Economic Regulation Authority

Spinning reserve and load rejection reserve (margin values and Cost_LR parameters) settlement values 2023/24

Determination

30 March 2023

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Economic Regulation Authority

Level 4, Albert Facey House

469 Wellington Street, Perth WA 6000

Telephone 08 6557 7900

Email info@erawa.com.au

Website www.erawa.com.au

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

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Executive summary

Synergy is the default provider of ancillary services used by the Australian Energy Market Operator (AEMO) to maintain the security of the South-West Interconnected System (SWIS). The Economic Regulation Authority determines the settlement parameters that AEMO uses for compensating ancillary services providers in the Wholesale Electricity Market (WEM).

The three administered ancillary services are spinning reserve, load rejection reserve and system restart. Spinning reserve and load rejection reserve are complementary but opposite contingency reserve ancillary services, used to maintain system frequency when there is a sudden loss of supply or demand. System restart services are used to restore power to the electricity system, where the electricity system, or parts of the system, are subject to widespread blackout.

Under the Wholesale Electricity Market Rules, the ERA must determine the spinning reserve settlement parameters that apply to the upcoming financial year. The load rejection reserve and system restart parameters are determined for a three-year period, with annual updates, if necessary, in intervening years where there have been material changes.[1] The spinning reserve and load rejection reserve settlement parameters determined in this determination will apply from 1 July to 1 October 2023 only. In the new market, commencing on 1 October 2023, ancillary services payments will be set through real-time markets for each service and will not be determined by the ERA.

The ERA uses modelling to inform its determination. Market modelling forecasts the spinning reserve quantities, load rejection reserve costs and balancing market prices from which the settlement parameters used to reimburse Synergy (and other providers) for the provision of these services are calculated. In the forecast modelling the ERA accounts for several factors, including fuel costs, generator efficiency, maintenance costs, market demand, ancillary services requirements and other factors.

As this determination will apply only for three months, the ERA considered rolling over the last year's settlement parameters. However, following consideration of changes in the market after the 2022 determination, the ERA considered it prudent to revisit the values.

The two main factors driving changes in the ERA's 2023/24 modelling outcomes are higher expected gas prices, and lower and more frequent minimum demand trading intervals, when compared to the last year determination.

The ERA has forecast an increase in gas prices over 2023/24. This is partially driven by forecast tight coal supply conditions and greater dependence on gas fired generation and therefore, higher demand for gas fuel. Higher gas fuel costs place upwards pressure on ancillary service costs.

Secondly, rooftop solar output is predicted to lead to lower minimum demand levels and more frequent minimum demand trading intervals. The model finds the least cost operating mode during minimum demand periods to schedule generators to provide multiple services. Where this occurs, a large portion of the costs, usually related to the minimum generation level of a facility being recovered through the load following markets, and a lesser portion through the administered mechanism.

1 Wholesale Electricity Market Rules (WA), 1 February 2023, Rules 3.13.3A, 3.13.3B and 3.13.3C, (online).

As part of the determination process, the ERA held a public consultation on its issues paper and received one formal submission from Synergy. Synergy's submission raised the following main issues:

- Sufficiency of the reimbursement provided to Synergy.
- Simplifying assumptions included in the modelling.
- Load following quantities provided by non-Synergy facilities.
- Assumptions around costs and dispatch of Synergy's battery.

Synergy's submission also states the WEM Rules require the ERA determine settlement values to compensate Synergy for the difference in financial position but for the provision of ancillary services.[2] The ERA considers this position extends beyond the WEM Rules' specific requirements about the costs the ERA can and should consider in determining the settlement parameters.[3]

The ERA reviewed Synergy's feedback carefully, re-assessed the input assumptions that are included in its modelling, and considered whether it should re-model and re-calculate the ancillary services settlement parameters. All issues raised in Synergy's submission are address in more detail throughout this determination. After considering Synergy's feedback, the ERA considered changes were not required to the modelling or the values proposed in the issues paper.

Spinning reserve settlement parameters (peak and off-peak margin values and spinning reserve quantity)

The ERA must determine the parameters for spinning reserve (referred to as 'margin values' for peak and off-peak trading intervals) annually.

The interplay of factors that influence the spinning reserve settlement parameter quantities, in the ERA's modelling, such as forecast facility scheduling decisions, ancillary services quantities, balancing market prices, and cost allocation between individual ancillary services has ultimately resulted in a relatively small changes in the margin values compared to the ERA's 2022 determined margin values.

In accordance with clause 3.13.3A of the WEM Rules, the ERA determines that:

- The values of margin peak and margin off-peak parameters for 2023/24 are 10.93 per cent and 6.85 per cent respectively, with average spinning reserve quantities of 284 MW and 198 MW respectively.

The details for this determination are explained in Section 3.1.

Load rejection reserve and system restart ancillary services settlement parameter (Cost_LR)

Load rejection reserve and system restart settlement parameter (referred to as 'Cost_LR') are determined three-yearly. AEMO increased the load rejection reserve quantity from 90MW in the ERA's 2022 determination to 97MW from 1 July 2022. This has triggered the need for the ERA to reassess the load rejection reserve parameter, the "L" component in Cost_LR, as part of this determination.

2 Synergy, 17 February 2023, Submission to *Spinning reserve and load rejection reserve (margin values and Cost_LR parameters) settlement values 2023/24 - Issues paper*, p. 1, (online).

3 Wholesale Electricity Market Rules (WA), 1 February 2023, Rules 3.13.3A, 3.13.3B and 3.13.3C, (online).

The system restart contracts are unchanged from the ERA's 2022 determination and remain in effect over the full three-year contracts' term. They have not been reassessed in this determination.

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

- The value of the load rejection reserve cost is $4.91 million for 2023/24 and $1.24 million for the first three months of 2023/24.
- The system restart costs remain unchanged from the values determined in the ERA's 2022 determination.[4]

[4] Economic Regulation Authority, 2022, *Spinning reserve, load rejection reserve, and system restart ancillary service (margin values and Cost_LR parameters) settlement values 2022/23 – Determination*, (online).

1. Background

The Economic Regulation Authority determines the parameters used to calculate payments for spinning reserve, load rejection reserve and the system restart service. Spinning reserve and load rejection reserve are complementary but opposite ancillary services, used to maintain system frequency when there is a sudden loss of supply or demand. The system restart service is needed where the electricity system or parts of the system are subject to widespread blackout. With the onset of the new market, ancillary services will be renamed to 'essential system services'.

Synergy is the default provider of the spinning reserve and load rejection reserve ancillary services.[5]

The ERA determines the administered ancillary service settlement parameters following consultation. The ERA published an issues paper for public consultation between 20 January 2023 and 17 February 2023 and sought stakeholder feedback for this determination.

The calculation of parameters for the spinning reserve and load rejection reserve uses an electricity market model to forecast balancing prices and ancillary services quantities to determine the spinning reserve and load rejection reserve availability costs and from these derive the settlement parameters.[6] The ERA must determine the parameters for spinning reserve (margin values) annually, while the load rejection reserve and system restart parameter (Cost_LR) are determined three-yearly, with annual updates, if necessary, in intervening years, where there have been material changes.

This determination also includes a review of the load rejection reserve payments, in response to AEMO increasing the maximum load rejection requirement from when the previous three-year determination was made.[7]

The same parameter (Cost_LR) used for the load rejection reserve payments also covers payments for the system restart service. The ERA must determine revised values for system restart if the values are materially different from a standing determination.[8] As there have been no changes to AEMO's system restart service arrangements since the ERA's last determination in 2022, this determination did not consider system restart costs.[9]

1.1 Requirements for the ERA's determination

Payments to Synergy for providing a spinning reserve service are based on the calculation method specified in the WEM Rules.[10] The clearing price in the balancing market, the quantity of spinning reserve provided by Synergy and a constant parameter - the margin peak percentage, or margin off-peak percentage depending on the type of trading interval -

5 Wholesale Electricity Market Rules (WA), 1 February 2023, Rule 3.11.7A, (online).

6 Wholesale Electricity Market Rules (WA), 1 February 2023, Rules 3.13.3A, 3.13.3B and 3.13.3C, (online).

7 Economic Regulation Authority, 2022, *Decision on the Australian Energy Market Operator's 2022/23 ancillary services requirements*, (online).

8 Wholesale Electricity Market Rules (WA), 1 February 2023, Rule 3.13.3C, (online).

9 Economic Regulation Authority, 2022, *Spinning reserve, load rejection reserve, and system restart ancillary service (margin values and Cost_LR parameters) settlement values 2022/23 – Determination*, (online).

10 Wholesale Electricity Market Rules (WA), 1 February 2023, Rule 9.9.2(f), (online).

determine the payment quantity.[11] Load rejection reserve and system restart are paid to Synergy and any other contracted system restart service providers as a lump sum.

The ERA has estimated ancillary service settlement parameters to apply from the start of the 2023/24 financial year until the new market commences. From 1 October 2023 the ERA's determination will be superseded by a new market-based mechanism.

In accordance with the WEM Rules, when determining settlement parameter values the ERA must consider the Wholesale Market Objectives and:[12]

- The profit Synergy foregoes from withholding capacity to provide the ancillary services.
- The loss in efficiency of Synergy's generators from operating at only part load prior to being dispatched to provide spinning reserve.

While not explicitly stated in the WEM Rules, the ERA's determination also considers out-of-merit costs where generators are scheduled to provide ancillary services and where those costs are not otherwise recovered from market mechanisms (such as through interactions with load following ancillary services).[13] The basis for cost allocation is outlined further in Appendix 7.

1.2 The ERA's process

As the spinning reserve and load rejection reserve settlement parameters are determined in advance, the ERA must forecast market outcomes. For this, the ERA uses modelling. The likely costs are a function of many factors without necessarily a linear relationship and modelling presents the best means of estimating economically efficient future values. The determination is based on a two-stage consultation process and electricity market modelling. The model the ERA used for this determination is functionally the same as that used for the 2022/23 determination, with refined reserves provision settings and revised input assumptions.

1.2.1 Consultation

The first stage of the consultation process for this determination occurred in October 2022, when the ERA confidentially provided selected market participants with the set of input assumptions for their generators, for market participants to review and amend.[14] The input assumptions included the physical and economic parameters necessary to determine, among other variables, the short run marginal cost of market generators. This data collection and assumptions consultation was a closed process due to the confidential nature of the data.

The ERA also held one-on-one meetings and discussions with some market participants to clarify specific aspects of the data provided and to discuss some follow up queries. All information provided in course of the consultation stages have been included in the modelling.

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11 A peak trading interval occurs between 8:00am and 10:00pm. Off-peak trading intervals occur between 10:00pm and 8:00am.

12 Wholesale Electricity Market Rules (WA), 1 February 2023, Rules 3.13.3A and 3.13.3B, (online).

13 The market's settlement equations assume the load following provision would be deployed to manage contingency. The settlement equations net off the quantity of upwards spinning reserve from the settlement quantity.

14 All market participants were consulted and provided updates related to their facilities in May 2022, as part of a consultation process conducted for the ERA's WEM review 2022. The October 2022 data collection focused on material changes since then.

The ERA engaged with AEMO to explore operational and ancillary services scheduling practices. These meetings informed how to best reflect AEMO's operational practice in the modelling.[15]

The second stage of consultation began on 20 January 2023 with the publication of the issues paper and closed on 17 February 2023. The issues paper outlined the findings of the ERA model and the expected settlement parameter values.[16]

The ERA received one submission to the public consultation from Synergy.

Synergy's submission expressed concern that the proposed margin values and Cost_LR parameters would not provide adequate compensation. It also expressed general concerns around the accuracy of the modelling and the reliance on simplifications adopted in the model to determine the ancillary services parameters. Synergy's submission is published on the ERA website.[17] The ERA's response to Synergy's concerns is presented throughout this determination, and in appendices 3 and 5.

1.2.2 Modelling process

Electricity market modelling for the determination was conducted in two stages. The first stage was a calibration exercise where the market simulation model was back-cast over 2021/22 financial year. Through this process, the modelling eliminated the effect of environmental parameters, such as the output of non-scheduled generators and electricity demand, to test how faithfully the model scheduled generators and emulated the market's historical pricing outcomes.

Once the model was operating satisfactorily, the ERA undertook forecasting for the 2023/24 period. The forecasting consisted of a 'base case' and sensitivity modelling. The sensitivity modelling was designed to isolate and understand the effects of input parameters subject to relatively substantial degrees of change and those input parameters expected to have the greatest influence on forecast results.

The base case aligns the input parameter electricity demand with AEMO's expected demand in the Electricity Statement of Opportunities and expected rooftop solar growth.[18]

The base case adjusts the operational properties of generators to reflect their current bidding behaviour, then includes AEMO's expectation on how ancillary services will be scheduled and operated during the forecast period. Appendix 5 provides a more detailed explanation of the assumptions, Appendix 6 details the sensitivity analysis, and Appendix 8 outlines the model calibration.

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15 These discussions relate to the operational decision-making processes and identifying how AEMO system operators schedule generators and reflecting this in the programmed model constraints. This includes updating market contingencies and expected operating practices and ancillary service quantities. For example, the model reflects AEMO's current views and practice on the need for spinning reserve to cover rooftop solar systems lost during contingency events, and the expected ancillary service requirements for load following ancillary service and load rejection reserve.

16 Economic Regulation Authority, 2023, *Spinning reserve and load rejection reserve (margin values and Cost_LR parameters) settlement values 2023/24 - Issues paper,* (online).

17 Synergy, 17 February 2023, Submission to *Spinning reserve and load rejection reserve (margin values and Cost_LR parameters) settlement values 2023/24 - Issues paper,* (online)

18 Australian Energy Market Operator, 2022, *2022 Wholesale Electricity Market Electricity Statement of Opportunities*, (online).

1.2.3 Determination period

The ERA prepared a 12-month forecast using a PLEXOS-based model covering the period from July 2023 to June 2024. With the commencement of the new market, the current mechanism and the ERA's determination will be superseded by new market-based mechanisms from 1 October 2023.[19] Therefore, this determination will apply for the three months from 1 July 2023 to 1 October 2023.

The ERA must review the costs if it determines there have been material changes in costs rendering a standing determination outdated.[20] The system restart contracts cover the period 2022/23, 2023/24 and 2024/25, and have not been considered in this determination. The approved values have not changed from the ERA 2022 determination.[21]

[19] Wholesale Electricity Market Rules (WA), 1 February 2023, Rules 3.13.3A, 3.13.3B and 3.13.3C, (online).

[20] Wholesale Electricity Market Rules (WA), 1 February 2023, Rule 3.13.3C, (online).

[21] Economic Regulation Authority, 2022, *Spinning reserve, load rejection reserve, and system restart ancillary service (margin values and Cost_LR parameters) settlement values 2022/23 – Determination*, (online).

2. Spinning reserve and load rejection reserve

Spinning reserve and load rejection reserves are the ancillary services for when the electricity system suffers a substantial loss in supply or demand. Where a generator fails or a transmission connection is lost, and the frequency cannot be brought back under control, the system can result in cascading failures with each disconnection triggering further disconnections resulting in a widespread blackout.

AEMO has a limited window within which to stabilise system frequency before under frequency load shedding starts disconnecting customers and the associated rooftop solar systems. AEMO must activate these reserves rapidly to arrest changes in power system quality before generators' capacity to accommodate faults is exceeded and their protection settings disconnect them - typically within six seconds.

2.1 What is spinning reserve?

Spinning reserve refers to generation capacity, battery capacity, and interruptible load used to maintain power system frequency within the electricity system's tolerance range when there is a sudden, unexpected increase in demand or loss of supply or a transmission line. This might occur when a generator or network asset trips or fails. The WEM Rules allow spinning reserve to be provided by scheduled generators, interruptible loads, a combination of the two, or batteries.[22,23]

The WEM Rules and Technical Rules require enough spinning reserve to be able to cover whichever is the greater of:

- 70 per cent of the largest output of any generator
- 70 per cent of the largest contingency event that would result in generation loss[24]
- the expected maximum increase in demand over a period of 15 minutes.[25]

The estimated spinning reserve quantities derived from the ERA's modelling used in the determination on margin values in 2022/23 were 284MW in peak periods and 235MW in off-peak periods.

Following AEMO's review and analysis of how the system has historically responded to contingencies, AEMO assumes that a proportion (nominally 10 per cent) of rooftop solar generation will disconnect from the network following a contingency event.[26] AEMO considers that this risk follows other contingencies on the electricity network, such as the loss of a

[22] While WEM Rule 3.9.2 does not explicitly state batteries, it is understood batteries above 10MW batteries must register as a scheduled or non-scheduled generator. Refer to AEMO, 2019, Participation guidelines for energy storage systems in the WEM, p. 37, (online).

[23] Wholesale Electricity Market Rules (WA), 1 February 2023, Rule 3.9.2, (online).

[24] Western Power, 2016, *Technical Rules for the South West Interconnected System*, Revision 3, Rule 2.2.1, pp. 6-7, (online).

[25] Wholesale Electricity Market Rules (WA), 1 February 2023, Rule 3.10.2(a), (online).
Western Power, 2016, *Technical Rules for the South West Interconnected System*, Revision 3, Rule 3.3.3.3 (b), p. 44, (online).

[26] The term 'contingencies' relates to asset failures that result in unexpected disconnection of energy or demand from the electricity system. This could be a generator, a transmission line, substation, a group of consumers, a battery, or a combination of the above.

generator, and needs to be covered through an increased spinning reserve quantity to maintain system security at all times.[27]

2.2 What is load rejection reserve?

Load rejection reserve provides a rapid decrease in generation output when a large amount of load is lost, such as when a transmission line trips off. When a large load is lost, system frequency increases. The generators providing load rejection reserve automatically reduce output to maintain system frequency within the limits necessary for system security. These large load rejection events typically happen a few times each year.

AEMO sets the quantity of load rejection reserve necessary to meet the standard described in the WEM Rules. The standard for load rejection reserve must be sufficient to keep frequency below 51 Hertz for all credible load rejection events. The quantity of capacity needed to maintain the standard for load rejection reserve may be relaxed by up to 25 per cent where AEMO considers the probability of transmission faults to be low.[28] AEMO's 2022/23 ancillary services requirements increased the maximum load rejection requirement to 97MW, from 90MW in the previous year.[29]

2.3 System restart service

System restart is the ancillary service provided by generators capable of re-energising the electricity system, or parts of the electricity system, following a full system blackout. Generators that can start without grid supply will re-energise part of the transmission network, which then allows other generators to start. Because there have been no changes to AEMO's system restart service requirements since the ERA's last Cost_LR determination in 2022, the R component of COST_LR has not been reassessed as part of this determination.[30]

2.4 How ancillary service costs are recovered from the market

The costs of spinning reserve, load rejection reserve and system restart services are recovered from market participants through the mechanisms described in this section. Ultimately generators and retailers alike pass these costs through to electricity consumers in the WEM.

2.4.1 Spinning reserve service

Synergy's costs to provide the spinning reserve service are referred to as the availability cost. This is the sum of forecast costs comprising foregone revenue, change in generator costs, and out of merit generation costs. The estimated availability cost is then converted to a proportion of the forecast balancing price (a percentage margin).

27 AEMO presentation to the ERA on distributed photovoltaic trip impact on frequency stability 11 November 2021.

28 Wholesale Electricity Market Rules (WA), 1 February 2023, Rule 3.10.4, (online).

29 Economic Regulation Authority, 2022, *Decision on the Australian Energy Market Operator's 2022/23 ancillary services requirements*, (online).

30 Economic Regulation Authority, 2022, *Spinning reserve, load rejection reserve, and system restart ancillary service (margin values and Cost_LR parameters) settlement values 2022/23 – Determination*, p. 13 (online).

The availability payments (the compensation for providing the service) should approximate the availability cost for spinning reserve. The availability payments are determined via multipliers (the margin values for peak and off-peak) that are applied to the actual balancing market price and the quantity of spinning reserve modelled for the period via Formula 1.

Formula 1

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

where at is availability payment for an interval t,

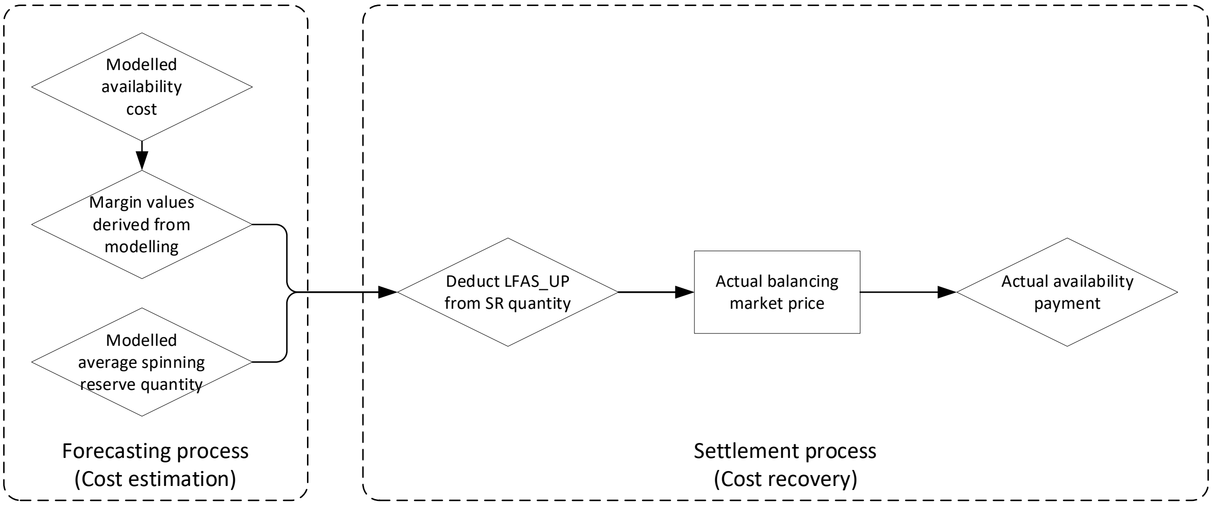
m is margin value,

p_t is balancing price for the interval and

q_t is spinning reserve quantity for the interval.

The values determined by the ERA, the peak and off-peak margin values and the spinning reserve quantities, are applied to the actual balancing market price. This occurs independently of the actual quantities of spinning reserve scheduled in the market. This process is indicated in Figure 1.

Figure 1: Application of modelled values to cost recovery



Source: ERA

As discussed in Section 4.4, Synergy receives no compensation when prices are negative. The margin values are adjusted to enable Synergy to recover the cost it incurs when prices are negative, during intervals when the balancing price is positive.

Other providers of spinning reserve receive compensation based on their contracted cost. AEMO’s spinning reserve contracts apply pricing at a discount to the margin values to ensure the contracted values are lower than Synergy’s prices.[31]

31 AEMO can only contract third-party spinning reserve providers if it is expecting a shortfall in the service or where the cost will be lower than the default provider. For example, if the margin values were 20 per cent, a third-party provider may discount the contracted value by 1 per cent and receive an equivalent margin value of 19 per cent to provide spinning reserve.

2.4.2 Load rejection reserve service and system restart service

Load rejection reserve and system restart costs are recovered from the market and paid to providers monthly as a lump sum.

Synergy is compensated for providing load rejection reserve through the “L” component of Cost_LR. The cost of providing load rejection reserve is borne by market participants and based on their share of consumption.

The ERA reviews AEMO's proposed system restart costs against the WEM Rules requirements and determines system restart parameters consistent with the WEM Rules. Generators providing system restart services are compensated through the R component of the Cost_LR parameter. System restart costs are borne by market customers and based on their share of electricity consumption.[32]

Providers of system restart service are paid according to their contracts and any shortfalls in the ERA-approved amount are recovered through a shortfall charge. The shortfall charge collects any difference between the sum contracted between AEMO and suppliers of system restart service, and the sum determined by the ERA.

Cost_LR is determined on a three yearly basis with annual reassessments if necessary.[33] The costs of the ‘L’ component of the Cost_LR parameter has been recalculated due to the increase to the load rejection reserve quantities from June 2022.[34]

2.4.3 Cost allocation and recovery

There are overlapping ancillary services providing frequency control management over different time frames. The allocation of costs to the administered mechanisms set through this determination process will depend on what costs are recovered through what market mechanisms.

Costs are allocated first to the balancing market, then through the load following markets, with the residual allocated to load rejection reserve and spinning reserve. Only the incremental costs not recovered through other mechanisms are included in calculating the availability costs for load rejection reserve and spinning reserve.

The principles of cost recovery and examples of which costs are included in the availability cost are covered in detail in Appendix 7.

32 Wholesale Electricity Market Rules (WA), 1 February 2023, Rule 9.9.1 (online).

33 Wholesale Electricity Market Rules (WA), 1 February 2023, Rules 3.13.3B and 3.13.3.C, (online).

34 Economic Regulation Authority, 2022, *Decision on the Australian Energy Market Operator’s 2022/23 ancillary services requirements*, (online).

3. The ERA's determination

This section provides the ERA's values for the current determination. Section 4 then outlines how the ERA arrived at these values.

3.1 Spinning reserve (margin values) for 2023/24

The spinning reserve numbers are based on the ERA's base case modelling scenario and are shown in Table 1. Both the availability costs and the margin values (peak and off-peak) are lower than in 2022/23, while the spinning reserve quantity is the same or lower for peak and off-peak periods respectively. The margin values are a function of the quantity of negatively priced intervals, the average positive balancing market price, and the availability cost.

The average balancing market prices forecast in this year's modelling are higher by 34 per cent and 27 per cent for peak and off-peak periods respectively than in last year's forecast model. This means that the margin values do not need to rise to the same degree to compensate Synergy for the spinning reserve services it provides. Pricing outcomes in the context of the market modelling are explained in Section 4.

Table 1: Determined spinning reserve settlement parameters

Time period	Availability cost ($m)	Spinning reserve quantity (MW)	Margin values (%)	Availability cost ($m)	Spinning reserve quantity (MW)	Margin values (%)
	2022/23 (determined)			2023/24 (determined)		
Peak	11.84	284	11.44	9.72	284	10.93
Off-peak	2.91	235	6.57	2.26	198	6.85

Source: ERA modelling

3.2 Load rejection reserve costs for 2023/24

The new market is scheduled to start 1 October 2023. The ERA has modelled load rejection reserve costs (Table 2) for all of 2023/24 and for the first 3 months of 2023/24. The ERA conducted modelling on the full 2023/24 year, because of the sensitivity of the modelling to out of merit costs driven by seasonal outputs of rooftop solar generation.

Table 2: Determined load rejection reserve values ($ million)

Time period	Load rejection reserve availability cost (determined)		
	2022/23 ($m)	2023/24 ($m)	2023/24 (July, August and September 2023 only) ($m)
Peak	2.73	2.11	0.69
Off-peak	2.08	2.8	0.55
Total	4.81	4.91	1.24

Source: ERA modelling

3.3 System restart costs for 2022/23 to 2024/25

There are no changes to the system restart costs for the period 2022/23 to 2024/25 and these costs are the same as determined in 2022.[35] The contract values are summarised in Table 3.

Table 3: AEMO's contracted system restart costs ($) (determined)

	2022/23	2023/24	2024/25
Contracted sum	3,418,696	3,420,859	3,418,696

Source: AEMO

[35] Economic Regulation Authority, 2022, *Spinning reserve, load rejection reserve, and system restart ancillary service (margin values and Cost_LR parameters) settlement values 2022/23 – Determination*, p. 13 (online).

4. Market modelling

The ERA has previously explained the disconnection between the spinning reserve compensatory mechanism (margin values) and the accrual of out of merit costs to provide the service.[36] The trend for ancillary service costs to be driven by out of merit costs rather than foregone energy sales is forecast to continue in 2023/24. Sections 4.4 to 4.6 outline the relationship between negatively priced intervals, out of merit costs and the compensatory mechanism.

The major market elements expected to influence the cost of spinning reserve and load rejection reserve in 2023/24 are:

- higher gas fuel prices
- lower minimum demand levels and more frequent minimum demand trading intervals.

These factors and the interactions between them have driven the focus of the ERA's modelling.

Synergy's submission questioned the peak spinning reserve quantity being almost identical to that of the 2022/23 determination despite what it considered the "the new and continued AEMO practice of allocating ~10% of DPV solar generation to the SR contingency on the basis that this volume will likely disconnect from the network following a contingency event".[37] This element of the model of allocating 10 per cent of distributed rooftop solar to the spinning reserve contingency has been a feature of the ERA's modelling since the 2021 determination.[38] This additional contingency was applied in the ERA's 2022/23 forecast modelling and is described in the 2022 determination.[39]

Rooftop solar generation is expected to increase over the forecast period.[40] Inverter standards were revised in December 2020 and became mandatory in December 2021.[41] However, in the absence of information on material non-compliance, rooftop solar systems installed beyond December 2021 are assumed to be compliant with the new inverter performance standards. This means that the older, non-compliant rooftop solar installations, that could disconnect following a contingency on the network, peaked prior to the 2022/23 determination, resulting in no increase in spinning reserve quantity despite increasing rooftop solar penetration.

4.1 Gas fuel prices

Since the back-cast period, fuel availability has affected the operating environment in the SWIS. Concerns exist for the contractual performance of Premier Coal and Griffin Coal.[42] The

36 Economic Regulation Authority, 2021, *Ancillary services costs: Spinning reserve load rejection reserve and system restart costs (Margin values and Cost_LR) for 2021/22 – Determination*, pp. 19-20, (online).

37 Synergy, 17 February 2023, Submission to *Spinning reserve and load rejection reserve (margin values and Cost_LR parameters) settlement values 2023/24 - Issues paper,* p. 2, (online).

38 In the 2021 determination, the ERA applied the 10 per cent rooftop solar contingency only to the North Country contingency, but following later advice from AEMO, in the 2022 determination this contingency has been applied across the WEM.

39 Economic Regulation Authority, 2022, *Spinning reserve, load rejection reserve, and system restart ancillary service (margin values and Cost_LR parameters) settlement values 2022/23 – Determination*, p. 7 (online).

40 Australian Energy Market Operator, 2022, *2022 Wholesale Electricity Market Electricity Statement of Opportunities*, p. 37, (online).

41 Standards Australia, 2020, AS4777, (online).

42 Western Australia, 18 October 2022, COAL-FIRED POWER STATIONS – PREMIER COAL, Legislative Assembly (W.J. Johnston), p. 4580a, (online).

ERA has sought information on expected deliveries and conditions during the forecast period from Summit Southern Cross Power and Synergy.

Reduction in coal availability increases dependence upon gas fired generation. The ERA expects this will increase prices in an already tight gas market. The gas demand forecast informing AEMO's most recent Gas Statement of Opportunities assumes that the coal availability issues will resolve no later than mid-2023.[43] Beyond this, AEMO assumes gas consumption increases following coal facility retirements.

The ERA's modelling includes a more conservative scenario where the coal supply issues persist throughout the forecast window, the announced coal retirements occur as scheduled, and no further retirements occur. The ERA modelled the future gas prices using an auto regressive integrated moving average (ARIMA) model. Forecast maximum monthly gas prices ranged between \$6.23/GJ for September 2022 and \$8.50/GJ for June 2024, with a mean maximum monthly price of \$7.31/GJ.[44] This is outlined further in Appendix 4.

The model is calibrated on past behaviour, which is not always a good indicator of future behaviour, particularly in complex markets. For example, changing conditions may alter participants' willingness to generate, when and how much they generate, and whether to reserve or on-sell fuel to other users. To ensure the influence of changing market conditions is understood, the ERA has conducted fuel price sensitivities applying a market wide spot gas driven opportunity cost, substituting contracted gas values.

For two of the sensitivity scenarios that tested the model's sensitivity to fuel input prices, the ERA used the same forecast gas prices as those used for the Energy Price Limits studies.[45] One sensitivity applied a single gas forecast price during the whole modelling period to all gas fired generation facilities, while the second used a monthly gas price increases based on the gas forecast described in Appendix 4. Applying a uniform market price increased the cost of spinning reserve and load rejection reserve by around 16 per cent and a uniform rising fuel price by 24 per cent. The sensitivities are discussed in Appendix 6.

4.2 Minimum demand

Rooftop solar continues to be a substantial influence on the daily, weekly, and seasonal demand profiles in the WEM. Minimum demand levels and the frequency of minimum demand trading intervals are driven by rooftop solar output. Consistent with previous modelling exercises, the ERA prepared demand profiles as a model input, deducting distributed generation from an underlying demand forecast. The ERA used expected solar growth forecasts from AEMO's Electricity Statement of Opportunities and conducted a sensitivity model run using these forecasts.[46] The sensitivity had only a marginal effect on forecast ancillary service costs (Appendix 6).

Where forecast operational demand falls below a threshold advised by AEMO, the State Government's emergency solar management arrangements are assumed to place a floor on

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43 Robinson Bowmaker Paul, *2022, Gas Powered Generation Forecast Modelling 2022 – Final Report*, p. 20, (online).

44 While the method used was identical to that of the energy price limits, the forecast for the final publication of the energy price limits was updated using more recent data.

45 Economic Regulation Authority, 2022, *Energy price limits 2022, Draft determination*, p. 16, (online).

46 Australian Energy Market Operator, 2022, *2022 Wholesale Electricity Market Electricity Statement of Opportunities*, p. 36, (online).

operational demand.[47,48] The demand for system security services is highest when demand is lowest. Scheduling decisions under low load conditions have a material effect on the costs to provide and maintain ancillary services as discussed in Section 4.3.

4.3 Modelling interactions and ancillary service costs

The modelling indicates a modest reduction in the cost to provide spinning reserve. The issues raised in Sections 4.1 and 4.2 work to cancel each other out. Lower coal continues to drive higher gas prices which is expected to increase costs. However, out of merit costs reduce because of the overlap between generators providing the ancillary services.

The peak margin values are lower, and margin values off-peak are only marginally higher than in the previous year, but will be applied to actual balancing prices in the forecast period. Over recent years, average balancing market prices have not materially reduced despite an increasing amount of low-cost renewable generation on the system. In 2022 reduced coal availability saw a substantial increase in balancing prices in the WEM (Table 4). If these conditions continue, the ERA's modelling indicates higher prices are likely to persist into 2023.

Table 4: Balancing market pricing outcomes

Year	Average balancing market price ($/MWh)		Comment
	Peak	Off-peak	
2012	$59.96	$45.22	Carbon pricing mechanism in effect
2013	$59.60	$37.95	
2014	$57.38	$42.77	
2015	$52.23	$32.79	
2016	$63.18	$41.37	
2017	$67.22	$46.07	
2018	$51.24	$40.51	Increased solar and low-cost generation energy the market
2019	$49.38	$41.22	
2020	$51.42	$45.39	
2021	$52.38	$45.24	
2022	$67.98	$62.84	Reduced coal availability

Source: ERA analysis of AEMO data

The market is increasingly operating under extreme conditions. The projected increase in rooftop solar in the forecast period suggests the market will increasingly encounter periods of extremely low demand. In the modelling, the ERA has used values consistent with the

47 AEMO presented to the ERA on 21 September 2022.

48 Government of Western Australian, *Emergency Solar Management*, (online), [accessed 27 November 2022] and
Energy Policy WA, 2021, *Low Load Responses – Distributed Photovoltaic Generation Management, Position Paper*, pp. 1-5, (online).

Electricity Statement of Opportunities where non-scheduled generators' output is curtailed by AEMO to maintain system security.

Synergy's submission compares the 2023/24 ancillary services parameters against the ERA's 2021 determination.[49,50] Material differences in the market dynamics between the 2021/22 determination and this determination reduce the applicability of such a comparison. For one, there is no battery included in the 2021/22 forecast model, while the battery is operational throughout the full 2023/24 forecast period. Other factors contributing to a materially different modelling set of inputs include, but are not limited to:

- Changes to fuel mix with the retirement of generators (Muja 5 and Perth Power Partnership), and addition of two waste-to-energy facilities.
- Changes to the demand profile.
- Higher rooftop solar quantities.
- Fuel availability.
- The treatment of the 10 per cent rooftop solar contingency.

These variances in input assumptions have resulted in different pricing outcomes in both forecasts, with average balancing prices in the 2023/24 forecast model being 23 per cent and 112 per cent higher that in the 2021/22 forecast, for peak and off-peak trading intervals respectively.

Unlike the current WEM, the ERA PLEXOS model is co-optimised, that is the model will seek to minimise the total operational cost of providing energy and all ancillary services. At times of low demand PLEXOS will seek to minimise the overall system cost, balancing several needs and constraints including:

- the cost to provide electricity and avoid unserved energy
- the cost to provide all ancillary services and avoid ancillary service shortfalls
- the future need for generation capable of increasing output into the evening peak.

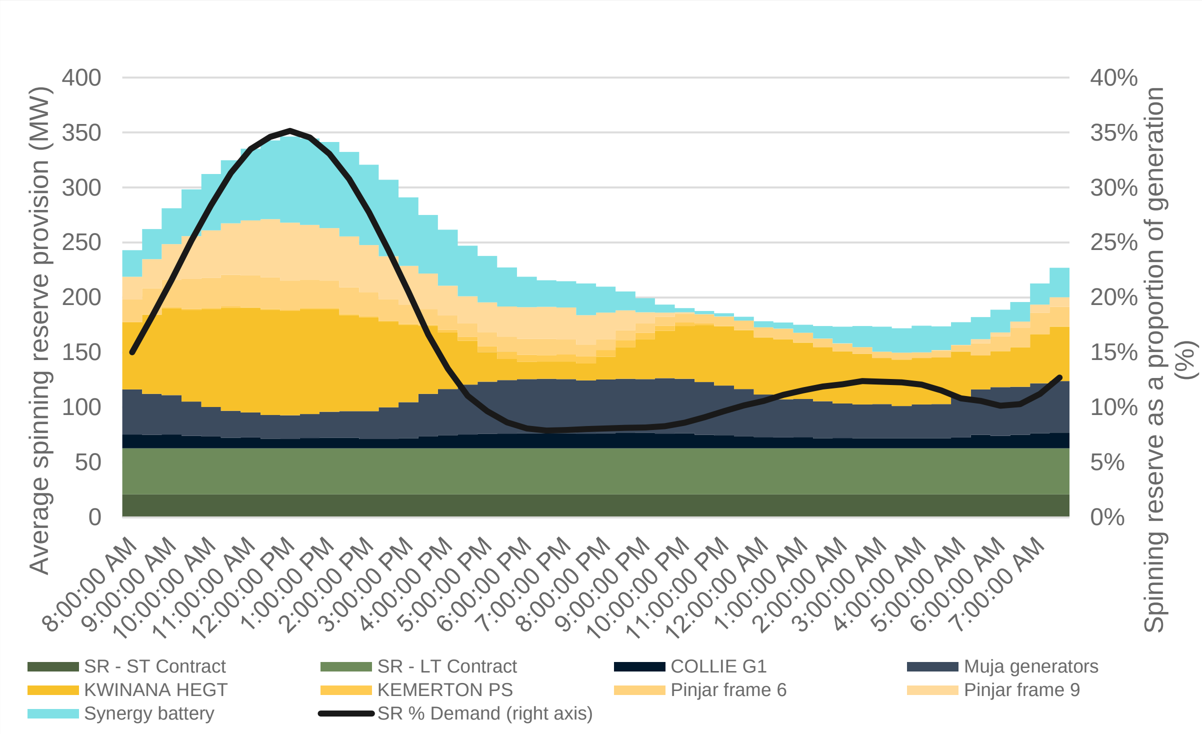
Low demand is driven by rooftop solar output. Rooftop solar comprises a supply risk in and of itself in addition to the potential generator loss. This is proportionate to the quantity of distributed generation output during an interval.

Figure 2 shows the average spinning reserve requirement and provision by time of day and its proportion of average electricity demand. The profile of the spinning reserve 'risk', or the quantity of spinning reserve the model needs to cover increases during the period when resource flexibility is lowest. It rises from a typical figure of between 10 to 15 per cent to a third of electricity demand when demand is low.

49 Economic Regulation Authority, 2021, *Ancillary service costs: Spinning reserve, load rejection reserve and system restart costs (Margin values and Cost_LR) for 2021/22 – Determination*, (online).

50 Synergy, 17 February 2023, Submission to *Spinning reserve and load rejection reserve (margin values and Cost_LR parameters) settlement values 2023/24 - Issues paper,* p.2, (online).

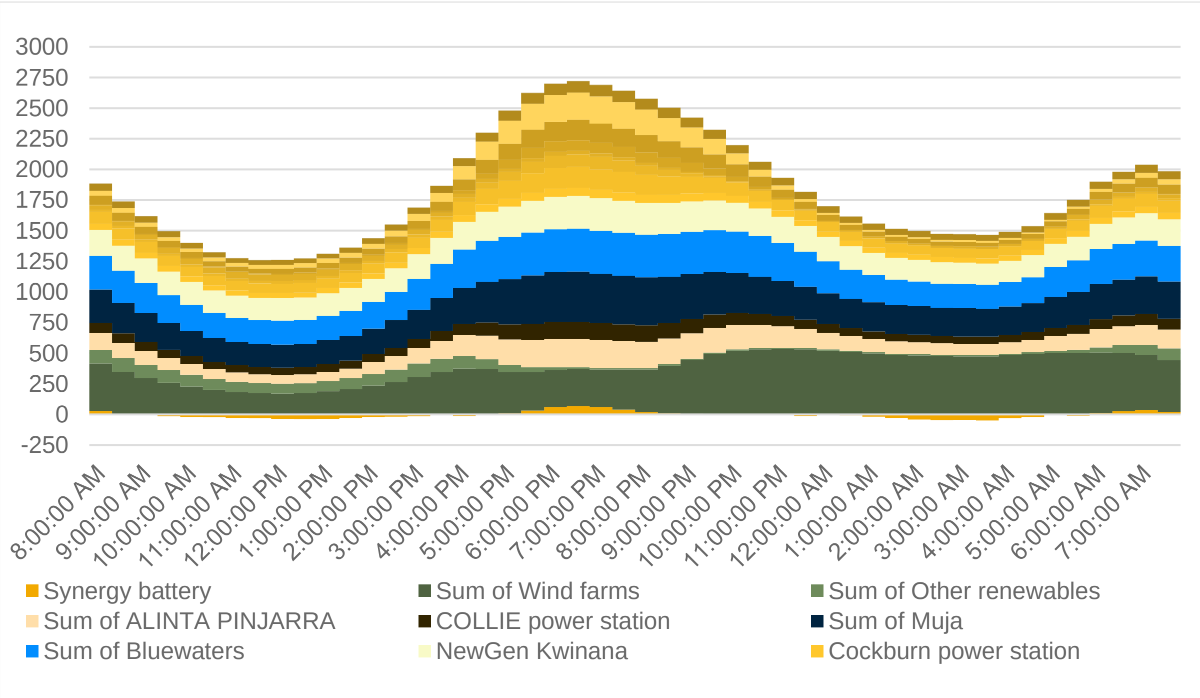
Figure 2: Average spinning reserve provision and demand



Source: ERA modelling

As electricity demand falls larger generators, particularly inflexible thermal plant like coal fired generators and combined cycle gas turbines, will reduce their output (Figure 3). As demand increases from the trough into the evening peak, the larger generators increase their output including the coal facilities.

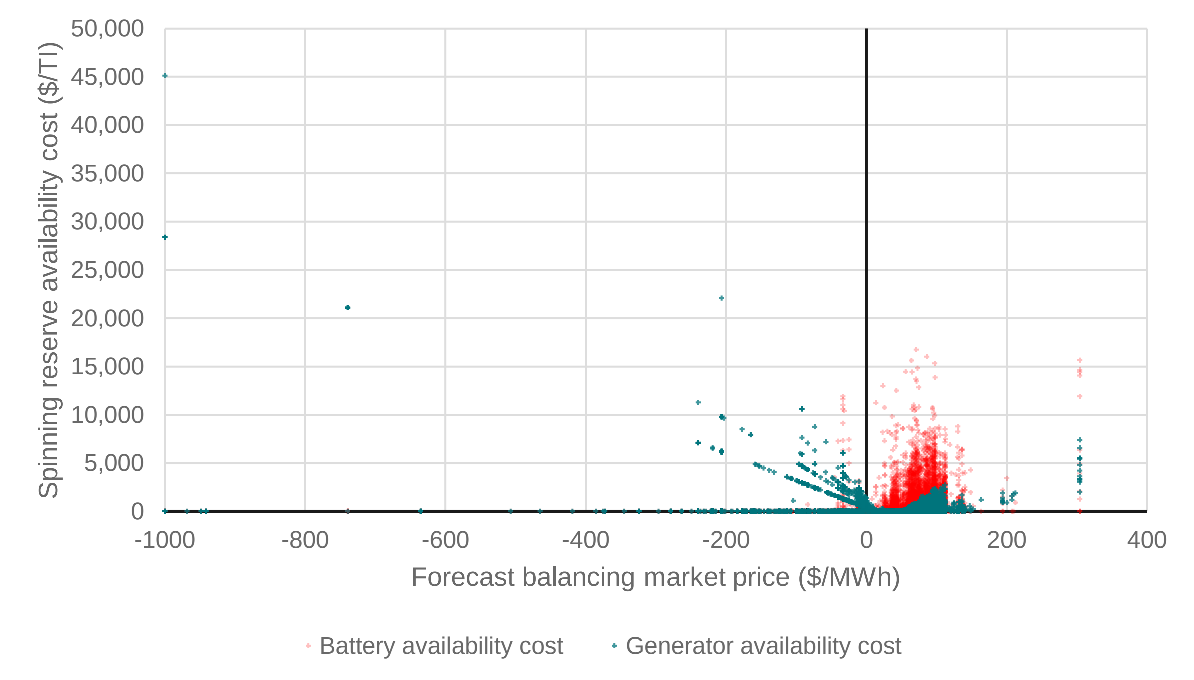
Figure 3: Average generation by generator and time of day



Source: ERA modelling

The cost of providing spinning reserve has a u-shaped distribution relative to the balancing market price. At high balancing market prices, the costs are driven by energy sales foregone from generators in merit. At low and negative balancing market prices, the costs are driven by out of merit costs. Out of merit costs increase sharply as the balancing market price falls (Figure 4).

Figure 4: Spinning reserve availability cost versus balancing market price



Source: ERA modelling

In very low demand periods balancing prices are usually low and variable generation, such as wind, is curtailed in preference to facilities capable of also providing ancillary services. As the demand falls, most generators providing spinning reserve are also providing other services, such as load following reserves, within the capabilities of each generator.

AEMO's Electricity Statement of Opportunities summarises recent minimum demand events and forecasts further decline in minimum demand.[51] Figure 5 shows an example of the model's scheduling during a minimum demand event spanning six daylight hours. As the market heads into a very low demand period, a change in generator dispatch can be observed. Wind farms and other variable generators are curtailed, while several gas fired generators are scheduled to support supply and ancillary services.

Both gas fired and coal fired generators can provide spinning reserve, while providing services to the load following market. Gas fired generators are typically scheduled during very low demand periods, as they are more flexible and have lower cycling costs than coal fired generators.

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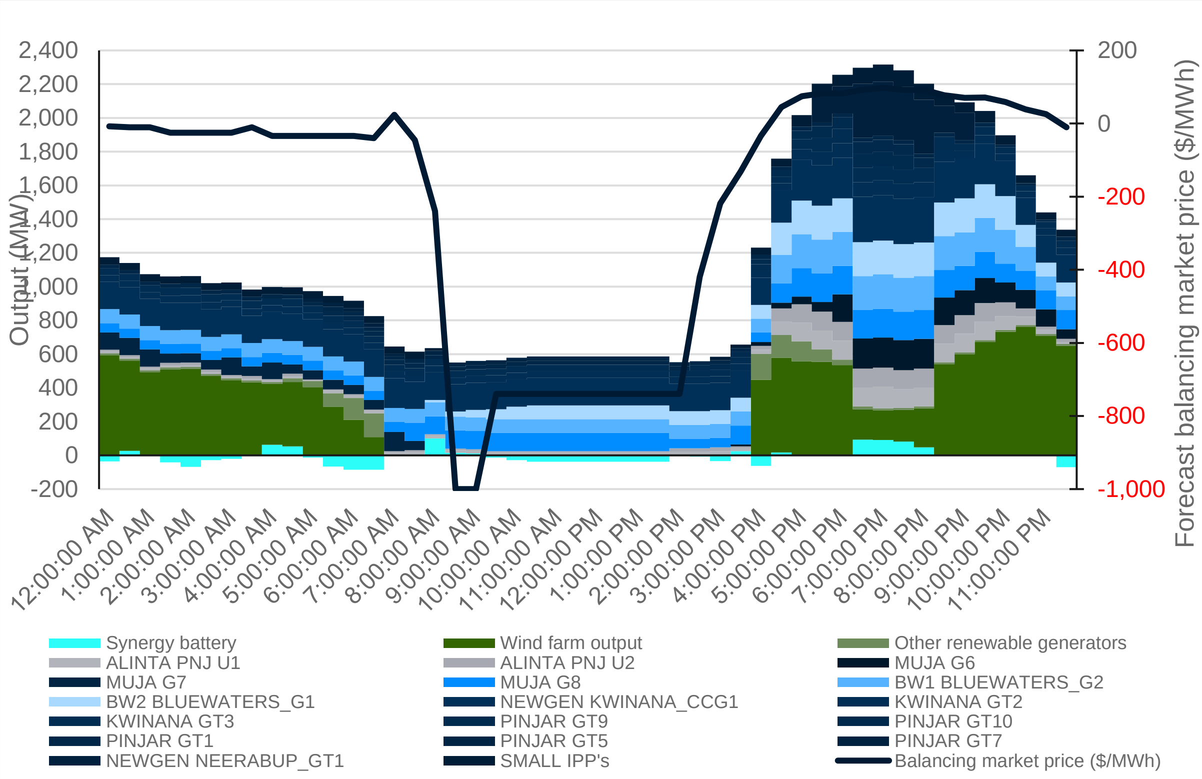
51 Australian Energy Market Operator, 2022, *2022 Wholesale Electricity Market Electricity Statement of Opportunities*, p. 44, 49-50, (online).

Figure 5: Sample extract generation and price from base case



Source: ERA modelling

A generator providing multiple services requires a smaller payment via the administered mechanism than if the generator was providing spinning reserve alone. For example, if all generators providing spinning reserve were also providing some load following ancillary services, the minimum generation quantity that comprises the greatest element of out of merit availability costs would be recovered through the LFAS market.

Synergy's submission states:

> "The requirement for a particular ancillary service could lead to additional units being committed but these units, once committed, could provide multiple services. Determining which service prompted the need for a specific unit to be committed, and therefore to which service the cost should be attributed to, is only possible by comparing the unit commitment decisions between two models, one which has a requirement for a specific service and one that does not."[52]

Synergy's cover letter maintains the ERA's function is to determine the level of compensation necessary to cover "the difference between the financial position Synergy would have been in but for providing ancillary services and Synergy's actual financial position after providing the ancillary services". This position is considerably beyond the WEM Rules which state the determination should compensate Synergy for:[53]

- The margin Synergy could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve Service.

52 Synergy, 17 February 2023, Submission to *Spinning reserve and load rejection reserve (margin values and Cost_LR parameters) settlement values 2023/24 - Issues paper,* p. 3, (online).

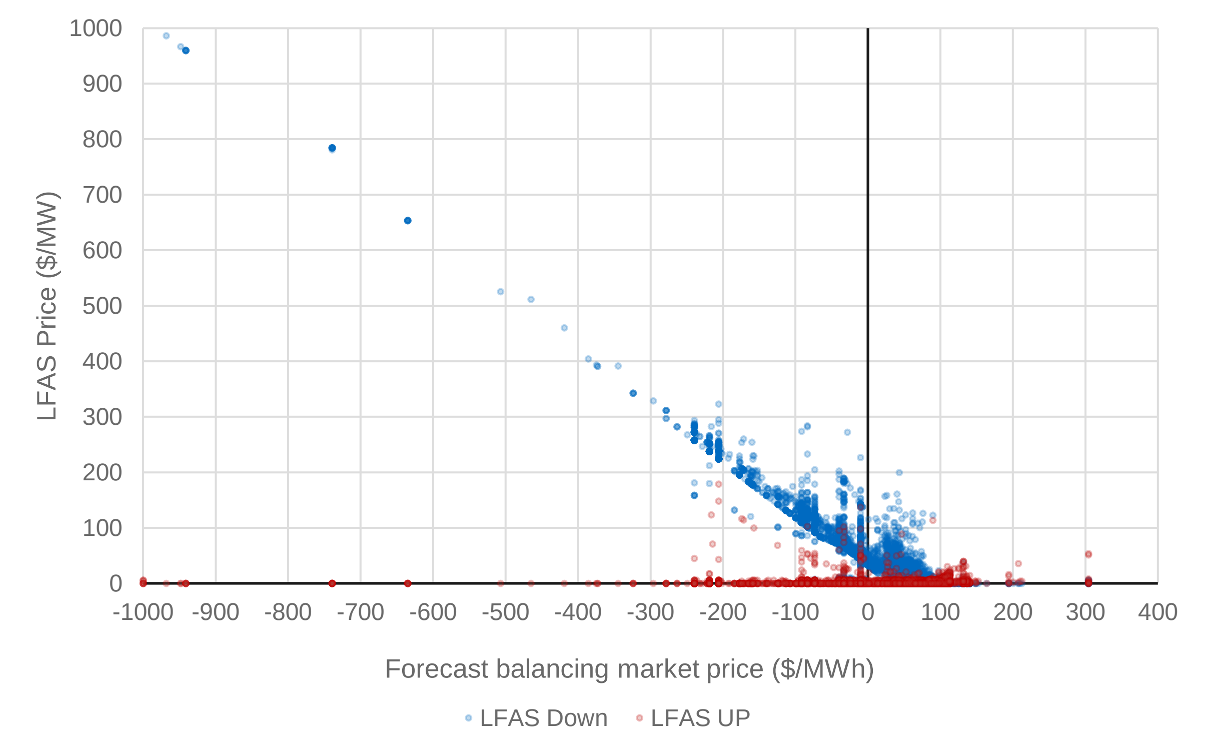
53 Wholesale Electricity Market Rules (WA), 1 February 2023, Rules 3.13.3A, (online).

- The loss in efficiency of Synergy's Scheduled Generators that AEMO has scheduled (or caused to be scheduled) to provide Spinning Reserve Service that could reasonably be expected due to the scheduling of those reserves.

The ERA has demonstrated running multiple models and counterfactual scenarios is unnecessary and inappropriate to determine cost allocation.[54] Cost allocation occurs in electricity markets without the need for counterfactual scenarios. The ERA has published and been using the ancillary services cost recovery allocation mechanism, as described in Appendix 7, for multiple years. This allocation approach allows for generation quantities that are used to provide multiple services to be recovered only once. As long as the costs are recovered, it is irrelevant through which mechanism this occurs.

Figure 6 shows the load following costs as a function of the balancing market price. The cost of the service – particularly for LFAS down – increases as the balancing market price decreases. This is explained in more detail in Appendix 7.

Figure 6: Load following costs versus balancing market price



Source: ERA modelling

In high priced periods, generators forego revenue by withholding capacity for reserves. The battery also foregoes the greatest arbitrage opportunity by providing the contingency reserves at these times.

Synergy questioned the range of input assumptions applied to its battery.[55] Through the first stage of the consultation, the ERA provided Synergy with the data of its facilities, including the battery, that will be included in the modelling. Synergy, as well as other market participants, were given the opportunity to comment on this data and to provide any updated information.

54 Economic Regulation Authority, 2019, *Determination of the spinning reserve ancillary service margin peak and margin off-peak parameters for the 2018-19 financial year*, pp 21-30, (online).

55 Synergy, 17 February 2023, Submission to *Spinning reserve and load rejection reserve (margin values and Cost_LR parameters) settlement values 2023/24 - Issues paper,* p. 3, (online).

The ERA modelling included all information provided by Synergy and other market participants relevant to their facilities.

In response to higher balancing market prices in the last year, the marginal cost of supplying LFAS has reduced. This has resulted in less non-Synergy LFAS being offered. The majority of the Synergy generators are capable of providing load following and spinning reserve ancillary services simultaneously. In such cases, the costs at minimum stable level are partially recovered through the LFAS market, which reduces both the spinning reserve cost and quantity.

In its submission, Synergy queried the reduced provision of load following ancillary services through non-Synergy generators by stating:

> "The divergent impact of this modelling approach relative to actual SWIS market outcomes is evident in the model's allocation of LFAS UP and LFAS DOWN to non-Synergy facilities. In Calendar year 2022, Alinta, NewGen Kwinana and NewGen Neerabup provided 40% of LFAS and LFAS down by volume and received 59% of revenue by value. The LFAS UP / DOWN Provision by Time of Day charts in the Issues Paper[2] indicates almost non-existent LFAS UP provision by non-Synergy facilities and what appears to be materially less than 20% of LFAS DOWN provision by non-Synergy facilities.
>
> The clear impact of modelling under-provision of LFAS by non-Synergy facilities relative to real world outcomes is that out of merit mingen costs and dispatch quantity costs relating to spinning reserve and load following markets are assumed to be recovered in LFAS markets, but in practice are not.
>
> Synergy requests ERA that the ERA revisits the allocation of LFAS UP and LFAS DOWN to non-Synergy facilities such that they align with recent market evidence and notes that failure to do so is likely to result in material under-remuneration of Synergy for Spinning Reserve and Load Rejection services."[56]

The upper limits on the quantity of non-Synergy LFAS used in the modelling were based on the observed reduction in quantities offered into LFAS markets by non-Synergy generators. The ERA also sought information from Synergy and AEMO on 'consumed LFAS'.[57] However, no new information was supplied that would change the ERA's modelling assumptions. Instead, the ERA has assumed that all LFAS providing generators capable of providing a spinning reserve response are available, subject to the practical performance capabilities of the facilities involved.

In recent months there has been a profound change in the quantities offered by non-Synergy providers in the WEM's load following markets. Only Synergy, is obliged to participate in the load following ancillary service markets. As discussed earlier in this Section 4.3, balancing prices in the WEM increased substantially in 2022 due to low coal availability. Coal plant generation has been largely replaced by gas, triggering higher balancing prices. Independent power producers have reduced the quantities they provide to load following markets.

Figure 7 shows that downward load following ancillary services quantities provided by independent power producers in the forecast period are in line with the actual provision in that market over the recent past. In addition, some of the quantities are covered by the Synergy battery in the model, leading to lower than actual quantities provided by Synergy's generators.

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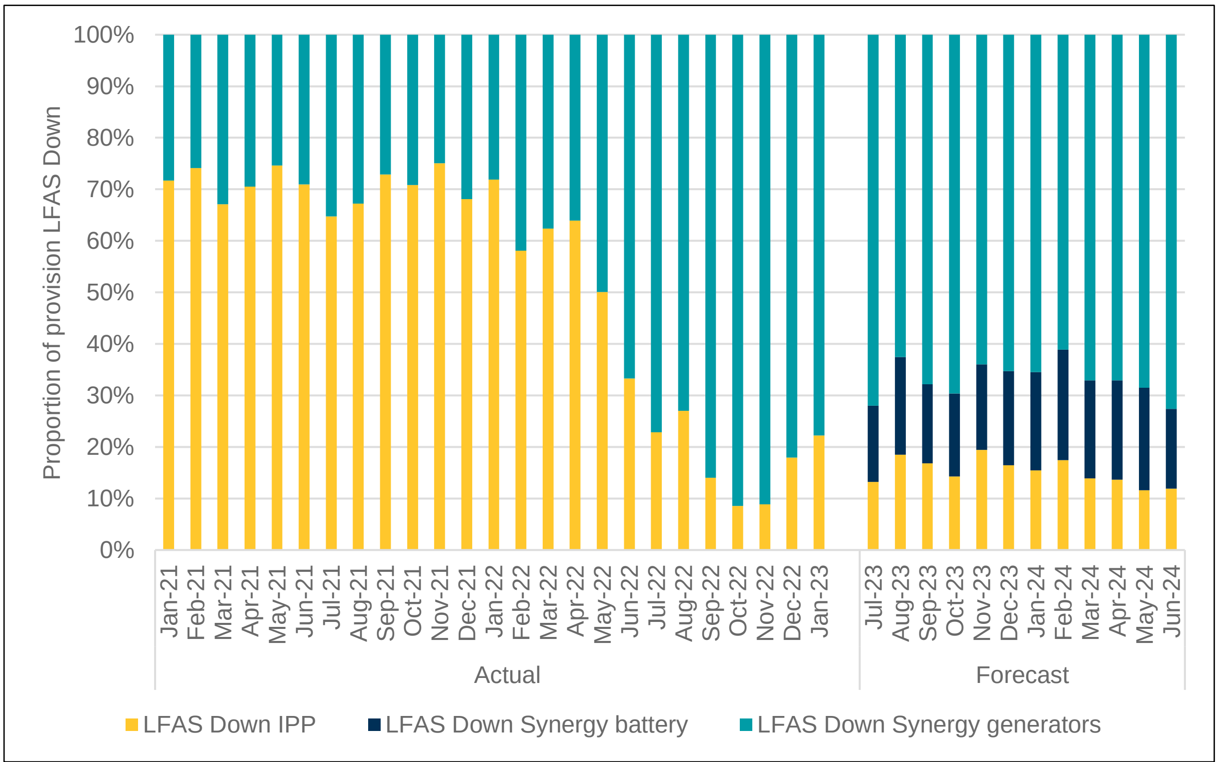
56 Synergy, 17 February 2023, Submission to *Spinning reserve and load rejection reserve (margin values and Cost_LR parameters) settlement values 2023/24 - Issues paper,* p. 3, (online).

57 This relates to an operational or planning assumption that not all load following capable of providing a spinning reserve response will be available, warranting a higher reserve requirement than might strictly be implied within the WEM Rules.

There is no real-market observation of the battery's operations, as the battery is yet to be commissioned.

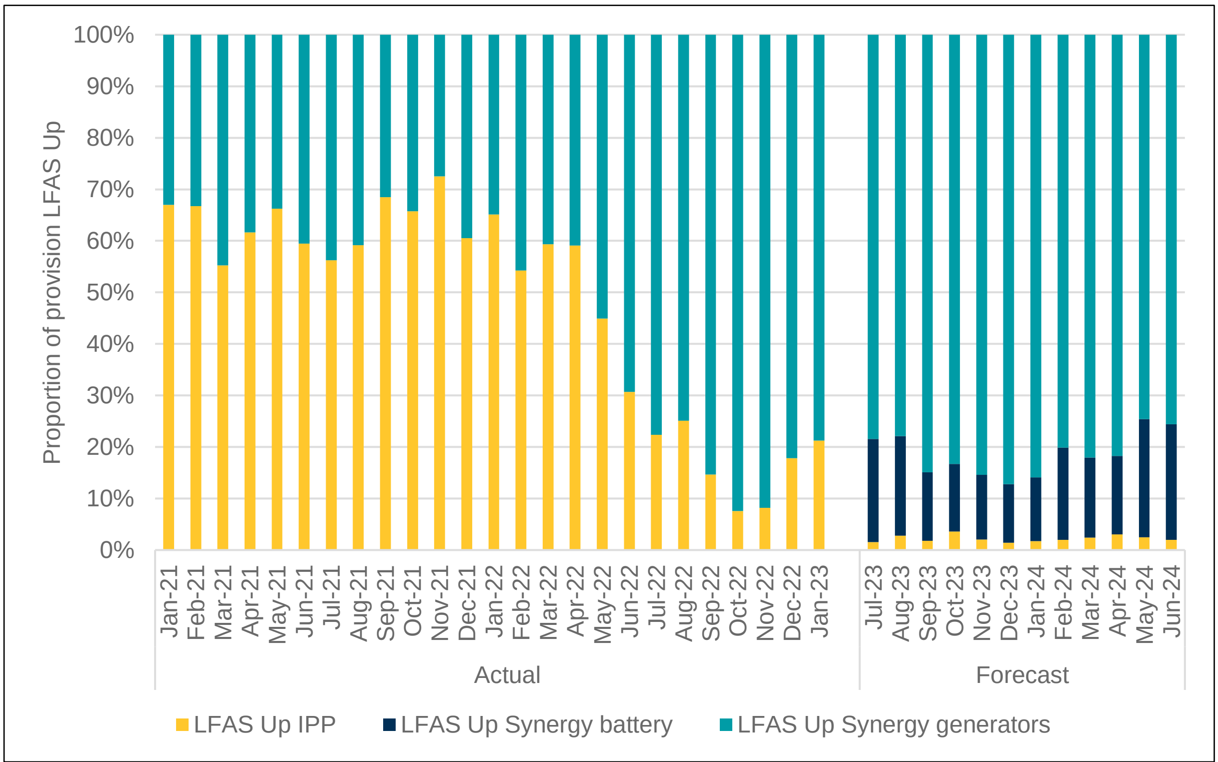
Figure 7: LFAS Down – actual vs forecast provision



Source: ERA analysis of AEMO data and ERA modelling

The provision of upwards load following ancillary services by independent power producers in the forecast model is materially below the actual provision (Figure 8). As with the downward services, the modelling inputs are consistent with recent real-time provisions, however, the optimisation software has substituted the majority of the provision from non-Synergy generators with provision from the Synergy battery. This is the lowest cost outcome for the whole market in a co-optimised model, based on a particular set of inputs. Overall, the provision of upward load following ancillary services quantities by Synergy's generators is consistent with the recent past provision.

Figure 8: LFAS Up – actual vs forecast provision



Source: ERA analysis of AEMO data and ERA modelling

4.4 Out of merit costs

Due to periods of very low demand, Synergy's out of merit costs have become the main driver of availability costs. The ERA has again taken these costs into consideration when proposing the settlement parameters.

Generators are generally dispatched by AEMO according to a merit order where offers are stacked from least cost to most expensive. To maintain system security in some circumstances, generators are dispatched regardless of cost, or out of merit. Most generators brought online or taken offline out of merit can be identified by output being discretely bid into the market.

Unlike other market participants, Synergy's out of merit costs are not readily identifiable from market data. This is because, Synergy, which holds roughly half the accredited capacity in the market, bids into the market as a portfolio rather than as individual generation facilities. Consequently, scheduling decisions affecting Synergy's dispatch (and its operating cost) are independent of its bids and cannot be separately identified as out of merit unless the overall quantity changes.

Low-cost generators such as coal plant can be replaced with high-cost generators such as gas peaking plant without affecting the revenue Synergy earns. Synergy can therefore incur costs that are not visible to the market compensation mechanisms (constrained on payments) or from the market data. Modelling is used to estimate these out of merit costs to understand the level of compensation due to Synergy for the provision of load rejection reserve.

As Synergy receives no revenue through the margin value mechanism for spinning reserve when prices fall below zero, the costs they might be expected to accrue when prices are negative need to be recovered via the margin values when prices are positive.

4.5 Compensatory mechanism

As explained in Section 2.4.1, Synergy's costs to provide spinning reserve are recovered through the margin value percentages applied to the actual balancing market price and the modelled quantity of spinning reserve. The design of the margin value remuneration mechanism assumes a positive relationship between the cost to supply spinning reserve and balancing prices in the WEM. Historically, the market prices have overwhelmingly been positive and in the range where the cost of spinning reserve to the market increases with balancing prices. The higher the balancing price, the more revenue Synergy may forego to provide the spinning reserve service.

Changes in the load profile have substantially reduced prices and daytime negative prices are now a common occurrence. Where this occurs, the driver for spinning reserve is out of merit costs, incurred when large coal and gas generators are operating at or just above their minimum stable generation thresholds. This means that when prices are very low or negative, the relationship between balancing price and the cost to provide spinning reserve is an inverse relationship – the lower the price the higher the cost. When prices are high, the relationship is positive such that the higher the price, the higher the opportunity cost to provide spinning reserve.

The change in out of merit costs from overlapping ancillary service provision provides a counterweight to the increased costs driven by fuel prices.

To ensure Synergy is appropriately compensated for providing spinning reserve, the ERA has calculated the availability cost over 2023/24 and then amended the margin value percentages to scale the level of compensation paid during positively priced intervals to make up for the lack of revenue during negatively priced intervals. This is consistent with the approach the ERA took when it calculated margin value percentages for 2021/22 and for 2022/23.

This fundamental departure in the assumed relationship between cost and compensation increases the risk Synergy will be under or over compensated. Critical to this is the number and depth of negatively priced intervals and the cost of generation that provides the services in these intervals.

If there are fewer negatively priced intervals or the prices are not as negative as forecast in the model, Synergy could gain through the compensation mechanism. If there are more negatively priced intervals, or the prices are more negative than forecast, Synergy could be undercompensated. This is because of two effects:

1. Out of merit costs during negative priced intervals comprise most of the availability cost – more events would increase the overall availability cost.

2. Synergy earns no revenue when the balancing price falls below zero. All things being equal, if the number of negative priced events increases, there are fewer intervals over which Synergy can earn revenue to compensate for the service it provides. While the method used to set the margin values accounts for the forecast negatively priced events, a higher number of events will mean the margin values themselves will be too low.

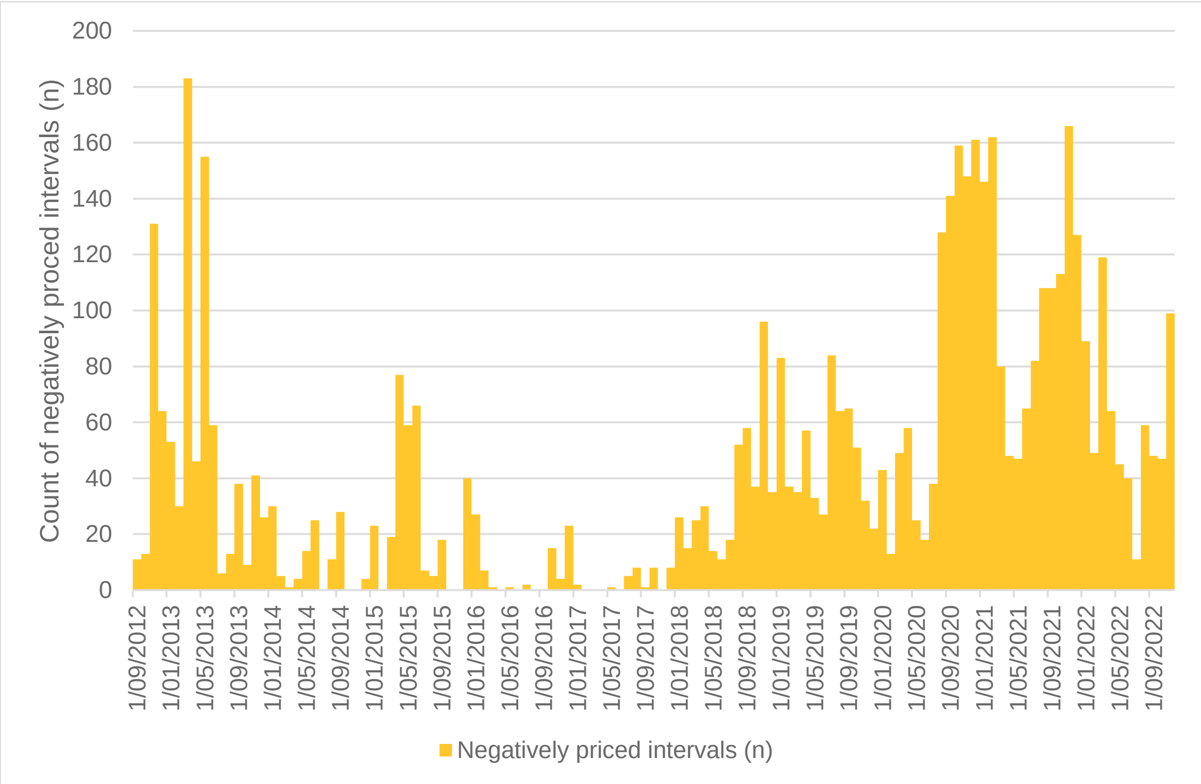
The margin value compensatory mechanism is unsuited to the cost and market price distribution. However, the onset of the new market will supersede this mechanism. In the new market, frequency control ancillary services, as well as spinning reserve and load rejection reserve will be provided through market mechanisms and renamed essential system services.

4.6 Incidence and influence of negatively priced intervals

The spinning reserve and load rejection reserve availability costs are predominantly driven by out of merit generation when prices are low or negative. In the base case, the ERA made alterations to the offer curves to indicate where generators bid below the costs derived from the input data they provided.

The frequency of intervals where the balancing market settles below $0/MWh has been increasing over time with a step change in mid-2020, as demonstrated in Figure 9.

Figure 9: Negative price events during peak periods since balancing market start



Source: ERA analysis of AEMO data

Based on past behaviour, it seems likely that market participants will continue to adjust their bidding to avert the deepest negatively priced intervals. This behaviour would moderate the incidence and depth of negative price events in the real world, but this is difficult to reliably reflect in the model. If the margin values are derived from a forecast that is more pessimistic than the actual number and depth of negatively priced intervals, Synergy will receive higher revenues from the margin values than anticipated.

Appendix 1 List of Tables

Appendix 2 List of Figures

Appendix 3 Summary of stakeholder feedback

The issues paper was published on 20 January 2023. The issues paper did not ask any specific consultation questions, but sought market participants' feedback overall.

The ERA received one formal submission from Synergy, which is available on the ERA's website.[58]

Synergy's submission includes concerns around the accuracy of the ERA forecast model, specifically related to simplifications included into the modelling. These have been addressed throughout this document, including in this appendix and in Appendix 5.

Synergy has also included a table outlining queries and seeking clarification related to specific sections of the issues paper. This table is replicated in Table 5 below, including the ERA's responses to these queries.

58 Synergy, 17 February 2023, Submission to *Spinning reserve and load rejection reserve (margin values and Cost_LR parameters) settlement values 2023/24 - Issues paper,* (online).

Table 5: Response to Synergy's comments

#	Section Ref[59]	Page ref	Classification	Issue	ERA response
1	5.3 Modelling interactions and ancillary service costs	15	Major	The Issues Paper states "*Quantities associated with upwards ancillary service reserves (spinning reserve and LFAS up) and the minimum generation quantities must be bid at the market floor price to ensure they are in-merit and dispatched.*" Synergy understands minimum generation quantities associated with provision of upwards ancillary service must be bid at the market floor so they are in-merit and dispatched, however the required upwards ancillary reserve must be bid at the **market cap** to ensure they are out of merit and available to be dispatched upward if required.	The modelling undertaken is correct, as per Synergy's statement. The explanation in section 5.3 in the issues paper is incorrect. This has been corrected in this determination.
2	5.3 Modelling interactions and ancillary service costs	15	Major	The Issues Paper states "Downward reserves (load rejection reserve and LFAS down) must be bid at the market cap to ensure the quantities are out of merit and available for dispatch if required". Synergy understands downward reserves (load rejection reserve and LFAS down) and the minimum generation quantities must be bid at the market floor to ensure the quantities are in merit and available to be dispatched down if required.	
3	Appendix 4, Generator operational constraints	29	Clarification	"*For example, without a constraint the model could schedule 120MW from a coal fired power station to spinning reserve, which might take a full half hour to deliver – substantially slower than the six second to five-minute response time needed for this service.*" This example suggests the ERA has not limited the response of individual facilities consistent with their Standing Data maximum Spinning Reserve response (being the response they can provide in requires six second to five-minute response window), which is typically 10-30% of nameplate for a coal fired generator.	The example provided in the issues paper is only a general one. It does not refer to any specific generation facility in the WEM. All information that has been provided by market participants is included in the modelling and generators provide energy and ancillary services up to their maximum capabilities (as provided).

59 Economic Regulation Authority, 2023, *Spinning reserve and load rejection reserve (margin values and Cost_LR parameters) settlement values 2023/24 - Issues paper*, (online).

#	Section Ref[59]	Page ref	Classification	Issue	ERA response
				Synergy would like the ERA to confirm that in-service coal units were modelled based on their physical maximum Spinning Reserve capability.	
4	Appendix 4, Battery	29-30	Clarification	The Issues Paper states that the battery is assumed to be a price taker in all markets in which it operates. Is this assuming that there are no out of merit costs for the battery? What avoidable fixed costs are assumed? What is the $/MWh cost?	All information that has been provided by market participants on the technical and economic parameters of their facilities has been included into the modelling inputs. The ERA has not included any further assumptions.
5	Appendix 4, Battery	30	Moderate	*"If the battery is providing load following ancillary services equal to the contingency reserves, it arguably is not incurring any additional cost to provide the contingency reserve above that which it would receive revenue through the balancing and load following markets*." Synergy disagrees with this statement. Whilst the battery may not incur any additional direct costs, it may incur lost revenue or opportunity costs. These can arise because the battery needs to reserve an additional portion of its storage capacity for contingency reserve enablement and may forego current or future opportunities to transact that stored energy in the balancing market.	The ERA PLEXOS model looks ahead 24-hours. This allows the optimisation to consider future market prices and battery returns when making its decisions. Consequently, the model allows for this element of the opportunity cost to be captured.
6	Appendix 4, Differences between the model and the WEM	30	Clarification	The ERA Offer Construction Guidelines require facility bidding at average operating costs. Can the ERA explain why marginal operating cost and not average operating cost is used?	The ERA 'Offer Construction Guideline' is not yet in force and will apply after the new WEM Commencement Day. Under the current WEM Rules, generators are expected to bid at their short run marginal cost in the balancing market. The ERA's current 'Guideline to inform Balancing Market offers' accepts the fact that generators need to be able to recover their average variable costs under certain conditions.[60]

60 Economic Regulation Authority, 2019, *Guideline to inform Balancing Market offers*, (online).

#	Section Ref[59]	Page ref	Classification	Issue	ERA response
					In the ERA PLEXOS model, generators' net profits consider all costs included as inputs, including start-up and shut-down costs.

Appendix 4 Gas price forecast

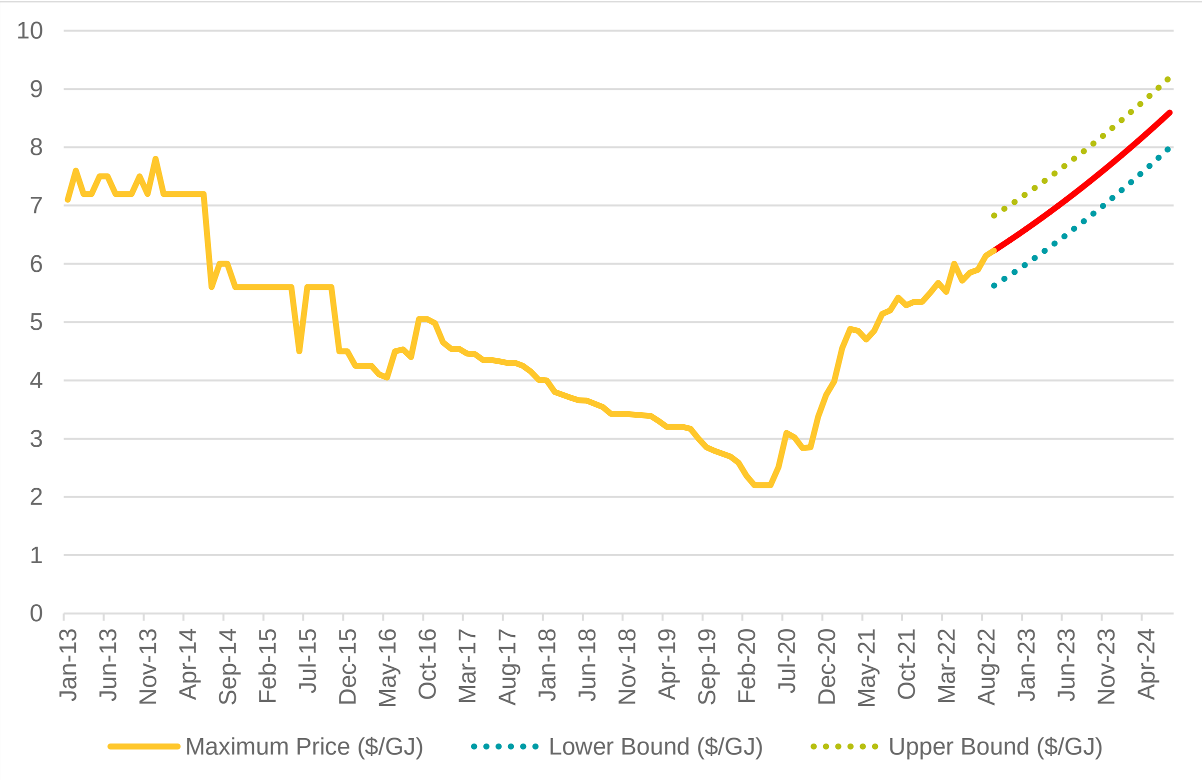
Time Series Forecast Modelling of Gas Prices

Maximum monthly gas prices for a nine-year period were extracted from the price history table on the gasTrading Australia website.[61] This resulted in the data set comprising 127 maximum monthly prices, ranging between $2.20/GJ and $7.80/GJ, with a mean of $4.95/GJ and a standard deviation of $1.50/GJ. Z-score standardisation of the maximum monthly gas prices produced values between -1.8 and 1.9, indicating that there were no outliers in the data.

The best ARIMA model fitting the data had one level of differencing, with 1 autoregressive and 1 moving average lagged error term. Model diagnostics and z-score standardisation of the differenced data revealed outliers in July 2014, June 2015, July 2015, and November 2015. These outliers were replaced with the mean of the differenced data, and the model was rerun to produce forecast differences with 95 percent confidence intervals for the period of interest i.e., September 2022 to July 2024. The differences in values between the forecasts produced by the original data set and the outlier adjusted set were so small that the original data set was selected for forecasting the price differences.

The forecast price differences, were used to calculate the forecast of maximum monthly gas prices and prediction intervals for this period. The forecast maximum monthly gas prices and prediction intervals are represented in Figure 10.

Figure 10: Forecast maximum monthly gas prices for the period September 2022 to July 2024



61 GasTrading, Historical Prices and Volumes, July 2013 to August 2022, (online) [accessed 18 November 2022].

Source: ERA analysis of gasTrading data

Note. Forecast values are represented in red. Upper and lower bounds represent prediction intervals at a 95% level of confidence.

Forecast maximum monthly gas prices ranged between $6.23/GJ for September 2022 and $8.50/GJ for June 2024, with a mean maximum monthly price of $7.31/GJ and a standard deviation of $0.73/GJ.

Appendix 5 Modelling process and model description

The ERA used its PLEXOS model of the WEM to model the 2023/24 financial year to inform the ancillary services settlement parameters.

The underlying methods and assumptions for the model are provided in this Appendix.

ERA's model of the Wholesale Electricity Market

Model configuration

The ERA's PLEXOS WEM model has been configured to co-optimise electricity generation with load following ancillary services, spinning reserve, load rejection reserve and ready reserve.[62] The model is configured to identify the least cost means of meeting the energy and the defined ancillary service requirements in the WEM. The model forecasts dispatch and pricing outcomes for each 30-minute interval for the 2023/24 financial year, to support ERA's obligation to determine ancillary services parameters for the 2023/24 financial year to apply until the new market commences on 1 October 2023.[63]

The model draws from a database that describes the physical characteristics and associated costs and operational constraints for generators and battery storage facilities that are expected to connect to the South-West Interconnected System (SWIS).

Market configuration

The ERA's PLEXOS WEM database includes an energy market and four ancillary services for modelling spinning reserve, load rejection reserve, and both upwards and downwards load following ancillary services (LFAS). Ready reserve is applied as a scheduling constraint in the model, requiring a scheduled generator, a battery or demand side capacity available within fifteen minutes notice to cover 30 per cent of the largest contingency output from a single unit (largest generator operating in the WEM and ten per cent of the estimated output from rooftop solar generation).

Overlap between reserves, such as between the upwards LFAS and spinning reserve, is applied in the model when calculating how the reserve requirement will be met. For example, if a spinning reserve contingency risk of 300MW is assumed, the model would set the spinning reserve requirement to 210MW (70 per cent of the contingency). If the market has 100MW of upwards LFAS, this would be deducted from the 210MW requirement. The model would then optimise the scheduling of energy demand, 100 MW of upwards LFAS and 110MW of spinning reserve.

The model is configured on 30-minute trading intervals throughout the forecast period, with the trading day starting at 8:00am, and uses a 24-hour look-ahead functionality.

62 Ready reserve is the ancillary service for fast-start generators to be available within fifteen minutes to cover 30 per cent of the total output of the generator with the highest total output synchronised to the SWIS.

63 While the ERA has the obligation to make a determination for the full 2023/24 financial year, with the commencement of the new market on 1 October 2023 the current mechanism will be superseded by the new market-based mechanisms.

Ancillary services requirements

The ERA's model uses the following ancillary service requirements:

- Spinning reserve contingency: The spinning reserve 'risk', or contingency, is the greater of 70 per cent of the largest output from a single generator or the 'North Country contingency'.[64] There is an additional contingency, which AEMO applies related to the loss of rooftop solar generation, which is equivalent to 10 per cent of the output of all rooftop solar systems installed.[65]
- Load rejection reserve requirement: The requirement is set at 97MW in the planning horizon in advance of the trading interval when the generating units providing the reserve are committed.

In the model, generators and batteries were limited to provide no more than 30 per cent of the spinning reserve and load rejection contingency quantity to reflect the need to spread risk across multiple generators and prevent the model selecting a single facility as the source for the ancillary services.[66]

In its submission Synergy queries that,

> "Whilst the Issues Paper acknowledges that the above limitation is not a fixed amount in AEMO operational practice, it does not consider the impact of this simplification on model outputs. Synergy believes that this modelling limitation is an oversimplification of the WEM and is not reflective of real-world scenarios in the ancillary services market."[67]

All models apply heuristics to manage the data load. The WEM is a very manually dispatched system, and without assuming simplification, forecast modelling would be very difficult to accomplish. This specific simplification has been applied based on the best information available from AEMO and has been used in the ERA's modelling in recent years. This approach has been used to achieve a reasonable balance between model complexity and expediency to yield reasonable accuracy in an environment of uncertainty about future conditions. This is a common approach and the ERA's model is no more simplified than that employed used by other practitioners engaged by AEMO when it was responsible for proposing settlement parameters.

Two contracts for spinning reserve were assumed to be in place for the duration of the forecast period, with a combined capacity of 63MW.

Upward and downward load following ancillary services requirements: these are set at 110MW for daylight hours (5:30am to 7:30pm) and at 65MW overnight. These requirements are aligned with the latest ERA decision on the AEMO ancillary services requirements.[68]

AEMO advised that it may apply different requirements at various times of the day, or on different days depending on system conditions. The ERA has adopted a single requirement based on the latest information available.

64 The North Country Contingency is the combined output of Yandin, Warradarge, Beros Road, and Badgingarra wind farms connected in the same part of the network.

65 AEMO stated that this number can vary, but the ERA has adopted a 10 per cent contingency for simplicity.

66 AEMO advised that this is an operational practice and that 30 per cent is not always fixed for all facilities. The restriction is applied more dynamically based on the system conditions and available facilities. The ERA has applied fixed 30 per cent across all trading intervals and facilities for simplicity.

67 Synergy, 17 February 2023, Submission to *Spinning reserve and load rejection reserve (margin values and Cost_LR parameters) settlement values 2023/24 - Issues paper,* p.3, (online).

68 Economic Regulation Authority, 2022, *Decision on the Australian Energy Market Operator's 2022/23 ancillary services requirements,* (online).

The ERA's model also applies an ancillary service enablement duration. The current market parameters require spinning reserve to be sustained for 15 minutes and load rejection reserve for 60 minutes. The model sets a 30-minute requirement for spinning reserve and both load following ancillary services – one trading interval. The load rejection reserve ancillary service must be sustained for 60 minutes – two trading intervals.

Network configuration

The network is assumed to be unconstrained, but with specific network constraints (such as applied under Generator Interim Access contracts) separately modelled based on the observed application of the constraint tool developed by Western Power.

The application of the Generator Interim Access (GIA) constraint was modelled in steps, partially with some pre-processing outside PLEXOS. The unconstrained half-hourly generation for non-scheduled generators connected under the constrained access contracts was estimated outside PLEXOS. This provided a base output profile to which the constraints, driven by scheduling decisions for scheduled generators connected in those parts of the network in combination with the amount of unconstrained non-scheduled generators in each trading interval, were applied. The application of the GIA constraints programmed into the model was compared against historical observed constraint application to test the model's validity.

Electricity demand

There was no half-hourly demand forecast available for the modelling period. The ERA took the last full year's demand profile (2021/22 financial year) and added back AEMO's rooftop solar output estimate to derive an underlying demand profile. This was scaled to align with AEMO's expected forecast peak demand, minimum demand and operational consumption indicated in the 2022 Electricity Statement of Opportunities.[69]

Rooftop solar electricity generation was estimated using stochastic output data derived from the distributed rooftop solar output data provided by AEMO, within sunrise and sunset periods, available from Geoscience Australia.[70] This was escalated monthly through the forecast period to account for new installations expected to connect during the forecast period. New installations were assumed to have the same generation characteristics as existing installations. The rooftop PV output profile was then deducted from the scaled forecast underlying demand to derive an operational demand used in the forecast period. Conceptually, this approach was like that used by AEMO for its ESOO forecast.

The forecast model included a demand constraint that restricted the generation of any non-scheduled generation once demand fell below a certain level (for a trading interval). This constraint was included in anticipation of the expected operation of the system during low load events.

Rooftop solar assumptions

For the base scenario, the same installation rate and capacity from the expected case from the ESOO were used.[71] The solar installation rates in terms of installed capacity and the

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69 Australian Energy Market Operator, 2022, *2022 Wholesale Electricity Market Electricity Statement of Opportunities*, (online).

70 Geoscience Australia, Geodetic Calculators, Perth location, (online).

71 Ibid.

number of installations from the Clean Energy Regulator's postcode data for SWIS postcodes was also reviewed to ensure the assumption's currency.

Rooftop solar capacity and generation were estimated from postcode data reported by the Clean Energy Regulator and actual rooftop PV generation profiles, which were provided by AEMO. Growth in rooftop solar was forecast based on the last year's monthly installation rates aligned with AEMO's projected growth rates, extrapolated from linear and power trendlines of best fit, and relative growth rate calculations. The growth wedge accrued monthly. These forecasts were compared for consistency with AEMO's expected solar growth uptake.

Generator configuration

The ERA collected and verified the physical and operational characteristics for each generator in the SWIS and estimates for generators and facilities committed but not yet constructed. These include:

- fuel consumption rates (heat rates)
- operation and maintenance costs (load dependent and independent)
- generator commitment and decommitment costs
- fuel supply costs, daily, weekly, or monthly limits, take or pay quantities and over-run costs.

Market standing data was used to define:

- generator ramp rates
- minimum stable generation thresholds
- minimum time to synchronisation (cold, warm, and hot)
- minimum down time.

Other information items from the market surveillance data catalogue were used to define:

- forced outage rates
- historical bidding patterns
- historical market participation and generation patterns
- generator loss factors.

Fuel input costs

Fuel input costs were collected from market participants and scrutinised to ensure consistency with the short run marginal cost principles in the WEM Rules and the opportunity cost of gas.[72] Many generators' fuel input costs reflect spot market costs. The fuel input costs reflect a conservative estimate of the future spot market price for the forecast period.

Historical back-casting and model calibration were undertaken using actual fuel input prices provided by market participants. This was necessary to observe the extent to which the model output can reasonably reproduce actual market outcomes. Back-casting was used to calibrate and tune the market model, which was then used for the forecast modelling. To do this, the

72 The ERA sought an information update from market participants in May 2022 for the WEM Report project. This data was used for this issues paper and further updates were sought only from the largest market participants in October 2022.

input assumptions must reflect the actual input costs as closely as possible. To forecast ancillary service costs for 2023/24, the ERA must include assumptions on forward fuel prices.

For the base case scenario, the ERA used fuel prices provided by market participants.

For two of the sensitivity scenarios that tested the model's sensitivity to fuel input prices, the ERA used the same forecast gas prices as those used for the Energy Price Limits studies.[73] One sensitivity applied a single gas forecast price during the whole modelling period to all gas fired generation facilities, while the second used a monthly gas price increase based on the gas forecast described in Appendix 4.

Fuel availability

Fuel availability has been considered as an input into the forecast model due to the current and forecast issues in these markets. The ERA collected further information from affected market participants and included their expectations into the base case.

Heat rates

Heat rate is a measure of a generator's efficiency in converting fuel to electricity. It is the energy content of the fuel needed to produce a given output quantity. The heat rates determine the fuel-related operating cost of a generator. Marginal heat rates reflect the incremental change in fuel required to generate an additional unit of output. Thermal generators provided the ERA with their heat rate curves that were used to calculate marginal heat rates.

All thermal generators provided the ERA with their heat rate curves, which were used to calculate the marginal heat rate. This enables the model to simulate generator dispatch. Where the derived marginal heat rate curves were not convex, the non-convex load points were manually adjusted to make the curve convex. This is a relatively modest change to the accuracy of the heat rate, but ensures the model calculates within a reasonable timeframe and reduces the risk the software cannot find optimal generator schedules.

Bid-cost mark-ups

The marginal costs for some generators were adjusted to account for historical bidding behaviour such as altering portions of the offer curve when generation is bid at the market floor price or below zero, and/or offered at the market cap price. This bidding behaviour may reflect the generator's cycling costs (generators bid at negative prices or at the floor price to avoid being decommitted, or to provide ancillary services), or fuel supply constraints. However, these details are not transparent to the ERA.

Outages

The back-casting model used actual generator outages as a fixed input to the model. In addition, coal generator economic decommitments in the back-casting period were treated equivalent to outages. For the forecast period, facility outages were modelled either as planned (where information available), or as unplanned outages.

Unplanned outages were modelled as a percentage of the unit's operating hours in a year and as a percentage of the total hours in a year through generator's forced outage rates. The

[73] Economic Regulation Authority, 2022, *Energy price limits 2022 - Draft determination*, p. 16, (online).

forecast forced (unplanned) outages were derived from historical outage rates. Where a clear outage pattern could be discerned from historical data (such as a "sawtooth" outage pattern), this was used to determine the forced outage rate. The modelling also accounts for partial outages through generators' partial forced outage rates. These are applied randomly throughout the forecast period.

For new generators committed to commence generation in the market within the forecast period, the ERA used generic technology specific availability rates to set maintenance requirements. These target availability rates were tested directly with project proponents.

Wind and (grid connected) solar generator output

Variable generators' output is driven by resource availability. An output profile for generators is needed as an input to the model. In the back-casting model, actual wind farm or solar farm output was used as a fixed input to the model.

The ERA PLEXOS model used actual generation outputs for some of the grid connected renewable facilities, reprofiled where appropriate. New wind farms in the market have no or only limited operational data. For these wind farms, the ERA used the generation forecasts estimates that had already been prepared by independent, AEMO-accredited experts and provided by market participants for the capacity certification process.[74]

For generators connected under the Generator Interim Access contracts, several constraints have the possibility of limiting wind farm output in a single network region. The first constraint limited the total output of wind farms in the north country region. This was applied first to the forecast unconstrained output of the wind farm prior to input into the PLEXOS model.[75] The second set of constraints depends on the combined output of the wind farms with other generators connected in the region. This constraint was applied dynamically within PLEXOS and was developed with guidance from AEMO and Western Power.

Rooftop solar assumptions

For the base scenario, the same installation rate and capacity from the expected case from the 2022 Electricity Statement of Opportunities were used.[76] The solar installation rates in terms of installed capacity and the number of installations from the Clean Energy Regulator postcode data for SWIS postcodes was also reviewed to ensure the assumption's currency.

A sensitivity run used the high rooftop solar uptake growth from AEMO's 2022 Electricity Statement of Opportunities.[77] Output capacity factors were derived from data provided by AEMO. The output of solar variability was based on past year's output patterns.

Generator operational constraints

In the forecast WEM model there are operational constraints to alter the behaviour or availability of generators. These constraints define specific operating rules or impose limits

74 These estimates are used as inputs to the relevant level method for reserve capacity allocation.

75 For all these generators the ERA used output data prepared by AEMO's accredited experts.

76 Australian Energy Market Operator, 2022, *2022 Wholesale Electricity Market Electricity Statement of Opportunities*, (online).

77 Ibid.

within the system and prevent unrealistic model outputs. For example, the tendency for non-Synergy generators to withdraw from the LFAS market from mid-afternoon into the evening.

Constraints were also applied to limit the ancillary service quantity any one facility can provide. These constraints impose an upper limit to the provision of up to 30 per cent of the spinning reserve and load rejection reserve risk per facility. This approach ensures the diversification of resources in case a unit fails to perform, or is physically unable to deliver the ancillary service in the required timeframe.

Without such constraints, PLEXOS could schedule an unrealistic quantity of capacity to an ancillary service reserve that the generator could not sensibly provide. For example, without a constraint the model could schedule 120MW from a coal fired power station to spinning reserve, which might take a full half hour to deliver – substantially slower than the six second to five-minute response time needed for this service.

Renewable energy certificate prices

Where generators do not have a historical bidding profile upon which to base their offer curves into the electricity market, the modelled offers were based on their marginal cost including the forward value of renewable energy certificates (REC) over the outlook period. The nominal REC (large-scale green certificate) was derived from a two year forward contract price reported by Bloomberg for forward supply maturing in the years modelled.

Battery

One battery system is included in the model to operate during the forecast period. The battery is expected to commence operation early 2023, before the start of the modelling period.

A battery is capable of simultaneously providing multiple services – energy output, energy load, and ancillary services like load following, spinning reserve and load rejection reserve. The battery is assumed to be a price taker in the markets it operates. A battery's capacity to provide services depends on its available state of charge and its output level.

In the WEM, a battery can monetise output from the load following, the energy output and energy input if balancing market prices are negative. If the battery is providing load following ancillary services equal to the contingency reserves, it arguably is not incurring any additional cost to provide the contingency reserve above that which it would receive revenue through the balancing and load following markets. If the battery can provide a reserve without limiting its current or future potential value streams, it is arguably not incurring any incremental cost to provide the reserve.

Synergy's submission sought clarification on whether the "expected operation of the battery facility in the ancillary services market" is aligned with the comments Synergy made in its 2022 submission.[78] The operation of the battery is aligned with the expected operation, as per Synergy's 2022 submission.[79] The only exception is a more conservative spinning reserve assumption where in order to align with the modelling resolution, the reserve is sustained for the whole trading interval rather than 15 minutes.

78 Synergy, 11 March 2022, Submission to *Spinning reserve and load rejection reserve (margin values and Cost_LR parameters) settlement values 2022/23 - Issues paper* pp. 5-6, (online).

79 There are fewer than one per cent of the trading intervals over the full year where the requirements on the operation of the battery are not fully aligned with Synergy's expectations, as published in its 2022 submission. This is not considered a material source of error in the modelling.

PLEXOS uses a value, termed a shadow price, to determine whether and when the battery charges or discharges and provides ancillary services. The battery shadow price is derived through the co-optimisation process from changes to the costs across energy and ancillary services and reflects the future value of energy held in storage i.e., the potential saving of thermal costs from the last or next unit of energy in storage. Consequently, the decision to run the battery in the model is determined relative to the costs of meeting the supply from other generators. While the shadow price may effectively proxy the battery opportunity cost, they are not necessarily the same. This co-optimisation process is configured to minimise total system operating costs.

Differences between the model and the WEM

The WEM, although relatively small in comparison to international energy markets, has several features that are complex to model. The scheduling of generators for example is not co-optimised, rather it is sequentially optimised (LFAS, then energy, then other ancillary services), with LFAS the only ancillary service determined in a market. Other ancillary services such as load rejection reserve and spinning reserve are manually scheduled without regard to pricing following a set of dispatch guidelines. This may result in higher prices than in a co-optimised market.

To ensure generators are in merit to provide ancillary services, ancillary service quantities are bid at the floor, or at the cap to ensure that the ancillary services are available. Some of this is captured through the mark-up process.

The requirement to bid at the floor rather than at a generator’s marginal cost is a market design feature to compensate for the lack of co-optimisation in costs across the different market services. However, the resulting pricing distortion poses challenges for cost allocation and model calibration. Model calibration sought to provide a reasonable and accurate rendition of market outcomes and as a result the offer curves were altered to reflect this element of the WEM Rules. In terms of allocating costs, the default calculation assumed the costs offered to the market (including mark-ups) reflect a generator’s marginal cost. In these instances, the next positive offer was used as a substitute for the base offer which may have been subject to an ancillary service offer distortion. This results in a more realistic ancillary service cost rather than assuming the marginal cost is ($1,000) per MWh.

Manual scheduling is also a point of difference. Individual system management operators will have different approaches to managing system security. One operator may allow ancillary service reserves to ride through periods where they may be thinner than is ideal, while another operator may choose to intervene and reschedule Synergy’s generators to increase reserves. It is not possible to account for the individual operators’ tendencies in generator scheduling and data is not available to model this stochastically.

AEMO schedules Synergy’s generators according to a set of dispatch guidelines, many of which are not readily transferable to the ERA PLEXOS model. To fully reflect the application of the guidelines would require an iterative modelling process, which was impractical for this exercise. Instead, scheduling was conducted using the marginal costs rather than the dispatch guidelines except in a few specific instances in the dispatch guidelines related to firm constraints for specific generators. Where this was the case modelling constraints were derived from the dispatch guidelines.

Generator output data shows some large thermal generators, such as Collie and Muja, are withdrawn from service but that these withdrawals are unrelated to outages. Model refinements allowed the model to better determine when large thermal generators were likely to be out of merit and should be decommitted.

Generators may offer generation at the minimum and maximum price caps. It is also within the WEM Rules for generators to offer generation at below its marginal cost. The model forecasts an increasing number of negatively priced events in the market. The model is calibrated on past behaviour which may not accurately predict future behaviour – particularly when such behaviour has substantial cost implications. Some bidding behaviour – such as withdrawing generation from the market or changing from participating in one market such as LFAS and moving into the balancing market at different times of day - may also be subject to change.

As prices are negative throughout the mid-day trough through most of the year, generators have adopted a different offer-price bidding during these periods of the day. The model uses a single bidding behaviour for each unit and does not account for daily or seasonal bidding changes. This is required to achieve a balance between accuracy and calculation times and to prevent over-fitting of the model for future (unknown) bidding behaviour.

In its submission, Synergy raised a concern around the ERA's "reliance on a single bid curve grossly misrepresents bidding behaviour in the WEM, which has material impact on the determination of appropriate ancillary services parameters."[80]

As per the previous comment in the Ancillary Services requirements section, the ERA's modelling strikes a balance between complexity, accuracy, and reasonable model running times when emulating the WEM.

Throughout the back-casting exercise the ERA has assessed different parts of the offer curves of the WEM facilities and has identified a single bid curve for each facility that best represents its past behaviour. Only parts of an offer curve are material at any point in time and the single offer curve reflects a composite of the material parts of the offer curves relevant at different load points.

Finally, while the ERA has wide access to information necessary to model the market, it does not hold every piece of information. Information on fuel supply contracts in Western Australia in the gas and coal markets are generally opaque. Fuel supplies may also be tied to the availability or demand for fuel in other markets such as to or from mining or industrial projects. It is not feasible to model the two markets (gas and electricity) for this determination. Informal engagement with generators in preparing the input assumptions indicates there are some unspecified fuel supply constraints that may apply in practice that were not provided to the ERA and are not included in the modelling.

Quality assurance processes

The ERA undertook quality assurance processes at different stages of preparing the model and reviewing the model outputs. These included:

- reviewing the model inputs
- verification of the model inputs
- reviewing model outputs
- sensitivity analysis.

Several sensitivity scenarios were tested during the modelling process. These scenarios tested different aspects of the model, such as using different input costs, different configuration

80 Synergy, 17 February 2023, Submission to *Spinning reserve and load rejection reserve (margin values and Cost_LR parameters) settlement values 2023/24 - Issues paper,* p. 4, (online).

settings to ensure a proper understanding of the model, how it schedules generators to emulate market dynamics.

Model inputs relevant to individual facilities were collected from market participants**.** These data build and update data already provided by most participants under the WEM Rules.[81] This information was collated and compiled with other physical generator characteristics relevant to the modelling and provided to market participants for review.

Discussions were held with AEMO regarding the scheduling of ancillary services, and market constraints. The application of the GIA constraints programmed into the model was compared against historical observed constraint application to test the model's validity.

The ERA has reviewed the model's generator scheduling, the reasonableness of aggregate model outputs, and market dynamics. The model outputs were first compared to a historical period with known prices and demand characteristics (back-casting). Sources of variability such as outages and variable generator outputs were not modelled at this stage, rather were used as fixed inputs to minimise error in the back-casting model. This approach reduced potential sources of error and allowed refinement of inputs and model configuration to better reflect individual generators' bidding characteristics.

The forecast model outputs also looked at patterns of generator dispatch and pricing behaviour. Price duration curves for the different model iterations, capacity factors, commitment and decommitment patterns were compared with comparable past periods and dispatch trends. Where values were substantially higher or lower than expected, a deeper assessment was undertaken. A sample of dispatch results during different pricing events in the outputs were used to check the model for credible results.

The cost allocation script was verified against the method of allocating availability cost by using a parallel calculation of the model outputs.

81 Wholesale Electricity Market Rules (WA), 1 February 2023, Rule 2.16, (online).

Appendix 6 Sensitivity analysis

The ERA conducted sensitivity analysis modelling runs, testing the bidding behaviour (markups), fuel prices, and solar photovoltaic generation uptake. Sensitivity analysis allows to better understand the relationships between the assumptions and the outputs. Table 6 summarises the different sets of input assumptions and the sensitivity runs relative to the base case.

Table 6: Base case and sensitivity analysis runs input assumptions

Feature	Markups	Expected solar uptake	High solar uptake	Generator fuel $	EPL gas $7.2	Rising gas $7.2 to $8.5
Base case	X	X		X		
High solar	X		X	X		
Unmodified generator data		X		X		
Uniform market gas price		X			X	
Uniform rising gas price		X				X

Source: ERA modelling

Throughout the modelling validation process, sensitivities were conducted to test and assess the model's performance under different conditions.

The two sensitivities that test the effect of uniform gas prices (single market gas price and monthly rising gas prices) both exclude markups and are applied on the generators' unmodified input parameters.[82] Higher fuel prices would have interacted with the mark-ups, as applying different fuel prices from those used in the base case was expected to result in materially different offer curves driven by the base case calibration process. Consequently, the behavioural elements were not applied to these scenarios, instead using the unmodified generator data.

The ERA also conducted additional scenario analysis on fuel availability, specifically coal, to understand how potential restrictions could affect the outcomes of the modelling, including balancing market prices and availability costs.[83]

Because the behavioural elements in the model are not uniformly applied through all sensitivity runs, the results can only be compared on a like for like basis. Thus, the results that have mark-ups applied can be directly compared with results with similar input conditions (base case and solar). Results without mark-ups are comparable (unmodified generator data, uniform market gas, rising market gas).

[82] This approach differs from the modelling undertaken in the previous years, where markups were retained for these sensitivities.

[83] The coal availability scenarios' outputs will not be published, as they were conducted using commercially sensitive information.

Availability cost sensitivity

Table 7 summarises the availability cost for the different sensitivity runs. Of the sensitivity runs, the availability costs for spinning reserve and load rejection reserve were most sensitive to the variations in fuel prices. Applying a single, uniform gas price ($7.2/GJ) to all gas fired generators has inflated the market prices and consequently reduced the out of merit spinning reserve availability cost. Availability costs are then driven mainly by foregone revenue. Rising uniform gas prices drive market prices further up, which in turn increases availability costs.

Table 7: Ancillary service availability cost (2023/24 financial year)

Availability cost	Mark-ups applied	Spinning reserve ($m)		Load rejection reserve ($m)	
		Peak	Off-peak	Peak	Off-peak
Base case	Yes	9.72	2.26	2.11	2.80
High solar	Yes	9.96	2.31	1.97	2.80
Unmodified generator data	No	15.45	5.21	1.25	1.57
Uniform market gas price	No	17.85	6.34	1.45	1.71
Uniform rising gas price	No	19.06	7.00	1.30	1.79

Source: ERA modelling

Without the deeply negative prices driven by the deep cycling costs of large coal fired thermal generators and minimum generation quantities bid at the floor, the modelling runs without the large negative tranches have substantially fewer negative pricing events. As a result, ancillary service costs are influenced more by foregone revenue than out of merit costs. LFAS prices for runs with markups were nearly double that of those without.

The pricing outcomes in the non-markup scenarios are consistent with the back-cast observations discussed in Appendix 8.

Rooftop solar quantity variation made relatively little difference to the availability costs. This result is consistent with previous years' modelling outcomes.

Balancing market price sensitivity

Peak electricity prices were more sensitive than off-peak prices to changes in input parameters. Some of the parameter changes, such as rooftop solar uptake, only affect peak periods. The results of the sensitivity runs are summarised in Table 8.

The 'unmodified generator data' sensitivity dispatched generators without altering their offer curves to bid at the market floor or below their short run marginal cost through the markup process used to calibrate the model. This sensitivity was based solely on the generator inputs provided by market participants, without any behavioural modifications to the offer curve. It eliminated the alterations or 'markups' to the offer curves where generators bid at the floor or below their short run marginal cost to secure a place within the balancing merit order. As outlined above, the runs with and without these modifications should not be directly compared.

Gas prices also influenced the balancing market price in both peak and off-peak periods. The higher balancing prices drive foregone revenues and the availability costs. The second of the two gas price sensitivity runs started at the same gas market spot price, but continued to escalate over the forecast window.

In the real market, generators compete to remain connected during periods of low demand. This is not reflected in these scenarios and consequently the main conclusion to be drawn is that costs are generally higher and that this drives higher availability costs.

Table 8: Sensitivity analysis pricing outcomes (2023/24 financial year)

Sensitivity	Spinning reserve and load rejection reserve availability cost			Balancing market price			
	Total availability cost ($m)	Cost difference ($m)	Relative difference (%)[84]	Peak price ($/MWh)	Relative difference (%)	Off-peak price ($/MWh)	Relative difference (%)
Base case	16.9	-	-	30.90	-	43.54	-
High solar	17.0	0.1	0.6%	30.08	(3%)	43.39	(0.3)%
Unmodified generator data	23.5	-	-	54.39	-	49.91	-
Uniform gas market price	27.4	3.9	16.6%	60.57	11.4%	55.56	11.3%
Uniform rising gas price	29.2	5.7	24.3%	64.86	19.3%	58.94	18.1%

Source: ERA modelling

[84] The relative difference is between like for like modelling runs. Base case and high roof top PV use the same offer curve modifications (markups). Unmodified generator data, uniform gas market price and rising gas market price did not apply the offer curve modifications. The gas price sensitivities use the unmodified generator data as the comparator.

Appendix 7 Ancillary services cost allocation

Generators provide many services in an electricity market, including ancillary services. It is not uncommon for generators to be providing multiple services within a market including into the balancing market, load following ancillary services and contingency mitigation ancillary services like spinning reserve and load rejection reserve.

Most generators when constrained on for a particular need – such as to maintain system security – would be compensated through a constrained-on payment. Synergy however bids as a portfolio. Capacity can be cleared to run but is not linked to any particular generator. Consequently, capacity from low-cost generators like Collie or the Muja power stations can be substituted for capacity from relatively high-cost generators like the Pinjar power station within the portfolio in a manner that would not be compensated by constrained-on payments through market settlement. This section steps out how different elements of the operational costs (such as the minimum generation quantity and quantity dedicated to downwards LFAS) are allocated across the various services in the electricity market and broadly reflects the following priorities:

1. Balancing market
2. Load following ancillary services market
3. Load rejection reserve and spinning reserve

The SWIS ready reserve is modelled as a contingency such that sufficient fast-start generators are available to meet the requirements under the WEM Rules.[85] No specific cost modelling is considered with this service.

Balancing market

The balancing market provides the base service and notional costs allocated to ancillary services only accrue where the balancing market revenue is insufficient to cover the cost. In these situations, Synergy recovers the cost of providing ancillary services through other market mechanisms. How costs are allocated between the different services is illustrated in figures A 2 to A 14.

Load Following Ancillary Services

LFAS participation and cost should be independent of the provision of spinning reserve ancillary services to reflect the discrete LFAS market and ensure consistency of treatment and opportunity with non-Synergy generators. The WEM Rules require generators to bid their minimum generation quantities at the market floor when they participate in the LFAS market. These quantities accrue to LFAS for the purposes of cost allocation even where other ancillary services are provided. This ensures consistent risk exposure for Synergy and other LFAS service providers.

Spinning Reserve and Load Rejection Reserve

The costs accruing to spinning reserve and or load rejection reserve will depend on the market circumstances at the time. The following subsections step out different combinations of

85 Wholesale Electricity Market Rules (WA), 1 February 2023, Rule 3.18.11.A, (online).

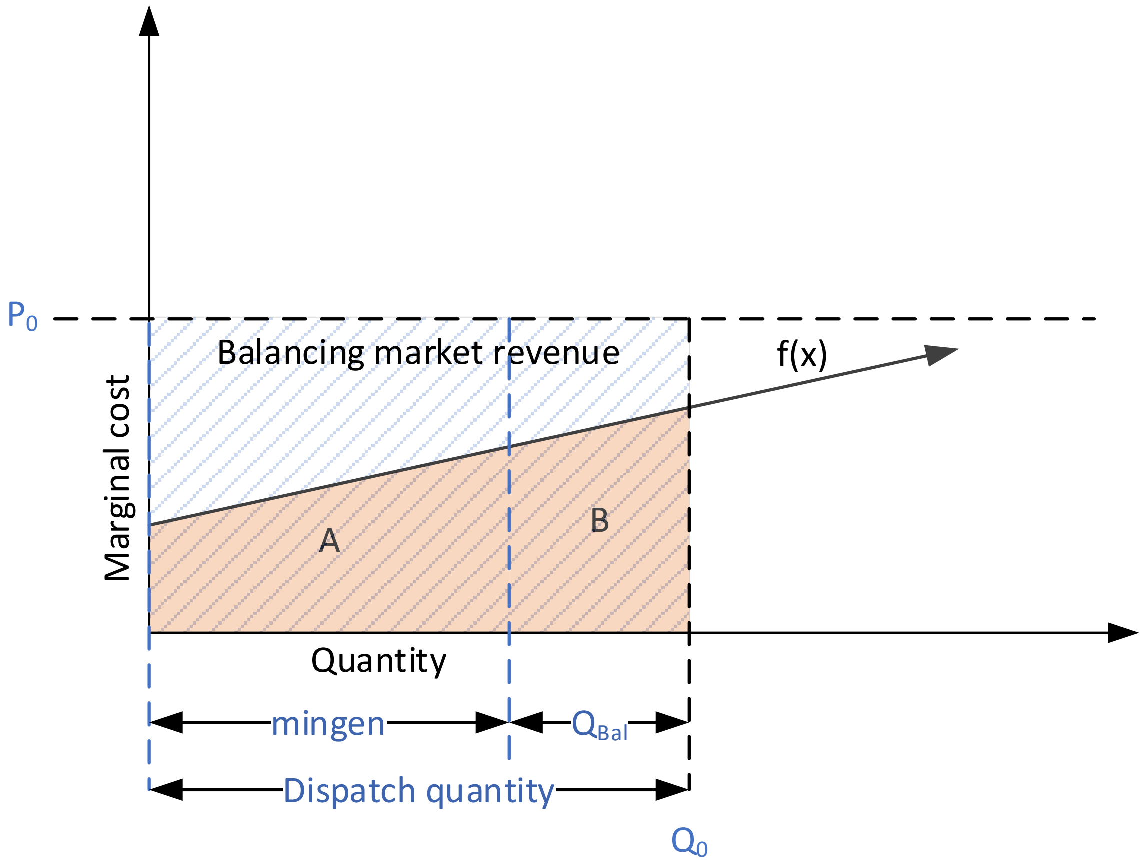
ancillary services and explain the rationale for accruing costs to different ancillary services when the generator is within the economic merit order or out of merit.

The diagrams follow a similar format with quantity on the x axis and price on the y axis. The line f(x) shows the marginal cost curve for the generator in question and the area under the curve shows the costs incurred by the generator for its output. P_0 is the balancing market price.

Solid blocks of pale orange denoted by capital letters indicate areas of cost or foregone revenue accruing to different market mechanisms. Hatched areas in pale orange are avoided costs.

In this example, the area marked 'A' is the minimum stable generation level of the generator (Figure A 1). The area marked 'B' is dispatch above the minimum – here into the balancing market. Balancing market revenue for this generator is the area bound by the balancing price and the dispatched quantity (P_0 x Q_0) shown by the blue hatched area.

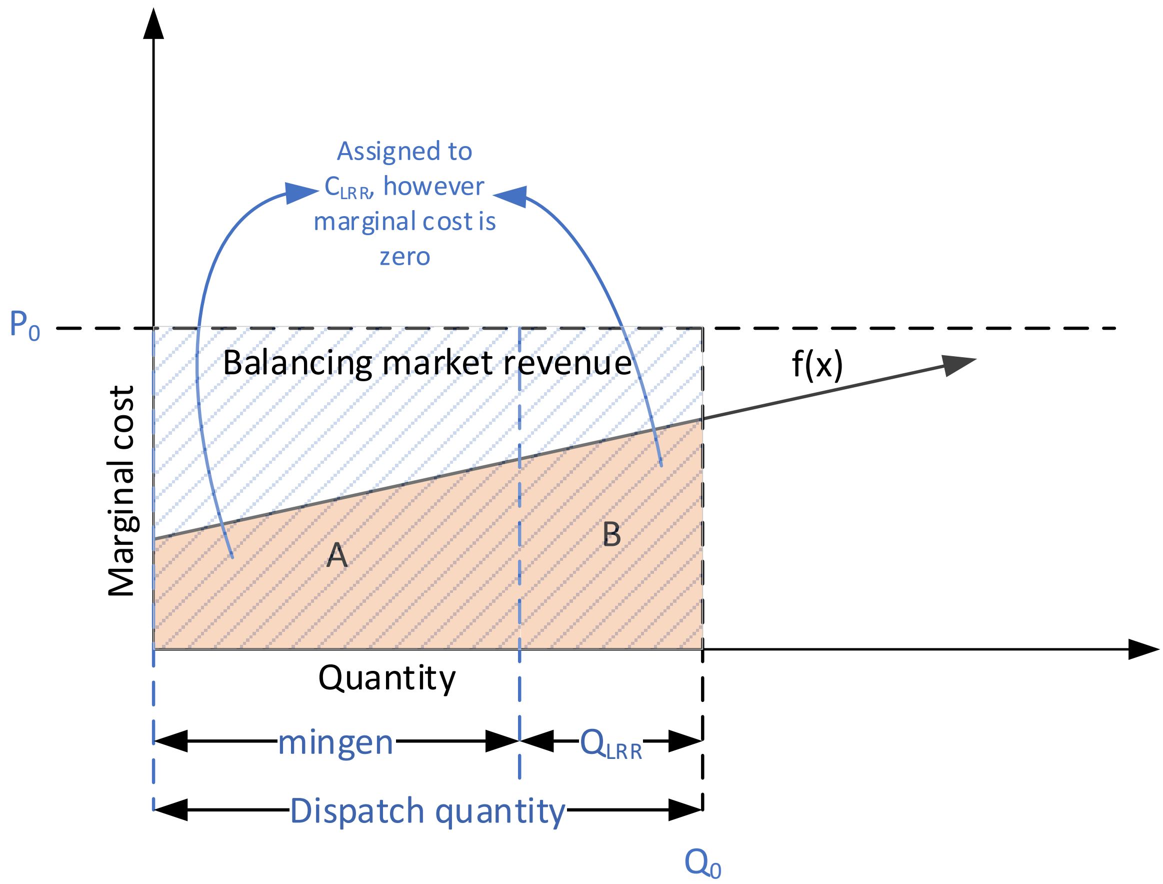
Figure A 1: Dispatch conceptual diagram



A generator providing load rejection reserve only

Where a generator is providing load rejection reserve and its marginal cost of production is less than the balancing price it is considered to be 'in-merit'. Figure A 2 shows the different costs incurred by the generator.

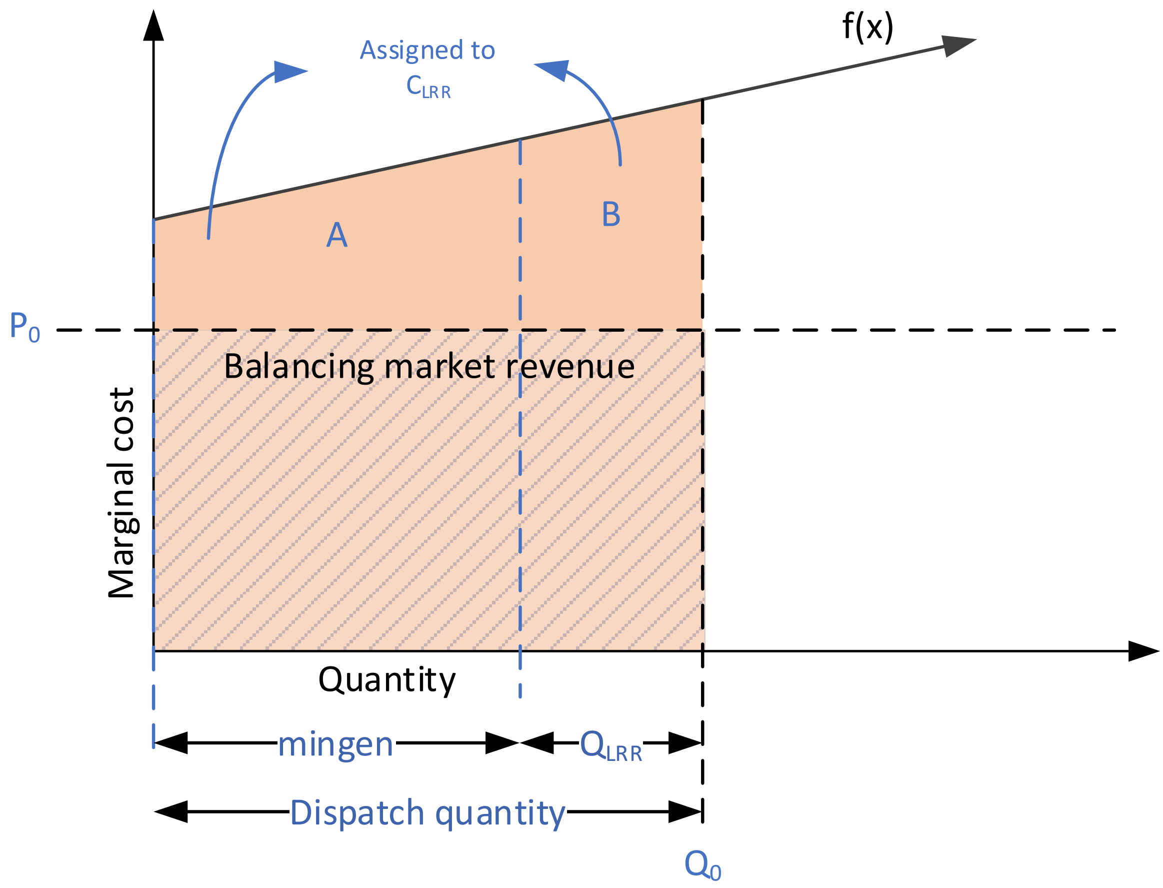
Figure A 2: Generator providing load rejection reserve when in merit



Such a generator would earn revenue from the balancing market for its full dispatch. No incremental costs are assumed to be incurred to be capable of reducing its output. Consequently, the generator would require no additional compensation to provide load rejection reserve, because the costs incurred (area 'A' and 'B') are less than the revenue it would receive.

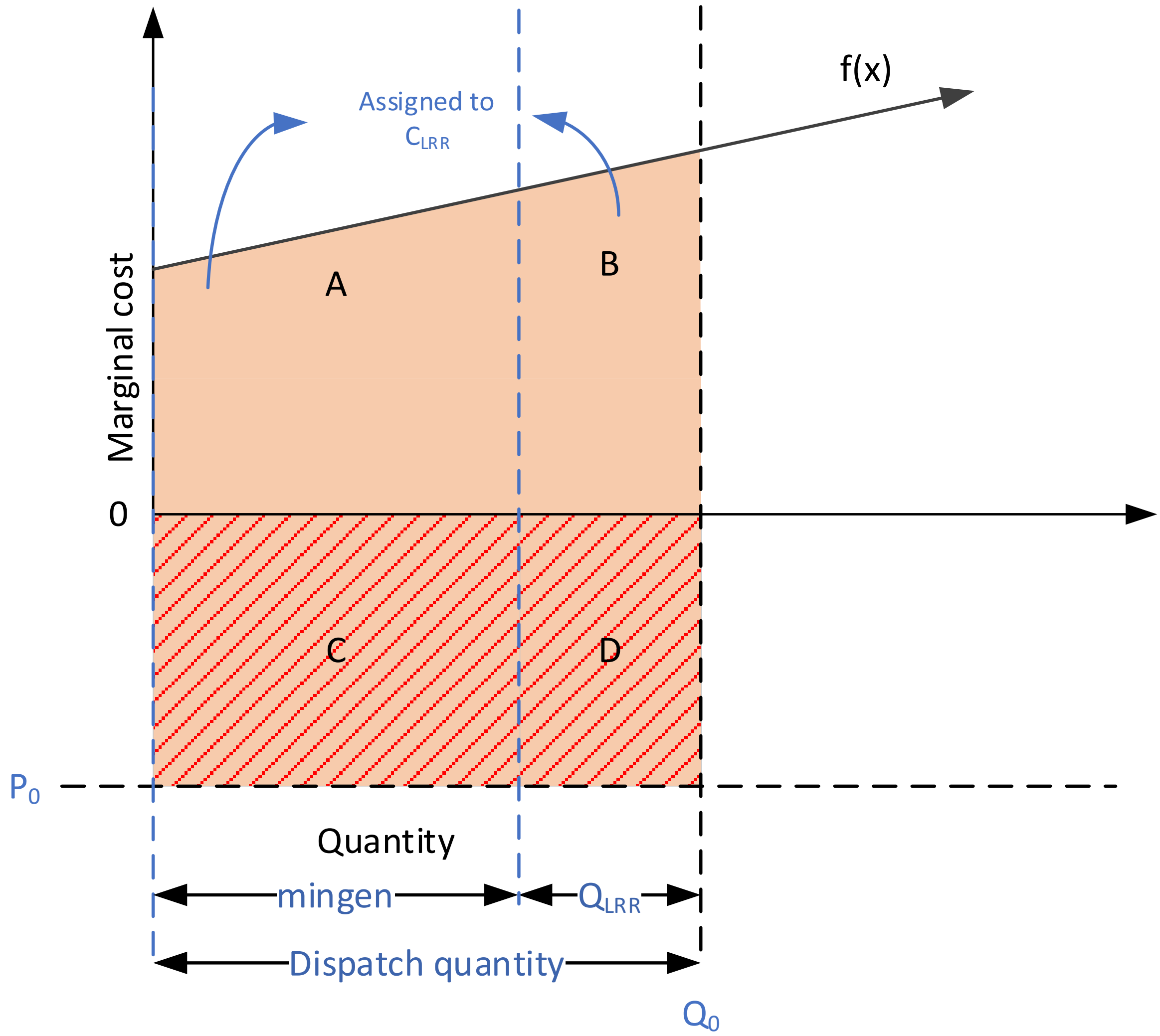
However, when that same generator's marginal cost exceeds the balancing price (such as in Figure A 3), it is considered 'out of merit'. The balancing market will provide some compensation up to the balancing market price, as the generator incurs costs that exceed this. In this situation the generator would need to be compensated for the difference between the balancing market revenue and the operational costs for its minimum generation (minimum stable generation level or area 'A') and the quantity of load rejection reserve provided (Q_{LRR}), or area 'B'.

Figure A 3: Generator providing load rejection reserve when out of merit



Where prices clear below zero, the gap between the balancing market price, and the marginal cost of the generator is larger, and also compensates the generator for the cost of dispatch into a negatively priced market (Figure A 4).

Figure A 4: Generator providing load rejection reserve when out of merit and prices are negative

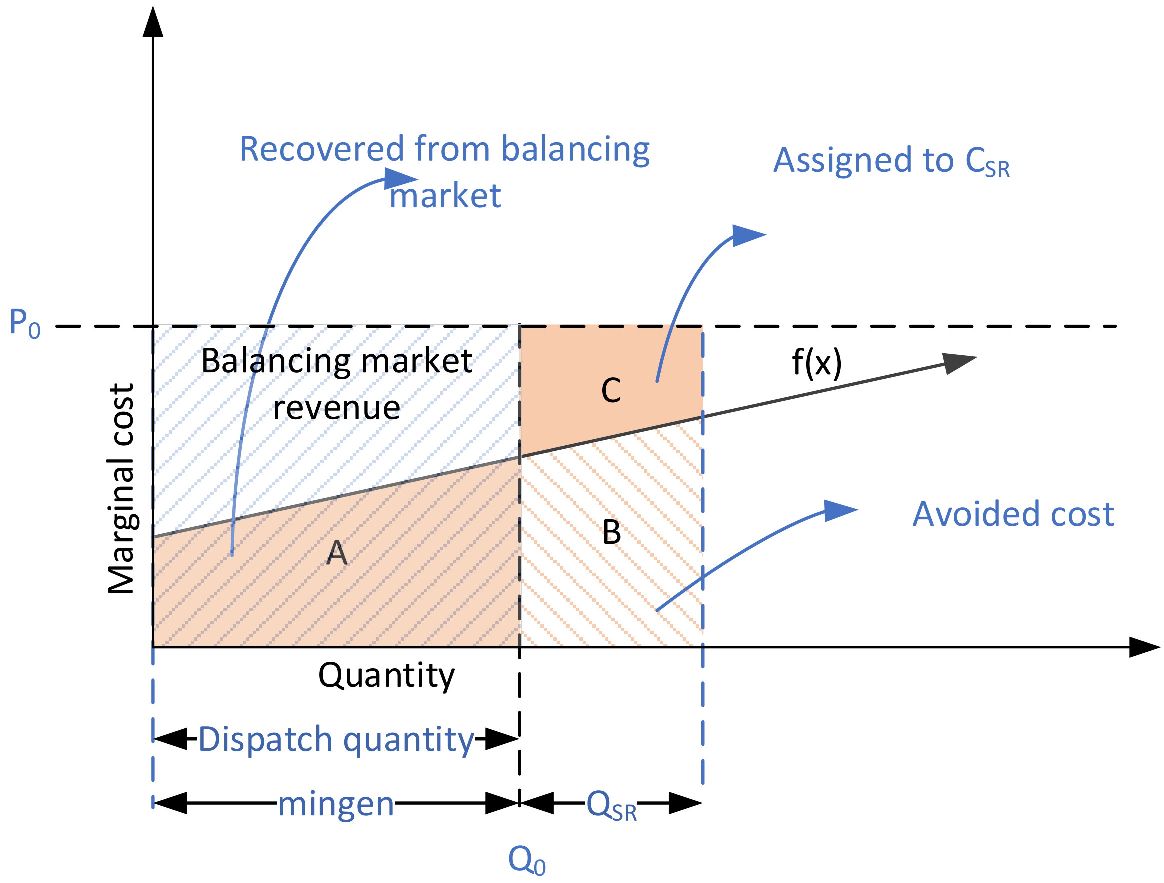


When prices are negative, areas ‘C’ and ‘D’ are paid by a generator to remain in service. These also need to be compensated for in addition to areas ‘A’ and ‘B’ – the full marginal cost of the generators dispatch.

A generator providing spinning reserve only

Figure A 5 below shows a generator providing spinning reserve only. The generator has some of its in-merit capacity withheld to provide spinning reserve (Q_{SR}). As with the previous example, the hatched area shows balancing market revenue and the areas shaded tan depicts the area under the marginal cost curve f(x) or the balancing market price P_0.

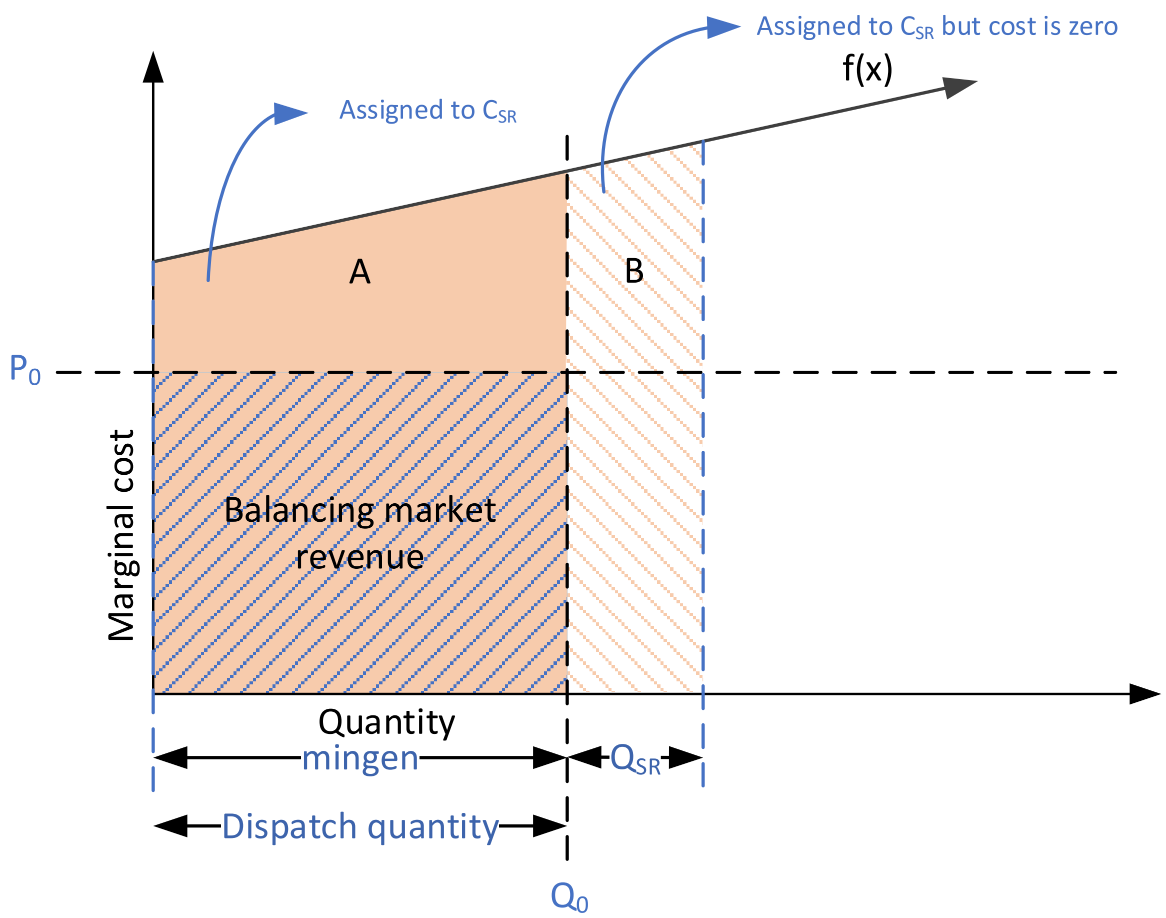
Figure A 5: A generator providing spinning reserve only when in merit



Here, area 'A' is entirely within the region compensated by the balancing market and requires no additional compensation. Area 'B' is the cost avoided that would have been covered by the revenue from the balancing market – this does not require compensation. Area 'C' however is foregone revenue that would have been earned had the generator been able to dispatch within merit. This represents the opportunity cost of providing spinning reserve. This cost should be assigned to the availability cost for spinning reserve.

Where a generator is providing spinning reserve and it is scheduled to run out of merit (as shown in Figure A 6), area 'A' is not entirely covered by balancing market revenue. This area above the balancing price requires compensation. Area 'B' however, is an avoided cost and requires no compensation. The generator avoids further out of merit operational costs by not dispatching this quantity. In this example, the generator only needs to be compensated for the operating cost difference between the balancing price and its out of merit dispatch quantity – usually to its minimum generation.

Figure A 6: A generator providing spinnign reserve only when out of merit



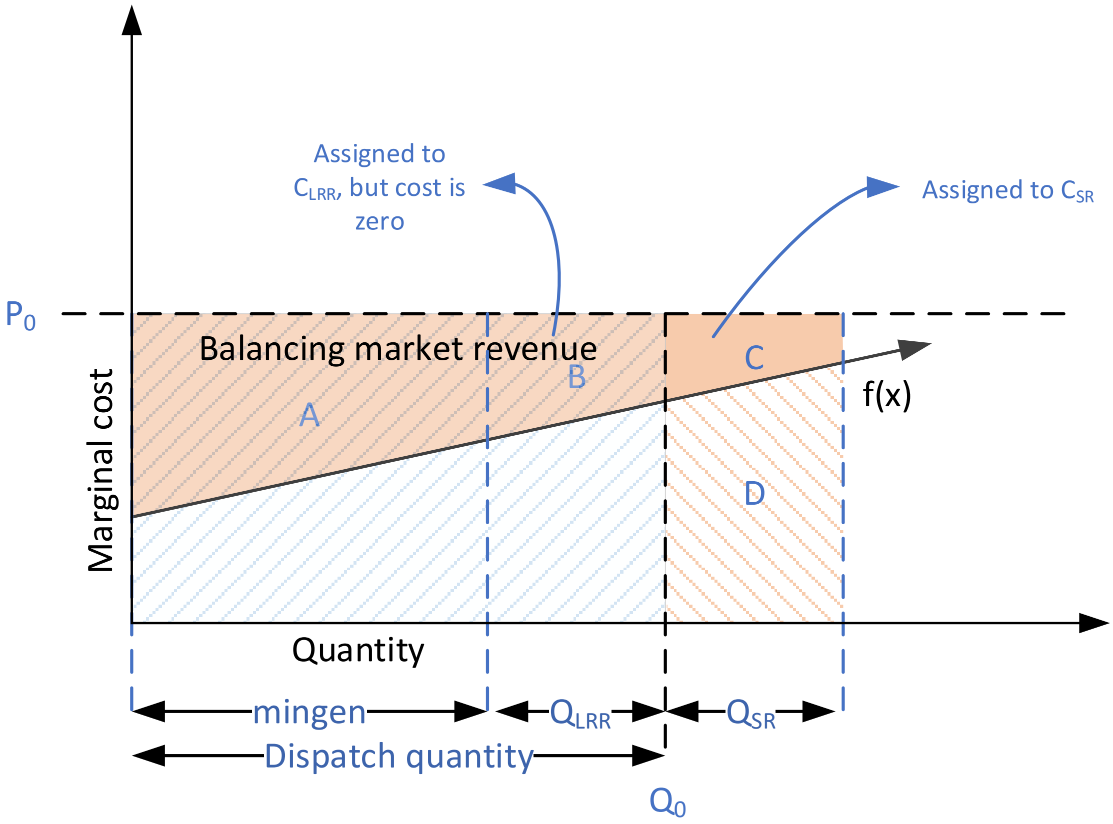
Where a generator is providing spinning reserve out of merit, and generation is withheld, there is no opportunity cost of providing spinning reserve. It avoids a cost that exceeds the revenue it would have received had it been dispatched. Area 'B' does not need to be compensated – only area 'A'.

A generator providing load rejection reserve and spinning reserve services

Where a generator is providing both spinning reserve and load rejection reserve, costs may be incurred for one or other service or both, depending on whether the generator is in or out of merit.

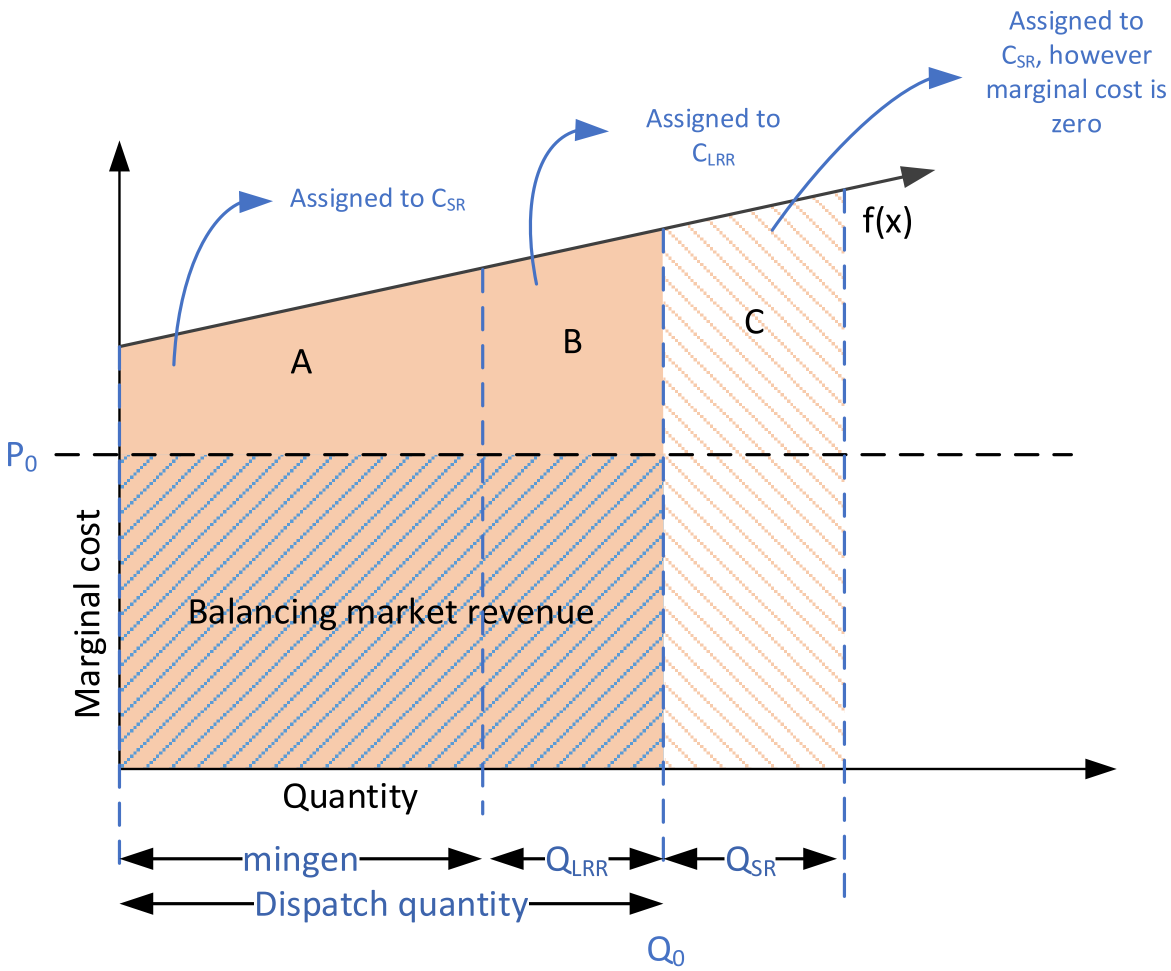
For a generator in merit (shown in Figure A 7), the costs to run up to the minimum generation quantity are recovered through the balancing market and no compensation is required. As with the example for load rejection reserve only, the cost for being available to reduce output when in merit is fully recovered through the balancing market and again, no additional revenue is required to keep a generator whole to this point. However, for the spinning reserve provided (Q_{SR}) the generator could have generated more in merit. There is an opportunity cost in terms of foregone revenue indicated by area 'C' which would accrue to the availability cost for providing spinning reserve. Area 'D' is avoided cost that requires no compensation.

Figure A 7: Generator providing spinning reserve and load rejection reserve in merit



For a generator operating out of merit providing both spinning reserve and load rejection reserve (shown in Figure A 8), a different set of costs accrue to the operation. There is a cost of generating to the minimum generation quantity (Area 'A'), this is applied to the cost to provide spinning reserve. Area 'B' is operation out of merit for the purpose of providing load rejection reserve. Area 'C' is the capacity dedicated to spinning reserve and is an avoided cost and has a marginal cost of zero.

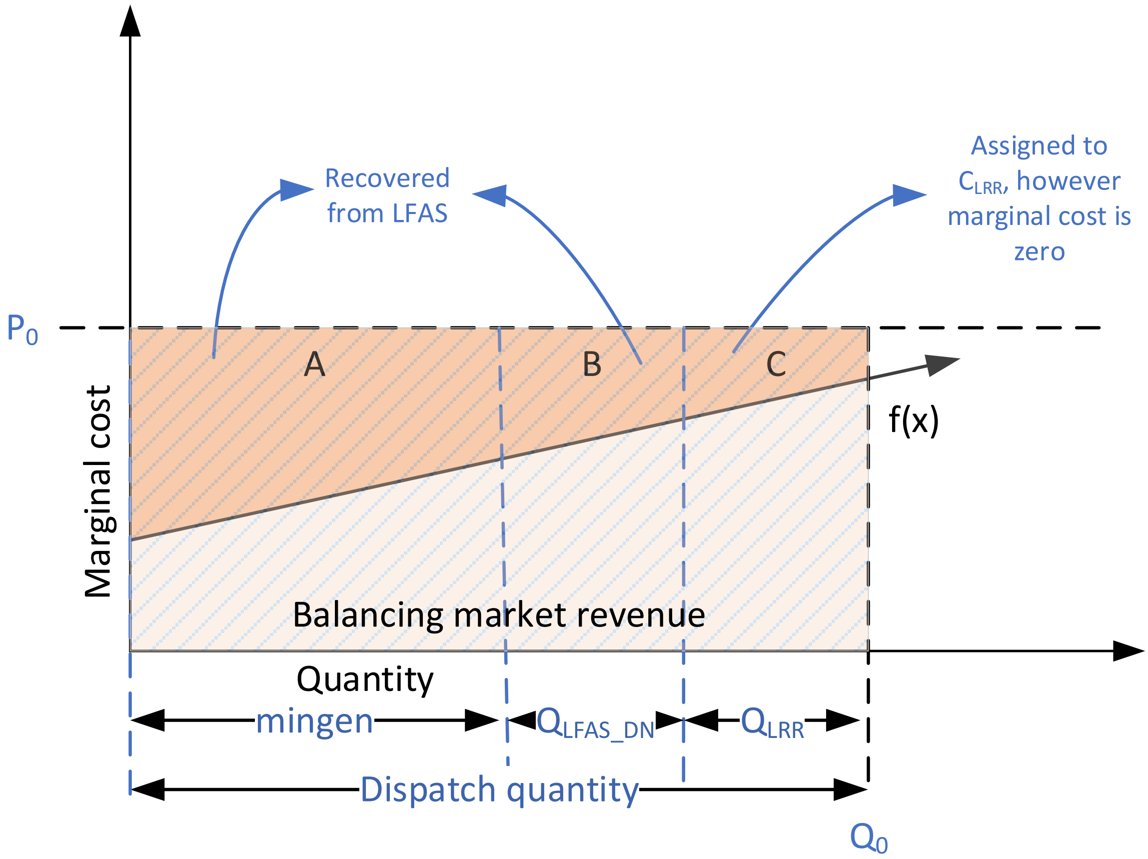
Figure A 8: Generator providing spinning reserve and load rejection reserve out of merit



A generator providing load rejection reserve and load following ancillary services

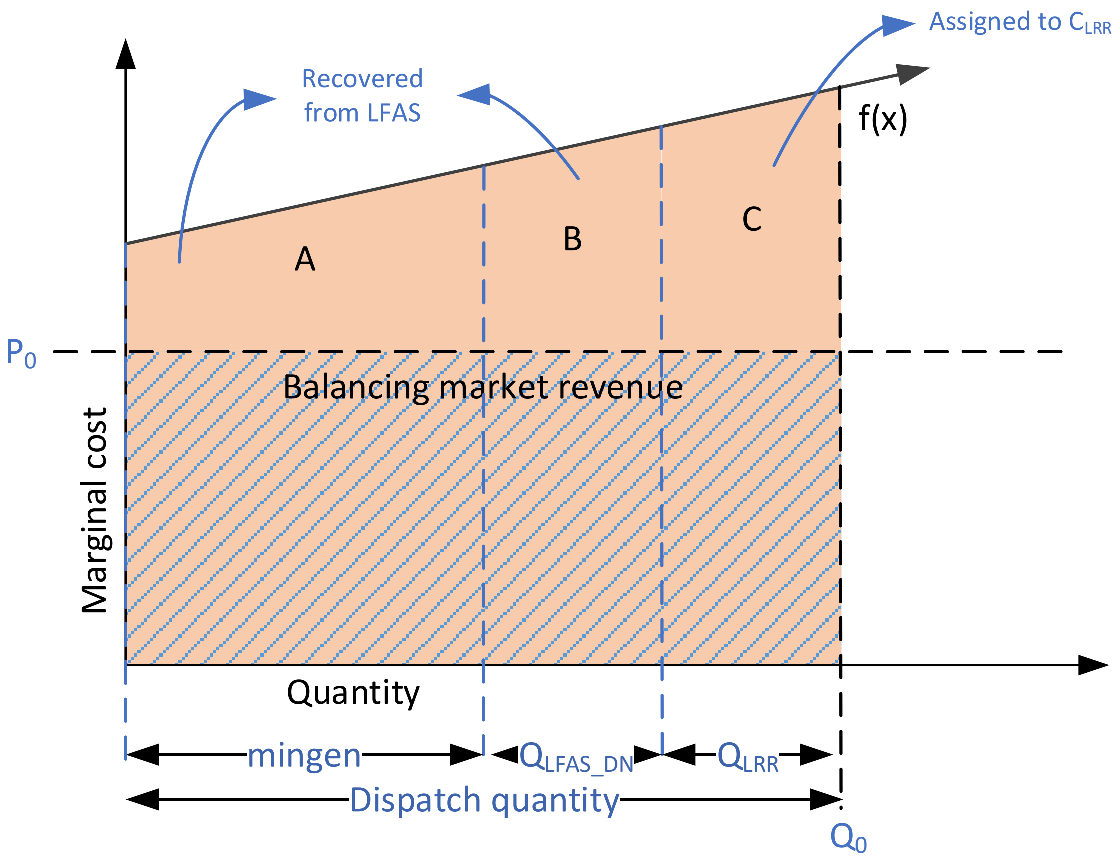
Where the generator is also providing LFAS services, depending on whether the generator's marginal cost is above or below the balancing price depends on whether a cost is incurred to provide each service. Where a generator is providing these services and is in merit (shown in Figure A 9), area 'A' and the operational costs to the minimum generation are fully recovered from the balancing market and notionally assigned to LFAS participation. Area 'B' is LFAS market participation and the costs are recovered from the LFAS market. Area 'C' is assigned to the cost of load rejection reserve; however, the costs are fully recovered from the balancing market. In this example, no additional incremental costs are accrued to any service that it cannot recover through normal market mechanisms.

Figure A 9: A generator providing LFAS and load rejection reserve operating in merit



Out of merit however, (shown in Figure A 10) the operational costs for being constrained on for the region up to minimum generation (area 'A') and that assigned to the LFAS service (area 'B') are assigned to the LFAS market. Area 'C' is constrained on to provide load rejection reserve and accrues to the load rejection reserve availability cost.

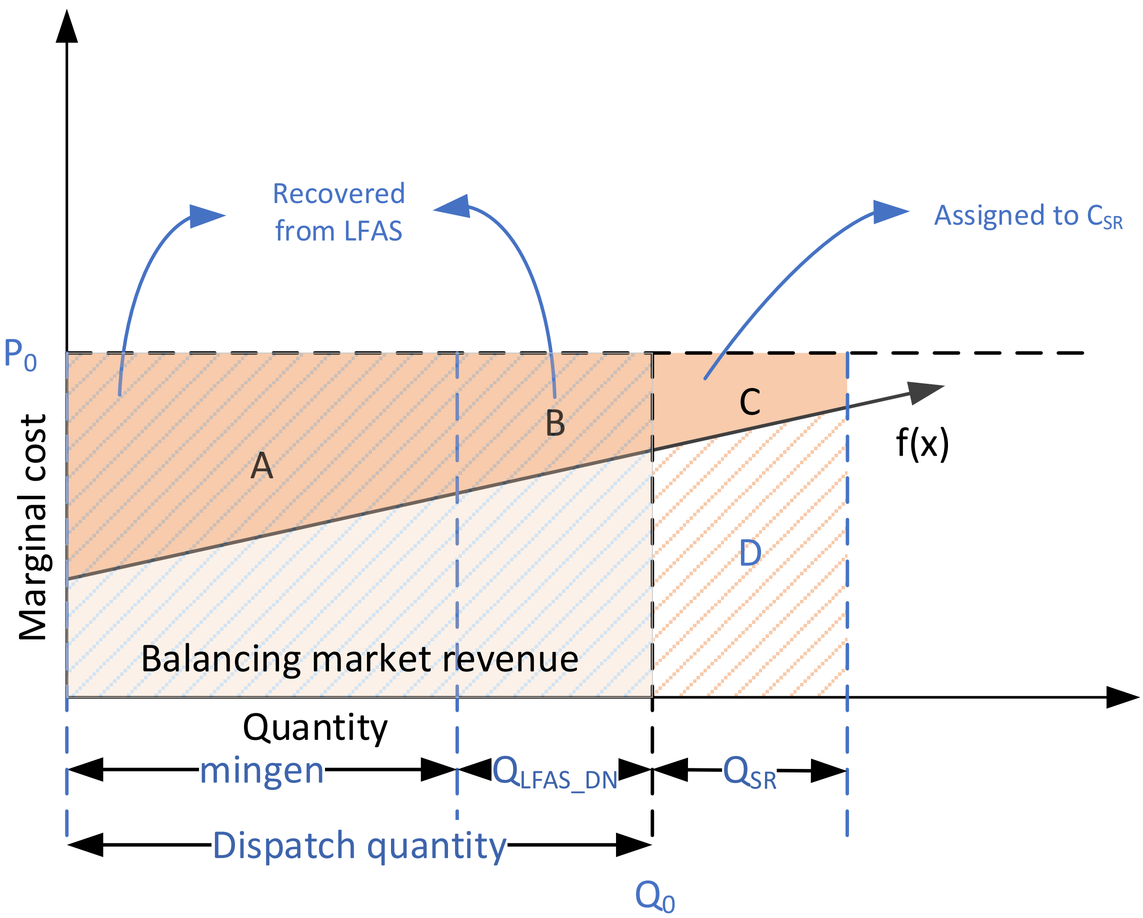
Figure A 10: A generator providing LFAS and load rejection reserve operating out of merit



A generator providing spinning reserve and load following ancillary services

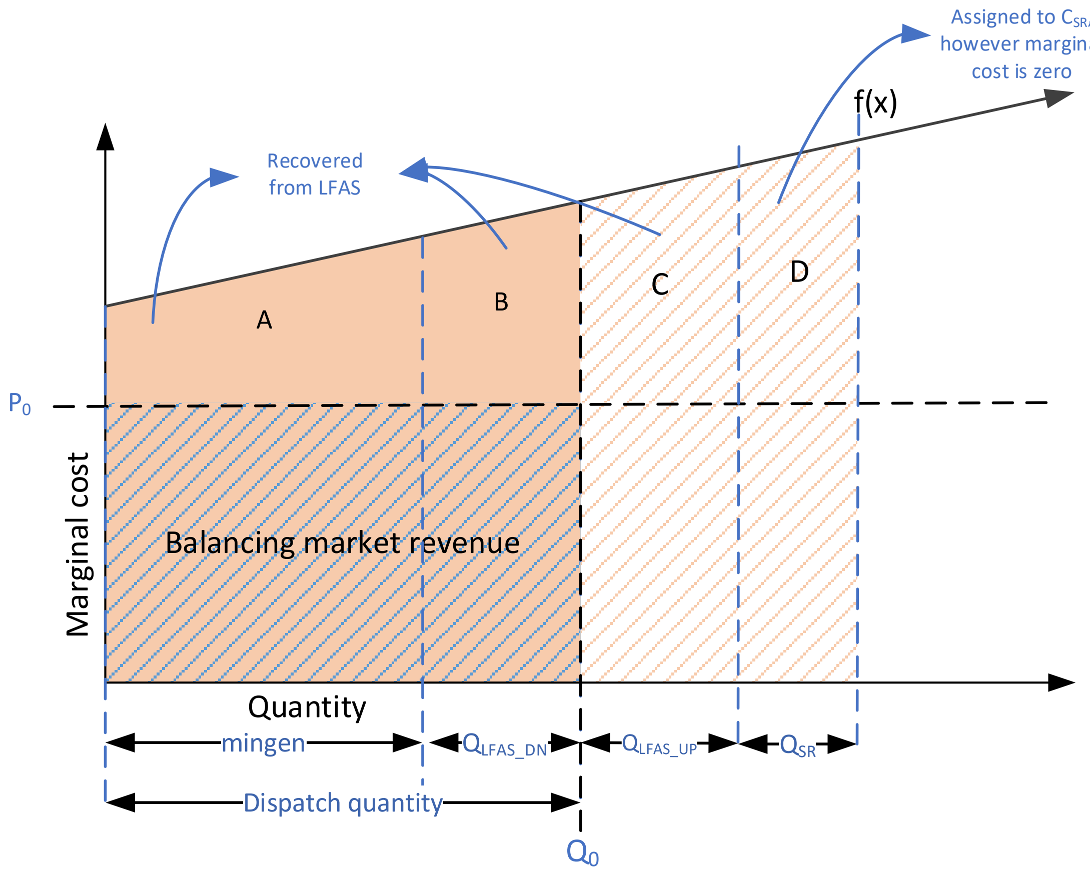
Where a generator is providing spinning reserve and load following ancillary service in merit (shown in Figure A 11), the area up to minimum generation is fully recovered through the balancing market and is assigned to the cost of providing LFAS. Area 'B' is recovered through the LFAS market and is similarly covered by the balancing market. Area 'C' reflects foregone revenue for in merit sales and is the opportunity cost of providing spinning reserve. This cost would accrue to the spinning reserve availability cost. The avoided operational costs are indicated by area 'D' and this requires no compensation.

Figure A 11: A generator providing spinning reserve and load following ancillary service operating in merit



When operating out of merit and providing spinning reserve and load following ancillary service, the minimum generation quantity is assigned to the cost of providing load following ancillary service (Figure A 12). The balancing market revenue is insufficient to cover this cost. This cost (area 'A') and that of area 'B' are assumed to be recovered through the LFAS market. Area C is an avoided cost linked to the LFAS market. Area 'D' is an avoided cost that would accrue to the availability cost of spinning reserve. However, the marginal cost to be able to increase output is zero.

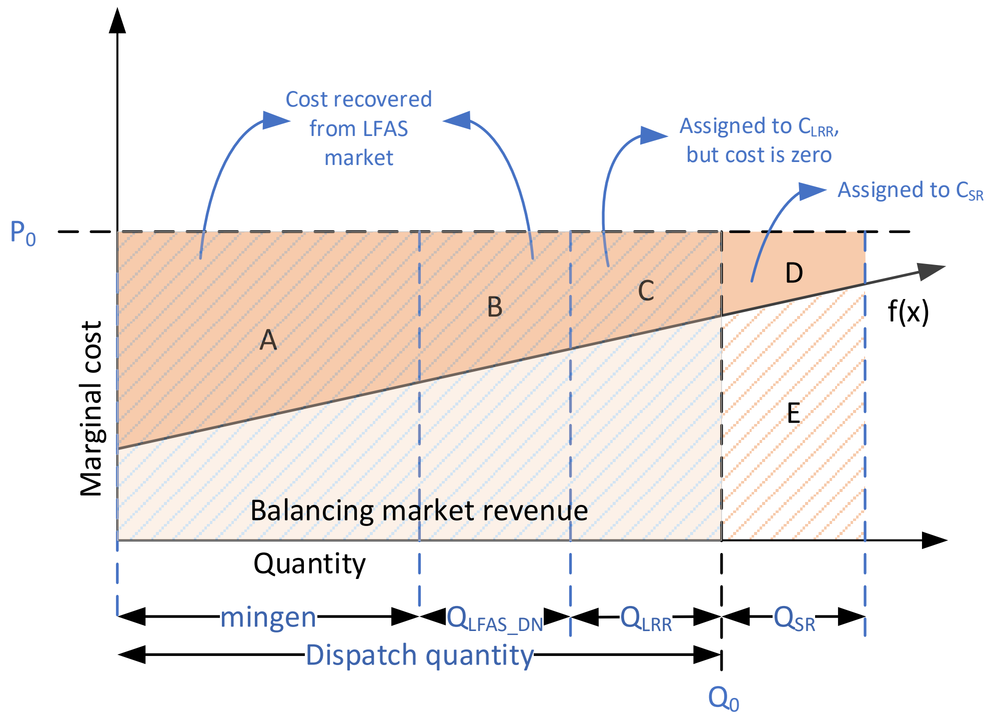
Figure A 12: A generator providing spinning reserve and load following ancillary service operating out of merit



A generator providing spinning reserve, load rejection reserve and load following ancillary services

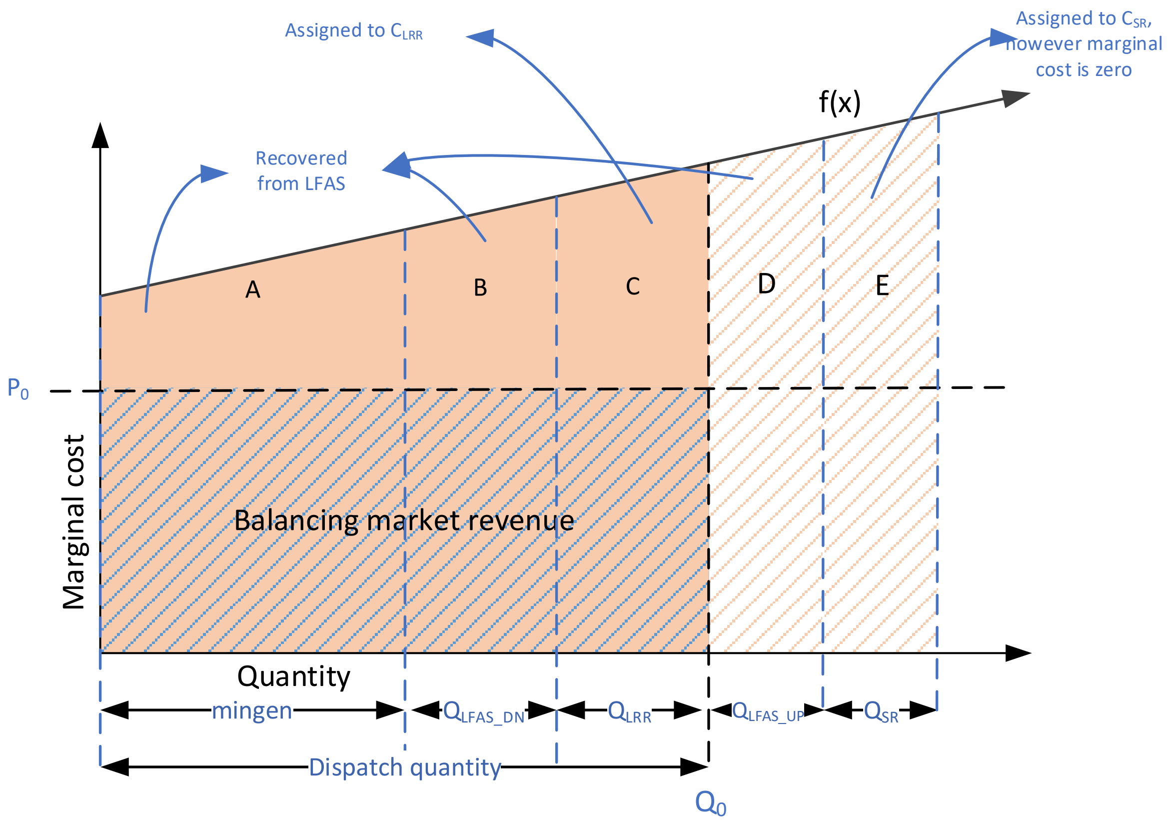
The costs associated with a generator providing LFAS, load rejection reserve and spinning reserve are shown in Figure A 13 below. The cost to minimum generation shown by area ‘A’ and the cost to provide load following ancillary service down shown by area ‘B’ are assumed to be recoverable from the balancing and LFAS markets. Area ‘C’ is the load rejection reserve provision. The cost for this service is fully recovered from the balancing market. Areas ‘D’ and ‘E’ are linked to spinning reserve. Area ‘D’ is foregone revenue as the marginal cost of the generator is less than the balancing market price and would accrue to the spinning reserve availability cost. Area ‘E’ is avoided cost and requires no compensation.

Figure A 13: A generator providing LFAS, load rejection reserve and spinning reserve operating in merit



If the balancing market price was to fall below the marginal production cost of the generator, (Figure A 14) area ‘A’ which is for LFAS provision and with areas ‘B’ and ‘D’ the cost would be recovered through the LFAS market. Area ‘C’ is the cost of the generator being constrained on to provide load rejection reserve and the cost difference between what it would receive from the balancing market and the cost of production. The output withheld for spinning reserve (area ‘E’) is an avoided cost and requires no additional revenue to keep the generator whole and the marginal cost is zero.

Figure A 14: A generator providing LFAS, load rejection reserve and spinning reserve operating out of merit



Appendix 8 Model calibration and back-casting results

Modelling the WEM

The ERA's model uses inputs provided by market participants and incorporates advice from market participants on their short run marginal cost input parameters.

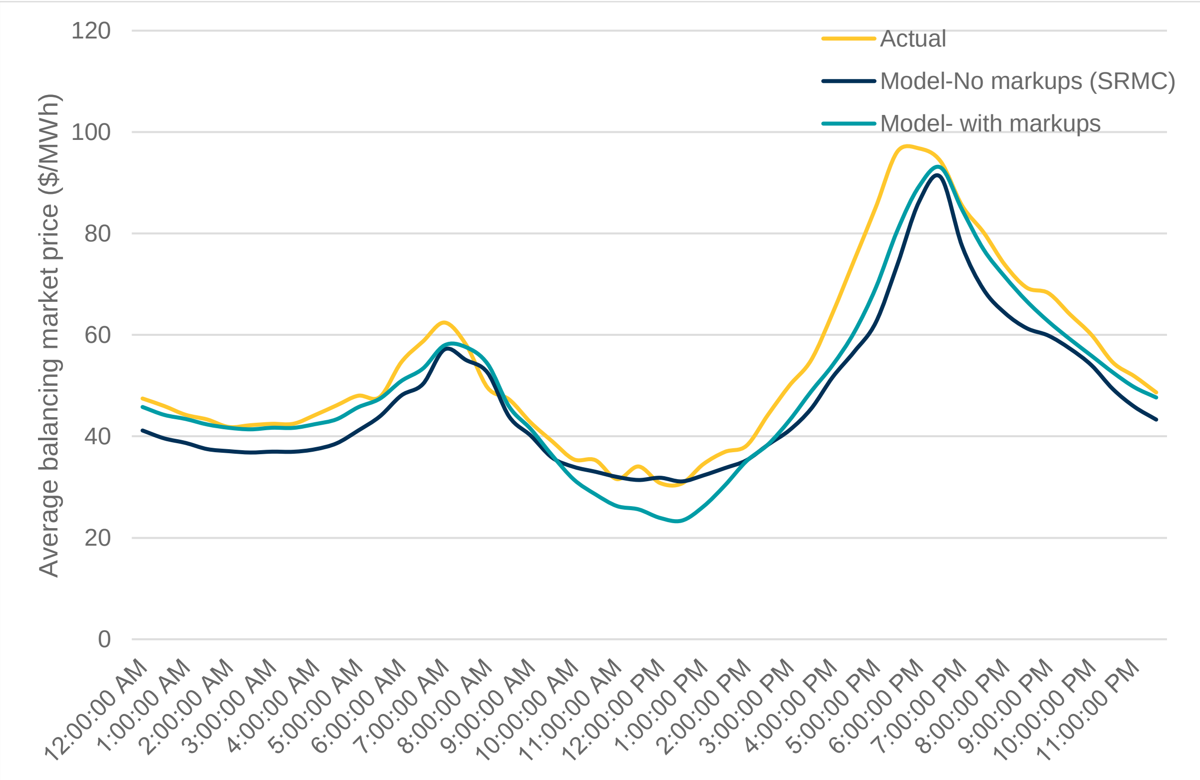
The back-cast model was run using inputs from the 2021/22 financial year. Using actuals eliminated variables such as non-scheduled generator output, changes to operational demand and outages. The outputs of the back-cast were used in conjunction with balancing market offers and ancillary services market participation to guide changes to the offer profiles into the model.

Termed 'markups', this tuning applies modifications to generators' offers to align them with observed behavioural patterns in the market. Applying markups includes identifying offer tranche sizes, capacity tranches offered at the market caps, and tranches offered below the calculated short run marginal cost. The outputs of the model are evaluated against the observed pricing and dispatch outputs.

The pricing outcomes from the back-casting indicate a fair alignment between the modelled outcomes and the actual market. Consistent with previous years, the model deviates in the top fifth of prices with the model on average underestimating prices compared to the market.

The price profile in Figure 11 indicates that on average prices are underestimated during the midday solar trough through to the evening peak. The differences between the actual and modelled values shows a similar distribution to previous modelling exercises.

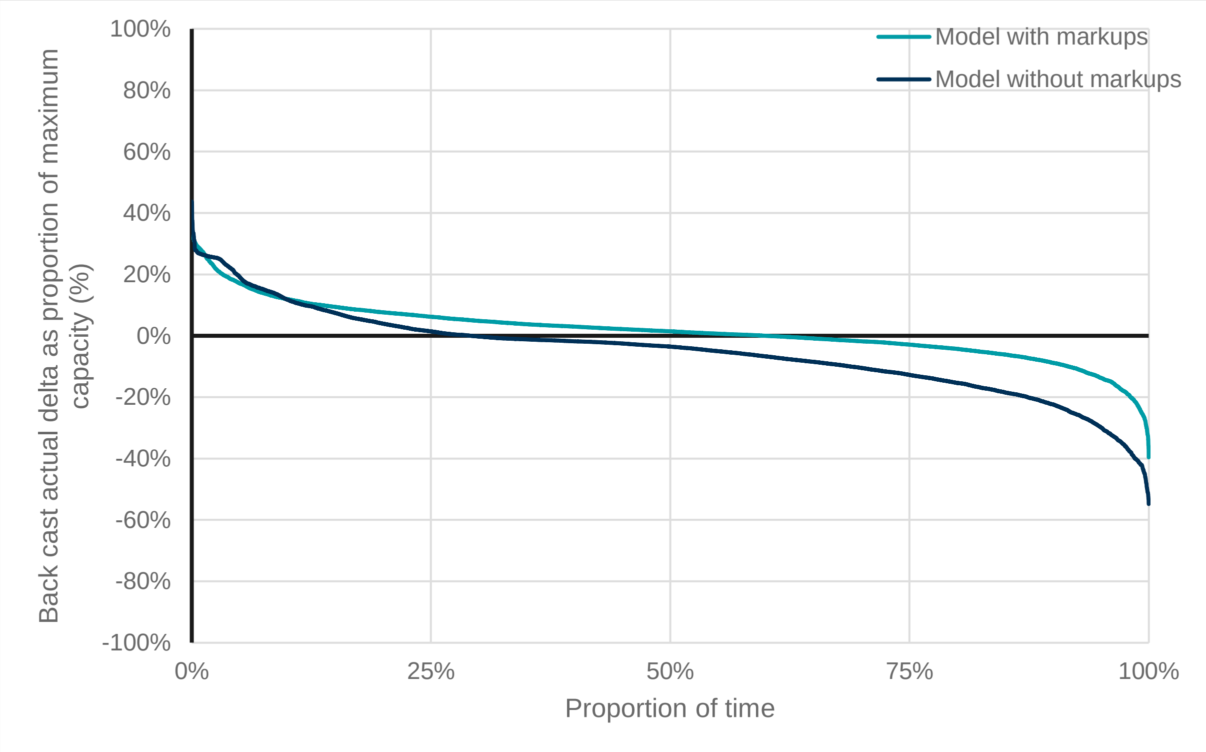
Figure 11: Back-cast pricing profile



Source: ERA modelling and AEMO data

Generation dispatch for comparable generators shows a reasonable fit following calibration and tuning. The model was also run without markups to assess their influence on the model outputs. While the price compared better on average during certain times of day, Figure 12 shows that the dispatch outcomes were further from the actual market and, forecast errors for large generators was substantially larger. For example, the correlation coefficient between the model and the actual market for Synergy's coal portfolio reduced from 0.82 to 0.64 when the model was run without markups.

Figure 12: Back-cast error as a proportion of maximum capacity Synergy coal portfolio with and without markups



Source: ERA modelling

Differences between back-cast and forecast model and assumptions

General settings are assumed to be comparable between the back-cast and forecast modelling settings, for example, general bidding patterns are assumed to be consistent between the back-cast and forecast models. However, other parameters and assumptions have changed or have potential to change between the back-cast and forecast. These include:

- The increase in load rejection reserve requirements (outlined in Section 2.2).
- The retirement of old assets and commissioning of new assets after the back-cast window.
- Changes to market participant behaviour within the back-cast window.
- Changes to AEMO scheduling practices and the operating environment.

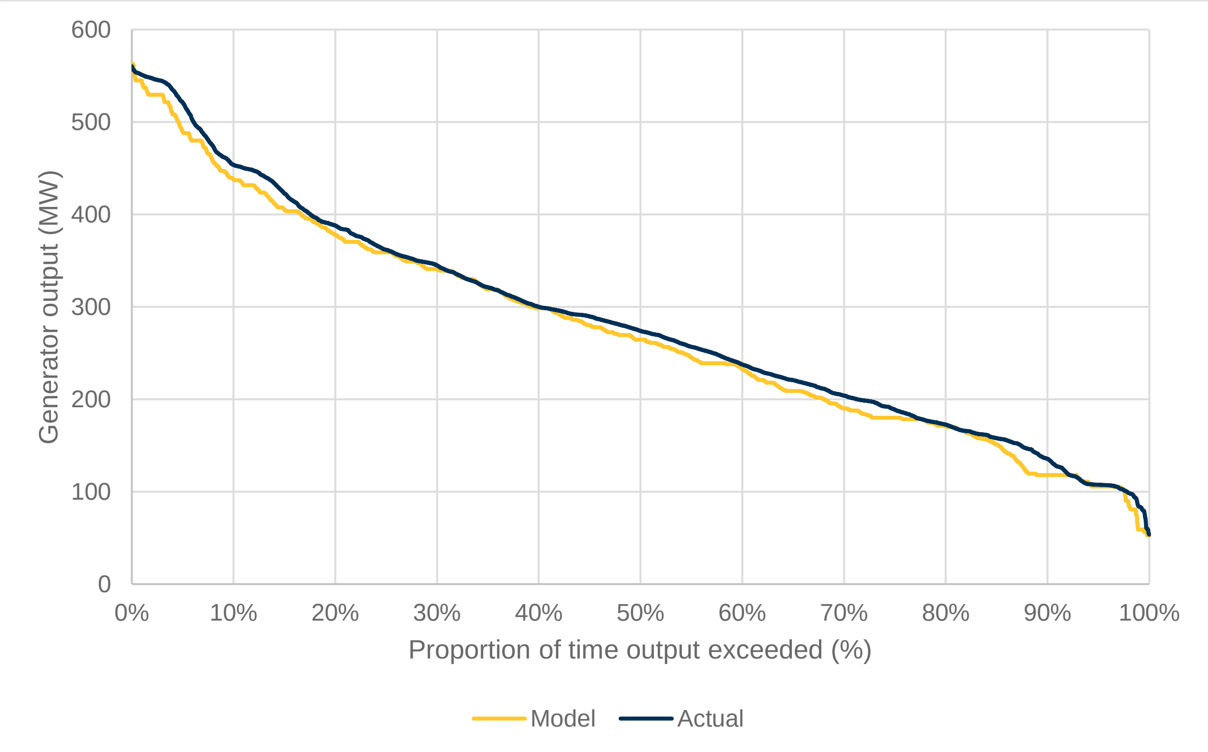
Synergy's new asset, the first large battery storage facility in the SWIS, is scheduled to commence operation prior to the forecast period. Assumptions on operational parameters in the modelling were guided by the expected operational information provided by Synergy for the 2022/23 determination.[86]

The implications of changes to the operating environment that emerged after the end date of the back-cast period are discussed in Section 4.

Dispatch outcomes

Generally, the model provides a good fit for overall generator scheduling. The exception to this is around peaking generators. These tend to be under scheduled or over scheduled (such as for the larger generators at Pinjar Power Station). With the approach to mark-ups discussed above, the effect of capacity offered at the cap is more likely to affect the dispatch of smaller peaking generators over larger generators lower in the merit order. The cycling of particular generators within Synergy's portfolio may also reflect engineering preferences for generator cycling and distributing duty across multiple similar units not reflected in the modelled dispatch economics.

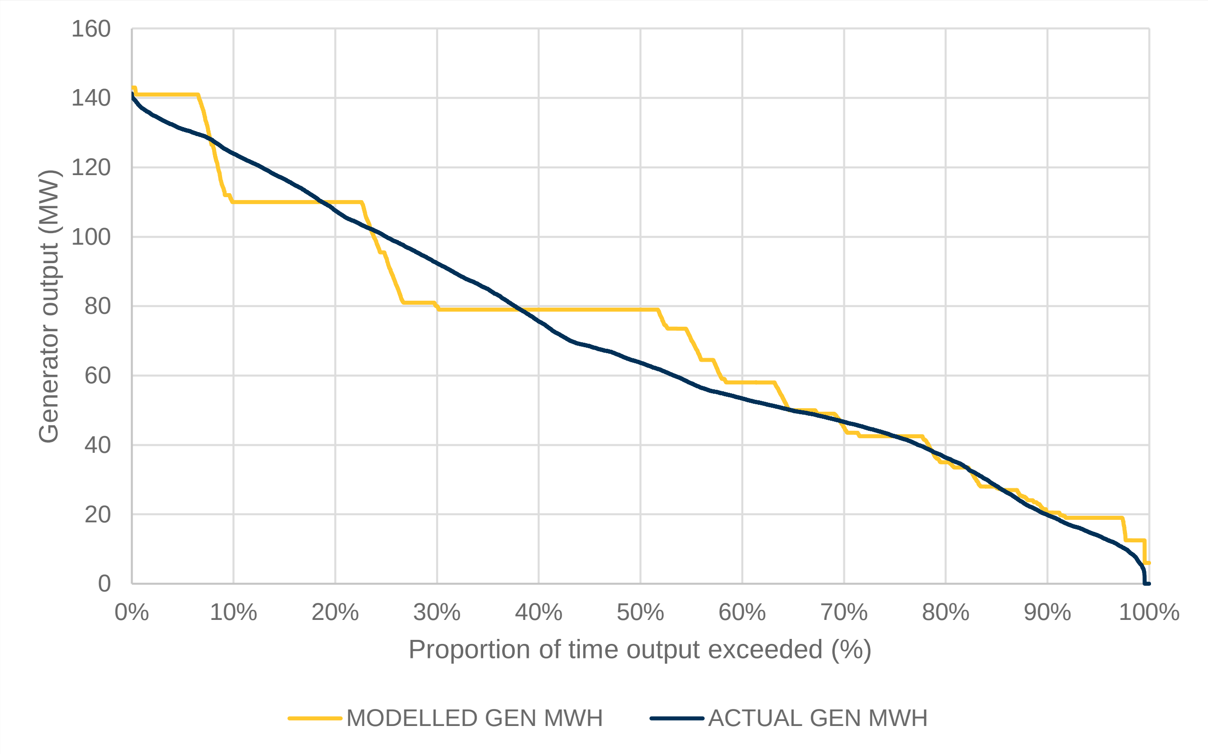
Figure 13: Back-cast output duration curve Synergy coal portfolio



Source: ERA modelling and analysis of AEMO data

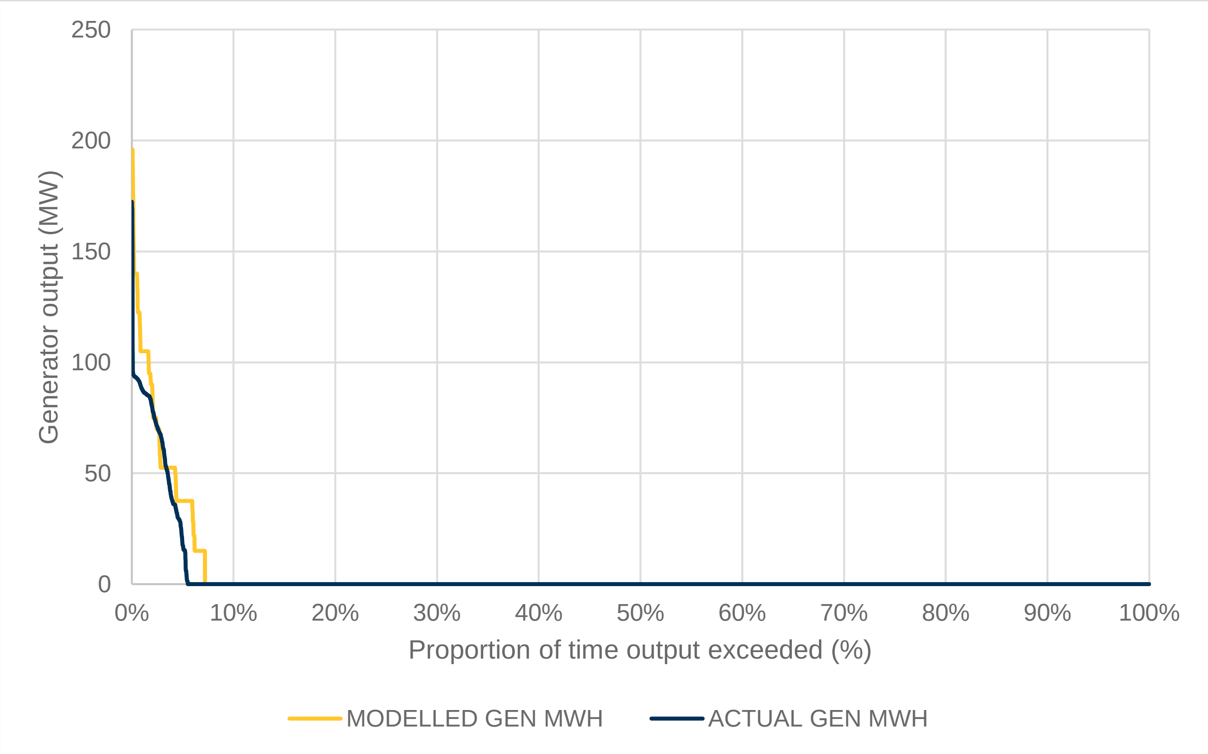
[86] Synergy, 2022, Submission to *Spinning reserve, load rejection reserve, and system restart ancillary service (margin values and Cost_LR parameters) settlement values 2022/23 - Issues paper,* (online).

Figure 14: Back-cast output duration curve Alinta Pinjarra power station



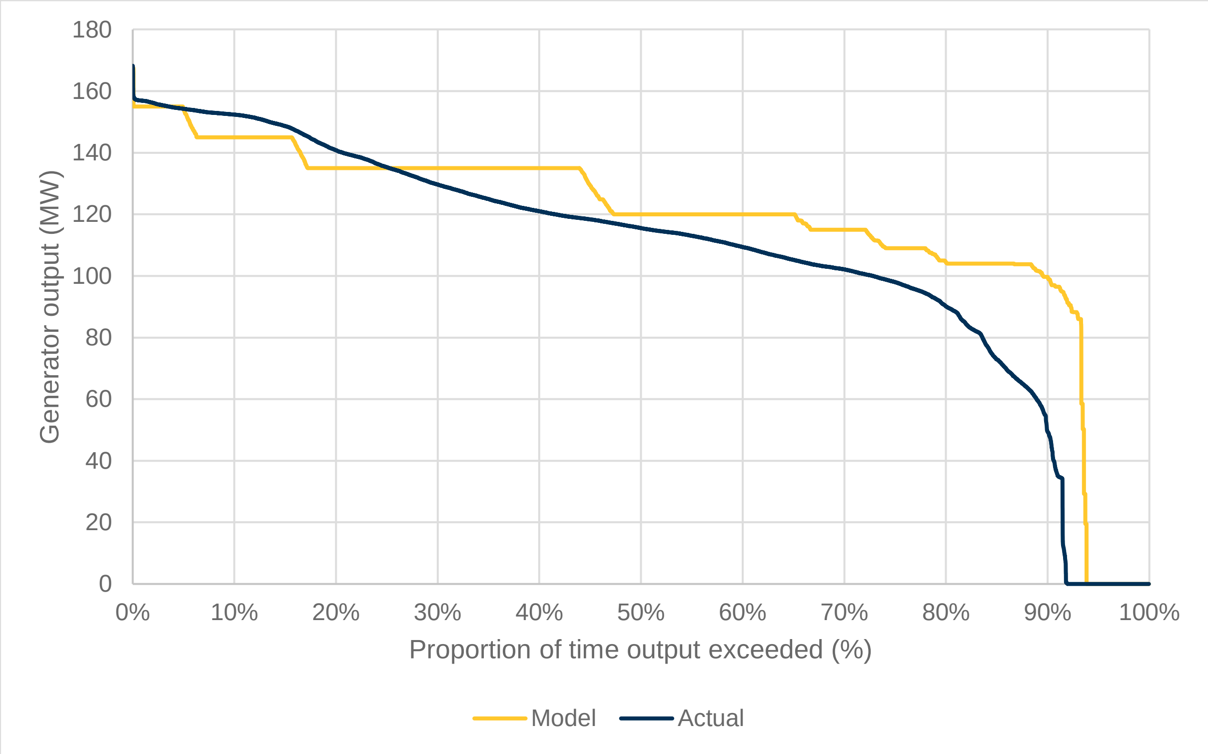
Source: ERA modelling and analysis of AEMO data

Figure 15: Back-cast output duration curve Alinta Wagerup power station



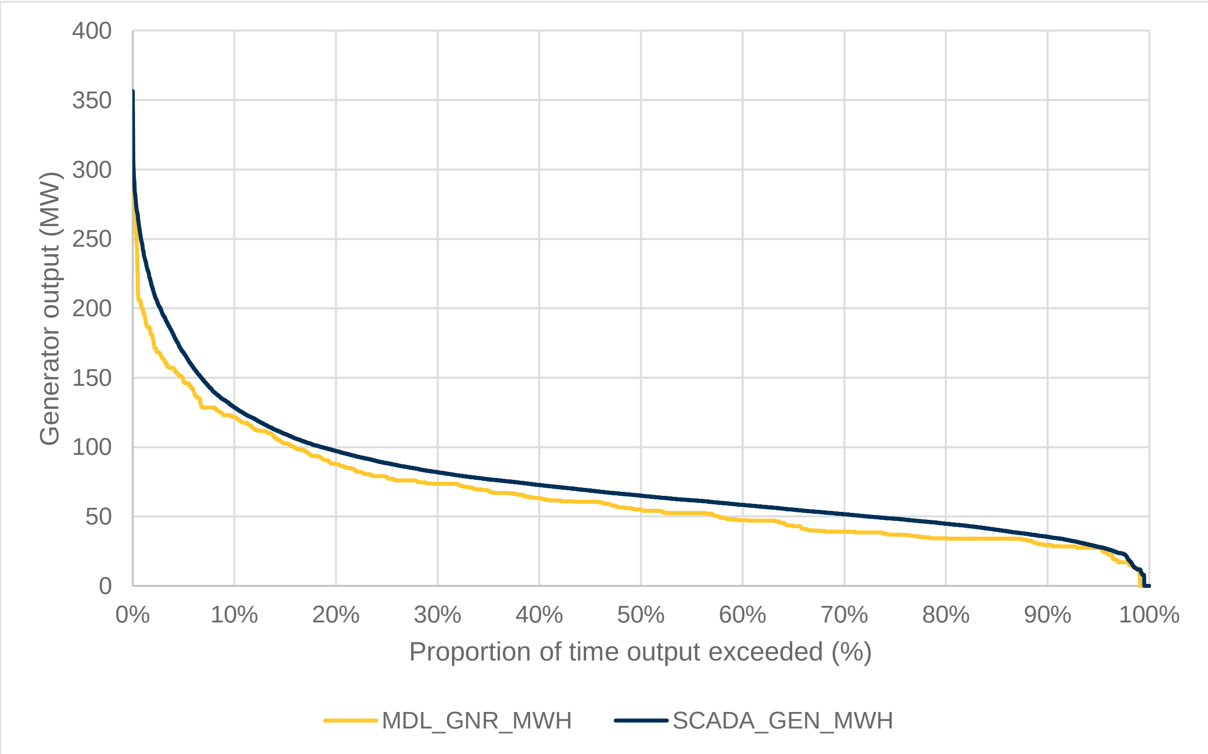
Source: ERA modelling and analysis of AEMO data

Figure 16: Back-cast output duration curve Newgen Kwinana power station



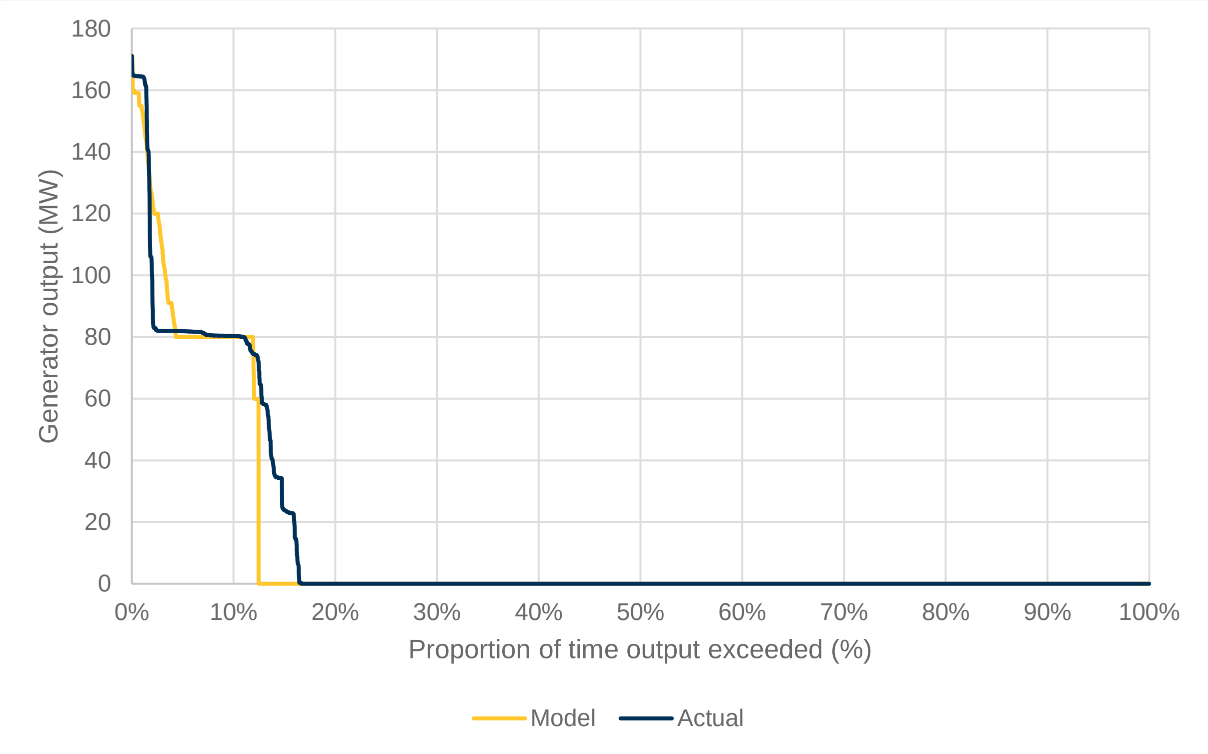
Source: ERA modelling and analysis of AEMO data

Figure 17: Back-cast output duration curve Synergy large capacity gas turbines (>100MW)



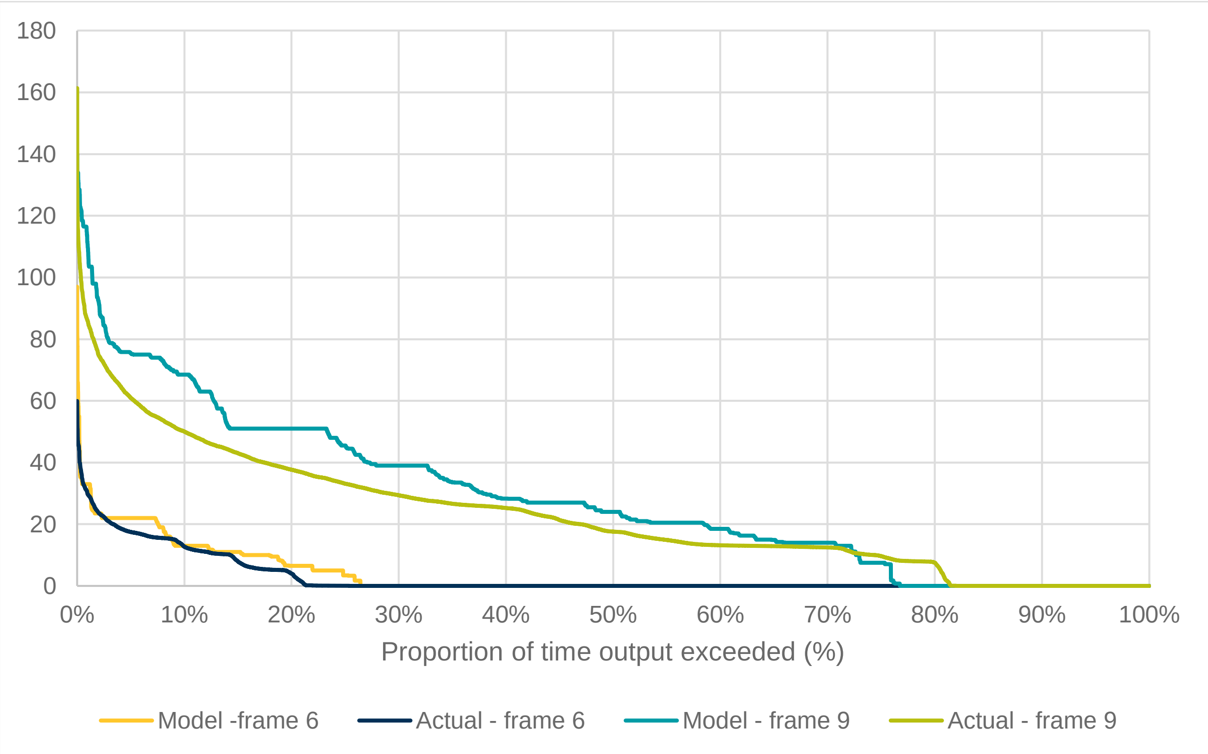
Source: ERA modelling and analysis of AEMO data

Figure 18: Back-cast output duration curve Newgen Neerabup power station



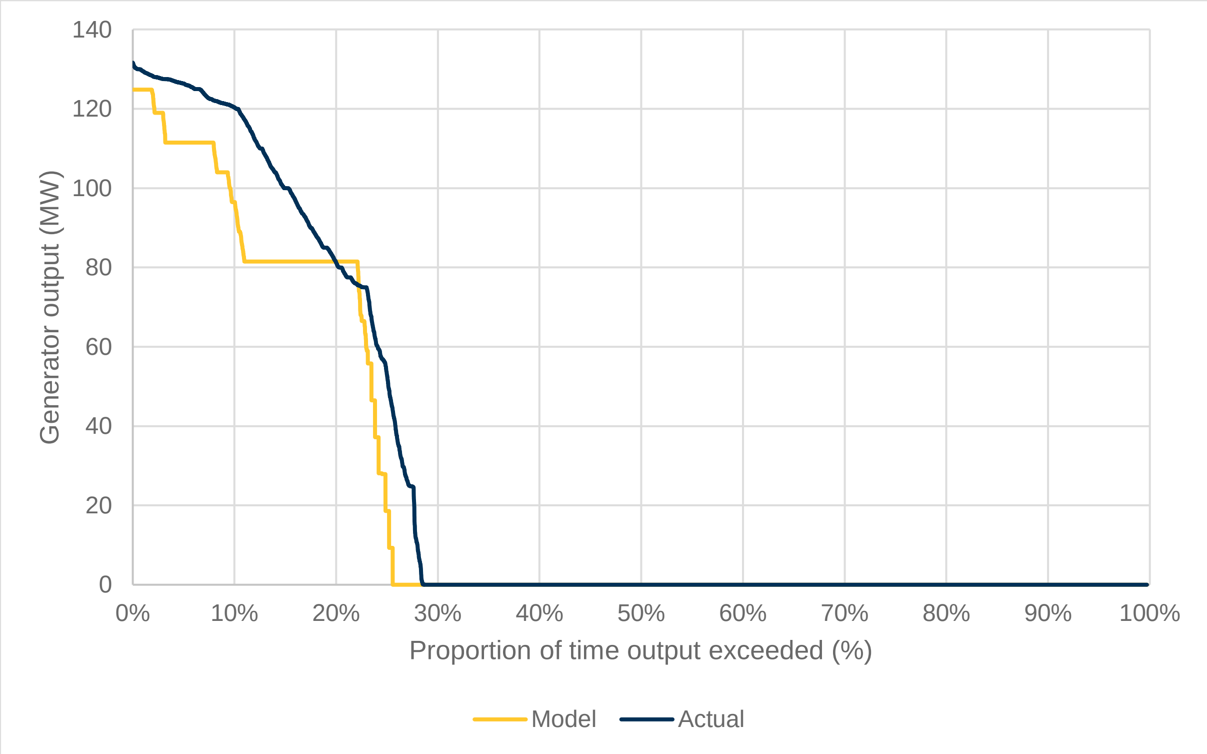
Source: ERA modelling and analysis of AEMO data

Figure 19: Back-cast output duration curve Synergy Pinjar power station



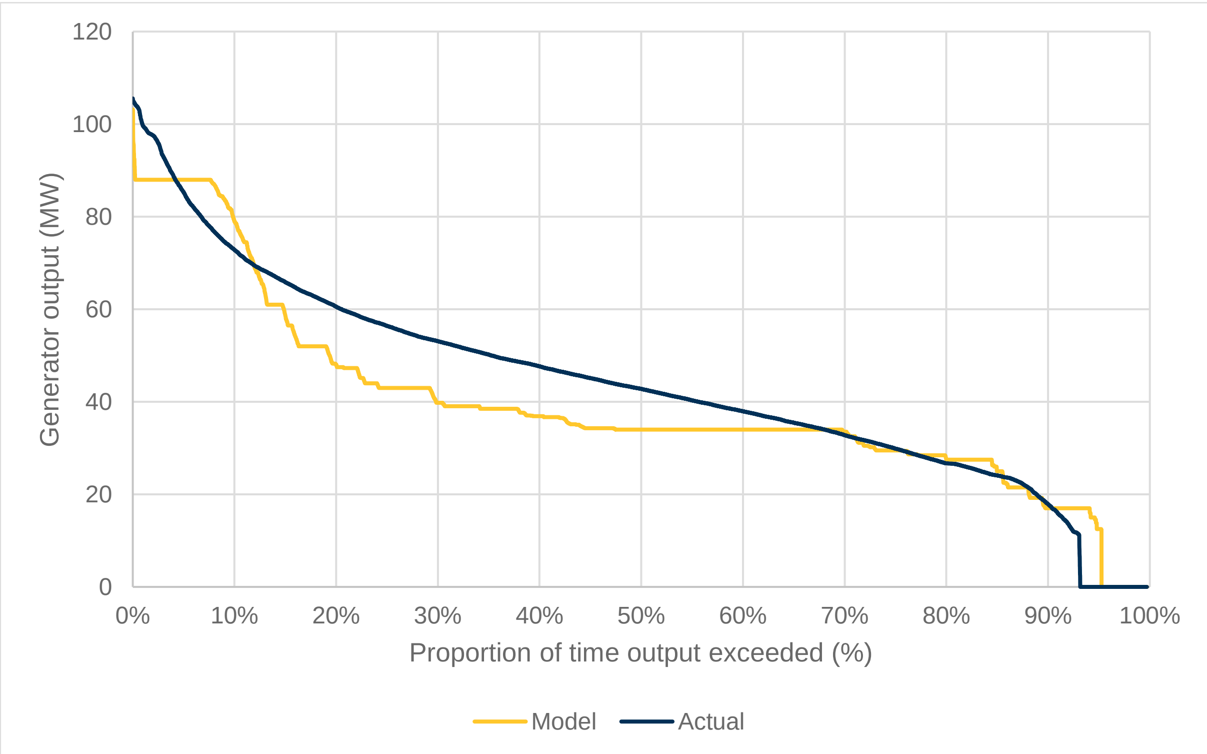
Source: ERA modelling and analysis of AEMO data

Figure 20: Back-cast output duration curve Cockburn power station



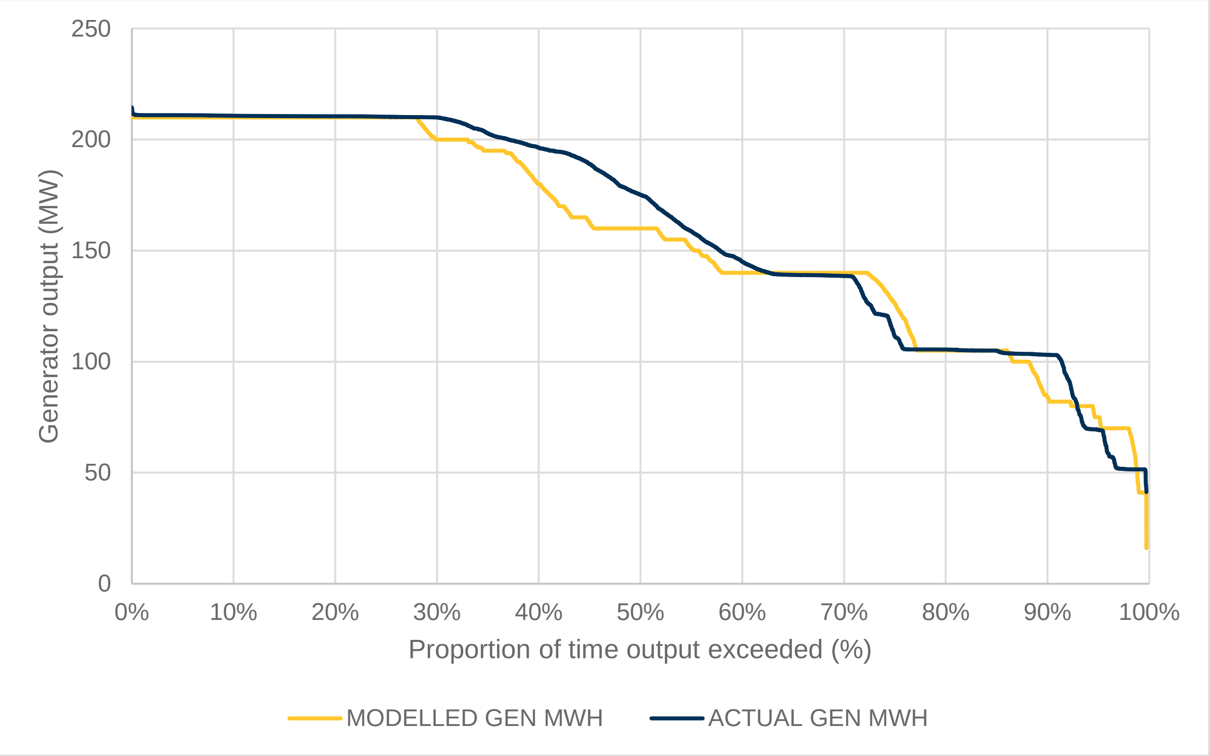
Source: ERA modelling and analysis of AEMO data

Figure 21: Back-cast output duration curve Kwinana HEGT



Source: ERA modelling and analysis of AEMO data

Figure 22: Back-cast output duration curve Bluewaters power stations



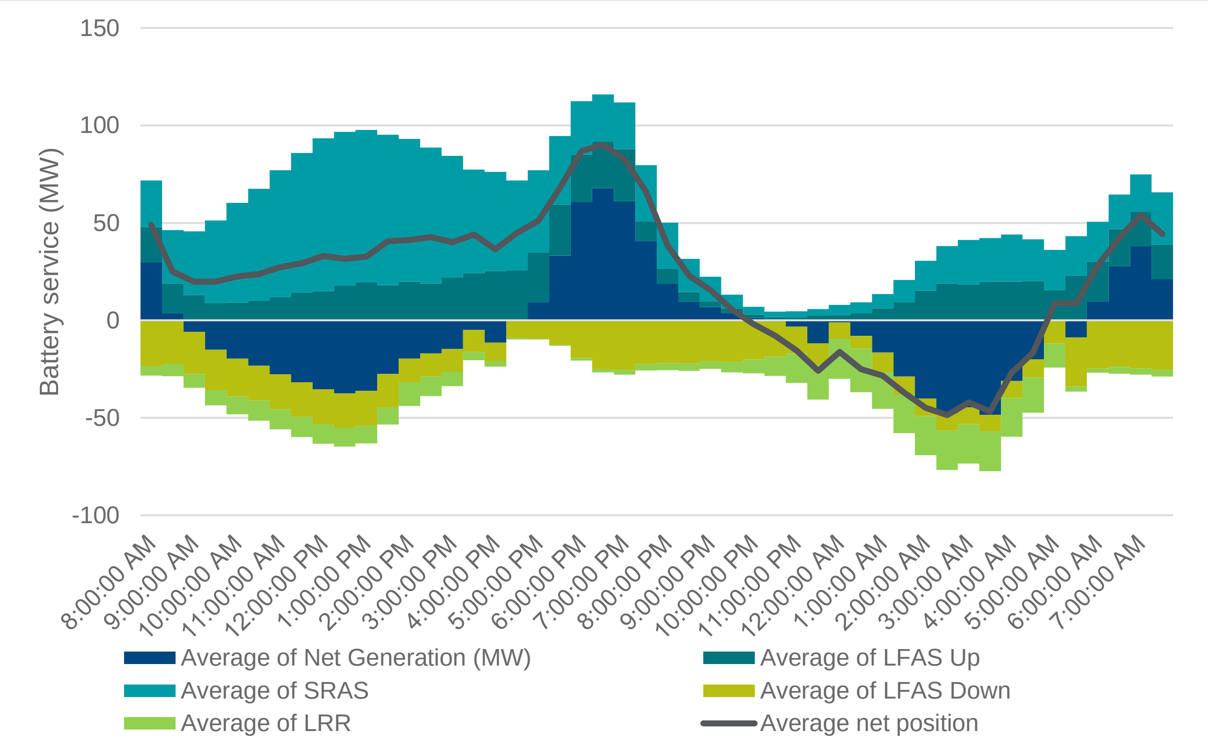
Source: ERA modelling and analysis of AEMO data

Appendix 9 Additional modelling outputs

Battery activity

Figure 23 shows the battery service provision in both the balancing market and providing ancillary services. The chart aggregates upwards services (discharge into balancing, load following upwards, and spinning reserve) and downwards services (charging, load following downwards, and load rejection reserve). Although the sum of average upwards services exceeds 100MW on the chart, the aggregate needs to be balanced against the downwards services. This net position is shown by the grey line titled 'net position'. The battery provides most of its services during the middle of the day.

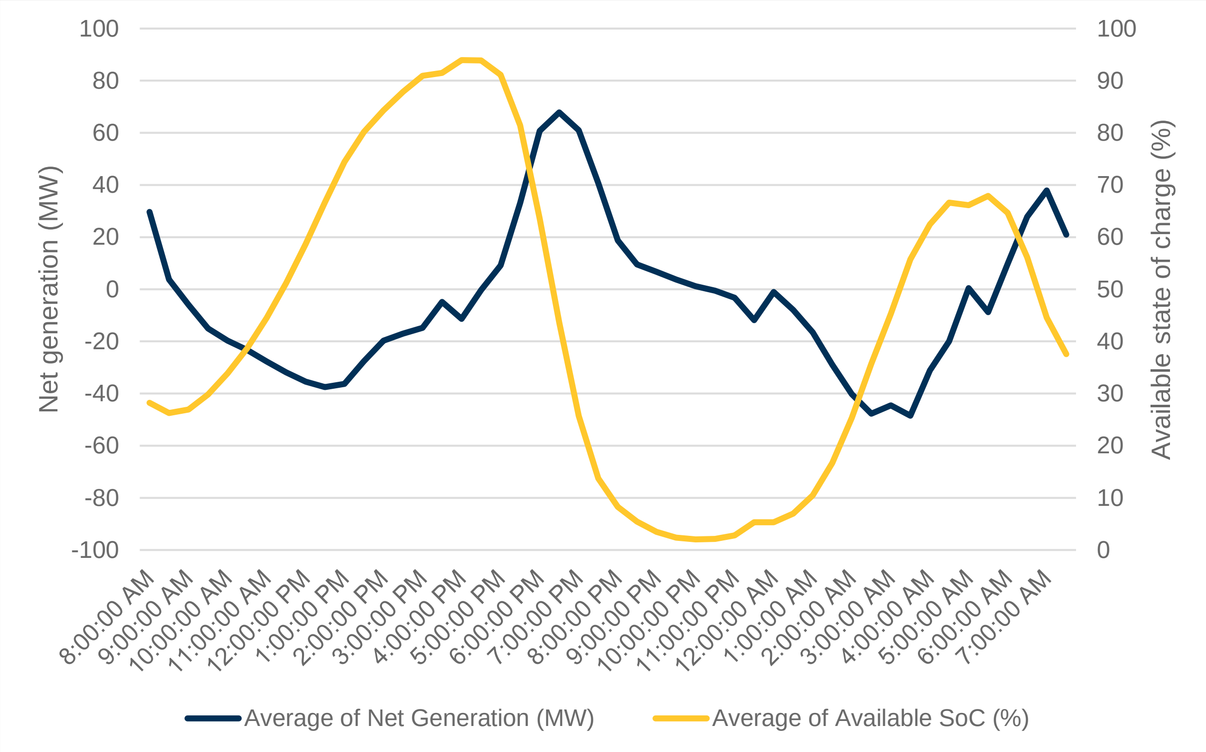
Figure 23: Battery activity by service



Source: ERA modelling

Updates to the battery model undertaken in the last year have resulted in the battery providing greater levels of ancillary services and lower levels of energy arbitrage. This was achieved by including a duration definition for the ancillary services, as described in Appendix 5. The battery undertakes one substantial discharge cycle in the evening peak with a more moderate discharge smoothing out supply in the morning peak.

Figure 24: Battery average available state of charge versus battery net generation



Source: ERA modelling

Ancillary service quantities and provision

As outlined in Section 4.3 the spinning reserve requirement is at its greatest during the middle of the day. The increase in reserve requirement is driven by a standing solar contingency where a proportion of distributed rooftop solar systems disconnect following contingency events such as the loss of a transmission line or generator. Consequently, the source of risk is highly dependent on the time of the day. The North Country Contingency comprises the largest risk during the middle of the day and overnight after the peak.

As the system moves into the peak, larger generators like Newgen Neerabup, Newgen Kwinana, and Collie become much more prevalent at setting the risk, while the Generator Interim Access runback scheme curtails the output of connected windfarms in the North Country Region, reducing the combined risk from these generators.