cost of providing spinning reserve and load rejection reserve, and ultimately the balancing price. Given the margin values are sensitive to the same input assumptions that drive the forecast balancing price, the reasonableness of the input assumptions can also be informed by the model outputs - specifically the balancing price.

The low $3.50/GJ delivered Synergy gas price used by the model for AEMO's base case resulted in relatively low balancing prices ($35.15/MWh – peak period, and $31.16/MWh – off-peak). The spinning reserve margin values this produced are relatively high (39.65 and 23.24 per cent respectively) compared to current values.

4.4.4.1 Stakeholder comments

Synergy noted that the balancing price outcomes from the modelling prior to any back-casting exercise were "materially higher than historical outcomes" and considered this was indicative of a flawed model.[40] However, Synergy supported the margin values derived by the modelling for the base case.

4.4.4.2 Conclusion

The ERA is not confident that the forecast low balancing price results from the $3.50/GJ gas price scenario will eventuate in 2020/21. Input prices would need to be substantially lower than any market expectations or forecasts. The 500MW of new wind and solar farms expected to be in service for most of the year in 2020/21 would lower the modelled balancing prices in the

[40] Synergy, 2020, *Spinning Reserve, Load Rejection Reserve and System Restart Costs: Margin Values and Cost_LR Ancillary Services Parameters for 2020/21 Issues Paper submission*, (online), P. 6

base case when compared to recent market prices.[41] [42] However, the extent to which the farms will be constrained is not known.

Synergy prepares forecast electricity prices which are reflected in its standard product offerings. Synergy's forecast energy prices can be inferred from its standard product prices and are shown in Table 3.[43] The $35.15/MWh peak, and $31.16/MWh off-peak, balancing prices from AEMO's modelling are below Synergy's future price expectation. Synergy's peak forecast electricity price is around $46/MWh and off-peak $33/MWh.

Table 3: Synergy standard product prices for 2020/21 financial year compared to modelled base case values ($/MWh)

	Buy	Sell	Mid-point (inferred average price)*	Base case modelled values
Peak	42.34	49.81	*46.08*	35.15
Flat	37.59	44.22	*40.90*	
Off-peak (inferred off-peak price)*	*30.94*	*36.39*	*33.67*	31.16

Source: ERA analysis of Synergy standard product prices as of 26 February 2019.

** Inferred values are italicised*

The average balancing prices for 2018/19 were $49/MWh peak and $41/MWh off-peak and have been higher to date for 2019/20. This is because demand has been higher due to hot weather and Badgingarra wind farm has been constrained down more than anticipated to date. However, there are still another three months left in the financial year and so it is uncertain what the balancing price results will be for the whole of 2019/20.

Of the three gas price modelling outputs, the $7.00/GJ gas price most closely matches Synergy's price forecasts. However, as outlined in the previous section, the fuel price cannot be justified as a market cost for gas. Consequently, while $7.00/GJ may be closer, the ERA can only justify $5.25/GJ as a reasonable market cost for Synergy gas.

4.5 ERA conclusion

The ERA has reviewed AEMO's modelling approach and, except for deriving Synergy's gas price from back-casting, considers that it reflects the recommendations from the review for 2019/20. The ERA acknowledges the substantial improvement in AEMO's modelling and quality assurance processes in the 2020/21 proposal.

However, the ERA does not support AEMO's base case modelling scenario. The Synergy gas price underpinning the scenario does not appear to have a justifiable basis nor does the method for its derivation. It was impractical to replicate or amend the modelling after AEMO

41 AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version),* (online), Pp53-63

42 AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version),* (online), P. 56

43 The inferred values are calculated by using the mid-point between the buy and sell prices and for off-peak values by using the ratio of peak and off-peak values.

submitted its proposal. Therefore, the ERA has considered the fuel price sensitivities as the basis for setting the margin values and load rejection reserve costs.

The fuel price sensitivity using $5.25/GJ as a Synergy gas price input is the closest of the three cases to what the ERA considers a reasonable and justifiable market cost for gas that is supported by information from publicly available sources and the range of gas prices submitted by other market participants. The modelling yields results that are close to those forecast by Synergy to underpin its standard product prices (below during peak periods and above during off peak periods).

The following sections of this paper outline matters specific to providing spinning reserve, load rejection reserve and system restart services, and the ERA's determination of the relevant parameter values for them, in more detail.

5. Spinning reserve and load rejection reserve

To make its determination for spinning reserve and load rejection reserve parameters, the market rules require the ERA to consider AEMO's proposal, stakeholder views, and the WEM market objectives. The consideration of the market objectives is common to both spinning reserve and load rejection reserve. System restart is addressed separately in section 6.

The wholesale electricity market has five objectives. These are to:[44]

- 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 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 that 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.

Most of the market objectives are not directly relevant to the determination. Reliability and security objectives are met through the ancillary service quantities, standards and requirements that are established by other mechanisms. For example, quantities of spinning reserve and load rejection reserve are established through the annual ancillary services requirement report, which the ERA approves.

The margin values and the "L" component of Cost_LR market settlement parameters are primarily concerned with Synergy's remuneration for the ancillary services it provides. Setting an appropriate price for the services provided is important to support market objectives such as minimising the long-term costs to consumers and fostering competition. Managing end user demand and avoiding discrimination are not relevant to the determination.

Section 4 explored the economically efficient gas price – assumed to be the market price of gas. The $5.25/GJ delivered Synergy gas price scenario is closest to what the ERA considers is reasonable for the market price of gas, as explained in section 4.5. Basing the determination on this scenario avoids passing through inefficient costs to customers, which supports the market objective to minimise the long-term cost of electricity to consumers.

A lower modelled gas price would likely have the perverse effect of increasing the cost of spinning reserve in the market if the future balancing market prices were substantially above the modelled prices.

The gas price assumption selected as the basis for AEMO's load rejection reserve cost does not provide the lowest cost of load rejection reserve to the market. However, using the sensitivity selected provides an appropriate level of compensation to Synergy for providing load rejection reserve.

44 Rule Change Panel, 2020, *Wholesale Electricity Market Rules (22 February 2020)*, clause 1.2.1 (online)

5.1 Spinning reserve and margin values

Spinning reserve refers to generation capacity and interruptible load used to maintain power system frequency within a defined range if there is a sudden loss of supply or increase in demand.[45] This might occur when:

- a generator or network asset trips off or fails
- network demand suddenly rises due to a large load re-connecting.

The market rules require enough spinning reserve to be able to cover either the loss of 70 per cent of the largest output of any generator, or the expected maximum increase in demand over a period of 15 minutes, whichever is the greatest.[46]

There are three classes of spinning reserve that operate over different timeframes. However, AEMO is primarily concerned with generators capable of responding within six seconds. The system's electricity frequency declines when supply is lost unexpectedly. If this frequency decline is not quickly arrested by spinning reserve, customer load is shed by disconnecting selected suburbs to reduce demand until the supply and demand are brought back into balance. If this does not occur in time, generator protection settings may cause generators to systematically disconnect, which could lead to a system blackout.

The margin values are an administered mechanism to compensate Synergy as the default provider of spinning reserve. The availability payment amounts are calculated using:

- The clearing price in the balancing market.
- The quantity of spinning reserve provided by Synergy.
- A constant parameter, the margin peak value or margin off-peak value, depending on the trading interval.

AEMO uses modelling to forecast Synergy's availability cost, and to estimate the margin values through which the availability cost is to be recovered. AEMO's proposal must reflect:[47]

- The margin Synergy could reasonably have expected to earn on foregone energy sales due to providing spinning reserve.
- The consequential reduction in generator efficiency for generators providing spinning reserve.[48]

5.2 ERA determination of margin values

5.2.1 AEMO's proposed margin values

Table 4 summarises AEMO's proposed margin values for 2020/21.[49]

---

45 Interruptible load refers to customer loads that have contractual arrangements to be quickly turned off, without notice, when frequency drops. This capacity provides part of the required spinning reserve.

46 Rule Change Panel, 2020, *Wholesale Electricity Market Rules (22 February 2020)*, clause 3.10.2 (online)

47 Rule Change Panel, 2020, *Wholesale Electricity Market Rules (22 February 2020)*, clause 3.13.3A (online)

48 Generators have lower efficiency at lower output. Consequently, generators scheduled to operate at lower output in order to be able to increase their output for provide spinning reserve will suffer lower efficiency.

49 AEMO uses the modelled spinning reserve quantity in its settlement calculations but this is not determined or approved by the ERA. Refer to market rule 3.13.3A.

Table 4: Spinning reserve margin values and main variables used in their calculation, proposed for 2020/21 compared to those approved for 2019/20

Margin value parameters	2019/20 ERA approved*	2020/21 AEMO proposed
Margin peak (%)	17.32	39.65
Margin off-peak (%)	12.92	23.24
Modelled values		
Average annual peak spinning reserve requirement (MW)	235.4	251.66
Average annual off-peak spinning reserve requirement (MW)	236.4	240.24
System average marginal peak price ($/MWh)	56.48	35.15
System average marginal off-peak price ($/MWh)	46.08	31.16
Estimated Synergy peak availability cost ($m)	6.91	5.06
Estimated Synergy off-peak availability cost ($m)	3.43	2.42
Estimated Synergy total availability cost ($m)	10.34	7.48

Source: *Previous ancillary services parameter review, the ERA's 2019 issues paper and determination, and AEMO's proposal for 2020/21*

Note: **The ERA only determines the margin values for peak and off-peak periods.*

The total estimated availability cost has reduced to $7.48 million in 2020/21 from $10.34 million in 2019/20 (a reduction of 27 per cent). However, the proposed margin values have almost doubled compared to the values in 2019/20. Three main factors could be driving the increase in margin values and decrease in forecast spinning reserve total costs. These factors are changes in the:

- Demand for electricity, the generation mix and fuel price assumptions.
- Modelling of the scheduling of generators in the WEM. For example, increases in the overall quantity of spinning reserve required, including where greater quantities of load-following-raise is unable to provide a spinning reserve response.
- Market modelling in response to actual and anticipated market rule changes and new connections, as explained in Appendix 1.

Many of the market-driven changes to the modelling outlined in Appendix 1 came into effect during 2019/20 and some are scheduled to commence in 2020/21. It is unclear how these market-driven changes will affect real-life market dynamics. However, the model used the best available information at the time.

The availability cost is recouped from the product of the quantity of spinning reserve, balancing price and margin value. Although AEMO has forecast a reduction in the total cost of compensating Synergy for that spinning reserve, the balancing price is forecast to reduce even further. This means the margin value percentages must increase, with lower balancing prices, to ensure Synergy's availability cost is recompensed.

AEMO's base case spinning reserve quantity forecast for peak periods has increased by 7 per cent from 235.4 MW in 2019/20 to 251.7 MW in 2020/21 and for off-peak periods has increased by 1.6 per cent from 236.4 MW in 2019/20 to 240.2 MW in 2020/21.

The larger spinning reserve quantities are driven by four factors that were included in AEMO's modelling:

- Two new wind farms in the North Country (Yandin and Warradarge) connected to the same transmission line form a single contingency.
- Excluding used LFAS quantities from the spinning reserve requirement.
- Excluding LFAS capacity that is unable to provide a spinning reserve response.
- Changes to the allocation of spinning reserve costs.[50]

AEMO modelled the two new wind farms connecting to the North Country area of the electricity network: Yandin and Warradarge. The modelling assumed they would only be constrained when the model could not schedule enough spinning reserve to the contingency the wind farms caused. The modelling did not identify any intervals where the wind farms needed to be constrained for this reason, even though the combined output of those two wind farms comprised the largest contingency for around 21 per cent of the time in the base case.[51]

5.2.2 Stakeholder feedback

Alinta supported AEMO's decision to model the estimated contingency effects of the two new wind farms.[52] However, Perth Energy considered that the treatment of the future wind farm-related contingency was not consistent with the market rules.[53]

The ERA has considered Perth Energy's comments. The connection of two new wind farms on the same line could create a collective contingency that is larger than any contingency that could arise from the loss of the largest output of a generator.

Clause 3.10.2 of the market rules specifies the quantity of spinning reserve that AEMO should dispatch to manage its spinning reserve obligations.[54] This requirement can conflict with AEMO's obligation to ensure system security, when there is a larger contingency from the wind farms. When this situation arises in practice, AEMO will schedule additional spinning reserve if it is available or constrain the wind farms if not.

Energy Policy WA is working with AEMO to resolve the ancillary service requirements arising from the North Country contingency, as part of the energy market reforms.[55] The modelling assumed that the matter would be resolved to ensure system security in advance of the new wind farms connecting by October 2020.

Synergy did not support AEMO's ancillary services cost modelling. Synergy analysed its "costs generated from fuel consumption for gas-fired generators used for ancillary services" for the previous 12 months. After allowing for revenue from relevant market sources, Synergy

50 Described in Appendix 1 – Spinning reserve full runway cost allocation

51 AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version),* (online), P.15

52 Alinta, 2020, *Response to issues paper – Margin Values and Cost_LR Ancillary Service parameters for the 2020/21 financial year*, (online)

53 Perth Energy, 2020, *Response to Issues Paper: Margin Values and Cost_LR Ancillary Services parameters for 2020/21*, (online) P.1

54 Rule Change Panel, 2020, *Wholesale Electricity Market Rules (22 February 2020)*, clause 3.10.2 (online)

55 Market Advisory Committee, *11 February meeting minutes*, item 8(b) (online)

calculated that its remuneration should be around $29 million per year for providing spinning reserve and load rejection reserve, compared to $11.7 million approved by the ERA in the 2019 determination. However, Synergy provided no detail on how it derived the cost figure or whether the underlying cost definition was consistent with those of the ERA's determinations or the market rules.[56]

5.2.3 *Margin values for 2020/21*

After considering AEMO's proposal, stakeholder feedback and the WEM objectives, the ERA-determined margin values to apply in 2020/21 summarised in Table 5 are based on the $5.25/GJ Synergy gas price scenario sensitivity modelling.[57]

Table 5: Modelled spinning reserve quantities and ERA-determined margin values for 2020/21

	Margin value (%)	Spinning reserve quantity (MW)
Peak	25.46	252.03
Off-peak	21.42	240.66

5.3 Load rejection reserve

Load rejection reserve provides a rapid decrease in generation output when a large amount of load is lost, such as when a transmission line trips off because of a lightning strike, bushfire, or overloading. When this happens, the system frequency increases. The generators providing load rejection reserve automatically reduce output to maintain system frequency within the limits necessary for security of the system. Typically, these large load rejection events only happen a few times each year.

Synergy is the only active provider of load rejection reserve, and AEMO's proposal must cover the costs for providing the load rejection reserve service.[58]

AEMO sets the load rejection reserve requirement. The market rules require the standard to be adequate to keep frequency below 51 hertz for all credible load rejection events. The standard may be relaxed by up to 25 per cent where AEMO considers the probability of transmission faults to be low.[59]

AEMO is conducting a trial that aims to reduce the quantity of load rejection reserve required, and so reduce the cost for Synergy and the market. AEMO is reducing the pre-dispatch

56 Synergy, 2020, response to *Spinning Reserve, Load Rejection Reserve and System Restart Costs: Margin Values and Cost_LR Ancillary Services Parameters for 2020/21 Issues Paper*, (online), P. 6

57 AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version),* (online), Table 10, P.56

58 Rule Change Panel, 2020, *Wholesale Electricity Market Rules (22 February 2020)*, clause 3.13.3B(a) (online)

59 The nominal requirement is currently a maximum of 120 MW of load rejection reserve, which AEMO can relax down to 90 MW. In practice, the quantity of load rejection reserve needed is not fixed and varies with the size of contingency and with available load relief. Load relief refers to the way some loads, such as motors, increase their consumption in response to increase of system frequency. In the case of load rejection events, as system frequency increases so too will demand. Termed 'load relief' this reduces the amount generators need to reduce their output and the size of the load rejection reserve required. Load relief varies with system demand and can be around 30 MW for a frequency increase to 51 hertz. The load rejection reserve requirement is set through AEMO's ancillary services report which is approved by the ERA.

planned quantity to around 90 MW rather than the maximum 120 MW. Real-time dispatch decisions could reduce this further.

Some generators, including wind farms, have their protection settings set to reduce output when the frequency rises above a threshold such as 51 hertz, as set in their network access contracts. These generators will automatically reduce output or trip when the system frequency reaches the threshold, requiring no operator intervention. AEMO's trial also takes this wind farm capability into account in its real-time generator dispatch.

5.3.1 AEMO's proposed load rejection reserve value

AEMO proposed a new value for load rejection reserve for 2020/21 of $721,000. This is substantially lower than the value proposed by AEMO for the previous determination for this same year ($4.3 million) and the value approved by the ERA in its 2019 determination ($1.4 million).[60]

In the 2019 determination, the ERA did not accept AEMO's load rejection reserve proposal, as the ERA could not reconcile modelled outputs with AEMO's generator scheduling practice as reported in its 2018 Ancillary Service Report.[61] Since then, the ERA Secretariat and AEMO have worked together to better understand AEMO's practices and how these are incorporated in the modelling. AEMO has provided a detailed explanation of its load rejection reserve operational practice in Appendix F of the ancillary services parameter review final report.[62]

AEMO made substantial changes to the model to determine a dispatch outcome for both spinning reserve and load rejection reserve simultaneously. Previously, AEMO used separate models to determine spinning reserve and load rejection reserve, which could produce conflicting dispatch outcomes.

The calculation of the cost of load rejection reserve makes allowance for expected energy sales foregone when load rejection reserve events occur. It accounts only for the direct costs of providing the load rejection reserve.[63] Facilities are only compensated where they are dispatched to provide load rejection reserve out-of-merit. Such facilities are assumed to run out-of-merit for only as long as needed for load rejection reserve. The cost of load rejection reserve captures the start-up costs for generators dispatched out-of-merit to provide load rejection reserve.[64]

How AEMO schedules and reschedules plants is central to the actual cost of providing load rejection reserve. Most of the time, generation already in-merit provides enough load rejection reserve so that no re-dispatch is necessary. The output of Synergy's coal fired generators is turned down by AEMO during low demand periods to avoid decommitment costs. As the generators approach minimum output, they are unable to provide the reserve. Therefore, it is more likely that gas fired generators will need to be dispatched out of merit to maintain load rejection reserve.

---

60 The previous AEMO proposal and ERA determination covered each of three years (2019/20 to 2021/22) and proposed $4,343,500 for 2020/21. The new AEMO proposed value is only for 2020/21. Unless AEMO makes another submission for load rejection reserve costs to apply in 2021/22, the approved cost reverts to $1.4 million.

61 ERA, 2019, *Ancillary service parameters: spinning reserve margin (for 2019/20) and load rejection reserve and system restart costs (for 2019/20 to 2021/22)* – Determination, (online), P. 2.

62 AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version),* (online), P. 86

63 AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version),* (online), P. 13

64 AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version),* (online), P. 44

AEMO's modelling better accounts for the actual scheduling practice used in AEMO's load rejection reserve trial and more closely reflects the observed levels of load rejection reserve reported in AEMO's 2019 annual ancillary services report.[65]

The ERA sought stakeholder feedback on the load rejection reserve modelling.

5.3.2 Stakeholder comments on load rejection reserve modelling

The ERA received submissions on load rejection reserve from Bluewaters Power, Perth Energy and Synergy.

Bluewaters Power and Perth Energy generally supported AEMO's attempt to better match the modelling assumptions on load rejection reserve with actual practice.

Synergy disagreed that the forecast load rejection quantity at the time of Synergy's gate closure would be the same as the load rejection quantity procured, stating:

> Synergy interprets this as meaning the LRR requirement and thereby Synergy's compensation will be determined on the requirement at the time of Synergy's gate closure. However, the existing mechanism used by AEMO to advise the market of LRR requirements is not useful, not automated and is often sent prior to independent power producer (IPP) balancing gate closures as opposed to Synergy's balancing gate closure. The assumption that the methodology outlined in the EY Report will account for commitment costs incurred at Synergy's gate closure is therefore flawed.[66]

Synergy stated that AEMO's market load rejection requirements were often sent prior to independent power producers' gate closures but after Synergy's gate closure. Therefore, Synergy's facility commitment costs, to provide load rejection reserve and incurred at Synergy's gate closure, were not appropriately included in modelled outcomes.

AEMO acknowledged Synergy's concern and confirmed that dispatch changes were made after Synergy's gate closure.[67] These changes are understood to reduce the quantity of load rejection reserve required because AEMO makes allowance for the automated frequency response from two wind farms.[68] The modelled compensation paid to Synergy is based on AEMO's expectation of load rejection reserve required at Synergy's gate closure, which may be more than it actually needs to provide in the interval.

Synergy also questioned why no contracts had been let to procure load rejection reserve from other providers. Synergy suggested it might be because the administered payments had been set too low, contrary to market objectives to encourage competition and promote economic efficiency.[69]

In the issues paper, the ERA sought specific feedback from stakeholders on ways to further reduce the cost of load rejection reserve through greater provision of this service by wind and

---

65 AEMO, 2019, *Ancillary Services Report for the WEM 2019*, (online), P. 11-12

66 Synergy, 2020, *Spinning Reserve, Load Rejection Reserve and System Restart Costs: Margin Values and Cost_LR Ancillary Services Parameters for 2020/21 Issues Paper submission*, (online), P. 4

67 Section 1.2 of the EY report (first item of Table 1) and Appendix F respond to the subject:
AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version),* (online), P. 4, 86-92

68 AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version),* (online), P. 18, 19

69 Synergy, 2020, *Spinning Reserve, Load Rejection Reserve and System Restart Costs: Margin Values and Cost_LR Ancillary Services Parameters for 2020/21 Issues Paper submission*, (online), P. 4

solar farms. Perth Energy acknowledged that wind and solar farms would be able to provide load rejection reserve:

> Wind and solar farms can reduce their output quickly without adverse technical ramifications and it would be appropriate to consider making more use of them for the period until the new dispatch system is implemented. The paper suggests that this reserve would rarely be called upon. Also, it is likely that AEMO would be able to reconfigure the dispatch order relatively quickly so the imposition placed on wind and solar farms should not be high.[70]

5.3.3 Load rejection reserve costs for 2020/21

In the 2019 determination the ERA encouraged AEMO to:[71]

- Clarify its practice for the management of load rejection reserve including its over frequency risk evaluation method.
- Re-examine planning for and actual use of load rejection reserve.
- Re-examine the historical incidence of plant rescheduling.
- Review the modelling assumptions.
- Consider and account for the automatic contribution from inverter-connected generation such as solar photovoltaics that would trip or decrease output when over-frequency occurs, due to its over-frequency settings.

AEMO's modelling has sought to address the ERA's past recommendations and has:

- Integrated the optimisation of both spinning reserve and load rejection reserve in a single model to reflect the inherent relationship between these services.
- Sought to explain and reflect AEMO's actual dispatch practices where feasible, including its dynamic approach to calculating the load rejection reserve requirement.[72]

In response to the last recommendation in the 2019 determination above, AEMO stated:[73]

> AEMO has neither the means to quantify nor monitor the amount of aggregate PV output reduction in response to over-frequency events. This limits AEMO's ability to incorporate over-frequency responses from rooftop PV into the dynamic LRR requirements. This matter is addressed in more detail in section 3.8 of the report.[74]

The ERA has considered AEMO's modelling, its proposed load rejection reserve service value ($721,000), stakeholder comments and the market objectives.

70 Perth Energy, 2020, *Response to Issues Paper: Margin Values and Cost_LR Ancillary Services parameters for 2020/21*, (online) P. 4

71 ERA, 2019, *Ancillary service parameters: spinning reserve margin (for 2019/20) and load rejection reserve and system restart costs (for 2019/20 to 2021/22*) – Determination, (online), P. 22

72 AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version),* (online), *P.17 and Appendix F*

73 AEMO, 2019, *Margin values and Cost_LR proposals for 2020/21*, (online), P. 4

74 AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version),* (online), P. 21

5.3.3.1 Determination

The ERA determines that the load rejection reserve value is $1,167,000 for 2020/21, being the sum of the peak and off-peak load rejection availability costs from the modelling.[75]

5.3.3.2 Recommendations

Consistent with the ERA's recommendation in the last determination report, the ERA considers that AEMO could continue to explore additional means by which to maintain system security at the least cost. The issues paper explored the possibility for non-scheduled generators to provide load rejection reserve at low cost. The ERA raised the option to explore the contribution available from inverter-connected distributed generation such as rooftop PV towards over-frequency management.

The ERA acknowledges that AEMO does not have metered quantities of rooftop PV. However, publicly available data on monthly installations of rooftop PV by location, when coupled with AEMO's PV output estimates, is sufficient to warrant exploring the possible contribution photovoltaic generation could make to over-frequency management in the WEM. The subject is discussed further in Appendix 4.

The ERA will explore these matters further with AEMO through its review of AEMO's annual ancillary services requirement report.

---

75 AEMO, 2019, *Ancillary Services Review – Ernst and Young Final report (public version),* (online), *Table 10, P.56*

6. System restart service

System restart services, also termed black start, energise the electricity system following a complete or localised system black-out. Generators that can start without grid supply re-energise part of the transmission network that then allows other generators to start.[76]

Natural disasters such as bushfires, earthquakes and cyclones can damage infrastructure and isolate a network region or disable system restart facilities. Multiple services, in several regions, may be necessary in order to restore electricity supply if one provider is on an outage, and another is in an isolated region where repairs may take some time to reconnect to the main grid.[77] To mitigate the risk of common failure, facilities providing the service should not be in the same geographical or electrical area (sub-network) and should have the capability, and be in a location, where they can re-energise other generation to enable restart of the system.

AEMO requires at least three facilities to provide the system restart service and has divided the SWIS into three sub-network areas for system restart purposes. AEMO's restart contract costs are based on contracts with generators in each of the following areas:

- North Metropolitan
- South Metropolitan
- South Country.[78]

AEMO has contracts with Synergy for services in the North Metropolitan (Pinjar units 3 and 5) and South Country (Kemerton GT11 and GT12) areas, and with Perth Energy to service the South Metropolitan area.[79] The South Country contract runs until 23 October 2028 and is the dominant component of the total proposed system restart cost of $3,277,661 for 2020/21 (see section 6.1).

The North Metropolitan and South Metropolitan services contracts expire on 30 June 2021. AEMO has commenced work on procuring new services.[80] AEMO is engaging with service providers and working to encourage participation in the planned tender process by existing providers and new providers that are technically capable of providing the service. This could include other generators in service areas where black start capable generators already exist or could include generators that may be modified to be able to provide the service.

Generators providing system restart services are compensated through the R component of the Cost_LR parameter. System restart costs are borne by market customers based on their share of electricity consumption.[81]

---

76 Rule Change Panel, 2020, *Wholesale Electricity Market Rules (22 February 2020)*, clause 3.9.8 (online)

77 Western Power, 2014, *System Restart Services (System Restart Standard)*, Western Power, Perth, (online), P. 11-12

78 AEMO, 2018, *2018 Ancillary Services Report*, (online), P. 19

79 Ibid, P. 21

80 AEMO, 2019, *Request for expression of interest - System Restart Service, 20 December 2019* (online)

81 Rule Change Panel, 2020, *Wholesale Electricity Market Rules (22 February 2020)*, clause 9.9.1 (online)

When entering into an ancillary services contract, AEMO must:[82]

- Seek to minimise the cost of meeting its ancillary service requirements.
- Consider a competitive tender process unless it would not minimise the cost of ancillary services to the market.
- Report to the ERA the capacity, prices, and terms for calling on the contracted facility to provide the restart capacity.

The ERA reviews AEMO's proposed system restart costs against the market rule requirements, and only determines system restart costs consistent with the rules. However, contract costs can exceed the efficient costs of system restart. Although the ERA approves the efficient system restart costs, AEMO can recover the full contract cost through the shortfall mechanisms. This is a situation where the market rules appear inconsistent with the market objectives.

6.1 ERA determination of system restart costs

To make its determination, the ERA must consider AEMO’s proposal, stakeholder views, and the WEM market objectives. These are covered separately below.

6.1.1 AEMO’s proposed system restart value

AEMO proposed a new system restart cost of $3,277,661 for 2020/21, which is not materially different to AEMO’s previous proposal for that year of $3,293,000.

AEMO also advised:

> As two of the Ancillary Service Contracts for System Restart Facilities expire in June 2021 and are practically unable to be renegotiated for the 2020/21 Financial Year, AEMO has proposed the R component of the Cost_LR value for the 2020/21 Financial Year based on these contracts.

The new proposed value is based on the same existing service contracts and reflects the total contracted cost to AEMO, escalated by the Consumer Price Index (CPI), in accordance with contract terms. The small variance between their new proposed value and previous proposed value (for the same year 2020/21) is due to application of a more recent CPI forecast.

AEMO indicated that it planned to resubmit proposed costs for system restart services for 2021/22 to the ERA by 30 November 2020. These costs will likely be based on new system restart contract costs for the North and South Metropolitan areas, from the tender process.

6.1.2 Stakeholder comments on system restart

In the issues paper (section 3.3.3), the ERA described the challenges to system restart procurement, such as the technical requirements to be able to provide system restart, which limit the number of possible providers. The ERA asked stakeholders if they considered that the pool of possible suppliers could be expanded.[83]

---

82 Rule Change Panel, 2020, *Wholesale Electricity Market Rules (22 February 2020)*, clause 3.11.9(a), 3.11.9(b), and 3.11.10 (online)

83 ERA issues paper, *Spinning Reserve, Load Rejection Reserve and System Restart Costs: Margin Values and Cost_LR Ancillary Services parameters for 2020/21, December 2019* (online), P. 19

The ERA received submissions on the system restart service from Bluewaters Power and Perth Energy. Both generators noted the limitations of reducing system restart costs in the SWIS because only some facilities have the technical capability to provide the service. Perth Energy provided an example of this. A past assessment of its Kwinana Swift generator identified that even with 100 MW of available capacity it would be unlikely that this generator could start any other generators in either the North Metropolitan or South Country areas because of the capacity required to charge up transmission infrastructure and deliver energy.

Bluewaters Power supported the ERA's suggestion to broaden the pool of possible suppliers in the SWIS but commented that "the natural limitations of the SWIS will be a restriction" in achieving lower system restart service costs.[84]

Perth Energy commented further that:

> Existing System Restart Services generators have immense market power because of their location. For this reason a competitive process is unlikely to lead to any cost reductions. It should also be noted that since the contracts moved from Western Power to AEMO the costs which Western Power charge for testing, which it had previously absorbed, are now billed to black start generators.[85]

The comments received may help inform AEMO's procurement process and the ERA's determination of system restart costs for 2021/22, which will likely be based on new contracts for the North and South Metropolitan from July 2021.

6.1.3 WEM objectives

System restart services are an essential system measure to recover from major supply disruptions and are in the long-term interests of consumers. Competitive procurement is particularly challenging in the WEM because the system restart market is highly concentrated and further restricted by dividing the network into sub-regions.

Where competition cannot be relied upon to deliver efficient pricing, regulation may have a role. However, the ERA has no oversight over AEMO's procurement process or contracts. The ERA does approve the remuneration to market participants for restart services, but this is after the contracts have been let. The shortfall charge recovers the difference between the contracted sum and the amount approved by the ERA.[86] The shortfall charge means neither the contract principal nor the contracted party are exposed to the risk that the regulator might deem a contract inefficient. This potentially undermines the procurement process.

AEMO's current procurement approach meets the WEM objective of ensuring security and reliability of the system, but not the objective of minimising the long-term cost to consumers.

Generators able to provide the restart service are aware that AEMO's restart obligation is insensitive to the cost approved by the ERA because of the shortfall charge mechanism. Although the ERA may approve a lower system restart cost than AEMO proposes, the shortfall change ensures the generator receives the higher cost proposed by AEMO based on the system restart contract. This can increase the cost of the service that provides insurance to cover the possibility of very infrequent system blackouts.

---

[84] Bluewaters, 2020, *Response to issues paper – Margin Values and Cost_LR Ancillary Service parameters for the 2020/21 financial year*, (online) P. 2

[85] Perth Energy, 2020, *Response to Issues Paper: Margin Values and Cost_LR Ancillary Services parameters for 2020/21*, (online) P. 5

[86] Independent Market Operator, 2011, Final Rule Change Report: Cost_LR, Rule Change Panel, Perth, online, p. 4

Short of changing the oversight provisions in the market and requiring ERA approval prior to entering into a contract, there are still some procurement improvements AEMO could explore.

To increase the pool of supply in system restart services, AEMO could seek to increase the pool of system restart providers by specifying the service or required outcomes rather than a specific technical approach. It could also reduce the risk of unrelated costs being recovered through restart contracts by requiring an itemised breakdown of the tender costs to verify the components included. This would provide for a reasonable (commercial) return on the assets necessary to provide a restart service but limit the ability to earn a return on unrelated assets, costs, market risks, or other factors.

6.1.4 System restart costs for 2020/21

AEMO's approach in proposing the system restart value for 2020/21 has not changed from that in their previous proposal for the same year, submitted for the ERA determination in March 2019. The current determination is based on the same ERA reasoning as used in its 2019 determination.

For the current determination, the ERA accepts AEMO's proposed system restart contract costs for South Metropolitan sub-region and, based on available information, South Country sub-region. For the North Metropolitan contract where the pricing was previously found to be inconsistent with the market objectives, the ERA has not accepted AEMO's proposed value for this contract. Instead it has applied a revised forecast consumer price index to the previously approved value.

The ERA determines the system restart value to be $2,868,473 for 2020/21.

6.1.4.1 Recommendation

The ERA recognises the challenges to procuring system restart services efficiently given the constraints outlined in prior sections, including responses from stakeholders. However, there are opportunities to improve the processes used to source the system restart services.

AEMO has briefed the ERA on steps it is taking to improve the procurement process. The ERA recommends that AEMO continues to:

- Explore what would encourage providers to participate in a procurement process, noting that the lack of competition in the WEM to provide this service means that tender prices could well exceed the cost of providing the service.
- Brief the ERA on its proposed procurement strategy, including how it proposes to address shortcomings in its procurement process in advance of, and during, the tender process.

The ERA recommends that AEMO:

- Reviews and updates system restart documentation currently on AEMO's website,[87] including that prepared by Western Power System Management some years ago when System Management was part of Western Power. Ideally it should endeavour to ensure that the specified requirements are no more prescriptive than necessary and are 'outcomes' or 'performance' based where possible rather than specific technical requirements that may unnecessarily restrict how the service can be provided.

[87] AEMO ancillary service web page, System Restart Service (SRS), (online)

- Seeks pricing from service proponents based on the cost to provide the service and requires a detailed cost breakdown of the prices to allow verification of their reasonableness.
- Submits a revised system restart proposal, including detailed cost justification, to the ERA for review prior to entering into a contract with a service provider for system restart services, consistent with market rule 3.13.3C.
- In recognition of the timeframe within which the ERA must make its determination, provides all supporting documentation, including contracts, bids and their foundation, to the ERA with its proposal.

Appendix 1 Modelling changes

Market-driven changes

There are three main changes to the WEM that AEMO has captured in the modelling for spinning reserve and load rejection reserve for 2020/21.

The main changes are:

- Spinning reserve full runway cost allocation:
  - Blocks of spinning reserve costs were previously allocated to generators based on their output. Above certain thresholds, the share of spinning reserve liabilities increased substantially. Some generators avoided generating above the thresholds that would have triggered additional spinning reserve liabilities.
  - A revision to the market rules, that changes the cost allocation of spinning reserve, commenced on 1 September 2019.[88] This provides a progressive increase in the allocation of spinning reserve liabilities as a generator's output increases rather than allocating the liability in blocks.[89] This has changed generators' bidding behaviour with some generators now bidding higher quantities into the market with the more gradual exposure to spinning reserve liabilities.
- Different LFAS requirements over a 24-hour period:
  - Prior to 2019/20, AEMO identified that it needed 72 MW of LFAS to maintain the balance of supply and demand in real time. This assumption has been included in past modelling of spinning reserve and load rejection reserve proposals.
  - In June 2019, AEMO proposed changes that increased the LFAS requirement to 85 MW between 5:30 AM and 7:30 PM and decreased it to 50 MW at all other times. This was to respond to the increased volatility in supply and demand resulting from higher levels of intermittent generation connected to the network.[90]
  - In anticipation of needing more LFAS, AEMO has included a higher LFAS requirement of 116 MW in the daytime and 70 MW overnight in the modelling for its 2020/21 proposal.
  - Some generators, such as Synergy's gas turbines (excluding Cockburn), can provide both LFAS and spinning reserve. Therefore, a higher LFAS requirement could mean more generation capable of providing spinning reserve may already be dispatched and operating in the market and able to provide spinning reserve.[91]

---

88 RCP, 2019, *RC_2018_06 Commencement Notice*, (online)

89 RCP, 2019, *RC_2018_06 Final Rule Change Report*, (online), P. 5

90 AEMO, 2019, *Ancillary Services Report for the WEM*, (online), P. 16

91 This assumes that for a plant providing spinning reserve and LFAS, the MW have not been consumed already to provide the LFAS_UP service.

- Modelling the spinning reserve required to accommodate a single transmission node contingency from the planned connection of new generators on the North Country 330kV line:
  - During 2020, two wind farms (Yandin and Warradarge) are expected to connect to the same transmission line in the North Country area.[92] The possibility of a network outage on the transmission line coinciding with large outputs from the wind farms at times will create the single largest contingency in the WEM and set the spinning reserve quantity.
  - The modelling increases the spinning reserve requirement to meet the largest contingency, including that set by the North Country transmission line, if there is reserve available to provide the required spinning reserve. If there is insufficient reserve able to cover spinning reserve requirement, the model flags a shortfall. No shortfall events were observed in the modelling results.
  - These assumptions influence the quantity of spinning reserve required for 2020/21.
- Generator Interim Access (GIA) network constraints:
  - GIA enables the connection of new generators on a constrained basis. In previous ancillary service parameters modelling, no facilities connected under GIA were operational. However, new facilities have been connected (or are expected to be connected) within the period modelled.
  - AEMO requested guidance from Western Power on the expected level of curtailment for future GIA facilities. AEMO advised the ERA that Western Power had stated it could not provide such an assessment, in part because the constraint equations for those facilities have not yet been developed.
  - Recent market data from AEMO shows that the level of curtailment experienced by existing GIA connected facilities is not significant under 'system normal' conditions.[93]
  - As a result, a reduced capacity factor has not been applied to the GIA facilities and so this did not affect the modelling.

Modelling improvements

AEMO has made two main improvements to the modelling of spinning reserve and load rejection reserve costs, as outlined below:

- Concurrent cost minimisation for spinning reserve and load rejection reserve:
  - For the 2018 review, the modelling optimised the dispatch of spinning reserve and load rejection reserve separately in different modelling runs. The first modelling run optimised for spinning reserve. A second modelling run was conducted to generate a balancing merit order for those intervals from the first modelling run where insufficient load rejection reserve had been scheduled. This approach could have

[92] With respect to the transmission system, North Country generally refers to the area from Neerabup terminal (north of Perth), up to Geraldton.

[93] The margin values review is modelled under system normal conditions – with no transmission lines out of service. AEMO advises that GIA generators may be affected due to planned and unplanned network outages, however that has not been considered in the review.

resulted in rescheduling in the second modelling run that failed to provide adequate spinning reserve.

- The 2019 modelling identifies the least cost dispatch of generators to provide both spinning reserve and load rejection reserve. This modelling approach is more consistent with the WEM objectives.

- Modelling the ready reserve:

  - The market rules require Synergy to provide ready reserve, meaning that Synergy must reserve enough generation to replace 30 per cent of the largest output of any generator and that generation must be available in 15 minutes.[94] Should a generator fail, spinning reserve alone may not be adequate to return the system frequency to normal limits. AEMO may dispatch ready reserve generation to meet the shortfall.

  - AEMO did not include this reservation in previous modelling but has now included ready reserve in the modelling for spinning reserve and load rejection reserve for 2020/21. Withholding generation for ready reserve limits the generation choices available to the model to dispatch and consequently could affect scheduling decisions.

Details of the changes to the modelling are in EY's method and assumptions report and ancillary services parameter review 2019 final report (public version).[95, 96] AEMO conducted a consultation process on these changes as described in the method and assumptions report.

94 Rule Change Panel, 2020, *Wholesale Electricity Market Rules (22 February 2020)*, clause 3.18.11A (online)

95 Ernst and Young, 2019, *Ancillary Services Parameter Review 2019 Methodology and Assumptions Report, Public Version*, (online)

96 Ernst and Young, 2019, *Ancillary services parameter review 2019 final report (public version)*, (online)

Appendix 2 Summary of stakeholder public submissions

Content summary
Alinta Energy
Alinta Energy supported AEMO’s modelling approach that incorporated the expected changes in the market, including the effect of Yandin and Warradarge wind farms on the spinning reserve requirement.
Bluewaters Power
Bluewaters Power stated that the expected implementation of the security constrained economic dispatch engine in October 2022 would provide a market mechanism to facilities for recovering their costs. Until then the administered procurement mechanisms for ancillary services should ensure facilities recover their costs. This was important given the uptake of distributed energy resources in the system. Bluewaters Power supported AEMO’s back-casting approach because it provided “the rigor around the model assumptions to ensure appropriate forecasting”. There was also support for AEMO’s pricing of Synergy gas based on market cost rather than contract cost as has been validated by the back-casting approach. Bluewaters Power favoured AEMO’s testing of the model outcomes and considered the best way to assess the accuracy of the model was back-casting and sensitivity analysis. Bluewaters Power stated that the load rejection reserve modelling introduced achieved better alignment between the model and actual practices of AEMO, when compared to the modelling last year. For system restart, Bluewaters Power supported the review into the broader requirements and tender for North and South Metro system restart services and noted that the natural limitations of the SWIS would restrict improvements to price outcomes.
Perth Energy
Perth Energy noted AEMO’s increasing difficulty in maintaining system stability with increasing uptake of intermittent generation. Perth Energy cautioned the ERA that costs of customer supply interruptions, which could result from limiting the ancillary services requirement or improperly remunerating Synergy, could quickly overwhelm any short-term savings. Instead of seeking further reductions in ancillary service costs, Perth Energy commented that AEMO’s resources should be focussed on ensuring that the proposed security constrained dispatch engine can be implemented within the proposed timeframe. Perth Energy recommended two issues for the ERA to examine in its determination: • The inconsistency of AEMO’s estimated average wholesale price and Synergy’s Standard Product prices. • The inclusion of the North Country network contingency in the spinning reserve ancillary services requirement.

Perth Energy considered a $3.50/GJ Synergy gas price [excluding transport costs][97] was reasonable given DMIRS[98] data and historical price information. It also noted that, based on sensitivity analyses results, a higher gas price of $7.00/GJ contributed to a small change in Synergy's availability cost.

Specifically, for load rejection reserve and system restart costs, Perth Energy:

- Supported the future use of wind and solar farms to provide load rejection reserve.
- Stated that system restart services were costly to provide, and providers have market power due to there being limited providers that could provide the service. Therefore, there were limited opportunities to achieve significant contract price reductions.

Synergy

Overall, Synergy expressed concern that the parameters proposed by AEMO would under-renumerate Synergy for the spinning reserve and load rejection reserve services it provided. As such, the proposed values do not satisfy market objective (a) to promote an economically efficient market, nor the requirements under clause 3.13.3A of the market rules (which requires compensating Synergy for the margin it could reasonably have expected to earn on energy sales foregone due to the supply of spinning reserve and the resulting loss in efficiency of Synergy's scheduled generators).

Synergy claimed there were underlying issues in AEMO's modelling. This was evidenced by the need to drastically reduce coal and gas price assumptions for both Synergy and independent power producers, as well as removing load-independent variable operating and maintenance costs from specific Synergy plants, to obtain historically aligned modelling results.

Synergy did not support the use of a forecast $3.50/GJ gas price for Synergy in this modelling as this failed to consider Synergy's ancillary service obligations as the default provider. It stated firm gas supply arrangements under long-term gas supply agreements come at higher gas prices. It stated that a "gas price of $3.50/GJ is inappropriate, unsubstantiated and not supported by shifting microeconomic dynamics".

Synergy considered the load rejection reserve modelling, based on the requirement at Synergy gate closure was flawed. Instead, Synergy suggested that "a better solution would have been for AEMO to publish a dynamic forward forecast of LRR, which is reflective of the latest bidding information. This information should be published and therefore available to all market participants ahead of time such that Synergy and other market participants could reflect this information in their balancing submissions".

Despite its criticism of the modelling Synergy recommended the ERA accept AEMO's proposed margin values. It stated, "the proposed margin values are an improvement to the grossly inadequate parameters currently in force. Synergy therefore supports the adoption of the proposed margin values and recommends that the modelling issues raised in this submission are considered for the next review".

[97] Confirmed verbally by Perth Energy on 26 February 2020.

[98] WA Department of Mines, Industry Regulation and Safety

Appendix 3 List of Tables

Appendix 4 Renewable generation and load rejection reserve

Since 9 October 2016 it has been mandatory that new inverters installed comply with the revised Australian Standard AS/NZS 4777.2:2015.[99] It requires them to reduce their output for over-frequency linearly from their output at a system frequency of 50.25 hertz, to zero output at 51.5 hertz.[100] Over 500 MW of inverter capacity for rooftop PV systems has been installed in the SWIS since that date.[101]

The market rules require sufficient load rejection reserve service capacity to be scheduled to keep the system frequency below 51 hertz for all credible load rejection events, except that the quantity of reserve may be relaxed by up to 25 per cent where System Management considers the probability of transmission faults is low.[102]

Inverters complying with the above requirements will reduce their output by around 60 per cent if the system frequency increases from 50.25 hertz to 51 hertz.

This means that whenever there is sufficient output from the nominal 500 MW or more of rooftop PV inverters to cover the required amount of load rejection reserve (around 90MW), such as in sunny conditions, it may not be necessary to re-schedule any market generators to provide load rejection reserve. Rule changes are likely to be required to enable this source of load rejection reserve to be accounted for in market generator scheduling.

AEMO could review the likely contribution of rooftop PV system inverters automatically reducing their output when the system frequency rises, to lessen the need to reschedule market generators for load rejection reserve in dispatch planning and scheduling. A more dynamic approach to this, based on the expected output from these rooftop PV systems during each day, could reduce load rejection reserve requirements and costs further.

When the Energy Transformation reforms are implemented (scheduled for October 2022) load rejection reserve will be replaced by the contingency lower essential system service. This service will be managed by the co-optimised energy and essential system services dispatch engine.

The ERA suggests that the Energy Transformation Implementation Unit's reforms should account for the ability of wind farms, solar farms, and rooftop PV systems to automatically reduce their output in over-frequency events, and so provide load rejection response. This could reduce the need to re-schedule market generators to provide this service. Rule changes and technical standards changes to achieve this could be implemented as part of the reforms.

99 Western Power *Network Integration Guideline: Inverter Embedded Generation, July 2019,* P. 11 (online)

100 AS/NZS 4777.2:2015 – Grid Connection of energy systems via inverters Part 2: Inverter requirements. Western Power requires inverters to be set to have zero output at 51.5 hertz rather than the 52.0 hertz specified in the AS/NZS standard. See Western Power *Network Integration Guideline: Inverter Embedded Generation, July 2019,* P. 11 (online)

101 ERA analysis of Clean Energy Regulator installations by postcode data. (Online)

102 Rule Change Panel, 2020, *Wholesale Electricity Market Rules (22 February 2020)*, clause 3.10.4 (online)