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

Issues paper

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Economic Regulation Authority
WESTERN AUSTRALIA

DMS197181

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Invitation to make submissions

Submissions are due by 4:00 pm WST, Friday , 8 March 2019

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

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

You can also send comments through:

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

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

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1. Introduction

The Economic Regulation Authority determines the parameters in the Wholesale Electricity Market Rules that are used in the calculation of payments for spinning reserve, load rejection reserve and the system restart service. The Australian Energy Market Operator's (AEMO) reviews these parameters and submits its proposed new values to the ERA for determination. The market rules require the ERA to publish issues papers and seek stakeholder feedback as part of its process for determining these ancillary service parameters.

The calculation of parameters for the spinning reserve and load rejection reserve uses common estimation models. In the market rules, the same parameter (Cost_LR) used for the load rejection reserve payments also covers payments for the system restart service. This year, the timing of the review of parameters for these three ancillary services has coincided. The ERA is conducting its review and determination of spinning reserve, load rejection reserve and system restart service parameters simultaneously as discussed in this discussion paper.

Spinning reserve payment parameters (margin values)

Synergy is the default provider of ancillary services, including spinning reserve, under the market rules.[1] Payments to Synergy for providing a spinning reserve service are based on the calculation method specified in the market rules.[2] The clearing price in the balancing market, the quantity of spinning reserve provided by Synergy and a constant parameter margin peak, or margin off-peak[3] depending on the type of trading interval, determine the amount of payments.

Each year, AEMO proposes margin values to be applied for the next financial year to the ERA for determination.[4] AEMO submitted its proposal on the margin values for the 2019/20 financial year on 30 November 2018. The ERA must determine the margin values by 31 March 2019 that are to apply from 1 July 2019 to 30 June 2020.[5]

When determining the margin values, the ERA must consider AEMO's proposal in the context of the Wholesale Electricity Market (WEM) objectives.[6] The ERA is also required to undertake a public consultation process, which must include publishing an issues paper and inviting public submissions.[7]

Load rejection reserve and system restart payment parameter (Cost_LR)

Payments to providers of load rejection reserve are based on AEMO's estimate of the annual cost of providing the service.[8] Currently, Synergy is the only provider of the load rejection reserve in the market.

AEMO estimates Synergy's cost of providing this service for each of the next three financial years and submits a proposal to the ERA for determination. The ERA must determine the total cost payable to Synergy for the next three financial years by 31 March before the start of the

1 Clause 3.11.7A of the market rules.

2 Clause 9.9.2(f) of the market rules.

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

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

5 Clause 3.13.3A of the market rules.

6 Clause 1.2 of the market rules.

7 Clause 3.13.3A(b) of the market rules.

8 Clause 3.13.3B(a) of the market rules.

first financial year in the three-year determination period. This cost determines the first part of the parameter Cost_LR in the market rules, conventionally referred to as the “L” component of the Cost_LR parameter.

AEMO estimates the annual cost of the system restart service and submits a proposal to the ERA for determination. Similar to that for the load rejection reserve, this cost is determined for each of the next three financial years. This cost determines the second part of the Cost_LR parameter, conventionally referred to as the “R” component of the Cost_LR parameter. The timing of the review and determination of the cost of system restart service is equivalent to that for the load rejection reserve.[9]

AEMO engaged Ernst & Young (EY) to assist in calculating the margin values and Synergy’s cost of providing the load rejection reserve. AEMO’s proposals and EY’s public reports are available on the ERA’s website. AEMO also provided the ERA with confidential reports, prepared by EY, on the calculation of margin values and the load rejection component of the Cost_LR ancillary services parameter.[10]

The spinning reserve and load rejection reserve availability costs and system restart costs have changed substantially from previous years. In its previous determination of margin values, the ERA recommended ways for AEMO to improve the calculation of Synergy’s opportunity cost of providing spinning reserve. EY developed models consistent with these recommendations. The ERA’s recommendations also influenced the calculation of the cost of load rejection reserve.

Other than the change in the method for the calculation of the opportunity cost of providing capacity reserve, several factors may explain the changes in margin values and the load rejection reserve costs. These are changes in electricity demand, fuel price or generation mix or any changes in the simulation of the WEM. With a material change to the modelling process, it is not possible to estimate the effect of individual factors contributing to changes in margin values for spinning reserve and load rejection cost separately. However, it appears that among the possible factors, the change in the method for the calculation of the opportunity cost of providing spinning reserve and load rejection reserve has had a material impact. This is discussed in section 1.1. System restart costs have also changed but for different reasons explored in section 4.

The modelling exercise was common to both spinning reserve and load rejection reserve ancillary services and many of the conceptual changes to the spinning reserve modelling also apply to the load rejection reserve outcomes.

This issues paper is to assist interested parties to make submissions on the proposed margin values for 2019/20 and the components of the Cost_LR parameter for the period from 2019/20 to 2021/22, as submitted by AEMO. It is intended to be read in conjunction with AEMO’s proposals and supporting documentation.

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

[9] Clause 3.13.3B (a) of the market rules

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

1.1 Proposed margin values for 2019/20

Table 1 summarises AEMO's proposed margin values for 2019/20. When compared to the margin values in 2018/19 and preceding years, the margin values proposed for 2019/20 have substantially decreased to levels close to those set at the commencement of the market.[11]

EY's forecast of the total cost of spinning reserve is approximately 21 per cent lower than that approved in 2018/19. Three main factors could be driving the decrease in margin values and forecast spinning reserve total costs:

- Changes in the electricity market features such as demand, generation mix and fuel price.
- Changes in the simulation of the schedule of generators in the WEM, as explained in section 2.3.1.
- Changes in the calculation of Synergy's availability cost, as recommended by the ERA in its determination of margin values last year.

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

Values	2019/20 proposed	2018/19 approved
Margin peak (%)	17.32	50
Margin off-peak (%)	12.92	25
Average annual peak spinning reserve capacity (MW)	235.4	224.1
Average annual off-peak spinning reserve capacity (MW)	236.4	189.0
System marginal peak price ($/MWh)	56.48	54.44
System marginal off-peak price ($/MWh)	47.04	39.52
Estimated Synergy's peak availability cost ($m)	6.91	7.97
Estimated Synergy's off-peak availability cost ($m)	3.43	5.09
Estimated Synergy's total availability cost ($m)	10.34	13.06

The average annual spinning reserve capacity has increased, particularly during off-peak periods,[12,13] indicating an increased requirement for the supply of spinning reserve from

[11] 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.

[12] EY estimated these average spinning reserve quantities by adding the amount of load following raise capacity that was ineligible for spinning reserve provision. EY, *Margin values review for 2019/20, Public Version, Australian Energy Market Operator*, 2018, p. 28.

[13] EY explained that the average spinning reserve quantities during peak and off-peak periods are similar in part due to increased installation of rooftop solar PV, which reduced the daytime operational demand. EY, *Margin values review for 2019/20, Public Version, Australian Energy Market Operator*, 2018, p. 4.

Synergy facilities. The forecast amount of spinning reserve from contracted third parties and load following raise has remained constant.[14]

An increased supply of spinning reserve from Synergy facilities is expected to increase the overall cost of spinning reserve supply from its facilities. However, both the peak and off-peak availability costs for Synergy have substantially decreased.

Synergy's opportunity cost of providing spinning reserve is generally determined by the difference between the balancing price and the energy supply cost for Synergy's facilities providing spinning reserve. Both system marginal peak and off-peak prices have substantially increased. If the energy supply cost for Synergy's facilities providing spinning reserve remained constant, this could be expected to increase the cost of spinning reserve supplied from Synergy facilities.

However, an increase in the balancing price indicates an increase in Synergy's supply costs, given that Synergy plant sets the balancing market clearing price in many trading intervals. An increase in Synergy's energy supply costs can partly offset the effect of balancing price increase on the spinning reserve availability costs. The increase in the balancing price increases the availability cost, whereas the increase in Synergy supply costs reduces availability cost.[15]

A change in the mix of Synergy plants providing the spinning reserve service could change Synergy's availability cost. However, the mix of facilities providing spinning reserve has not changed when compared to the analysis last year.

These outcomes of the model suggest that the change in the method for the calculation of Synergy's opportunity cost of providing spinning reserve has had a material effect on the availability cost and margin value results. Changes to the modelling method are discussed in section 2.3. More details about the ERA's recommendations for the calculation of the opportunity cost of providing spinning reserve were provided in the ERA's determination of margin values last year.[16]

As specified in the market rules, the product of margin values, the balancing price and the spinning reserve quantity provided by Synergy approximates Synergy's availability cost. When compared to last year's results, margin values should decrease to offset the increase in the product of balancing price and spinning reserve quantity provided by Synergy. Margin values should decrease further to account for the decrease in Synergy's availability cost below that from last year.

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[14] The market rules imply an equivalence between load following raise reserve capacity and spinning reserve. The system operator can use the load following raise reserved capacity to respond to sudden shortfalls in supply. The market rules estimate the amount of spinning reserve quantity provided by Synergy facilities by deducting the amount of load following raise capacity and contracted spinning reserve capacity from the total requirement for the spinning reserve.

[15] The effect of balancing price and energy supply costs on the spinning reserve availability cost is more complex than discussed here. For instance, a change in balancing price changes the schedule of in-merit capacities in the balancing market. This influences the availability of plants for the provision of spinning reserve.

[16] ERA, 2018/19 determination of Margin Peak and Margin Off-Peak parameters, 2018. https://www.erawa.com.au/cproot/18797/2/Determination%20of%20margin%20peak%20and%20margin%20off-peak%20parameters%20for%20the%202018-19.pdf

1.2 Load rejection reserve

Table 2 contains AEMO's proposed load rejection reserve parameter values for 2019/20 to 2021/22. The table also shows the load rejection reserve performance and standard.

Table 2. Proposed load rejection reserve values ('L' parameter of Cost_LR)

Year	Requirement	Actual performance (% time at standard)[17]			Approved value	Proposed value
		<90 MW	<120 MW	>120 MW	($'000)	($'000)
2016/17	120 MW but may be relaxed by up to 25 per cent (to 90 MW) when the risk is considered low.	3.5	14	86	$1,400	$0
2017/18		6.5	21.5	78.5	$1,400	$0
2018/19			N/A		$1,400	$0
2019/20						$4,738.2
2020/21			N/A		To be determined	$4,343.5
2021/22						$1,086.6

The proposed load rejection reserve costs are estimates from EY's modelling. The change in values between the historical values and proposed values reflects the fundamental change in the approach to modelling spinning reserve outlined in section 2. This modelling change is common to the modelling of the load rejection reserve, which is discussed further in section 3.

[17] The load rejection reserve performance statistics relates to the period from May to April reported in AEMO's, 2018 Ancillary Services Report, 2018, p11, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2018/2018-Ancillary-Services-Report.pdf

1.3 System restart service

Table 3 summarises the proposed contracted system restart values for 2019/20 to 2021/22 and previously approved system restart values.

Table 3. System restart service cost (R parameter of Cost_LR)

Financial year	IMO*/ AEMO proposed ($'000)	ERA approved ($'000)
2013/14	$508	$508
2014/15	$521	$521
2015/16	$534	$534
2016/17	$929	$547.9
2017/18	$3,273	$561.7
2018/19	$3,355	$575.7
2019/20	$3,325	
2020/21	$3,291	
2021/22	$3,374	

* IMO was the former Independent Market Operator

The proposed values are contracted sums provided by AEMO. The difference in quantities reflect actual contracted sums and not the sums approved by the ERA. This is discussed in section 4.

2. Spinning reserve

The South West Interconnected System (SWIS) uses different ancillary services to maintain the balance of supply and demand at all times. 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.[18]

When a sudden supply shortfall occurs, the system operator uses reserved generation capacity, dispatchable load,[19] or interruptible load[20] to restore the supply-demand balance. If the operator does not have sufficient reserved generation capacity or dispatchable demand resources to restore the balance, it has to disconnect customers.

The market rules specify that at any point in time, the SWIS should have sufficient spinning reserve to cover the greater of 70 per cent of the total output of the largest generator dispatched in the system or the maximum increase in system demand expected over a period of 15 minutes.[21,22]

Resources providing a spinning reserve service incur costs in providing the service:

- Generators forgo the opportunity to provide their reserved capacity in the energy market, and the opportunity to earn revenue on energy sales. They may also incur some costs from reduced operational efficiency.
- Demand resources, such as large industrial and commercial electricity consumers or aggregated loads, incur costs when receiving instructions from the system operator to reduce their consumption.

The market rules apply a 'causer pays' approach where generators pay for the cost of the spinning reserve service based on their contribution to the amount of spinning reserve required. Generally, the larger the capacity of a generator dispatched for the supply of energy in a trading interval, the higher the share of the generator for funding the spinning reserve service in the period.[23]

Synergy is the default provider of spinning reserve service in the SWIS.[24] Market participants other than Synergy can provide the service in two circumstances:

- if Synergy's facilities are not sufficient to cover the spinning reserve requirements

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

19 A dispatchable load is a load where the quantity of electricity consumed can be increased or decreased on instruction from system operator. Refer to clause 2.29.5 (c) of the market rules.

20 Interruptible loads can be automatically reduced in response to frequency changes. Refer to clause 2.29.5(a) of the market rules.

21 Clause 3.10.2 of the market rules.

22 This requirement may be relaxed by up to 12 per cent where AEMO expects that the shortfall will be for a period of less than 30 minutes.

23 This payment approach is specified in Appendix 2 of the market rules. Generators pay based on specified capacity blocks, with increasing costs for larger capacity blocks. Generators with less than 10 MW capacity dispatched are exempt from the payment. In November 2018, the Public Utilities Office proposed to enhance the payment method. Refer to Rule Change Panel, *Rule Change Notice : Full Runway Allocation of Spinning Reserve Costs (RC_2018_06)*, 2018, https://www.erawa.com.au/cproot/19875/2/RC_2018_06 - Rule Change Notice and Proposal.pdf.

24 Clause 3.11.7A of the market rules.

- if non-Synergy facilities can provide the service at lower cost than Synergy's facilities.[25]

The market rules specify a formula for the calculation of spinning reserve payments to Synergy for each trading interval. Spinning reserve payments are based on the product of:

- the megawatt quantity of capacity reserve provided by Synergy
- the balancing price[26]
- margin peak and margin off-peak values, as applicable to the trading interval.[27]

An increase in any of the factors above increases the spinning reserve payment to Synergy.

Each month, AEMO settles spinning reserve payments after the balancing market is settled, so the first two factors above will be available for the calculation of payments. Each year, AEMO proposes the value of margin peak and margin off-peak parameters, otherwise referred to as margin values, to the ERA for determination. Margin values determined by the ERA remain constant throughout a financial year.

Between May 2017 and April 2018, AEMO had three spinning reserve contracts that together provided a maximum 68 MW of spinning reserve.

Although it is not a requirement of the market rules, AEMO used the same formula (equation 1 below) as the basis for the pricing of spinning reserve in contracts with market participants other than Synergy.[28] AEMO lets contracts through a tender process and requires participants to offer a percentage discount to margin values determined for the financial year covering the contract period.[29,30]

Because of this design of the pricing of the contracts, and similar to payments to Synergy, an increase in margin values, the balancing price or the quantity of reserve provided by the contracted facility increases the amount of payments to the contracted service provider.

2.1 Margin values and spinning reserve payments

The market rules specify a formula for calculating payments to Synergy for each trading interval t.[31] The formula in a simplified form is:

25 Clause 3.11.8 of the market rules.

26 The formula uses a balancing price of zero if the balancing market clears at a negative price.

27 Clause 9.9.2(f) of the market rules.

28 AEMO, *Ancillary Service Contract - Spinning Reserve - Wholesale Electrcity Market*, 2018, p. 21, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/Ancillary-Services/2018/2018-04-17-Ancillary-Service-Contract--Spinning-Reserve--WEM.docx.

29 AEMO, *Invitation to Tender – Spinning Reserve for the Wholesale Electricity Market*, 2018, p. 14, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/Ancillary-Services/2018/Invitation-to-Tender---WEM-Spinning-Updated-Submission-Date.pdf.

30 It appears that AEMO uses the discount to margin values as a contract pricing approach to satisfy the requirement of the market rules, i.e. the spinning reserve contracts to provide a less expensive alternative to the provision of spinning reserve through Synergy facilities.

31 Clause 9.9.2(f) of 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[32], 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.

Conceptually, availability payments should compensate Synergy for the opportunity cost of providing the spinning reserve service. 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.[33]

In proposing the margin values for the ERA's determination, the market rules require the ERA and AEMO to take account of:

- "The margin Synergy could reasonably have been expected to earn on energy sales foregone due to the supply of Spinning Reserve Service."
- "The loss in efficiency of Synergy's scheduled generators that System Management has scheduled (or caused to be scheduled) to provide Spinning Reserve Service… that could be reasonably expected due to the scheduling of those reserves".[34]

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.

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

33 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.

34 Clause 3.13.3A(i) and (ii) of the market rules.

2.2 Summary of the ERA's review 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:

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.[35] 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.

For the review of 2019/20 margin values, AEMO considered the ERA's recommendations from the determination of margin values for 2018/19. EY used the ERA's proposed concept for the calculation of the opportunity cost of providing the spinning reserve service and estimated margin values based on regression analysis. EY also published a report, and held a workshop

35 This was explained in detail in the ERA's determination paper last year, pages 30–33.

for stakeholders, to explain the details of the model used and to present the results of backcasting analyses.

2.3 Modelling margin values for 2019/20

The calculation of margin values is conducted in three steps. EY used the same model for the calculation of the load rejection reserve service costs as explained in section 3 but with some additional steps. First, a model of the WEM is developed to forecast market outcomes. This provides an estimate of balancing prices, spinning reserve requirement and the amount of ancillary service, including spinning reserve, provided by each facility and for each trading interval. Second, the opportunity cost of spinning reserve is calculated based on the model outcomes for each trading interval. Third, values of margin peak and margin off-peak parameters are estimated to provide the best fit between the opportunity cost of reserve (estimated in the second step) and the product of balancing price and the quantity of spinning reserve provided by Synergy (estimated in the first step), as specified in equation 1.

2.3.1 Simulation of the WEM

EY developed a model to simulate the WEM. AEMO published EY's overview of the model and its main inputs and outputs.[36] Generally, the model aims to emulate the real-time dispatch engine used in the WEM consistent with the market rules, to calibrate the model and test its accuracy and assumptions. EY ran the model using observed market data from 2017/18 comprising: demand, wind and solar generation, and outages. This modelling approach is referred to as backcasting.

On average, the modelled balancing prices reasonably matched the observed clearing price in the balancing market. EY assessed generation duration curves by facility and discussed how and why they deviated from the observed data.

EY explained that it would use the results of backcasting to calibrate the model. This was done based on deriving bidding quantity and prices for each generation facility. The calibrated model would then be used with forecast inputs to simulate the WEM outcomes in the 2019/20.

This approach to modelling the WEM is different to that used in the calculation of margin values in previous years. Previous models used a 'unit commitment' modelling approach. This is based on the concurrent minimisation of energy and ancillary services cost to determine the operation schedule of generators in each trading interval. EY's model does not appear to use a constrained optimisation technique; it determines the schedule of generators using a cost merit-order reflecting generators' short-run marginal costs adjusted for their historical bidding behaviour.[37] Based on the backcasting report, this approach appears to yield outputs generally consistent with the dispatch of generators under the market rules.

In advance of estimating margin values, AEMO published a report on EY's modelling assumptions including facilities' technical parameters and costs, and market design.[38] AEMO sought stakeholders' feedback on this assumptions report. AEMO and EY also held a

[36] EY, *Wholesale Electricity Market modelling and backcasting report*, 2018, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/Ancillary-Services/2018-Review---WEM-Modelling-and-Backcasting-Report.pdf.

[37] The ERA does not have access to the model EY has developed and therefore cannot confirm the details of the model used. EY stated that its model of the WEM does not use a unit commitment algorithm. This implies that their model is based on stacking generator outputs based on short-run marginal cost.

[38] EY, *Ancillary services parameters – Draft assumptions report*, 2018, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/Ancillary-Services/2018/EY-Draft-Assumptions-Report---2018-09-13---Public-version---Further-Finalised.pdf.

workshop to present EY's modelling of the WEM, backcasting results and its assumptions for the calculation of margin values (and load rejection reserve costs).

AEMO received two submissions from stakeholders. EY addressed stakeholders' feedback in its final report to the ERA.

Question

Did market participants receive sufficient information about the calculation method underpinning assumptions and data used? If not, what processes could improve the transparency of the process for the calculation of margin values?

2.3.2 Calculation of Synergy's opportunity cost of providing spinning reserve

EY estimated Synergy's opportunity cost of providing spinning reserve, in line with the ERA's recommendations, in its estimation of margin values for 2018/19.[39] EY assumed that the opportunity cost for a generation facility to provide spinning reserve is:

- The loss of revenue due to reduced energy sales attributable to the generation unit's capacity withheld for providing spinning reserve.
- Less the operating costs that would have otherwise been incurred if the unit had not reserved its capacity.

EY's calculation also accounts for possible changes in the operational efficiency of a generator providing spinning reserve.

The calculation of the opportunity cost of providing spinning reserve is complex because it depends on the balancing price. The balancing price itself depends on the amount of capacity reserved from facilities able to provide the spinning reserve service. The calculation of the opportunity cost of spinning reserve requires a recursive optimisation method.[40] This recursive method should be run for each trading interval in the forecast financial year. This is not possible to be conducted in a short period of time because it entails numerous optimisation iterations each of which is computationally intensive.

Instead of a recursive method, EY approximated Synergy's opportunity cost of providing spinning reserve through a seven-step modelling process. The ERA will review EY's modelling approach in more detail after receiving the outputs of EY's model.

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39 Refer to Appendix 2 of ERA, *Determination of the spinning reserve ancillary service margin peak and margin off-peak parameters for the 2018-19 financial year*, 2018, https://www.erawa.com.au/cproot/18797/2/Determination of margin peak and margin off-peak parameters for the 2018-19.pdf.

40 This is because the opportunity cost of providing spinning reserve depends on the balancing price which is in turn influenced by the mix of plants providing the spinning reserve. Consequently, a recursive optimisation provides the best method to estimate the opportunity cost of spinning reserve. The model should iteratively change the scheduling of plants in the balancing market until the balancing price before and after the provision of ancillary services becomes equal and the total cost of energy and ancillary services dispatch is minimised.

2.3.3 Estimation of margin values

Consistent with the ERA's recommendation last year, EY used regression analysis to estimate margin values. EY used a robust linear regression to address non-normality of regression residuals.[41] EY also stated that the method better manages outliers that were observed in the results.[42]

The market rules imply an equivalence between the load following raise and spinning reserves. The system operator can use the capacity reserved for load following raise to cover sudden drops in the supply of electricity due to generator or network outages.

The market rules estimate the quantity of spinning reserve provided by Synergy by deducting two amounts from the total spinning reserve requirement: the amount of load following raise reserve, and spinning reserve provided through spinning reserve contracts with independent power producers.

AEMO advised that similar to the previous reviews of margin values, the calculation excluded the load following raise reserve provided by Cockburn and NewGen Kwinana facilities.[43] This is despite NewGen Kwinana frequently providing load following raise reserve.[44] Its exclusion from the calculation of the spinning reserve service effectively increases the supply of spinning reserve service provided by Synergy facilities thereby increasing the total spinning reserve requirement and cost.

The market rules specify technical requirements for providing the spinning reserve service. Facilities should be able to respond within seconds of any contingency event and sustain or exceed the required response for periods ranging from seconds to several minutes.[45]

It is reasonable to exclude a facility from the calculation of spinning reserve payments if it does not meet the technical requirement for providing the spinning reserve service, despite providing the load following raise service.

However, AEMO explained that NewGen Kwinana load following raise reserve was ineligible to reduce the spinning reserve requirement because it lacks a spinning reserve contract with AEMO.[46]

In its determination paper for the 2018/19 margin values, the ERA stated that excluding load following raise reserve capacity from the calculation of spinning reserve payments due to a lack of a contract with AEMO does not appear to be consistent with the market rules. The system operator can use load following raise capacity as an equivalent to spinning reserve subject to technical requirement in the market rules being met. Facilities providing load following raise reserve are compensated through the load following service market and do not

41 Normality of errors is an assumption underpinning running an ordinary least square regression analysis.

42 It is not clear why EY considers some of the outcomes of the model as outliers. The outcomes of the model, including extremely large or small values, are outputs of the same calculation process and may not be outliers but simply extreme values from the distribution of those variables.

43 This is also shown in EY's calculation of the opportunity cost of spinning reserve. After deducting the total amount of load following raise reserve, EY adds back the load following raise capacity that does not contribute to meeting the spinning reserve requirement. Refer to EY's final report, page 21.

44 Cockburn facility runs very infrequently.

45 Clause 3.9.3 of the market rules.

46 Jacobs, 2018-19 Margin Peak and Margin Off-peak Review, Australian Energy Market Operator, Final report - PUBLIC, 3.0, p.34, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/Ancillary-Services/2017-Review--Margin-Values-Final-Report-201819.PDF

require a contract with AEMO for providing spinning reserve service, otherwise they would be compensated twice for the same capacity held on reserve.

Question

Excluding some of the load following raise capacity from the calculation of margin values can increase the total cost of spinning reserve service in the system.

Should a load following raise capacity be excluded from the calculation of spinning reserve margin values if it does not have a contract with AEMO for the provision of spinning reserve? Excluding a load following raise capacity from the calculation of margin values increases the amount of spinning reserve procured through Synergy facilities.

The ERA seeks stakeholders' feedback on AEMO's reasoning for excluding some of the load following raise capacity from the calculation of margin values.

3. Load rejection reserve

3.1 What is the load rejection reserve?

The 'L' component of the Cost_LR ancillary services parameter represents Synergy's cost of providing the load rejection reserve ancillary service. Load rejection reserve requires generators to rapidly reduce output in response to a decrease in load to main system frequency. The load rejection reserve is the opposite contingency service to spinning reserve.

The load rejection requirement is set by AEMO.[47] The market rules require the standard to be sufficient to keep frequency below 51 hertz for all credible load rejection events but the standard may be relaxed by up to 25 per cent where AEMO considers the probability of transmission faults to be low.[48]

The Eastern Goldfields line poses the largest single credible load rejection contingency in the SWIS.[49] The risk of this contingency occurring was used to set the requirement, which is currently a maximum of 120 MW of load rejection reserve, with the ability to reduce this to 90 MW if the risk of transmission faults is low.[50]

Load rejection reserve costs are borne by market customers based on their share of consumption.[51]

Conceptually, a generator incurs no cost if it is in merit and capable of rapidly reducing output. EY's initial assumption was that the availability cost of load rejection reserve is negligible, and where generators were constrained on to provide load rejection, existing market 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 schedule of Synergy's plants according to Synergy's dispatch guidelines provided to System Management will not provide sufficient load rejection reserve. Different plant must be scheduled out of merit to cover the service where the risk is not low enough to relax the load rejection requirement.

Unlike other market generators, Synergy's portfolio bidding means rescheduling within the portfolio does not trigger constrained on or off compensation, a point raised by Synergy in consultation with AEMO on the draft assumptions report.[52] Thus portfolio bidding shields the market from bearing the cost to constrain Synergy's generators to ensure sufficient reserve. An out of merit generator scheduled-on to provide sufficient reserve should have a marginal cost above the balancing price. If such circumstances arise, Synergy would not be compensated through other market mechanisms so the 'L' component of the Cost_LR parameter exists to compensate Synergy should this occur.

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47 Clause 3.11.11 of the market rules

48 Clause 3.10.4 of the market rules

49 AEMO, 2018 Ancillary Services Report, 2018, p19, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2018/2018-Ancillary-Services-Report.pdf

50 AEMO, 2018 Ancillary Services Report, 2018, p18-19, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2018/2018-Ancillary-Services-Report.pdf

51 Clause 9.9.1 of the market rules

52 Regnard D., Ancillary Services Parameters – Draft Assumptions Report, Submission, 2018, p1

Similar to the spinning reserve service, the market rules allow AEMO to procure load rejection reserve through service contracts with market participants other than Synergy.[53] AEMO has not sought supply of load rejection reserve from non-Synergy generators and its ancillary services plan indicates it would seek up to 120 MW of load rejection reserve only from Synergy's balancing portfolio.[54]

3.2 Estimation of load rejection costs

EY used the same WEM simulation model, configuration and input assumptions to estimate the load rejection reserve requirement as that used for the calculation of spinning reserve margin values. The modelling was not optimised to provide the load rejection service, but was configured to concurrently optimise spinning and load following reserve services.[55] EY reviewed modelling outputs to identify intervals where the modelling did not schedule sufficient load rejection to meet the upper bound of the standard, that is, 120 MW. A secondary modelling exercise was then run to reschedule Synergy plants to provide additional load rejection reserve to meet the maximum requirement.

Out of merit plants rescheduled to cover the load rejection reserve should be able to recover some of their costs through the "L" component cost recovery mechanism, because the balancing market clearing price would not compensate them sufficiently. When calculating possible recommitment costs, EY estimated the difference in the marginal cost for the rescheduled generator including possible start-up costs and the balancing price for the interval. The annual availability cost for the load rejection service was estimated by summing all of the plant commitment costs where the spinning reserve optimisation had scheduled load rejection reserve quantities less than the maximum requirement.

While the market rules specify the costs Synergy should be compensated for providing spinning reserve, no such guidance exists for load rejection reserve.[56] The costs that EY has included are:[57]

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

It does not include foregone profits from Synergy plant that might have run if Synergy plants were not rescheduled out of merit to provide sufficient load rejection reserve.[58] This is broadly consistent with the compensation approach for spinning reserve.

To some degree, EY's modelling replicates how AEMO's processes schedule load rejection reserve. However, the ancillary service standard sets a maximum value that EY applied as a fixed target quantity. The 2018 ancillary service report sets the standard as between 90 MW and 120 MW.[59]

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53 Clause 3.11.8A of the market rules.

54 AEMO (2018) 2018 Ancillary Services Report, AEMO, Perth, p20, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2018/2018-Ancillary-Services-Report.pdf

55 EY, Load Rejection Reserve Service Cost for 2019-20, 2020-21 and 2021-22: Public Version, 2018, pp 24-25

56 Clause 3.13.3B of the market rules

57 EY, Load Rejection Reserve Service Cost for 2019-20, 2020-21 and 2021-22: Public Version, 2018, p9

58 EY, Load Rejection Reserve Service Cost for 2019-20, 2020-21 and 2021-22: Public Version, 2018, p9

59 AEMO, 2018 Ancillary Services Report, 2018, p19, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2018/2018-Ancillary-Services-Report.pdf

EY's model was configured to de-commit units where the load rejection reserve requirement would reduce a generator's output below its minimum generation level.[60] However, by applying a fixed rather than a flexible requirement. EY may have overestimated the rescheduling requirement. Consequently, the modelling may overestimate the load rejection cost where the modelling does not reflect the actual standard and System Management's practice.

The extent to which modelled and actual load rejection reserve availability costs are disconnected will depend on the alignment between the availability of the reserve and the reserve requirement. For example, if reserve availability aligns well with the risk of transmission outage, then rescheduling generation should only be necessary infrequently. However, if reserve availability is not well aligned with the transmission outage risk, such that the availability is low but transmission fault risk is high, then rescheduling would be a more common occurrence.

AEMO's ancillary services report also identifies periods, on average three intervals per day, where AEMO did not reschedule generators to meet the required load rejection reserve quantity.[61] Instead of rescheduling generators to meet the load rejection reserve requirement, the report states:

> "Whilst there were periods of insufficient LRR [Load Rejection Reserve] to respond automatically in six seconds, a number of generators within the Balancing Portfolio acknowledged that if necessary they [Synergy] would trip their unit on AEMO instruction if the frequency could not be managed within the frequency operating standards"

This indicates differences between load rejection reserve scheduling practice and the modelling which warrants further consideration.

Not all of Synergy's generators are configured to provide load rejection reserve. The modelling assumes Muja would provide a substantial proportion of the load rejection reserve. Modelled rescheduling costs are understood to be higher where Muja is assumed to be on outage.[62]

Question

The ERA seeks feedback from market participants on the modelling approach, in particular on:

- how the load rejection reserve availability cost was estimated
- the potential for misalignment between the modelled cost and actual practice
- the costs included in calculating the load rejection reserve.

[60] EY, Load Rejection Reserve Service Cost for 2019/20, 2020/21 and 2021/22: Public Version, 2018, p15

[61] AEMO, 2018 Ancillary Services Report, 2018, p11, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2018/2018-Ancillary-Services-Report.pdf

[62] EY, Load Rejection Reserve Service Cost for 2019/20, 2020/21 and 2021/22: Public Version, 2018, p.2 and pp.30–31

4. System restart service

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 contracts are to ensure there remains capacity to start a generator independently of electricity supply from the network and commence re-energising the network.[63]

System Management has divided the SWIS into three sub-network areas for system restart purposes, and determined it requires a contracted system restart unit in each of the three sub-network areas being: North Metropolitan, South Metropolitan and South Country.[64] Generators providing system restart services are compensated through the "R" component of the Cost_LR parameter. Where there is a gap between the system restart values approved by the ERA and the value of contracts procured by AEMO, contracted values are recovered through a Cost_LR shortfall charge.[65]

AEMO let contracts with Synergy for services in the North Metropolitan (Pinjar units 3 and 5), and South Country (Kemerton GT11 and GT12), and with Perth Energy for the South Metropolitan service.[66]

When entering into an ancillary services contract, AEMO must:

- Seek to minimise the cost of meeting its ancillary service requirements.[67]
- Consider a competitive tender process unless it would not minimise the cost to the market of ancillary services.[68]
- Report the capacity, prices, and terms for calling the contracted facility to provide the capacity to the ERA.[69]

Restart costs are borne by market customers based on share of electricity consumption.[70] While this review process is rendered largely ineffective by the application of the shortfall charge,[71] the ERA intends to fulfil its functions under the market rules.

4.1 Contracted system restart costs

The restart cost component (the 'R' value) reflects the contracted system restart cost. AEMO's proposal contains only limited information outlining the basis for the contracted value. No information on the cost of restart services nationally or internationally was provided against

63 Clause 3.9.8 of the market rules

64 AEMO, 2018 Ancillary Services Report, 2018, p19 http://aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2018/2018-Ancillary-Services-Report.pdf

65 Clause 9.9.3B of the market rules

66 AEMO, 2018 Ancillary Services Report, 2018, p21, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2018/2018-Ancillary-Services-Report.pdf

67 Clause 3.11.9 (a) of the market rules

68 Clause 3.11.9 (b) of the market rules

69 Clause 3.11.10 of the market rules

70 Clause 9.9.1 of the market rules

71 Clause 9.9.3B of the market rules applies a 'shortfall charge' that would cover the difference between the ERA's determined values for the Cost_LR parameter and the contracted sum entered into by AEMO to provide load rejection reserve and system restart services.

which the proposal could be evaluated. The ERA intends to review the restart contracts and procurement process and compare the costs with those in other markets.

4.2 Past restart value determinations

Under the market rules, AEMO must procure the system restart service.[72] The market rules require AEMO to consider a tender process unless it would not meet its obligation to minimise the cost of providing the ancillary service.[73] However, the market rules provide no clear alternative should a tender process be unlikely to yield economically efficient prices.

The market rules place AEMO in a difficult position in procuring system restart services. In planning for system restart, the grid is broken into sub-regions, reducing the competitive pool of potential suppliers for each service. Sub-regions themselves do not compete against each other to provide a service because of the need for redundancy.

The rules do not specify any ceiling for the cost of procuring the service above which AEMO could discount the service requirement.[74] Therefore, AEMO's demand for the restart service is insensitive to prices offered by system restart service providers.

System restart service providers in sub-regions have market power because they do not compete to provide the service. They have the opportunity to charge price mark-ups above their cost of providing the service. These price mark-ups can be large because AEMO has no alternative procurement model for the service. While there is an obligation for Synergy to make its capacity available to provide a restart service, there exists no mechanism to mitigate the possibility of any market participant exercising market power when pricing a restart service.

This invites excessive pricing and AEMO will need to rely on the shortfall charge to ensure the system can recover from a system-wide outage.

In the previous determination, the ERA did not approve the full amount proposed for system restart services.[75] The ERA's determination stated the cost increase did not appear to reflect the cost to provide the service and so was inconsistent with the WEM objectives.[76] At the time of the previous determination, the sums were tendered and not contracted sums.

Among the concerns flagged in the ERA's determination in 2016 was a lack of a requirement for cost-benefit analysis in determining the level of redundancy in system restart services.[77] The ERA approved a nominal amount intended to cover the cost of a third restart service based on the previous contracted sum adjusted by the Consumer Price Index. The ERA further stated System Management could submit a revised proposal if it contracted for a third system restart service.

AEMO's proposal for the current review period reports it subsequently contracted and commissioned restart service contracts in the previous review period.[78] However, AEMO did

[72] Clause 3.11.4 of the market rules

[73] Clause 3.11.9 of the market rules

[74] The lack of a cost ceiling for the procurement of system restart service is the same as for some other ancillary services in the WEM, such as spinning reserve.

[75] ERA, Determination of the Ancillary Service Cost_LR Parameters from 2016/17 to 2018/19, 2016, p9

[76] ERA, Determination of the Ancillary Service Cost_LR Parameters from 2016/17 to 2018/19, 2016, p8

[77] ERA, Determination of the Ancillary Service Cost_LR Parameters from 2016/17 to 2018/19, 2016, p9

[78] AEMO, Proposed Cost_LR Values for Review Period from 1 July 2019 to 30 June 2022, 2018, Appendix 2

not submit a revised proposal reflecting the new contracts and the system restart contract sums materially exceeds the value determined by the ERA for the relevant review period.[79]

Questions

The ERA invites submissions exploring the system restart procurement process considering the gap between what the ERA determined to be a reasonable cost and what was subsequently contracted.

It also seeks views on the effect the shortfall charge has on AEMO's obligation to minimise the cost of procuring restart services under the market rules. In particular, it is interested in the views of market participants in alternative procurement mechanisms, including consideration of an administered system restart price.

[79] AEMO, 2018 Ancillary Services Report, 2018, p13 http://aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2018/2018-Ancillary-Services-Report.pdf