Load rejection reserve service cost for 2019-20, 2020-21 and 2021-22

PUBLIC VERSION

Australian Energy Market Operator

13 December 2018

Building a better working world

Notice

Ernst & Young ("we" or "EY") has been engaged by the Australian Energy Market Operator ("you", "AEMO" or the "Client") to provide electricity market modelling services to assist AEMO in calculating a number of market parameters in accordance with the Western Australian Wholesale Electricity Market Rules (the "Services"), in accordance with our Assignment commencing 1 August 2018, under the Master Consultancy Agreement entered into by AEMO and EY commencing 5 December 2016.

The enclosed report (the "Report") provides an overview of the simulation model, the generic data inputs and assumptions used in the delivery of the Services, and the results of the work. The simulation model will form the basis for the outputs produced. It incorporates feedback other stakeholders received during a public consultation process. The modelling methodology and assumptions were agreed in consultation with AEMO.

The Report should be read in its entirety, including the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report. The Report has been constructed based on information current as of 13 December 2018 (being the date of completion of this Report), and which has been provided by the Client or other stakeholders, or which is available publicly. Since this date, material events may have occurred that are not reflected in the Report.

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Executive Summary

EY has been engaged by AEMO to provide electricity market modelling services to assist AEMO in calculating ancillary services parameters for the Wholesale Electricity Market (WEM) in Western Australia, in accordance with the Western Australian Wholesale Electricity Market Rules (Rules).

This report provides an overview of the assumptions, methods and results associated with the modelling of the 'L' parameter of Cost_LR, representing the costs associated with the load rejection reserve service (LRRS) for the period from 2019-20 to 2021-22 for the purposes of clause 3.13.3B(a) of the Rules.

AEMO is required to determine, procure, schedule and dispatch generation facilities to meet the LRRS requirement in accordance with the Rules. LRRS is the service of holding capacity associated with a scheduled generator or dispatchable load in reserve, so that the scheduled generator can reduce output rapidly or the dispatchable load can increase consumption rapidly, in response to a sudden decrease in system load.

Clause 3.13.3B[1] of the Rules specifies that "Cost_LR must cover the costs for providing the Load Rejection Reserve Service and System Restart Service".

- Generators that provide LRRS are compensated through the 'L' parameter. The 'L' parameter will be proposed for determination to the Economic Regulation Authority (ERA) in this report.
- Generators capable of providing system restart services, that is, generators that are capable of 'black-starting' for energising the transmission network and other generators following a system black out, are compensated through the 'R' parameter. The proposed 'R' parameter is not considered in this report and will be proposed by AEMO separately.

To calculate the 'L' parameter of Cost_LR, modelling has been undertaken to forecast the dispatch of generation to meet operational demand in each half-hour trading interval within the study period. In consultation with AEMO, dispatch algorithms have been applied that seek to emulate the operational decisions made by controllers to meet the LRRS requirement on a trading interval basis, taking into account the technical limits of generator units. Using information on individual generator unit costs, the outcomes of dispatch modelling can be used to estimate the costs incurred by facilities supplying LRRS.

Proposed 'L' parameter of Cost_LR

Table 1 summarises AEMO and EY's proposal for the 'L' parameter of Cost_LR.

Table 1: 'L' parameter of Cost_LR

Parameter	Units	2019-20	2020-21	2021-22
'L' parameter of Cost_LR	$	4,738,225	4,343,504	1,086,587

As part of this review, AEMO and EY investigated a number of potential costs associated with the provision of LRRS identified within the modelling processes. These costs are summarised as follows:

- **LRRS availability costs:** Costs of a facility providing LRRS not recovered through other market mechanisms. AEMO and EY consider that it is appropriate to account for this cost in the calculation of the 'L' component of Cost_LR as it is directly associated with the facility or facilities providing LRRS.
- **LRRS response costs:** Energy profits forgone by facilities providing LRRS during a load rejection event. AEMO and EY consider that it is appropriate to account for this cost in the

[1] Clause 3.13.3B refers to clause 3.11.8B of the Rules, but relates to contracts associated with Dispatch Support Services. This is not relevant for the purpose of this Project.

calculation of the 'L' parameter of Cost_LR as it is directly associated with the facility or facilities providing LRRS.

- **Other facility costs**: Energy profits forgone and de-commitment costs from facilities not providing LRRS. AEMO and EY do not consider that it is appropriate to account for this cost in the calculation of the 'L' parameter of Cost_LR as it is not considered a cost that is directly associated with providing LRRS.

Drivers of LRRS costs

The key drivers contributing to LRRS costs are discussed below.

Muja power station

The Muja power station plays a significant role in providing LRRS in the WEM, and future decreasing utilisation is likely to increase the occurrences where AEMO is required to dispatch facilities specifically to meet the LRRS requirement. Dispatch simulations forecast a declining capacity factor for Muja C/D in 2020-21 but increasing in 2021-22 as a result of two main drivers in the application of the modelling:

1. **Outages:** Given that LRRS is made available from dispatch of the Muja power station, any planned (or unplanned) outages of these units removes LRRS provided. As part of the public consultation process, Synergy submitted a number of modelled outages for inclusion in this review. These outages were for the 2019-20 and 2020-21 year. No modelled planned outages were submitted for inclusion in the 2021-22 year resulting in a higher availability of Muja units in that year.
2. **New entrant renewables:** The merit order effect caused by new entrant generation connecting to the WEM places downwards pressure on the utilisation of Muja power station. The assumed connection of Alinta Energy's 210 MW Yandin wind farm in 2020-21 contributes to decreasing Muja utilisation through the provision of low cost generation in the WEM, placing downwards pressure on baseload utilisation. It is noted that the 2021-22 year does not contain new entrant market generators connecting to the WEM.

Future drivers of LRRS costs

New entrant market generators

A potential driver of increased LRRS shortfalls in future years is the connection of large- scale renewable generation projects in 2019-20 and 2020-21. By the end of the study period, 520 MW of new entrant renewable generation projects is assumed to be connected in the SWIS. A total of 310 MW of installed capacity is assumed to be connected in 2019-20 and a further 210 MW of generation is assumed to be connected in 2020-21. No new entrants are forecast in 2021-22.

New entrant renewable generation has an incentive to offer their available capacity into the balancing market based on the value for LGC's in the contract market. This results in an additional revenue stream from the creation of Large-scale Generation Certificates (LGC) and may result in a significant amount of new low cost generation competing for dispatch during low demand periods.

Interaction with the LFAS market

There are currently three primary units participating in the LFAS market, with the enablement of units for the purpose of LFAS directly impacting the provision of load rejection reserve.

The dispatch of Kwinana GT2 and GT3 for the enablement of 72 MW of LFAS down will provide LRRS capability. When either of these are on outage, other gas units such as Pinjar units may provide the service.

However, in trading intervals where an independent power producer (IPP) facility is cleared in the LFAS market, Synergy units providing LFAS will likely be dispatched at lower output levels depending on requirements in the energy market, and for the provision of the outstanding LFAS quantity. As such, LRRS contribution to load rejection reserve is reduced in trading intervals where IPP facilities are cleared for LFAS.

The outcome of this interaction is that increasing competition for the provision of LFAS is likely to decrease the LRRS that is also provided by the LFAS market, if new entrant LFAS providers are not capable of providing LRRS. Given the relatively few baseload generator units that are capable of providing LRRS, there may be benefit in exploring whether other facilities may be capable of providing LRRS.

1. Introduction

1.1 Background

EY has been engaged by AEMO to provide electricity market modelling services to assist AEMO in calculating ancillary services parameters for the Wholesale Electricity Market (WEM) in Western Australia, in accordance with the Western Australian Wholesale Electricity Market Rules (Rules).

This report provides an overview of the assumptions, methods and results associated with the modelling of the 'L' parameter of Cost_LR, representing the costs associated with the load rejection reserve service (LRRS) for the period from 2019-20 to 2021-22 for the purposes of clause 3.13.3B(a) of the Rules.

Clause 3.13.3B of the WEM Rules requires AEMO to submit proposed Cost_LR values for the period to the Economic Regulation Authority (ERA) by 30 November 2018 and the ERA to determine the Cost_LR values for those financial years by 31 March 2019.

The report includes an overview of the submissions received during the consultation that followed AEMO's publication of the Draft Assumptions Report dated 13 September 2018. A summary of how feedback has been considered and incorporated is provided in Section 1.5.2 below.

In preparing this report, we started with an initial set of assumptions and method selected by AEMO in consultation with EY. The assumptions and method have since been updated on the basis of stakeholder submissions and new information received during the public consultation process. We note that there is a significant range of alternative assumptions that, in isolation or in aggregate, could transpire to produce outcomes that will differ to those that were modelled.

All prices in this report refer to real June 2018 dollars unless otherwise stated. All annual values refer to the financial year (1 July – 30 June) unless otherwise labelled.

1.2 Load Rejection Reserve Service

AEMO is required to determine, procure, schedule and dispatch generation facilities to meet the LRRS requirement in accordance with the Rules. LRRS is the service of holding capacity associated with a scheduled generator or dispatchable load in reserve, so that the scheduled generator can reduce output rapidly or the dispatchable load can increase consumption rapidly, in response to a sudden decrease in system load. LRRS response is required in two categories of either 6 seconds or 60 seconds.[2]

In setting the ancillary service requirements, AEMO must consider the ancillary service standards and the South-West Interconnected System (SWIS) operating standards as defined in the Rules. That is, the level of LRRS must be sufficient to keep system over frequency below 51 Hz for all credible load rejection events.

The largest credible load rejection event is typically set as the loss of a network transmission element (for example, the loss of the 220 kV transmission circuit supplying the Eastern Goldfields region). This value has been proposed to be 120 MW by AEMO.[3] This may be relaxed by up to 25% (setting a requirement of 90 MW) by AEMO where it considers the probability of a network transmission fault is low. Nevertheless, AEMO plans to procure 120 MW of LRRS in all trading

[2] AEMO have advised that the manual tripping of a generator cannot be guaranteed in the required time frames. AEMO considers that this is not an acceptable means of planning to provide LRRS. In section 2.4 of AEMO's Ancillary Service Report for the WEM 2018-19 reference is made to possible contingent action of tripping a generator should there be insufficient LRRS available. AEMO does not consider tripping of generation to be providing the service.

[3] Section 4.3 of AEMO's Ancillary Service Report for the WEM 2018-19.

intervals. AEMO has advised that the manual tripping of generation does not contribute to LRRS due to their response times not complying with the required timeframes.

1.3 Provision of LRRS

There is currently no competitive market for the provision of LRRS, with Synergy acting as the default service provider. AEMO may contract with a rule participant to provide this service.[4] AEMO must seek to minimise the cost of meeting its obligation to schedule and dispatch facilities to meet the ancillary service requirements in each trading interval[5]. No contracts have been procured for LRRS historically.

Synergy acts as the default provider of LRRS through generators that are physically capable of providing the service in the Synergy balancing portfolio. Generators are not explicitly enabled to provide this service, but dispatch may be managed to ensure generator output is in the correct range for sufficient LRRS to be available taking into account their minimum stable generation value.

LRRS costs are currently borne by Synergy as the default service provider as part of obligations set out in the Rules.[6] Synergy is required to make its capacity to provide LRRS available to AEMO to enable AEMO to meet obligations prescribed in the Rules. In offering generation capacity for the purpose of LRRS, Synergy must offer capacity at the price cap.

1.4 Cost_LR parameter

Clause 3.13.3B[7] of the Rules specifies that "Cost_LR must cover the costs for providing the Load Rejection Reserve Service and System Restart Service".

- Generators that provide LRRS are compensated through the 'L' parameter. The 'L' parameter will be proposed for determination to the ERA in this report
- Generators capable of providing system restart services, that is, generators that are capable of 'black-starting' for energising the transmission network and other generators following a system black out, are compensated through the 'R' parameter. The proposed 'R' parameter is not considered in this report and will be proposed by AEMO separately.

The ERA's 2016 Determination paper[8] determined an annual cost for the 'L' parameter of Cost_LR to be $1.4 m for the period from 2016-17 to 2018-19. Prior to 2016-17, the 'L' parameter of Cost_LR has been determined to be zero.

Providers of LRRS are paid through monthly ancillary service settlement calculations determined by AEMO using the Cost_LRD parameter, which is an administered market parameter determined by the ERA for the review period defined in clause 3.13.3B of the Rules. The cost of providing LRRS is borne by market customers.[9]

The Cost_LRD parameter is used for two purposes in the ancillary service settlement amount calculation specified in clause 9.9.1 of the Rules:

- Synergy's ancillary service provider payment calculation, for services associated with LRRS, system restart services and dispatch support services, in accordance with clause 9.9.1 of the Rules, which specifies that for trading month (m):

[4] Rule 3.11.8A.
[5] Rule 3.11.9.
[6] Rule 3.11.7A.
[7] Clause 3.13.3B refers to clause 3.11.8B of the Rules, but relates to contracts associated with Dispatch Support Services. This is not relevant for the purpose of this review
[8] Economic Regulation Authority, *Determination of the Ancillary Service Cost_LR Parameters for 2016/17 to 2018/19*, Western Australia, March 2016.
[9] Clauses 3.13 and 9.9 of the Rules.

"the Synergy AS Provider Payment(p,m) = 0 if Market Participant p is not Synergy and (SR_Availability_Payment(m) + Cost_LRD(m) – ASP_Balance_Payment(m)) otherwise" [10]

- Calculating the cost borne by market participants according to the proportion of their consumption according to clause 9.3.7.

Cost_LRD is specified in clause 3.22.1(g) of the Rules, which states:

"Cost_LRD as the sum of:

(i) Cost_LR (as described in clauses 3.13.3B and 3.13.3C) divided by 12 as a monthly amount; and

(ii) the monthly amount for Dispatch Support Service" [11]

1.5 Cost_LR calculation

1.5.1 Summary

To calculate the 'L' parameter of Cost_LR, modelling has been undertaken to forecast the dispatch of generation to meet load demand in each half-hour trading interval within the study period. In consultation with AEMO, dispatch algorithms have been developed that seek to emulate the operational decisions made by controllers to meet the LRRS requirement on a trading interval basis, taking into account the technical limits of generator units. Using information on individual generator unit costs, the outcomes of dispatch modelling can be used to estimate the costs incurred by facilities supplying LRRS. Further information is provided in this report.

1.5.2 Public consultation process

As part of this ancillary service parameter review, a period of public consultation was conducted based on the following published reports:

- **2018 WEM Modelling and Backcasting Report – 31 August 2018.** This report provides an overview of the model used to simulate generator dispatch in the WEM, including key inputs used in the modelling and outputs derived from it. The report also outlines the results of the backcasting exercise to demonstrate modelling outputs against historical dispatch and balancing price outcomes.
- **2018 Draft Assumptions Report – 14 September 2018.** This report details the facility and market- related assumptions that were, at the time the report was published, proposed for market modelling of the Margin_Peak, Margin_Off-Peak, SR_Capacity_Peak, SR_Capacity_Off-Peak and the Cost_LR values. AEMO invited submissions from stakeholders seeking feedback on facility parameters and market-related assumptions provided in the report.

AEMO and EY also conducted a stakeholder consultation workshop on 18 September 2018 where EY presented both reports to attendees. EY outlined the assumptions and the key modelling methodologies to be employed.

One public submission and one confidential submission was received.

Synergy provided a public submission[12] to AEMO regarding the constrained-on payment mechanism and its interaction with the Cost_LR parameter.

[10] SR_Availability_Payment(m) is defined in clause 9.9.2(g) and ASP_Balance_Payment(m) is the total payment to Market Participant p for Contracted Ancillary Services in Trading Month m, determined in accordance with clause 9.9.3.
[11] Dispatch Support Services (DSS) are not considered in this review. AEMO does not have any DSS contracts at present.
[12] Ancillary service parameters

As part of the publication of the Draft Assumptions Report, a methodology was proposed for the calculation of the Cost_LR parameter that considered the interactions between the market parameter and the constrained-on payment mechanism leading to an initial proposal of zero for the 'L' parameter of Cost_LR. Synergy expressed the view that their costs of providing LRRS are not adequately recovered through constrained-on payments and that the 'L' parameter of Cost_LR is an appropriate mechanism to recover costs going forward. This is discussed in section 1.5.3.

A market participant provided a confidential submission with respect to fuel costs. This is discussed in section 3.2.3 on gas prices.

1.5.3 Approach

AEMO and EY investigated the comments made by Synergy and conducted an examination of the fundamental principles of the Cost_LR market mechanism in the context of the design of the WEM. Consideration has been given to the role of AEMO in procuring sufficient LRRS and the interactions of the Cost_LR parameter with other market mechanisms. The key points of the assessment are listed below in Table 2.

Table 2: Summary of key points in considering the Cost_LR market mechanism in the WEM

Key point	Rule reference	Rule text
AEMO is required to schedule and dispatch facilities to meet ancillary service standards in the WEM.[13]	3.12.1	"AEMO must schedule and dispatch facilities (or cause them to be scheduled and dispatched) to meet the Ancillary Service Requirements in each Trading Interval in accordance with Chapter 7."
Synergy (in respect of its facilities, including but not limited to the Balancing Portfolio) are the default provider of ancillary services in the WEM.	3.11.7A	"Synergy must make its capacity to provide Ancillary Services from its facilities available to AEMO to a standard sufficient to enable AEMO to meet its obligations in accordance with these Market Rules."
AEMO may enter into a contract with a rule participant but must seek to minimise the cost of meeting its obligations to schedule and dispatch facilities to meet the ancillary service requirements.	3.11.8A 3.11.9	"AEMO may enter into an Ancillary Service Contract with a Rule Participant for Load Rejection Reserve Service, System Restart Service or Dispatch Support Service. Where it intends to enter into an Ancillary Service Contract, AEMO must: (a) seek to minimise the cost of meeting its obligations under clause 3.12.1; and (b) give consideration to using a competitive tender process, unless AEMO considers that this would not meet the requirements of clause 3.11.9(a)."

[13] The following are the defined Ancillary Services in the WEM, as listed in section 3.9 of the Rules. Ancillary Services include Load Following Service, Spinning Reserve Service, Load Rejection Reserve Service, Dispatch Support Services; and System Restart Services.

Key point	Rule reference	Rule text
When providing LRRS, Synergy must ensure that the quantities for provision of this service are priced at the price caps. Specifically for LRRS, this requires quantities priced at the Minimum STEM Price, irrespective of the short run marginal cost (SRMC) for the facilities.	7A.2.9.	"Synergy, in relation to the Balancing Portfolio: (c) must: i. ensure that quantities in the Balancing Portfolio Supply Curve that are required for the provision of Ancillary Services, other than LFAS, are priced at the Price Caps, to reflect that these quantities are not generally available for Balancing; ii. advise AEMO in a manner and form prescribed by AEMO, the Facilities which are likely to provide the quantities specified in clause 7A.2.9(c)(i); and iii. for each completed Trading Interval, advise AEMO which Facilities actually provided the Ancillary Services referred to in clause 7A.2.9(c)(i) in the Trading Interval."

Based on the above points, Synergy may be required to bid a portion of its facilities below its SRMC (i.e. higher cost facilities committed at the Minimum STEM Price) as a result of being the default provider for LRRS. Depending on the balancing price, Synergy may not recover its operating costs for providing this service.

For these reasons, this report will consider that the Cost_LR parameter is the appropriate mechanism to compensate Synergy for its cost in providing LRRS. We note this differs from the approach outlined in the Draft Assumptions Report.[14]

1.5.4 Cost of providing LRRS

Clause 3.13.3B of the Rules specifies that "Cost_LR must cover the costs for providing the Load Rejection Reserve Service". As part of this review, AEMO and EY investigated a number of potential costs associated with the provision of LRRS identified within the modelling processes. These costs are summarised in Table 3.

[14] Draft Assumptions Report

Table 3: Summary of costs that may be incurred as a result of providing LRRS

Description	Inclusion	Justification
LRRS availability costs – Costs of a facility providing LRRS not recovered through other market mechanisms Synergy are required to offer the quantity that is capable of providing LRRS at the minimum STEM price to ensure this service will always be dispatched. As such, facilities within the balancing portfolio may be compensated at a balancing price (or LFAS price) below their SRMC to meet the LRRS requirement.	Included	AEMO and EY consider that it is appropriate to account for this cost in the calculation of the 'L' parameter of Cost_LR as it is directly associated with the facility or facilities providing LRRS.
LRRS response costs – Energy profits forgone by facilities providing LRRS during a load rejection event A generating unit may be instructed to curtail its generation output in response to an actual load rejection event and as a result would incur forgone energy profit.	Included	The Rules considers the quantity of energy reduction provided by a facility for load rejection due to a load rejection reserve event is non-qualifying constrained off generation. AEMO and EY consider that it is appropriate to account for this cost in the calculation of the 'L' parameter of Cost_LR as it is directly associated with the facility or facilities providing LRRS.
Other facility costs – Energy profits forgone and de-commitment costs from facilities not providing LRRS There are potential energy profits forgone (or de-commitment costs) from facilities that are not dispatched due to Synergy being the default provider of LRRS. For example, if a generator unit is ramped down (or de-committed), to maintain supply demand balance in response to another unit providing LRRS, there may be energy profits that are foregone.	Excluded	AEMO and EY do not consider that it is appropriate to account for this cost in the calculation of the 'L' parameter of Cost_LR as it is not considered a cost that is directly associated with providing LRRS. The modelling approach is to consider a preliminary dispatch scenario to meet energy and other ancillary service requirements prior to meeting LRRS requirements. In reality, AEMO dispatches to meet ancillary service requirements first and the dispatch of units for energy is subsequent to this. Some facilities will be dispatched in the preliminary dispatch scenario but will not be required once LRRS requirement is met. This can impact any participant, not just Synergy. IPPs are not compensated for this. As a point of comparison, the methodology used for latest margin values determination (2018-19) has only considered costs associated with facilities directly providing the services.

1.6 Report structure

The following summarises the structure of the remainder of this report:

- Section 2 presents an overview of modelling the WEM
- Section 3 provides a summary of the final market-related assumptions used as inputs in the modelling
- Section 4 details the calculation of costs and the modelling methodology applied
- Section 5 details the results of the modelling simulations
- Section 6 discusses specific aspects of the modelling in greater detail
- Appendix A summaries the consultation process
- Appendix B describes the plant parameters used with the market simulation model. Specific values have been redacted due to confidentiality
- Appendix C specifies planned maintenance periods
- Appendix D details the unit re-dispatch merit orders
- Appendix E provides the facility maximum LRRS capability.

2. Modelling the Wholesale Electricity Market

2.1 Wholesale electricity market modelling

Wholesale electricity market modelling in this review is conducted using EY's in-house market dispatch modelling software 2-4-C®. 2-4-C® seeks to replicate the functions of the real-time dispatch engines used in wholesale electricity markets with dispatch decisions based on market rules, considering generator bidding patterns and availabilities to meet regional demand in a period.

The WEM is modelled as a single node gross pool dispatch energy market. Modelling for this review is on a trading interval (30 minute) granularity in a time-sequential manner. This captures the variability of renewable generation, thermal unit outages (both unplanned and planned) and ramp rate limitations as well as the underlying changes to system demand.

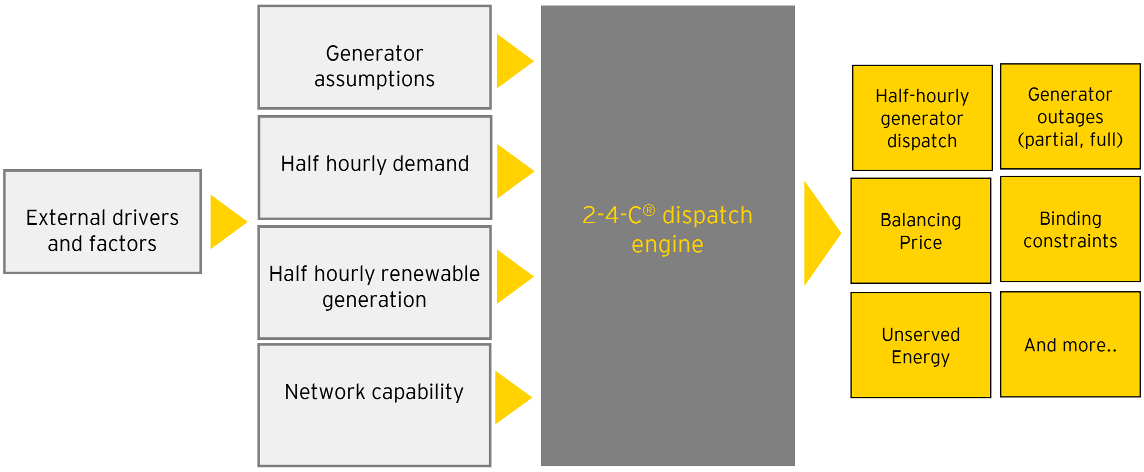
At a high level, for each trading interval in the defined study period, 2-4-C® simulates the dispatch of generators to meet a forecast load demand target subject to defined constraints. Constraints in the model can represent a range of physical limits associated with network power transfer limits, generator plant capability, contractual supply limits and more.

Each generator unit is modelled individually. The outputs that are reported from the model include the output of each generator (in MW or GWh), the loss factor adjusted market clearing price[15] (in $/MWh), presence of unserved energy (USE)[16] and generator availability amongst many other metrics.

2.2 Data and input assumptions

In practice, electricity market modelling of this nature is highly complex and involves establishing a large set of data and input assumptions that are often inter-related. These input assumptions can be grouped into four general categories which are described at a high level below. Figure 1 provides a high level overview in diagram form, including categorising the input assumptions in four categories.

Figure 1: Simplified high level overview of the inputs and outputs to 2-4-C®



[15] The balancing price, constrained by maximum and minimum energy price limits.

[16] Unserved energy can be the result of voluntary or involuntary load shedding. Voluntary load shedding is modelled as demand side participation offering into the market as a response to high pricing events. Involuntary load shedding is the result of insufficient capacity to meet the load demand in a trading interval, requiring system load to be curtailed and occurs as a last resort.

The following points describes the four types of input assumptions in Figure 1:

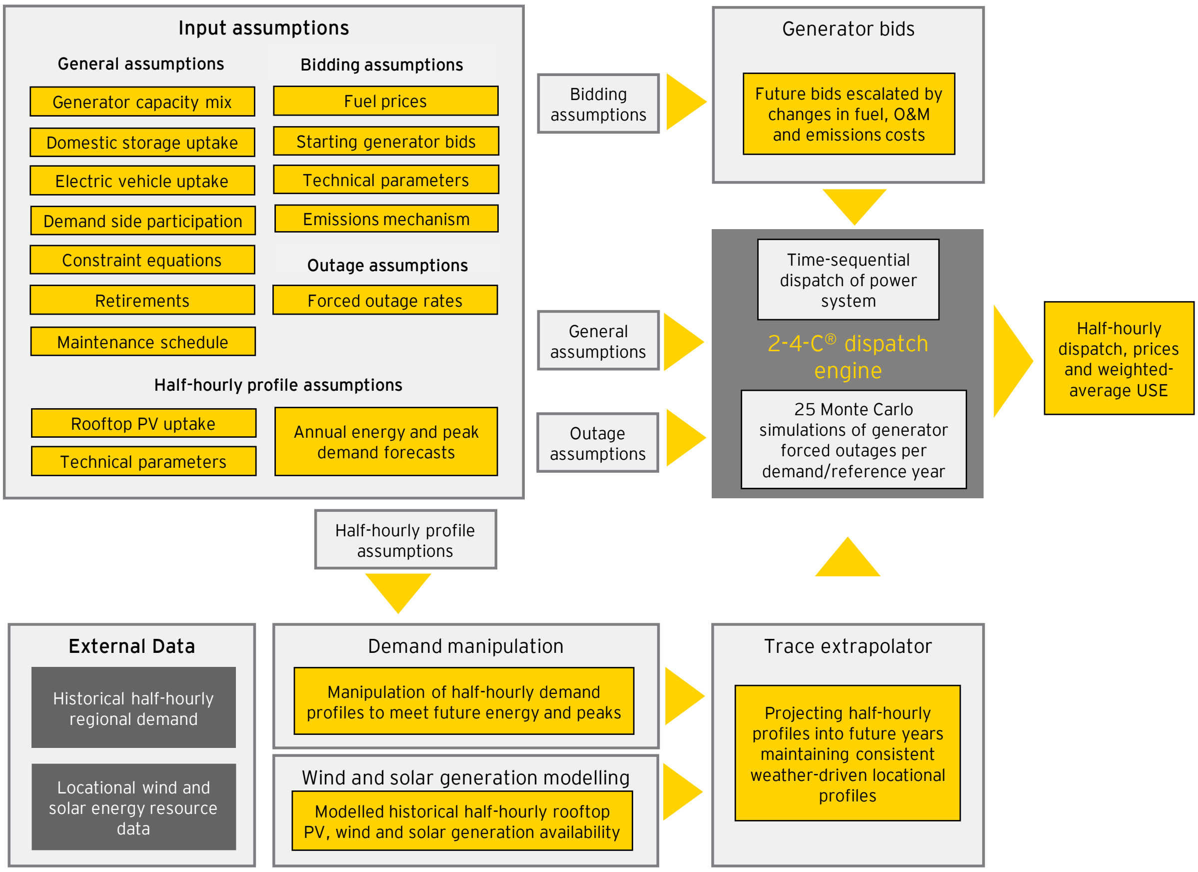
- Generator assumptions are the relevant technical and cost parameters for each existing and new entrant generator in 2-4-C®. These assumptions include generator bidding profiles, generator heat rates, ramp rates, fuel costs, fixed and variable operating and maintenance costs, emissions factors, outage rates (including mean time to repair and mean time to fail), marginal loss factors, planned maintenance periods, new entrant technology capital costs and more.
- Half-hourly demand involves using half-hourly data trace based on assumptions of peak demand and annual energy projections, historical half-hourly demand, the uptake of rooftop solar PV, electric vehicles (EVs) and behind-the-meter battery storage, using data sourced primarily from the AEMO 2018 Western Australia Electricity Statement of Opportunities (ESOO).[17] EY's half-hourly profile modelling tools combine these together to produce forecasts of the future half-hourly demand.
- Network capability defining power transfer limits and network limitations that constrain the physical dispatch of generator units and dispatchable loads. In actual market dispatch and 2-4-C®, these are typically implemented in the form of network constraint equations.[18] However, the WEM currently operates without network constraint equations implemented in generation dispatch processes. Management of network constraints is currently facilitated by a number of post-contingent generation curtailment schemes and manual intervention by AEMO if required.
- Renewable generation modelling involves developing half-hourly available generation profiles for each modelled wind or solar farm. The input assumptions and data include historical wind and solar resource data that is used to create expected/historical annual energy production.[19]

Some of the input assumptions are processed in models external[20] to the 2-4-C® dispatch software to determine the quantities to be used.

[17] AEMO Electricity Statement of Opportunities.
[18] A network constraint equation is used by the dispatch engine to manage power flows across the transmission network by dispatching generation on or off for a particular constraint. The WEM does not automatically apply network constraint equations in dispatch, however, the Public Utilities Office reform packages are expected to be in place by 2022. This falls outside the study period of this review.
[19] Landfill/biomass generators are treated as thermal generators.
[20] An example of an external assumption not used directly in the dispatch modelling for the WEM is the Reserve Capacity Requirement. This may impact forward looking generator capacity requirements by setting the Capacity Credit requirement and the surplus used in calculating the Reserve Capacity Price. However, it is not explicitly used in dispatch modelling.

Figure 2 shows a detailed flow diagram detailing the interactions between 2-4-C®.

Figure 2: Data flow diagram for the market simulations



2.3 Simulation parameters

The potential for any particular outcome in the electricity market is probabilistic. Various combinations of prevailing customer demand, availability and costs of conventional and intermittent generation, energy storage devices, demand side participation, transmission network capability and generator availability will influence market outcomes.

Within a single scenario, Monte Carlo simulations of generator outages, multiple reference years of historical data and consideration to probability of exceedance (POE) peak demand forecasts can be taken into account. This captures the probabilistic nature of key half-hourly variations in the market in the overall outcomes reported.

Each Monte Carlo simulation iteration has modelled a different series of unplanned generator outage events according to outage rates specified by unit technology.

For this review, a total of 50 Monte Carlo iterations of generator outages have been modelled. EY has modelled 25 iterations of simulations in each of the two reference years modelled, using the 50% POE demand forecast. The 50% POE demand forecast represents AEMO's expected outcomes for the study period.

Table 4 provides a summary of key simulation parameters.

Table 4: Simulation parameters

Simulation parameter	Description
Demand profiles	For each future simulation year the 50% POE values for each forecast year were modelled in a half-hourly time sequential series.
Reference years	The 2015-16 and 2016-17 reference years were modelled. Different reference years have variability in terms of the half-hourly demand shapes, wind and solar profiles according to the weather patterns in those years.
Monte Carlo iterations	On the demand profile EY modelled 50 Monte Carlo iterations[21] of thermal generator outages (full and partial unplanned outages).
Results	All results are provided as a weighted average over all 50 iterations. These iterations are made up of 25 iterations, for each of the two reference years modelled, using a single demand profile.
Study period	The study period is from 2019-20, 2020-21 and 2021-22.

2.4 Back-casting of simulation results

As part of the review, EY performed a back-cast of its half-hourly modelling of the WEM. The objective of the back-cast was to devise suitable bidding profiles for each generator to emulate its dispatch patterns in an historical year to demonstrate the computational and mathematical accuracy of the model. Further information can be found in EY's 2018 WEM Modelling and Back-casting Report.

2.5 Dispatch

2.5.1 Overview of Dispatch Process

The dispatch of generation facilities is based on meeting operational demand in each trading interval, based on price quantity pairs offered into the market, subject to generator plant capability and availability, with the objective of minimising cost of generation supply.

Bidding profiles are devised to emulate dispatch priorities associated with providing energy and ancillary services. For the purpose of this review and calculating the theoretical cost of meeting LRRS, the model has been configured with short run-marginal cost (SRMC) bids, with the majority of available capacity offered in at SRMC to determine a theoretical least cost dispatch pattern. Specific departures exist for generator units providing ancillary services.

- Generators that provide load following ancillary services (LFAS) are offered at the price caps to ensure that they are dispatched accordingly. IPP facilities that provide LFAS offer their LFAS quantity based on a historical offer profile.
- Contracted spinning reserve providers offer their capacity at the ceiling price effectively reserving a portion of their capacity for spinning reserve.
- Coal units offer the capacity that is technically capable of providing load rejection at the floor price, to ensure they are dispatched, subject to availability.

[21] 50 iterations of Monte Carlo simulations produces converged dispatch outcomes suitable for the purposes of the modelling

- All other coal units offer their minimum generation load at a low price to avoid unit cycling and for spinning reserve purposes.

2.5.2 Planning for LRRS on the weekend

The dispatch model used in this review performs dispatch on a single trading interval (30 minute) basis in a time-sequential manner. The model has not been configured to consider the outcomes of future trading intervals for unit commitment decisions. The LRRS model however implements this to some degree by identifying consecutive future trading intervals where there is load rejection shortfall and where there is insufficient ramp down capability to maintain supply demand balance when responding to a load rejection shortfall. In such a scenario, to meet the LRRS standard, where the required quantity to ramp down causes a generator unit to fall below its minimum stable operating load, the LRRS model may de-commit a unit to ensure that energy balance is maintained and the LRRS standard is met.

In the rare circumstance a unit is considered for de-commitment, AEMO has defined de-commitment windows to be:

- Friday, 22:00 to Saturday, 04:00
- Saturday, 22:00 to Sunday, 04:00

If there are two or more consecutive trading intervals with a modelled LRRS shortfall in a de-commitment window, a unit is de-committed within the Synergy portfolio until 03:00 on the next business day (accounting for public holidays). In the event of a modelled de-commitment, any energy shortfall is assumed to be met by the Synergy balancing portfolio.

3. Market related assumptions

The key market related assumptions applied in the modelling for the 'L' parameter of Cost_LR are summarised in Table 5. Additional information is provided below.

Table 5 Overview of key market related assumptions

Input assumption	Description of data source and value
Energy, Rooftop PV, Behind-the-meter storage, Electric vehicles, Industrial demand	AEMO 2018 WEM Electricity Statement of Opportunities (ESOO) Expected Scenario. 50% Probability of Exceedance (POE) for peak demand.
New entrant market generators	SWIS renewable planting based on information available via capacity credit accreditation process and a submission from a market participant discussed in section 3.2.1.
Generation retirements	Synergy's announced 380 MW base retirement schedule, as specified in section 3.2.2.
Fuel prices (gas and coal)	Contract fuel prices as provided by market participants, summarised in Appendix B.
Demand response	DSM capacity to be modelled as per AEMO 2018 WEM ESOO with 57 MW in 2018-19 and 66 MW from 2019-20 onwards for the duration of the study period.
Auxiliary factors	As provided by market participants, summarised in Appendix B.
Planned maintenance	A combination of typical maintenance schedules for technology types and specific planned maintenance for unit generators detailed in Appendix C.
Spinning reserve contracts	Bluewaters is assumed to be contracted for 13 MW of spinning reserve across each unit (26 MW in total) with the contracted capacity withheld at the price cap. Interruptible load contracts are assumed to total 42 MW.

3.1 Demand modelling

Demand assumptions used in modelling include annual energy projections, peak demand, the uptake of rooftop solar PV, electric vehicles (EVs) and behind-the-meter battery storage based on the AEMO 2018 WEM ESOO. An overview of demand parameters over the forecast period is provided in Table 6 below.

Table 6 Demand Parameters

Year	Operational Energy (GWh p.a. sent-out)	Annual peak demand 50% POE (MW)	Installed Rooftop PV Capacity (MW)	Behind-the-Meter Storage Energy (MWh sent-out)	Annual energy required by EVs (GWh)
2019-20	18,307	3,914	1,149	63	2.4
2020-21	18,382	3,928	1,303	97	5.8
2021-22	18,506	3,951	1,455	133	12.3

3.1.1 Energy projections

The expected scenario from AEMO's 2018 WEM ESOO (expected growth scenario) has been adopted as the source of electricity demand and energy projection.

Figure 3 shows this expected trajectory in annual operational energy consumption (to be met by large scale generation facilities) for the WEM.

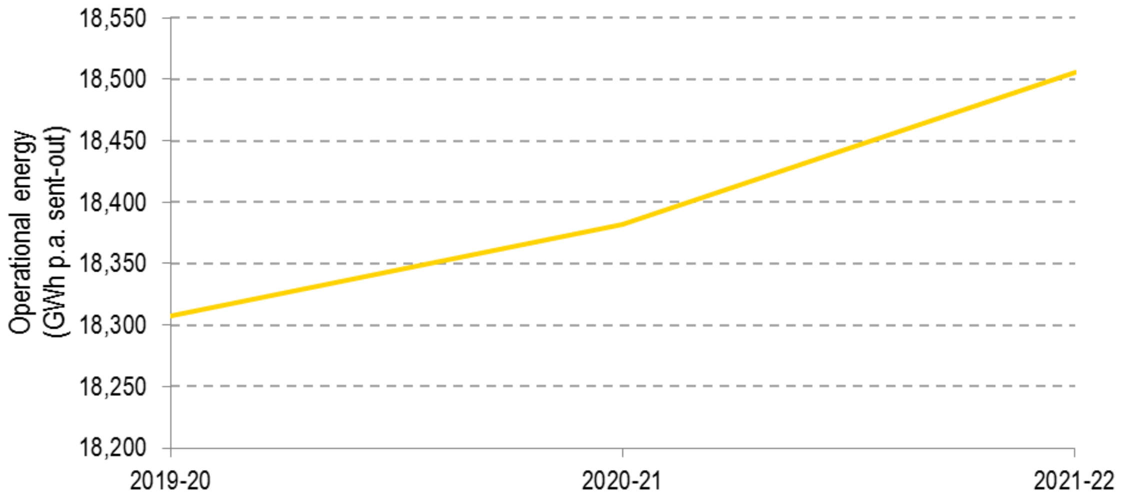


Figure 3: AEMO expected annual regional energy forecast in the WEM

3.1.2 Peak demand

Figure 4 shows AEMO's expected peak demand forecast based on a 50% POE. Peak demands are significantly influenced by weather conditions, particularly hot temperatures in summer and cold temperatures in winter, driving cooling and heating air conditioning loads, respectively.

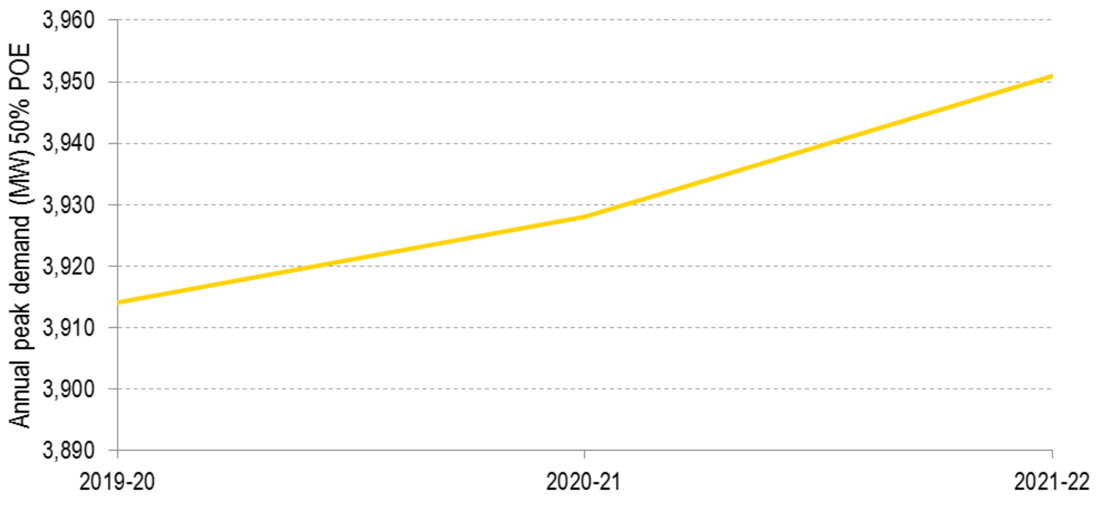


Figure 4: AEMO expected annual 50% POE regional peak demand forecast in the WEM

The peak demand (and near-peak demand conditions) increases the risk of price volatility, and therefore the magnitude of the peak demand in any given year is a significant factor in determining overall wholesale market pricing trends. EY has used AEMO's published peak demand forecasts representing a 50% probability of exceedance (POE) peak demand level.

The 50% POE peak represents a typical year, with a one in two chance of the peak demand being exceeded in at least one half hour of the year and is representative of a statistically likely scenario.

3.1.3 Rooftop PV

Modelling uses AEMO's expected scenario for rooftop solar photovoltaic (PV) uptake from AEMO's 2018 WEM ESOO.

Figure 5 shows the rooftop PV trajectory used in this scenario. The uptake in rooftop PV systems in recent years has been rapid in the WEM, driven by supportive government policies and attractive payback periods. While many of the supportive government policies have now been removed (or significantly scaled back), AEMO still expects significant growth in rooftop PV uptake due to decreasing costs of PV systems and increasing (real or customer perceived) retail energy costs.

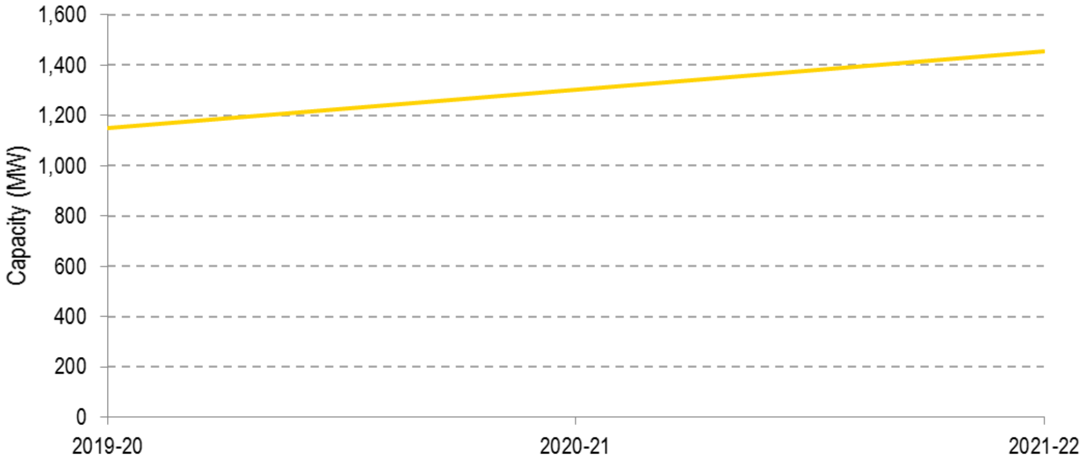


Figure 5: AEMO expected installed rooftop PV capacity forecast for the WEM

3.1.4 Behind-the-meter storage

EY separately models behind-the-meter (domestic) storage profiles and EV charging profiles to capture their impact on the shape of grid demand without changes to the total underlying operational energy forecast by AEMO based on information provided in AEMO's 2018 WEM ESOO.

Figure 6 demonstrates this uptake.

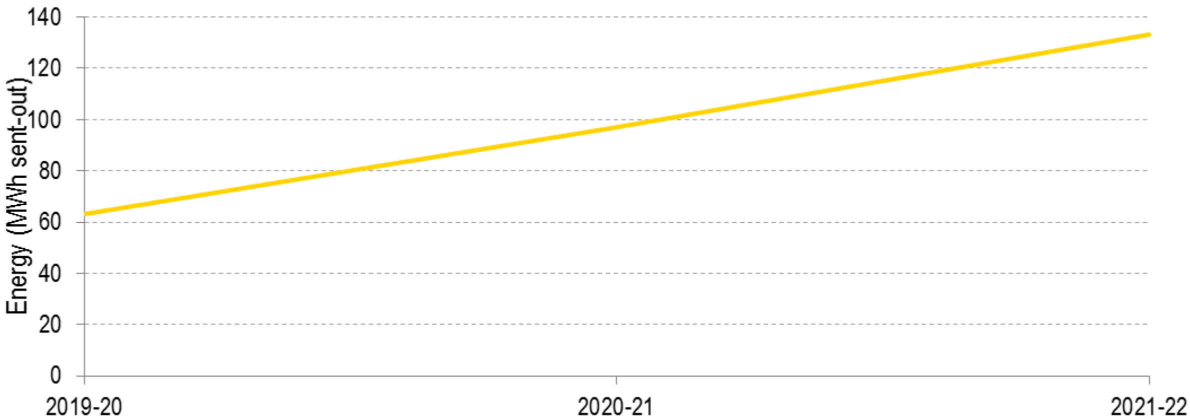


Figure 6: Household battery storage uptake trajectory per region

3.1.5 Electric vehicles

Modelling assumptions use AEMO's expected scenario for electric vehicle (EV) uptake trajectory from AEMO's 2018 WEM ESOO. The uptake of electric vehicles is projected to provide a new source of electrical load as consumers switch from petrol-based vehicles to those that rely on charging from the grid. Within the study period, however, the overall contribution from EVs to the annual SWIS operational energy forecast is expected to be less than 0.1%. The impact of EVs on peak demand within the study period is negligible.

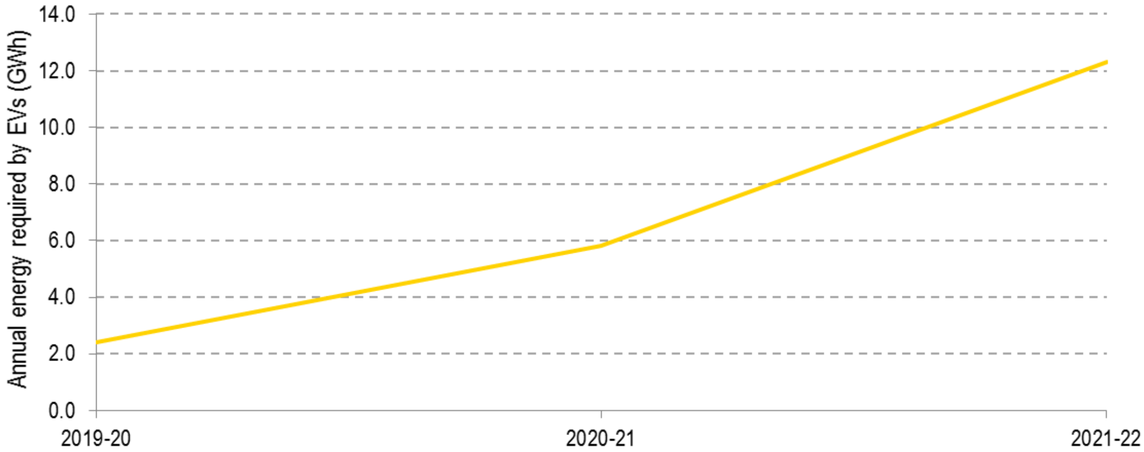


Figure 7: Projected electric vehicle energy consumption

3.2 Generator assumptions

3.2.1 New entrant market generators

The following new entrant market generators are included based on capacity credit certification and a market participant submission during the consultation period. Table 7 provides a summary of the SWIS new entrant list. New entrant renewable projects are assumed to offer all capacity into the balancing market at -$40/MWh to reflect an implicit contracted Large-scale Generation Certificate (LGC) revenue.

Revised commissioning dates for new entrant generators have been adopted, where provided by market participants.

Table 7: SWIS new entrants list

Project	Capacity (MW)	Load area	Technology	Capacity factor	Commissioning date
Emu Downs Solar Farm	20	North Country	Single axis tracking (SAT) PV	29%	1 Oct 2018
Northam Solar Project	10	East Country	SAT PV	27%	1 Oct 2018
Westgen Solar Farm	30	Kwinana	SAT PV	29%	1 Oct 2019
Merredin Solar Farm	120	East Country	SAT PV	28%	1 Jul 2019
Badgingarra Wind Farm	130	North Country	Wind turbine	44%	1 Jul 2019
Yandin Wind Farm	210	North Country	Wind turbine	44%	30 Sep 2020

3.2.2 Thermal generation retirements

In accordance with the Energy Minister's directive for the retirement of generation capacity in the WEM, Synergy's 380 MW retirement schedule[22] is modelled, presented in Table 8. Mungarra Power Station and West Kalgoorlie Power Station may be retained for network support[23], however these stations are not modelled for the purposes of dispatching energy and ancillary services.

[22] Synergy 380 MW announcement
[23] PUO - Arrangements for continued power supply reliability in the North Country and Eastern Goldfields

Table 8: Thermal generation retirement list

Power Station	Region	Type	Retirement date
Kwinana Gas Turbine 1	Kwinana	Gas	30 Sep 2018
Muja A	Muja	Black coal	30 Apr 2018
Muja B	Muja	Black coal	30 Apr 2018
Mungarra Power Station	North Country	Gas	30 Sep 2018
West Kalgoorlie Gas Turbine 2, 3	Eastern Goldfields	Gas	30 Sep 2018

3.2.3 Gas prices

Short-term gas pricing is not considered in the modelling. The assumed gas price trajectory for the SWIS for uncontracted gas supplies is based on publicly available information from the 2017 Western Australia Gas Statement of Opportunities (GSOO)[24]. As existing gas generators' current gas contracts roll off, it is assumed that these generators will be forced to adopt this price trajectory for their future gas contracts. However, no new gas generators are forecast to enter the market.

A market participant submitted that the AEMO 2017 GSOO low gas price forecast should be adopted for the modelling exercise, and that adoption of the expected gas price forecast over-estimates fuel cost inputs for gas generators, noting that spot market prices have been lower in recent years.

A submission was also received asserting that only pipeline commodity fees should be included in the formulation of generator offer curves and that reservation fees are a sunk cost. The submission also considers that it is important for AEMO to determine the proportion of generators that use spot transportation and apply a weighted average transport price for specific generators.

As a result of submissions received during the consultation period EY used gas generators' fuel costs provided by market participants for all existing gas generators rather than forecast values. This overcomes the need to make assumptions on the abovementioned points raised in submissions. Furthermore, no new entrant gas generators are being modelled during the review period, which negates the requirement to assume a gas price for uncontracted gas supplies.

3.2.4 Coal prices

For this assessment, the coal price is assumed to remain constant at $2.60/GJ for the study period as per the 2018-19 Margin Value[25] review. Synergy has submitted variations to coal prices for Muja and Collie units, which have been adopted.

3.2.5 Forced outage rates

EY conducted a number of Monte Carlo iterations in the market modelling to capture the impact of forced (unplanned) generator outages. Each Monte Carlo iteration assigns random outages to each generating unit, based on assumed outage statistics. The same outage statistics are applied for generators with the same fuel type. A 'mean time to repair' and a 'mean time to fail' value is assigned to each generator in the simulation. A unit on a forced outage is excluded from the balancing merit order. The nature of outages for wind and solar generators is different to large thermal generating units due to the modular nature of wind turbines or solar panels within facility.

[24] WA Gas Statement of Opportunities
[25] 2018-19 Margin Value Review, Pg.22

The capacity factors modelled for wind and solar facilities are based on observed and expected output of the wind and solar facilities modelled, and as such implicitly include the impact of overall facility availability.

3.2.6 Planned maintenance

Planned maintenance of units throughout the study period is modelled in future years based on available information on scheduled outages from AEMO's maintenance planning schedules (via MT PASA)[26] in combination with typical maintenance schedules for technology types. Units on planned maintenance outages are excluded from the balancing merit order. Planned maintenance for unit generators are presented in Appendix C. This information also includes planned maintenance information received directly from the participants.

3.2.7 Marginal Loss Factors

Transmission losses occur when electrical energy is transported from generators to the demand centres. Marginal Loss Factors (MLF) apportion the cost of these losses across all participants in the market. They are a scaling factor, normally in the range of 0.9 to 1.1.

Volume weighted loss factors are applied to every generator unit in the WEM based on Western Power's most recent calculation of loss factors[27] for 2018-19. A static loss factor is applied in each trading interval within the study period and applied to generator bidding profiles to determine offers referred to the regional reference node. The regional reference node in the WEM model is set at the Muja 330 kV busbar [28] Appendix B summarises the MLFs used. New entrant generators are given an MLF of 1.000.

3.2.8 Auxiliary factors

Auxiliary factors account for station auxiliary loads and are used to calculate as-generated values based on sent-out generator values, or vice-versa. Appendix B summarises the auxiliary factors used.

3.2.9 Demand response

Demand side management capacity is modelled as per AEMO's 2018 WEM ESOO with 57 MW in 2018-19 and 66 MW from 2019-20 onwards for the duration of the study period.

[26] Scheduled outages are submitted to AEMO for use in their projected assessment of system adequacy assessments for short-term and medium-term timeframes. MT PASA refers to this assessment for the medium term horizon, which is a three year assessment.

[27] 2018-19 loss factor report.

[28] Recent reforms have discussed a move of the regional reference node to a demand centre. However, the timing of this change is not expected to occur within the timeframe being considered for this study.

4. Calculation method

Section 1.5.4 identified the following costs of providing LRRS that were to be included for the purposes of the 'L' parameter of Cost_LR:

- **LRRS availability costs:** Costs of generation facilities providing LRRS not recovered through other market mechanisms
- **LRRS response costs**: Energy profits forgone by generation facilities providing LRRS during a load rejection event.

The following sections outline the methodology for calculating each of these costs.

4.1 LRRS availability costs

4.1.1 Calculating the cost of providing LRRS

LRRS is currently provided by generators in the Synergy balancing portfolio only. Although provision for dispatchable loads[29] to provide this service is discussed in the Rules,[30] there are currently no registered dispatchable load facilities in the WEM.[31] The Rules also allow for non-Synergy generators to provide this service but no contracts have been entered into to date. The cost calculation is therefore centred on the cost to Synergy generators in providing LRRS.

Synergy generators that provide LRRS are not required to be enabled to provide this service[32], but do so by being online and having an output in the correct range as a by-product of being dispatched in the balancing market and for other ancillary services. That is, by providing energy into the balancing market or by being enabled for other ancillary services, generators will innately provide reserves for load rejection, if the generator is technically capable of doing so within the response times specified in the Rules.[33]

Synergy are required to offer quantities of facilities providing LRRS at the minimum STEM price to ensure these facilities will always be dispatched. As such facilities within the balancing portfolio may be compensated at a balancing price (or LFAS price) below their SRMC to meet the LRRS requirement.

In calculating the cost associated with a generator being dispatched to provide LRRS, we therefore consider the cost associated with a generator in a trading interval, which is defined by:

$$L_{it} = Startup\_cost_{it} + fuel\_cost_{it} + O\&M\_cost_{it}$$

where:

- L_{it} is the total cost of unit i supplying generation associated with LRRS in trading interval t
- $Startup\_cost_{it}$ includes the opportunity costs of fuel, water, internal power, additional labour and wear and tear directly attributable to the start-up of unit i in trading interval t

[29] Defined in the Rules as a load with a rated capacity of not less than 0.2 MW, through which electricity is consumed where such consumption can be increased or decreased to a specified level upon instruction to do so by AEMO and registered in accordance with clause 2.29.5(c).

[30] Clause 3.9.6(b) of the Rules discusses dispatchable loads providing LRRS by increasing consumption rapidly in response to a load rejection event.

[31] http://data.wa.aemo.com.au/#facilities.

[32] 2018 Ancillary Services Report - Section 2.4

[33] Clause 3.9.7 of the Rules requires that the relevant facility can either respond within 6 seconds and sustain the response for at least 6 minutes, or respond within 60 seconds and sustain the response for at least 60 minutes, for any individual contingency event.

- $fuel\_cost_{it}$ is the cost of the fuel used in of a unit's modelled production of electrical energy.
- $O\&M\_cost_{it}$ is the variable operational costs associated with the quantity dispatched.

The total cost of providing LRRS for the simulated year, for a set of generator units $i = 1, 2, 3 \dots, N$, for each of the $t = 1, 2, 3 \dots, T$ trading intervals in a year, is given by:

$$Total\ cost\ of\ LRRS = \sum_{t=1}^{T} \sum_{i=1}^{N} L_{it} . w_i, \quad w_i = \begin{cases} 1 & \text{if unit } i \text{ is a Synergy plant} \\ 0 & \text{otherwise} \end{cases}. \tag{1}$$

In deriving the calculation of 'L' parameter of Cost_LR, the total cost of Synergy's provision of LRRS is proposed to be given by:

$$\begin{aligned} Cost_L &= \sum_{t=1}^{T} \big(B_t + c(x)\big) w_t, \\ c(x) &= \int_{Q_t - r_t}^{Q_t} (f(x) - p)\, dx, \\ w_t &= \begin{cases} 1 & \text{if LRRS requirement is not met initially} \\ 0 & \text{otherwise} \end{cases} \end{aligned} \tag{2}$$

where:

- B_t denotes the fixed startup costs (in $) incurred in trading interval t due to the unit providing LRRS.
- $f(x)$ denotes the heat rate based plus variable O&M marginal cost function (in $/MWh) of the unit providing LRRS that is turned on, which includes consideration of $fuel\_cost$ and $O\&M\_cost$.
- Q_t is the balancing market quantity (in MWh) that cleared for the unit during trading interval t.
- r_t is the quantity (in MWh) that is required to provide LRRS to meet the requirement.
- w_t is a filter that removes trading intervals that have sufficient LRRS through the dispatch of units in the energy and ancillary service markets.[34]
- p is the balancing price (in $/MWh) for that trading interval.

The calculation for the variable component of the 'L' parameter of Cost_LR described above is illustrated in Figure 8 for the scenario where a singular unit is required to provide LRRS for a specific trading interval.[35] In practice, this calculation may be performed across multiple units. Fixed costs for start-up are also included, but not shown below.

[34] These trading intervals have historically occurred when the dispatch of coal fired generation for energy purposes and dispatch of gas units to provide LFAS is adequate to cover the LRRS requirement. In intervals where this is not the case, gas units are required (after accounting for LFAS and taking into consideration load rejection capability) to provide LRRS, and coal units may not be required.

[35] Marginal heat rate curves are illustrative and need not be upwards sloping.

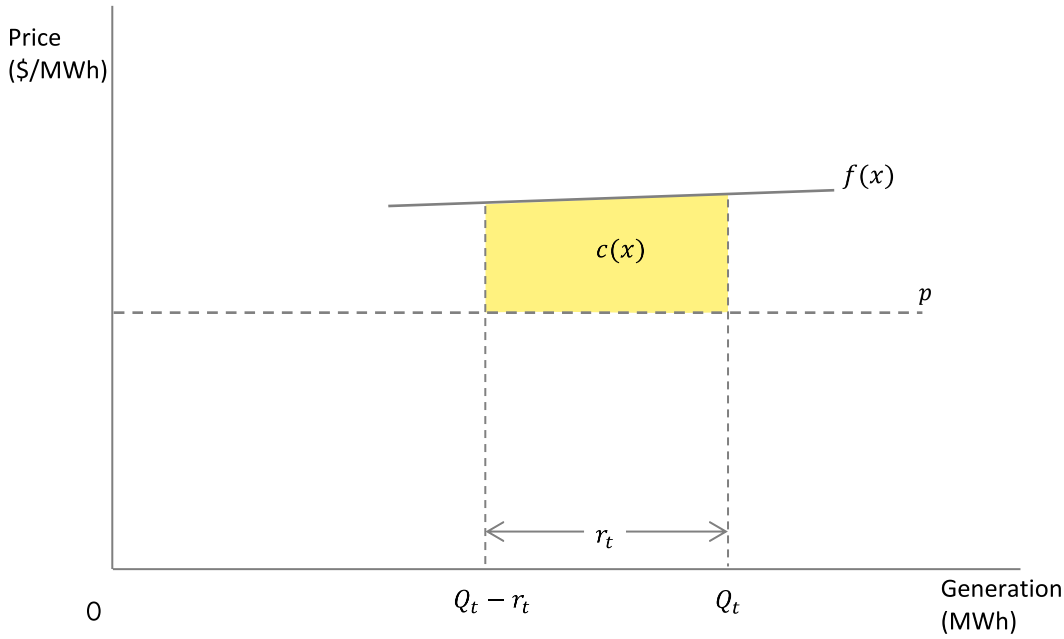


Figure 8: Illustrative diagram of the ‘L’ parameter of Cost_LR calculation for a single trading interval

4.1.2 Modelling of availability costs

For the three year study period associated with the Cost_LR determination, the method used for calculating the LRRS availability cost is outlined below:

1. **Preliminary dispatch and generation outage model run.** This provides a preliminary view of the dispatch outcome for the market with the majority of available capacity offered in at SRMC to determine a theoretical least cost dispatch pattern. The dispatch outcomes are determined using the below steps and specific departures exist for generator units providing ancillary services:

    - Preliminary dispatch outcomes are determined on the basis of short run marginal cost balancing merit order profiles with respect to generation outage events. EY's *Wholesale Electricity Market modelling and Backcasting Report* dated 31 August 2018, provides greater detail on the market modelling implementation.

    - Coal units offer the capacity that is technically capable of providing load rejection at the floor price, to ensure they are dispatched, subject to availability.

    - All other coal units offer their minimum generation load at a low price to avoid unit cycling and for spinning reserve purposes. Spinning reserve is also provided through dispatch in the 2-4-C simulation

2. **Half hourly forecasting of the least cost mix of upwards LFAS providers.** This forecast will be made on the basis of an assumed merit order for the provision of upwards LFAS. The simulation conducted in step 1 above will determine the set of plants available for LFAS provision. The assumed LFAS requirement will be on the basis of AEMO forecasts. Generators that provide LFAS are offered at the price caps to ensure they are dispatched accordingly. IPP facilities that provide LFAS offer their LFAS quantity based on a historical offer profile.[36] Contracted spinning reserve providers will have their contracted SR capacity

[36] It is noted that out of merit generation costs will be influenced by the availability of generators. The probabilistic nature of this modelling is captured by using 50 iterations of Monte Carlo simulations with results average across all iterations of simulations. AEMO has also advised of periods where market participants other than Synergy are cleared in the LFAS market but presently do not have ancillary service contracts to provide LRRS. This scenario may contribute to additional out of merit generation costs associated with meeting the LRRS standard and has been considered in cost calculations.

bid at the ceiling price effectively reserving a portion of their capacity for spinning reserve. Spinning reserve is also provided through dispatch of generation in the 2-4-C simulation.

3. **Identification of modelled periods where LRRS is not met.** The result of the dispatch outcomes in steps 1, 2 and 3 will be used to flag where the LRRS standard of 120 MW was not met requiring the dispatch of additional generation to meet the LRRS requirement. The model identifies units to meet the shortfall quantity based on a ramp up and ramp down merit order, consistent with the principles of the dispatch guidelines and technical capabilities of the facilities. This is formulated in consultation with AEMO.
4. **Half hourly, balancing price modelling.** Balancing price is calculated for each trading interval over the modelling period.
5. **Calculating LRRS interval availability cost (as per equation above).** For trading intervals that require generation to be dispatched to meet the LRRS requirement, the cost incurred by the generator being committed is calculated as the fixed start-up cost plus the costs associated with energy production to meet the LRRS standard. The costs associated with producing energy is based on facility cost data provided by Synergy and the balancing price modelled in step 4. AEMO has provided information with regards to the order in which units are to be dispatched. This aligns with the Synergy dispatch guideline and is ordered from cheapest available LRRS plant to most expensive.
6. **Determining LRRS annual availability cost (as per equation above).** The total generation costs in a year is the summation across all trading intervals for that year. This is used as an input into the calculation of the 'L' parameter of Cost_LR**.**

4.2 Calculating the cost of responding to a load rejection event

A generating unit may be instructed to curtail its generation output in response to an actual load rejection event and as a result would incur lost revenue resulting from foregone energy sales at the prevailing balancing price.

The energy profits forgone as a result of a generator unit being curtailed to provide LRRS are a function of the prevailing balancing price at the time of the load rejection event[37] occurring and the LRRS response quantity.[38] The value of the energy profit forgone is calculated here.

Load rejection events can occur at any time of the year, and are dependent on network outages and the coincident system conditions. However, load rejection events that have led to over-frequency in the SWIS are rare,[39] and the response required from LRRS has historically been limited to within a 30 minute trading interval.[40]

Analysis of the forgone energy profits as a result of a load rejection event is presented in Table 9, considering an upper bound scenario assuming the load rejection event occurs during a trading interval at the maximum balancing price for a sustained period of two trading intervals. The same analysis is presented based on the observed market average balancing price for the 2017-18 year.

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[37] Defined as an event which causes a facility to respond and sustain a response in time periods specified in clause 3.9.7 of the Rules.

[38] Defined in the Rules as the quantity of energy reduction, in MWh, provided by a Facility as a LRRS Response due to a Load Rejection Event, but excluding any such contribution that occurred because AEMO had instructed the Facility to provide Downwards LFAS Enablement or Downwards LFAS Backup Enablement.

[39] AEMO provided information to EY regarding over-frequency events on the SWIS. A total of 11 load rejection events resulted in over-frequency occurring since 2013. The required sustained response times in the events ranged from a few minutes up to 28 minutes.

[40] We note that the LRRS response is required across two time periods, one that responds in 6 seconds for at least 6 minutes and the other requiring response within 60 seconds for at least 60 minutes. See clause 3.9.7 of the Rules.

A maximum of two events have occurred in a year based on network outage statistics[41] of key bulk transmission circuits.

The assessment presented in Table 9 would overstate the costs associated with LRRS as it does not take into account the energy contribution required for downwards LFAS enablement or backup downwards LFAS enablement as prescribed in the Rules for the trading interval. LFAS enablement is typically also provided by the Synergy Balancing Portfolio.

Notwithstanding this simplification, the total energy profits that are forgone are small, with the annual total estimated value of energy profits forgone to be estimated at $72,480 in the upper bound scenario defined and $12,804 for the typical scenario defined.

The magnitude of energy profits foregone due to an LRRS event are significantly smaller when compared to the LRRS availability costs (see section 5.1). As such, this simplified approach is deemed appropriate and the value of the typical scenario has been included in the 'L' component of Cost_LR parameter.

Table 9: Analysis of a load rejection event occurring at maximum and average energy price for two trading intervals

Input assumption	Description of data source and value
Load rejection response quantity (MW, sustained over time)	120 MW (set by AEMO requirement)
Load rejection response time (highly conservative)	1 hour or two trading intervals[42]
Maximum balancing price (highly conservative)	$302 / MWh[43] (based on maximum STEM price)
Average balancing price (based on observed market data for 2017-18 FY)	$53.35 / MWh
Total energy profits forgone @ maximum balancing price for a single trading interval	$36,240
Total energy profits forgone @ maximum balancing price for two trading intervals	$72,480
Total energy profits forgone @ average balancing price for a single trading interval	$6,402
Total energy profits forgone @ average balancing price for a two trading intervals	$12,804

[41] We understand that network outage events on the 220 kV network may occur, on average, twice a year.
[42] As indicated in footnote 40 above, the LRRS response requirement is for up to 60 minutes, although as indicated in footnote 39 above, the duration of historical load rejection events has fallen short of this requirement.
[43] https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Price-limits.

5. Results

5.1 Summary

5.1.1 'L' parameter of Cost_LR

Table 10 summarises AEMO and EY's proposal for the 'L' parameter of Cost_LR.

Table 10: 'L' parameter of Cost_LR

Parameter	Units	2019-20	2020-21	2021-22
'L' component of Cost_LR	$	4,738,225	4,343,504	1,086,587

5.1.2 Costs of Providing LRRS

Table 11 provides a summary of the results of the simulations and Cost_L calculation outcome.

Table 11: Summary of results

Reporting metric	Units	2019-20	2020-21	2021-22
System metrics				
LRRS requirement	MW	120	120	120
Average annual balancing price	$/MWh	45.35	43.86	40.31
Cost calculations				
LRRS availability costs – Costs of facility providing LRRS not recovered through other market mechanisms	$	4,725,421	4,330,700	1,073,783
LRRS response costs – Energy profits forgone by facilities providing LRRS during a load rejection event	$	12,804	12,804	12,804
Total included cost of providing LRRS	$	4,738,225	4,343,504	1,086,587

5.1.3 Excluded Costs

As part of this review, AEMO and EY investigated a number of additional potential costs associated with the provision of LRRS. These costs are excluded from the 'L' parameter of Cost_LR for the reasons outlined in section 1.5.4 and consist of:

- ► Potential energy profits forgone (or de-commitment costs) resulting from lower cost facilities not being dispatched in the model due to Synergy being the default provider of LRRS.
- ► Annual costs associated with unit de-commitment of coal facilities for LRRS for the weekend.

Table 12 provides a summary of these costs.

Table 12: Summary of excluded costs

Reporting metric	Units	2019-20	2020-21	2021-22
System metrics				
Number of de-commitment events for Synergy coal plant for LRRS purposes	Number	Redacted	Redacted	Redacted
Cost calculations				
Other facility costs – Energy profits forgone and de-commitment costs from facilities not providing LRRS	$	1,694,230	1,498,104	452,568

5.2 Scenarios of load rejection costs

The following sections present analysis of specific scenarios observed in the modelling.

5.2.1 No additional cost

Load rejection capability is typically provided by the Muja coal units and the dispatch of Kwinana HEGT's for the purpose of meeting the LFAS down requirement. In the majority of trading intervals in the year, there is sufficient LRRS provided by the combination of these units provided Muja offers its load rejection capable generation capacity at the floor price and Kwinana HEGT units are cleared for LFAS down. In this scenario:

- Muja provides a total of 87.4 MW of LRRS.
- Kwinana HEGT's provide a total of 72 MW down of LFAS and LRRS.
- A total of 159.4 MW of LRRS is typically provided in most trading intervals throughout the year.

Consideration is given to the scenario where NewGen Kwinana is cleared for a quantity of LFAS as this displaces LRRS provided by the Kwinana HEGT units. As NewGen Kwinana does not provide LRRS, this would result in:

- Muja providing a total of 87.4 MW of LRRS (having not changed its offers)
- Kwinana HEGT's provide a total of 42 MW down of LFAS and LRRS.
- A total of 129.4 MW of LRRS can be provided in trading intervals when NewGen Kwinana clears for LFAS.

The main driver of LRRS shortfall and therefore costs, are outages associated with the Muja units. This is discussed further in section 6.

5.2.2 Gas units provide LRRS

This scenario represents a trading interval that incurs high generation costs due to coal generation being unable to operate within the suitable ranges to provide LRRS as a result of Muja units being on outage. Table 13 provides a summary of the unit generation leading to the need to procure additional LRRS and the units that are used.

A summary of the decisions made by the modelling algorithm is described below:

- The balancing market price in this trading interval is $67.97/MWh.

- 87 MW of LRRS is available from the balancing market:
    - Muja_G7, Muja_G8 – 45 MW, as the other Muja units are on outage.
    - Kwinana GT3 – 42 MW from being dispatched in the LFAS market.
        - In this interval, NewGen Kwinana has been cleared for a quantity of LFAS, reducing the amount of load rejection being provided by LFAS units.
- A 33 MW LRRS shortfall is present in this trading interval.
- Muja_G5 and Muja_G6 are on outage and are unavailable. Therefore, Pinjar gas units are dispatched to meet the shortfall in this trading interval.
- To maintain Synergy's quantity in merit, Collie's quantity in the final dispatch scenario is lowered without violating its minimum generation value.
- The total costs associated with providing additional LRRS in this trading interval is (value redacted).

Table 13: A trading interval when load rejection reserve was met by available gas units[44]

			LRRS Provision		
Unit_Id	Preliminary dispatch scenario (MW)	Final dispatch scenario (MW)	Operating cost ($)	Balancing revenue ($)	Net cost ($)
Collie_G1	318	261	-	-	-
Muja_G8	213	213	-	-	-
Muja_G7	213	213	-	-	-
Muja_G6	0	0	-	-	-
Muja_G5	0	0	-	-	-
Pinjar_GT10	0	33	Redacted	+1,122	Redacted
Kwinana_GT2	25	25	-	-	-
Kwinana_GT3	67	67	-	-	-
NewGen Kwinana	335	335	-	-	-

[44] Costs have been redacted for the purpose of this public report.

6. Discussion

6.1 LRRS costs

Table 14 provides a summary of metrics associated with LRRS in the WEM in the preliminary dispatch scenario in the modelling.

Table 14: Summary of metrics associated with LRRS

Reporting metric	Units	2019-20	2020-21	2021-22
System metrics				
Percentage of trading intervals where LRRS requirement is not met in preliminary dispatch scenario	%	17.0	15.1	3.0
Average energy dispatched for load rejection purposes in a trading interval where LRRS requirement is not met in preliminary dispatch scenario	MWh	8.0	7.2	8.0

The key drivers contributing to the percentage of trading intervals with modelled load rejection shortfalls requiring the dispatch of facilities to provide LRRS are discussed below. Consideration of potential drivers of future LRRS is also discussed.

6.2 Muja power station

The Muja power station plays a significant role in providing load rejection in the WEM, and future decreasing utilisation is likely to increase the occurrences where AEMO is required to dispatch facilities specifically to meet the LRRS requirement. From the available baseload generators[45] in the SWIS, LRRS capability is currently provided by Muja power station and the Kwinana HEGTs[46] (discussed in section 6.3.2) only.

The forecast energy and capacity factor for Muja C/D[47] across the study period in the preliminary dispatch scenario is detailed in Table 15. The number of hours on outage, as submitted by Synergy for modelling is provided below. A comparison against the most recent publication of the AEMO 2018 ESOO is provided.

Table 15: Generation dispatch statistics for Muja C/D

Muja metrics	2018 AEMO ESOO	2019-20	2020-21	2021-22
Muja C/D energy generated (sent-out, MWh)	4,316	4,549	4,345	4,645
Capacity factor (%)	60.4	63.7%	60.9%	65%
Number of hours on outage as submitted by Synergy	N/A	Redacted	Redacted	Redacted

[45] As defined in AEMO's 2018 2018 ESOO.

[46] Although Kwinana GT2 and GT3 are gas turbines, they are considered baseload generators by AEMO due to their dispatch for LFAS.

[47] Muja C/D consists of Muja_G5, Muja_G6, Muja_G7,Muja_G8.

Dispatch simulations forecast a declining capacity factor for Muja C/D in 2020-21 but increasing in 2021-22 as a result of two main drivers:

- **Outages:** Given that LRRS is made available from dispatch of the Muja power station, any planned (or unplanned) outages of these units removes LRRS provided by baseload generation. As part of the public consultation process, Synergy submitted a number of modelled outages for inclusion in this review. These outages were for the 2019-20 and 2020-21 year. No modelled planned outages were submitted for inclusion in the 2021-22 year resulting in a higher availability of Muja units in that year.

- **New entrant renewables:** The merit order effect caused by new entrant generation connecting to the WEM places downwards pressure on the utilisation of Muja power station. The assumed connection of Alinta Energy's 210 MW Yandin wind farm contributes low cost generation to the WEM, placing downwards pressure on baseload utilisation. It is noted that the 2021-22 year does not contain new entrant market generators connecting to the WEM.

6.3 Potential drivers of future LRRS costs

6.3.1 Impact of new entrant generation

A potential driver of increased LRRS costs in future years is the connection of large- scale renewable generation projects in 2019-20 and 2020-21. By the end of the study period, 520 MW of new entrant renewable generation projects is assumed to be connected in the SWIS. A total of 310 MW of installed capacity is assumed to be connected in 2019-20 and a further 210 MW of generation is assumed to be connected in 2020-21. As discussed above, no new entrants are forecast in 2021-22.

New entrant renewable generation has an incentive to offer their available capacity into the balancing market based on the value for LGC's in the contract market. This results in an additional revenue stream from the creation of Large-scale Generation Certificates (LGC) and may result in a significant amount of new low cost generation competing for dispatch during low demand periods.

6.3.2 Interaction with the load following ancillary service market

There are currently three primary units participating in the LFAS market, with the enablement of units for the purpose of LFAS directly impacting the provision of load rejection reserve.[48] The details of LFAS providing units are provided in Table 16.

Table 16: Load rejection capability of units providing load following

Facility	Load following up (MW)	Load following down (MW)	Load rejection capability (MW)
Kwinana GT2	Min(Redacted, spare capacity)	Min(Redacted, spare capacity)	Spare capacity down
Kwinana GT3	Min(Redacted, spare capacity)	Min(Redacted spare capacity)	Spare capacity down
Pinjar units	Spare capacity, (Redacted MW/min	Spare capacity, (Redacted MW/min	Spare capacity down
NewGen Kwinana	Redacted	Redacted	Redacted

The dispatch of Kwinana GT2 and GT3 for the enablement of 72 MW of LFAS down will provide LRRS capability. When either of these are on outage, other gas units such as Pinjar units may provide the service.

However, in trading intervals where an IPP facility is cleared in the LFAS market, Synergy units providing LFAS will likely be dispatched at lower output levels depending on requirements in the

[48] Pinjar units can also provide LFAS if required.

energy market, and for the provision of the outstanding LFAS quantity. As such, LRRS capability is reduced in trading intervals where IPP facilities are cleared for LFAS.

The outcome of this interaction is that increasing competition for the provision of LFAS is likely to decrease the load rejection that is also provided by the LFAS market, if new entrant LFAS providers are not capable of providing LRRS. Given the relatively few baseload generator units that are capable of providing LRRS, there may be benefit in exploring whether other facilities may be capable of providing LRRS.

Appendix A Summary of Consultation

Table 17 summarises the key points made in relation to market-related parameters and methodology.

Table 17: Key points raised in public submissions

Submission topic	High level summary of feedback received
Constrained payments	A submission was received relating to market settlement calculations and constrained payments.
Unit commitment	A submission was received regarding unit commitment decisions.
Modelling future balancing prices	A submission was received regarding modelling future balancing market prices and the impact of dynamic changes occurring in the market currently (fuel cost, behind-the-meter solar and large-scale new entrant).
New entrant generator list	Updates to the indicative in-service dates for renewable projects were provided.
Gas prices	A submission was received relating to the assumed gas price trajectory.
Gas transport charge	A submission was received relating to fixed reservation charges for gas transport infrastructure.

In its consideration of the above points, EY in consultation with AEMO concluded that on:

- **Unit commitment**, EY considered implementing a unit commitment algorithm in the model, but upon consultation with AEMO came to a view that this would be impractical for the following reasons:
    1. The extensive back-casting exercise conducted for the purposes of model calibration and demonstration of calculation accuracy did not employ a unit commitment algorithm. Our back-cast achieved relatively accurate balancing price and generation dispatch outcomes when compared against historical market outcomes. Specifically, our back-casting tested duration curves for price and generation by facility, showing good alignment. The back-casting results would be void if a unit commitment algorithm were added at this stage of the process.
    2. In real world operations, forecast errors result in unit commitment decisions that are imperfect. In consultation, Synergy suggested that forecast error should not be modelled in the unit commitment algorithm due to this being impractical. EY does not consider the proposal to employ a perfect foresight model of unit commitment to be any more realistic than the modelling approach that was proposed in the Draft Assumptions Report.
- **Renewable projects**, there are no significant renewable generation projects that are likely to be on-line in the 2019-20 year that have not already been consulted on.
- **Fuel price assumptions**, the modelling will apply the data provided by market participants directly.

The following table summarises submissions received as part of the public consultation period for market related assumptions.

Table 18: Submissions received as part of the public consultation period for market related assumptions

Market generator	High level summary of feedback received	Report section discussed
Synergy	In relation to the calculation of LRRS reserve costs, Synergy submitted that market settlement calculations to date have not adequately calculated upwards out of merit generation quantities and therefore do not adequately compensate Synergy for any upwards out of merit generation dispatched by AEMO to meet the LRRS requirement. Synergy submitted that the interactions between the constrained-on payment mechanism and the Synergy Balancing Portfolio bidding mechanism mean that the generation quantity that is dispatched "out of merit" does not qualify for constrained-on payments due to the way the Balancing Portfolio quantities are calculated. Synergy also asserted that in the rare instance that the total dispatch capacity is higher than Synergy's clearing volume and qualifies as a constrained-on quantity, the constrained-on compensation price is likely to represent a lower cost generator than the unit that is actually dispatched out of merit. This is due to the way the constrained-on mechanism calculates the Balancing Portfolio constrained-on compensation price, which is the next loss factor adjusted price less the balancing price in the Balancing Portfolio balancing submission. Synergy also submitted that unit commitment decisions and the costs associated with them are key factors in determining its cost of providing ancillary services. Synergy submitted that "…when deciding which facilities to commit, the generation business will take a forward view of load forecasts over a number of days." Synergy considers that the modelling methodology should consider a 2-4 day unit commitment technique. Synergy also submitted a concern that the proposed modelling method assumed future balancing merit order profiles will reflect past profiles, citing key changes in fuel costs, and outputs from distributed solar and new large-scale renewable generators in the future. Synergy considers that accounting for these variables through historical balancing offers and future load forecasts will not capture their impacts on how ancillary service requirements are met.	Section 1.5.3
Confidential	A market participant submitted that the AEMO 2017 GSOO low gas price forecast should be adopted for the modelling exercise, and that adoption of the expected gas price forecast over-estimates fuel cost inputs for gas generators, noting that spot market prices have been lower in recent years. A submission was also received asserting that only pipeline commodity fees should be included in the formulation of generator offer curves and that reservation fees are a sunk cost. The submission also considers that it is important for AEMO to determine the proportion of generators that use spot transportation and apply a weighted average transport price for specific generators.	Section 3.2.3

Appendix B Facility related assumptions

At the request of AEMO, EY prepared pre-populated excel spreadsheets containing assumptions for each market participant facility. AEMO requested market participants to review and update commentary on facility-related assumptions. AEMO received responses from 13 out of 15 participants. The type of assumptions requested and used in modelling are shown in the template Data and assumptions workbook.[49]

In the event that the assumptions were not updated or a response was not provided, EY has retained the default assumptions for the purposes of modelling.

Where data has been submitted that is inconsistent with existing standing data, EY has adopted the values provided via submissions.

[49] http://wa.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/Ancillary-Services/2018/PUBLIC---EY-Assumptions-Book---AEMO-Margin-Value-Review---2018-09-13c.pdf

Appendix C Planned maintenance periods

Planned maintenance of units throughout the study period is modelled in future years based on available information on scheduled outages from AEMO's maintenance planning schedules (via MT PASA)[50] in combination with typical maintenance schedules for technology types. Units on planned maintenance outages are excluded from the balancing merit order.

Appendix D Unit re-dispatch merit orders

For trading intervals in which sufficient load rejection cannot be sourced from on-line generators, the following commitment and de-commitment merit order is applied.

Table 19 Unit re-dispatch merit orders

Ramp down merit order	Ramp up merit order
Redacted	Redacted
Redacted	Redacted
Redacted	Redacted
Redacted	Redacted
Redacted	Redacted
	Redacted
	Redacted
	Redacted
	Redacted
	Redacted
	Redacted
	Redacted
	Redacted
	Redacted
	Redacted
	Redacted
	Redacted

Appendix E Facility maximum LRRS capability

Table 20: Facility maximum LRRS capability

Unit ID	Maximum LRRS capability (MW)
KEMERTON_GT11	Redacted
KEMERTON_GT12	Redacted
KWINANA_GT2	Redacted
KWINANA_GT3	Redacted
MUJA_G5	Redacted
MUJA_G6	Redacted
MUJA_G7	Redacted
MUJA_G8	Redacted
PINJAR_GT1	Redacted
PINJAR_GT10	Redacted
PINJAR_GT11	Redacted
PINJAR_GT2	Redacted
PINJAR_GT3	Redacted
PINJAR_GT4	Redacted
PINJAR_GT5	Redacted
PINJAR_GT7	Redacted
PINJAR_GT9	Redacted