Spinning reserve, load rejection reserve, and system restart ancillary service (margin values and Cost_LR parameters) settlement values 2022/23

Issues paper

8 February 2022

Economic Regulation Authority

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Invitation to make submissions

Submissions are due by 4:00 pm WST, Wednesday 9 March 2022.

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

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

You can also send comments through:

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

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

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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 ERA determines the compensation parameters for three administered ancillary services each year.

The cost to market participants for these three ancillary services is expected to be $23 million in 2022/23, an increase of 33 per cent on the ERA's 2021/22 determination. These costs are ultimately passed on to electricity consumers.

The three administered ancillary services are spinning reserve, load rejection reserve and system restart. 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.

To undertake this year's determination, the ERA has considered three new factors affecting market dynamics in the forecast period, 2022/23: the commission of the first large battery storage facility in the SWIS; the retirement of Muja C generator unit 5 in October 2022 and a change in AEMO's management of risks associated with rooftop solar. The ERA's modelling indicates that collectively, the three factors will result in a net increase in ancillary services costs for 2022/23.

The planned introduction of the first battery to the Wholesale Electricity Market (WEM) in late 2022 (with a capacity of 100MW) is expected to improve system security due to the battery's almost instantaneous dispatch response capability and this is expected to enable more lower cost renewable energy to participate in the market. These benefits of batteries are likely to be better realised following the commencement of the new WEM in October 2023. Then, batteries will be eligible to receive revenue from new services which are currently not priced, for example a fast frequency control ancillary service.

There has historically been a risk in over-reliance on a single facility to provide ancillary services in case that facility is not available when required. AEMO manages such risks by requiring multiple generators to provide ancillary services. Accordingly, batteries will be constrained by AEMO in the level of ancillary services they can provide and ERA's modelling has been undertaken consistent with this approach. Constraining a battery's provision of ancillary services, limits the battery's ability to put downward pressure on ancillary services costs and requires more costly units, such as conventional generators, to provide some ancillary services.

The participation of batteries also affects energy prices in two ways – when they are charging and when they are discharging. Batteries present significant demand load when they are charging. Although charging will typically be during midday low demand periods, modelling indicates, unsurprisingly, that the new battery will increase the average balancing prices during these periods under the current WEM design. Batteries discharge during high demand periods when the prices are higher and act to moderate prices at these times. The net impact depends on the shape of the market offer curve. The ERA's analysis shows that, as the WEM currently stands, the net impact of the new battery - compared to the counterfactual of no battery - will be an average increase in balancing market prices.

This increase in average balancing prices shown by the ERA's analysis appears counter-intuitive to the general view that battery storage systems will put downward pressure on energy prices. It is important to note that the ERA has modelled the current WEM and that new rules in the new market may change this pricing outcome. For example, generators currently committed to providing ancillary services must bid their output at the floor price. In the new market, the offer curve will be less steep as generators will not be required to bid at the floor. This means that the charging of the battery will have a smaller effect on midday prices.

The effect of the second change modelled by the ERA for this determination, the retirement of Muja 5, is that the remaining large coal generators will be constrained less in the middle of the day when demand is typically low. The reduced constraint increases output from the remaining coal generation facilities. The increased output leads to an increase in ancillary service costs as the spinning reserve requirement is set in the market rules at 70 per cent of the output of the largest generator. Higher daytime generation by coal facilities is supported by the additional load from batteries charging during the middle of the day.

The third change arises from AEMO acting on new information about the risk of rooftop solar disconnecting when there is a fault in the system, called the solar contingency. In 2022/23, AEMO plans to apply its assumptions about the risk of solar contingencies occurring in one part of the network, to the whole network, which will increase the quantity, and therefore the cost, of spinning reserve during daylight hours.

In the new market, ancillary services will be provided by market mechanisms and not determined by the ERA. When the new market commences the ERA will no longer have oversight of AEMO’s system restart contract.

In past determinations, the ERA identified opportunities for AEMO to reduce costs to consumers by increasing the supply of system restart providers and by including only efficient costs in contracts. The ERA maintains this view. As the market becomes less reliant on conventional generators, alternative providers are needed to maintain the pool of sources capable of restarting the electricity system.

The ERA is now consulting with interested parties to inform its determination of the compensation parameters and seeks feedback on the assessment of market dynamics, modelling, and best practice approaches to procurement for ancillary services outlined in this issues paper. The ERA will consider stakeholder feedback and make its determination by 31 March 2022.

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 'essential system services'.

Synergy is the default provider of these contingency services. As Synergy bids as a portfolio, it is difficult to identify the scheduling costs for Synergy to provide spinning reserve and load rejection reserve. Synergy can therefore incur costs that are invisible to the normal market compensation mechanisms and from the market data. Modelling is necessary to estimate these costs to understand the level of compensation due to Synergy.

The calculation of parameters for the spinning reserve and load rejection reserve use electricity market models to forecast future costs. The same parameter (Cost_LR) used for the load rejection reserve payments also covers payments for the system restart service.

Historically, contracted values for system restart have not reflected the cost of the service provided. This is inconsistent with the market objectives. In past determinations, the ERA has made suggestions on AEMO's procurement process to ensure that only efficient costs are included in system restart contracts.

The ERA reviews the administered ancillary service parameters and determines the values following consultation. The WEM Rules require the ERA to publish an issues paper and seek stakeholder feedback as part of the determination.

The review timing for these three ancillary services settlement parameters coincides this year. This paper details how the ERA is intends to simultaneously determine spinning reserve, load rejection reserve and system restart service parameters.

1.1 Spinning reserve payment parameters (margin values) and load rejection reserve and system restart parameter (Cost_LR)

Payments to Synergy for providing a spinning reserve service are based on the calculation method specified in the WEM Rules.[1] 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 - determine the payment quantity.[2] Load rejection reserve and system restart are paid to Synergy and any other contracted system restart service providers as a lump sum.

For this year's determination, the ERA has estimated ancillary service settlement parameters to apply throughout 2022/23. Following consultation on the estimated parameters, the ERA will finalise the parameters by 31 March 2022.

1 Wholesale Electricity Market Rules (WA), 1 February 2022, Rule 9.9.2(f) (online)

2 A peak trading interval occurs between 8:00AM and 10:00PM. Off peak trading intervals occur between 10:00PM and 8:00AM

When determining settlement parameter values, the ERA must consider the market objectives and:

- 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.
- Changes to Synergy's costs that are caused by scheduling out-of-merit generation that Synergy would not otherwise incur and are not otherwise recovered through other market mechanisms (such as through interactions with load following ancillary services)[3].

1.2 The ERA's process

As the costs for ancillary services are determined in advance, modelling presents the best means of estimating future values. The model the ERA uses is functionally the same as that used for the 2021/22 determination, with the addition of a battery energy storage system and revised input assumptions. The assumptions set for the base case and the model configuration are outlined in section 0.

1.2.1 Consultation

The first stage of the consultation process for this determination occurred in August 2021, when the ERA confidentially provided market participants with the set of input assumptions for their generators, for market participants to review and amend. The input assumptions included the physical and economic parameters necessary to determine 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.

This issues paper explores the model findings and the expected settlement parameter values. The ERA Secretariat staff are available to meet with interested parties and market participants on the modelling findings during the consultation period.

After the consultation period is closed and any additional sensitivities and modelling refinements arising from consultation are complete, the ERA will make a final determination.

AEMO and the ERA hold regular sessions exploring ancillary services scheduling practices. These will continue throughout the ERA's determination process and will inform how to best reflect AEMO's operational settings for spinning reserve and load rejection reserve in the modelling.[4]

1.2.2 Modelling process

Modelling of the market for the determination was conducted in two stages. The first stage was a calibration exercise where the market simulation model was back-cast over 2020/21.

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

4 These ongoing 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.

This enabled environmental parameters, such as the output of non-scheduled generators and electricity demand, to be eliminated from the model 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 2022/23 period and the first three months of 2023/24, to the commencement of the new market on 1 October 2023. The forecasting consisted of a 'base case' and sensitivity modelling. The forecasting 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.[5]

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. Explanation box 1 summarises the assumptions underlying the base case. Appendix 3 provides a more detailed explanation of the assumptions while Appendix 4 details the model calibration and sensitivity analysis.

1.2.3 Determination period

The spinning reserve ancillary service determination period covers one year, 2022/23.

The determination for Cost_LR is required to span 2022/23, 2023/24, and 2024/25. However, one of the mechanisms for Cost_LR, load rejection reserve, is scheduled to be abolished with the commencement of the new market on 1 October 2023. As a result, the ERA has only modelled load rejection cost for 2022/23 and the first three months of 2023/24.

The system restart contracts extend through the entire determination period (2022/23, 2023/24, and 2024/25) with the restart parameter value in place until the new market arrangements for system restart costs commence.

5 AEMO, 2021, *2021 Electricity Statement of Opportunities*, (online).

2. Spinning reserve and load rejection reserve

Spinning reserve and load rejection reserves are the contingency reserves 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.[6]

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[7]
- the expected maximum increase in demand over a period of 15 minutes.[8]

The estimated spinning reserve quantities derived from the ERA's modelling used in the determination on margin values in 2020/21 were 252MW in peak periods and 240MW 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.[9] In past determinations, the AEMO considered that this applied only to faults that occur when contingencies arise on the North Country region of the network (which are also subject to Generator Interim Access arrangements). However, in late 2021 AEMO advised that this risk

6 Wholesale Electricity Market Rules (WA), 1 February 2022, Rule 3.9.2 (online).

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

8 Wholesale Electricity Market Rules (WA), 1 February 2022, 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)

9 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.

applies more broadly and follows other contingencies on the electricity network and needs to be covered, through an increased spinning reserve quantity to maintain system security.[10]

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.[11] Historically, AEMO has set the quantity of load rejection reserve needed to maintain the standard at a maximum of 120MW, which AEMO can relax down to 90MW. In June 2020, AEMO reduced the maximum load rejection reserve to 90MW.[12]

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. A diversity of system restart services is needed across the network to ensure that the system can be re-energised if a particular black start provider fails, or where parts of the network become physically isolated – such as through a bushfire or storm. AEMO procures these services through contracts.

AEMO has determined that it needs three service providers in geographically different parts of the network to provide for system recovery. These regions are: [13]

- North Metropolitan
- South Metropolitan
- South Country.

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

[11] Wholesale Electricity Market Rules (WA), 1 February 2022, Rule 3.10.4 (online)

[12] Australian Energy Market Operator, 2020, *Ancillary Services Report for the WEM 2020*, p. 17 (online)

[13] Economic Regulation Authority, 2020, *Decision on the Australian Energy Market Operator's 2020/21 Ancillary Services requirement* (online)

Economic Regulation Authority, 2020, *Approval of revised 2020/21 LFAS Ancillary Service Requirement*, (online).

When entering an ancillary services contract, AEMO must:[14]

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

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. These costs are passed on to all 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).

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 value percentages 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

$$at = \frac{1}{2}m \times pt \times qt$$

where at is availability payment for an interval t,

m is margin value,

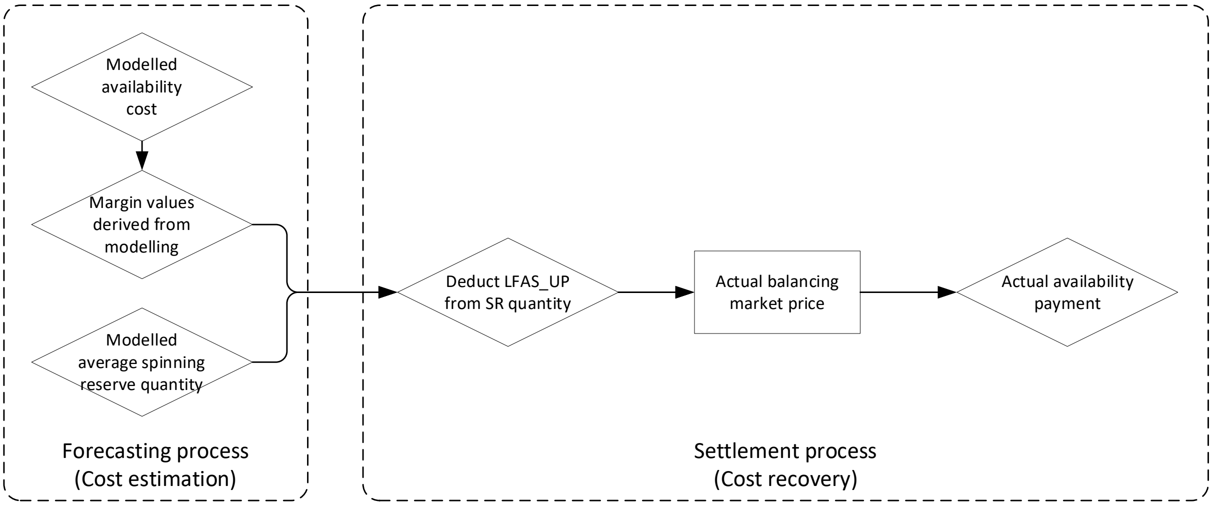
pt is balancing price for the interval and

qt 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.

[14] Wholesale Electricity Market Rules (WA), 1 February 2022, Rules 3.11.9(a), 3.11.9(b), and 3.11.10 (online).

Figure 1: Application of modelled values to cost recovery



Source: ERA

As discussed in section 4.3, 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.[15]

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 Rule 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.[16]

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.

15 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.

16 Wholesale Electricity Market Rules (WA), 1 February 2022, Rule 9.9.1 (online).

There is a problem with the application of the shortfall charge if the ERA determines a lower system restart value than the contracted system restart cost from a third-party service provider. The difference would first be deducted from Synergy's component of the Cost_LR charge. The shortfall charge would only be invoked if the total contracted value exceeded the Cost_LR value. Any difference between third-party contracts and the deemed efficient contract value would penalise Synergy. The ERA assumes that this problem with the shortfall charge will be resolved with the new market.

Cost_LR is determined on a three yearly basis with annual reassessments if necessary.[17]

[17] Wholesale Electricity Market Rules (WA), 1 February 2022, Rules 3.13.3B and 3.13.3.C (online)

3. Proposed settlement parameters

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

3.1 Proposed spinning reserve (margin values) for 2022/23

The proposed spinning reserve numbers are based on the ERA's base case modelling scenario. While the availability cost in peak periods has increased between the two years, the margin values have increased to a substantially lesser degree.

The balancing market prices forecast in this year's modelling are higher than last year, meaning that margin values do not need to rise to the same degree to compensate Synergy for the spinning reserve services it provides. During off peak periods, the margin values reduced substantially due to lower spinning reserve quantities, and a reduction in the availability cost. Pricing outcomes in the context of the market modelling are explained in section 4.

Table 1: Determined and proposed spinning reserve settlement parameters

Time period	Availability cost ($m)	Spinning reserve quantity (MW)	Margin values (%)	Availability cost ($m)	Spinning reserve quantity (MW)	Margin values (%)
	2021/22 (determined)			2022/23 (proposed)		
Peak	3.04	240	12.6	11.84	235.48	13.6
Off-peak	3.49	241	23.2	2.98	176.11	5.8
Total	6.53	NA		14.83	NA	

Source: ERA modelling

3.2 Proposed load rejection reserve costs for 2022/23 to 2023/24

The new market is scheduled to start 1 October 2023. The ERA has modelled load rejection reserve costs for all of 2022/23 and for the first 3 months of 2023/24. The ERA did not conduct modelling on the full year because of the sensitivity of the modelling to out of merit costs driven by seasonal outputs of rooftop solar generation.

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

Time period	Load rejection reserve availability cost		
	2021/22 (determined)	2022/23 (proposed)	2023/24 (proposed) (July, August and September 2023 only)
Peak	4.331	2.77	0.57
Off-peak	3.054	1.96	0.54
Total	7.386	4.74	1.12

Source: ERA modelling

3.3 Proposed system restart costs for 2022/23 to 2024/25

The ERA reviews AEMO's contracted system restart costs against the WEM Rule requirements and will determine system restart parameters consistent with the WEM Rules.

AEMO currently has one contract for each of the three regions, North Metropolitan, South Metropolitan, and South Country. Only aggregate values are presented in Table 3 as the value of individual contracts is commercial in confidence.

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

	2021/22 (determined)	2022/23 (proposed)	2023/24 (proposed)	2024/25 (proposed)
Estimated sum	3,369,438			
Contracted sum		3,418,696	3,420,859	3,418,696

Source: AEMO

4. Market modelling

The ERA is required to make a determination on efficient ancillary services costs in accordance with the WEM objectives. To estimate these costs, the ERA must identify how the costs detailed in section 3 will be affected over the forecast period. The ERA's modelling of the market will inform its determination of ancillary service settlement parameters. Modelling is required due to the complex interactions, the expectation of new resources in the market, and because portfolio bidding makes it difficult to identify incremental costs from historical market data.

Market dynamics in the 2022/23 forecast period are driven by three new market changes:

1. A large-scale grid-connected battery coming into the market [18]
2. The retirement of Muja unit 5 [19]
3. A material change in AEMO's assessment of the risk of contingencies in one or more parts of the network. [20]

Of these three changes, the battery has the most complex interactions within the market model. The battery will increase the supply of energy to the market when it discharges and increase demand for energy from the market when it charges. Both battery activities will influence electricity prices and ancillary service costs.

The battery charges during periods of low demand, typically during the middle of the day, when negative prices occur. The battery then discharges in the evening peak, placing downward pressure on prices. As described in section 4.1.1, the battery is forecast to increase balancing market prices overall, because the price increases that occur while the battery charges are greater than the price decreases that occur when the battery is providing additional supply into the market.

The removal of 195.8MW of capacity in with WEM with the retirement of Muja Unit 5 in October 2022 means that the remaining large thermal generators with high cycling costs do not need to reduce output as much to stay online in the middle of the day when demand is low. This allows them to operate under less pressure when ramping into the evening peak and maximise their output. This will increase the quantity of spinning reserve required.

After considering operational data in 2021, AEMO considers the risk of rooftop solar disconnection in the event of a contingency to be more widespread than was modelled for 2021/22. This will increase the level of spinning reserve the market needs to cover in 2022/23.

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18 Government of Western Australia media statement, 20 October 2021, 'Contractor announced for WA's biggest battery', (online) [accessed 17 January 2022]

19 Government of Western Australia media statement, 5 August 2019, 'Muja Power Station in Collie to be scaled back from 2022', (online) [accessed 17 January 2022]

20 The solar contingency risk is based on empirical evidence that a substantial proportion of rooftop solar systems disconnect due to the voltage and frequency disturbances following contingency events deepening the frequency fall following the loss of a large generator.

Explanation box 1: Modelling assumptions

The base case assumed that electricity demand would align with AEMO’s expected demand scenario from its Electricity Statement of Opportunities, with a solar uptake aligned to AEMO’s expected rooftop solar growth rates.[21]

Generator offer curves are derived from the information collected from market participants during the first stage of consultation for this determination. The offer curves were refined to account for observed practice in bidding at the market floor or otherwise below the expected offer curve.

Other generator features are based on information confirmed with generators such as heat rate curves, start up and shut down times and costs, ramp rates and other physical and financial characteristics that would be reflected in an asset’s short run marginal cost.

The model’s scheduling practice reflects AEMO’s advice on the anticipated ancillary service requirements for 2022/23 and beyond. This advice confirmed AEMO’s operational practice around scheduling both spinning reserve and load rejection reserve and the limits that individual assets can provide. The advice included an amendment to AEMO’s treatment of the risk of rooftop solar disconnection following contingency events.

Muja G5 is the only generator asset expected to exit the market during 2022/23. The base case assumes the generator will exit the market on 1 October 2022.[22]

Consistent with other large batteries in operation in Australia, the modelling assumed that the battery was able to switch between full charge to discharge capacity almost instantaneously. Explanation box 2 illustrates this capacity.

The modelling assumed that the battery will be available to provide substantial contingency reserves and energy arbitrage within storage operating limits provided by Synergy. The battery is assumed to operate inside a state of charge tolerance range above the floor but below completely full. The battery also incurs storage losses on the round trip efficiency of the asset.[23]

Within the battery’s 200MWh storage operational range, the model subjects the battery to a cost optimisation with other generation assets in blocks of 24 hours. This is intended to minimise the operational cost of the battery and generators over current and future intervals, within a ‘look ahead’ window of two trading intervals.

The model may allocate the battery to generation (discharging), demand (charging), and ancillary service reserves – of load following ancillary service up and down, spinning reserve, and load rejection reserve – subject to the operational constraints of the reserves. An example of an operational constraint is the 30 per cent contribution limit AEMO currently applies to spinning reserve and load rejection reserve from a single source.

The assumptions for the base case are outlined in further detail in Appendix 3.

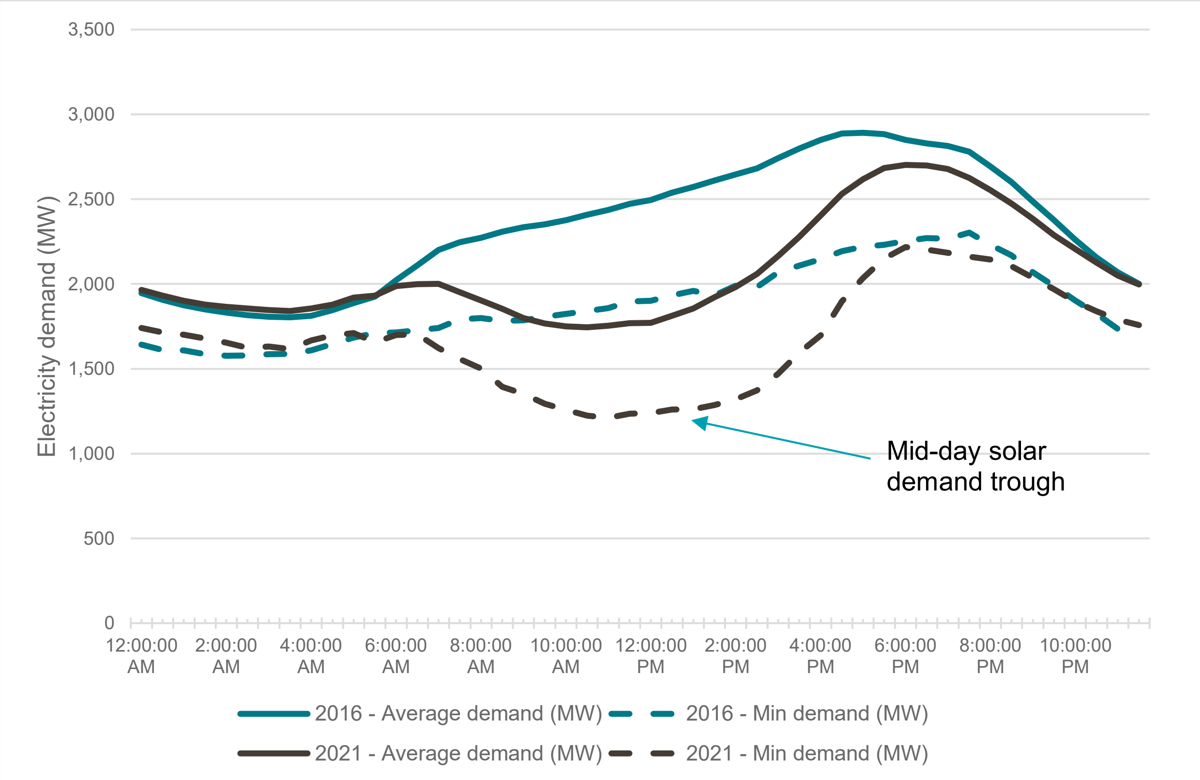
4.1 Market dynamics

The prevailing modelled market dynamics are an extension of those reported in the ERA's ancillary service costs determination for 2021/22, and modified to account for the new battery coming online, the retirement of Muja Unit 5, and changes to the rooftop solar risk.[24]

The 2021/22 modelling found changes to the load profile and contingency risk profile were leading to higher out of merit generation to provide both spinning reserve and load rejection reserve. AEMO's anticipated changes to the solar contingency risk will further increase the requirement for spinning reserve.[25]

Figure 2 highlights the scale of changes to the load profile that have come with rooftop solar installations. The chart shows the average half hourly electricity demand for the month of February in 2016 and 2021. Minimum demand now occurs in the middle of the day and is more pronounced on weekends when commercial and industrial loads are lower.

Figure 2: Changes in electricity demand – February 2016 and 2021



Source: ERA analysis of AEMO data

21 AEMO, 2021, *2021 Electricity Statement of Opportunities*, (online)

22 Government of Western Australia media statement, 5 August 2019, Muja Power Station in Collie to be scaled back from 2022, (online) [accessed 17 January 2022].

23 Round trip efficiency refers to the proportion of energy input into a battery that can be retrieved from the battery and the losses that occur between a battery charging and discharging.

24 Economic Regulation Authority, 2021, Ancillary service costs: Spinning reserve, load rejection reserve and system restart costs (margin values and Cost_LR) for 2021/22 (online)

25 Briefing from AEMO system management staff to ERA Secretariat on the solar contingency risk. 30 November 2021.

Minimum electricity demand has been declining since 2016/17. For the last two years the rate of decline has increased to around 200MW per year. The addition of battery charging capacity to the market would reduce the rate of decline but there has not been enough capacity committed to fully offset it. This means many of the pressures applied to the system from low daytime demand remain and the market dynamics driving costs will also be a feature of the market into the future.

4.1.1 Battery storage

Synergy intends to commission a battery early in the forecast period.[26] AEMO's capacity mechanism places obligations on capacity providers to be available at certain times of day and for a battery to be available for a four-hour window in the afternoon. However, because Synergy's battery will be operating outside capacity obligations (no battery system has received capacity certification for the period covered by the forecasting window) it is not constrained by obligations under the capacity mechanism for the forecast period modelled. [27]

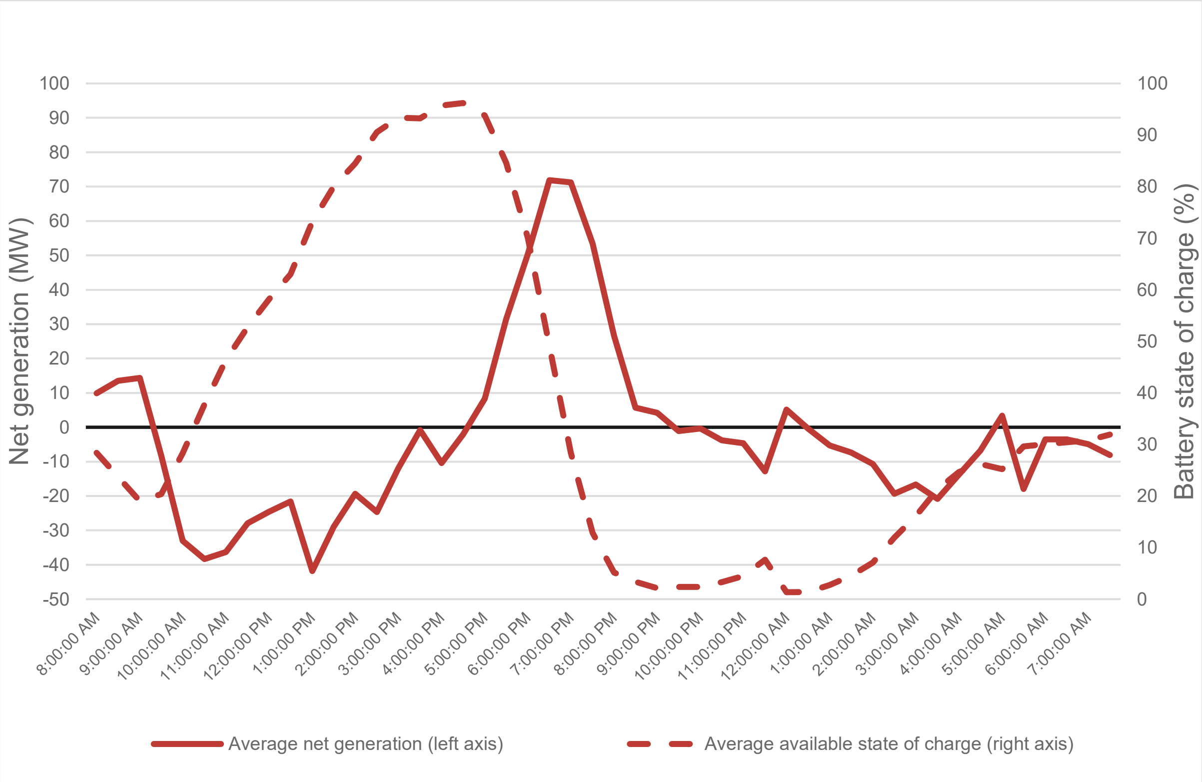
4.1.1.1 Battery operation

The model typically operated the battery over two charge/discharge periods per day over one day-long discharge cycle (Figure 3). Negative net generation values (on the left axis) indicate the battery is charging and positive values when the battery discharges. The first charging period is overnight and discharging during the morning ramp and the second charging period during the mid-day trough into the afternoon peak ramp. Once fully charged the battery discharges from late afternoon into the evening before commencing the next charge cycle.

26 Government of Western Australia media statement, 5 August 2019, Muja Power Station in Collie to be scaled back from 2022, (online) [accessed 17 January 2022]

27 AEMO (2021) Summary of capacity credits assigned by facility for the 2020 reserve capacity cycle (online)

Figure 3: Battery diurnal charge discharge cycle

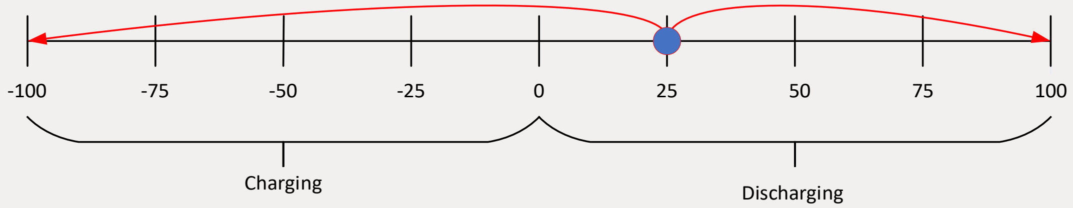


Source: ERA modelling

Explanation box 2: Battery operational capability

If the range of options available to the battery is considered in terms of a number line, the battery, subject to its state of charge, can move freely within its maximum output and its maximum input.

Consider a 100MW battery that is half full and discharging at one quarter of its potential output or 25MW. The battery could increase its output to 100 per cent or 100MW or switch to fully charging at 100MW. In this example the upward movement range is 75MW and its downward movement range is 125MW (25MW less -100MW).



The state of charge will determine how long the battery can maintain the output level. A 100MW battery at a zero state of charge at the start of an interval and charging at its full capacity can still provide spinning reserve by reducing the rate at which it charges. It could also provide load rejection reserve by holding off charging. The opposite is the case at a full state of charge. A full 100MW battery discharging at its maximum output can reduce its output rate and provide spinning reserve or be ready to reduce its output to provide load rejection reserve by reducing its charge rate.

The battery can simultaneously provide multiple services to the energy market and actively engage in price arbitrage benefitting from low or negative prices to charge and high prices to discharge.

In the WEM, a battery can earn revenue in the load following market and in the balancing market. In the balancing market it can charge when prices are low (and be paid if the prices are negative) and discharge when prices are high. A battery could conceivably provide ancillary services like spinning reserve and load rejection reserve as well as load following reserves without necessarily interfering in the future options available to the battery.

Batteries are subject to storage losses that occur through the charge to discharge cycle, known as the round trip efficiency. Regardless of electricity demand and supply by other market participants, the round trip efficiency losses result in a battery always increasing demand more than it can increase supply.

The model uses a derived value, termed the shadow price, to determine when the battery charges or discharges. The battery shadow price represents the future value of energy held in storage, that is, the potential saving of thermal costs from the last or next unit of energy in storage. Consequently, the decision to run the battery in either charging mode is determined relative to the costs of meeting the supply from other generators and the costs in alternative markets such as LFAS. While the shadow price may effectively proxy the battery opportunity cost, they are not necessarily the same.

The opportunity cost for a battery is only realised if the activity of the battery limits the battery's ability to earn future revenues. It is possible that the difference between the load following reserve for which a battery earns revenue and the spinning reserve it provides beyond that do not incur any incremental cost. Identifying where a reserve limits the future potential to earn revenue is challenging. While storage analogues such as hydroelectricity can provide some guidance, the batteries are still an emerging technology and experience in electricity markets is limited.

The ERA's analysis shows that, under the existing WEM design, the net impact of the new battery - compared to the counterfactual of no battery - will be an average increase in balancing market prices, with a consequent increase in margin values. It is important to note that the context for the ERA's modelling is the current market and that two of the features that have a material influence on the value of batteries will be different in the new market, which is due to commence in October 2023. First, under the current WEM Rules generators committed to providing ancillary services must bid their output at the floor price. In the new market, the offer curve will be less steep as generators will not be required to bid at the floor. This means that the charging of the battery will have a smaller effect on midday prices. Second, there is currently no market derived price for a fast frequency control ancillary service. In the new market, this will be an identified service with a market-based price. A revenue stream from the new essential service will materially increase the value of batteries in the market.

1. **Question**

What are any alternative views on how the output from the battery can be valued?

4.1.2 Muja retirement

The output of the largest generators tends to reduce with demand. This is to avoid the risk of disconnection and accruing substantial shutdown and restart costs.

Muja unit 5, with a generation capacity of 195.8MW, is scheduled to retire in October 2022.[28] This generator comprises 12.5 per cent of the coal fired thermal generator capacity in the market. With its retirement, there is more room for scheduled generators to operate at low output without turning off and less pressure on low-cost thermal generators to turn down. With fewer generators competing to stay online, prices will not go as low, as often, because they have more room to operate with less risk of facing shut down and start-up costs. With higher output from large low-cost generators, the contingency risk associated with losing their output is more prominent.

Newgen Kwinana sets the spinning reserve contingency most of the time in the forecast period, followed by the North Country contingency and then Collie. The solar contingency is additive to the largest contingency for each interval where previously it had only been an element of the North Country contingency.

4.1.3 Solar contingency risk

Following disruptions related to the North Country contingency, AEMO found that some distributed inverter-connected solar generators disconnected.[29, 30] Loss of supply from rooftop

28 Government of Western Australia media statement, 5 August 2019, Muja Power Station in Collie to be scaled back from 2022, (online) [accessed 17 January 2022]

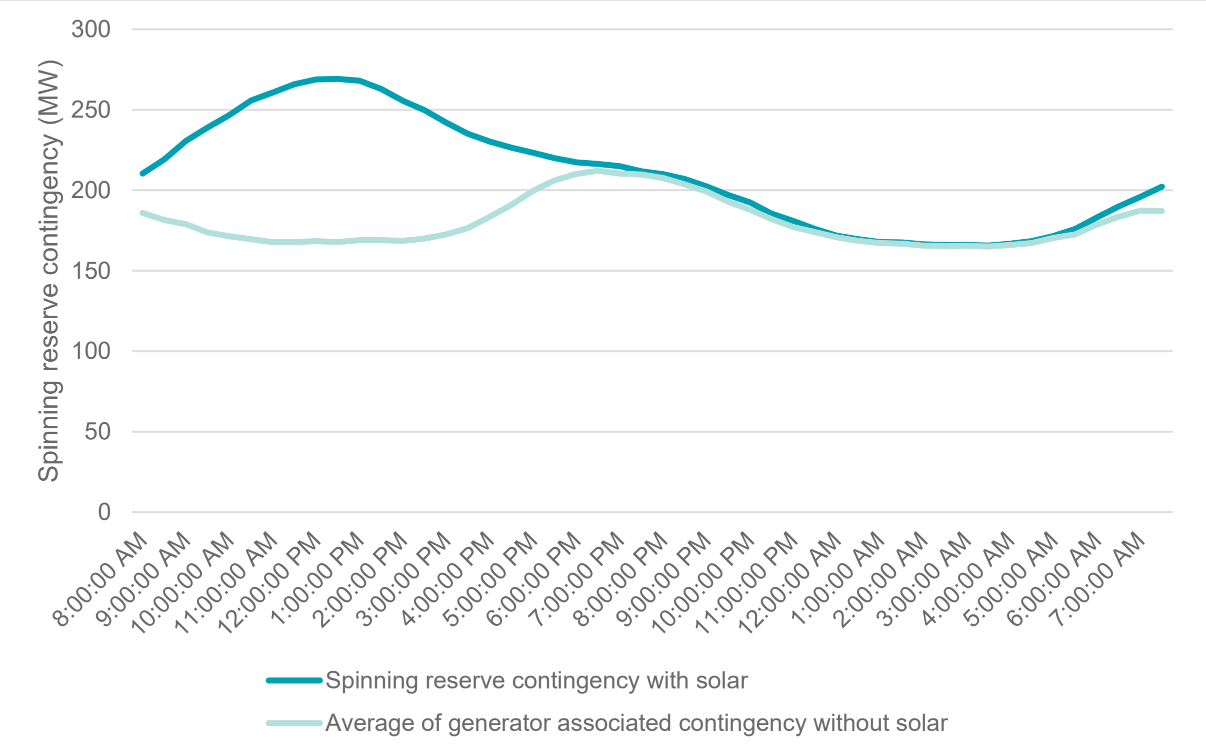
29 The North Country or Marnet contingency refers to grouped outages in the northern reach of the network towards Geraldton with a number of generators connected under the GIA scheme. GIA refers to Western Power's Generator Interim Access scheme. This scheme allows generators to connect to the network without paying network reinforcement costs in exchange for being constrained back when the lines become heavily loaded.

30 AEMO, 2021, Ancillary services report for the WEM 2021, June 2021, p.10 (online)

solar increases demand on the system and deepens any shortfall in generation. The 2021/22 modelling covered the effect of this contingency as it applied only to the North Country.

AEMO recently advised that the contingency risk associated with solar is now more widespread and comprises an underlying baseline risk on top of all other contingencies.[31] The effect of this risk can be seen in Figure 4. The addition of the solar contingency across all hours as a baseline contingency means the largest generator contingency sets the requirement more often than in 2021/22.

Figure 4: Spinning reserve contingency risk by time of day



Source: ERA modelling

4.1.4 Providing the reserves

To mitigate the risk of a generator allocated to provide spinning reserve failing to respond, AEMO spreads the provision over several generators. AEMO aims for a single source to provide no more than 30 per cent of the total requirement, which is reflected in the modelled base case. The battery has the capability to provide substantial spinning reserve and load rejection reserve beyond the 30 per cent constraint allowed in the base case as demonstrated in the sensitivity analysis on this constraint. However, AEMO's scheduling practice means no single source can provide it all.

The battery's capacity to switch from total discharge to total charge means there are periods of time when AEMO's risk management constraints prevented it from providing more reserves. The consequence is gas and coal units were still needed and many of the gains that could be realised from the battery in terms of reducing ancillary service costs are missed. Sensitivity analysis on the limits on battery reserve provision indicated that fewer resources could be

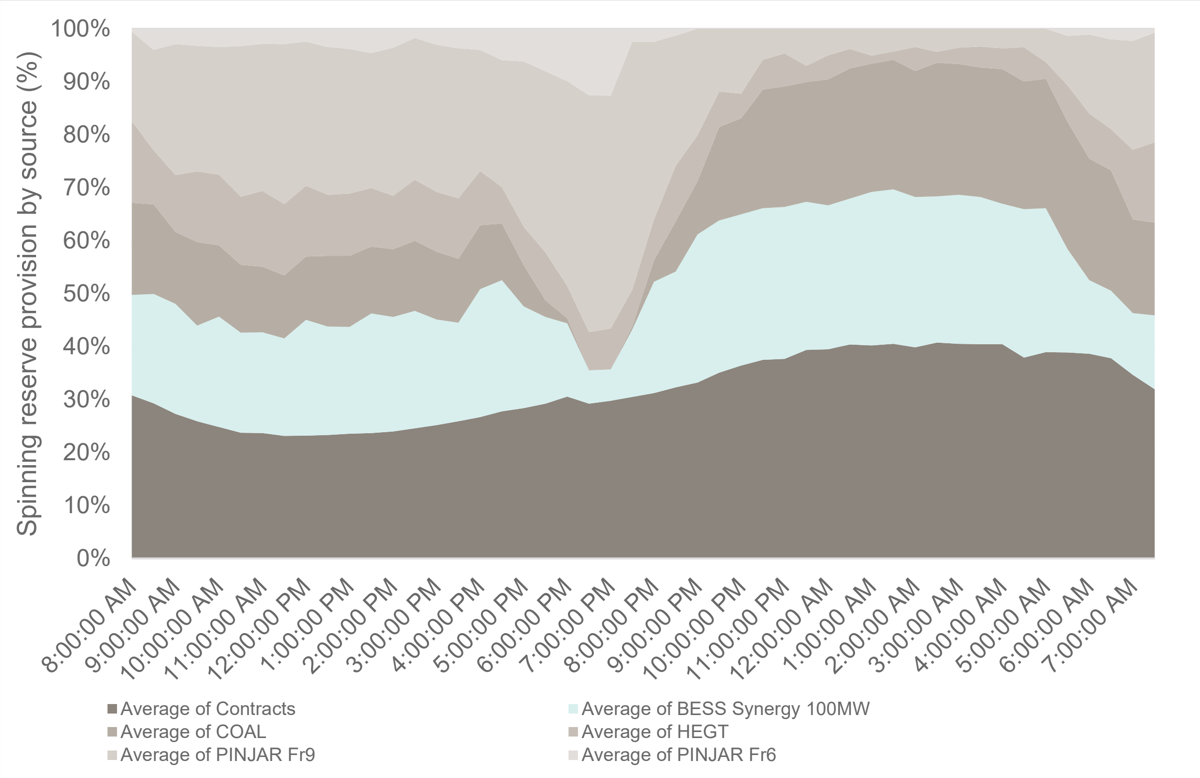
[31] Meeting between the ERA Secretariat staff and AEMO on 11 November 2021.

used to meet the requirement.[32] There is a trade-off between risk mitigation and cost. If the battery has a lower forced outage risk than conventional generation, AEMO may wish to revisit this constraint it imposes on the market.

Spinning reserve provision patterns alter over the course of the day (Figure 5). The battery's spinning reserve provision alters depending on its charge state and the prevailing balancing market price and whether the battery is providing ancillary services or energy arbitrage. When the battery reduces its contribution to spinning reserve into the peak, the larger frame 9 turbines at Pinjar tend to pick up the slack. With the prices high and the gas fired generators in merit, the least cost option for the model is to enable the battery to maximise arbitrage at this point and reduce the output of the gas fired generators to provide the reserve.

Coal ceases to provide spinning reserve into the evening peak as the low cost generators seek to maximise their output with the duty picked up by the large and small Pinjar generators. The smaller frame 6 Pinjar generators cease providing spinning reserve overnight with the battery picking up the duty.

Figure 5: Spinning reserve average duty by source and time of day



Source: ERA modelling

Coal fired generators can reduce output rapidly and provide load rejection reserve by discharging steam. However, they require headroom above their minimum operating level to do so. As the output of these generators diminishes, so does their ability to provide load rejection reserve. Then, gas fired generators are brought online out of merit to provide the reserve where the low cost generators cannot.

32 Sensitivity analysis was conducted on the capacity of the battery to provide higher levels of ancillary services than AEMO normally allows. These allowed the battery to provide up to 50 per cent of the reserves and 90 per cent of the reserves.

As demand increases into the evening peak and gas fired generators come into merit, they substitute lower cost generation in providing load rejection reserve. In the evening, AEMO is more likely to schedule gas fired generators in preference to increasing the output of slower moving coal fired or combined cycle generators. While the 2020/21 was a hot summer with relatively high electricity demand allowing thermal generators more room to operate, over recent years coal units have been decommitted for periods of time. Increasing the commitment from in merit gas fired generators to provide load rejection reserve minimises the system cost of meeting the reserve.

When the balancing market prices are high and the service can be provided by generators operating in merit, the cost of providing load rejection reserve is low. The out of merit load rejection reserve costs are a function of the difference between a generator’s marginal cost and the clearing price. Load rejection reserve costs are at their highest when large negative price events occur during midday low demand periods. This means that a reduction in negative price intervals will reduce load rejection reserve costs.

Many drivers interact to increase costs overall. The solar contingency reduces the output of generators that have historically set the reserve, including Synergy’s other large thermal generators at Collie. However, the duty has simply transferred to other large generators with greater flexibility. The risk of rooftop solar generators tripping-off following a contingency means the requirement in the mid-day trough created by rooftop solar increases the spinning reserve requirement when flexibility is at its lowest.

Forecast spinning reserve during the mid-day demand trough is moderated to some degree by the operation of the battery system.

In terms of spinning reserve provision, during the forecast window, the battery and contracted third party providers of spinning reserve take the bulk of the duty. However, in order to ensure diversity of supply, some upwards capability can still be provided by low-cost generators when in merit, while the gas fired generators are still needed to run even when the demand is low. For both spinning reserve and load rejection reserve, Synergy’s gas fired generation from multiple units is still necessary to provide substantial contingency reserves.

The load rejection reserve is much flatter given the contingency is scaled to network outages in the Kalgoorlie region. However, the need for flexibility and generation is dependent on gas fired generation to meet the contingency reserve requirement.

The next section outlines why these costs are not fully recovered through existing market mechanisms.

4.2 Out of merit costs

Generators are generally dispatched according to a merit order where offers are stacked from least cost to most expensive. Under some circumstances, generators may need to be dispatched regardless of their costs to maintain system security – this is termed “out of merit”. Most generators brought online or taken offline can be identified because their output is discretely bid into the market.

Synergy’s out of merit costs are not readily identifiable from market data. This is because unlike other market participants, Synergy, which holds roughly half the accredited capacity in the market, is able to offer its bids into the market as a portfolio rather than as individual facilities. The offer tranches are not tied to specific generators. Consequently, scheduling decisions affecting Synergy’s dispatch (and their 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.

The modelling indicates that Synergy's out of merit costs are likely to remain the largest driver of the availability cost. The magnitude of those costs is sensitive to the lowest clearing price in the balancing market. When prices are negative, Synergy must pay to keep the generators in service, exacerbating the unrecovered ancillary service cost. The deeper the negative price gets, the greater the degree of compensation needed.

As mentioned in Section 2.4.1, Synergy also receives no revenue through the margin value mechanism for spinning reserve when prices fall below zero. This means the costs they might be expected to accrue when prices are negative, needs to be recovered via the margin values when prices are positive.

4.3 Spinning reserve compensatory mechanism

As explained in section 2.4.1, Synergy's cost to provide spinning reserve is recovered through the margin value percentages applied to the 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 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.

In last year's determination, the ERA explained the disconnection between the spinning reserve compensatory mechanism (margin values) and the accrual of costs to provide the service.[33] There had been a shift in the major driver of ancillary service costs from foregone energy sales to out of merit costs.

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 threshold. This means the relationship between balancing price and the cost to provide spinning reserve has reversed and is now an inverse relationship. Now, as prices decrease, spinning reserve costs rise and as prices rise, spinning reserve costs decrease.

To ensure Synergy is appropriately compensated for providing spinning reserve, the ERA has calculated the availability cost over 2022/23 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.

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.

33 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*, (online) p. 19-20

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

1. Negative priced intervals drive 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 corollary also applies. If fewer negatively priced events occur, it is likely the availability cost would be lower. The opportunity to recover the availability cost over positively priced intervals would also not need to account for as many negatively priced intervals meaning the margin values would need to be lower.

The timing of the battery coming online also has implications for Synergy's compensation. The modelling assumes the battery will be commissioned on time, by September 2022. Once the battery is in operation it is expected to reduce the number of negatively priced intervals and this assumption is included in the base case model. However, if the battery is commissioned later than anticipated, the number of negatively priced intervals over the forecast period and the availability cost may increase compared to the base case model. The margin values for 2022/23 are to account for the number of negatively priced intervals in the base case. With more negative intervals than anticipated the more likely Synergy will be undercompensated for providing spinning reserve.

The State Budget has allocated operating subsidies to Synergy.[34] If Synergy is undercompensated, the Government's system security transition payment, will cover the shortfall.

The margin value compensatory mechanism is unsuited to the cost and market price distribution. However, the onset of the new market will supersede the mechanism, which now only has to operate until October 2023. Once the new market design commences, most ancillary services – to be renamed essential services – will be provided through market mechanisms.

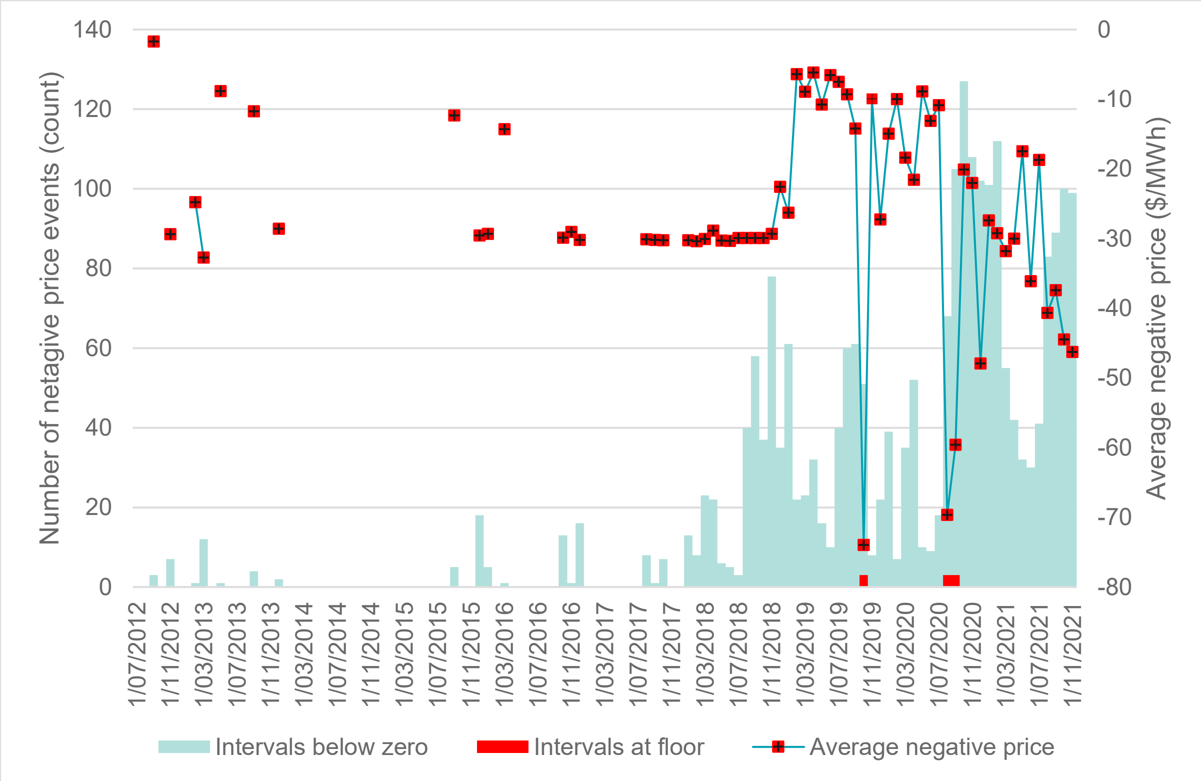
4.3.1 The incidence and influence of negatively priced intervals

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. Even though the model back cast provides a reasonable fit with the pricing outcomes in the real market, the forecast indicates a substantial increase in floor price events and intervals clearing below zero.

The frequency of intervals where the balancing market settles below 0$/MWh has been increasing over time. During 2020/21 financial year, the market cleared below zero during peak periods 900 times or around 9 per cent of intervals. The base case forecast model forecasts over 2,200 negatively priced events or around 22 per cent of intervals.

[34] Government of Western Australia. State Budget 2021-22 *Budget Paper 2.* pp.793-795 (online)

Figure 6: Negative price events during peak periods since market start



Source: ERA analysis of AEMO data

It seems likely, based on past behavioural changes, that market participants will continue to adjust their bidding to avert the deepest negatively priced intervals. However, there is no objective basis to set such assumptions. If there are fewer negatively priced intervals, or the negatively priced intervals are not as deeply negative as the forecast, margin values derived from a forecast that is overly pessimistic on pricing outcomes will result in higher revenues for Synergy.

5. System restart service procurement

The ERA has a role to determine the efficient cost for system restart services, as detailed in section 3.3, and to provide oversight of the procurement process.

The supply of electricity from conventional generation, such as coal and gas fired generators, is being displaced by renewable energy from non-scheduled generators. Without intervention, the pool of resources available to restart the system will diminish in coming years and the market risks foregoing new investment opportunities for replacement system restart services. The need for non-scheduled generation to supply an increasing proportion of ancillary services has been recognised in both the WEM and the National Electricity Market (NEM)[35].

Expanding the pool of units available to restart the system will provide:

- Reassurance that system security can be maintained as conventional generation is displaced.
- Downward pressure on system restart costs as more providers, including units with negligible short run marginal cost of supply, compete for system restart contracts.

As is occurring in the NEM, changes to procurement processes are required to allow units other than conventional generators to provide system restart services in the WEM.

In past determinations, the ERA proposed changes to ensure that only efficient costs are included in system restart contracts now and into the future as the market becomes less dependent on conventional generation. In its current determination, the ERA will maintain the same focus on supporting AEMO's procurement practices to meet the WEM objectives, in particular minimising the cost of electricity to consumers.

With the commencement of the new market in October 2023, the ERA will no longer have the same oversight of the procurement of system restart contracts. The transition to a new regulatory environment occurs as action is needed to secure the future pool of system restart providers.

5.1 Expanding the pool of system restart providers

At this time of transition in the market, the ERA seeks stakeholder views on increasing the pool of system restart providers to minimise the cost of electricity to consumers. In procuring ancillary services, AEMO is focused on covering the technical requirements to ensure system security. While AEMO has an obligation to minimise costs in its procurement, it has no financial exposure to its system restart contracts.[36] The ERA believes AEMO needs to further develop how it meets its obligations to minimise costs. It is in the interests of market participants to make their views known on the current and future procurement of system restart services.

5.1.1 Inclusive procurement

As conventional generation has typically provided all system restart services in the WEM, procurement practices are written around conventional established generators and currently

[35] System restart ancillary services guideline. 8 February 2021. Section 2, NER clause 3.11.7 (online)

[36] AEMO, 2019, Power System Operating Procedure: Ancillary Services, pp. 11-12 (online)

exclude non-scheduled generators and non-market participants.[37] More inclusive procurement would enable more participants to apply, potentially increasing the pool of providers. This change would be consistent with the WEM system restart procurement procedure, which requires AEMO to seek to minimise the cost of meeting its ancillary service obligations.[38]

The ERA has previously suggested an outcome-focused procurement approach to allow AEMO to evaluate providers based on ability to provide the service. In practice, this approach could include:

- Allowing non-market participants, such as stand-by generators, to re-energise the grid.
- Changing the availability requirements to include non-scheduled generators.
- Allowing overlapping arrangements with multiple alternative suppliers to meet the need for 24 hour coverage.[39]

5.1.2 Information for decision making

The procurement process must provide all information necessary to allow AEMO to identify the service provider/s best placed to provide value for money while meeting the technical requirements. Currently, AEMO's processes do not support AEMO to assess if only relevant costs were submitted as part of the tender.

Changing the procurement process to require an itemised cost breakdown of tendered costs will limit tenderers from seeking to recover costs for unrelated infrastructure, market participation risks, or other factors not directly linked to the provision of a system restart service.[40]

5.1.3 Timeframe for change

The current system restart contract terms are long in the context of a rapidly changing market. The South Country contract runs until 23 October 2028 and the two restart contracts signed in 2021 run for five years. During the contract terms, new suppliers could enter the market with the appropriate signals from AEMO's procurement process.

For example, two new battery sources will be commissioned during these contract terms. A proposed of return on investment is required to give the two new battery sources time to consider investing to make the battery assets capable of restarting the electricity network. Investment signals could take the form of a review on system restart services and alternative means of meeting the need, and advance contracting to bring new supply into the market. These signals could be provided in the same manner as the capacity mechanism ensures system security.[41]

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37 In the NEM, AEMO's SRAS guideline states: "a competitive tender must be open to any prospective SRAS provider able to meet the technical and reliability requirements" AEMO, 2021, SRAS Guideline, p10 section 7.3 (a) (online)

38 AEMO Power System Operation Procedure: Ancillary Services. 1 July 2019.Section 5.1.3 and 5.1.4 (online)

39 In the NEM, AEMO's system restart procurement guideline allows multiple providers with overlapping services to bid for system restart provision. AEMO, 2021, SRAS Guideline, p10 section 3.1 (c) (online)

40 In its 2019 determination, the ERA identified that non-system restart costs had been included in a proposal for a system restart contract. These costs were not approved by the ERA. Economic Regulation Authority, 2019, *Ancillary service parameters: spinning reserve margin (for 2019/20) and load rejection reserve and system restart costs (for 2019/20 to 2021/22) – Determination*, pp. 26-27 (online)

41 Details on the planning for and procurement of reserve capacity is available on AEMO's website: Reserve Capacity Mechanism (online)

2. Question

The ERA will not have an oversight role the next time restart contract procurement will be undertaken. The ERA is interested in methods available to AEMO to improve the supply of restart capable providers and putting downward pressure on supply cost.

What procurement strategies, methods and approaches can reduce the cost of system restart services to the market?

Appendix 1 : List of Tables

Appendix 2 : List of Figures

Appendix 3 : ERA model description

Model configuration

The ERA WEM model has been configured to co-optimise electricity generation with load following ancillary services (LFAS), spinning reserve, load rejection reserve, and ready reserve.[42] The model will identify the least cost means of meeting the energy and the different ancillary service requirements. Based on this co-optimised dispatch, the WEM model forecasts balancing prices for each 30-minute interval for the 2022/23 financial year.

The model draws from a database of fields that describe the physical characteristics and associated costs and operational constraints for generators connected to the South West Interconnected System (SWIS).

Market configuration

The WEM database includes an energy market and four 'reserve' services for modelling spinning reserve, load rejection reserve, and both upwards and downwards LFAS. Ready reserve is applied as a scheduling constraint in the model, requiring a scheduled generator or demand side capacity available within fifteen minutes notice to cover 30 per cent of the largest contingency (largest output from a single 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 undertaken by the model when calculating how the reserve requirement will be met. For example, assume a spinning reserve contingency risk of 300MW, the model would set the spinning reserve requirement to 210MW (70 per cent of the contingency). If the market had 100MW of upwards LFAS, this would be deducted from the 210MW requirement. The model would then optimise the scheduling of energy demand, 100MW of upwards LFAS, and 110MW of spinning reserve.

Spinning reserve contingency

Based on information provided by AEMO, the spinning reserve 'risk', or contingency, is the larger of 70 per cent of the largest output from a single generator or the 'North Country contingency'.[43]

There is an additional contingency AEMO applies related to the loss of rooftop solar generation equivalent to ten per cent of the output of systems installed under previous Australian Standards for inverter performance. The current standard is in the process of phasing in and allows for a twelve-month transition process. Systems installed beyond December 2021 are assumed to comply with the current Australian Standard. AEMO has advised that it would assume a proportion of the rooftop solar capacity installed under the previous standard would disconnect into the future.

In the model, generators were limited to providing no more than 30 per cent of the contingency quantity to reflect the need to spread risk across multiple generators and prevent the model selecting a single low-cost generator for ancillary service duty where in practice the spinning

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42 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.

43 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.

reserve response would not be sufficient or plausible. The same constraint has been applied to the battery, although, two more sensitivities were tested, that allow the battery to provide up to 50 per cent and 90 per cent respectively of the spinning reserve contingency in each trading interval.

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

Load following ancillary services

The upwards and downwards LFAS requirements in the modelling are set up at 110MW for daylight hours (5:30AM to 7:30PM) and to 65MW overnight. These requirements are aligned with the latest ERA decision on the AEMO ancillary services requirements.[44]

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.

Load rejection reserve

The load rejection reserve contingency is assumed to be 90MW in the planning horizon in advance of the trading interval when the generating units providing the reserve are committed. In practice, some wind farms automatically reduce their output when the frequency in the system exceeds a predetermined threshold and there is a degree of load relief available – so more load rejection reserve can be available than was anticipated. While the dynamic requirement may be closer to 60MW, AEMO may have already committed scheduled generators out-of-merit to provide the load rejection reserve requirement hence the model assumes a 90MW threshold consistent with that used by AEMO in its forward planning.[45]

Like the spinning reserve approach, the model limits generators (and the battery) to provide no more than 30 per cent of the contingency quantity to spread the risk.

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.[46]

The application of the Generator Interim Access constraints was modelled in steps, partially with some pre-processing outside of 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 generation in each trading

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[44] Economic Regulation Authority, 2021, Decision on the Australian Energy Market Operator's 2021/22 ancillary services requirements, (online)

[45] Load relief is the reduction in consumption from frequency dependent loads (for example, induction motors). These loads decelerate in response to a fall in system frequency. Since power consumption of these loads relies on their rotational speed, less power is drawn during a frequency drop

[46] The network is configured with 11 nodes in the model, but it operates as a single node rather than multiple nodes with programmed constraints.

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 2022/23. The ERA took the last complete demand profile (2020/21) and added back AEMO's estimated rooftop solar output to derive an underlying demand figure. This was scaled to align with AEMO's expected forecast peak demand, minimum demand and operational consumption indicated in the 2021 Electricity Statement of Opportunities (ESOO).[47]

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.[48] 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 similar to that used by AEMO for its ESOO forecast.

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

Generator configuration

The ERA collected and verified (as part of its first consultation step in this current process) 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

47 AEMO, 2021, *2021 Electricity Statement of Opportunities*, (online)

48 Geodetic Calculators: Perth location (online)

- 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. 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 input assumptions must reflect the actual input costs as closely as possible.

To forecast ancillary service costs for 2022/23, the ERA must include assumptions on forward fuel prices. For the base case scenario, the ERA used fuel prices provided by market participants. For three of the scenarios that test 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.[49] Sensitivities were conducted around the EPL fuel price, as well as variations to this price by +/- $1/GJ.

Heat rates

Heat rates are a measure of a generator's efficiency and the fuel inputs for different levels of output. 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 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 time-frame and reduces the risk the software cannot find optimal generator schedules. Synergy provided adjustments for its generators.

As Synergy bids as a portfolio, its offer tranches are not explicitly connected with particular generators. To overcome this, load points for Synergy's generators were evenly divided across most of the output range between minimum stable generation level and maximum output capacity.

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 floor or below zero, and/or offered at the market cap. This bidding behaviour may reflect generator cycling costs (generators bid at negative prices or at the floor price to avoid being

49 Economic Regulation Authority (2021) Energy Price Limits Review 2021, Draft Decision, online

decommitted, or to provide LFAS up and spinning reserve), 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 percentage of the unit's operating hours in a year and as a percentage of the total hours in a year through generators' forced outage rates. The forecast forced (unplanned) outages were derived from the 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 WEM forecast model used actual generation outputs, 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.[50]

For GIA generators, 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. 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 ESOO were used.[51] 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.

[50] These estimates are used in as inputs to the relevant level method for capacity allocation.

[51] AEMO, 2021, 2021 Electricity Statement of Opportunities, online

Rooftop solar capacity was estimated from postcode data reported by the Clean Energy Regulator. Growth in rooftop solar was forecast based on the last two year's monthly installation rates aligned with AEMO's projected growth rates, extrapolated from linear and power lines 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.

Sensitivity bands of plus or minus 25 per cent of the expected rooftop solar uptake growth wedge were used. 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 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 below the six second to five-minute response time needed.

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 will be based on their marginal cost including the forward value of renewable energy certificates (REC) over the outlook period. The nominal REC (Large generation certificate) was derived from a two year forward contract price reported by Bloomberg for forward supply maturing in October 2023.[52]

Batteries

Two battery systems are scheduled to be committed during the forecast period. The second a year after the first battery. There is only one month within the forecast window when both batteries are likely to be operating simultaneously. Only one battery has been configured in the model to be operating in the forecast window.

The introduction of the battery to the model moderates some financial market outcomes that have been of concern to generators and the market operator. Modelling indicates it will slow the pace of falling demand and improve supply into the evening peaks, and lift electricity prices.

52 The price is $37 per MWh

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

In the WEM, a battery can monetize output from the load following, the energy output and energy input if spot market prices are negative. If the battery is providing load following reserves 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 spot 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.

PLEXOS uses a value termed a shadow price to determine whether and when the battery charges or discharges and ancillary services provision. 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 either mode 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.

Batteries with capacity obligations must make themselves available into the balancing market during the periods of 4:00PM till 8:00PM daily. They can provide ancillary services within this period but must ensure they do not fully discharge prior to the end of the capacity obligation window. The batter in this model is not configured to conform to these obligations as no battery has applied for capacity certification within the forecast window.

Sensitivity analysis

Bidding behaviour

Mark-ups are alterations to a generators' offer curve. Discussed further in Appendix 3, the mark ups in the base case reflected recent observed behaviour during periods of low demand. Since the incidence of negative prices in the market has been progressively increasing over recent years and particularly since the spot market cleared at the market floor of -$1,000/MWh, generators have altered their bidding practices to reduce the quantity of generation bid below zero when the market is more likely to clear with prices below zero.

The sensitivity run without mark-ups resulted in prices more closely approximating current prices. There were fewer negative prices and around one tenth of the floor price events. Generator bids were determined entirely on the marginal cost estimated by the model. Dispatch in this modelling run was substantially different from the base case and the real market. The price bids below zero appear to have a material effect on peak electricity pricing during the mid-day trough. The greater the quantity of generation bid at the floor, the lower the market clearing price is likely to be.

Battery

Discussed in Section 4.1.1, removal of the battery from the model substantially dropped peak prices and doubled the incidence of prices clearing at the market floor. The battery charging during the mid-day trough helped lift prices. The 'no battery' sensitivity bears the closest resemblance to the modelling assumptions set used to determine parameters for the 2021/22 financial year. Notwithstanding the continued changes to the load profile wrought by rooftop solar, the results are relatively consistent between years.

This indicates that notwithstanding the battery, pricing is relatively consistent between years. Unsurprisingly, the availability costs for the two contingency reserves were marginally higher in the no battery sensitivity. This reflects the additional uptake of rooftop solar further reducing operational electricity demand served by the market and the additional contingency risk from solar. The battery itself tends to charge during the mid-day trough increasing demand and supporting prices. It also substitutes a quantity of out of merit generation costs that would otherwise increase the availability cost for the contingency services.

Two additional battery sensitivities were run to compare with the base case scenario limiting the ancillary service provision to no more than thirty per cent from a single source.[53] The two sensitivities allowed the battery provision to rise to fifty per cent in one sensitivity and operate at 95 per cent in another.

Gas prices

In the base case fuel prices collected from market participants were used. This reflects their expected costs during the forecast window. Sensitivities were conducted around the fuel prices to understand how sensitive the model as configured is to change in price. There has been an increase in the market price for gas and the sensitivity analysis as conducted to understand how much the values might move should they increase more than anticipated.

The gas price sensitivities applied a uniform forecast market gas price for all generators, overriding individual generators' fuel prices. The ERA used the same forecast gas price of $5.04 undelivered calculated for the draft determination of energy price limits for 2021.[54]

High and low cases bracketed the expected EPL forecast price by one dollar each side. The low gas price sensitivity dropped both the peak and off-peak balancing market prices. The EPL forecast gas price resulted in a marginal reduction in balancing market prices largely due to some market generators having prices marginally above this price. The high gas price resulted in similar pricing outcomes as some generators' reported gas prices collected in the first consultation phase on assumptions sat between the forecast EPL price and the high gas price sensitivity.

Solar uptake

Two sensitivity runs were conducted adjusting the solar uptake rate. One was at a lower uptake rate and one was at a higher uptake rate. The low uptake rate scenario resulted in higher peak balancing market prices and no material difference in off-peak balancing market prices in either scenario. The high PV uptake scenario resulted in relatively little difference from the base case in terms of the availability cost for ancillary services. This may be due to the greatest effects on scheduling already being incurred.

53 This reflects a limit AEMO places on spinning reserve provision that no more than thirty per cent can come from a single source to ensure diversity of supply in case a resource becomes unavailable.

54 Nidras P., 2021, Gas price forecast – final draft report to Economic Regulation Authority, published in ERA, 2021, Energy price limits review 2021, pp 12, 76-93, (online)

Differences between the model and the WEM

Models are inevitably a simplification of the real world. 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 (load rejection reserve and load following lower) or at the cap to ensure the upwards services are available (spinning reserve and load following raise). Some of this is captured through the mark-up process.

The requirement to bid at the floor rather than at a generator's marginal rate 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 posed some challenges for cost allocation and model calibration. Model calibration sought to provide a reasonable and accurate rendition of market outcomes and as a consequence the offer curves were altered to reflect this element of the WEM Rules (see figure A 3 to figure A 17). 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 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 where the 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.

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) in this process [or ‘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 informing this paper.

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

Scenarios tested include running the model based purely on generators’ short run marginal cost to compare with the base case, where parts of the output curve were varied in accordance with generators’ observed bidding practices. Sensitivities were conducted on the exclusion of the battery, fuel prices, behavioural factors, rooftop solar uptake rates, how much spinning reserve and load rejection reserve the battery is allowed to provide to cover the spinning reserve. This information can then be used to identify the best means to configure the model to ensure a reasonable representation of the WEM operations.

Model inputs relevant to individual generators were collected from market participants. These data build and update data already provided by most participants under the WEM Rules.[55] 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.

55 Wholesale Electricity Market Rules (WA), 1 February 2022, Rule 2.16.

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 fixed inputs used 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 conducted on the scheduling decisions and refinements were made as necessary.

Ancillary service 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.[56] 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 other ancillary services through other market mechanisms. How costs are allocated between the different services is illustrated in figures A 3 to A 17.

[56] Wholesale Electricity Market Rules (WA), 1 February 2022, Rule 3.18.11.A.

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

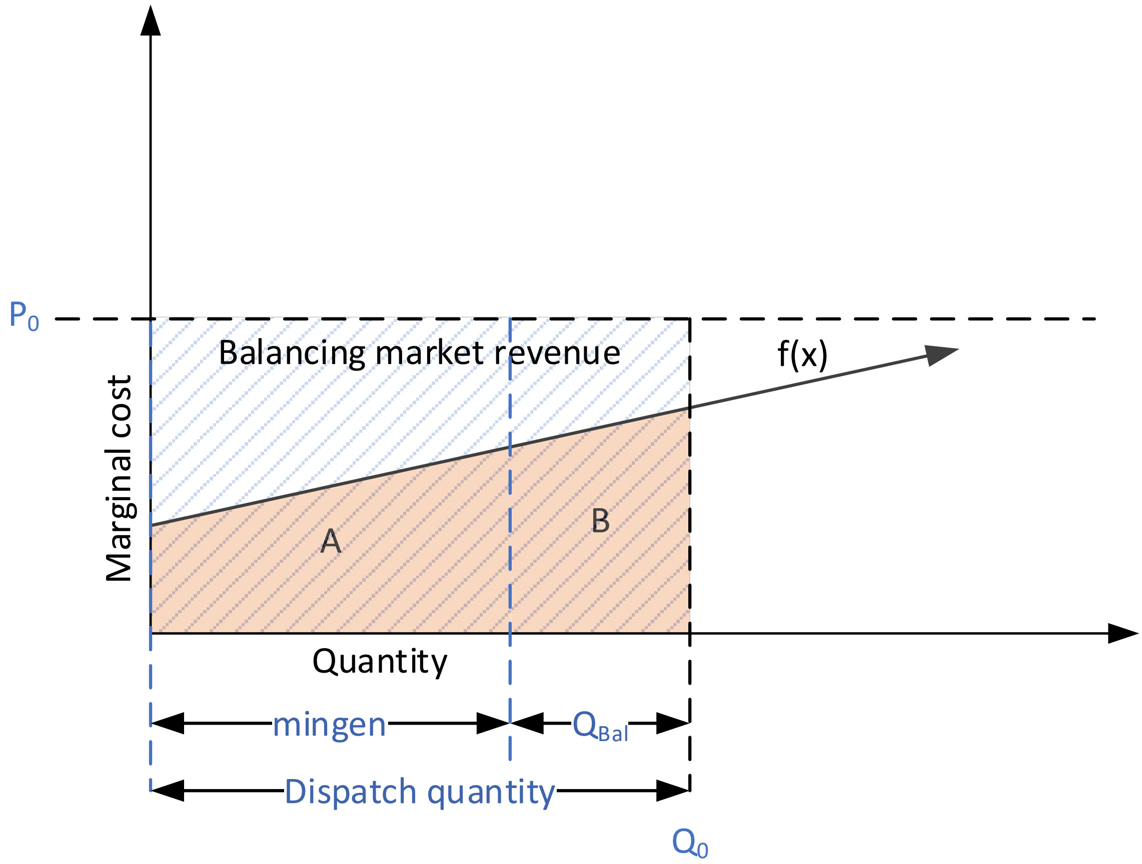
The costs accruing to spinning reserve and or load rejection reserve will depend on the market circumstances at the time. The following subsections step out different combinations of ancillary services and explain the rationale for accruing costs to different ancillary services when the generator is 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.

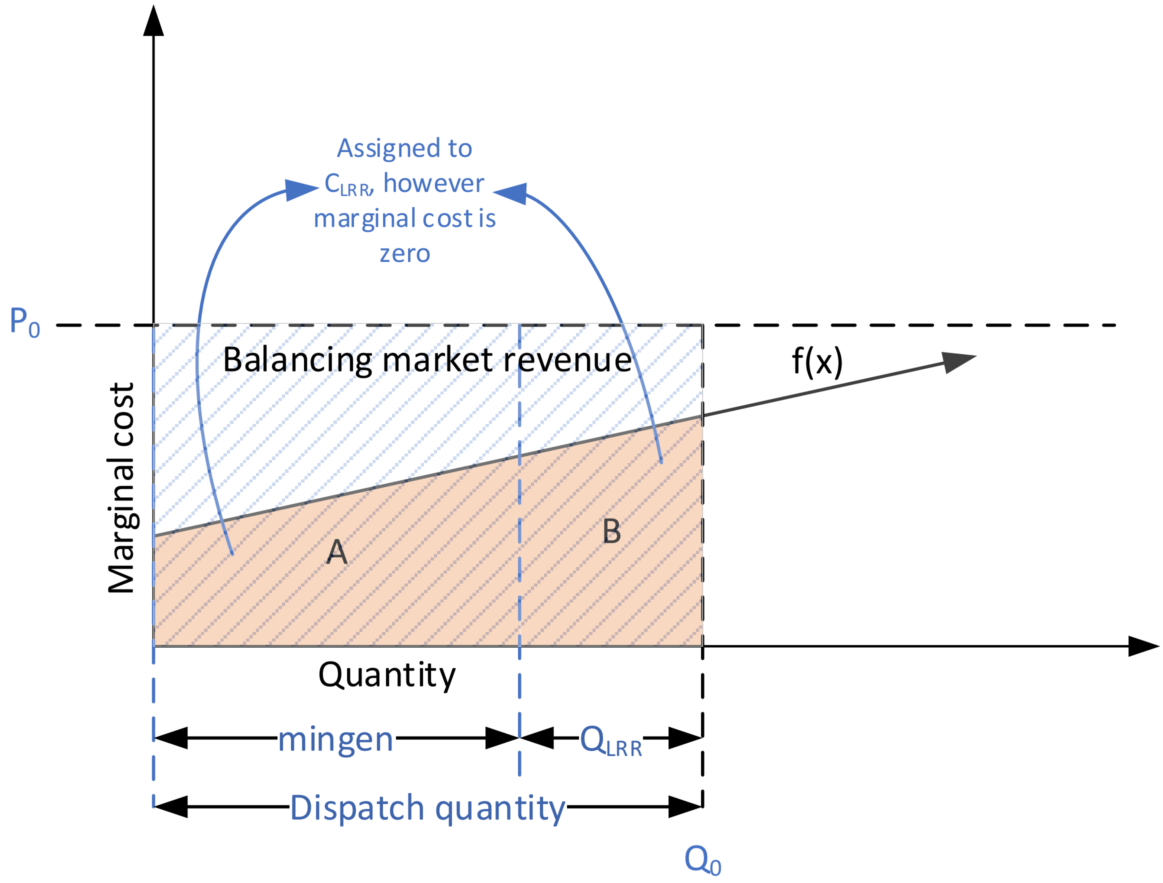
Figure A 1 Dispatch conceptual diagram



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.

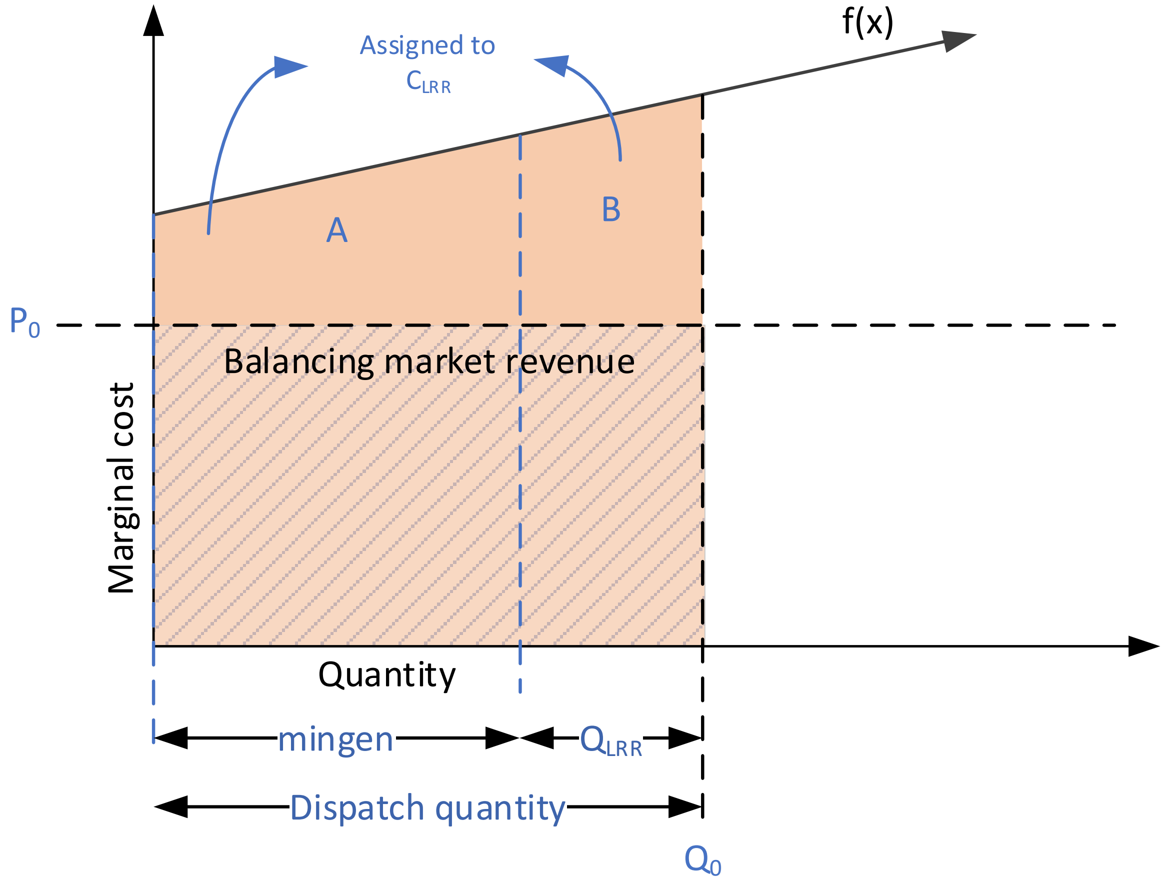
Figure A 2: Generator providing load rejection reserve when in merit



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.

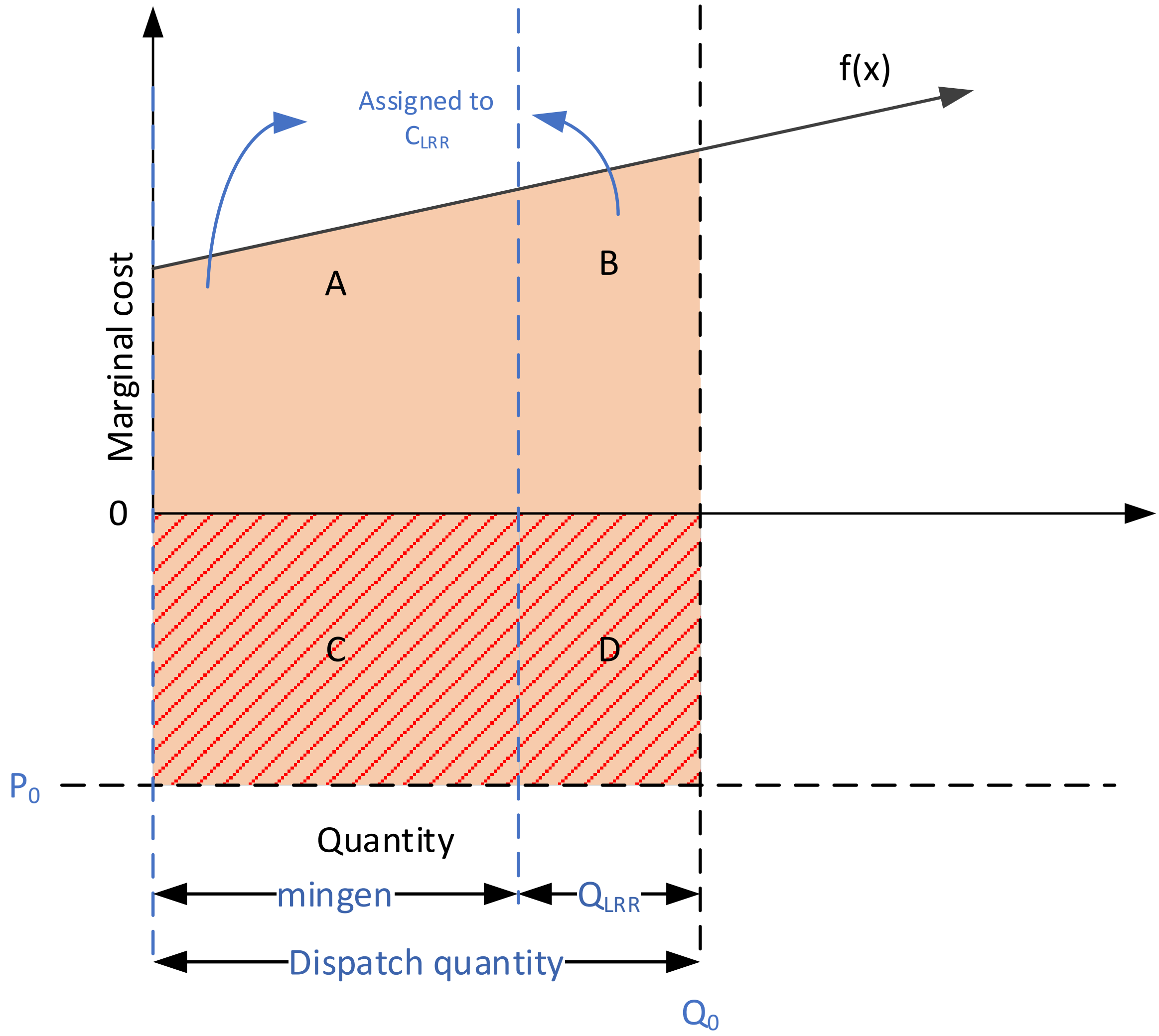
However, when that same generator's marginal cost exceeds the balancing price (such as in Figure A 3), it is considered 'out-of-merit'. Balancing market will provide some compensation up to the balancing market price, as the generator incurs costs that exceed this. In this situation the generator would need to be compensated for the difference between the balancing market review 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

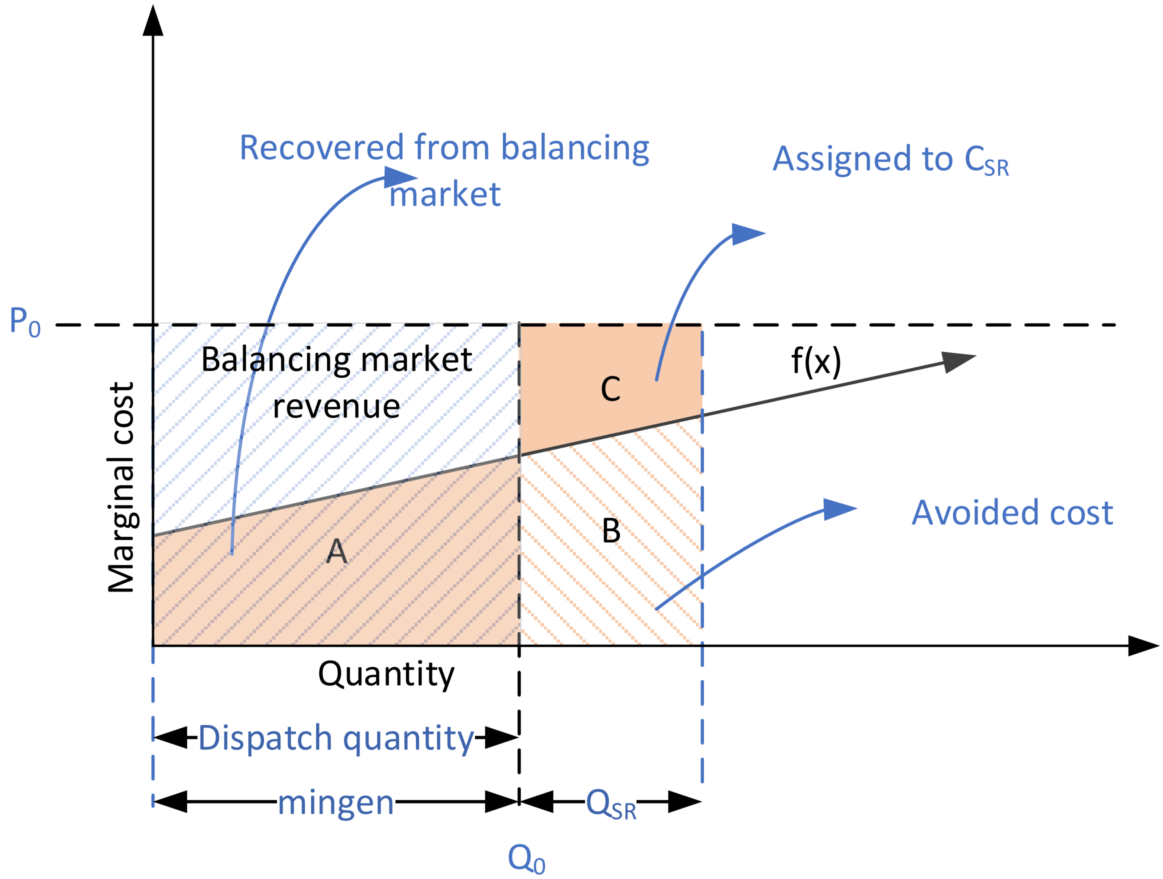


When prices are negative, areas 'C' and 'D' are paid by a generator to remain in service. These also need to be compensated for in addition to areas 'A' and 'B' – the full marginal cost of the generators dispatching.

A generator providing spinning reserve

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 tan areas the area under the marginal cost curve f(x).

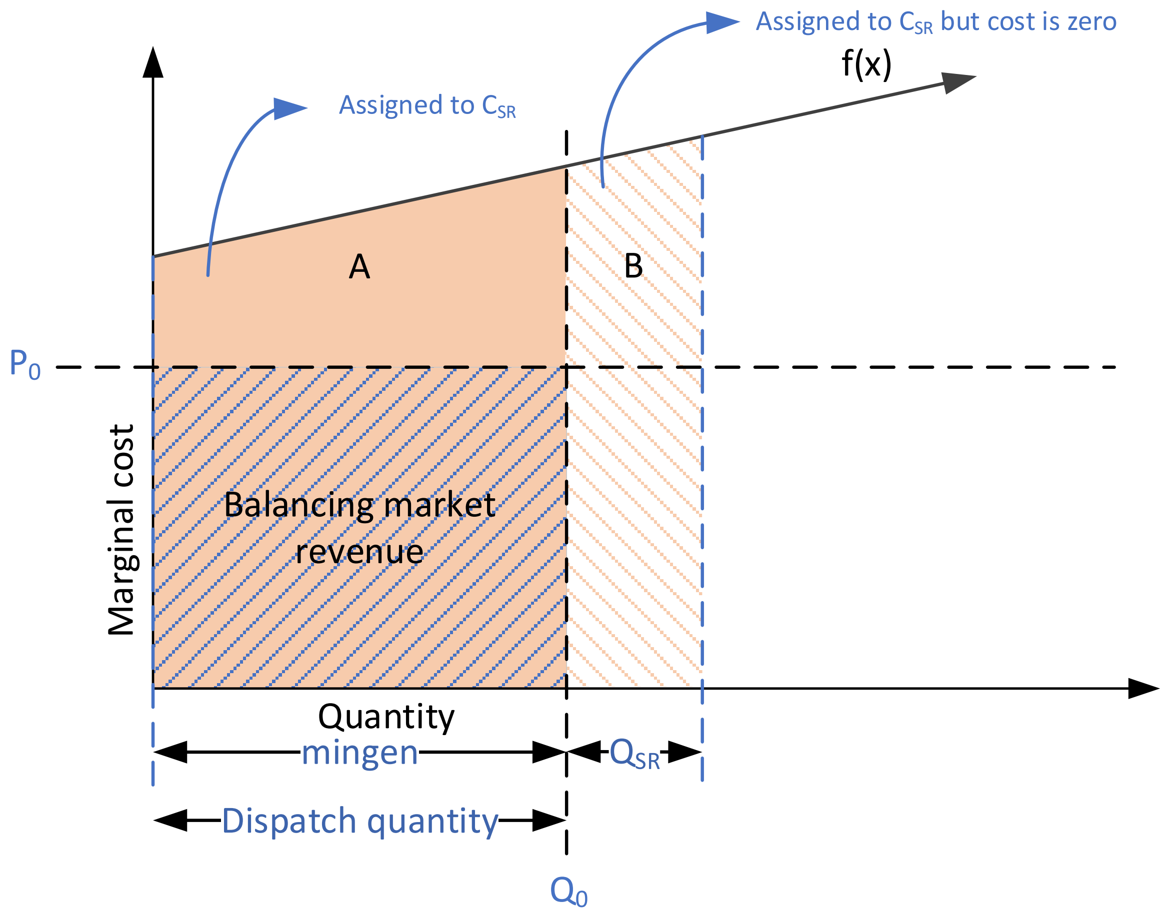
Figure A 5: A generator providing spinnign reserve only when in merit



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



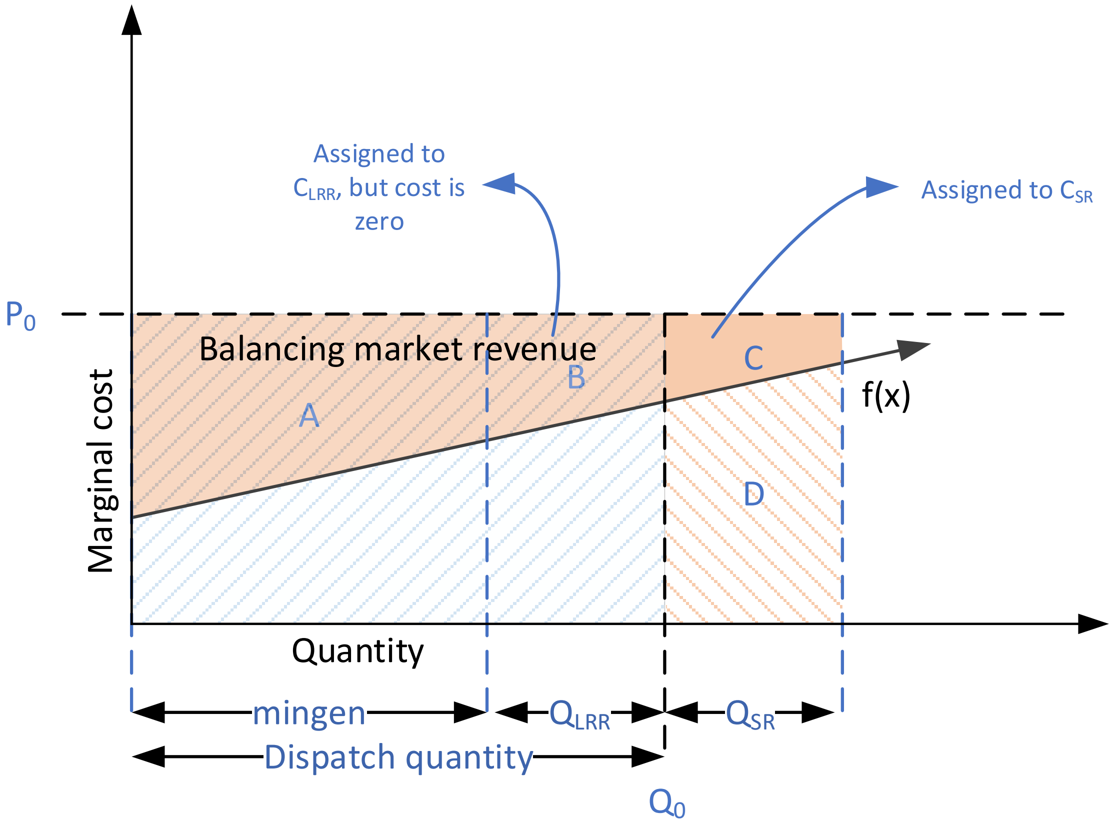
Where a generator is providing spinning reserve out-of-merit, and generation is withheld, there is no opportunity cost of providing spinning reserve. It avoids a cost that exceeds the revenue it would have received had it been dispatched. Area 'B' does not need to be compensated – only area 'A'.

A generator providing Load Rejection Reserve and Spinning Reserve Service

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.

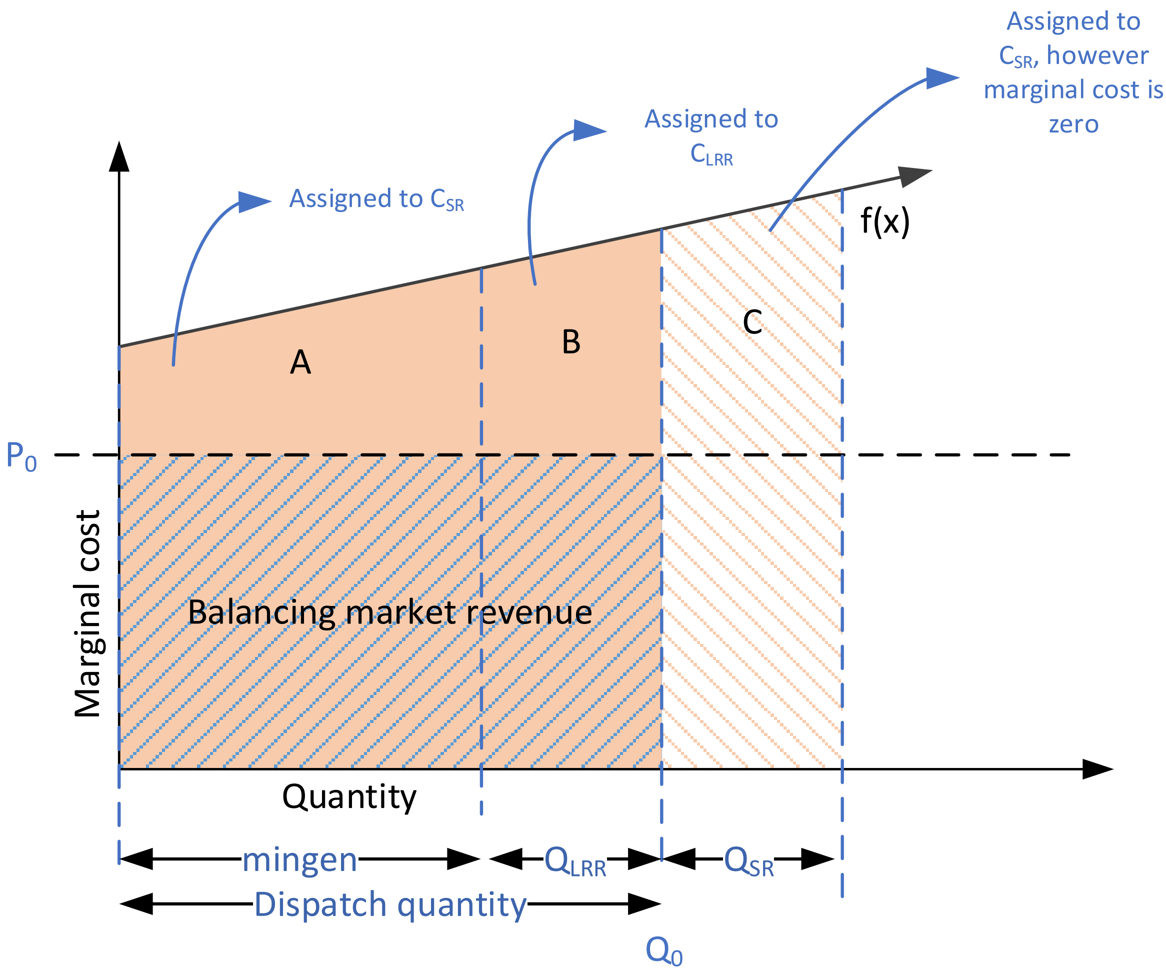
For a generator in merit (shown in Figure A 7), the costs to run up to the minimum generation quantity are recovered through the balancing market and no compensation is required. As with the example for LRR only, the cost for being available to reduce output when in merit is fully recovered through the 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 spinning reserve. Area ‘C’ is the capacity dedicated to spinning reserve and is an avoided cost and has a marginal cost of zero.

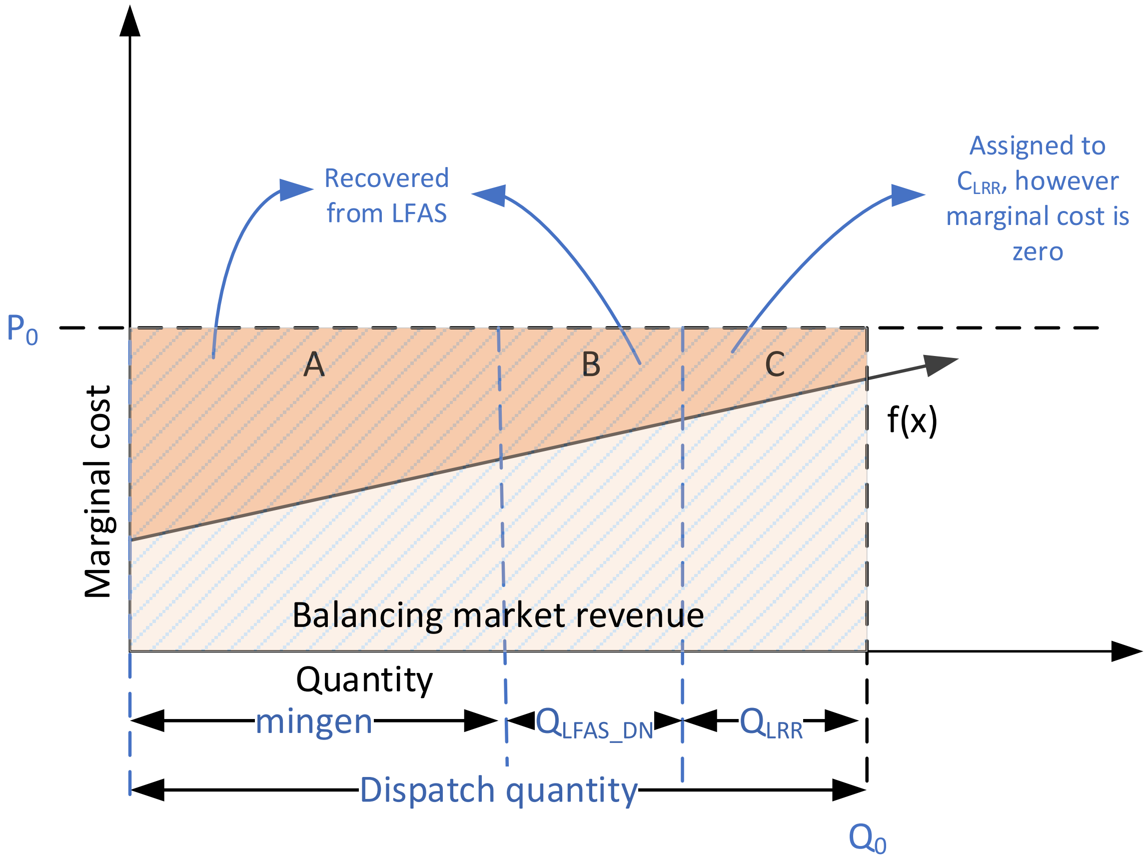
Figure A 8: Generator providing spinning reserve and load rejection reserve out-of-merit



A generator providing load rejection reserve and load following ancillary service

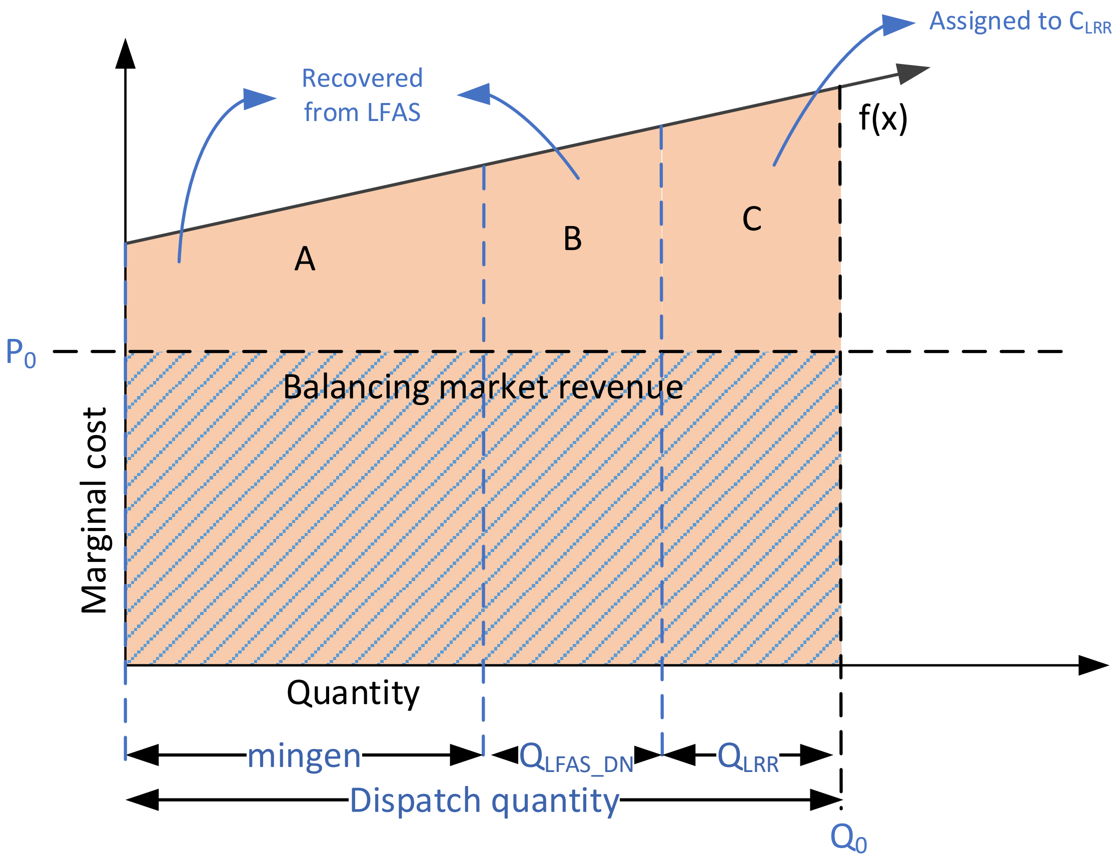
Where the generator is also providing LFAS services, depending on whether the generator's marginal cost is above or below depends on whether a cost is incurred to provide each service. Where a generator is providing these services and is in merit (shown in Figure A 9), area 'A' and the operational costs 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.

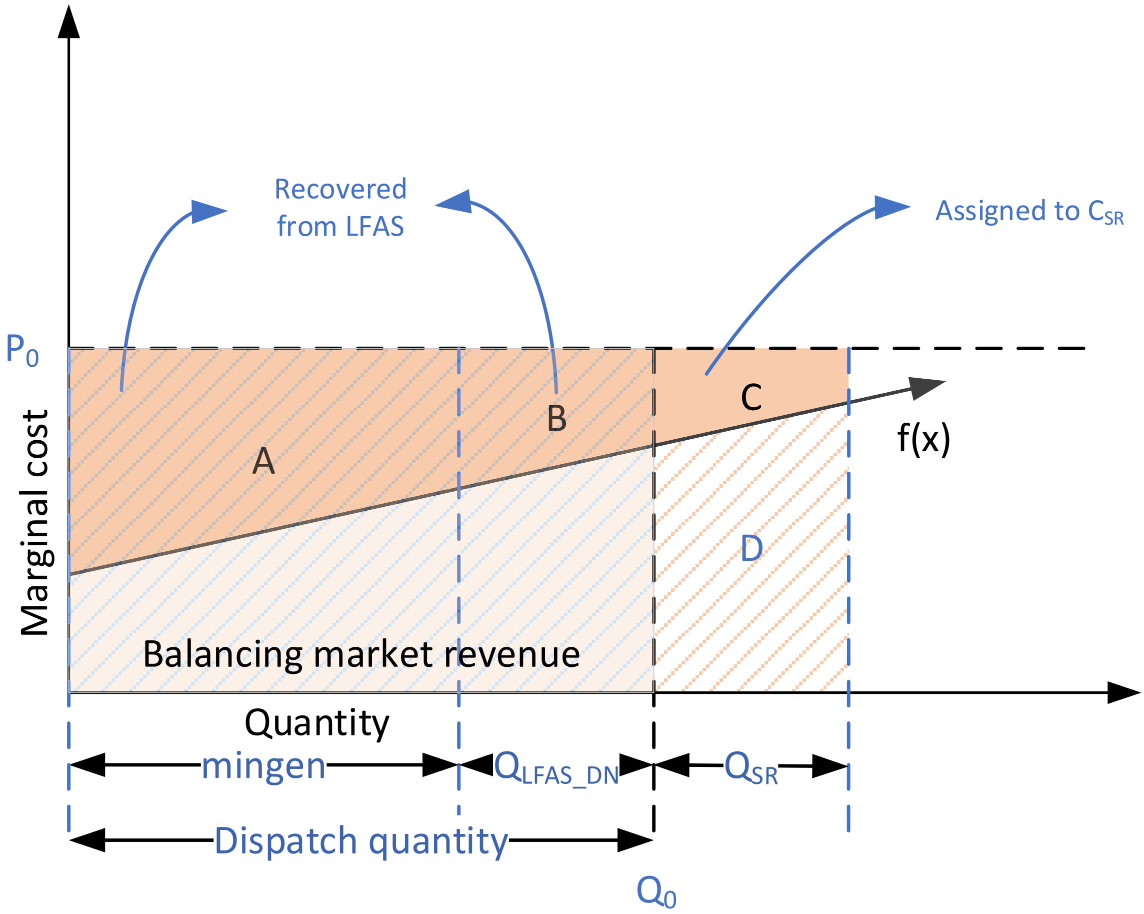
Figure A 10: A generator providing LFAS and load rejection reserve operating out-of-merit



A generator providing spinning reserve and load following ancillary service

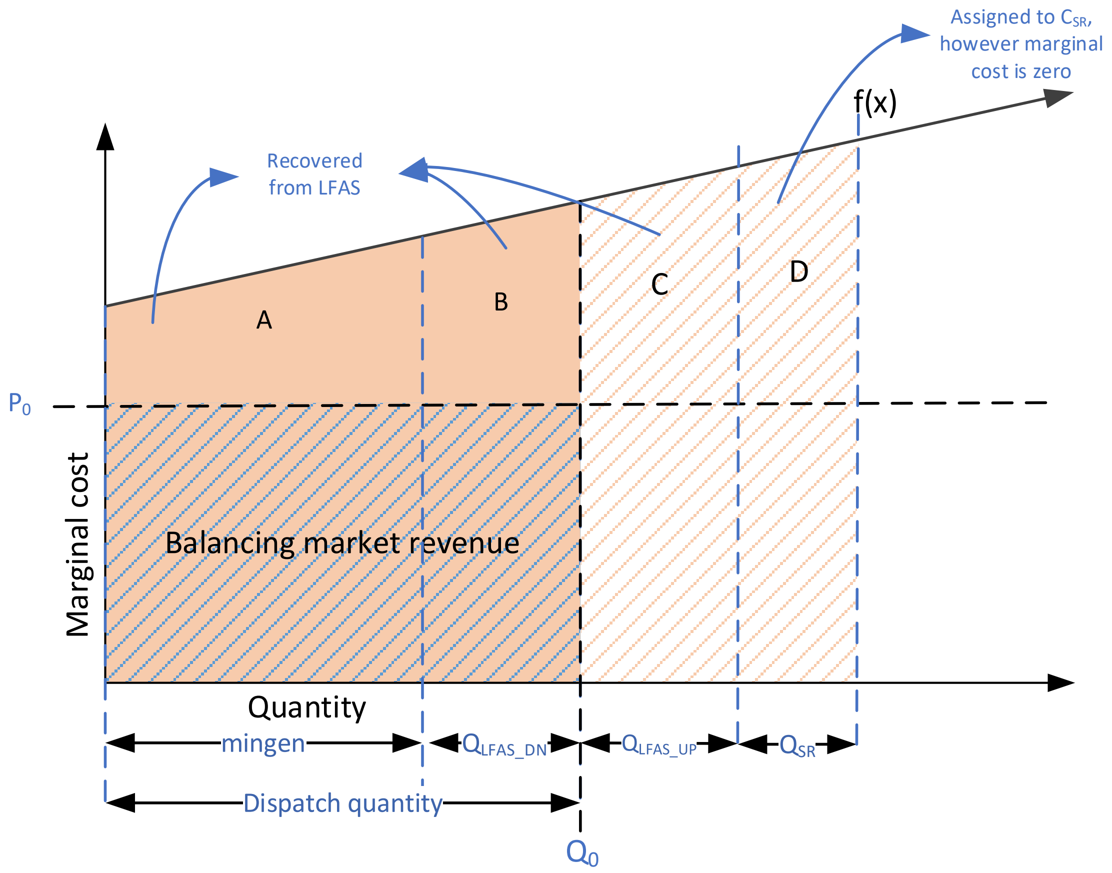
Where a generator is providing spinning reserve and load following ancillary service in merit (shown in Figure A 11), the area up to minimum generation is fuller recovered through the balancing market and is assigned to the cost of providing LFAS. Area 'B' is recovered through the LFAS market and is 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 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.

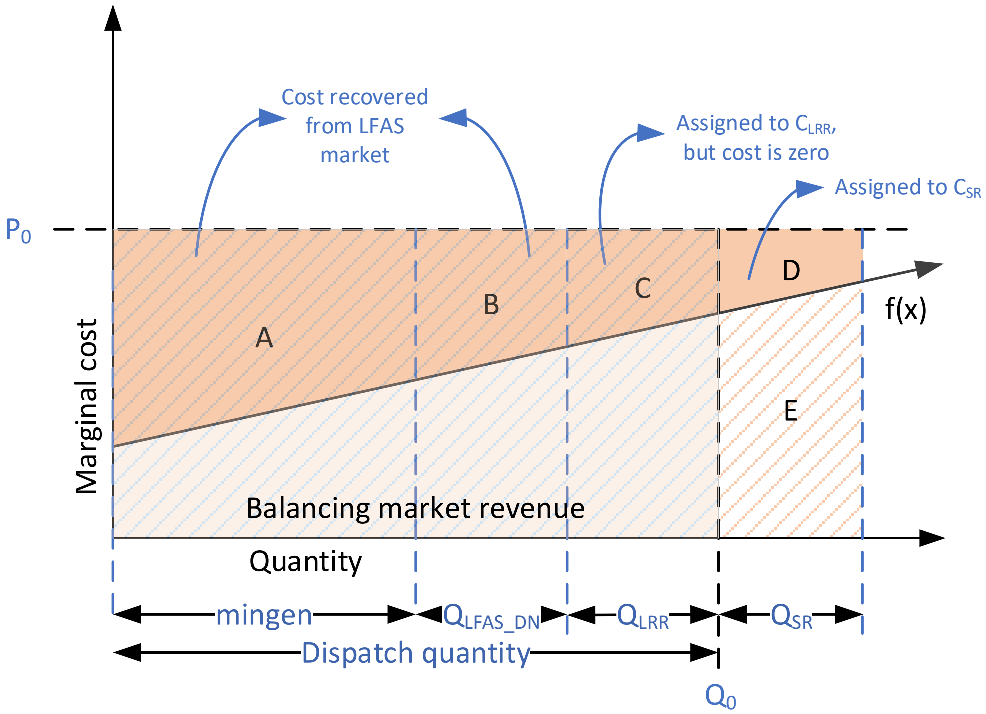
Figure A 12: A generator providing spinning reserve and load following ancillary service operating out-of-merit



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

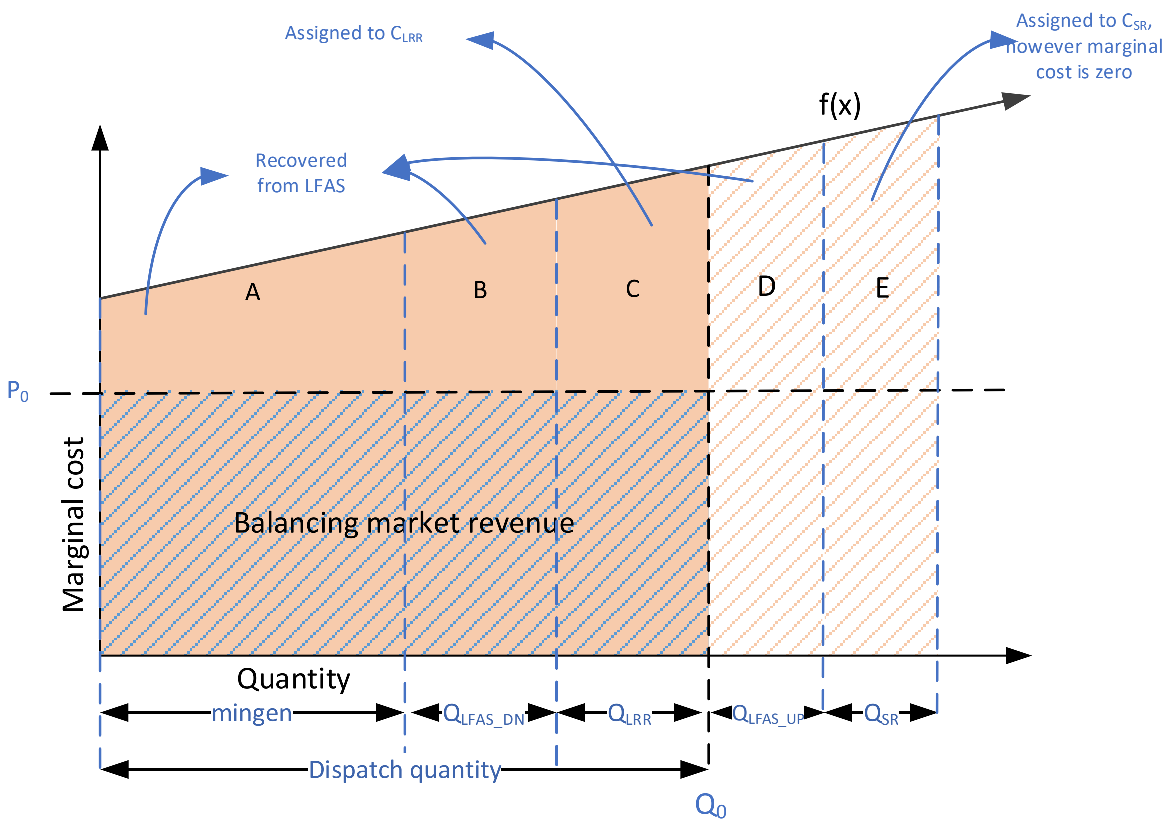
The costs associated a generator providing LFAS, load rejection reserve and spinning reserve are shown in Figure A 13 below. The cost to minimum generation shown by area ‘A’ and the cost to provide load following ancillary service down shown by area ‘B’ are assumed to be recoverable from the balancing 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 4 : Model calibration and back casting results

The ERA has commissioned and developed a model of the wholesale electricity market using the PLEXOS modelling software. The software is a computer modelling package for physical energy systems and is widely used for modelling electricity markets. PLEXOS is configured to determine the least cost dispatch of generating resources to meet a given demand, against a set of constraints and defined properties for generation and network assets.

In the first step, the ERA undertook a back-cast exercise (against the 2020/21 financial year) to calibrate the model. Once the back-cast results were deemed satisfactory, the model was converted into a forecast model.

The quality of the back-cast model was assessed by comparing the outputs with real market outcomes in terms of balancing price and generation facilities' dispatch outcomes.

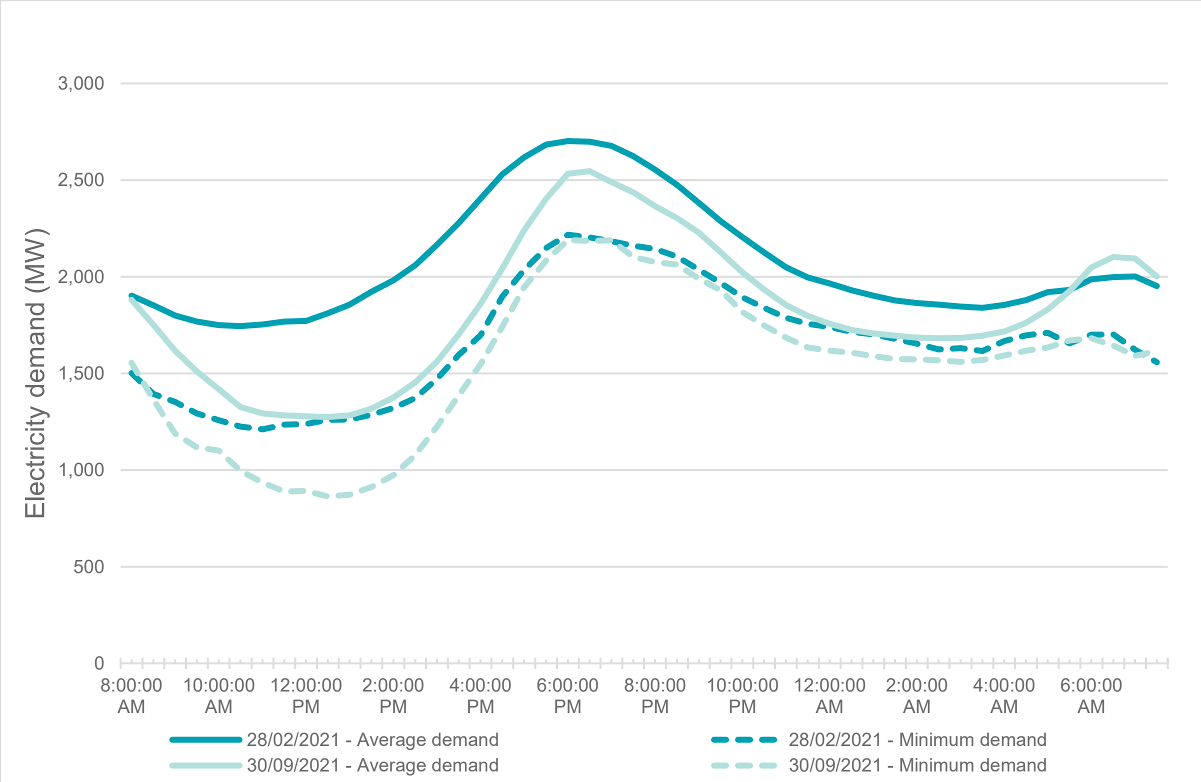
Battery price effects

The effect of the battery on the market price needs to be considered in terms of whether the battery is increasing supply or demand and how this changes over the course of the day and with seasons. As discussed in Section 4.1.1, the battery charges when prices and demand are low and discharges when prices and demand are high. Around this cycle, it provides spinning reserve, load rejection reserve as well as the load following ancillary services. The model schedules resources to minimise the generator operational costs to the system. This optimisation does not minimise generator producer surplus (or profit).

Producer surplus refers to the difference between a generator's costs and its revenue in the electricity market. The WEM clears the balancing price at the cost of the marginal generator. This price is received by all generators dispatched into the market. The model is configured to minimise generator costs for spot and ancillary service markets. The higher balancing market price resulting from the battery charging is separate from the operating cost optimisation.

Low demand periods are typically in the middle of the day due to electricity demand substitution from rooftop solar generation. Minimum demand varies throughout the year. Figure 7 shows the average load profile by time of day for the months of February and September. Average demand and minimum decreases during the shoulder periods when ambient temperatures are mild and temperature sensitive loads such as heating and cooling loads are low. During the shoulder periods, such as the months March, April, and from August to December the weather is usually relatively mild and the output of solar quite pronounced.

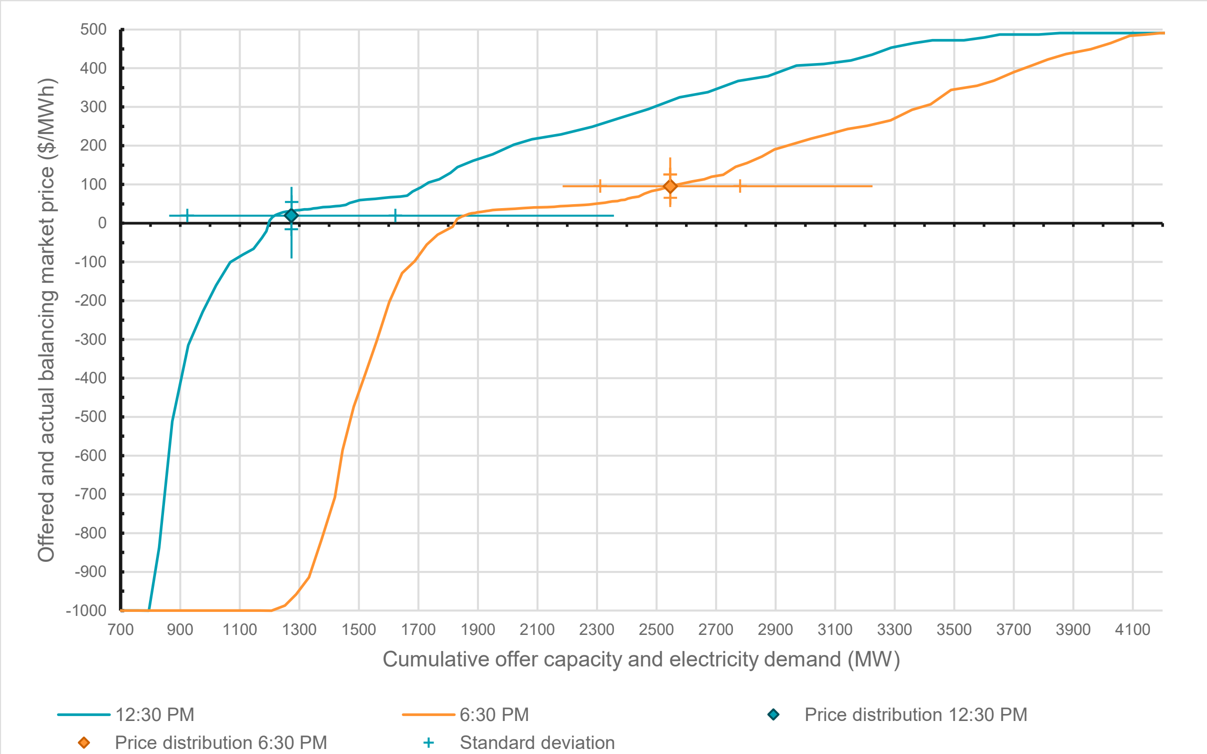
Figure 7: Average and minimum electricity demand profile by time of day



Source: ERA analysis of AEMO data

When demand is low, market prices are similarly low, often becoming negative, and this presents a good time for the battery to charge. Low points in the demand curve often intersect the steepest parts of the offer curve. Figure 8 shows the average offer curves at 12:30 PM and 6:30 PM and where the demand intersected the offer curves at those times. The diamonds indicate the average price and demand with the bars radiating from them the maxima and minima demand (horizontal axis) and price (vertical axis). The crosses indicate one standard deviation from the mean.

Figure 8: Offered prices and electricity demand September 2021



Source: ERA analysis of AEMO data

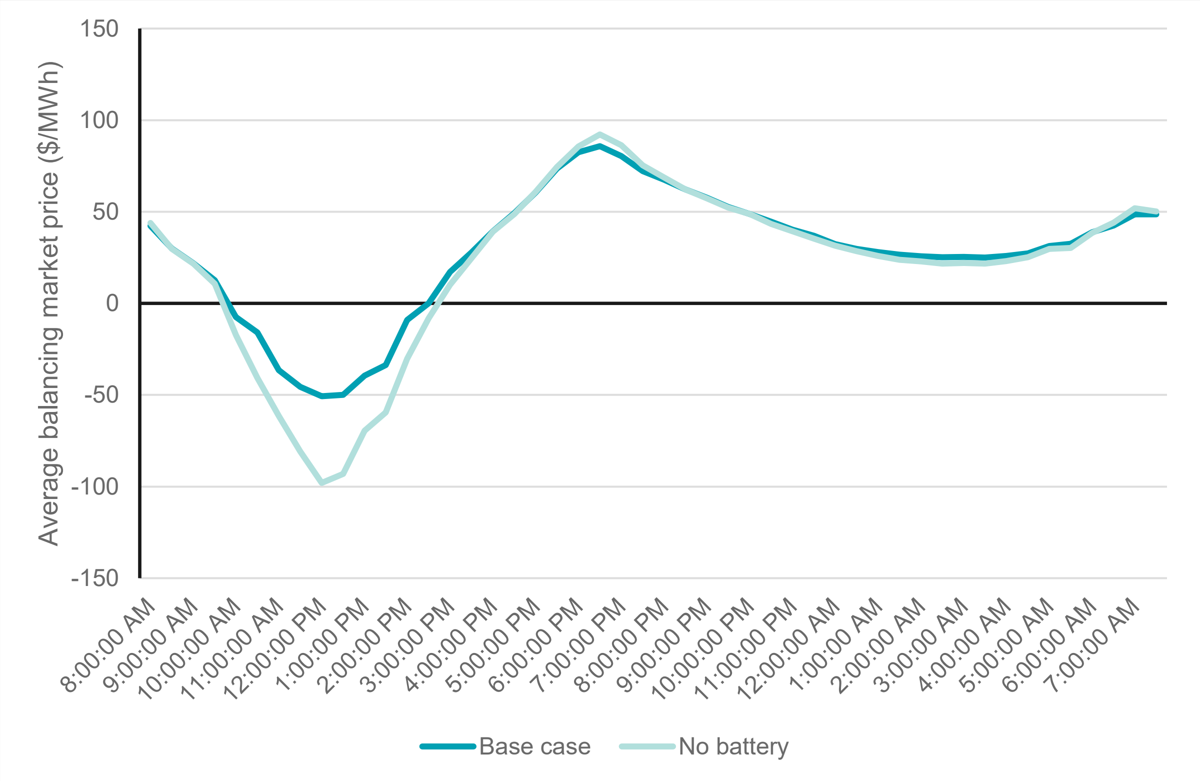
The influence of a deviation in demand, such as would result from the battery, on price will depend on the slope of the offer curve. The steepest part of the offer curve is at the inflection point around $25/MWh where the offers fall rapidly below zero. The steepest part of the offer curve is close to the market floor. Here, 100MW of demand could alter the clearing price by up to $600. Once the market clears above $40/MWh, the steepest part of the offer curve, a 100MW of additional supply could result in a less pronounced decrease in price of around $50 to $60 maximum.

Some of the capacity offered at negative prices is driven by the WEM Rules which require generators providing ancillary services to bid at the price floor. However, other tranches of negative offers can be from large thermal generators with high cycling costs that would rather pay to generate than incur a higher cost to turn off.

At midday an additional 100MW of demand from a battery can result in a price difference of hundreds of dollars per MWh. At 6:30 PM in the evening, additional supply will shift the offer curve to the right. However, because the offer curve here is less steep, 100MW of additional supply from a battery discharging will result in a price difference of less than $50 per MWh.

From the modelling results, the difference in price outcomes is on average substantial across the whole sample but varies by time of day and time of year (Figure 9). The greatest price difference is in the middle of the day when both demand is lowest, and the battery demand comprises a more substantial portion of total demand. At time of the year when the demand is higher, such as summer, the differences are much less pronounced and the battery is a less prominent load source. However, on average the battery reduces the number of negative priced intervals and roughly halves the number of floor price events.

Figure 9: Average forecast price by time of day 2022/23



Source: ERA modelling

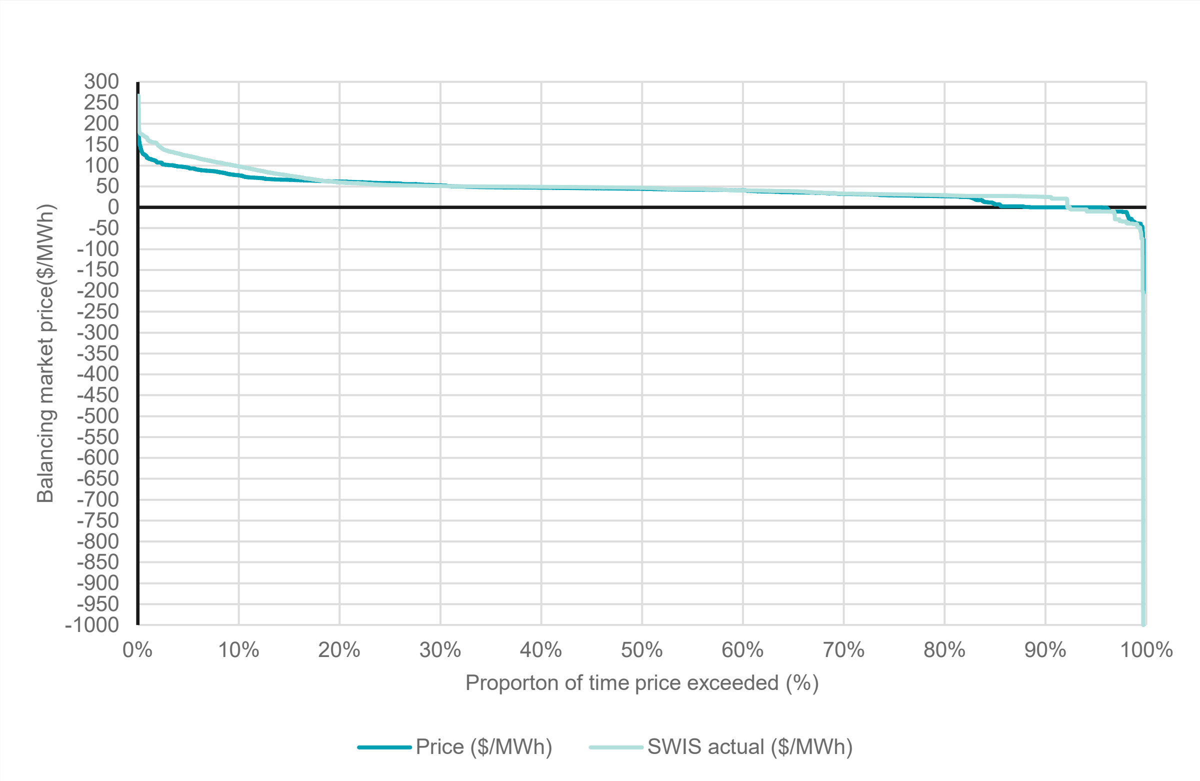
While the model is consistently minimising the generator operating costs, the producer surplus for generators is greater because costs are lower and the price is higher. The additional load from the battery during times of low demand has a disproportional effect in comparison to the supply in periods of high demand.

In the real market, this difference in pricing outcomes may be more muted. The modelling does not reflect the capacity withdrawn to the market caps resulting in a shallower escalation to the market caps. Also, when demand is low, less generation is bid at the market floor. This is subject to market participant behaviour. The modelling assumptions are most sensitive to error at the extremes.

Pricing outcomes

When the model is run based solely on heat rates without modifications to the offer curves (these price 'mark-ups' are discussed in the Appendix 3) it consistently forecast lower prices than those observed in the balancing market. The back-cast results indicate a fairly good price fit for much of the price duration curve with some deviation from the actual market at the top and bottom 15 per cent of the curve (Figure 10). The price profile over the course of the day also shows a comparable fit, albeit below the actual price profile (Figure 11).

Figure 10: Back-cast and actual price duration curves 2020/21 financial year



Source ERA modelling and analysis of AEMO data

Figure 11: Half hourly price profile balancing market Vs back-cast 2020/21 financial year.

There are several potential reasons why this might be the case. These include:

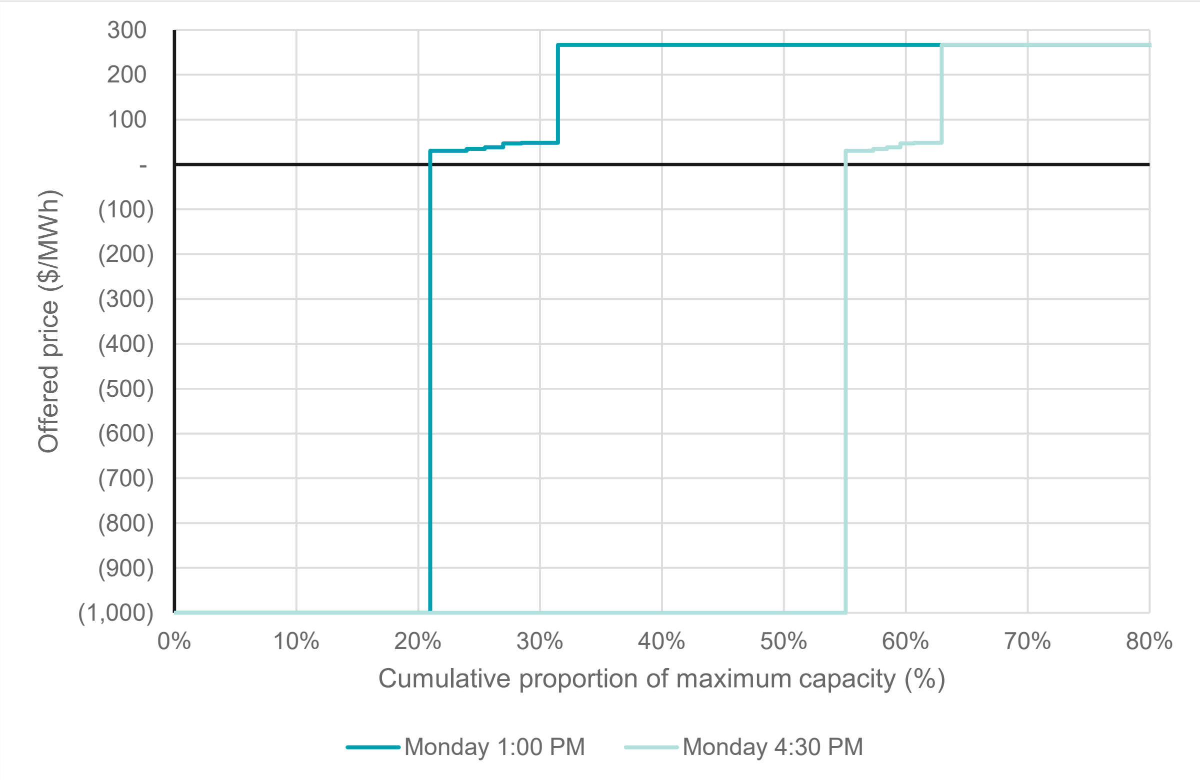
- Erroneous data inputs
- Incorrect model configuration
- Market inefficiency
- Market power in the balancing market

Comparing pricing outputs against the reference year and movements in the pricing outcomes in the electricity market, the back cast provides a reasonable fit for values below zero albeit with some deviation. The upper quartile of the price duration curve is under-estimated.

The root cause of this appears related to market participant behaviour. Market participants can withhold or reserve part of their output capacity from the market and bid this at the cap. A reduction in generation capacity available to the market at its short run marginal cost increases the cost of supply cleared in the market.

Figure 12 shows an example of an offer curve for a market participant in a shoulder period within the back- cast period. This particular generator effectively withdraws much of its capacity from the market to minimise its exposure to the market price during the mid-day trough period and increases the capacity available to the market after demand has recovered.

Figure 12: Offered capacity by time of day



Source: ERA analysis of AEMO data

This type of behaviour is common in the market and varies by time of year and time of day, depending on the prevailing market circumstances. The model calibrated the back-cast by modifying the lower part of the offer curve (as described in Appendix 3). The upper part of the offer curve where it elevates above the short run marginal cost of the generator has not been incorporated into the suite of mark-ups, as the basis for withdrawing such capacity from the market is unclear and subject to a high degree of change.

In practice, the effect of capacity bid at the market caps increases the cost of supply. Despite the incidence of low-cost generation entering the electricity market, the overall effect on average prices has been far less stark and the prices are relatively stable over time (Table 4).

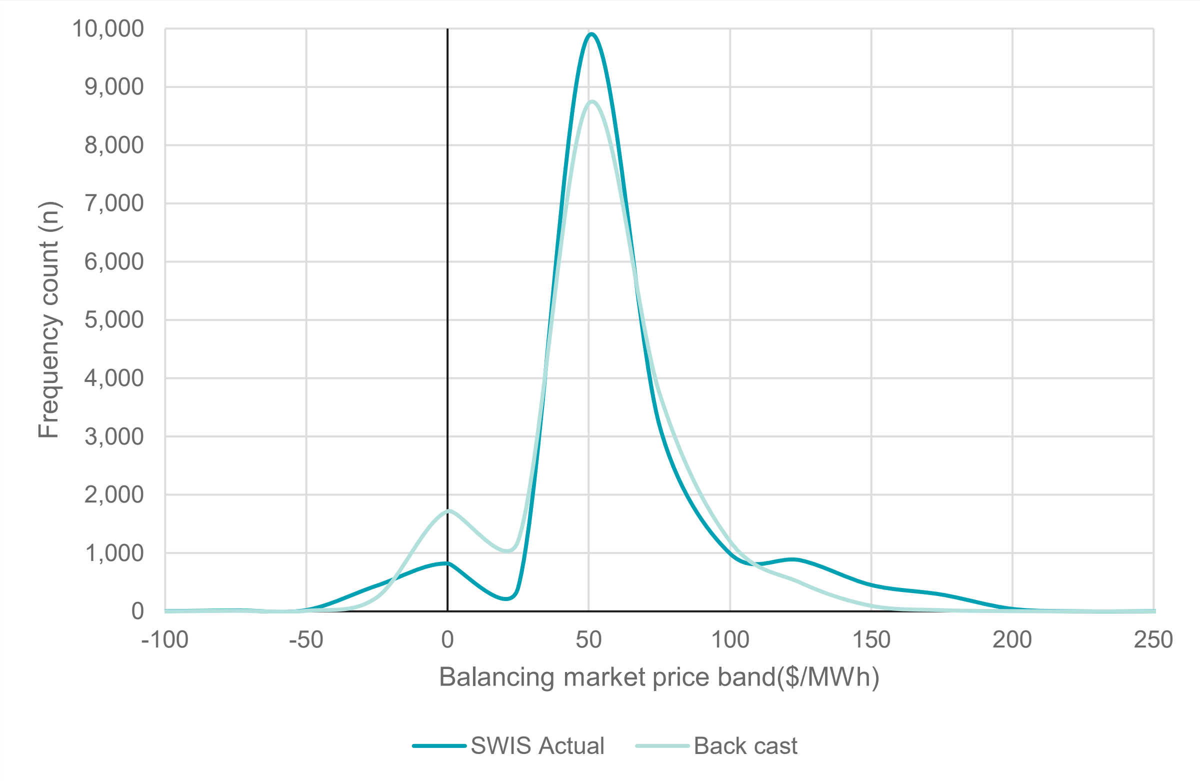
Table 4: Balancing market pricing outcomes

Year	Average balancing market prices ($/MWh)		Comments
	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 entering the market
2019	$49.38	$41.22	
2020	$51.42	$45.39	
2021	$52.38	$45.24	

Source: ERA analysis of AEMO data

Over the last few years, the lower end of the price duration curve has been shifting. A relatively small number of very low-priced intervals is skewing the average back-cast and forecast pricing outcomes. The reduction in prices has been largely offset by an increase in intervals with prices that clear above $75/MWh. Figure 13 compares the frequency distribution of pricing outcomes for the real market Vs the back-cast, the difference in the price distribution shows a greater number of intervals with prices below $25/MWh and fewer intervals above $100/MWh.

Figure 13: Distribution of prices in back cast sample and balancing market



Source: ERA modelling and analysis of AEMO data

The difference between the model and the actual market average prices is due to differences in the price distribution between the two. The number of negatively priced intervals is not offset to the same extent by higher priced intervals. This reflects the decision not to alter the upper portion of generator offer curves.

Sensitivity analysis

Sensitivity analysis modelling runs were conducted on the battery, bidding behaviour (mark-ups), fuel prices, and solar photovoltaic generation uptake.[57,58] Sensitivity analysis enables a deeper understanding of the relationships between assumptions and outputs. Table 5 outlines different sets of input assumptions and the sensitivity runs relative to the base case.

Table 5: Base case and sensitivity analysis runs input assumptions

Feature	Battery	Markups	Solar uptake			Fuel price			
Run			Low	Expected	High	Generator provided price	Low gas	EPL Gas	High gas
Unmodified generator data	X			X		X			
Base case	X	X		X		X			

57 Bidding behaviour is discussed in Appendix 3.

58 Refer to Appendix 3 for more information on mark-ups.

Feature	Battery	Markups	Solar uptake			Fuel price			
Run			Low	Expected	High	Generator provided price	Low gas	EPL Gas	High gas
No Battery		X		X		X			
Battery moderate AS constraint (50% cap)	X			X		X			
Battery low AS constraint (90% cap)	X			X		X			
Low gas price	X	X		X			X		
Expected gas price	X	X		X				X	
High gas price	X	X		X					X
Low solar	X	X	X			X			
High solar	X	X			X	X			

Source: ERA

Each sensitivity run altered only a single parameter from the base case. Throughout the modelling validation process, additional sensitivities were conducted to test and assess the model's performance to particular conditions. This included additional battery sensitivities above AEMO's 30 per cent limit on the proportion of the spinning reserve quantity the battery was allowed to provide relaxing the provision constraint limit to 50 per cent (moderate AS constraint) and further to 90 per cent (low AS constraint).

Availability cost sensitivity

Of the sensitivity runs, the availability cost for spinning reserve and load rejection reserve was most sensitive to the treatment of the battery.

Allowing the battery to contribute a greater proportion of its available output to ancillary services reduced the availability cost substantially by displacing more out of merit gas fired generation. Reducing the output constraint on the battery from no more than 30 per cent of the reserves (the base case assumption) to 50 per cent of the reserves reduced the availability cost by around 28 per cent or about $5.6 million. Allowing a contribution as high as 90 per cent reduced the availability cost by $7.5 million. Discussed in section 4.1.4, if the risk associated with the battery not performing is less than the risk a generator would not perform is lower, AEMO may wish to reconsider this constraint on the battery.

The increase in the rooftop solar contingency was the next most sensitive output to availability cost, which adds around $1.7 million to the modelled availability cost.

The third most sensitive parameter was changes to gas prices. Increasing gas prices to all generators to $6 per GJ increased the availability cost by 11 per cent. Reducing them to $5 reduced the availability cost by 13 per cent and to $4 by 15 per cent.

Rooftop solar quantity made relatively little difference to availability costs. Reducing the uptake rate of rooftop solar reduced the cost by around 5 per cent and increasing the uptake made no material difference to the availability cost.

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 and the associated disconnection contingency, only affect peak periods. The interactions with the battery outlined in section 4.1.1 indicate sensitivity to the inflection point in the offer curve, where prices dip below zero, that drive the price variation. The results of the sensitivity runs are summarised in Table 6.

The ‘unmodified generator data’ sensitivity ran generators without altering their offer curves to bid at the market floor or below their short run marginal cost through the mark-up 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 ‘mark-ups’ 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. Prices were around 45 per cent higher without the bidding behavioural elements altering generator offer curves (such as bidding generation at the market floor). Under the current WEM Rules, not all of this is avoidable because ancillary service quantities must be offered at the market floor to ensure they are in merit.

Relaxing the constraint on the quantity of ancillary services the battery can provide also increased the balancing market peak price outcomes. The greater the reserve quantity available to the battery, the higher the peak balancing price, but the lower the ancillary service cost. Removing the battery from the model reduced peak electricity prices (for reasons explained in section 4.1.1) but made marginal difference to off-peak electricity prices.

Gas prices also influenced the balancing market price in both peak and off-peak periods. Lowering the gas price reduced both the balancing market price and the ancillary service cost.

Table 6: Sensitivity analysis pricing outcomes

Sensitivity	Spinning reserve and load rejection reserve availability cost			Balancing market price			
	Total availability cost ($m)	Cost difference ($m)	Relative difference (%)	Peak price (S)	Relative difference (%)	Off-peak price ($)	Relative difference (%)
Base case	19.6	-		23.12		34.23	
No battery	18.4	(1.2)	(6)	13.75	(41)	32.90	(4)
Battery moderate AS	18.1	(1.5)	(7)	25.87	12	35.22	3

Sensitivity	Spinning reserve and load rejection reserve availability cost			Balancing market price			
	Total availability cost ($m)	Cost difference ($m)	Relative difference (%)	Peak price (S)	Relative difference (%)	Off-peak price ($)	Relative difference (%)
constraint (50% cap)							
Battery low AS constraint (90% cap)	17.2	(2.4)	(12)	28.40	23	36.39	6
Unmodified generator data	15.9	(3.6)	(18)	33.51	45	32.99	(4)
Low PV	18.2	(1.4)	(7)	24.36	5	34.51	1
High PV	19.1	(0.5)	(2)	23.55	2	34.16	0
$4 gas	15.2	(4.4)	(23)	17.57	(24)	26.22	(23)
$5 gas	16.2	(3.4)	(17)	20.66	(11)	30.15	(12)
$6 gas	21.8	2.2	11	22.56	(2)	33.53	(2)
No PV contingency	17.9	(1.7)	(9)	24.16	4	34.34	0

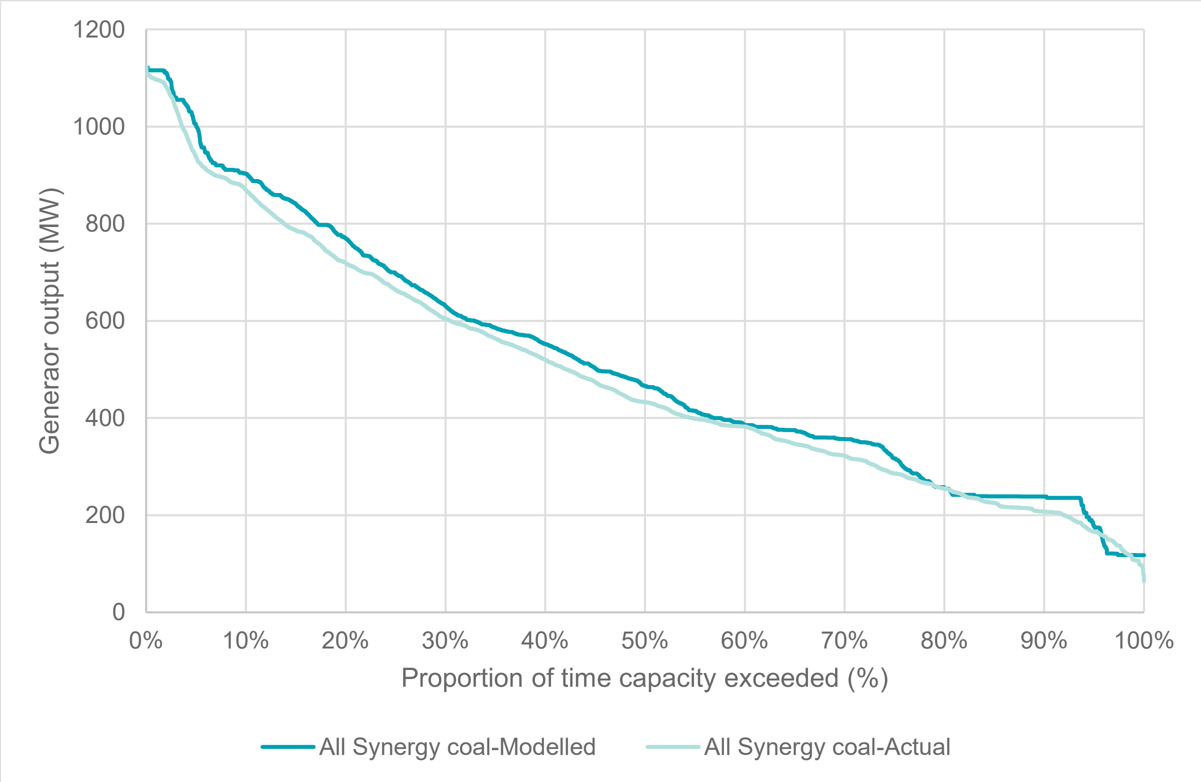
Source: ERA modelling

Dispatch outcomes

The data inputs were sourced directly from generators building on past data collections under market rule 2.16. This is considered the most reliable source of data collected. The sourced data have been complemented with other material available.

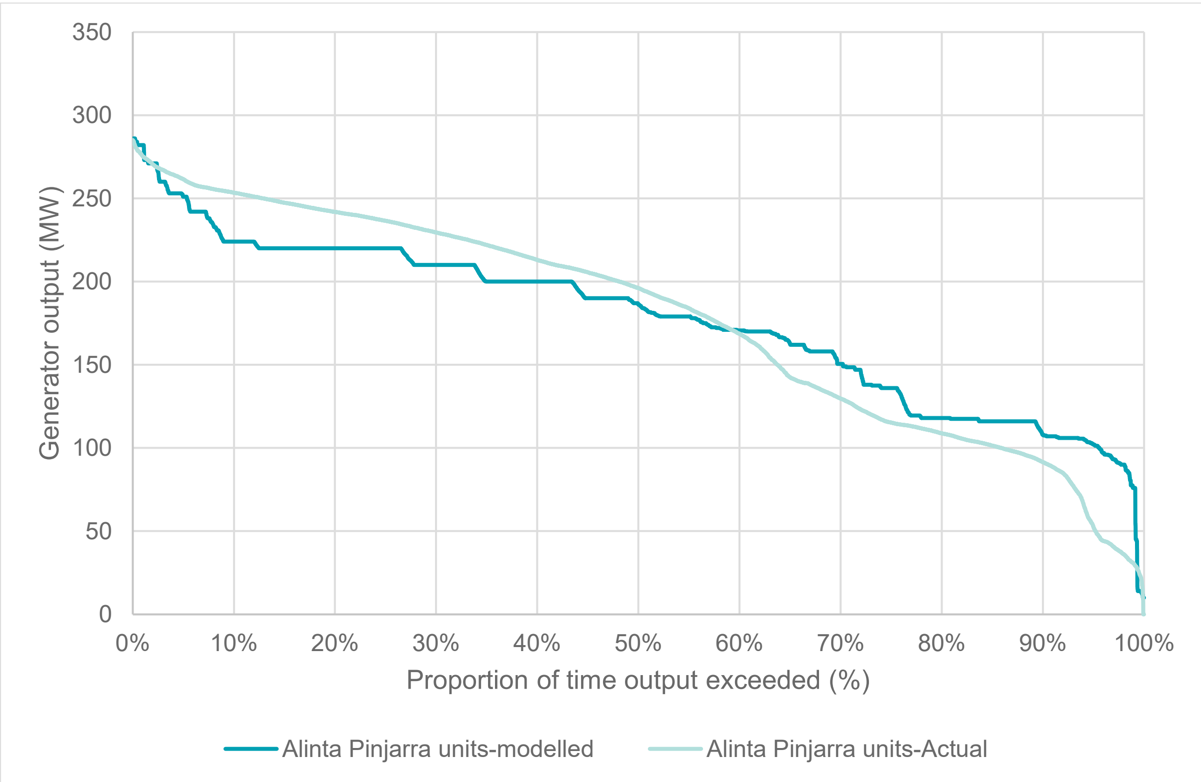
The following charts (Figure 14 to Figure 17) show the back-cast output duration curves for major generators in the WEM. The actual generator outputs for non-scheduled generators were used to isolate the environmental variables from the back-cast, and are therefore not shown here.

Figure 14: Back-cast output duration curve Synergy coal portfolio



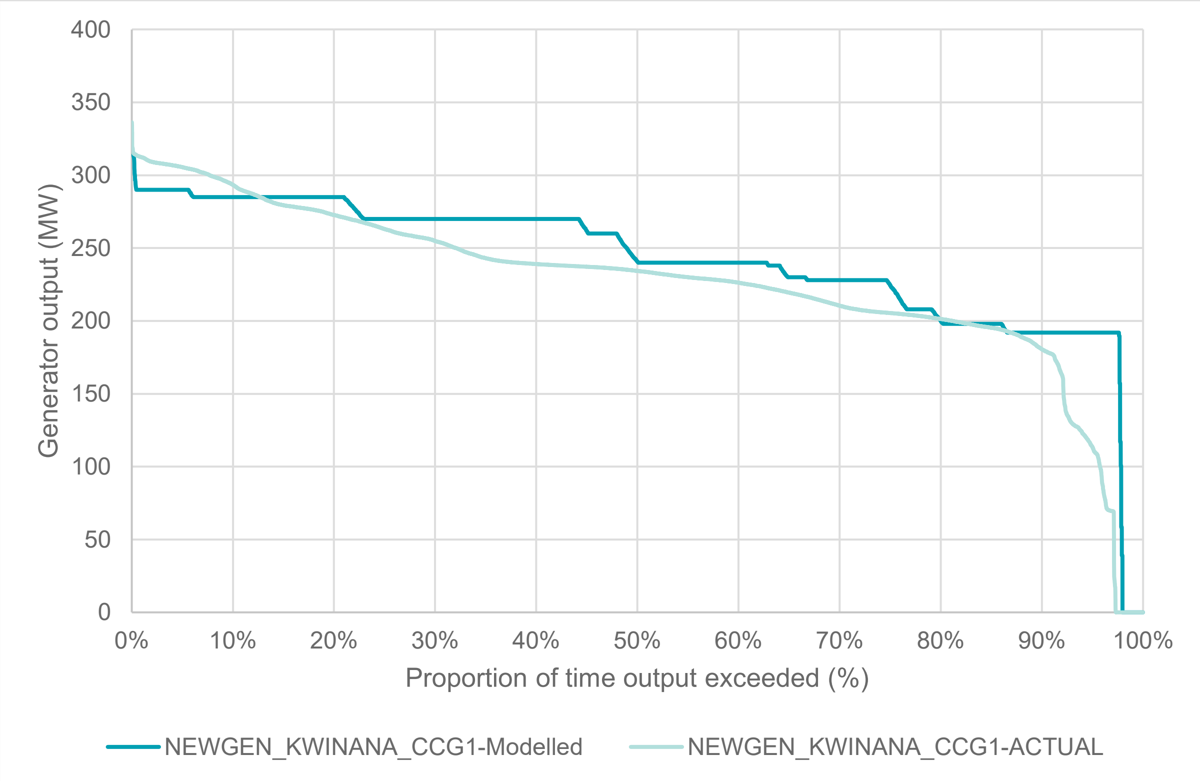
Source: ERA modelling and analysis of AEMO data

Figure 15: Back-cast output duration curve Alinta Pinjarra



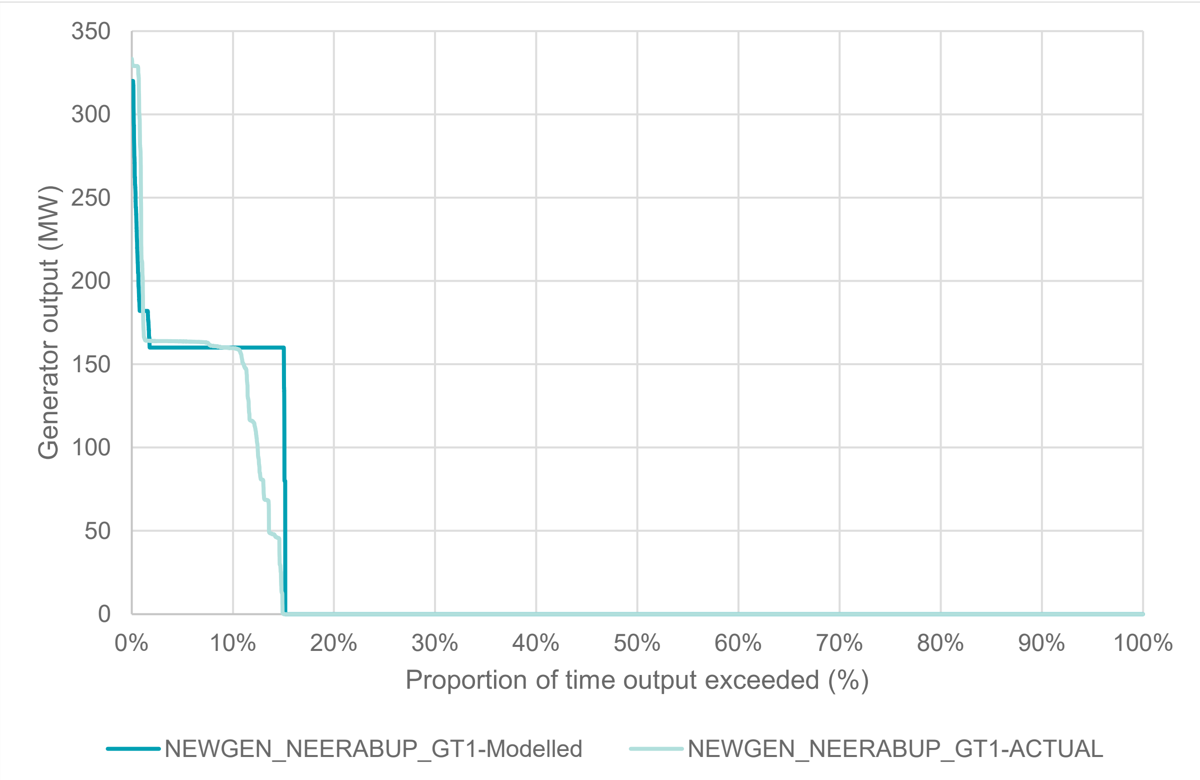
Source: ERA modelling and analysis of AEMO data

Figure 16: Back-cast output duration curve Newgen Kwinana



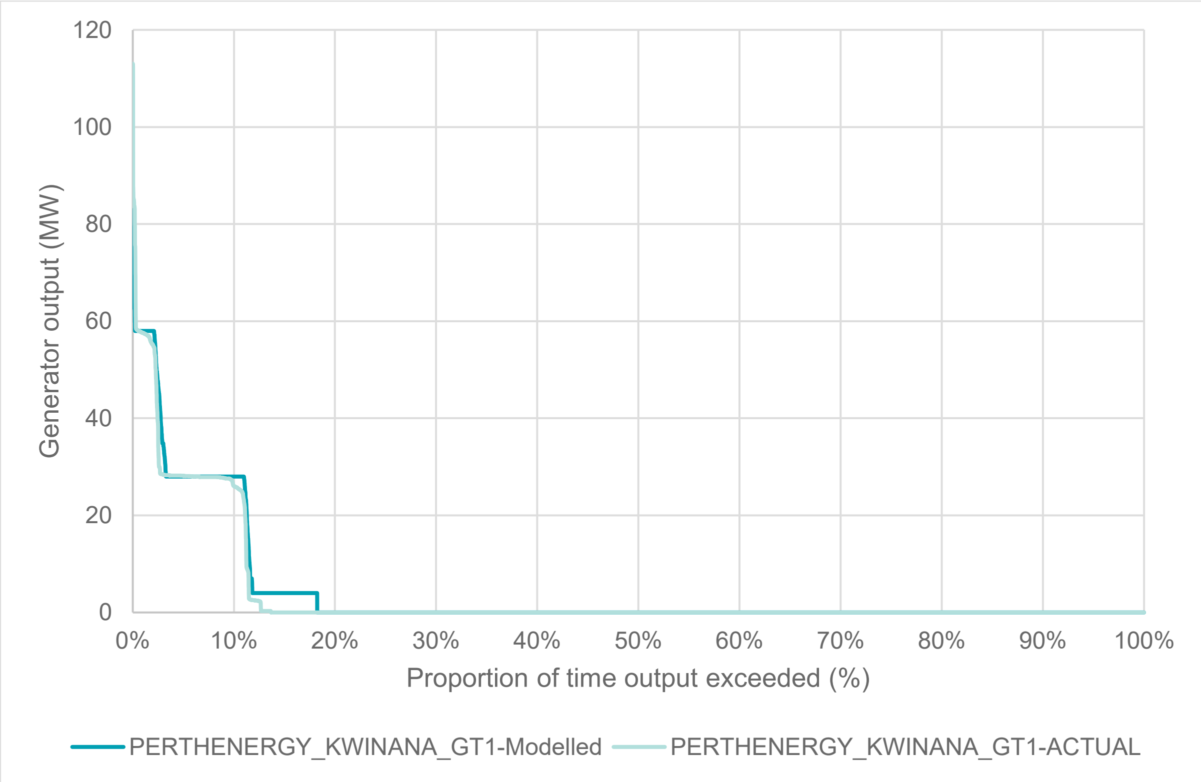
Source: ERA modelling and analysis of AEMO data

Figure 17: Back-cast output duration curve Newgen Neerabup



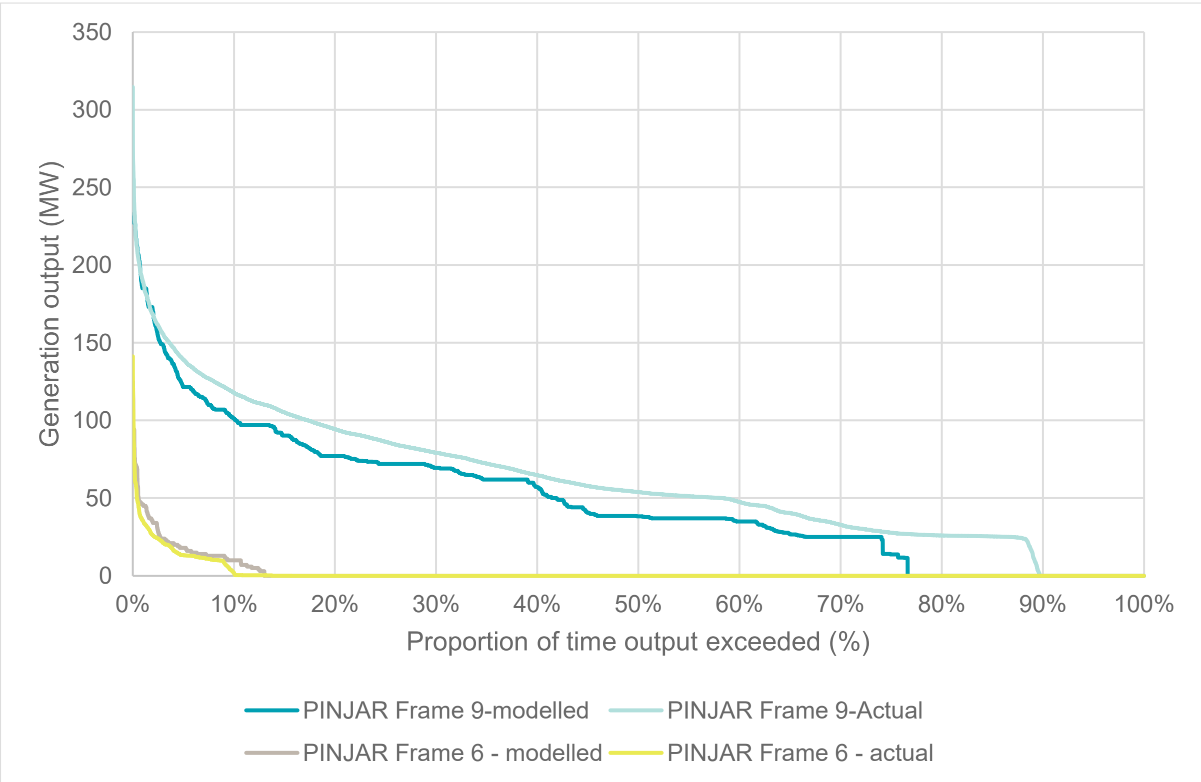
Source: ERA modelling and analysis of AEMO data

Figure 18: Back-cast output duration curve Perth Energy Kwinana Swift



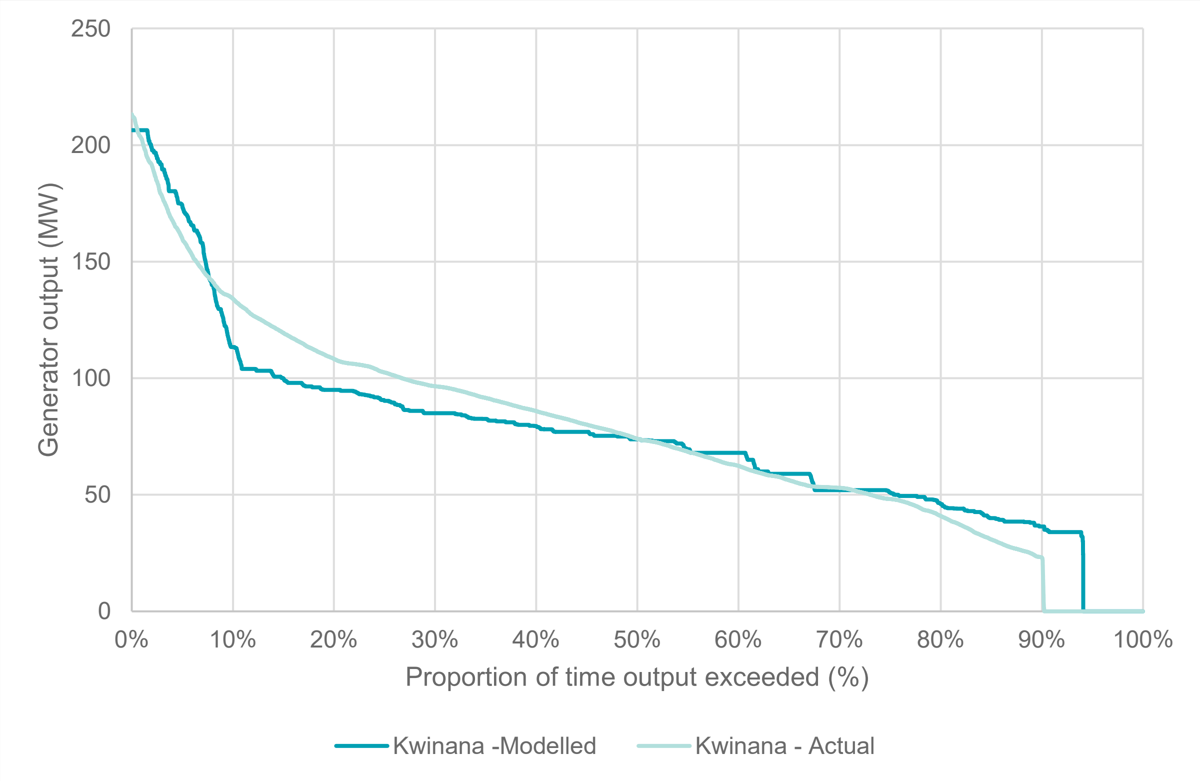
Source: ERA modelling and analysis of AEMO data

Figure 19: Back-cast output duration curve Synergy Pinjar



Source: ERA modelling and analysis of AEMO data

Figure 20: Back-cast output duration curve Kwinana HEGT



Source: ERA modelling and analysis of AEMO data

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 in the Pricing outcomes section 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.

The ERA is available to brief owners of generator assets on the modelling outcomes relevant to their generators during the consultation period.