Ancillary service parameters: spinning reserve margin (for 2019/20) and load rejection reserve and system restart costs (for 2019/20 to 2021/22)

Determination

31 March 2019

Economic Regulation Authority

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1. Overview

Ancillary services are used by the Australian Energy Market Operator (AEMO) to maintain the security of the electricity system. The costs of these services are borne by market participants. Costs for three of the four services, spinning reserve, load rejection reserve and system restart are calculated using an administered mechanism. The cost of the fourth service, load following that helps to balance supply and demand in real time, is determined through a market mechanism.

Spinning reserve and load rejection reserve are complementary but opposite ancillary services used to maintain system frequency when there is a contingency or fault in the electricity system. Spinning reserve provides a rapid increase in generation to compensate for the sudden loss of a large generator and 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.

AEMO proposes and the ERA must approve values for the three administered services: annually for spinning reserve and every three years for load rejection reserve and system restart services.

On 30 November 2018, AEMO proposed values for spinning reserve payments (margin peak and margin off-peak values) for 2019/20, and load rejection reserve and system restart payments (Cost_LR) for the next three financial years. The ERA published an issues paper on 24 January 2019 and invited stakeholders to comment on AEMO's proposed values. The ERA took stakeholders comments into account in making its determination. This determination should be read in conjunction with the ERA's issues paper, AEMO's proposed margin values and Cost_LR values and the consultation papers on margin values and load rejection reserve prepared for AEMO by Ernst and Young.

Spinning reserve ancillary service

AEMO uses two parameters for the calculation of payments to Synergy for the provision of the spinning reserve service: margin value peak and margin value off-peak. These parameters are applied to the balancing price and the spinning reserve quantity.

Last year, the ERA identified conceptual problems in the calculation of margin values and provided recommended improvements for AEMO to consider in its next proposal. AEMO engaged a new consultant, Ernst and Young (EY), to assist in estimating margin values for 2019/20 and EY developed a model generally consistent with the ERA's recommendations.

The ERA is concerned that the modelling may have overestimated the quantity of spinning reserve for 2019/20 and hence the cost because the modelling did not:

- Net off quantities of load following generation that can respond quickly enough (within six seconds) to substitute for spinning reserve.
- Recognise that some generators limit the quantity of capacity they bid into the balancing market to avoid increasing their liability to pay spinning reserve costs. As the spinning reserve requirement is based on a proportion of the largest generator operating at any one time, the model will have overestimated the output of some generators and also overestimated quantity of spinning reserve.

The modelling results EY provided were too limited a sample for the ERA to validate the outputs and the EY reports lacked explanatory content that made it difficult to identify errors.

Given these problems, the ERA assessed three options for determining margin values to apply in 2019/20: approve the values proposed by AEMO, extend the (substantially higher) margin values approved for 2018/19 or revert to the margin values at market start.

The margin values from market start are likely to underestimate Synergy's costs of providing spinning reserve. Given the problems identified in the modelling of margin values in 2018/19 and the substantial changes recommended the ERA does not support extending the approved margin values from 2018/19 for 2091/20. These values will overestimate Synergy's costs of providing spinning reserve. The ERA has approved the 2019/20 margin values proposed by AEMO but with recommendations on how the modelling and estimation approach can be improved.

Load rejection reserve

The Market Rules set the load rejection reserve requirement at 120 MW, but this can be adjusted down to 90 MW if the likelihood that a major load will be lost is low. AEMO's 2018 Ancillary Service Report identified that, in practice, it operated below the 120 MW threshold 14.9 per cent of the time and below the 90 MW threshold 6.5 per cent of the time. However, EY was instructed to model assuming a firm load rejection reserve requirement of 120 MW for all trading intervals. The modelled output does not align with the Market Rules nor AEMO's actual practise. Therefore, the modelling will have overestimated the cost of load rejection.

The ERA again assessed three options for determining load rejection reserve costs for 2019/20, 2020/21 and 2021/22: approve the values proposed by AEMO, extend the annual load rejection reserve cost approved for the previous three years (2016/17 to 2018/19) or revert to the default value ($0) for load rejection reserve at market start.

The ERA rejected the zero load rejection reserve costs as the modelling exercise did suggest that Synergy's plant would need to be rescheduled to ensure enough load rejection reserve was available and Synergy should be compensated for this. However, the values proposed by AEMO are likely to overestimate this cost. Therefore, the ERA has approved the cost of load rejection at $1.4 million per year ($4.2 million for the three-year period) and recommends AEMO reviews and resubmits revised proposals for 2020/21 and 2021/22.

System restart

In reviewing AEMO's proposed system restart cost, the ERA examined a sample of black start costs in markets in Europe, the US and Australia. This demonstrated the costs proposed by AEMO are among the most expensive in the sample.

The ERA recognises that the cost of providing system restart services in each of three network sub-areas, limits the number of generators in each area capable of providing the submission and so the lack of competition means that tender prices could well exceed the cost of providing the service. Even so the proposed costs of providing system restart in one of the network sub-areas (North Metropolitan) have increased. From the information provided it is unclear why costs have increased so substantially.

In determining system restart costs for 2019/20 to 2021/22, the ERA has rejected the proposed cost for system restart in the North Metropolitan area and instead has applied the CPI to the previous contract value for system restart in that sub-region. The ERA has also made recommendations regarding AEMO's procurement process.

In accordance with clauses 3.13.3A and 3.13.3B of the Wholesale Electricity Market Rules the Economic Regulation Authority determines that:

- The value of margin peak and margin-off peak parameters for the 2019/20 financial year are 17.32 per cent and 12.92 per cent respectively.
- The values of Cost_LR parameter (combined costs for load rejection and system restart) are $4,324,238 for the 2019/20 financial year, $4,299,148 for the 2020/21 financial year, and $4,361,377 for the 2021/22 financial year.

In its determination, the ERA considered the objectives of the Wholesale Electricity Market, AEMO's calculation and proposal, and stakeholders' comments in response to the ERA's issues paper published on 24 January 2019.

The ERA's determination is explained in more detail in the following report and should be read in conjunction with the documents listed above.

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.[1]
- Load rejection reserve: provides a rapid decrease in generation output where load is lost, such as when a transmission line trips. This service is required to maintain system frequency within acceptable limits.
- System restart: provides the capability of starting up in total system blackout conditions and is able to energise the power system to enable other generators to be started up.

The Australian Energy Market Operator (AEMO) undertakes a review of these ancillary services and submits proposed values to the Economic Regulation Authority.

The ERA is responsible for determining values for spinning reserve, load rejection reserve and system restart. These costs are then allocated to market participants according to the market rules.

To make its determination, the ERA undertakes public consultation and considers the Wholesale Electricity Market objectives,[2] and AEMO's proposal.[3]

This year, the timing of the review of these three ancillary services has coincided. The ERA is conducting its review and determination of spinning reserve, load rejection reserve and system restart simultaneously.

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

1 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.

2 Clause 1.2 of the market rules.

3 Clause 3.13.3A of the market rules.

3. AEMO ancillary service proposal

On 30 November 2018, AEMO submitted its proposal on ancillary services. This included setting:

- spinning reserve margin values for 2019/20
- load rejection reserve service costs for 2019/20, 2020/21 and 2021/22
- system restart service costs for 2019/20, 2020/21 and 2021/22.

AEMO engaged Ernst & Young (EY) to assist it to calculate the spinning reserve margin values and cost of providing the load rejection reserve services. AEMO's proposals and EY's public reports are available on the ERA website.[4,5] AEMO also provided the ERA with EY's confidential reports on the ancillary services.[6]

The ERA published an issues paper on 24 January 2019 and sought stakeholder feedback on the estimation of ancillary service parameters. The ERA received three submissions in response.

On 6 February 2019, AEMO updated some of the variables used to calculate spinning reserve margin values and system restart service values.

- Changes to spinning reserve margin values were mainly limited to changes in weighted average balancing prices, and did not warrant changes to the estimated spinning reserve margin values.
- The revision to the system restart costs was to correctly apply the Department of Treasury's forward estimates of the Consumer Price Index to system restart contract prices.

AEMO also provided results of several sensitivity analysis scenarios for spinning reserve margin values and load rejection reserve service cost estimations.

4 https://www.erawa.com.au/electricity/wholesale-electricity-market/ancillary-services-parameters/spinning-reserve-margin_peak-and-margin_off-peak

5 https://www.erawa.com.au/electricity/wholesale-electricity-market/ancillary-services-parameters/load-rejection-cost_lr

6 Confidential reports contain generator specific information relating to the input parameters, operation and performance that is not in the public domain.

4. Market modelling

The modelling of spinning reserve margin values and load rejection reserve service values requires a simulation of the Wholesale Electricity Market (WEM).

This section discusses aspects of the modelling shared by both spinning reserve margin values and load rejection reserve services.

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 Modelling method

Modelling will inevitably require a degree of simplification. The purpose is to provide a reasonable estimate of the cost of providing ancillary services consistent with the objectives and requirements of the market rules.

The payment mechanism for spinning reserve specified in the market rules is based on a linear estimation of the cost of spinning reserve and contains approximations. Appendix 1 provides a summary of the formula specified in the market rules and the general process for the calculation of spinning reserve margin values.

It is impractical to perfectly re-create the market in a model; it is also unnecessary to develop a highly complex and costly model when the outputs of such a model are eventually used as inputs to a linear approximation of the cost of spinning reserve service.

Nevertheless, there are elements of the modelling that could be improved without incurring substantial administration costs.

Expected reforms in the WEM, currently under development by the Public Utilities Office, will introduce co-optimised dispatch of energy and ancillary services. This will require the design of a competitive spinning reserve provision market that eliminates the need for the current administrative process.

4.2 Stakeholder comment

The ERA received submissions in response to the issues paper from AEMO, Synergy and Bluewaters. Submissions provided comment on:

- the modelling method and assumptions
- apparent discrepancies between modelling assumptions and AEMO’s practice
- apparent differences between modelling outputs and actual outcomes.

Synergy said the modelling should be dismissed because of the collective effect of what it described as shortcomings.[7]

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[7] Synergy, 2019, Submission to the ERA’s *Ancillary Service parameters: spinning reserve margin peak and margin-off peak (for 2019/20) and load rejection reserve and system restart (for 2019/20 to 2021/22) –* Issues paper, p.1, (online).

Synergy challenged the underlying modelling method, citing a hypothetical example where a generator is rescheduled out of merit.[8] In its example, Synergy noted that a generator with a bid price above the clearing price in the balancing market could displace a generator with a bid price below the clearing price, where the latter was incapable of providing ancillary services. Synergy argued that if such a situation was to occur under the 'portfolio umbrella', it would not be compensated.

Detailed stakeholder comments are addressed below in the ERA's consideration of modelling.

4.3 ERA consideration

In assessing AEMO's proposal and stakeholder comments, the ERA has given the modelling approach further consideration.

4.3.1 Competitive spinning reserve market

To ensure economically efficient market outcomes, AEMO dispatches facilities to meet demand in ascending supply cost order. This order is referred to as the balancing merit order in the Wholesale Electricity Market Rules. Quantities of generation bid and priced by individual facilities are used to form the balancing merit order. For Synergy, this is offered to the balancing merit order for its generation as a portfolio. Unlike other facilities that schedule their facilities, AEMO schedules Synergy's facilities individually based on guidelines provided by Synergy.

Synergy is the default provider of spinning reserve services in the WEM. AEMO reschedules Synergy's facilities to maintain the reliability of the system.

When dispatching facilities to meet demand, AEMO can only depart from the balancing merit order if it is necessary to maintain system security and reliability. AEMO can issue dispatch instructions to facilities to dispatch them out of the balancing merit order sequence.

Where a facility is dispatched outside the balancing merit order, either upwards or downwards, the market rules specify that the market generator is eligible to be paid compensation to cover the cost, or foregone revenue, of the required change in amount of electricity generated. These are known as constrained-on or constrained-off payments.

It is reasonable to exclude these constrained-on or constrained-off costs from the calculation of the spinning reserve payment, and it is not necessary to base the calculation of spinning reserve costs on arrangements in the market rules that cause economic inefficiency.

Under Synergy's hypothetical example, Synergy would not need to be compensated for such rescheduling. For example, similar adjustments are made in the dispatch of generators in the WEM every trading interval for ramp rate constraints. Generators incapable of moving the required quantity in an interval are pulled from the merit order and do not receive any compensation for being rescheduled out of merit order.[9] Portfolio bidding allows Synergy to average its output across all its operating plant, thereby avoiding some of its capacity being rescheduled out of merit order.

8 Ibid, p. 4.

9 A market participant notifies AEMO if they cannot fully comply with a dispatch instruction. The market rules (clause 6.16A) specify that the capacity constrained off quantity for a generator is zero, if the ERA notifies AEMO that the market participant has not adequately or appropriately complied with a dispatch instruction.

As the ERA explained in the determination of 2018/19 spinning reserve margin values, units that are inflexible and cannot provide spinning reserve may be rescheduled out of merit order and do not need any compensation.[10]

In its 2018/19 determination, the ERA's recommendation for the calculation of the cost of spinning reserve was based on an assessment of the outcomes of a competitive spinning reserve market. The administrative payment process of the spinning reserve service should emulate the outcomes of a competitive market for the service as closely as possible. This meets the objectives of the market by lowering the long-term cost of electricity supply to consumers. Payments to Synergy will be just sufficient to cover its marginal cost of providing spinning reserve service. The difference between the energy market price and the marginal cost of generating the energy determines the opportunity cost of providing spinning reserve.

In a competitive market, the system operator would seek to minimise (or co-optimise) the cost of energy and ancillary services. The market operator may not schedule a low energy supply cost generator that is not able to provide ancillary services, and instead dispatch a higher energy supply cost generator. The low-cost generator displaced out of the energy market merit order would not require compensation because it is not flexible enough to provide ancillary services, and if dispatched could increase the total cost of energy and ancillary services supplied in the system.

Although the WEM does not currently use an automated co-optimised energy and ancillary services dispatch engine, AEMO seeks to minimise the total supply cost of energy and ancillary services using its dispatch guidelines and processes to meet one of the objectives of the WEM: to minimise the cost of electricity supply to consumers.

4.3.2 Use of historical data

In its submissions to AEMO and the ERA, Synergy questioned the use of history to predict future outcomes.[11] Synergy's position was that the modelling should deploy a forward-looking unit commitment model.[12]

EY responded, noting that in practise commitment decisions are based on forecasts that were subject to error.[13] While Synergy considered a 'perfect foresight' model should be used, EY considered this to be a no more realistic assumption than the one used.

The ERA is satisfied with EY's justification for the modelling method, and that this aspect of the modelling provides a reasonable basis for approximation.

4.3.3 Co-optimisation

Synergy argued for full co-optimisation across all ancillary services: load following, spinning reserve and load rejection reserve. Failing to do so, Synergy claimed, would produce "infeasible and inaccurate dispatch outcomes".

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10 ERA, 2018, *Determination of the spinning reserve ancillary service margin peak and margin off-peak parameters for the 2018-19 financial year*, pp. 14–15 and p.27 (online)

11 Synergy, 2018, Submission to *AEMO's Ancillary services parameters - Draft assumption report, Public Version*, p.2 and Synergy, 2019, Submission to the ERA's *Ancillary Service parameters: spinning reserve margin peak and margin-off peak (for 2019/20) and load rejection reserve and system restart (for 2019/20 to 2021/22)* – Issues paper, p.2, (online).

12 Ibid.

13 EY, 2018, *Margin values review for 2019/20*, pp.10–11, (online).

However, no such optimisation exists in the WEM.

EY’s modelling process provides a reasonable approximation of the current process where AEMO schedules Synergy’s portfolio based on its dispatch guidelines and then considers rescheduling, for instance, when the dispatch guidelines provide insufficient load rejection reserves. Synergy provides a guideline to AEMO for dispatch of its facilities. Synergy’s dispatch guideline is developed to minimise Synergy’s cost of energy and ancillary services.

A co-optimised energy and ancillary service model would likely yield similar results to that adopted by EY.

The ERA is satisfied with EY’s modelling process, which approximates AEMO’s current dispatch process.

4.3.4 Modelling input assumptions

Synergy challenged the facility outage assumptions, noting that no outage information was provided beyond 2020 and that this materially reduced the load rejection reserve results.

In preparing its proposal, AEMO consulted with market participants on operational parameters. This consultation included holding a workshop with market participants.

Bluewaters considered it had been provided “a number of opportunities to provide feedback and input for the assumptions and calculation methods” and that the modelling method “was clearly detailed between the ERA and EY’s workings”.

Synergy was afforded the same opportunities throughout this process to provide its outage planning information to AEMO and its consultant.

The ERA recognises that assumptions about generation outages would have an effect on the load rejection reserve service results.

However, the ERA does not accept that the absence of Synergy’s input to the modeller decision is justification for rejecting the modelling outputs. While there may be legitimate reasons to believe the assumptions Synergy provided, AEMO should test the assumptions, particularly unexpected assumptions, with the source as part of its quality assurance process.

A recommendation for AEMO to submit revised proposals covering the load rejection reserve for 2020/21 and 2021/22 is discussed later in this determination paper. This will provide Synergy with the opportunity to submit appropriate assumptions at that time.

4.3.5 Discrepancy with actual outcomes

4.3.5.1 Off-peak modelling

Both Synergy and Bluewaters were critical of the off-peak modelling outputs.

Bluewaters considered the model overestimated the off-peak spinning reserve quantities by maximising the output from Collie and NewGen Power Kwinana, which was not consistent with the observed market behaviour of these two units. Bluewaters noted that the historical bidding of NewGen Power Kwinana and Collie during off-peak periods showed they were often dispatched below 200 MW to avoid higher spinning reserve liabilities.

Under the market rules, generators pay for the spinning reserve cost. The total cost of the spinning reserve service is allocated to generators based on a system of predetermined blocks, with the largest proportion of the cost assigned to the block comprising any generator with an output larger than 200 MW. It is possible that Collie and NewGen Power Kwinana consider the benefits of higher output against the cost of additional spinning reserve liabilities when preparing their price-quantity offers.

The model does not appear to correctly account for the effect of spinning reserve liabilities on generators' balancing offers.

The cost allocation mechanism for the spinning reserve is currently subject to a rule change proposal.[14] If implemented, this will change generators' liability to pay for spinning reserve. In turn this may alter generators' balancing offers and put some downward pressure on electricity prices.

For AEMO's next proposal, the ERA recommends that AEMO specifically consider the effect the allocation of spinning reserve liabilities has on bidding behaviour, prices and the spinning reserve requirement during low load periods.

4.3.5.2 Load following dispatch

Synergy argued that there were discrepancies between modelling assumptions for load following dispatch and AEMO's practice. Synergy commented that:

- Its capacity was preferentially used by AEMO for load following over non-Synergy facilities.[15]
- The limitations in AEMO's dispatch processes, specifically the inability to measure load following ancillary service usage, were well documented.[16,17]

AEMO's modelling assumptions for the dispatch of load following ancillary services are explained in the EY report.[18]

The ERA finds AEMO's modelling assumptions for the dispatch of load following ancillary services are reasonable and consistent with the requirements of the market rules.

4.3.5.3 Reflection of current balancing

Synergy was critical of EY's forecast not reflecting balancing prices in the current financial year. Synergy noted EY's model forecasts that peak-period balancing prices in 2019/20 would increase by more than 10 per cent over the currently observed price levels in 2018/19. Synergy argued that this contradicted recent decreasing balancing price trends most likely caused by increased penetration of small- and large-scale renewable generation.

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14 The Rule Change Panel, *Full Runway Allocation of Spinning Reserve Costs (RC_2018_06)*, (online).

15 Synergy, 2019, Submission to the ERA's *Ancillary Service parameters: spinning reserve margin peak and margin-off peak (for 2019/20) and load rejection reserve and system restart (for 2019/20 to 2021/22) –* Issues paper, p.2, (online).

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

17 AEMO, 2018, *Ancillary Services Report for the WEM 2018-19*, pp. 24–26, (online)

18 EY, 2018, *Margin values review for 2019/20*, p. 16 (online).

Synergy stated that:

> If the assumptions in the model were adopted and balancing prices in 2019/20 were merely to stay the same as in 2018/19 without further decline, Synergy would under-recover its availability costs by around $1.2 million.

There appears to have been substantial changes in the load profile in 2018/19 that are not reflected in the modelling assumptions.

- Synergy's peak price forecasts for standard products produce peak results slightly lower than EY's forecasts ($53.5/MWh for standard products against $56.50/MWh from EY's model). Standard product prices do not necessarily represent average prices in the future and may contain some risk premium.
- However, the estimated off-peak results show a material discrepancy – $35.30/MWh from standard products against $46/MWh from EY's model.

Generally, an overestimation of balancing prices results in overestimation of spinning reserve availability costs. EY's balancing price forecasts appear to be high and this can lead to overestimation of Synergy's availability costs.

It is not clear how Synergy estimated it would under-recover its availability cost. If balancing prices in the 2019/20 financial year are similar to the observed prices in 2018/19, Synergy is likely to have a lower availability cost than that estimated by EY.

The ERA considers that AEMO used the best available information for the modelling. The ERA recommends that AEMO reviews recent changes to the load and generation profile in future proposals.

4.4 ERA position on modelling approach

The ERA's review process has previously identified material errors and conceptual shortcomings in AEMO's approach to estimating ancillary service parameters.

AEMO adopted some of the ERA's recommendations in the determination of 2018/19 spinning reserve margin values, specifically those dealing with the substance of the modelling.

AEMO did not adopt all the recommended process improvements. Quality assurance needs a stronger focus from AEMO. Specifically, AEMO did not:

- Materially change its process for collecting model inputs.
- Review the model outputs prior to submission.
- Conduct sensitivity analysis prior to modelling the market.
- Ensure its proposal and accompanying reports provided sufficient explanation of the results to justify the reasonableness of the proposed values.

While AEMO submitted its proposal on time, submission of the supporting information was late and too limited to allow a sufficient quality assurance process by the ERA. For example, only partial modelling results were provided in late January 2019 and sensitivity analysis was not provided until February 2019.

AEMO must execute its responsibilities to the market with prudence, mindful that it acts as an agent for market participants who bear the financial consequences of the modelling, and thus deserve a full account, explanation and justification of the results.

The ERA recommends that for all future reviews of ancillary services AEMO:

- Ensures all accompanying documentation (such as consultants' reports) relating to its proposals contain a detailed discussion of the results including reconciling modelled results with observed practice.
- Ensures its consultants conduct sensitivity analyses prior to conducting the modelling exercise proper and include a detailed discussion of the results in the draft assumptions report.
- Rigorously tests input assumptions for the model with market participants including using blank forms to collect modelling input data prior to conducting a back-casting exercise.
- Ensures its consultants conduct back-casting analysis in every process and use the results to validate the input assumptions.
- Ensures its consultants include detailed discussion of results, and possible limitations of the modelling in the final assumptions report.
- Submits all supporting information, including modelling output workbooks, together with its proposal, by 30 November.
- Ensures a proper quality assurance process has been conducted on the proposals and their supporting documentation with supporting statements on how the quality assurance was conducted and any issues identified.

5. Spinning reserve margin value

5.1 Background

The spinning reserve ancillary service 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.[19]

Synergy is the default provider of ancillary services, including spinning reserve, under the market rules.[20]

Payments to Synergy for providing a spinning reserve service are based on the calculation method specified in the market rules.[21] Payment amounts are determined with the use of:

- The clearing price in the balancing market.
- The quantity of spinning reserve provided by Synergy.
- A constant parameter margin peak or margin off-peak[22] depending on the trading interval.

New margin values are determined for each financial year. This determination focuses on the spinning reserve margin values. The other spinning reserve parameters are set by AEMO.

The market rules require AEMO to calculate and submit proposed spinning reserve margin values to the ERA by 30 November of the prior year.[23]

The ERA must determine, by 31 March, the spinning reserve margin values that are to apply in the upcoming financial year.

When proposing the spinning reserve margin values, the market rules require AEMO to take account of:

- The margin Synergy could reasonably have been expected to earn on energy sales forgone due to the supply of the spinning reserve service.
- The loss in efficiency of Synergy's scheduled generators that AEMO has scheduled (or caused to be scheduled) to provide the spinning reserve service, that could be reasonably expected due to the scheduling of those reserves.[24]

5.2 AEMO proposal

Table 1 summarises AEMO's proposed spinning reserve margin values for 2019/20.

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19 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.

20 Clause 3.11.7A of the market rules.

21 Clause 9.9.2(f) of the market rules.

22 A peak trading interval occurs between 8:00am and 10:00pm. An off-peak trading interval occurs between 10:00pm and 8:00am.

23 Clause 3.13.3A (a) of the market rules.

24 Clauses 3.13.3A (i) and 3.13.3A (ii) of the market rules.

Table 1. Spinning reserve margin values and main variables used in their calculation, proposed by AEMO for the 2019/20 compared to those for 2018/19

Reporting metric	Unit	Determined for 2018/19	AEMO's proposed values (30 November 2018)	AEMO's revised values (6 February 2019)
Weighted average balancing price, peak trading intervals	$/MWh	-	59.23	**56.57**
Weighted average balancing price, off-peak trading intervals	$/MWh	-	47.04	**46.19**
Arithmetic average balancing price, peak trading intervals	$/MWh	54.44	56.48	56.48
Arithmetic average balancing price, off-peak trading intervals	$/MWh	39.52	46.08	46.08
Average annualised availability cost, peak trading intervals	$m	7.97	6.91	6.91
Average annualised availability cost, off-peak trading intervals	$m	5.09	3.43	3.43
SR_Capacity_Peak	MW	224.10	235.40	235.40
SR_Capacity_Off-Peak	MW	189.00	236.40	236.40
Margin_Peak	%	25.00	17.32	17.32
Margin_Off-Peak	%	50.00	12.92	12.92

The spinning reserve margin values proposed for 2019/20 have decreased substantially when compared to 2018/19. The proposed levels are close to those set at the commencement of the market.[25] EY's forecast of Synergy's opportunity cost of providing spinning reserve over the next financial year is approximately 21 per cent lower than that estimated in 2018/19.

The ERA's issues paper provided a discussion of the possible reasons for the decrease in the spinning reserve availability cost. Three main factors could be driving the decrease in the availability cost:

- Changes in the electricity system, including demand, generation mix and fuel price.
- Changes in the model used to simulate the dispatch of generators in the WEM.
- Changes in the method for the calculation of Synergy's availability cost.

Although changes in system conditions such as demand, generation mix and fuel price can result in changes to spinning reserve margin values, enhancements to the method for calculating the opportunity cost of providing spinning reserve appear to have materially reduced the estimate of availability cost.

As part of the determination of spinning reserve margin values for 2018/19, the ERA provided recommendations for enhancing the calculation of spinning reserve margin values. A summary of those recommendations is provided in Appendix 1.

25 As per clause 3.13.3A of the market rules at the commencement of the WEM the margin peak parameter was 15 per cent and the margin off-peak parameter was 12 per cent.

For the review of 2019/20 spinning reserve margin values, AEMO considered the ERA's previous recommendations and EY adopted the following recommendations.

- EY used the ERA's proposed concept for the calculation of the opportunity cost of providing the spinning reserve service.
- EY estimated the spinning reserve margin values based on regression analysis.
- EY published a report, and held a workshop for stakeholders, to explain the details of the model used and present the results of back-casting analyses.

5.3 Stakeholder comment

Most of the stakeholder feedback on the spinning reserve margin addressed the modelling more generally. This was outlined in section 4.2.

Bluewaters argued that load following ancillary services should only be excluded from the estimation of spinning reserve requirements where there was a technical reason for doing so.[26]

5.4 ERA consideration

The ERA has considered AEMO's proposed spinning reserve margin values and stakeholder comments.

The ERA has reviewed EY's modelling approach and considers that it reflects the recommendations from the 2018/19 review.

Overall spinning reserve costs are expected to reduce in 2019/20:

- The substantial decrease in the spinning reserve margin off-peak value, from 50.00 per cent for 2018/19 to 12.92 per cent for 2019/20, is only partially offset by the higher off-peak quantity of spinning reserve estimated by EY. [27]
- Similarly, the decrease in the spinning reserve margin peak value, from 25.00 per cent for 2018/19 to 17.32 per cent for 2019/20, is only partially offset by the higher peak quantity of spinning reserve estimated by EY.

The market rules imply an equivalence between the load following and spinning reserve services. The system operator can use the capacity reserved for load following to cover sudden drops in the supply of electricity due to generator or network outages. Effectively, if load following can be provided quickly enough, within six seconds, it can substitute spinning reserve.

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[26] Bluewaters Power, 2019, Submission to the ERA's *Ancillary Service parameters: spinning reserve margin peak and margin-off peak (for 2019/20) and load rejection reserve and system restart (for 2019/20 to 2021/22)* – Issues paper, p2, (online).

[27] Based on average spinning reserve quantity, average off-peak balancing price, and margin values estimated by EY this year and those estimated last year, the cost of spinning reserve service for a typical off-peak interval (with average balancing price and average spinning reserve requirement) has decreased by approximately 62 per cent.

However, when estimating spinning reserve margin values, AEMO excluded part of NewGen Power Kwinana's load following capacity that could be used for spinning reserve. AEMO advised that it was excluded because AEMO may only purchase spinning reserve from third parties through a contract, pursuant to market rule 3.11.8. AEMO stated that procuring by an ancillary service contract would ensure a facility was fully configured to meet all the technical requirements for the provision of the service. It also obliged the rule participant to meet any ongoing operating and commissioning requirements. In follow up correspondence to the ERA, AEMO suggested that without a specific contract a load following service provider may not be obliged to provide capacity for spinning reserve, even if it could technically provide the service.[28]

Market rule 3.11.8 outlines the basis for entering into contracts for spinning reserve with market participants other than Synergy. AEMO can enter into ancillary service contracts for spinning reserve with a market participant other than Synergy if AEMO considers that Synergy's capacity is not sufficient to cover the service requirements or those contracts provide a less expensive alternative to the provision of spinning reserve than Synergy.

Market rule 9.9.2(f) implicitly recognises the common relationship between load following and spinning reserve, and that capacity reserved for load following would be dispatched in response to a contingency event.

If technical requirements and obligations for the provision of load following services for a facility are sufficient for the provision of a spinning reserve service, no additional contractual arrangements are necessary for the facility to be eligible for the provision of spinning reserve. AEMO should only exclude load following capacity from counting towards contingency services where there is a technical justification for doing so. It should count all reserved capacity for load following capable of responding to contingencies in its modelling. This includes the portion of output capable of responding to contingency events.

For example, if 30 MW of load following was approved, but only 5 MW was found to be capable of responding within six seconds, as set by the spinning reserve requirements, then 5 MW should be counted towards offsetting the spinning reserve quantity.

The market rules implicitly assume that both load following and spinning reserve capacity would be deployed to manage frequency during a contingency event. If there are system security justifications for this not being the case, AEMO should pursue revision to the market rules to exclude all load following capacity from the calculation of spinning reserve requirement.

As new market participants join the load following ancillary service market, Synergy's load following output approved through the market will be reduced. Failing to account for the capacity reserved for load following services, available to manage contingencies, will result in an excessive quantity of spinning reserve being procured.

The ERA recommends that AEMO provide clarity on the technical reasons to exclude load following capacity from counting towards available spinning reserve. AEMO should also ensure the affected market participants are aware of the reasoning and are provided the opportunity to challenge it in the assumptions testing. If AEMO decides some load following capacity is not meeting the technical requirements and obligations for the provision of spinning reserve, it should provide clear information to the market on the reasons for such a decision.

[28] Email to the ERA from AEMO, 15 March 2019.

5.5 ERA determination

AEMO's proposal may have overestimated the quantity of spinning reserve required for two reasons. Firstly, it excluded quantities of load following that could substitute for spinning reserve. Secondly, generators bid quantities of capacity below 200 MW to avoid increasing their spinning reserve liability. The model does not appear to correctly account for this and overestimates generators' outputs. As the spinning reserve requirement is based on a proportion of the largest generator operating at any one time, the model will overestimate the quantity of spinning reserve required in the market.

Options available to the ERA for the spinning reserve margin are to:

- approve the spinning reserve values as proposed
- continue with the previous values
- default to values provided at market start.

Continuing with the existing values for spinning reserve margin, as suggested by Synergy, is not appropriate:

- The modelling foundation and approach were extensively reviewed for the 2018/19 process and the ERA raised concern about the results from 2018/19.
- The current concerns with the spinning reserve margin values modelling are not sufficient to warrant extending the duration of the 2018/19 determination.
- Results of sensitivity analyses conducted by EY showed that margin values were generally robust to changes in many inputs to the model. Spinning reserve margin peak values varied between 9 and 18 per cent in the six sensitivity analyses scenarios tested, significantly less than that determined last year (25 per cent). Similarly, spinning reserve margin off-peak values varied between 5 and 17 per cent, substantially less than that determined last year (50 per cent).

The default spinning reserve margin values set at the commencement of the market are below the proposed values for 2019/20, but not substantially so (2.4 per cent for peak and less than one per cent for off-peak).

The matters outlined in the issues paper[29] and this determination are incremental improvements compared to earlier modelling approaches. It is hoped that future processes will address:

- How the allocation of spinning reserve affects the bidding behaviour of generators such that the modelling outputs reflect behavioural expectations in the WEM.
- Detailed and proper explanation of the model drivers and model outcomes that reflect credible results.
- Recent changes to system load profiles that were not forecast or anticipated at the time the assumptions were set.

29 ERA, 2019, *Ancillary service parameters: spinning reserve margin values (2019/20) and load rejection reserve and system restart (2019/20 to 2021/22) – Issues paper* (online)

In accordance with clauses 3.13.3A and 3.13.3B of the market rules, the ERA determines that the value of:

- Spinning reserve margin peak for 2019/20 is 17.32 per cent.
- Spinning reserve margin off peak for 2019/20 is 12.92 per cent.

Under the market rules, the ERA is not responsible for determining the cost of spinning reserve peak and off-peak capacity. The ERA recommends that AEMO reviews the spinning reserve requirement during off-peak periods, as this appears to overestimate spinning reserve costs.

6. Load rejection reserve service

6.1 Background

Load rejection reserve services are provided by generators that are instructed to decrease their output quickly where load is lost, such as when a transmission line trips. This service is required to maintain system frequency within acceptable limits.

Currently, Synergy is the only provider of load rejection reserve.

Load rejection reserve service costs are allocated based on the consumption of each market participant.

Clause 3.13.3B of the market rules establishes the requirements for the ERA's determination of the values for load rejection reserve:

- AEMO must submit a proposal for the values by the 30 November prior to the start of the review period.
- The ERA must undertake a public consultation process in approving the values, which must include an issues paper and invitation for public submissions.
- By 31 March of the year in which the review period commences, the ERA must determine the values for the parameter for the review period.

6.2 AEMO proposal

Table 2 details AEMO's proposed load rejection service values for 2019/20 to 2021/22. Historic approved load rejection reserve service values are provided for the previous three years.

Table 2. AEMO's load rejection reserve service values

Year	Approved value ($'000)	Proposed value ($'000)
2016/17	$1,400	-
2017/18	$1,400	-
2018/19	$1,400	-
2019/20	-	$4,738.2
2020/21	-	$4,343.5
2021/22	-	$1,086.6

The proposed load rejection reserve costs are estimates from EY's modelling.

The change between the historical and proposed load rejection reserve service values is mainly due to a fundamental change in the approach to modelling the load rejection reserve service cost.

6.3 Stakeholder comment

Most of the stakeholder feedback on the load rejection reserve service addressed the modelling more generally. This was outlined in section 4.2.

AEMO made some comments supporting its approach to modelling the rescheduling cost for the provision of load rejection reserve. These are discussed in the following sections.

6.4 ERA consideration

The ERA has considered AEMO's proposed load rejection reserve service values and stakeholder comments.

A generator that provides a load rejection reserve service incurs no cost for the provision of the service if it is dispatched in the balancing market in merit and is able to rapidly reduce output.

EY's initial assumption was that the availability cost of load rejection reserve was negligible, and where generators were constrained on to provide load rejection reserve, existing constrained payment mechanisms would compensate.

While a generator may incur no cost in being available to turn down, it must be in merit in the balancing market to do so. There are likely to be occasions where the scheduling of Synergy's facilities according to Synergy's dispatch guidelines provided to AEMO will not provide sufficient load rejection reserve. Different Synergy plant must be scheduled out-of-merit to cover the service where the risk is not low enough to relax the load rejection reserve requirement.

The market rules provide constraint payments for individual generators dispatched outside the balancing merit order. Synergy bids as a portfolio and rescheduling facilities within the portfolio will not generally trigger constrained-on or -off compensation. This point was raised by Synergy in consultation with AEMO on the draft assumptions report.[30] An out-of-merit Synergy generator scheduled-on to provide load rejection reserve will have a marginal cost above the balancing price. A load rejection reserve payment exists to compensate Synergy should this occur.

EY developed a model to estimate Synergy's cost of providing the load rejection reserve by identifying intervals where sufficient load rejection reserve was not available to meet the upper bound of the load rejection reserve requirement of 120 MW. A secondary modelling exercise was then run to reschedule Synergy facilities to provide additional load rejection reserve to meet the maximum requirement in these intervals. EY included two costs in the calculation of Synergy's cost of providing load rejection reserve service:

- The recommitment cost for the facilities rescheduled out of merit to provide load rejection reserve services.
- Forgone profits resulting from a load rejection event.

30 Synergy, 2018, Submission to AEMO's *Ancillary Services Parameters – Draft Assumptions Report*, p.1, (online)

The basis of modelling and input data were those used for the estimation of spinning reserve margin values.

The load rejection reserve standard is 120 MW of load rejection reserve.[31] This standard may be reduced by 25 per cent, to 90 MW, where AEMO considers the risk of a contingency event to be low.[32]

The ERA agrees with Synergy's view that constrained-on and -off payments are unlikely to compensate Synergy for rescheduling to provide load rejection reserve. In response to Synergy's representations on compensation, AEMO undertook some validation work. While AEMO satisfied itself there was a possible issue with rescheduling occurring, and that Synergy incurred a cost as a consequence, it did not provide this to the ERA in support of its proposal. Therefore, the ERA could not confirm the validity of AEMO's rescheduling assumptions.

AEMO's most recent ancillary services report makes two statements relevant to the question of whether Synergy incurs a rescheduling cost.

- The first statement was about the quantity of load rejection reserve provided. The report stated that the 120 MW standard was only met or exceeded around 85 per cent of the time.[33] AEMO also stated the 90 MW minimum quantity of load rejection reserve was not met 6.5 per cent of the time.
- The second statement was about rescheduling of facilities and AEMO's evaluation of the risk of over frequency:

> There were periods when the minimum requirement for LRR [load rejection reserve] was not met (approximately 6.5% of the time). This was a consequence of generators providing LRR operating at low output during low system demand. Whilst there were periods of insufficient LRR to respond automatically in six seconds, a number of generators within the Balancing Portfolio acknowledged that if necessary they would trip their unit on AEMO instruction if the frequency could not be managed within the frequency operating standards. Therefore the risk of an over frequency condition was considered low during those time frames.

These statements raise two points:

- The load rejection reserve standard is not always met.
- There are periods where AEMO does not reschedule Synergy's generators to meet the standard as it considers the risk of over frequency is low.

The load rejection reserve cost estimate provided by AEMO is based on a scenario that differs from its statements in the ancillary services report and from the requirement in the market rules. AEMO's load rejection reserve estimates reflect a scenario in which the maximum standard is always met and Synergy facilities are always rescheduled to ensure meeting the maximum standard.

31 AEMO, 2018, *Ancillary services report for the WEM 2018–19*, p.11, (online).

32 Clause 3.10.4 of the market rules.

33 AEMO, 2018, *Ancillary Service Report for the WEM 2018-19*, p.11, (online).

In its submission to the issues paper, AEMO explained that prior to dispatch of units, AEMO planned for availability of up to 120 MW of load rejection reserve. In real time when units are dispatched, the actual availability of load rejection reserve can change because several system conditions change. AEMO takes action, when required, to ensure system security is not compromised. AEMO noted that a substantial part of the cost of the provision of load rejection reserve was incurred during the pre-dispatch planning period. AEMO explained that the modelling of the load rejection reserve cost attempted to simulate the planning and dispatch processes for scheduling and operating available Synergy facilities to meet the load rejection reserve requirement.

AEMO also explained that the model for the estimation of load rejection reserve cost only de-committed Synergy coal units that were not providing load rejection reserve, within defined periods on the weekends. AEMO stated that the model used did not overestimate the load rejection reserve cost.

If, during the pre-dispatch planning stage, AEMO schedules some of Synergy's capacity to provide load rejection reserve up to the maximum120 MW, those capacities must be available to run and so should be offered at the floor price, which is below their short run marginal cost. It is therefore possible that some facilities are dispatched when the market clearing price is lower than their supply cost. The estimation of load rejection reserve cost should include these costs.

However, AEMO's statements provided in the ancillary services report or in its submission to the issues paper do not clarify if those periods with load rejection reserve below 120 MW were due to relaxing the maximum requirement during the planning phase or due to changes in system conditions in real-time or both. It is also not clear what risk assessment method AEMO uses to evaluate the risk of over frequency in the system. If AEMO considered that some of the periods with load rejection reserve below 120 MW were low risk, this was not reflected in the AEMO's use of a similar risk assessment method during the planning phase. AEMO was unable to provide details on the alignment of risk and availability of load rejection reserve that would validate the modelling assumption.

The assumptions and results do not sufficiently reflect the practice observed and documented in AEMO's 2018 Ancillary Services Report. The basis, frequency and effect of rescheduling practice has not been adequately established in the material presented to the ERA. The ERA considers the load rejection reserve results to be unreasonable.

In the absence of reasonable modelling assumptions and/or clarifications on the consistency between practice and modelling, the ERA approves a value of $1.4 million, which is the same as the previous load rejection reserve cost.

To develop its future load rejection reserve service proposals, the ERA encourages AEMO to:

- 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 photovolatics that would trip or decrease output when over-frequency occurs, due to its over-frequency settings.

6.5 ERA determination

Options available to the ERA for the load rejection reserve services are to:

- approve the load rejection reserve values as proposed
- continue with the previous values
- default to values provided at market start.

The ERA considers the modelling foundation for the current load rejection reserve value to be credible, but the assumptions to be unrealistic. The ERA cannot reconcile AEMO's explanations in response to questions raised in the issues paper with AEMO's ancillary services report, which indicated a substantially lower level of conformance with the 120 MW standard than indicated by the modelling.

The ERA is not satisfied that the modelling outputs reasonably reflect the costs Synergy incurs providing load rejection reserve. Two options remain: the use of the default value, or the continuation of the existing value.

The ERA considers that the use of the default value is not appropriate as the value applied at the start of the market was zero. It is credible that some rescheduling occurs, and therefore some level of load rejection reserve cost is appropriate.

The ERA considers the assumptions underpinning AEMO's proposed values result in an excessive estimate of the load rejection reserve value ($10.16 million for the three-year period 2019/20 to 2021/22).

The ERA determines that the load rejection reserve value should remain at the existing value of $1.4 million per year ($4.2 million for the three-year period).

The ERA recommends that AEMO undertakes a deeper analysis of the actual incidence of rescheduling and prepares and submits modelling with revised proposals for 2020/21 and 2021/22.

7. System restart service

7.1 Background

System restart ancillary services are provided by generators capable of starting up in total blackout system conditions, and able to energise the power system to enable other generators to be started up.

Currently, AEMO has contracts with three market participants for the provision of the service.

System restart service costs are allocated based the consumption of each market participant.

Clause 3.13.3B of the market rules establishes the requirements for the ERA's determination of the values for the system restart service:

- AEMO must submit a proposal for the values by the 30 November prior to the start of the review period.
- The ERA must undertake a public consultation process in approving the values, which must include an issues paper and invitation for public submissions.
- By 31 March of the year in which the review period commences, the ERA must determine the values for the parameter for the review period.

7.2 AEMO proposal

Table 3 details AEMO's proposed system restart service values for 2019/20 to 2021/22 and the historic approved system restart values.

Table 3. System restart service cost

Financial year	Approved ($'000)	IMO*/AEMO proposed ($'000)	AEMO's revised proposal (6 February 2019)
2013/14	$508	$508	-
2014/15	$521	$521	-
2015/16	$534	$534	-
2016/17	$547.9	$929	-
2017/18	$561.7	$3,273	-
2018/19	$575.7	$3,355	-
2019/20	-	$3,325	$3,316
2020/21	-	$3,291	$3,293
2021/22	-	$3,374	$3,375

* IMO was the former Independent Market Operator.

The proposed values are contracted sums provided by AEMO. The difference in values reflects actual AEMO contracted sums.

7.3 Stakeholder comment

In the issues paper, the ERA invited submissions on the system restart procurement process, considering the gap between what the ERA determined to be a reasonable cost and what was subsequently contracted.

The ERA also sought views on the effect the shortfall charge has on AEMO's obligation to minimise the cost of procuring restart services under the market rules. The ERA sought views on alternative procurement mechanisms, including consideration of an administered system restart price.

Bluewaters noted that, given the substantial difference between what was proposed by AEMO and what was approved by the ERA previously, system restart costs should be thoroughly reviewed. It encouraged the ERA and AEMO to improve the transparency of the system restart consultation process, which could increase the participation of other generators in offering the service. [34]

Bluewaters also responded that:

> The application of the shortfall charge in relation to the contracted values for system restart service minimises the benefit of ERA's review and approval of these costs. While it is theoretically inefficient to introduce administered pricing in competitive markets, the lack of competition and the pricing model in this situation warrants further investigation into this alternative to provide better value for money for the consumer to the extent that contracts do not represent cost of the service.

7.4 ERA consideration

The ERA has considered AEMO's proposed system restart service values and stakeholder comments.

System restart costs are based on the pricing of contracts entered into by AEMO for procuring system restart services in case of a system-wide blackout. System restart services exist to ensure there remains capacity to start a generator independently of electricity supply from the network and commence re-energising the network.[35]

For system restart purposes, AEMO has divided the South West Interconnected System into three sub-network areas, and determined that it required a contracted system restart facility in each of the three sub-network areas:

- North Metropolitan
- South Metropolitan
- South Country.[36]

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34 Bluewaters Power, 2019, Submission to the ERA's *Ancillary Service parameters: spinning reserve margin peak and margin-off peak (for 2019/20) and load rejection reserve and system restart (for 2019/20 to 2021/22)* – Issues paper, p.4, (online).

35 Clause 3.9.8 of the market rules

36 AEMO, 2018, *Ancillary Services Report for the WEM 2018–19*, p.19, (online).

AEMO is compensated for the system restart service through the system restart value. Where there is a gap between the system restart values approved by the ERA and the costs from contracts procured by AEMO, full contract costs are recovered through a shortfall charge.[37]

When entering into an ancillary services contract, AEMO must:

- Seek to minimise the cost of meeting its ancillary service requirements.[38]
- Consider a competitive tender process unless it would not minimise the cost to the market of ancillary services.[39]
- Report to the ERA the capacity, prices and terms for calling the contracted facility to provide the service.[40]

Restart costs are borne by market customers, based on their share of electricity consumption.[41]

While this review process of system restart costs is rendered a theoretical exercise by the application of the shortfall charge and AEMO's ability to recover all contracted costs,[42] the ERA undertakes this determination to fulfil its functions under the market rules.

In the previous system restart determination set in 2016, the ERA did not approve the full amount proposed by AEMO for system restart services.[43] The ERA's determination stated the cost increase for one proposed supplier did not appear to reflect the cost to the supplier of providing the service and so was inconsistent with the WEM objectives.[44] At the time of the previous determination, the proposed costs were tendered and not contracted sums. AEMO was invited to submit revised proposals covering system restart.

AEMO's 2016 proposal was rejected for two of the three contracts – North Metropolitan and South Country. Substantial detail was redacted at the time because the tender was still open. With the tenders closed and contracts awarded, some aspects of the proposal rejection can be explained as they are pertinent to the current review.

The prices for the system restart service did not reflect cost recovery of capital or operational expenses. [redacted] increased its tendered service cost for North Metropolitan by a factor of five compared to the previous contract, with limited explanation. On review of the financial models underpinning the contracts, [redacted] pricing was not based on the cost to provide a system restart service or the cost recovery of the capital and operational costs necessary to provide the service. Instead the contract was based on the revenue needed to be recovered through the contract to ensure a return on investment of around 5 per cent. This transferred market risks from the balancing market and reserve capacity mechanism onto the system restart contract.

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37 Clause 9.9.3B of the market rules applies a 'shortfall charge' that would cover the difference between the ERA's determined values and the contracted sum entered into by AEMO to provide the service.

38 Clause 3.11.9 (a) of the market rules.

39 Clause 3.11.9 (b) of the market rules.

40 Clause 3.11.10 of the market rules.

41 Clause 9.9.1 of the market rules.

42 Clause 9.9.3B of the market rules applies a 'shortfall charge' that would cover the difference between the ERA's determined values and the contracted sum entered into by AEMO to provide the service.

43 ERA, 2016, *Determination of the Ancillary Service Cost_LR Parameters from 2016/17 to 2018/19*, p.9.

44 Ibid, p.8.

In the ERA's 2016 determination, this pricing strategy was determined to be inconsistent with the market objectives and was rejected. Instead, the ERA applied Consumer Price Index to the previously proposed contracts.

AEMO's contract with [redacted] remains in place. The ERA has not changed its position that the pricing strategy in this system restart contract is inconsistent with the market objectives.

Among the concerns flagged in the ERA's determination in 2016 was that the process for determining the standard for system restart services set out in the Market Rules does not explicitly require an economic evaluation that takes account of the risks and costs of providing the service.[45] The ERA approved a nominal amount intended to cover the cost of a third system restart service based on the previous contracted sum adjusted by the Consumer Price Index. The ERA further stated AEMO could submit a revised proposal if it contracted for a third system restart service.

Subsequent to that rejection, AEMO entered contracts with [redacted] rather than resubmitting proposals to the ERA for approval. AEMO's costs were recovered by the shortfall charge for the difference between the cost of the contracts it entered into and the cost recovery approved by the ERA from market participants. It is understood that there was unlikely to have been sufficient time to re-tender before the existing contracts expired.

For the current determination, the ERA reviewed tendered pricing for the South Country service and this appeared broadly consistent across the two tenders received for the new services. AEMO did not provide the financial models underpinning the tenders to confirm the reasonableness of the tenders. Consequently, the ERA has not reviewed them.

AEMO now has three system restart contracts:[46]

- North Metropolitan – [redacted] until 2021.
- South Metropolitan – [redacted] until 2021.
- South Country – [redacted] 2027.

AEMO's current system restart proposal is based on contracts awarded from its previous review period.[47] AEMO did not retender for system restart services. Proposed system restart contract costs continue to materially exceed the value determined by the ERA for the previous review period.[48]

AEMO's current proposal, based on these contract costs, noted the limited number of facilities capable of providing a system restart service in each of three separate electrical sub-networks. Separate networks are required to mitigate the risk of a contingency affecting more than one facility.

The ERA's issues paper (section 4.2) discussed reasons why tendered prices could be much higher than the actual cost of service provision. Due to limited suppliers capable of providing the service each sub-region, and limited participation in tenders, market power may result in higher prices.

45 ERA, 2016, *Determination of the Ancillary Service Cost_LR Parameters from 2016/17 to 2018/19*, pp.8-9.

46 AEMO, 2018, *Proposed Cost_LR Values for Review Period from 1 July 2019 to 30 June 2022*, Appendix 1.

47 Ibid, Appendix 2.

48 AEMO, 2018, *Ancillary Services Report for the WEM 2018–19*, p.13, (online).

The ERA agrees with the statement from AEMO that a system restart service provider would need to recover the cost of new equipment necessary to provide the service over a period of time. To do otherwise would risk no parties being willing to provide the ancillary service. The ERA acknowledges that [redacted] constructed and commissioned 5 MW of diesel generator capacity at [redacted] to provide the service to AEMO for South Country.

However, the contracts entered into should reflect the operational cost to provide the service plus a reasonable return on, and of, the capital invested. This does not appear to be the case for the North Metropolitan system restart contract.

The ERA considers that there is opportunity to improve the processes used to source system restart services.

The ERA considers that the current procurement process provides:

- insufficient incentive for the market operator to balance cost against risk
- insufficient incentive for prospective suppliers to provide restart services.

To improve the process, procurement must be underpinned by an understanding of:

- the likely risk from different levels of service
- barriers to participation
- how terms and conditions may affect the cost and willingness to provide restart service
- the costs to provide the service.

A conventional tendering process seems unlikely to reliably deliver pricing consistent with the market objectives unless extra facilitation measures are used to encourage participation, and thus competitive pricing, in tenders. More competitive tenders may result if AEMO expands its briefing process to encompass a wider range of suppliers, clearly informs them of the services being sought and avoids being overly prescriptive in how the requirements can be met. Ensuring that the risks of providing the service are appropriately assigned, in tender documents and in the subsequent steps, to the party best able to manage each risk may also encourage more providers to submit tenders.

The costs of procurement of these services are paid for by market participants. AEMO uses the shortfall charge to recover any difference in costs between the contract price and the amount approved by the ERA for the system restart service. Improving the procurement process would reduce the likelihood of a disconnection between the contracted system restart cost and the ERA’s determination.

Some of the restart contracts expire during the term of this determination. It recommends that AEMO submits a revised system restart proposal 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. The ERA also encourages AEMO to brief the ERA on its proposed procurement strategy, including how it proposes to address shortcomings in its procurement process well in advance of commencing procurement.

7.5 ERA determination

For the current determination, the ERA accepts system restart contract costs for South Metropolitan sub-region and, on the basis of available information, South Country sub-region.

AEMO has awarded the North Metropolitan contract where the pricing was previously found to be inconsistent with the market objectives. The ERA continues to have concerns with this contract's costs.

For this determination the ERA applies the CPI to the previous contract for the system restart value for North Metropolitan sub-region.

The ERA determines the system restart value to be:

- $2,924,238 for 2019/20
- $2,899,148 for 2020/21
- $2,961,377 for 2021/22.

The ERA acknowledges the services procurement challenges and recommends that AEMO seeks advice on alternative procurement models. As part of this review, it should also explore what would encourage potential providers to participate in a procurement process, noting that the lack of competition in the WEM means that tender prices could well exceed the cost of providing the service.

Alternatively, it could consider an administered approach to setting system restart costs based on an engineering assessment of the explicit cost to provide the service in each of the three network areas plus a reasonable return, rather than inviting a price to provide the service. However, this would require a change to the market rules.

If the current procurement by tender process is to continue, it is recommended that AEMO:

- Seeks pricing based on the cost to provide the service and require a detailed cost breakdown.
- Provides all supporting documentation including contracts, bids and their foundation to the ERA in support of its proposal.
- Provides detailed cost justification to the ERA via a proposal in advance of letting contracts, allowing itself time to respond to the ERA's determination.

The ERA determines the Cost_LR value, which is the sum of the load rejection reserve and system restart costs, to be

- $4,324,238 for 2019/20
- $4,299,148 for 2020/21
- $4,361,377 for 2021/22.

Appendix 1 Summary of the ERA's recommendations for determination of 2018/19 margin values

The market rules specify a formula for calculating payments to Synergy to compensate it for the opportunity cost of providing the spinning reserve service. Conceptually the higher the balancing market prices and the quantity of reserve provided by Synergy, the higher the opportunity cost of providing the service and this is represented in the calculation formula in the market rules:

Equation 1

$$a_t = \frac{1}{2} m \times p_t \times q_t$$

where a_t is the spinning reserve availability payment, m is the constant margin peak (margin off-peak) parameter if the trading interval t is a peak (off-peak) trading interval. Variable p_t is the balancing price[49], in dollars per megawatt hour ($/MWh), and q_t is the megawatt (MW) quantity of spinning reserve provided by Synergy's facilities. The multiplier ½ is to convert the spinning reserve quantity from MW to MWh units.

Synergy may forgo some energy sales in the balancing market, because AEMO withholds some of its generation capacity for the provision of spinning reserve service. It may also incur some costs due to decrease in operational efficiency or increase in start-up costs. These costs generally offset savings on fuel and operating costs for the capacity reserved.[50]

The value of parameters for margin peak and margin off-peak should be set so that equation 1 best estimates the opportunity cost of providing spinning reserve based on the balancing price and the spinning reserve quantity provided. The margin values are set for the next financial year, so a model is required to forecast balancing price and spinning reserve quantity provided by Synergy for each trading interval in the next financial year. The model should also provide a forecast of Synergy's opportunity cost of spinning reserve for each trading interval. Once these forecasts are available, the value of margin peak and off-peak can be estimated for peak and off-peak periods separately.

It is therefore important that:

- The calculation of the opportunity cost of spinning reserve is theoretically valid.
- The forecast of balancing price and spinning reserve quantity is reasonably accurate and uses the best available data.
- Margin values best estimate the forecast opportunity cost based on balancing price and spinning reserve quantity forecasts with the linear relationship provided in equation 1.

Summary of the ERA's review of margin values in 2018/19

In its determination of margin values for 2018/19, the ERA suggested areas for improvement in the calculation of margin values by AEMO's consultant:

49 If the balancing price during a trading interval is negative, the value of variable P_t is set to zero.

50 Equation 1 provides an approximate value for the opportunity cost of spinning reserve provided by Synergy. The relationship between the opportunity cost of providing spinning reserve, balancing price and the quantity of reserve provided is more complex than the linear relationship shown in equation 1.

1. The ERA provided recommendations for AEMO to enhance the calculation of Synergy's opportunity cost of providing spinning reserve.

   a. For previous estimation of margin values, AEMO's consultants considered that the difference between Synergy's generation net benefits, or economic surplus, with and without the provision of spinning reserve service represents Synergy's opportunity cost of withholding its generation facilities for the spinning reserve.

   b. The ERA assessed the calculation of the opportunity cost of providing the spinning reserve service based on the principle that the administrative process for spinning reserve payments should emulate the outcomes of a competitive spinning reserve market as closely as possible. The ERA explained in detail how spinning reserve market participants bid based on the marginal cost of spinning reserve and how that cost is determined. The ERA recommended that the opportunity cost of the spinning reserve service should be determined based on the marginal cost of the plants actually providing the reserve, rather than changes in the net benefits of Synergy's generation portfolio.

2. The ERA used regression analysis to refine the calculation of margin values.

   a. In previous years AEMO's consultants rearranged equation 1 to estimate margin values for each trading interval. They used the average of margin values over trading intervals (peak and off-peak separately) for setting margin peak and margin off-peak values for a calendar year.

   b. In its determination paper the ERA explained that using average of margin values may not provide the best linear fit based on the forecasts of the opportunity cost of providing spinning reserve, balancing price, and reserve quantity as shown in equation 1.[51] The ERA used regression analysis to estimate margin values and showed how this approach can minimise the errors in estimating availability payments.

3. The ERA recommended a thorough review of calculation inputs and more intensive verification process with parties providing data. The ERA also supported improving the transparency of the calculation process.

   a. The simulation model used for the calculation is complex – and comprises many assumptions, changes in which can materially affect the value of margin peak and margin off-peak parameters. The ERA supported improving the transparency of the estimation process by providing detailed information to stakeholders on the simulation model used and the calculation of margin values.

[51] This was explained in detail in the ERA's determination paper last year. ERA, 2018, *Determination of the spinning reserve ancillary service margin peak and margin off-peak parameters for the 201819 financial year*, pp. 30–33, (online).