RCP Rule Change Panel

Rule Change Notice: Method used for the assignment of Certified Reserve Capacity to Intermittent Generators (RC_2019_03)

This notice is given under clause 2.5.7 of the Market Rules.

Submitter: Sara O'Connor – Economic Regulation Authority (**ERA**)

Date submitted: 17 December 2020

The Rule Change Proposal

The ERA is seeking to replace the Relevant Level Methodology (**RLM**) to reflect the outcome of the ERA's 2018 review of the RLM.

Background of the Proposal Development

The ERA completed its 2018 review of the RLM on 31 March 2019 with the publication of its final report. The ERA's report contained a recommendation to change the RLM.[1]

The ERA discussed its review of the RLM at the 30 April 2019 Market Advisory Committee (**MAC**) meeting, and consulted with the MAC about its intention to develop a Proposal to change the RLM.

The ERA made a further presentation to the MAC on 11 June 2019 to update the MAC on the status of its development of a Proposal to change the RLM.

On 19 July 2019, the ERA submitted a Pre-Rule Change Proposal (**PRC**): Method used for the assignment of CRC to Intermittent Generators (**RC_2019_03**) to RCP Support. The PRC was discussed at the 29 July 2019 MAC meeting.

After the 29 July 2019 MAC meeting, RCP Support identified that, because the proposed RLM assesses the contribution of individual Intermittent Generators based on the contribution of the Intermittent Generation fleet as a whole, there may be an interaction between the ERA's proposed RLM and the Network Access Quantity (**NAQ**) framework that the Energy Transformation Implementation Unit (**ETIU**) is planning to implement as part of the Energy Transformation Strategy.

ETIU, the ERA, AEMO and RCP Support discussed this interaction issue in December 2019 and the ERA decided to defer submitting RC_2019_03 while ETIU developed the NAQ framework and the related Amending Rules.

The ERA provided an update on its progress in developing RC_2019_03 at the 20 October 2020 MAC meeting.

On 23 October 2020, ETIU published the draft Amending Rules for the NAQ framework. The Rule Change Panel notes that the Amending Rules for the NAQ framework are expected to

[1] All documents relating to the ERA's review including the final report are available on the ERA's website at https://www.erawa.com.au/electricity/wholesale-electricity-market/methodology-reviews/review-of-method-used-to-assign-capacity-to-intermittent-generators-2018.

be published in the Gazette on 22 December 2020.

On 10 November 2020, the ERA submitted an updated PRC to RCP Support for presentation and discussion at the 17 November 2020 MAC meeting, including the following supporting documents:

- additional scenario analyses prepared by the Lantau Group;[2]
- an informal summary prepared by RCP Support of the concerns it had raised at the 20 October 2020 MAC meeting; and
- a document addressing the concerns raised by RCP Support and AEMO and explaining the changes made to accommodate the draft Amending Rules to implement the NAQ framework.

The papers, presentations and minutes of the relevant MAC meetings are available on the Rule Change Panel's website at [Rule Change Panel: Market Advisory Committee Meetings - Economic Regulation Authority Western Australia].

The Rule Change Panel notes that the Rule Change Proposal as submitted differs from the PRC discussed at the 17 November 2020 MAC meeting.

Decision to Progress the Rule Change Proposal

The Rule Change Panel has decided to progress the Rule Change Proposal on the basis of its preliminary assessment that the proposal raises a valid issue and may be consistent with the Wholesale Market Objectives.

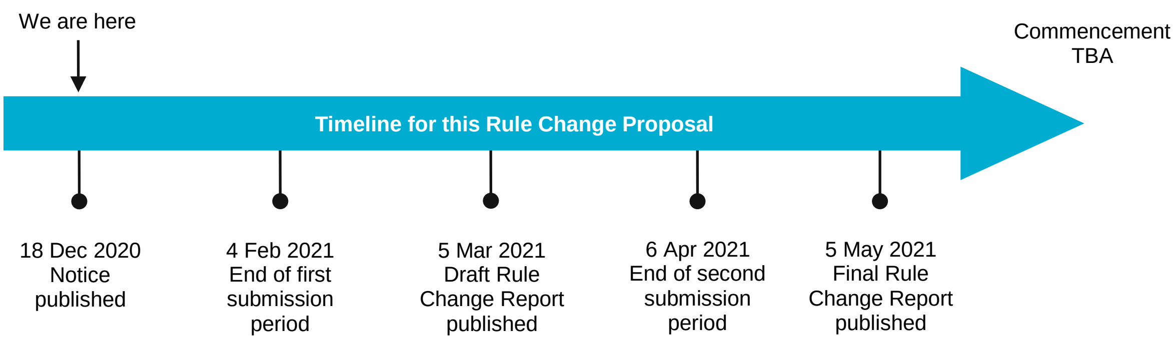
Timeline

This Rule Change Proposal will be progressed under the Standard Rule Change Process described in section 2.7 of the Market Rules.

The Rule Change Panel notes that the commencement of the proposed changes (if the Rule Change Proposal is approved or approved in an amended form) will depend on the time AEMO needs for implementing the changes.

As discussed at the 17 November MAC meeting, the Rule Change Panel is not extending the first submission period beyond the mandatory 30 Business Days to account for the Christmas holiday period. This is due to the views expressed by stakeholders about the urgency of the Rule Change Proposal. However, stakeholders may seek an extension if necessary.

The projected timeline for progressing this proposal is:



2 The Rule Change Panel notes that the analyses are based on an earlier version of the PRC.

Call for Submissions

The Rule Change Panel invites interested stakeholders to make submissions on this Rule Change Proposal. The submission period is 30 Business Days from the Rule Change Notice publication date. Submissions must be delivered to the RCP Secretariat by **5:00 PM on Thursday 4 February 2021**.

The Rule Change Panel prefers to receive submissions by email, using the submission form available at: https://www.erawa.com.au/rule-change-panel/make-a-rule-change-submission sent to support@rcpwa.com.au.

Submissions may also be sent to the Rule Change Panel by post, addressed to:

Rule Change Panel
Attn: Executive Officer
C/o Economic Regulation Authority
PO Box 8469
PERTH BC WA 6849

Wholesale Electricity Market Rule Change Proposal

Rule Change Proposal ID: *RC_2019_03*
Date received: *17 December 2020*

Change requested by:

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Organisation:	Economic Regulation Authority
Address:	Level 4, Albert Facey House, 469 Wellington Street, Perth WA 6000
Date submitted:	17 December 2020
Urgency:	*high*
Rule Change Proposal title:	Method used for the assignment of certified reserve capacity to intermittent generators
Market Rule(s) affected:	Appendix 9, clause 4.9.5, 4.10.2, 4.10.3, 4.10.3A(a), 4.11.1, 4.11.2, 4.11.3C, 4.11.3E, 4.28C.7, 10.5.1(f)x, and Chapter 11.

Introduction

Clause 2.5.1 of the Wholesale Electricity Market (WEM) Rules (Market Rules) provides that any person may make a Rule Change Proposal by completing a Rule Change Proposal form that must be submitted to the Rule Change Panel.

This Rule Change Proposal can be sent by:

Email to: support@rcpwa.com.au

Post to: Rule Change Panel
Attn: Executive Officer
C/o Economic Regulation Authority
PO Box 8469
PERTH BC WA 6849

The Rule Change Panel will assess the proposal and, within 5 Business Days of receiving this Rule Change Proposal form, will notify you whether the Rule Change Proposal will be further progressed.

In order for the proposal to be progressed, all fields below must be completed, and the change proposal must explain how it will enable the Market Rules to better contribute to the achievement of the Wholesale Market Objectives.

The objectives of the market are:

(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;

(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;

(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;

(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and

(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

Details of the Proposed Rule Change

1. Describe the concern with the existing Market Rules that is to be addressed by the proposed rule change:

Background

To provide a reliable supply of electricity for consumers, the Wholesale Electricity Market (WEM) was designed to have sufficient capacity available to satisfy electricity demand at all times, including during supply emergencies. The reliability planning criterion of the WEM rules specifies the required amount of capacity in the South West Interconnected System (SWIS) to maintain the reliability of the system.

The Australian Energy Market Operator (AEMO) procures the required capacity two years in advance by assigning capacity credits to capacity suppliers including generator and demand side program facilities. This ensures that sufficient capacity will be available on time to meet the reliability criterion of the SWIS.

Electricity retailers fund the procurement of capacity credits based on their contribution to peak demand in the WEM. Retailers pass the cost of procuring capacity to electricity consumers through retail tariffs. If more capacity is procured than required, the SWIS will be more reliable but consumers may pay for generation capacity that is not needed.

AEMO uses methods specified in the market rules to forecast the contribution of facilities to meeting the reliability planning criterion to assign capacity credits to facilities. Intermittent generators, by their nature, have variable, weather-dependent output. This variability must be taken into account when determining to what extent intermittent generators can be relied upon to contribute to system reliability. AEMO uses the relevant level method (RLM) set out in the market rules to determine the quantity of capacity credits allocated to intermittent generators.

As the number of intermittent generators in the relatively small and isolated SWIS continues to grow, the RLM becomes increasingly important to ensure that intermittent generators receive capacity credits that reflect their contribution to reliability.

The ERA review of the relevant level method

Under the market rules, every three years the ERA reviews the RLM and examines whether it meets the WEM objectives. The ERA reviewed the current RLM and published its final report on 31 March 2019.[1]

The ERA found that the current method had several shortcomings due to modelling errors in forecasting capacity values and inconsistency with the planning criterion of the SWIS.

Modelling errors in the current relevant level method result in excessive errors when forecasting the capacity contribution of intermittent generators to reliability in the SWIS. The current method is not effective in achieving market objectives, as explained in section 4. Increased penetration of intermittent generators in the system will exacerbate the forecasting inaccuracy of the current RLM.

Under the market rules, the ERA is also responsible for determining the value of two constant parameters that are used in the current RLM (parameters K and U). The ERA found that the application of these constant parameters was not conceptually correct and therefore finding values for these parameters was not possible. A detailed explanation of the shortcomings of the current method was presented in the ERA's final report.[2]

The ERA proposed a method for the calculation of the capacity contribution of intermittent resources based on international best practice. The proposed method eliminates the modelling errors in the current method and provides forecasts of capacity values for intermittent generators consistent with the reliability planning criterion of the SWIS. The proposed method forecasts the capacity value of intermittent generation facilities as the amount of additional demand the SWIS can cover by adding those facilities to the system while maintaining the reliability target of the SWIS.

Implementation of the proposed method in the market rules

The ERA is now seeking to implement that proposed method through this rule change proposal, replacing the current RLM set out in appendix 9 of the market rules.

In accordance with clause 2.5.1B of the market rules, in July 2019 the ERA presented a pre-rule change proposal to the Market Advisory Committee to receive their feedback. The Market Advisory Committee recommended a high urgency rating for the assessment of the rule change proposal.[3][4]

In December 2019 the ERA, Energy Policy WA (EPWA), the Rule Change Panel Support and AEMO agreed to delay the RLM rule change proposal until related changes to the market rules were published. The delay would allow the ERA to address any interactions between the rule change proposal and EPWA's proposal for assigning capacity credits to resources in a constrained network access regime.

In October 2020, EPWA published details on how capacity credits would be assigned under a constrained network access mechanism.[5] EPWA's draft amending rules included the details

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[1] ERA, 2019, *Relevant level method review 2018, Capacity valuation for intermittent generators*, Final report, (online).

[2] Ibid.

[3] Rule Change Panel, 2019, Meeting minutes for the Market Advisory Committee meeting of 29 July 2019 , p. 15, (online).

[4] Rule Change Panel, 2019, *Meeting papers for the Market Advisory Committee meeting of 29 July 2019* , pp. 102–165, (online).

[5] Energy Policy WA, 2020, Energy Transformation Taskforce Consultation webpage (online)

of the method for the capacity valuation of electric storage resources, and the capacity certification approach for aggregated facilities and non-scheduled facilities. These changes overlapped with some aspects of the implementation of the ERA's proposed RLM.

The ERA developed minor changes in the existing rule change proposal to accommodate the changes proposed by EPWA. These were to:

- Ensure the method accounts for the availability of storage resources in the resource mix in the SWIS.
- Remove features identified by EPWA's market rule changes as no longer required.
- Accommodate the assignment of capacity values to non-scheduled facilities, seeking certification of reserve capacity through the RLM.

No changes to the proposed method were needed as a result of EPWA's proposed method for the assignment of capacity credits under the constrained network access mechanism. This was because, by design, the proposed RLM excluded the effect of network constraints from the calculation. The results of the proposed RLM would be suitable for use as inputs to the dedicated process EPWA has developed to account for the effect of network constrains on the capacity contribution of resources.

These changes are explained in detail in appendix 3.

The ERA has further developed the rule change proposal to enhance the proposed method. These enhancements also address the feedback the ERA received from AEMO and Rule Change Panel Support in the Market Advisory Committee meeting on 20 October 2020. These changes enhance the consistency of the proposed method with the planning criterion of the SWIS and market objectives through:

- The calculation of capacity values at the target level of system adequacy consistent with the requirement of the planning criterion.
- Use of forecast demand in the SWIS as input into the calculation consistent with the requirements of the planning criterion and long-term projected assessment of system adequacy in the SWIS.
- Improving the assignment of capacity values to individual facilities based on their long-term performance.
- Improving the assignment of capacity values to aggregated facilities.

The details and reasoning for these changes are presented in appendix 3.

The ERA presented an updated preliminary rule change proposal to the Market Advisory Committee on 17 November 2020 and sought feedback. Feedback received in response to the updated preliminary rule change proposal is addressed in section 4, appendix 3. The ERA did not make any major changes to the rule change proposal following the feedback received.

2. Explain the reason for the degree of urgency:

The ERA recommends this rule change proposal be assessed with high urgency rating because:

- The current RLM can result in unnecessary over- or under-estimation of the capacity contribution of intermittent generators. An over-estimation of the capacity contribution of intermittent generators can undermine the reliability of the system because sufficient capacity may not be available to meet system demand reliably. Under-estimation of the capacity contribution of intermittent generators can result in procuring capacity in excess of what the system requires to meet the reliability criterion and can increase the cost of electricity supply to consumers.

- The current RLM does not suitably allocate capacity credits to intermittent generation facilities based on their expected capacity contribution to the reliability of the SWIS. Some facilities receive capacity credits above their expected contribution and others below their expected contribution, when compared to the results of the proposed method.

- The proposed method will increase the transparency of the calculation of the capacity contribution of intermittent resources. Stakeholders can use the proposed method, which is based on conventional methods for system capacity adequacy assessment, to replicate AEMO's calculation of capacity credits. Unlike the current method, the proposed method does not rely on constant parameters whose purpose and calculation are not defined in the market rules.

3. Provide any proposed specific changes to particular Market Rules: *(for clarity, please use the current wording of the rules and place a ~~strikethrough~~ where words are deleted and underline words added)*

Refer to appendix 1 and appendix 2.

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4. Describe how the proposed rule change would allow the Market Rules to better address the Wholesale Market Objectives:

(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system.

The proposed changes to the RLM will increase the economic efficiency and reliability of the SWIS. The proposed changes will provide a more reliable forecast of the capacity contribution of intermittent generators in the SWIS than the current method and this will avoid over- or under-procurement of capacity due to the use of the current RLM. An over-procurement of capacity above what is required can increase the cost of electricity supply to electricity consumers and lower the economic efficiency of the SWIS. Electricity consumers may pay for the procurement of capacity that is not required.

(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors.

The proposed RLM is transparent and technology neutral. Market participants and new entrants to the system can replicate the method and assess the contribution of their capacity to the reliability of the SWIS and forecast the number of certified reserve capacity they can receive.

In comparison, the current RLM is not transparent; it uses constant parameters in the calculation, the purpose and calculation of which is not defined under the market rules. Market participants and new entrants to the SWIS cannot determine the value of these parameters.

Transparency in the market enhances competition because prospective entrants to the market will have clear information to assess their entry to the market. With increased transparency existing market participants can better assess their operational or exit decisions.

(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions.

The proposed method is technology-neutral and does not discriminate against any supply technology. The basis of calculation is to measure the expected contribution of a facility to meeting the dominant reliability planning criterion in the market rules. The method can suitably be used to determine the capacity contribution of existing technologies such as biogas, solar, and wind generators, and new technologies such as wave generation and offshore wind turbines.

The current RLM discriminates against facilities and technologies. For instance, it does not account for the capacity contribution of new or recently upgraded facilities when calculating the capacity contribution of existing facilities. This approach risks over-estimating or under-estimating the capacity value of existing technologies. Also, the current RLM does not correctly account for the differences in the availability of capacity of intermittent generators and how this influences their capacity value. This is particularly important with the uptake of renewable energy technologies in the SWIS.

Modelling results also indicate that the current RLM assigns substantially lower certified reserve capacity to intermittent generators when compared to the proposed method. This creates discrimination against renewable energy technologies.

(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system.

The proposed method will provide a more reliable forecast of the capacity contribution of intermittent resources, which will lower the long-term cost of electricity supply to customers. An over-estimation of the capacity contribution of resources may result in under-procuring capacity, which can result in frequent use of high cost emergency reserves in the system or disconnection of customers, both of which increase the long-term cost of electricity supply to consumers.

5. Provide any identifiable costs and benefits of the change:

The ERA sought AEMO's advice on its expected cost of implementing the proposed method. AEMO stated that its expected cost of implementing changes to the current RLM for incorporating Collgar Wind Farm's rule change proposal (RC_2018_03) was approximately $170,000.[6]

In its rule change proposal, Collgar proposed basing the calculation of Relevant Level for intermittent generators on sent-out generation of facilities during peak demand periods, rather than the periods when load net of the sent-out generation of intermittent generators was the largest. In comparison to the changes proposed by the ERA, Collgar's proposal required slight changes to the current RLM and did not contain any fundamental changes.

The proposed changes to the RLM in this proposal, however, are extensive. AEMO will need to review the proposed changes to the market rules and automate the calculation. The proposed RLM cannot be run manually and needs an automated calculation program. The program should also be connected to AEMO's information technology systems to ensure input data can be suitably processed.

These changes suggest that the cost of implementing the proposed RLM can be higher than that estimated by AEMO for implementing Collgar's proposed changes.

In its submission to the ERA's draft decision for AEMO Allowable Revenue and Forecast Capital Expenditure 2019/20 to 2021/22, AEMO provided an internal project sizing method for the development and implementation of business-as-usual rule changes.[7] AEMO categorised

[6] Rule Change Panel, 2018, *Capacity Credit Allocation Methodology for Intermittent Generators*, (online).

[7] AEMO's submission to *Australian Energy Market Operator Allowable Revenue and Forecast Capital Expenditure 2019/20 to 2021/2022, Draft decision*, May 2019, p. 19, (online).

these projects into four levels and estimated upper bounds for the cost of each category. The ERA expects the implementation of the proposed RLM falls into either a medium or large project category:

- Medium projects have typical cost below $500,000, with some impact, complexity or risk, and may involve three or more divisions within AEMO.

- Large projects have typical cost above $500,000 (but less than $2.5 million), that may have impact on market(s) or participants, and/or on AEMO's reputation. These projects involve multiple stakeholder groups and are complex and contain significant risks.

AEMO included a forecast capital expenditure of $1.42 million to accommodate known business-as-usual rule changes that may need to be delivered during the fifth allowable revenue period but were undefined at the time of submitting its allowable revenue to the ERA for review in May 2019.

The ERA will also publish the model it developed to demonstrate the application of the proposed method. This will support the assessment of the rule change proposal and AEMO's implementation of the proposed method. Existing and prospective facility owners can also use the sample model developed.

To assist stakeholders in assessing the proposed changes, the ERA also provides the results of the model in the form of modelling scenarios and sensitivity analyses in appendices 4 and 5.

Appendix 1 Marked up changes to the market rules

Legend:

Yellow underline : Proposed addition by RLM rule change proposal

~~Yellow strikethrough~~ : Proposed deletion by RLM rule change proposal

Underline : Addition from EPWA, tranche 1, 2 or 3 changes

~~Strikethrough~~ : Deletion from EPWA, tranche 1, 2 or 3 changes

~~Blue strikethrough and underline~~ : Proposed deletion by RLM rule change proposal of an addition proposed by EPWA tranche 1, 2 or 3 changes

Appendix 9: Relevant Level Determination

This Appendix presents the method~~ology~~ for determining the Relevant Levels for Facilities ~~that have applied for certification of Reserve Capacity under clause 4.11.2(b) for a given Reserve Capacity Cycle~~ ("**Candidate Facilities**") for which

(a) Market Participants have applied for certification of Reserve Capacity for a given Reserve Capacity Cycle under section 4.9; and

(b) the Certified Reserve Capacity is to be assigned using the method in clause 4.11.2(b).

Part A: Introduction

For the purposes of the Relevant Level determination in this Appendix 9:

(a) the full operation date of a Candidate Facility for the Reserve Capacity Cycle ("**Full Operation Date**") is:

i. the date provided under clause 4.10.1(c)(iii)(7) or revised in accordance with clause 4.27.11A, where at the time the application for certification of Reserve Capacity is made the Facility, or part of the Facility (as applicable) is yet to enter service (excluding a part of a Facility that is an Electric Storage Resource for which Certified Reserve Capacity is not being assessed in accordance with the methodology in this Appendix 9); or

ii. the date most recently provided for a Reserve Capacity Cycle under clause 4.10.1(k) otherwise;~~ and~~

(b) a Candidate Facility will be considered to be:

i. a new Candidate Facility, if the seven-year period identified in Step 1(a) of this Appendix commenced before 8:00 AM on the Full Operation Date for the Facility ("**New Candidate Facility**"); or

ii. an existing Candidate Facility ("**Existing Candidate Facility**"), otherwise.

(c) each Candidate Facility will be assigned to one of the following Facility groups, based on AEMO's assessment of the general profile of the Available Capacity of that Candidate Facility through the relevant Capacity Year. In determining the general profile of Available Capacity, AEMO must have regard to the technology, Facility type and Facility Class of that Candidate Facility, as determined by AEMO based on the information specified in clauses 4.10.1 and 2.33.3 and the requirements of clauses 4.11.1(bD)(i) and 4.11.1(bE):

   i. biogas technology group ("**Biogas Facility Group**"), or

   ii. solar technology group ("**Solar Facility Group**"), or

   iii. wind technology group ("**Wind Facility Group**"), or

   iv. non-scheduled Electric Storage Resources group comprising Facilities to which clause 4.11.1(bD)(i) applies ("**Non-Scheduled ESR Facility Group**"), or

   v. Non-Scheduled Facilities group comprising Facilities to which clause 4.11.1(bE) applies ("**Other Non-Scheduled Facility Group**").

(d) AEMO may identify and name one new Facility group or several new Facility groups (other than those specified in the list above) and assign any Candidate Facility to that new Facility group, if AEMO has cause to believe that the general profile of the Available Capacity of that Candidate Facility through the relevant Capacity Year substantially differs from the general profile of the Available Capacity of other Candidate Facilities assigned to respective Facility groups in paragraph (c).

(e) for the purpose of this Appendix 9, the individual Facilities, other than those that are Electric Storage Resource, within an aggregated Facility that is, or to be, registered as a Semi-Scheduled Facility under section 2.30, are to be treated as separate Candidate Facilities and be assigned to the relevant Facility group as per the list above.

(f) the available capacity of a Candidate Facility for a Trading Interval is the amount of capacity available to be sent out (in MW) at the end of the Trading Interval and, for clarity, is not on Planned Outage or Forced Outage ("**Available Capacity**").

Part B: Determination of the Relevant Level

AEMO must perform the following steps to determine the Relevant Level for each Candidate Facility:

Determination of ~~Existing Facility Load for Scheduled Generation~~input data

Step 1: Identify:

(a) the ~~five~~ seven-year period ending at 8:00 AM on 1 April of Capacity Year 1 of the relevant Reserve Capacity Cycle; and

(b) each 12 month period, from 8:00 AM on 1 April to 8:00 AM on 1 April, occurring during the ~~five~~ seven-year period identified in Step 1(a)~~, where the 12 Trading Intervals with the highest Existing Facility Load for Scheduled~~

~~Generation in that 12 month period have not previously been determined under this Appendix 9; and~~

~~(c) any 12 month period, from 1 April to 31 March, occurring during the five year period identified in step 1(a), where the 12 Trading Intervals with the highest Existing Facility Load for Scheduled Generation in that 12 month period have previously been determined under this Appendix 9~~.

Step 2: Determine:

(a) the quantity of electricity (in MWh) sent out by each Candidate Facility using Meter Data Submissions ~~for each of the Trading Intervals in the period identified in step 1(b)~~, which, for a Candidate Facility that is a Semi-Scheduled Facility containing an Electric Storage Resource, must exclude any generation or consumption measured by the Electric Storage Resource Metering required to be installed in accordance with clause 2.29.5BA, for each of the Trading Intervals in the period identified in Step 1(b) ("**Sent Out Generation**"); and~~.~~

(b) for each New Candidate Facility, for each Trading Interval in the period identified in Step 1(b) that falls before 8:00 AM on the Full Operation Date for the Facility, an estimate of the quantity of Available Capacity (in MW), if it had been in operation with the configuration proposed under clause 4.10.1(dA) in the relevant application for certification of Reserve Capacity. The estimates must reflect the estimates in the expert report provided for the Facility under clause 4.10.3, unless AEMO reasonably considers the estimates in the expert report to be inaccurate.

(c) for each Candidate Facility that is a component of an aggregated Facility registered, or to be registered, under section 2.30 for which Candidate Facility no meter data is available to determine the quantity of electricity sent out as per Step 2(a), for each Trading Interval in the period identified in Step 1(b), an estimate of the quantity of Available Capacity (in MW). The estimates must reflect the estimates in the expert report provided for the Facility under clause 4.10.3, unless AEMO reasonably considers the estimates in the expert report to be inaccurate.

Step 3: For each Candidate Facility, identify any Trading Intervals in the period identified in ~~step 1(b)~~ Step 1(b) where the Facility was directed to restrict its Injection under a Dispatch Instruction with a Dispatch Cap or Dispatch Target as published under clause [7.13.1x3(a)].~~:~~

~~(a) the Facility, other than a Facility in the Balancing Portfolio, was directed to restrict its output under a Dispatch Instruction as provided in a schedule under clause 7.13.1(c); or~~

~~(b) the Facility, if in the Balancing Portfolio, was instructed by System Management to deviate from its Dispatch Plan or change its commitment or output as provided in a schedule under clause 7.13.1C(d); or~~

~~(c) was affected by a Consequential Outage as notified by System Management to AEMO under clause 7.13.1A; or~~

Drafting Note

Step 3(d) was not marked for deletion in the Energy Policy WA Tranches 1, 2 or 3 amending rules. Given the changes to Step 3, it appears that Step 3(d) should have also been deleted and that change is marked up below.

~~(d) the Facility was directed to restrict its output under an Operating Instruction issued in accordance with a Network Control Service Contract, as provided in a schedule under clause 7.13.1(cC).~~

Step 4: For each Candidate Facility and Trading Interval identified in Step 3 identify the Sent Out Generation as the higher of:~~3(a):~~

(a) the quantity determined in ~~step 2~~Step 2(a); and~~identify the actual quantity as determined in step 2 if:~~

~~i. System Management has made a revised estimate of the maximum quantity in accordance with clause 7.7.5A(c) and the Power System Operation Procedure specified in clause 7.7.5A; and~~

~~ii. the revised estimate of the maximum quantity is lower than the actual quantity as determined in step 2;~~

(b) if AEMO made a revised estimate under clause 7.13.7 that estimate, otherwise AEMO's estimate made under clause 7.13.6, which for either of these estimates must exclude any generation or consumption measured by the meter required to be installed in accordance with clause 2.29.5BA for a Candidate Facility that is a Semi-Scheduled Facility containing an Electric Storage Resource.~~identify the actual quantity as determined in step 2 if:~~

~~i. step 4(a) does not apply; and~~

~~ii. the estimated maximum quantity determined by System Management under clause 7.13.1(eF) is lower than the actual quantity (as specified in a Meter Data Submission covering the Facility and the Trading Interval); and~~

~~(c) if steps 4(a) and (b) do not apply:~~

~~i. identify the revised estimate of the maximum quantity determined by System Management in accordance with the Power System Operation Procedure specified in clause 7.7.5A; or~~

~~ii. if there is no revised estimate, identify the estimate determined by System Management under clause 7.13.1(eF).~~

Step 5: [Blank]~~For each Candidate Facility and Trading Interval identified in step 3(b) use:~~

~~(a) the estimate recorded by System Management under clause 7.13.1C(e); and~~

~~(b) the quantity determined for the Facility and Trading Interval in step 2,~~

~~to estimate the quantity of energy (in MWh) that would have been sent out by the Facility had it not complied with System Management's instruction to change its commitment or output during the Trading Interval.~~

Step 6: [Blank]~~For each Candidate Facility and Trading Interval identified in step 3(c) use:~~

~~(a) the schedule of Consequential Outages determined by System Management under clause 7.13.1A;~~

~~(b) the quantity determined for the Facility and Trading Interval in step 2; and~~

~~(c) the information recorded by System Management under clause 7.13.1C(a),~~

~~to estimate the quantity of energy (in MWh) that would have been sent out by the Facility had it not been affected by the notified Consequential Outage during the Trading Interval.~~

Step 6A: [Blank]~~For each Candidate Facility and Trading Interval identified in step 3(d) use:~~

~~(a) the schedule of Operating Instructions determined by System Management under clause 7.13.1(cC);~~

~~(b) the quantity determined for the Facility and Trading Interval in step 2; and~~

~~(c) the information recorded by System Management under clause 7.13.1C(a),~~

~~to estimate the quantity of energy (in MWh) that would have been sent out by the Facility had it not been subject to an Operating Instruction during the Trading Interval.~~

Calculation of demand

Step 7: Determine:

(a) the Observed Demand (in MW) for each Trading Interval in ~~each 12 month period identified in step 1(b) the Existing Facility Load for Scheduled Generation (in MWh) as:~~ the period identified in Step 1(a) as:

(Total_Generation + DSP_Reduction + Interruptible_Reduction + Involuntary_Reduction)~~ – CF_Generation~~ x 2

where:

i. Total_Generation is the total sent out generation (in MWh) of all Facilities, as determined from Meter Data Submissions;

ii. DSP_Reduction is the total quantity of Deemed DSM Dispatch for all Demand Side Programmes for that Trading Interval;

iii. Interruptible_Reduction is the total quantity (in MWh) by which all Interruptible Loads reduced the magnitude of their ~~consumption~~Withdrawal in accordance with ~~the terms of an Ancillary Service Contract~~Essential System Service provision, as recorded by ~~System Management~~AEMO under clause 7.13.1C(c);

iv. Involuntary_Reduction is the total quantity of energy (in MWh) not served due to involuntary load shedding (manual and automatic), as recorded by System Management under clause 7.13.1C(b); and

~~CF_Generation is the total sent out generation of all Candidate Facilities, as determined in step 2 or estimated in steps 4, 5, 6 or 6A as applicable.~~

(b) the Scaled Demand for each 12-month period T identified in Step 1(b), by scaling the Observed Demand in that period T using the scaling function $f(t)$ as:

$$Scaled\ Demand(t) = f(t) \times Observed\ Demand\ (t)$$

where:

i. the maximum of $Scaled\ Demand(t)$ for all Trading Intervals during the period T equals AEMO's estimate of the one in ten year peak demand assuming expected demand growth, as determined for the purpose of clause 4.5.10(a)iv for the relevant Reserve Capacity Year;

ii. the sum of $Scaled\ Demand(t)$ divided by two over all Trading Intervals in period T is closest to AEMO's estimate of expected energy consumption in the SWIS for the relevant Reserve Capacity Year; and

iii. the function form of $f(t)$ must be consistent with the load forecasting method AEMO used to forecast the expected energy shortfalls in the SWIS for the purpose of clause 4.5.9(b) for the relevant Reserve Capacity Cycle. For clarity, the scaling function $f(t)$ AEMO uses must also account for expected generation from distributed energy resources, including behind-the-meter solar photovoltaic generation, in the relevant Reserve Capacity Year.

(c) for each Facility Group c, the $CF\_Generation(c)$ for each Trading Interval in the period identified in Step 1(a) as:

$$\sum_{f \in c} (Actual\ CF\_Generation(f)\ +\ Estimated\ CF\_Generation(f))$$

where, the expression above represents a summation across all Facilities f in the Facility Group c.

i. For Existing Candidate Facilities:

1. the $Actual\_CF\_Generation(f, t)$ for the Trading Interval is the Sent Out Generation determined in Step 2(a), or estimated in Step 4, or half of the quantity determined in Step 2(c), as applicable, and

2. the $Estimated\_CF\_Generation$ is zero.

ii. For New Candidate Facilities:

1. the $Actual\_CF\_Generation$, for the Trading Intervals falling after and including 8:00 AM on the Full Operation Date for the Facility, is the Sent Out Generation determined in Step 2(a), or estimated in Step 4, or half of the quantity determined in Step 2(c), as applicable, and zero otherwise; and

2. the $Estimated\_CF\_Generation$, for the Trading Intervals falling before 8:00 AM on the Full Operation Date for the Facility, is half of the quantity determined for the New Candidate Facility in Step 2(b) or half of the quantity determined in Step 2(c), as applicable, and zero otherwise.

(d) the $Storage\_Available\_Capacity$ (in MW) for each Trading Interval in the period identified in Step 1(a) as:

$$\sum_{f_s \in s} AC\_ESR(f_s)$$

where, the expression above represents a summation across all Facilities f_s in the Electric Storage Resources set s comprising all Electric Storage Resources, including those that are part of an aggregated Facility, that may receive Certified Reserve Capacity for the relevant Reserve Capacity Year, other than those included in the set of Candidate Facilities.

For each Electric Storage Resource Facility f_s, $AC\_ESR(f_s)$ (in MW):

i. is equal to zero, if the Trading Interval is not an Electric Storage Resource Obligation Interval;

ii. is equal to zero during a Trading Interval overlapping with the Electric Storage Resource Obligation Intervals, and subsequent Trading Intervals in that Trading Day, when the value of parameter p is less than the expected Forced Outage rate of the Facility;

iii. is equal to the maximum output determined under clause 4.11.3, otherwise.

iv. For each Trading Interval during the Electric Storage Resource Obligation Intervals and each Electric Storage Resource Facility f_s, the value of p should be drawn randomly from a uniform distribution of the range between zero and one.

v. For each Electric Storage Resource Facility f_s, the expected Forced Outage rate to be used in this paragraph is equal to what AEMO determines as the expected Forced Outage rate of the Facility f_s in the relevant Capacity Year, and otherwise if not available the Forced Outage rate calculated in accordance with the Market Procedure specified in clause 3.21.12 for the purpose of clause 4.11.1(h), and otherwise if not available, those values provided to AEMO as outlined in clauses 4.10.1(fA)v, 4.10.1(fB)v, 4.10.1(fC)v.

(e) the part of Scaled Demand to be covered by Facilities other than Candidate Facilities ("**Residual Demand**") for each Trading Interval in the period identified in Step 1(a):

$$Scaled\ Demand - 2 \times \sum_{c} CF\_Generation(c)$$

where the expression $\sum_c CF\_Generation(c)$ represents the sum of $CF\_Generation(c)$ calculated in Step 7(c) across all Facility groups c.

Step 8: Determine for each 12~~-~~month period identified in ~~step 1(b)~~ Step 1(b):

(a) the 12 Trading Intervals~~,~~ occurring on separate Trading Days~~, with the highest Existing Facility Load for Scheduled Generation~~ with the highest Scaled Demand; and

(b) the 12 Trading Intervals occurring on separate Trading Days with the highest Residual Demand.

Calculation of Relevant Level for the fleet of Candidate Facilities and facility groups

Step 9: ~~Identify, for each 12 month period identified in step 1(c), the following~~Determine:

(a) ~~the Existing Facility Load for Scheduled Generation previously determined under this Appendix 9 for each Trading Interval in the 12 month period;~~ for each 12 month period identified in Step 1(b) as the $Relevant\_Period$, the $Annual\_RL\_Fleet$ (in MW) using the calculation in Step 17, and the corresponding Net_Demand data defined in Table 1; and

(b) ~~subject to step 9A, the sent out generation (in MWh) for each Candidate Facility and for each Trading Interval in that 12 month period, where that sent out generation was used to determine the CF_Generation (which is one of the variables used to determine the Existing Facility Load for Scheduled Generation in step 7) for that Trading Interval; and~~ for the period identified in Step 1(a), as the $Relevant\_Period$, the $Full\_Period\_RL\_Fleet$ (in MW) using the calculation in Step 17, and the corresponding Net_Demand data defined in Table 1.

(c) ~~the 12 Trading Intervals occurring on separate Trading Days that were previously determined to have the highest Existing Facility Load for Scheduled Generation in the 12 month period.~~for the period identified in

Step 1(a), as the *Relevant_Period*, for each Facility group c the *Facility_Group_RL*(c), using the calculation in Step 17 and the corresponding *Net_Demand* data defined in Table 1.

(d) the *RL_Fleet* as the lower of:

i. the median of the *Annual_RL_Fleet* values determined in Step 9(a), and

ii. the *Full_Period_RL_Fleet* determined in Step 9(b).

Table 1. Relevant Level scenario and corresponding variables

Relevant Level scenario	*Facility Group*	*Net_Demand* data, used in Step 17(d)	*Relevant Period*
Annual_RL_Fleet	All Candidate Facilities	Residual Demand + *LOLE_adjustment1* + *LOLE_adjustment2* – *Storage_Available_Capaci* rounded to the nearest integer.	Each 12-month period identified in Step 1(b).
Full_Period_RL_Fle	All Candidate Facilities	Residual Demand + *LOLE_adjustment1* + *LOLE_adjustment2* – *Storage_Available_Capaci* rounded to the nearest integer.	Entire period identified in Step 1(a).
Facility_Group_RL(	All Facilities in the Facility group c	Scaled Demand + *LOLE_adjustment1* + *LOLE_adjustment2* – *Storage_Available_Capaci* $2 \times CF\_Generation(c)$ rounded to the nearest integer.	Entire period identified in Step 1(a).

~~Step 9A: For the purposes of step 9(b), if:~~

~~(a) AEMOSystem Management has determined a revised estimate under clause 7.13.7of the maximum quantity in accordance with the Power System Operation Procedure specified in clause 7.7.5A;~~

~~(b) the revised estimate relates to a Candidate Facility and a Trading Interval in a 12 month period identified in step 1(c); and~~

~~(c) AEMO determined the sent out generation for that Candidate Facility and for that Trading Interval in accordance with step 4 before it revised the estimate,~~

~~then AEMO must redetermine the sent out generation for that Candidate Facility and that Trading Interval in accordance with step 4.~~

~~Determining New Facility Load for Scheduled Generation~~

Step 10: ~~For each New Candidate Facility determine, for each Trading Interval in the period identified in step 1(a) that falls before 8:00 AM on the Full Operation Date for the Facility, an estimate of the quantity of energy (in MWh) that would have been sent out by the Facility in the Trading Interval, if it had been in operation with the configuration proposed under clause 4.10.1(dA) in the relevant application for certification of Reserve Capacity. The estimates must reflect the estimates in the expert report provided for the Facility under clause 4.10.3, unless AEMO reasonably considers the estimates in the expert report to be inaccurate.~~

Determine for each facility group c the value of $Adjusted\_Facility\_Group\_RL(c)$ using the calculation steps below:

(a) For each Facility group with interaction index $i(c)$ equal to zero, the value of $Adjusted\_Facility\_Group\_RL(c)$ is equal to $Facility\_Group\_RL(c)$ calculated in Step 9(c). The interaction index $i(c)$ is equal to one for Wind Facility Group and Solar Facility Group, or any New Facility Group that contains wind or solar generation, and zero otherwise.

(b) Calculate the $Facility\_Group\_IE$, representing the interaction effect between facility groups with $i(c)$ equal to one, as:

$$Full\_Period\_RL\_Fleet - \sum_{c} Facility\_Group\_RL(c)$$

where the expression $\sum_c Facility\_Group\_RL(c)$ represents the sum of all $Facility\_Group\_RL(c)$ for all Facility groups estimated in Step 9(c);

(c) Calculate the $AFP\_Facility\_Group\_RL(c)$ for each Facility group c, with interaction index $i(c)$ equal to one, as:

$$Facility\_Group\_RL(c) + \frac{Facility\_Group\_RL(c)}{\sum_c (Facility\_Group\_RL(c)) \times i(c))} \times Facility\_Group\_IE$$

where the $Facility\_Group\_RL(c)$ is determined in Step 9(c).

(d) Calculate the $Adjusted\_Facility\_Group\_RL(c)$ for each Facility group c, with interaction index $i(c)$ equal to one, as:

$$\frac{AFP\_Facility\_Group\_RL(c)}{\sum_c AFP\_Facility\_Group\_RL(c)} \times (Full\_Period\_RL\_Fleet - \sum_{c \in \{\forall c | i(c)=0\}} Facility\_Group\_RL(c))$$

where the expression $\sum_{c \in \{\forall c|c(i)=0\}} Facility\_Group\_RL(c)$ represents the sum of $Facility\_Group\_RL(c)$ for all facility groups c estimated in Step 9(c) with interaction index $i(c)$ equal to zero.

Allocation of Facility group Relevant Level to individual Candidate Facilities

Step 11: ~~For each New Candidate Facility determine, for each Trading Interval in the period identified in step 1(a), the New Facility Load for Scheduled Generation (in MWh) as:~~ For each Candidate Facility f within a Facility group c:

(a) ~~if the Trading Interval falls before 8:00 AM on the Full Operation Date for the Facility:~~

~~EFLSG + Actual_CF_Generation – Estimated_CF_Generation~~

~~where~~

~~EFLSG is the Existing Facility Load for Scheduled Generation for the Trading Interval, determined in step 7 or identified in step 9(a) as applicable;~~

~~Actual_CF_Generation is the sent out generation of the New Candidate Facility for the Trading Interval, as identified in step 9(b), determined in step 2 or estimated in steps~~ step ~~4, 5,6 or 6A as applicable; and~~

~~Estimated_CF_Generation is the quantity determined for the New Candidate Facility and the Trading Interval in step 10;~~

~~or~~

determine the quantities of

$$Actual\_CF\_Generation(f) + Estimated\_CF\_Generation(f)$$

as calculated in Step 7(c), during the Trading Intervals identified in Step 8(a) and 8(b), multiplied by two to convert to units of MW, and

(b) ~~the Existing Facility Load for Scheduled Generation for the Trading Interval, otherwise.~~ determine the $Facility\_Average\_Performance\_Level\ (f)$ as the mean of the quantities determined for Facility f in Step 11(a).

Step 12: ~~For each New Candidate Facility determine, for each 12 month period identified in step 1(a), the 12 Trading Intervals, occurring on separate Trading Days, with the highest New Facility Load for Scheduled Generation.~~ For each Facility group c determine the $Scaling\_Factor(c)$ as:

$$\frac{Adjusted\_Facility\_Group\_RL(c)}{\sum_{f \in c} Facility\_Average\_Performance\_Level(f)}$$

where the denominator represents the sum of $Facility\_Average\_Performance\_Level$ for all Facilities f in the facility group c.

~~***Determining the Facility Average Performance Level***~~

Step 13: ~~For each Existing Candidate Facility, determine the 60 quantities comprising:~~ Determine for each Candidate Facility f in the facility group c the Relevant Level (in MW) as:

$$\max(0, Scaling\ Factor(c) \times Facility\ Average\ Performance\ Level(f))$$

~~(a) the MWh quantities determined in step 2 or estimated in steps~~ step ~~4, 5,6 or 6A as applicable for each of the Trading Intervals determined in step 8, multiplied by 2 to convert to units of MW; and~~

~~(b) the MWh quantities determined in step 9(b) for each of the Trading Intervals identified in step 9(c), multiplied by 2 to convert to units of MW.~~

Calculation of Capacity Outage Probability Table

Step 14: Identify~~For each New Candidate Facility, determine the 60 quantities comprising~~:

(a) ~~the MWh quantities identified in step 9(b), determined in step 2 or estimated in steps~~ step ~~4, 5, 6 or 6A as applicable for each of the Trading Intervals identified in step 12 that fall after 8:00 AM on the Full Operation Date for the Facility, multiplied by 2 to convert to units of MW; and~~ all generation systems registered, or to be registered, as Scheduled Facilities, or as part of a Scheduled Facility, or certified for the relevant Reserve Capacity Cycle, and loads registered as Demand Side Programme that will receive Certified Reserve Capacity for Year 3 of the relevant Reserve Capacity Cycle;

(b) ~~the MWh quantities determined in step 10 for each of the Trading Intervals identified in step 12 that fall before 8:00 AM on the Full Operation Date of the Facility, multiplied by 2 to convert to units of MW.~~ For each generation system Facility identified in Step 14(a), the quantity of Certified Reserve Capacity AEMO would assign to the Facility based on clause 4.11.1, excluding any reduction applied to the Certified Reserve Capacity of the Facility under clause 4.11.1(h), and for each Demand Side Programme the quantity of Certified Reserve Capacity to be assigned to Demand Side Programme for the relevant Reserve Capacity Cycle;

(c) the Forced Outage rate, estimated using Market Procedure: Certification of Reserve Capacity specified in clause 3.21.12, for each Scheduled Facility identified in Step 14(a), for the relevant Reserve Capacity Cycle and the two preceding Reserve Capacity Cycles to the relevant Reserve Capacity Cycle, where available. For each Facility identified in Step 14(a) set the parameter U as the average of the three Forced Outage rates for the three Reserve Capacity Cycles identified in Step 14(c) for the Facility, or otherwise if not available, AEMO's expectation of the expected Forced Outage rate of the Facility determined under clause 4.11.1(h)(ii); and

(d) the Forced Outage rate for each Demand Side Programme, identified in Step 14(a), as zero.

Step 15: Determine ~~the average performance level (in MW) for each Candidate Facility f ("Facility Average Performance Level") as the mean of the 60 quantities determined for Facility f in step 13 or step 14 as applicable.~~ a table of capacity outage amounts X (in MW) and respective cumulative probability of that outage amount by incrementally adding the capacity of all Facilities identified in Step 14 to that table as explained below:

(a) Start with the first Facility G with the Certified Reserve Capacity C, rounded to the nearest integer, and parameter U identified in Step 14(c), for each outage amount X (in MW) from zero with increment of 1 MW, determine $P(X)$ as:

$$P(X) = (1 - U) \times P'(X) + U \times P'(X - C)$$

until $P(X)$ equals zero.

i. After $P(X)$ equals zero, store values of X and corresponding $P(X)$ in a table and repeat the calculation in this paragraph using each generation system or Demand Side Programme G identified in Step 14 and store values of X and corresponding $P(X)$ in the same table created for the previous Facility. If available, overwrite the value of $P(X)$ determined by adding the previous Facilities added to the table with the value of $P(X)$ determined by the new Facility added to the table.

ii. In the equation in this Step 15(a):

1. $P(X)$ is the cumulative probability of the capacity outage of X MW.

2. $P'(X)$ is the cumulative probability of the capacity outage of X MW before adding the Facility G to the table. $P'(X) = 1.0$ if X is less than or equal to zero. For the first Facility G added to the table, $P'(X) = 0$ if X is greater than zero.

(b) Identify the capacity outage probability table as a table listing all outage amounts X from zero to the total Certified Reserve Capacity of Facilities identified in Step 14, and corresponding $P(X)$ after adding the last Facility in Step 15(a) ("**Capacity Outage Probability Table**").

~~Determine the Facility Adjustment Factor~~Calculation of Loss of Load Probability and Loss of Load Expectation.

Step 16: Determine: ~~the variance (in MW) for each Candidate Facility f ("Facility Variance") as the variance of the MW quantities determined for Facility f in step 13 or step 14 as applicable.~~

(a) the loss of load probability in the SWIS for a Trading Interval with a system load of D MW as ("**Loss of Load Probability**");

$$P(CRC - D)$$

where,

i. CRC is the total Certified Reserve Capacities determined in Step 14(b) for all Facilities identified in Step 14(a);

ii. $P(CRC - D)$ is the cumulative probability of an outage of $X = CRC - D$ MW that is derived from the Capacity Outage Probability Table calculated in Step 15; and

(b) the loss of load expectation in the SWIS during a $Relevant\_Period$ as the sum of the Loss of Load Probability (in Trading Intervals), as determined in Step 16(a), for each Trading Interval in that $Relevant\_Period$ ("**Loss of Load Expectation**").

Calculation of the Relevant Level

Step 17: Determine the Relevant Level of a $Facility\_Group$ during a $Relevant\_Period$ using the steps below ~~facility adjustment factor (in MW) for each Candidate Facility f ("Facility Adjustment Factor") in accordance with the following formula~~:

~~Facility Adjustment Factor = min(G x Facility Variance (f), Facility Average Performance Level (f) / 3 + K x Facility Variance (f))~~

~~Where~~

~~G = K + U / Facility Average Performance Level (f)~~

~~K is determined in accordance with the following table:~~

~~**Reserve Capacity Cycle**~~	~~**Capacity Year**~~	~~**K value**~~
~~2012~~	~~2014/15~~	~~0.001~~
~~2013~~	~~2015/16~~	~~0.002~~
~~2014~~	~~2016/17~~	~~0.003~~
~~2015 onwards~~	~~From 2017/18 onwards~~	~~To be determined by the Economic Regulation Authority in accordance with clause 4.11.3C.~~

~~U is determined in accordance with the following table:~~

~~**Reserve Capacity Cycle**~~	~~**Capacity Year**~~	~~**U**~~
~~2012~~	~~2014/15~~	~~0.211~~
~~2013~~	~~2015/16~~	~~0.422~~

~~2014~~	~~2016/17~~	~~0.635~~
~~2015 onwards~~	~~From 2017/18 onwards~~	~~To be determined by the Economic Regulation Authority in accordance with clause 4.11.3C.~~

(a) Calculate the Loss of Load Expectation using the calculation in Step 16(b) and the Scaled Demand determined in Step 7(b), rounded to the nearest integer, as system load during the $Relevant\_Period$.

(b) Increase or decrease the Scaled Demand used in Step 17(a), with increments of whole MW and fixed across all Trading Intervals in the $Relevant\_Period$, and repeat the calculation in Step 17(a) until the Loss of Load Expectation is equal or approximate to eight Trading Intervals in 10 years. Identify the total amount of increase in Scaled Demand that makes the Loss of Load Expectation equal to eight Trading Intervals in 10 years as $LOLE\_adjustment1$.

(c) Calculate the Loss of Load Expectation using the calculation in Step 16(b) and (Scaled Demand + $LOLE\_adjustment1 - Storage\_Available\_Capacity$), rounded to the nearest integer, as system load during the $Relevant\_Period$.

(d) Change the system load calculated in Step 17(c) with increments of whole MW and fixed across all Trading Intervals in the $Relevant\_Period$, until the Loss of Load Expectation is equal or approximate to eight Trading Intervals in 10 years.

(e) Identify the total amount of change in the system load calculated in Step 17(d) that makes the Loss of Load Expectation equal to eight Trading Intervals in 10 years as $LOLE\_adjustment2$.

(f) Calculate the Loss of Load Expectation using the calculation in Step 16(b) and the Net_Load data identified in Table 1 corresponding to the $Facility\_Group$, as system load during the $Relevant\_Period$.

(g) Increase the Net_Load data in Step 14(f), with increments of whole MW and fixed across all Trading Intervals in the $Relevant\_Period$, and repeat the calculation in Step 17(f) with the increased Net_Load data until the Loss of Load Expectation calculated in Step 17(f) is equal or approximate to eight Trading Intervals in 10 years.

The $Relevant\_Level$ of the $Facility\_Group$ during the $Relevant\_Period$ is the total increase in Net_Load (in MW) identified in Step 17(g) that makes the Loss of Load Expectation calculated in Step 17(f) equal or approximate to eight Trading Intervals in 10 years.

~~Determining the Relevant Level for a Facility~~Publication of information

Step 18: Publish on the WEM Website a provisional forecast of the Trading Intervals that may be identified in Step 8 within 20 Business Days before the date specified in clause 4.1.11 (as modified or extended) for the relevant Reserve Capacity Cycle.~~Determine the Relevant Level for each Candidate Facility f (in MW) in accordance with the following formula:~~

~~Relevant Level (f) = max(0, Facility Average Performance Level (f) - Facility Adjustment Factor (f))~~

~~Publication of information~~

Step 19: [Blank]~~Publish on the Market Web Site by 1 June of Year 1 of the relevant Reserve Capacity Cycle on a provisional basis:~~

~~(a) a forecast of the Trading Intervals that may be identified in step 8; and~~

~~(b) a forecast of the Existing Facility Load for Scheduled Generation quantities that may be determined in step 7.~~

Step 20: [Blank]~~Publish on the Market Web Site within three Business Days after the date specified in clause 4.1.11 (as modified or extended) for the relevant Reserve Capacity Cycle:~~

~~(a) the Trading Intervals identified in step 8; and~~

~~(b) the Existing Facility Load for Scheduled Generation quantities determined in step 7.~~

Changes to other market rules

4.9. Process for Applying for Certification of Reserve Capacity

…

4.9.5. If AEMO assigns Certified Reserve Capacity to a Facility for a future Reserve Capacity Cycle under section 4.11 ("**Conditional Certified Reserve Capacity**"):

(a) the Conditional Certified Reserve Capacity is conditional upon:

i. the information included in the application for Certified Reserve Capacity remaining correct as at the date and time specified in clause 4.1.11 for that future Reserve Capacity Cycle; and

ii. AEMO's assessment of the Certified Reserve Capacity for the Facility for the Reserve Capacity Cycle, until the time specified in clause 4.1.15 for that future Reserve Capacity Cycle, remains equal to the Conditional Certified Reserve Capacity.

(b) For Facilities to which the relevant level method specified in clause 4.11.2(b) is applicable for the certification of Reserve Capacity, AEMO must determine the Conditional Certified Reserve Capacity by including the Facility as a Candidate Facility in determining Relevant Levels in the preceding Reserve Capacity Cycle assuming the Facility had applied for the certification of Reserve Capacity in the preceding reserve capacity cycle. When determining Conditional Certified Reserve Capacity AEMO can also have regards to expected resource mix and demand in the SWIS for Year 3 of the future Reserve Capacity Cycle to which the Conditional Certified Reserve Capacity is being assigned to.

(~~b~~c) the Market Participant holding the Conditional Certified Reserve Capacity must, in accordance with clauses 4.9.1 and 4.9.3, re-lodge an application for Certified Reserve Capacity with AEMO between the date and time specified in clause 4.1.7 and the time specified in clause 4.1.11 for that future Reserve Capacity Cycle;

(~~c~~d) if AEMO is satisfied that the application re-lodged in accordance with clause 4.9.5(b) is consistent with the information upon which the Conditional Certified Reserve Capacity was assigned and is correct, and AEMO's assessment of the Certified Reserve Capacity for the Facility remains equal to the Conditional Certified Reserve Capacity previously assigned to the Facility, then AEMO must confirm:

i. the Certified Reserve Capacity;

ii. [Blank]~~the Reserve Capacity Obligation Quantity~~; and

iii. the Reserve Capacity Security~~ or DSM Reserve Capacity Security~~ levels, that were previously conditionally assigned, set or determined by AEMO, subject to the Certified Reserve Capacity for an Intermittent Generator being assigned in accordance with clause 4.11.2(b); and

(~~d~~e) if the application re-lodged in accordance with ~~paragraph (b)~~clause 4.9.5(b) is found by AEMO to be inaccurate or is not consistent with the information upon which the Conditional Certified Reserve Capacity was assigned, or AEMO's assessment of the Certified Reserve Capacity for the Facility differs from the Conditional Certified Reserve Capacity previously assigned to the Facility then AEMO must process the application without regard for the Conditional Certified Reserve Capacity.

…

4.10. Information Required for the Certification of Reserve Capacity

4.10.2. ~~[Blank]~~The types of Facilities eligible to be nominated by a Market Participant under clause 4.10.11(i) for use of the method~~ology~~ described in clause 4.11.2(b), for the purpose of assigning Certified Reserve Capacity or Conditional Certified Reserve Capacity to the Facility are:

(a) a Semi-Scheduled Facility, except in respect of any Electric Storage Resource component of the Facility; and

(b) a Non-Scheduled Facility comprising only an Electric Storage Resource that has not been in operation for the full period of performance assessment identified in Step 1(a) of ~~the Relevant Level Methodology~~ Appendix 9.

4.10.3. An application for certification of Reserve Capacity that includes a nomination to use the method~~ology~~ described in clause 4.11.2(b) for a Facility that, in respect of the Facility or the component of the Facility nominated to use the method~~ology~~ described in clause 4.11.2(b):

(a) is yet to enter service;

(b) is to re-enter service after significant maintenance;

(c) is to re-enter service after having been upgraded; ~~or~~

(d) has not operated with the configuration outlined in clause 4.10.1(dA) for the full period of performance assessment identified in step 1(a) of the Relevant Level Method~~ology~~; or

(e) for which no meter data is available to determine the quantity of electricity sent out as per Step 2(a) of Appendix 9;

must include a report prepared by an expert accredited by AEMO in accordance with clause 4.11.6. AEMO will use the report to assign Certified Reserve Capacity for the Facility or the component of the Facility nominated to use the method~~ology~~ described in clause 4.11.2(b) and to determine the Required Level for that Facility.

4.10.3A. A report provided under clause 4.10.3 must include:

(a) for each Trading Interval during the period identified in Step 1(a) of ~~the Relevant Level Methodology~~Appendix 9~~,~~ a reasonable estimate of the expected capacity (in MW)~~energy~~ that would have been available to be sent out by the Facility or the part of the Facility nominated to use the method~~ology~~ described in clause 4.11.2(b) had it been in operation with the configuration proposed under clause 4.10.1(dA) in the relevant application for certification of Reserve Capacity. This estimate must factor in the effect of Planned Outages or Forced Outages on the capacity available to be sent out;

…

...

4.11. Setting Certified Reserve Capacity

4.11.1. Subject to clause ~~clauses 4.11.7 and~~ 4.11.12, AEMO must apply the following principles in assigning a quantity of Certified Reserve Capacity to a Facility for the Reserve Capacity Cycle for which an application for Certified Reserve Capacity has been submitted in accordance with section ~~clause~~ 4.10:

(a) subject to clause 4.11.2, the Certified Reserve Capacity for a Scheduled ~~Generator~~Facility comprising only generation systems for a Reserve Capacity Cycle must not exceed AEMO's reasonable expectation of the amount of capacity likely to be available, after netting off capacity required to serve Intermittent Loads, embedded loads and Parasitic Loads, for Peak Trading Intervals on Business Days ~~in the period~~ from~~:~~

~~i. the start of December for Reserve Capacity Cycles up to and including 2009; or~~

~~ii.~~ the Trading Day starting ~~on~~ 1 October ~~for Reserve Capacity Cycles from 2010 onwards,~~

in Year 3 of the Reserve Capacity Cycle to the end of July in Year 4 of the Reserve Capacity Cycle, assuming an ambient temperature of 41°C;

(b) ~~where the Facility is a generation system (other than an Intermittent Generator)~~for a Scheduled Facility comprising only generation systems, the Certified Reserve Capacity must not exceed the sum of the capacities specified in clauses 4.10.1(e)(ii) and 4.10.1(e)(iii);

(bA) where the Facility is an energy producing~~a generation~~ system, the Certified Reserve Capacity must not exceed ~~—~~the Declared Sent Out Capacity for the Facility notified to AEMO under clause 4.10.1(bA)(iii);

~~i. where that Facility is a Constrained Access Facility, the Constrained Access Entitlement as at the date and time specified in clause 4.1.12(b); or~~

~~ii. otherwise, the level of unconstrained network access as referred to in clause 4.10.1(bA)(iii);~~

(bB) where two or more~~ generation~~ Facilities share a Declared Sent Out Capacity, the total quantity of Certified Reserve Capacity assigned to those Facilities must not exceed the Declared Sent Out Capacity;

(bC) for a Scheduled Facility containing an Electric Storage Resource or Semi-Scheduled Facility containing an Electric Storage Resource, the total quantity of Certified Reserve Capacity determined for the Electric Storage Resource must be determined by AEMO in accordance with clause 4.11.2;

(bD) for a Non-Scheduled Facility containing only an Electric Storage Resource, including Small Aggregation of aggregated Electric Storage Resources, the total quantity of Certified Reserve Capacity must be:

i. determined in accordance with the Relevant Level Method~~ology~~; or

ii. if the Electric Storage Resource has not been in operation for the full period of performance assessment identified in step 1(a) of the Relevant Level Method~~ology~~, determined in accordance with clause 4.11.2;

(bE) for a Non-Scheduled Facility, excluding Non-Scheduled Facilities under clause 4.11.1(bD), the total quantity of Certified Reserve Capacity assigned to the Facility must be determined in accordance with the Relevant Level Method~~ology~~;

…

…

4.11.2. Where an applicant submits an application for Certified Reserve Capacity, in accordance with clause 4.10, and nominates under clause 4.10.1(i) to have AEMO use the method~~ology~~ described in clause 4.11.2(b) to apply to a Scheduled ~~Generator~~Facility or a Non-Scheduled ~~Generator~~Facility, AEMO:

(a) [Blank]~~may reject the nomination if AEMO reasonably believes that the capacity of the Facility has permanently declined, or is anticipated to permanently decline prior to or during the Reserve Capacity Cycle to which the Certified Reserve Capacity relates~~;

(aA) [Blank]~~if it rejects a nomination under clause 4.11.2(a), must process the application as if the application had nominated to use the methodology described in clause 4.11.1(a) rather than the methodology described in clause 4.11.2(b)~~; and

(b) subject to clause 4.11.12, ~~if it has not rejected the nomination under clause 4.11.2(a),~~ must assign a quantity of Certified Reserve Capacity to the relevant Facility for the Reserve Capacity Cycle equal to the Relevant Level as determined in accordance with the Relevant Level Method~~ology~~, but subject to clauses 4.11.1(b), 4.11.1(bA), 4.11.1(bB), 4.11.1(c), 4.11.1(f), 4.11.1(g), 4.11.1(h), and 4.11.1(i).

…

4.11.3C. For each three-year period, beginning with the period commencing on 1 January ~~2015~~2022, the Economic Regulation Authority must, by 1 April of the first year of that period, conduct a review of the Relevant Level Method~~ology~~. In conducting the review, the Economic Regulation Authority ~~must~~:

(a) must examine the effectiveness of the Relevant Level Method~~ology~~ in meeting the Wholesale Market Objectives; and

(b) ~~determine the values of the parameters K and U in step 17 of the Relevant Level Methodology to be applied for each of the three Reserve Capacity Cycles commencing in the period,~~

~~and the Economic Regulation Authority~~ may examine any other matters that the Economic Regulation Authority considers to be relevant.

…

4.11.3E. At the conclusion of a review under clause 4.11.3C, the Economic Regulation Authority must publish a final report containing:

(a) details of the Economic Regulation Authority's review of the Relevant Level Method~~ology~~;

(b) a summary of the submissions received during the consultation period;

(c) the Economic Regulation Authority's response to any issues raised in those submissions;

(d) ~~the values of the parameters K and U determined under clause 4.11.3C; and~~

~~(e)~~ any recommended amendments to the Relevant Level Method~~ology~~ which the Economic Regulation Authority intends to progress as a Rule Change Proposal.

…

4.28C. Early Certification of Reserve Capacity

4.28C.1. This section 4.28C is applicable to Facilities to which the following conditions apply:

(a) the Facility is a new Facility;

(b) the Facility is ~~a generating~~an energy producing system;~~ and~~

(c) the Facility is deemed by AEMO to be committed~~.~~;~~ and~~

(d) AEMO is satisfied that:

i. the construction of the Facility cannot be achieved within the Reserve Capacity Cycle for which Capacity Credits are being sought for the Facility; and

ii. the Commissioning Tests for the Facility cannot be achieved before the commencement of the Capacity Year for which Capacity Credits are being sought for the Facility~~.~~; and

(e) if the Facility is deemed by AEMO to be a Candidate Facility for the purpose of Appendix 9, the Facility would not be part of a facility group with interaction index $i(c)$ equal to one, as per Step 10(a) of the Relevant Level Method.

…

10.5. Public Information

10.5.1. AEMO must set the class of confidentiality status for the following information under clause 10.2.1 as Public and AEMO must make each item of information available from or via the Market Web Site after that item of information becomes available to AEMO:

…

(f) the following Reserve Capacity information (if applicable):

…

x. the following information identified for a Reserve Capacity Cycle under the Relevant Level Method~~ology~~:

1. ~~the Existing Facility Load for Scheduled Generation for each Trading Interval in the five year period determined under Step 1(a) of Appendix 9; and~~ the Scaled Demand determined under Step 7(b) of Appendix 9 determined for each Trading Interval in the period identified in Step 1(a) of Appendix 9.

2. ~~the 12 Trading Intervals occurring on separate Trading Days with the highest Existing Facility Load for Scheduled Generation for each 12 month period in the five year period; and~~ the Residual Demand calculated in Step 7(e) of Appendix 9 determined for each Trading Interval in the period identified in Step 1(a) of Appendix 9.

3. the Capacity Outage Probability Table calculated in Step 15(b) of Appendix 9.

4. the $Annual\_RL\_Fleet$ calculated in Step 9(a) of Appendix 9.

5. the $Full\_Period\_RL\_Fleet$ calculated in Step 9(b) of Appendix 9.

6. for each facility group c the $Facility\_Group\_RL(c)$ calculated in Step 9(c) of Appendix 9.

7. $LOLE\_adjustment2$ calculated in Step 17(c) of Appendix 9.

8. For each facility group c, the $Scaling\_Factor(c)$ calculated in Step 12 of Appendix 9.

…

…

…

11. Glossary

~~**Existing Facility Load for Scheduled Generation**: Means the MWh quantity determined for a Trading Interval under step 7 of the Relevant Level Methodology.~~

…

~~**New Facility Load for Scheduled Generation**: Means, for a new or upgraded Facility that has applied to be assigned Certified Reserve Capacity under clause 4.11.2(b), the MWh quantity determined for a Trading Interval under step 11 of the Relevant Level Methodology for that Facility and the relevant Reserve Capacity Cycle.~~

…

Observed Demand: An estimate of the total amount of electricity demand in the SWIS in MW over a Trading Interval that should have been supplied through the transmission grid if no load was reduced or disconnected by AEMO, as calculated in Step 7(a) of Appendix 9.

…

Relevant Level Method~~ology~~: Means the method of determining the Relevant Level specified in Appendix 9.

Appendix 2 The amended market rules after implementing the proposed changes

Appendix 9: Relevant Level Determination

This Appendix presents the method for determining the Relevant Levels for ("**Candidate Facilities**") for which

(a) Market Participants have applied for certification of Reserve Capacity for a given Reserve Capacity Cycle under section 4.9; and

(b) the Certified Reserve Capacity is to be assigned using the method in clause 4.11.2(b).

Part A: Introduction

For the purposes of the Relevant Level determination in this Appendix 9:

(a) the full operation date of a Candidate Facility for the Reserve Capacity Cycle ("**Full Operation Date**") is:

i. the date provided under clause 4.10.1(c)(iii)(7) or revised in accordance with clause 4.27.11A, where at the time the application for certification of Reserve Capacity is made the Facility, or part of the Facility (as applicable) is yet to enter service (excluding a part of a Facility that is an Electric Storage Resource for which Certified Reserve Capacity is not being assessed in accordance with the methodology in this Appendix 9); or

ii. the date most recently provided for a Reserve Capacity Cycle under clause 4.10.1(k) otherwise;

(b) a Candidate Facility will be considered to be:

i. a new Candidate Facility, if the seven-year period identified in Step 1(a) of this Appendix commenced before 8:00 AM on the Full Operation Date for the Facility ("**New Candidate Facility**"); or

ii. an existing Candidate Facility ("**Existing Candidate Facility**"), otherwise.

Assignment of candidate facilities to facility groups

After calculating the capacity value of the fleet of candidate facilities this proposed method apportions the estimated fleet-wide capacity value to facilities based on their contribution to the fleet-wide capacity value.

This requires placing candidate facilities within facility groups based on their general profile of availability of capacity through the relevant capacity year.

AEMO assigns facilities to default facility groups or new facility groups having consideration for their available capacity profile. For clarity all existing facilities in the SWIS must be placed in one of the default facility groups identified. Although it could be ideal to specify a quantitative measure for AEMO to assess placement in facility groups it is not practical to develop such method.

AEMO can create new facility groups to provide opportunity to new technologies to apply for the certification of reserve capacity. Such new technologies, for example, may be wave generation, offshore wind turbines, solar thermal or tracking solar.

The "other non-scheduled facility group" may contain solar, wind or biogas facilities. Nevertheless, these facilities have less than 10 MW installed capacity and are not likely to have any material capacity value interaction with other wind and solar farms. Although one option was to separate these components and place them in respective default technology groups, this could create an unnecessary cost (despite being small) for producing estimated data for individual components. Currently the installed capacity of such small facilities is very small in the SWIS.

The ERA will periodically review the RLM and will determine if new default facility groups are to be added to the list above.

(c) each Candidate Facility will be assigned to one of the following Facility groups, based on AEMO's assessment of the general profile of the Available Capacity of that Candidate Facility through the relevant Capacity Year. In determining the general profile of Available Capacity, AEMO must have regard to the technology, Facility type and Facility Class of that Candidate Facility, as determined by AEMO based on the information specified in clauses 4.10.1 and 2.33.3 and the requirements of clauses 4.11.1(bD)(i) and 4.11.1(bE):

   i. biogas technology group ("**Biogas Facility Group**"), or

   ii. solar technology group ("**Solar Facility Group**"), or

   iii. wind technology group ("**Wind Facility Group**"), or

   iv. non-scheduled Electric Storage Resources group comprising Facilities to which clause 4.11.1(bD)(i) applies ("**Non-Scheduled ESR Facility Group**"), or

   v. Non-Scheduled Facilities group comprising Facilities to which clause 4.11.1(bE) applies ("**Other Non-Scheduled Facility Group**").

(d) AEMO may identify and name one new Facility group or several new Facility groups (other than those specified in the list above) and assign any Candidate Facility to that new Facility group, if AEMO has cause to believe that the general profile of the Available Capacity of that Candidate Facility through the relevant Capacity Year substantially differs from the general profile of the Available Capacity of other Candidate Facilities assigned to respective Facility groups in paragraph (c).

Individual facilities within an aggregated facility are to be treated as separate candidate facilities

The individual components of aggregated Facilities are to be treated as separate Candidate Facilities and be assigned to the relevant Facility group as per Part A(c).

For clarity, the intention of this bullet point is not to break down an aggregated Facility to individual assets or generators. For example, an aggregated Facility that comprises several wind farms or wind turbines, and several solar farms is to be treated as two separate Candidate Facilities: one Candidate Facility comprising all wind turbines or farms and one Candidate Facility comprising all solar farms.

(e) for the purpose of this Appendix 9, the individual Facilities, other than those that are Electric Storage Resource, within an aggregated Facility that is, or to be, registered as a Semi-Scheduled Facility under section 2.30, are to be treated as separate Candidate Facilities and be assigned to the relevant Facility group as per the list above.

(f) the available capacity of a Candidate Facility for a Trading Interval is the amount of capacity available to be sent out (in MW) at the end of the Trading Interval and, for clarity, is not on Planned Outage or Forced Outage ("**Available Capacity**").

Part B: Determination of the Relevant Level

AEMO must perform the following steps to determine the Relevant Level for each Candidate Facility:

Determination of input data

Step 1: Identify:

(a) the seven-year period ending at 8:00 AM on 1 April of Capacity Year 1 of the relevant Reserve Capacity Cycle; and

(b) each 12 month period, from 8:00 AM on 1 April to 8:00 AM on 1 April, occurring during the seven-year period identified in Step 1(a).

Step 2: Determine:

(a) the quantity of electricity (in MWh) sent out by each Candidate Facility using Meter Data Submissions, which, for a Candidate Facility that is a Semi-Scheduled Facility containing an Electric Storage Resource, must exclude any generation or consumption measured by the Electric Storage Resource Metering required to be installed in accordance with clause 2.29.5BA, for each of the Trading Intervals in the period identified in Step 1(b) ("**Sent Out Generation**"); and

(b) for each New Candidate Facility, for each Trading Interval in the period identified in Step 1(b) that falls before 8:00 AM on the Full Operation Date for the Facility, an estimate of the quantity of Available Capacity (in MW), if it had been in operation with the configuration proposed under clause 4.10.1(dA) in the relevant application for certification of Reserve Capacity. The estimates must reflect the estimates in the expert report provided for the Facility under clause 4.10.3, unless AEMO reasonably considers the estimates in the expert report to be inaccurate.

Components of an aggregated Facility are to provide an estimate of their Available Capacity to AEMO

The individual components of aggregated Facilities are to be treated as separate Candidate Facilities and be assigned to the relevant Facility group as per Part A(e). These components are to provide an estimate of their Available Capacity to AEMO.

(c) for each Candidate Facility that is a component of an aggregated Facility registered, or to be registered, under section 2.30 for which Candidate Facility no meter data is available to determine the quantity of electricity sent out as per Step 2(a), for each Trading Interval in the period identified in Step 1(b), an estimate of the quantity of Available Capacity (in MW). The estimates must reflect the estimates in the expert report provided for the Facility under clause 4.10.3, unless AEMO reasonably considers the estimates in the expert report to be inaccurate.

Step 3: For each Candidate Facility, identify any Trading Intervals in the period identified in Step 1(b) where the Facility was directed to restrict its Injection under a Dispatch Instruction with a Dispatch Cap or Dispatch Target as published under clause [7.13.1x3(a)].

Drafting Note

Step 3(d) was not marked for deletion in the Energy Policy WA Tranches 1, 2 or 3 amending rules. Given the changes to Step 3, it appears that Step 3(d) should have also been deleted and that change is reflected here.

Step 4: For each Candidate Facility and Trading Interval identified in Step 3 identify the Sent Out Generation as the higher of:

(a) the quantity determined in Step 2(a); and

(b) if AEMO made a revised estimate under clause 7.13.7 that estimate, otherwise AEMO's estimate made under clause 7.13.6, which for either of these estimates must exclude any generation or consumption measured by the meter required to be installed in accordance with clause 2.29.5BA for a Candidate Facility that is a Semi-Scheduled Facility containing an Electric Storage Resource.

Step 5: [Blank]

Step 6: [Blank]

Step 6A: [Blank]

Calculation of demand

Step 7: Determine:

(a) the Observed Demand (in MW) for each Trading Interval in the period identified in Step 1(a) as:

(Total_Generation + DSP_Reduction + Interruptible_Reduction + Involuntary_Reduction) x 2

where:

i. Total_Generation is the total sent out generation (in MWh) of all Facilities, as determined from Meter Data Submissions;

ii. DSP_Reduction is the total quantity of Deemed DSM Dispatch for all Demand Side Programmes for that Trading Interval;

iii. Interruptible_Reduction is the total quantity (in MWh) by which all Interruptible Loads reduced the magnitude of their Withdrawal in accordance with Essential System Service provision, as recorded by AEMO under clause 7.13.1C(c);

iv. Involuntary_Reduction is the total quantity of energy (in MWh) not served due to involuntary load shedding (manual and automatic), as recorded by System Management under clause 7.13.1C(b); and

Calculation of Relevant Level based on forecast demand

The following step scales observed demand and produces a forecast demand, referred to as scaled demand.

The scaling function used is similar to that AEMO uses for the calculation of expected energy shortfall in the SWIS, for the purpose of clause 4.5.9(b) of the WEM Rules.

For clarity this scaling function also accounts for the uptake of distributed energy resources, such as behind-the-meter rooftop solar photovoltaic. This ensures the historical demand is scaled to also reflect the expected uptake of distributed energy resources in the system in the target capacity year. The scaling process removes the effect of distributed energy resources from observed system demand to estimate underlying demand in the SWIS. It then scales the underlying demand to reflect the forecast 10% PoE peak demand and expected energy consumption in the SWIS in the relevant capacity year. It then reduces the scaled underlying demand by the amount of expected generation from distributed energy resources to produce a forecast of operation demand in the SWIS for the relevant capacity year.

(b) the Scaled Demand for each 12-month period T identified in Step 1(b), by scaling the Observed Demand in that period T using the scaling function $f(t)$ as:

$$Scaled\ Demand(t) = f(t) \times Observed\ Demand\ (t)$$

where:

i. the maximum of $Scaled\ Demand(t)$ for all Trading Intervals during the period T equals AEMO's estimate of the one in ten year peak demand assuming expected demand growth, as determined for the purpose of clause 4.5.10(a)iv for the relevant Reserve Capacity Year;

ii. the sum of $Scaled\ Demand(t)$ divided by two over all Trading Intervals in period T is closest to AEMO's estimate of expected energy consumption in the SWIS for the relevant Reserve Capacity Year; and

iii. the function form of $f(t)$ must be consistent with the load forecasting method AEMO used to forecast the expected energy shortfalls in the SWIS for the purpose of clause 4.5.9(b) for the relevant Reserve Capacity Cycle. For clarity, the scaling function $f(t)$ AEMO uses must also account for expected generation from distributed energy resources, including behind-the-meter solar photovoltaic generation, in the relevant Reserve Capacity Year.

(c) for each Facility Group c, the $CF\_Generation(c)$ for each Trading Interval in the period identified in Step 1(a) as:

$$\sum_{f \in c} (Actual\_CF\_Generation(f) + Estimated\_CF\_Generation(f))$$

where, the expression above represents a summation across all Facilities f in the Facility Group c.

i. For Existing Candidate Facilities:

1. the $Actual\_CF\_Generation(f,t)$ for the Trading Interval is the Sent Out Generation determined in Step 2(a), or estimated in Step 4, or half of the quantity determined in Step 2(c), as applicable, and

2. the $Estimated\_CF\_Generation$ is zero.

ii. For New Candidate Facilities:

1. the $Actual\_CF\_Generation$, for the Trading Intervals falling after and including 8:00 AM on the Full Operation Date for the Facility, is the Sent Out Generation determined in Step 2(a), or estimated in Step 4, or half of the quantity determined in Step 2(c), as applicable, and zero otherwise; and

2. the $Estimated\_CF\_Generation$, for the Trading Intervals falling before 8:00 AM on the Full Operation Date for the Facility, is half of the quantity determined for the New Candidate Facility in Step 2(b) or half of the quantity determined in Step 2(c), as applicable, and zero otherwise.

Accounting for the available capacity of Energy Storage Resources

The sum of maximum discharge capability of Electric Storage Resources during the Electric Storage Resource Obligation Intervals is to be calculated. This estimate will be used in Step 17 to account for the available capacity of Energy Storage Resources.

The calculation also accounts for the effect of expected forced outages from Electric Storage Resources.

(d) the $Storage\_Available\_Capacity$ (in MW) for each Trading Interval in the period identified in Step 1(a) as:

$$\sum_{f_s \in s} AC\_ESR(f_s)$$

where, the expression above represents a summation across all Facilities f_s in the Electric Storage Resources set s comprising all Electric Storage Resources, including those that are part of an aggregated Facility, that may receive Certified Reserve Capacity for the relevant Reserve Capacity Year, other than those included in the set of Candidate Facilities.

For each Electric Storage Resource Facility f_s, $AC\_ESR(f_s)$ (in MW):

i. is equal to zero, if the Trading Interval is not an Electric Storage Resource Obligation Interval;

ii. is equal to zero during a Trading Interval overlapping with the Electric Storage Resource Obligation Intervals, and subsequent Trading Intervals in that Trading Day, when the value of parameter p is less than the expected Forced Outage rate of the Facility;

iii. is equal to the maximum output determined under clause 4.11.3, otherwise.

iv. For each Trading Interval during the Electric Storage Resource Obligation Intervals and each Electric Storage Resource Facility f_s, the value of p should be drawn randomly from a uniform distribution of the range between zero and one.

v. For each Electric Storage Resource Facility f_s, the expected Forced Outage rate to be used in this paragraph is equal to what AEMO determines as the expected Forced Outage rate of the Facility f_s in the relevant Capacity Year, and otherwise if not available the Forced Outage rate calculated in accordance with the Market Procedure specified in clause 3.21.12 for the purpose of clause 4.11.1(h), and otherwise if not available, those values provided to AEMO as outlined in clauses 4.10.1(fA)v, 4.10.1(fB)v, 4.10.1(fC)v.

(e) the part of Scaled Demand to be covered by Facilities other than Candidate Facilities ("**Residual Demand**") for each Trading Interval in the period identified in Step 1(a):

$$Scaled\ Demand - 2 \times \sum_{c} CF\_Generation(c)$$

where the expression $\sum_c CF\_Generation(c)$ represents the sum of $CF\_Generation(c)$ calculated in Step 7(c) across all Facility groups c.

Sampling periods of high reliability stress

After the application of scaled demand periods of high reliability stress (with high loss of load probability) are expected to mostly happen during the highest scaled demand periods. That is, periods of the highest scaled demand and highest residual demand would coincide. Nevertheless, periods of high reliability stress in the future might occur when Residual Demand is the highest, but demand is not the highest. This would be more likely to happen with increased penetration of intermittent generators.

The design of this clause ensures resources within one facility group receive Relevant Level consistent with their contribution to meeting the planning criterion.

The periods identified in this step are used in Step 11 to assign facility group Relevant Levels to individual facilities.

Step 8: Determine for each 12-month period identified in Step 1(b):

(a) the 12 Trading Intervals occurring on separate Trading Days with the highest Scaled Demand; and

(b) the 12 Trading Intervals occurring on separate Trading Days with the highest Residual Demand.

Calculation of Relevant Level for the fleet of Candidate Facilities and facility groups

Calculation of the Relevant Level of the fleet of Candidate Facilities and each facility group.

The following step calculates a sample of eight Relevant Levels for Candidate Facilities as a Fleet: one Relevant Level for each 12-month period in the preceding seven years and one based on entire seven-year period. Based on the sample produced the Relevant Level of the fleet of Candidate Facilities is set.

The Relevant Level of each facility group is also estimated based on the entire seven-year period.

Step 9: Determine:

(a) for each 12 month period identified in Step 1(b) as the $Relevant\_Period$, the $Annual\_RL\_Fleet$ (in MW) using the calculation in Step 17, and the corresponding Net_Demand data defined in Table 1; and

(b) for the period identified in Step 1(a), as the $Relevant\_Period$, the $Full\_Period\_RL\_Fleet$ (in MW) using the calculation in Step 17, and the corresponding Net_Demand data defined in Table 1.

(c) for the period identified in Step 1(a), as the $Relevant\_Period$, for each Facility group c the $Facility\_Group\_RL(c)$, using the calculation in Step 17 and the corresponding Net_Demand data defined in Table 1.

(d) the RL_Fleet as the lower of:

i. the median of the $Annual\_RL\_Fleet$ values determined in Step 9(a), and

ii. the $Full\_Period\_RL\_Fleet$ determined in Step 9(b).

Table 1. Relevant Level scenario and corresponding variables

Relevant Level scenario	$Facility\_Group$	Net_Demand data, used in Step 17(d)	$Relevant\_Period$
$Annual\_RL\_Fleet$	All Candidate Facilities	Residual Demand + $LOLE\_adjustment1 +$ $LOLE\_adjustment2 -$ $Storage\_Available\_Capaci$ rounded to the nearest integer.	Each 12-month period identified in Step 1(b).
$Full\_Period\_RL\_Fle$	All Candidate Facilities	Residual Demand + $LOLE\_adjustment1 +$ $LOLE\_adjustment2 -$ $Storage\_Available\_Capaci$ rounded to the nearest integer.	Entire period identified in Step 1(a).
$Facility\_Group\_RL($	All Facilities in the Facility group c	Scaled Demand + $LOLE\_adjustment1 +$ $LOLE\_adjustment2 -$ $Storage\_Available\_Capaci$ $2 \times CF\_Generation(c)$ rounded to the nearest integer.	Entire period identified in Step 1(a).

Step 10: Determine for each facility group c the value of $Adjusted\_Facility\_Group\_RL(c)$ using the calculation steps below:

Accounting for the possible interaction between the Relevant Level of facility groups

The following step accounts for the possible interaction between the Relevant Level of wind and solar facility groups and produces an adjusted facility group Relevant Level.

The step requires AEMO to set the interaction index to zero for any new facility group identified, other than those that contain solar and wind generation.

The ERA will periodically review the relevant level method and will consider if the interaction indexes for facility groups are to be modified.

(a) For each Facility group with interaction index $i(c)$ equal to zero, the value of $Adjusted\_Facility\_Group\_RL(c)$ is equal to $Facility\_Group\_RL(c)$ calculated in Step 9(c). The interaction index $i(c)$ is equal to one for Wind Facility Group and Solar Facility Group, or any New Facility Group that contains wind or solar generation, and zero otherwise.

(b) Calculate the $Facility\_Group\_IE$, representing the interaction effect between facility groups with $i(c)$ equal to one, as:

$$Full\_Period\_RL\_Fleet - \sum_{c} Facility\_Group\_RL(c)$$

where the expression $\sum_c Facility\_Group\_RL(c)$ represents the sum of all $Facility\_Group\_RL(c)$ for all Facility groups estimated in Step 9(c);

(c) Calculate the $AFP\_Facility\_Group\_RL(c)$ for each Facility group c, with interaction index $i(c)$ equal to one, as:

$$Facility\_Group\_RL(c) + \frac{Facility\_Group\_RL(c)}{\sum_c (Facility\_Group\_RL(c)) \times i(c))} \times Facility\_Group\_IE$$

where the $Facility\_Group\_RL(c)$ is determined in Step 9(c).

(d) Calculate the $Adjusted\_Facility\_Group\_RL(c)$ for each Facility group c, with interaction index $i(c)$ equal to one, as:

$$\frac{AFP\_Facility\_Group\_RL(c)}{\sum_c AFP\_Facility\_Group\_RL(c)} \times (Full\_Period\_RL\_Fleet - \sum_{c \in \{\forall c | i(c)=0\}} Facility\_Group\_RL(c))$$

where the expression $\sum_{c \in \{\forall c | c(i)=0\}} Facility\_Group\_RL(c)$ represents the sum of $Facility\_Group\_RL(c)$ for all facility groups c estimated in Step 9(c) with interaction index $i(c)$ equal to zero.

Allocation of Facility group Relevant Level to individual Candidate Facilities

Allocation of facility group Relevant Level to individual Candidate Facilities

Individual Candidate Facilities within a facility group will receive a portion of the adjusted facility group Relevant Level based on their average available capacity during peak scaled demand and peak residual demand periods identified in Step 8.

Step 11: For each Candidate Facility f within a Facility group c:

(a) determine the quantities of

$$Actual\_CF\_Generation(f) + Estimated\_CF\_Generation(f)$$

as calculated in Step 7(c), during the Trading Intervals identified in Step 8(a) and 8(b), multiplied by two to convert to units of MW, and

(b) determine the $Facility\_Average\_Performance\_Level\ (f)$ as the mean of the quantities determined for Facility f in Step 11(a).

Step 12: For each Facility group c determine the $Scaling\_Factor(c)$ as:

$$\frac{Adjusted\_Facility\_Group\_RL(c)}{\sum_{f \in c} Facility\_Average\_Performance\_Level(f)}$$

where the denominator represents the sum of $Facility\_Average\_Performance\_Level$ for all Facilities f in the facility group c.

Step 13: Determine for each Candidate Facility f in the facility group c the Relevant Level (in MW) as:

$$\max(0, Scaling\_Factor(c) \times Facility\_Average\_Performance\_Level(f))$$

<u>Calculation of Capacity Outage Probability Table</u>

Step 14: Identify:

(a) all generation systems registered, or to be registered, as Scheduled Facilities, or as part of a Scheduled Facility, or certified for the relevant Reserve Capacity Cycle, and loads registered as Demand Side Programme that will receive Certified Reserve Capacity for Year 3 of the relevant Reserve Capacity Cycle;

(b) For each generation system Facility identified in Step 14(a), the quantity of Certified Reserve Capacity AEMO would assign to the Facility based on clause 4.11.1, excluding any reduction applied to the Certified Reserve Capacity of the Facility under clause 4.11.1(h), and for each Demand Side Programme the quantity of Certified Reserve Capacity to be assigned to Demand Side Programme for the relevant Reserve Capacity Cycle;

(c) the Forced Outage rate, estimated using Market Procedure: Certification of Reserve Capacity specified in clause 3.21.12, for each Scheduled Facility identified in Step 14(a), for the relevant Reserve Capacity Cycle and the two preceding Reserve Capacity Cycles to the relevant Reserve Capacity Cycle, where available. For each Facility identified in Step 14(a) set the parameter U as the average of the three Forced Outage rates for the three Reserve Capacity Cycles identified in Step 14(c) for the Facility, or otherwise if not available, AEMO's expectation of the expected Forced Outage rate of the Facility determined under clause 4.11.1(h)(ii); and

(d) the Forced Outage rate for each Demand Side Programme, identified in Step 14(a), as zero.

Step 15: Determine a table of capacity outage amounts X (in MW) and respective cumulative probability of that outage amount by incrementally adding the capacity of all Facilities identified in Step 14 to that table as explained below:

(a) Start with the first Facility G with the Certified Reserve Capacity C, rounded to the nearest integer, and parameter U identified in Step 14(c), for each outage amount X (in MW) from zero with increment of 1 MW, determine $P(X)$ as:

$$P(X) = (1 - U) \times P'(X) + U \times P'(X - C)$$

until $P(X)$ equals zero.

i. After $P(X)$ equals zero, store values of X and corresponding $P(X)$ in a table and repeat the calculation in this paragraph using each generation system or Demand Side Programme G identified in Step 14 and store values of X and corresponding $P(X)$ in the same table created for the previous Facility. If available, overwrite the value of $P(X)$ determined by adding the previous Facilities added to the table with the value of $P(X)$ determined by the new Facility added to the table.

ii. In the equation in this Step 15(a):

1. $P(X)$ is the cumulative probability of the capacity outage of X MW.

2. $P'(X)$ is the cumulative probability of the capacity outage of X MW before adding the Facility G to the table. $P'(X) = 1.0$ if X is less than or equal to zero. For the first Facility G added to the table, $P'(X) = 0$ if X is greater than zero.

(b) Identify the capacity outage probability table as a table listing all outage amounts X from zero to the total Certified Reserve Capacity of Facilities identified in Step 14, and corresponding $P(X)$ after adding the last Facility in Step 15(a) ("**Capacity Outage Probability Table**").

Calculation of Loss of Load Probability and Loss of Load Expectation.

Step 16: Determine:

(a) the loss of load probability in the SWIS for a Trading Interval with a system load of D MW as ("**Loss of Load Probability**");

$$P(CRC - D)$$

where,

i. CRC is the total Certified Reserve Capacities determined in Step 14(b) for all Facilities identified in Step 14(a);

ii. $P(CRC - D)$ is the cumulative probability of an outage of $X = CRC - D$ MW that is derived from the Capacity Outage Probability Table calculated in Step 15; and

(b) the loss of load expectation in the SWIS during a $Relevant\_Period$ as the sum of the Loss of Load Probability (in Trading Intervals), as determined in Step 16(a), for each Trading Interval in that $Relevant\_Period$ ("**Loss of Load Expectation**").

Calculation of the Relevant Level

Calculation of relevant level as the contribution to meet the reliability planning criterion

The relevant level of the fleet of candidate facilities, or a facility group, is measured as the amount of additional demand the system can cover while maintaining the loss of load expectation at four hours in 10 years.

Step 17: Determine the Relevant Level of a $Facility\_Group$ during a $Relevant\_Period$ using the steps below:

(a) Calculate the Loss of Load Expectation using the calculation in Step 16(b) and the Scaled Demand determined in Step 7(b), rounded to the nearest integer, as system load during the $Relevant\_Period$.

(b) Increase or decrease the Scaled Demand used in Step 17(a), with increments of whole MW and fixed across all Trading Intervals in the $Relevant\_Period$, and repeat the calculation in Step 17(a) until the Loss of Load Expectation is equal or approximate to eight Trading Intervals in 10 years. Identify the total amount of increase in Scaled Demand that makes the Loss of Load Expectation equal to eight Trading Intervals in 10 years as $LOLE\_adjustment1$.

(c) Calculate the Loss of Load Expectation using the calculation in Step 16(b) and (Scaled Demand + $LOLE\_adjustment1 - Storage\_Available\_Capacity$), rounded to the nearest integer, as system load during the $Relevant\_Period$.

(d) Change the system load calculated in Step 17(c) with increments of whole MW and fixed across all Trading Intervals in the $Relevant\_Period$, until the Loss of Load Expectation is equal or approximate to eight Trading Intervals in 10 years.

(e) Identify the total amount of change in the system load calculated in Step 17(d) that makes the Loss of Load Expectation equal to eight Trading Intervals in 10 years as $LOLE\_adjustment2$.

(f) Calculate the Loss of Load Expectation using the calculation in Step 16(b) and the Net_Load data identified in Table 1 corresponding to the $Facility\_Group$, as system load during the $Relevant\_Period$.

(g) Increase the Net_Load data in Step 14(f), with increments of whole MW and fixed across all Trading Intervals in the $Relevant\_Period$, and repeat the calculation in Step 17(f) with the increased Net_Load data until the Loss of Load Expectation calculated in Step 17(f) is equal or approximate to eight Trading Intervals in 10 years.

The $Relevant\ Level$ of the $Facility\_Group$ during the $Relevant\_Period$ is the total increase in Net_Load (in MW) identified in Step 17(g) that makes the Loss of Load Expectation calculated in Step 17(f) equal or approximate to eight Trading Intervals in 10 years.

Publication of information

Step 18: Publish on the WEM Website a provisional forecast of the Trading Intervals that may be identified in Step 8 within 20 Business Days before the date specified in clause 4.1.11 (as modified or extended) for the relevant Reserve Capacity Cycle.

Step 19: [Blank]

Step 20: [Blank]

Changes to other market rules

4.9. Process for Applying for Certification of Reserve Capacity

…

Application of the proposed RLM for conditional certification of reserve capacity

AEMO can use the proposed RLM to determine the relevant level for a conditional certification of reserve capacity.

For conditional certification of reserve capacity AEMO must use the most recent run of the proposed RLM completed in the preceding reserve capacity cycle and include the application for conditional CRC as a Candidate Facility in that run to determine CRC for the Candidate Facility.

4.9.5. If AEMO assigns Certified Reserve Capacity to a Facility for a future Reserve Capacity Cycle under section 4.11 ("**Conditional Certified Reserve Capacity**"):

(a) the Conditional Certified Reserve Capacity is conditional upon:

i. the information included in the application for Certified Reserve Capacity remaining correct as at the date and time specified in clause 4.1.11 for that future Reserve Capacity Cycle; and

ii. AEMO's assessment of the Certified Reserve Capacity for the Facility for the Reserve Capacity Cycle, until the time specified in clause 4.1.15 for that future Reserve Capacity Cycle, remains equal to the Conditional Certified Reserve Capacity.

(b) For Facilities to which the relevant level method specified in clause 4.11.2(b) is applicable for the certification of Reserve Capacity, AEMO must determine the Conditional Certified Reserve Capacity by including the Facility as a Candidate Facility in determining Relevant Levels in the preceding Reserve Capacity Cycle assuming the Facility had applied for the certification of Reserve Capacity in the preceding reserve capacity cycle. When determining Conditional Certified Reserve Capacity AEMO can also have regards to expected resource mix and demand in the SWIS for Year 3 of the future Reserve Capacity Cycle to which the Conditional Certified Reserve Capacity is being assigned to.

(c) the Market Participant holding the Conditional Certified Reserve Capacity must, in accordance with clauses 4.9.1 and 4.9.3, re-lodge an application for Certified Reserve Capacity with AEMO between the date and time specified in clause 4.1.7 and the time specified in clause 4.1.11 for that future Reserve Capacity Cycle;

(d) if AEMO is satisfied that the application re-lodged in accordance with clause 4.9.5(b) is consistent with the information upon which the

Conditional Certified Reserve Capacity was assigned and is correct, and AEMO's assessment of the Certified Reserve Capacity for the Facility remains equal to the Conditional Certified Reserve Capacity previously assigned to the Facility, then AEMO must confirm:

i. the Certified Reserve Capacity;

ii. [Blank]; and

iii. the Reserve Capacity Security levels,

that were previously conditionally assigned, set or determined by AEMO, subject to the Certified Reserve Capacity for an Intermittent Generator being assigned in accordance with clause 4.11.2(b); and

(e) if the application re-lodged in accordance with clause 4.9.5(b) is found by AEMO to be inaccurate or is not consistent with the information upon which the Conditional Certified Reserve Capacity was assigned, or AEMO's assessment of the Certified Reserve Capacity for the Facility differs from the Conditional Certified Reserve Capacity previously assigned to the Facility then AEMO must process the application without regard for the Conditional Certified Reserve Capacity.

…

4.10. Information Required for the Certification of Reserve Capacity

4.10.2. The types of Facilities eligible to be nominated by a Market Participant under clause 4.10.11(i) for use of the method described in clause 4.11.2(b), for the purpose of assigning Certified Reserve Capacity or Conditional Certified Reserve Capacity to the Facility are:

(a) a Semi-Scheduled Facility, except in respect of any Electric Storage Resource component of the Facility; and

(b) a Non-Scheduled Facility comprising only an Electric Storage Resource that has not been in operation for the full period of performance assessment identified in Step 1(a) of Appendix 9.

4.10.3. An application for certification of Reserve Capacity that includes a nomination to use the method described in clause 4.11.2(b) for a Facility that, in respect of the Facility or the component of the Facility nominated to use the method described in clause 4.11.2(b):

(a) is yet to enter service;

(b) is to re-enter service after significant maintenance;

(c) is to re-enter service after having been upgraded;

(d) has not operated with the configuration outlined in clause 4.10.1(dA) for the full period of performance assessment identified in step 1(a) of the Relevant Level Method; or

(e) for which no meter data is available to determine the quantity of electricity sent out as per Step 2(a) of Appendix 9;

must include a report prepared by an expert accredited by AEMO in accordance with clause 4.11.6. AEMO will use the report to assign Certified Reserve Capacity for the Facility or the component of the Facility nominated to use the method described in clause 4.11.2(b) and to determine the Required Level for that Facility.

4.10.3A. A report provided under clause 4.10.3 must include:

(a) for each Trading Interval during the period identified in Step 1(a) of Appendix 9 a reasonable estimate of the expected capacity (in MW) that would have been available to be sent out by the Facility or the part of the Facility nominated to use the method described in clause 4.11.2(b) had it been in operation with the configuration proposed under clause 4.10.1(dA) in the relevant application for certification of Reserve Capacity. This estimate must factor in the effect of Planned Outages or Forced Outages on the capacity available to be sent out;

…

...

4.11. Setting Certified Reserve Capacity

4.11.1. Subject to clause 4.11.12, AEMO must apply the following principles in assigning a quantity of Certified Reserve Capacity to a Facility for the Reserve Capacity Cycle for which an application for Certified Reserve Capacity has been submitted in accordance with section 4.10:

(a) subject to clause 4.11.2, the Certified Reserve Capacity for a Scheduled Facility comprising only generation systems for a Reserve Capacity Cycle must not exceed AEMO's reasonable expectation of the amount of capacity likely to be available, after netting off capacity required to serve Intermittent Loads, embedded loads and Parasitic Loads, for Peak Trading Intervals on Business Days from the Trading Day starting 1 October in Year 3 of the Reserve Capacity Cycle to the end of July in Year 4 of the Reserve Capacity Cycle, assuming an ambient temperature of 41ºC;

(b) for a Scheduled Facility comprising only generation systems, the Certified Reserve Capacity must not exceed the sum of the capacities specified in clauses 4.10.1(e)(ii) and 4.10.1(e)(iii);

(bA) where the Facility is an energy producing system, the Certified Reserve Capacity must not exceed the Declared Sent Out Capacity for the Facility notified to AEMO under clause 4.10.1(bA)(iii);

(bB) where two or more Facilities share a Declared Sent Out Capacity, the total quantity of Certified Reserve Capacity assigned to those Facilities must not exceed the Declared Sent Out Capacity;

(bC) for a Scheduled Facility containing an Electric Storage Resource or Semi-Scheduled Facility containing an Electric Storage Resource, the total quantity of Certified Reserve Capacity determined for the Electric Storage Resource must be determined by AEMO in accordance with clause 4.11.2;

(bD) for a Non-Scheduled Facility containing only an Electric Storage Resource, including Small Aggregation of aggregated Electric Storage Resources, the total quantity of Certified Reserve Capacity must be:

i. determined in accordance with the Relevant Level Method; or

ii. if the Electric Storage Resource has not been in operation for the full period of performance assessment identified in step 1(a) of the Relevant Level Method, determined in accordance with clause 4.11.2;

(bE) for a Non-Scheduled Facility, excluding Non-Scheduled Facilities under clause 4.11.1(bD), the total quantity of Certified Reserve Capacity assigned to the Facility must be determined in accordance with the Relevant Level Method;

…

…

4.11.2. Where an applicant submits an application for Certified Reserve Capacity, in accordance with clause 4.10, and nominates under clause 4.10.1(i) to have AEMO use the method described in clause 4.11.2(b) to apply to a Scheduled Facility or a Non-Scheduled Facility, AEMO:

(a) [Blank];

(aA) [Blank]; and

(b) subject to clause 4.11.12, must assign a quantity of Certified Reserve Capacity to the relevant Facility for the Reserve Capacity Cycle equal to the Relevant Level as determined in accordance with the Relevant Level Method, but subject to clauses 4.11.1(b), 4.11.1(bA), 4.11.1(bB), 4.11.1(c), 4.11.1(f), 4.11.1(g), 4.11.1(h), and 4.11.1(i).

The ERA's review of the method

The proposed method does not use constant parameters K and U.

The ERA is also required to review the relevant level method again by 1 April 2021. The approval and implementation of the proposed method is expected to happen in 2021. There will not be sufficient time before 1 April 2021 to assess the application of the proposed method in practice. The next review of relevant level method is proposed to be postponed to 1 April 2022.

4.11.3C. For each three-year period, beginning with the period commencing on 1 January 2022, the Economic Regulation Authority must, by 1 April of the first year of that period, conduct a review of the Relevant Level Method. In conducting the review, the Economic Regulation Authority:

(a) must examine the effectiveness of the Relevant Level Method in meeting the Wholesale Market Objectives; and

(b) may examine any other matters that the Economic Regulation Authority considers to be relevant.

…

4.11.3E. At the conclusion of a review under clause 4.11.3C, the Economic Regulation Authority must publish a final report containing:

(a) details of the Economic Regulation Authority's review of the Relevant Level Method;

(b) a summary of the submissions received during the consultation period;

(c) the Economic Regulation Authority's response to any issues raised in those submissions;

(d) any recommended amendments to the Relevant Level Method which the Economic Regulation Authority intends to progress as a Rule Change Proposal.

…

4.28C. Early Certification of Reserve Capacity

Early certification of reserve capacity using the proposed RLM

Clause 4.28.C.1(e) is proposed to prohibit some intermittent generation facilities from applying for early certification of reserve capacity. The capacity value for some intermittent generation facilities, such as solar and wind generators, depends on resource mix in the system. The added clause prohibits applications for early certification for such facilities that would have an interaction index i(c) equal to one under Step 10(a) of the proposed RLM. This change effectively prohibits solar and on-shore wind generators from applying for early certification of reserve capacity.

Given that solar and wind farms have been able to be developed and commissioned within the default timeline for a Reserve Capacity Cycle, such facilities might not be eligible for applying for early certification of reserve capacity given EPWA's proposed change in clause 4.28C.1(d).

EPWA has proposed any eligible application for the early certification of reserve capacity is to be assessed as part of the certification of reserve capacity after the submission of application.

The ERA's proposed method is to be applied using the same principle specified by EPWA in draft amending rules (note EPWA's proposed changes to clause 4.28C.7).[1]

4.28C.1. This section 4.28C is applicable to Facilities to which the following conditions apply:

(a) the Facility is a new Facility;

(b) the Facility is an energy producing system;

(c) the Facility is deemed by AEMO to be committed;

(d) AEMO is satisfied that:

i. the construction of the Facility cannot be achieved within the Reserve Capacity Cycle for which Capacity Credits are being sought for the Facility; and

ii. the Commissioning Tests for the Facility cannot be achieved before the commencement of the Capacity Year for which Capacity Credits are being sought for the Facility; and

(e) if the Facility is deemed by AEMO to be a Candidate Facility for the purpose of Appendix 9, the Facility would not be part of a facility group with interaction index $i(c)$ equal to one, as per Step 10(a) of the Relevant Level Method.

…

10.5. Public Information

10.5.1. AEMO must set the class of confidentiality status for the following information under clause 10.2.1 as Public and AEMO must make each item of information available from or via the Market Web Site after that item of information becomes available to AEMO:

…

(f) the following Reserve Capacity information (if applicable):

…

x. the following information identified for a Reserve Capacity Cycle under the Relevant Level Method:

1. the Scaled Demand determined under Step 7(b) of Appendix 9 determined for each Trading Interval in the period identified in Step 1(a) of Appendix 9.

2. the Residual Demand calculated in Step 7(e) of Appendix 9 determined for each Trading Interval in the period identified in Step 1(a) of Appendix 9.

3. the Capacity Outage Probability Table calculated in Step 15(b) of Appendix 9.

4. the $Annual\_RL\_Fleet$ calculated in Step 9(a) of Appendix 9.

5. the $Full\_Period\_RL\_Fleet$ calculated in Step 9(b) of Appendix 9.

6. for each facility group c the $Facility\_Group\_RL(c)$ calculated in Step 9(c) of Appendix 9.

An indication of the capacity value of Electric Storage Resources

The parameter $LOLE\_adjustment2$ calculated in Step 17(c) provides an indication of the capacity value of Electric Storage Resources. This can provide insights to AEMO, the entity responsible for reviewing the Linear Derating Method and other stakeholders on the capacity value of these resources.

7. $LOLE\_adjustment2$ calculated in Step 17(c) of Appendix 9.

8. For each facility group c, the $Scaling\_Factor(c)$ calculated in Step 12 of Appendix 9.

…

…

…

11. Glossary

…

Observed Demand: An estimate of the total amount of electricity demand in the SWIS in MW over a Trading Interval that should have been supplied through the transmission grid if no load was reduced or disconnected by AEMO, as calculated in Step 7(a) of Appendix 9.

…

Relevant Level Method: Means the method of determining the Relevant Level specified in Appendix 9.

Appendix 3. Changes implemented to the previous rule change proposal and modelling scenarios

Much of the content of this appendix was presented to stakeholders as part of the updated pre-rule change proposal submitted to the Market Advisory Committee (MAC) for discussion at the MAC meeting on 17 November 2020.

Section 4 addresses the feedback the ERA has received from stakeholders since the presentation of the updated rule change proposal to the MAC on 17 November 2020.

All sensitivity analysis scenarios (previously presented in section 4 of this Appendix) and related discussions are now presented in appendix 4).

1. Introduction

In March 2019, the ERA recommended a new Relevant Level Method (RLM) to determine the quantity of capacity credits allocated to intermittent generators. In July 2019, the ERA presented a preliminary rule change proposal to the MAC to seek stakeholders' feedback on the proposal.

A rule change proposal is now being submitted to the Rule Change Panel after a delay to address possible interactions between the proposed RLM and Energy Policy WA's (EPWA) proposed amendments for the constrained network access regime.[1]

This appendix:

- Addresses feedback received since December 2019 on the proposal to implement the new RLM. The Appendix outlines the amendments made to the pre-rule change proposal, after receiving clarity on EPWA's proposal for allocating capacity credits in a constrained network environment. This is discussed in detail in section 3.
- Discusses the changes incorporated to the proposed method to improve its application. In general, the proposed changes better link the method with the reliability planning criterion of the SWIS and the long-term projected assessment of system adequacy specified in the market rules.[2] These enhancements were presented to the MAC on 17 November 2020 and are discussed in detail in section 3.2.
- Addresses feedback received from AEMO, the MAC, and Rule Change Panel Support team after the presentation of the updated rule change proposal to the MAC on 17 November 2020. This is discussed in detail in section 4. The ERA did not need to make any major change to the proposed method resulting from stakeholders' feedback received after the MAC meeting. The ERA has made minor changes to improve drafting, address stakeholder feedback and fix typographical errors.

To draft this rule change proposal, the ERA has worked from draft amending rules provided by EPWA. The rule change proposal is submitted assuming that EPWA makes no major

1 ERA, 2019, *Relevant level method review 2018, Capacity Valuation for intermittent generators*, Final report, (online).

2 Wholesale Electricity Market Rules (WA), 7 August 2020, Clause 4.5.

changes to its draft amending rules following its consultation process, which closed in late November 2020.

2. Background

In March 2019, the ERA's final report on its review of the RLM recommended that a new RLM was required as the current method did not provide a reasonable forecast of the capacity contribution of intermittent generators to reliability in the SWIS.[3]

The market rules require the ERA to progress recommendations from its review as a rule change proposal. In July 2019, the MAC recommended a high urgency rating following the presentation of a pre-rule change proposal for the new RLM.[4][5]

In December 2019, the ERA, EPWA, Rule Change Panel (RCP) Support and the Australian Energy Market Operator (AEMO) agreed to delay the RLM rule change proposal until after publication of the Minister for Energy's changes to the market rules. The delay would allow the ERA to address any interactions between the rule change proposal and EPWA's proposal for assigning capacity credits in a constrained network access regime.

In October 2020, EPWA published details on how capacity credits would be assigned under a constrained network access mechanism.[6] EPWA's draft amending rules included the details of the method for the capacity valuation of electric storage resources and the capacity certification approach for non-scheduled facilities. These changes overlap with some aspects of the implementation of the ERA's proposed RLM.

At the 20 October 2020 meeting of the MAC, the ERA Secretariat presented the changes required to the July 2019 pre-rule change proposal in order to address interactions with EPWA's proposals and improve the model. The required changes concern only the implementation of the ERA's recommended RLM, not the underpinning principles. Section 3 details these changes and addresses feedback received from the 20 October 2020 meeting of the MAC meeting and feedback received from stakeholders from July 2019.

On 10 November 2020 the ERA Secretariat provided an updated preliminary rule change proposal to the MAC and sought feedback. On 17 November 2020 the ERA Secretariat presented a summary of the updated rule change proposal to the MAC.[7] Feedback received in response to the updated rule change proposal is discussed and addressed in detail in section 4.

3 ERA, 2019, *Relevant level method review 2018, Capacity Valuation for intermittent generators*, Final report, p.2 (online).

4 Rule Change Panel, 2019, *Meeting minutes for the Market Advisory Committee meeting of 29 July 2019* , p. 15, (online).

5 Rule Change Panel, 2019, *Meeting papers for the Market Advisory Committee meeting of 29 July 2019* , pp. 102–165, (online).

6 Energy Policy WA, *Energy Transformation Taskforce Consultation*, (online) [accessed 29 October 2020].

7 Rule Change Panel, *Meeting papers for the Market Advisory Committee meeting of 17 November 2020* , (online).

3. Amendments to the 2019 pre-rule change proposal

The minor amendments in response to EPWA's proposed changes are discussed in section 3.1. The remainder of section 3 details the improvements made in response to feedback received from RCP Support and AEMO.

3.1 EPWA's proposed changes to the market rules to assign capacity credits in a constrained network environment

The Minister for Energy is expected to authorise EPWA's proposed changes to the market rules by February 2021.[8] The ERA's RLM pre-rule change proposal requires minor changes to ensure that it was consistent with these new clauses in the market rules. These changes include:

1. The addition of default facility groups for non-scheduled facilities: EPWA's changes require the RLM to determine the certified reserve capacity of non-scheduled facilities. These facilities are expected to be small facilities (with less than 10 MW capacity), such as community batteries. Two new default facility groups are introduced in the proposed RLM consistent with EPWA's classification of these facilities.

2. The removal of unnecessary features: EPWA proposed that scheduled facilities, such as thermal generators, may no longer choose to nominate to have AEMO use the RLM to have their capacity certified. The previous pre-rule change proposal was designed to be able to accommodate the capacity valuation of scheduled facilities. The ERA has implemented changes to remove those features of the proposed method that are no longer required.

3. The inclusion of storage resources in the resource mix: EPWA's proposed changes would allow for the participation of electric storage resources in the reserve capacity mechanism. EPWA has developed a separate method for the capacity certification of storage facilities. All electric storage resources registered as part of a scheduled facility or semi-scheduled facility would use a dedicated capacity valuation method – referred to as "linear derating method" – under the market rules.[9] The ERA has made changes to the proposed RLM to include the storage resources registered as part of scheduled or semi-scheduled facilities in the capacity resource mix modelled in the proposed RLM:

    a. The maximum discharge capability of electric storage resources during the electric storage resource obligation intervals is now deducted from expected demand in the system, also accounting for their expected level of forced outages.[10]

[8] EPWA, 2020, 'Governance of the Western Australian Energy Sector – A presentation for the Market Advisory Committee', (online).

[9] EPWA, 2020, 'Draft amending rules for reserve capacity mechanism and the network access quantity framework (ME V09)', Chapter 11, "Linear Derating Method", (online).

[10] EPWA's proposed amendments to the rules define:

EPWA has proposed a new framework for the registration and participation of facilities in the WEM.[11] The proposed RLM ensures drafting consistency with the new framework. Under the new framework, facility classes comprise scheduled facilities, semi-scheduled facilities, non-scheduled facilities, interruptible load, demand side programme and network.

In addition to changes required for consistency with EPWA's proposals, the ERA has identified areas of improvement in the previous pre-rule change proposal in response to feedback received from AEMO and RCP Support. These improvements are explained in sections 3.2, 3.3 and 3.4.

3.2 Consistency with the planning criterion

The proposed RLM has been developed to be consistent with the planning criterion. This will assist AEMO to estimate the capacity contribution of intermittent generators consistent with the requirements of the planning criterion and to assign certified reserve capacity to ensure system adequacy. This section outlines how the RLM is consistent with the planning criterion, addresses feedback received on the pre-rule change proposal and details the changes made to the pre-rule change proposal in response.

During consultation, RCP Support raised a concern that system reliability could be at risk due to a lack of consistency between the proposed RLM and the planning criterion. This concern is based on the RCP Support team's view that the planning criterion considers certified reserve capacity (CRC). The planning criterion requires consideration of available capacity and not CRC. These concepts are explained below. No changes to the rule change proposal have been made in response to RCP Support's comments about consistency with the planning criterion. However, the ERA has implemented changes that improve the calculation to better reflect the requirements of the planning criterion. For the scenarios tested, these changes also reduce the variation in the estimated sample for the capacity value of the fleet of intermittent generators. This may alleviate the RCP Support's concern about the use of median in setting the fleet capacity values.

3.2.1 Certified reserve capacity and available capacity

At the MAC meeting on 20 October 2020, Rule Change Panel Support explained that it has concerns about the consistency of the proposed RLM with the reliability planning criterion in the SWIS. RCP Support provided a summary of its feedback to the ERA after the Committee meeting and explained that:

> The current Planning Criterion of the Reserve Capacity Mechanism requires AEMO to ensure that there is sufficient Certified Reserve Capacity so demand can be met in a 1 in 10 year peak

Electric Storage Resource Obligation Duration as the eight contiguous Electric Storage Resource Obligation Intervals which commence at the time published by AEMO in accordance with clause 4.11.3A each Trading Day

Electric Storage Resource Obligation Interval as a Trading Interval in which a Reserve Capacity Obligation Quantity for an Electric Storage Resource applies.

Ibid, Chapter 11, "Electric Storage Resource Obligation Duration" and "Electric Storage Resource Obligation Interval".

11 Energy Transformation Taskforce, 2020, *Registration and Participation Framework in the Wholesale Electricity Market*, (online).

demand scenario including a reserve margin of 7.6% to account for the likelihood that not all Certified Reserve Capacity will be available.[12]

The planning criterion requires AEMO to ensure there is sufficient available capacity, not sufficient certified reserve capacity (CRC), to meet the specified level of forecast peak demand.

4.5.9. The Planning Criterion to be used by AEMO in undertaking a Long Term PASA study is that there should be sufficient available capacity in each Capacity Year during the Long Term PASA Study Horizon to:

(a) meet the forecast peak demand (including transmission losses and allowing for Intermittent Loads) supplied through the SWIS plus a reserve margin equal to the greater of:

i. 7.6% of the forecast peak demand (including transmission losses and allowing for Intermittent Loads); and

ii. the maximum capacity, measured at 41°C, of the largest generating unit;

while maintaining the ~~Minimum Frequency Keeping Capacity for normal frequency control~~ SWIS frequency in accordance with the Normal Operating Frequency Band and the Normal Operating Frequency Excursion Band. The forecast peak demand should be calculated to a probability level that the forecast would not be expected to be exceeded in more than one year out of ten.[13] [14]

The available capacity of all capacity resources in any electricity system is variable and uncertain, meaning it is a random (or probabilistic) value at the time that AEMO certifies capacities. Available capacity of resources in the system varies mainly based on availability of fuel (for example, natural gas, wind, or solar irradiance), mechanical failures and planned maintenance.

Certified reserve capacity is not equal to available capacity of resources and is a constant (or deterministic) value determined for a capacity year. The market rules define the certified reserve capacity as:

> For a Facility, and in respect of a Reserve Capacity Cycle, is the quantity of Reserve Capacity that AEMO has assigned to the Facility for the Reserve Capacity Cycle in accordance with clause 4.11 or clause 4.28B, as adjusted under these Market Rules including clause 4.14.8. Certified Reserve Capacity assigned to a Facility registered by a Market Participant is held by that Facility.

Certified reserve capacity reflects the contribution of resources to meeting the reliability planning criterion over a capacity year but not their actual or, necessarily, expected available capacity at the time of a forecast one-in-10 year peak demand event. The available capacity of a resource varies across a capacity year and, at the time of certifying reserve capacity, is uncertain during a forecast one-in-10-year peak demand event. Available capacity ranges between zero (or in the case of storage facilities below zero) and the rated capacity of the resource. The rated capacity of a resource is greater than or equal to the certified reserve

12 At the time of writing this paper, the minutes of the Market Advisory Committee meeting were not available. RCP Support provided a summary of their feedback in the meeting with more details to the ERA Secretariat. This feedback is available in Appendix 5. RCP Support, 2020, Email sent to the Secretariat of the ERA summarising the RCP's support feedback provided to the ERA in the Market Advisory Committee Meeting on 20 October 2020. The minutes of the Market Advisory Committee meeting are now published on the ERA website (online).

13 The part highlighted in grey indicates EPWA's proposed change to the planning criterion, which is limited to terminology used for referring to the allowance for frequency keeping capacity only.

14 Wholesale Electricity Market Rules (WA), 7 August 2020, Clause 4.5.9.

capacity of a resource. When assessing whether the SWIS has sufficient available capacity to meet the level of demand that is not likely to be exceeded only once in 10 years, AEMO should factor in this variability of availability of capacity. The box below provides an explanation of this concept for a hypothetical generator.

Explanation

Ex ante, available capacity of a resource is uncertain because it varies with air temperature, forced outages and planned outages. The system operator needs to account for this variability when estimating a generator's future contribution to system adequacy and certifying reserve capacity. This is illustrated using the conceptual example below.

At the time of peak demand, a hypothetical generator has three possible available capacities (sent-out), c, with the probabilities, p, shown in the equation below. For simplicity, this example assumes the available capacities are rated at 41 degree Celsius.

$$c = \begin{cases} 100\ MW, & p = 20\% \\ 50\ MW, & p = 40\% \\ 30\ MW, & p = 40\% \end{cases}$$

The rated capacity of the generator at 41 degrees Celsius is 100 MW. The system operator understands that the generator cannot always produce 100 MW. The generator can provide 100 MW at the time of peak demand only 20 per cent of the time. Eighty per cent of the time, the available capacity of the generator is either 50 MW or 30 MW.

Given the uncertainty in the available capacity of the generator, the system operator will use a measure to estimate to what extent it can rely on the generator to meet the peak demand target of the system. The average available capacity of a thermal generator during periods of peak demand provides an approximate proxy for estimating its contribution to meet peak demand, or their effective load carrying capability.

The hypothetical generator's expected contribution to meeting peak demand, v, can be calculated as:

$$v = (100 \times 20\%) + (50 \times 40\%) + (30 \times 40\%) = 52\ MW$$

The system operator would assign 52 MW of certified reserved capacity to the generator.

For simplicity, this example assumes the capacity delivery period comprises four periods, t, only. During all periods t the amount of demand in the system is extremely high and air temperature is 41 degrees Celsius. The hypothetical generator's actual available capacity during the four periods is as below:

$$available\ capacity = \{t_1 = 100\ MW, t_2 = 100\ MW, t_3 = 50\ MW, t_4 = 30\ MW\}$$

The actual capacity contribution of this generator during the delivery period can be estimated as the average of the available capacity of the generator during the period:

$$v_{actual} = \frac{100 + 100 + 50 + 30}{4} = 70\ MW$$

The actual available capacity of the generator is below its certified reserve capacity in trading intervals t_3 and t_4, and above its certified reserve capacity in trading intervals t_1 and t_2.

RCP Support stated that it:

is concerned that the proposed RLM is not consistent with the current Planning Criterion and as a result could present a risk to Power System Reliability. AEMO has also raised this concern. The concern is based on the following observations about the proposed RLM:

- The expected effective load carrying capability (**ELCC**) for the fleet of Intermittent Generators is based on the fleet's expected contribution to the reduction of the loss of load expectation (**LOLE**) over all Trading Interval in each of the Capacity Years in the reference period. RCP support is concerned that this ELCC may be higher than the expected contribution of the fleet during a 1 in 10 year peak demand scenario.
- The capacity value of the fleet is determined by taking the median of the fleet's ELCCs for each Capacity Year in the reference period. RCP Support is concerned that this implies that the fleet would be expected to be able to contribute less than the CRC, which would be inconsistent with the Planning Criterion and the reserve margin.

RCP Support understands that the ERA considers that the RLM is consistent with the Planning Criterion and will not provide any further analysis beyond those already provided as part of the final report of the RLM review. RCP Support is currently assessing this issue.

The effective load carrying capability (ELCC) of a resource is the amount of additional demand the system can cover after the addition of the resource while maintaining the reliability target of the power system. The ELCC is not the expected contribution to the reduction of the loss of load expectation. Loss of load expectation is expressed in units of time, ELCC is expressed in units of megawatt.

Based on the comments above RCP Support equates the CRC of resources to available capacity at the time of one-in-10 year peak demand.

Available capacity of any resource, including intermittent generators, at the time of one-in-10 year forecast peak demand is uncertain and can be smaller or larger than the CRC. Therefore, the CRC is not equal to available capacity, or necessarily expected available capacity, during a forecast one-in-10 year peak demand period.

The ERA provided a detailed discussion of the consistency of the proposed RLM with the planning criterion in its decision report.[15] Section 3.2.2 provides a summary of the discussion. The ERA has also altered the proposed method to improve the consistency with the requirements of the planning criterion and of the long-term projected assessment of system adequacy in the market rules.

In response to RCP Support's concern that the proposed method uses the median of ELCC values estimated for the fleet of intermittent generators, section 3.2.3 explains the ERA's reasoning for the use of median.

3.2.2 Consistency of the proposed RLM with the planning criterion

The ERA's proposed method forecasts the expected capacity value of resources based on their contribution to meeting the first requirement of the planning criterion, which requires AEMO to have sufficient available capacity in each capacity year to meet the forecast peak demand that is likely to be exceeded only once in 10 years.[16] The proposed method estimates

15 ERA, 2019, *Relevant level method review 2018: Capacity valuation for intermittent generators, Technical appendix*, p. 62-63, (online).

16 A second, but not currently binding, requirement of the planning criterion is to have sufficient available capacity to limit expected energy shortfalls to 0.002 per cent of annual energy consumption, including

the amount the additional demand the system can cover while meeting this requirement when the fleet of intermittent generators is added. The method uses a conventional system capacity adequacy analysis based on loss of load expectation (LOLE) as the measure of system adequacy risk. The proposed method is based on best international practice and is increasingly applied in the capacity valuation of resources in many other jurisdictions.

The planning criterion of the SWIS specifies there should be sufficient available capacity from resources to meet the level of peak demand that is likely to be exceeded only once in 10 years – commonly referred to as 10 per cent probability of exceedance (or 10% PoE) peak demand. When the level of demand in the SWIS exceeds the specified target, and AEMO has procured resources just sufficient to meet the 10% PoE peak demand, AEMO may not have sufficient available capacity to meet the balance of supply and demand and a loss of load can happen.[17]

It is important to note that adequacy of supply criteria in the SWIS and other electricity systems around the world do not set an absolute, but a probabilistic goal.[18] Two variables determine the expected number of loss of load events over a certain period in the system: available capacity of resources and system demand over the period. Both of these variables are uncertain and probabilistic in nature.

If AEMO procures resources just sufficient to meet the target 10% PoE peak demand requirement, the number of loss of load events expected to occur over a 10-year period would be one event. The actual number of loss of load events over a 10-year period may be higher or lower than one because, for example, the level of system demand might exceed the expected 10% PoE peak demand in several years within a 10-year period despite having extremely low probability of occurrence. The available capacity of resources is also variable and may not be sufficient to meet high levels of demand in the system in many periods.

To meet the requirement of the planning criterion, AEMO must ensure that the total capacity resource procured from resources is sufficient to limit the amount of expected loss of load events in the system to one event in 10 years. This requires a probabilistic model to estimate the expected frequency of loss of load events during the relevant capacity year because random variables determine this expected frequency. This expected frequency of loss of load is not just a function of demand or peak demand distribution in the system, but also the expected distribution of the available capacity of resources in the system.

The proposed RLM is consistent with the planning criterion: it estimates the amount of additional demand the system can cover by adding the fleet of intermittent generators while limiting the expected number of loss of load events to one day in 10 years, allowing for four hours of LOLE in 10 years. The method considers the expected resource mix, demand and available capacity of resources, the correlation between the available capacity of resources,

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transmission losses. Currently, the amount of capacity required to meet the first requirement of the planning criterion is more than sufficient to meet the second requirement. AEMO does not expect the second requirement of the planning criterion to dominate the first requirement over the next decade. Refer to AEMO, 2020, *Final report: 2020 assessment of system reliability, development of availability curve and DSM dispatch quantity forecasts for the South West Interconnected System*, Report prepared by RBP, pp. 10–11, (online).

17 A loss of load event does not necessarily contribute to involuntary load shedding or system blackout; in most cases, system operators manage loss of load events without significant impacts on consumers.

18 Newberry D. and Grubb M., 2014, '*The final hurdle?: Security of supply, the capacity mechanism, and the role of interconnectors*', *University of Cambridge Energy Policy Research Group*, Working Paper 1412, (online) [accessed 29 October 2020].

and the correlation between the available capacity of resources and system demand and forecasts the loss of load events in the system in the target capacity year.

The method uses a measure of expected loss of load events, which in the proposed method is through the calculation of a LOLE. The following discussion explains why LOLE, as the measure of system reliability risk, is a suitable measure for the calculation of capacity value of resources consistent with the planning criterion of the SWIS.

The one-in-10 criterion is the most common resource adequacy standard in electricity systems around the world. Different planners and regulators have interpreted the one-in-10 criterion in different ways, with each approach capturing one or more of the relevant shortfall event parameters of frequency, duration and magnitude.

The planning criterion in the SWIS explicitly specifies an expected frequency limit of one loss of load event in 10 years, without any limitation on the duration or magnitude of such loss of load events. This frequency requirement can be translated to a LOLE measure by assuming an expected duration for the loss of load event. For example, if the expected loss of load event has a duration of four hours, the LOLE equivalent of one expected shortfall event in 10 years would be four hours in 10 years.

The proposed method uses a half-hourly LOLE to measure the adequacy risk of the system. A half-hourly LOLE is a measure of the expected number of half-hours during a particular period during which load is expected to exceed resources' capacity. Interpreting the one-in-10 criterion using this measure would allow for some specified cumulative hours of hourly LOLE every 10 years. This measure, among other measures of LOLE, uses more data but accounts for both frequency and duration, providing a more precise indication of the expected level of reliability. The hourly LOLE can be converted to a loss of load probability, which provides the probability that supply will be inadequate to serve demand over a particular period. Nevertheless, the half-hourly LOLE does not account for the magnitude of a shortfall.

Use of LOLE is consistent with the common practice in system adequacy analysis, which commonly uses LOLE or expected unserved energy as the measure of system adequacy. Among common interpretations of the one-in-10 year criterion the half-hourly LOLE provides the most precise indication of the expected level of reliability.[19]

3.2.3 Improvement to calculate capacity values at the target level of loss of load expectation

The ERA implemented an improvement in the calculation to better align the calculation of the LOLE with the requirement of the planning criterion. This improvement requires the calculation of the ELCC of candidate facilities at a target LOLE level consistent with the expected duration of the shortfall event that is likely to happen once in 10 years. This provides the consistent basis upon which the expected amount of additional demand, which can be covered by candidate facilities, is estimated.

This change typically, but not necessarily, increases the estimate of the contribution of intermittent generators presented in previous case studies the ERA presented in its final report to demonstrate the application of the model. This is because the incremental reliability value of some resources typically (but not necessarily) increases when installed in a system with lower level of reliability. Historically, the SWIS has had excess capacity beyond that required

[19] Alberta Utilities Commission, 2017,*The economic foundations of capacity markets*, Report prepared by Charles River Associates, pp. 4-10, (online).

to meet the reliability target of the system. The previous scenarios presented by the ERA estimated the capacity contribution of resources based on the observed level of LOLE in the SWIS that typically were very low, partly due to excess capacity in the system.

To determine the target level of LOLE consistent with the planning criterion the ERA considered the design of the planning criterion and other relevant clauses in the market rules, practice in other jurisdictions and results of sensitivity scenarios.

The PJM Interconnection in the United States considers a LOLE=24 hours in 10 years (or 2.4 hours per year) when estimating the ELCC of resources. The Great Britain electricity system uses a system adequacy target of LOLE=30 hours per 10 years (or 3 hours per year). It recently used this target level to estimate the equivalent firm capacity of storage resources.[20] The National Grid's assessment of the duration of possible loss of load events showed that the bulk of the distribution of the duration of loss of load events were between 0.5 and four hours.

The electricity system in Ireland uses a system adequacy target of LOLE=80 hours per 10 year (or eight hours per year).[21] France's electricity system targets LOLE=3 hours per year. The Netherlands' electricity system targets LOLE=4 hours per year.[22]

EPWA's proposed changes to the market rules specify a requirement for electric storage resources to be eligible for reserve capacity certification. This requirement sets the "electric storage resource obligation duration" to four hours. This represents the duration over which storage facilities receiving capacity credits must sustain their maximum discharge capacity. AEMO determines the time window of this obligation period, which is based on AEMO's expectation of periods with the highest reliability stress.

Under the proposed certification method for storage facilities – referred to as the linear derating method – a storage facility that can sustain its maximum discharge capability (in MW) during the four-hour obligation window would receive 100 per cent of its maximum discharge capability as its capacity value.

This implies that the expected duration of a typical loss of load event in the SWIS is four hours and Electric Storage Resources' capacity over the four-hour obligation period helps to avoid the occurrence of loss of load. This expectation of the duration of a typical loss of load event is consistent with the National Grid's assessment of possible loss of load durations for the Great Britain electricity system.

This expectation of duration of the loss of load event in the SWIS suggests using a target LOLE=4 hours per 10 years (or 0.4 hours per year) in the proposed RLM. In comparison with other electricity systems around the world, this is an extremely low level of LOLE.

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[20] The ELCC can be calculated relative to several possible benchmark units or loads. For example, one might calculate the ELCC in terms of an increase in load that can be supplied at the target reliability level; in terms of a perfect generating unit; or in terms of a given unit type with a specified forced outage rate. This is commonly referred to as equivalent firm capacity.

[21] EirGrid and SONI, 2017, *I-SEM capacity market: methodology for the calculation of the capacity requirement and de-rating factors*, (online).

[22] UK Department of Energy and Climate Change, unknown date, *Annex C: Reliability standard methodology*, p. 4, (online).

The ERA conducted sensitivity analyses to assess how the level of the target LOLE might affect the results of the proposed RLM (refer to appendix 4). Three scenarios were investigated based on data for the 2019 Reserve Capacity Cycle:

1. Target LOLE equal to the observed LOLE in the system (as proposed in the previous version of the pre-rule change proposal).
2. Target LOLE of 24 hours in 10 years.
3. Target LOLE of 3 hours in 10 years.

For comparison, using the current RLM, AEMO assigned approximately 201 MW to intermittent generators for the same reserve capacity cycle.

Table 1. Relevant level of the fleet of candiate facilities (2019 reserve capacity cycle)

Relevant Period	Observed LOLE during the Relevant Period (trading intervals)	Relevant Level (MW) based on the observed LOLE during the Relevant Period	Relevant Level (MW), at the target LOLE=24 hours in 10 years during the Relevant Period	Relevant Level (MW), at the target LOLE=3 hours in 10 years during the Relevant Period
2014/15	0.000211915	304	332	324
2015/16	0.011383436	350	422	402
2016/17	0.0000114	239	293	280
2017/18	0.000208193	328	366	355
2018/19	0.000000105	176	238	217
2014–19 (full period)	**0.0118**	**347**	**384**	**370**

Note: the shaded cells indicate the selected relevant level (capacity value) for the fleet of candidate facilities, which is the smaller of the median of the relevant level for yearly samples and the relevant level for the full-period sample.

Results of sensitivity analyses show that the evaluation of the capacity value of intermittent generators at the observed level of LOLE in the system underestimates their capacity contribution. The ERA implemented minor changes in the updated pre-rule change proposal that requires the calculation of the relevant level at the target LOLE of four hours in 10 years.

The ERA's analysis demonstrates that the ELCC does not substantially change with small variations in the target level of LOLE in the system. This is because the ELCC of a resource (or a fleet of resources) is based on the difference between the LOLE between two scenarios - system LOLE with and without the fleet of intermittent generators - rather than the absolute value of the LOLE. For example, use of three, four or five hours of LOLE in 10 years would not result in material difference in the ELCC results.

3.2.4 Use of median of the sample of capacity values estimated

The capacity value of a resource, including an intermittent generator, is uncertain because it depends on the available capacity of the resource during the periods with the highest probability of occurrence of loss of load. Available capacity of resources is uncertain and therefore a random variable.

For example, the capacity value of a coal-fired generator is uncertain because at the time of estimating its capacity value its available capacity during periods of high reliability stress is uncertain. So, a forecast of the capacity value of the coal-fired generator depends on the expectation of air temperature and available capacity during the periods that are most likely to have the highest probability of loss of load.

The market rules specify that AEMO should not assign CRC to coal-fired generators, or other scheduled generators, beyond their capacity available to be sent out during business days, rated at the ambient temperature of 41 degrees Celsius. The market rules allow AEMO to discount the capacity value of the coal-fired generator based on AEMO's expectation of forced or planned outage rate in the target capacity year. The current reserve margin in the planning criterion of the SWIS also seeks to account for the effect of expected forced and planned outages from resources when estimating the total amount of capacity credits needed to meet the reliability planning criterion.[23]

In principle, the capacity value of scheduled generators is uncertain and thus is commonly presented through a distribution of possible availability states and respective probabilities, or a probability distribution. The CRC assigned to scheduled generators is the expected value of the availability distribution of the capacity value. For example, the coal-fired BW2_Bluewaters_G1 is a scheduled generation facility that has consistently received between 204 MW and 217 MW in capacity credits since the capacity year 2008/09. This facility was on forced outage between 1 January 2017 and 18 July 2017 – a substantial portion of the hot season period during which the loss of load expectation is typically the highest over a capacity year. The actual capacity value (or ELCC) of this generator in the 2016/17 capacity year was approximately zero.

The ERA does not suggest that AEMO forecast the capacity value of BW2_Bluewaters_G1 incorrectly. AEMO used the best available information at the time that it produced a forecast for the capacity valuation of this generator. The outage rate of this generator was very low before the 2016/17 capacity year. Instead, this example explains forecasting errors in the capacity valuation of generators. The magnitude of forecasting error in this case was approximately 217 MW.

The capacity value of intermittent generators depends on their available capacity during periods with the highest loss of load probability. That is, forecasting their capacity value contains uncertainty. The proposed method estimates the distribution of the capacity value of intermittent generators by deriving a sample based on their historical performance. Consistent with the assignment of CRC to other resources, a measure of central tendency of the distribution of the capacity value is chosen to reflect their capacity value:

- The proposed method produces a sample of eight capacity values; each reflecting the likely capacity value of intermittent generators in the target capacity year, given the expected resource mix and expected demand profile in the target capacity year.
- The CRC of the fleet of intermittent generators is set to the median of the seven of the samples drawn, capped at the eighth sample that reflects the capacity value of these resources over the entire seven-year period included in the modelling.

23 The purpose of the reserve margin in the planning criterion is not stipulated in the market rules. This assessment is based on the last determination of reserve margin in the SWIS conducted in 2012. Refer to Market Reform, 2012, *Review of the Planning Criterion used within the South West Interconnected System: Final Report*, p. 7, (online).

For example, for the 2019 reserve capacity cycle results shown in Table 1, the sample results for the capacity value of intermittent generation fleet varied between 217 and 402 MW. The proposed method sets the capacity value of the fleet of intermittent generators to the median of the sample, which in the case presented in Table 1 is 324 MW. This value is also capped at the full-period sample.

The ERA considered how to set the CRC of intermittent generators, given the observed variability in the drawn sample for the scenarios tested. The ERA detailed explanation for this proposed design.[24] The ERA also sought feedback on this aspect of the proposed RLM. In response to the ERA's draft report for the review of the RLM, Infrastructure Capital, SkyFarming and Synergy provided comment that the median or the five-year sample result could be used to set the capacity value of the fleet of intermittent generators. The ERA is aware that intermittent generation facility owners have commercial interests in having a larger estimate for their capacity value, given the current arrangements in the market rules.

Use of the median to set the fleet capacity value can provide a reasonable estimate for the central tendency of model results, which would be less sensitive to extremely low or high values when compared to the average of the sample. However, given the small size of the sample, it is possible that more than one extremely large or small value could cause large variations in the median value from year to year. By setting the fleet capacity value to the minimum of the median of annual results and the seven-year sample result, this effect can be mitigated.

Use of the minimum of the sample results is not reasonable because:

- In seven out of eight samples drawn, the capacity value of intermittent generators would be larger than the minimum of the sample.
- Assigning fewer capacity credits than appropriate can increase the supply cost of electricity to consumers because this can increase the price of capacity credits and total payments for capacity credits.
- It would be discriminatory against intermittent generators. Other capacity resources receive CRC consistent with their expected capacity value.

When designing the number of samples taken and setting the fleet capacity value, the ERA also considered the practice in other jurisdictions. The Midcontinent Independent System Operator, California Independent System Operator, New York Independent System Operator, PJM Interconnection and Southwest Power Pool in the United States and the National Grid in Great Britain use the concept of ELCC to determine the capacity value of resources such as wind, solar and storage. Their approach to the calculation of ELCC is similar to that in the ERA's proposed method. For example:

- The Midcontinent Independent System Operator (MISO) forecasts the ELCC of wind resources based on historical wind output data since 2005 by assuming the current wind penetration level existed in each of the historical years. For 2019/20, MISO calculated 14 annual wind-fleet ELCC values (one for each year between 2005 and 2018). MISO set the wind-fleet ELCC equal to the average of the 14 values.[25]

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[24] ERA, 2019, *Relevant level method review 2018: Capacity valuation for intermittent generators, Final report*, pp. 50-53, (online).

[25] PJM Interconnection, 2020, *Effective load carrying capability (ELCC)*, p. 14, (online) and Midcontinent Independent System Operator, *Planning year 2020/21 wind & solar capacity credit, December 2019*, p. 8, (online).

- The Southwest Power Pool in the United States uses the historical output of solar and wind in the last five years and calculates the ELCC of these resources over each sampled year. It then uses the average of capacity values estimated to set the capacity value of solar and wind resources.[26]
- Recently, the PJM Interconnection adopted the use of ELCC for the capacity valuation of intermittent generators and storage. PJM proposed to use 10 sampled years of historical output of intermittent generators, estimate the ELCC for each sample and use the average of the 10 samples produced to set the capacity value of the fleet of intermittent generators.

The ERA considered the trade-off in increasing the number of sample years and recommended using a seven-year sample period.[27] A larger sample would include the effect of other changes such as consumer behaviour change and changes in economic activity. This could make the annual capacity value results incomparable. A longer sample period would also require more synthetic output data for new facilities and can increase the uncertainty of results. The incremental cost of producing the estimated data from the current five years to seven years is not substantial.

Some stakeholders raised concerns that intermittent generators did not have obligations to provide their capacity during the target capacity year and would not be liable for paying refunds of capacity credit payments if they did not contribute to the reliability of the system as expected.

The RLM provides a forecast of the capacity contribution of intermittent resources. Reserve capacity obligation might be assigned to intermittent generators similar to the practice in other jurisdictions. The ERA does not recommend distorting the results of capacity valuation methods to address possible concerns with other aspects of the market rules. AEMO requires reliable tools to assess the reliability of the system. Such distortions would also create discrimination against intermittent generators for their capacity valuation.

The ERA is aware that market rules currently do not include any suitable measure to manage the uncertainty in forecasting capacity values. The reserve margin included in the planning criterion accounts only for the effect of expected resources outages and was calibrated last in 2012 based on the observed outage rate of resources in the SWIS in the preceding years to the review of the reserve margin. The current reserve margin does not include any allowance for uncertainty in the calculation of capacity values for resources and is not currently re-calibrated attuned with the pace of change in the system.

This design approach effectively passes the forecasting risk and the possible cost of not delivering capacity value as expected to consumers. The refunds of capacity credit payments, for a resource liable for paying refunds, is capped at the total capacity credit payments to the facility.[28] The cost to consumers of not delivering the capacity value as expected can be substantially larger than the payments for capacity credit to the facility.

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[26] Southwest Power Pool, 2019, *ELCC wind study report, SPP resource adequacy*, p. 7 (online).

[27] ERA, 2019, *Relevant level method review 2018 Capacity valuation for intermittent generators, Final report*, pp. 62-63, (online).

[28] Wholesale Electricity Market Rules (WA), 7 August 2020, Clause 4.26.1A(b).

In comparison, other jurisdictions include measures that seek to manage this forecasting risk, for example, by passing associated costs to capacity suppliers and incentivising them to produce the best forecast of their capacity contribution:

- PJM Interconnection in the United States uses a Pay-for-Performance mechanism. Under the mechanism the system operator calculates the expected capacity value of resources. Resources can opt for receiving capacity credits up to that estimated by the system operator, however, they would be liable for paying refunds of capacity credit payments if their actual capacity value falls below that assigned to them at the time of procurement. They would be liable for paying refunds consistent with the cost to consumers of delivering capacity value below committed to deliver. This mechanism passes cost of capacity value forecast errors back to resources. Resources also may receive rewards for contribution more than expected. This provides incentives to resources to produce the best estimate of their capacity value.[29]
- Annually, PJM Interconnection re-calculates the margin to be included in the procurement of capacity credits, among other factors, to account for uncertainty in estimating capacity values.[30]
- Ireland's electricity system operator uses probabilistic assessment of system adequacy and determines the capacity value of all resources based on possible demand scenarios in the system. It uses the results of the demand scenario that delivers the least-worst regret cost based on the value of incremental capacity to consumers.[31]

If the design of the WEM adopts the practice in other jurisdictions for managing the capacity valuation forecasting uncertainty, the proposed RLM would be needed to estimate the expected capacity value of resources or their capacity value in any plausible demand scenario. Managing this forecasting error risk becomes more important as more intermittent generation facilities enter the SWIS.

3.2.5 Use of historical data in the calculation

The ERA's proposed method uses the observed output of intermittent generators over the last seven years as a proxy to forecast their capacity contribution two years ahead. As with any other forecasting method, the capacity valuation method proposed is subject to forecasting error.

In its decision paper, the ERA sought to minimise forecasting error subject to cost and transparency consideration.[32] The ERA assessed whether the observed performance of intermittent generators contained sufficient information about the output of these resources, particularly during periods with the highest loss of load probability.

29 Refer to an explanation of this approach in the ERA's decision paper. ERA, 2019, *Relevant level method review 2018 Capacity valuation for intermittent generators, Final report*, p. 57, (online). Also refer to Charles River Associates, 2017, Navigating PJM's changing capacity market, (online).

30 PJM Interconnection, 2019, *PJM Manual 20: PJM Resource Adequacy Analysis, Revision 10* , p. 14, (online).

31 EirGrid and SONI, 2017, *I-SEM capacity market: methodology for the calculation of the capacity requirement and de-rating factors*, (online).

32 ERA, 2019, *Relevant level method review 2018 Capacity valuation for intermittent generators, Final report*, pp. 23-25, 61 (online).

The ERA's concerns about the lack of data were:

- The extent to which observed demand reflected the expected demand profile that could occur in a year during which a loss of load event could happen.
- Whether the observed output of intermittent generators suitably reflected their available capacity during periods of extremely large demand consistent with those that could occur in a year during which a loss of load event could happen.

Historically, periods of the highest demand in the SWIS have happened when air temperature has been extremely high. There was some analysis presented in the previous review of the RLM by the Independent Market Operator that the available capacity of wind resources might decrease when air temperature increases.[33]

The ERA found that, with increased penetration of behind-the-meter solar generation, periods of high demand mostly shifted towards later hours in the afternoon when air temperature was high but not the highest. The historical data for the observed performance of wind resources included many trading intervals with high air temperature consistent with what is likely to coincide with the occurrence of peak demand in the system.

Given this observation, the ERA concluded that an adjustment to historical output of intermittent resources would not be required. Any adjustment to the output of intermittent generators could be arbitrary and increase the uncertainty of results.

Another concern with the use of historical data was that the observed historical demand in the SWIS (over the modelling horizon of seven years) has been lower than AEMO's expectation of system demand in a one in 10 year peak demand event.

The relatively low level of observed demand in the SWIS could create a bias in the estimate of the capacity value of intermittent generators. This is because the capacity value estimated for the intermittent generators is determined by loss of load probability, which is dependent on system capacity margin in every trading interval over the historical years sampled. System margin is the difference between supply and demand. If observed demand is lower than that is expected to happen in a year with extremely high demand, the estimate of capacity value could be biased. This allowed for the capacity value of intermittent generators to be partly determined by their available capacity during periods of low supply capacity and relatively low demand.

The ERA's expectation was that this possible bias would be small and at the time the ERA did not recommend using a scaled demand profile. This was to avoid any subjective scaling of the observed system demand and keep the method as simple as possible. The ERA also explained that it would review this aspect of the method in the next review of the RLM.[34]

At the MAC meeting on 20 October 2020, AEMO stated that the ERA did not address AEMO's concern about the ability of the proposed method to accurately forecast the capacity value of intermittent generators based on weather conditions during peak demand levels that are

[33] Independent Market Operator. 2014, *2014 Relevant Level Methodology Review Final Report*, Report prepared by Sapere Research Group, pp. 51-52, (online).

[34] Ibid, p. 61.

considered in the planning criterion.[35] AEMO also stated that the proposed method is complex and iterative and asked for clarification.

AEMO also provided this feedback to the ERA as a submission to the ERA's draft report for the review of the RLM. The ERA addressed AEMO's feedback in its decision paper.[36] The ERA further considered this effect of lack of historical data while updating the rule change proposal.

The ERA ran sensitivity scenarios to investigate the extent to which the relatively low observed demand could bias the capacity valuation results. The ERA found that this effect is small when capacity values are estimated at the target LOLE of 24 hours in 10 years. However, at the target LOLE level of four hours in 10 years, this effect would be large and the use of historical demand data could bias intermittent generators' capacity value upwards.

The ERA implemented an improvement in the calculation as explained in section 3.2.6 to improve the robustness of the model. This improvement requires scaling the observed demand profile to the target year expected demand profile and better links the calculation of capacity values with the long-term projected assessment of system adequacy in the SWIS conducted annually by AEMO.

The proposed method does not contain any iteration, consistent with EPWA's expectation that the RLM provides an input into the calculation of capacity credits in a constrained network, or Network Access Quantities (NAQ). The ERA estimates that a full run of the proposed method takes between two to three hours on a typical desktop computer and can be fully automated. Low-cost measures can be taken to reduce the computation time to scale of minutes.

The model also uses conventional system adequacy analysis frequently used since the early 20th century. Many jurisdictions around the world use similar methods to that proposed by the ERA to assess the capacity value of resources or conduct system adequacy assessments. With increased penetration of intermittent resources many jurisdictions have decided to cease the use of subjective approximation or rule of thumb methods in favour of detailed probabilistic assessments. To the ERA's knowledge, there is no other known method that can objectively assess the capacity value of intermittent generators.

AEMO has indicated the need for detailed probabilistic assessment of system adequacy in the SWIS. This was reflected in EPWA's publication titled Operational Planning and PASA Framework.[37]

EPWA is currently developing changes to the design of the WEM. These include a move to security constrained economic dispatch and constrained network access for facilities. AEMO identified several issues around system security management in the SWIS to be improved to better align with the new security constrained economic dispatch design and increased penetration of intermittent generators.

AEMO's intended design for short- and medium-term projected assessment of system adequacy (PASA), presented through the Transformation Design and Operating Working

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35 Rule Change Panel, 2020, *Meeting minutes for the Market Advisory Committee meeting of 20 October 2020*, (online).

36 ERA, 2019, *Relevant level method review 2018, Capacity Valuation for intermittent generators, Final report,* p. 61-73, (online).

37 Energy Transformation Taskforce, 2020, *Operational planning and PASA framework, Information paper*, (online).

Group meeting, draws on probabilistic system capacity adequacy measurement methods similar to that proposed by the ERA in determining the capacity value of intermittent generators.[38]

In its presentation to the Transformation Design and Operating Working Group, AEMO explained that currently there was no direct link between system reliability principles and power system reliability assessment under the market rules.[39] AEMO explained that, under the new operating states framework, it was required to develop and publish the Reliability Standard Implementation Procedure that included main criteria for how it would assess reliability in medium-term and short-term projected assessment of system adequacy (PASA).[40]

AEMO explained that for a new medium-term PASA it intends to use a probabilistic modelling approach that uses common system capacity adequacy measures, such as loss of load probability and LOLE, to identify intervals with the greatest risk of unserved energy. AEMO's proposed method used maximum half-hourly demand net of total intermittent generation and generator outage patterns to calculate loss of load probability. This, in principle, is equal to the approach to the calculation of LOLE for the calculation of the capacity value of intermittent generators in the proposed RLM.

Recently, EPWA published the details of its proposed changes to short-term PASA and medium-term PASA. The changes are consistent with those previously indicated by AEMO and EPWA. These changes require AEMO to conduct a probabilistic assessment of system reliability. AEMO would use system adequacy analysis models consistent in principle with the proposed RLM to assess the reliability of the system in short to medium term.

The ERA's proposed method is in line with upcoming changes to management of system reliability in the SWIS. AEMO's experience with probabilistic assessment of system adequacy for the short term and medium term can support future improvements to the probabilistic system adequacy model the ERA has proposed for the RLM.[41] The implementation of the new short-term and medium-term PASA modelling tools and information technology systems would have some overlaps with the implementation of the proposed RLM.

3.2.6 Improving the calculation of expected system demand

As explained above, the ERA decided to improve the calculation of expected system demand used in the proposed RLM. The proposed method now scales the observed historical demand profile to the demand profile AEMO expects to be observed in the target capacity year, having an expected peak demand consistent with the requirements of the planning criterion.

The scaling function used is the same as the scaling function AEMO uses to estimate demand profiles in the SWIS for calculating the expected energy shortfall for the purpose of part (b) of the planning criterion. Therefore, AEMO would be able to use data produced for the purpose of preparing the Electricity Statement of Opportunity for the purpose of the proposed RLM. This scaling function is as explained below.

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38 Transformation Design and Operating Working Group, 2020, *Transformation Design and Operating Working Group meeting 13*, (online).

39 Ibid.

40 Energy Transformation Taskforce, 2020, *Revising the operating states and contingency events in the SWIS*, *Information paper*, (online).

41 EPWA, 2020, *Consolidated draft amending rules for WEM reforms, Tranche 2*, clauses 3.16 and 3.17, (online).

For each year within the sample period the historical system demand is scaled such that:

- The peak of the scaled demand equals the 10% PoE forecast peak demand.
- The scaled demand allocated across all trading intervals sums to the expected annual energy consumption forecast for the target capacity year.
- The shape of the scaled demand duration curve should be close to the observed system demand.

Given the three scaling features above, the scaling function $f(t)$ (t ∈ trading intervals in a sample year T) is used to forecast (scale) load for a given year T by multiplying the observed system demand by this function:

$$Scaled\ Demand(t) = f(t) \times Observed\ Demand(t)$$

where,

$$\max(Scaled\ Demand(t)\ \forall t \in T) = 10\%\ PoE\ peak\ demand\ in\ the\ relevant\ capacity\ year$$

$$\sum_{t=1}^{8760\times 2} Scaled\ Demand(t) \times 0.5 = expected\ energy\ consumption\ forecast\ in\ the\ relevant\ capacity\ year$$

The following function form will ensure the shape of the scaled demand varies with differing 10% PoE peak demand and expected energy consumption in a way that is consistent with the historical observed demand in each sample year T:

$$f(t) = \begin{cases} \frac{p-z}{m^2}(m-h)^2 + z, & h \le m \\ \frac{e-z}{(n-m)^2}(h-m)^2 + z, & h > m \end{cases}$$

where,

p denotes the ratio of the forecast 10% PoE peak to the observed peak demand in the sampled year T,

e denotes the ratio of the expected annual energy consumption forecast to the observed energy consumption in the sampled year T,

m denotes the rank of the observed system demand in trading interval t (sorted in descending order) in the sampled year T, over which the load duration curve of the sampled year T flattens,

n denotes the total number of trading intervals in a year,

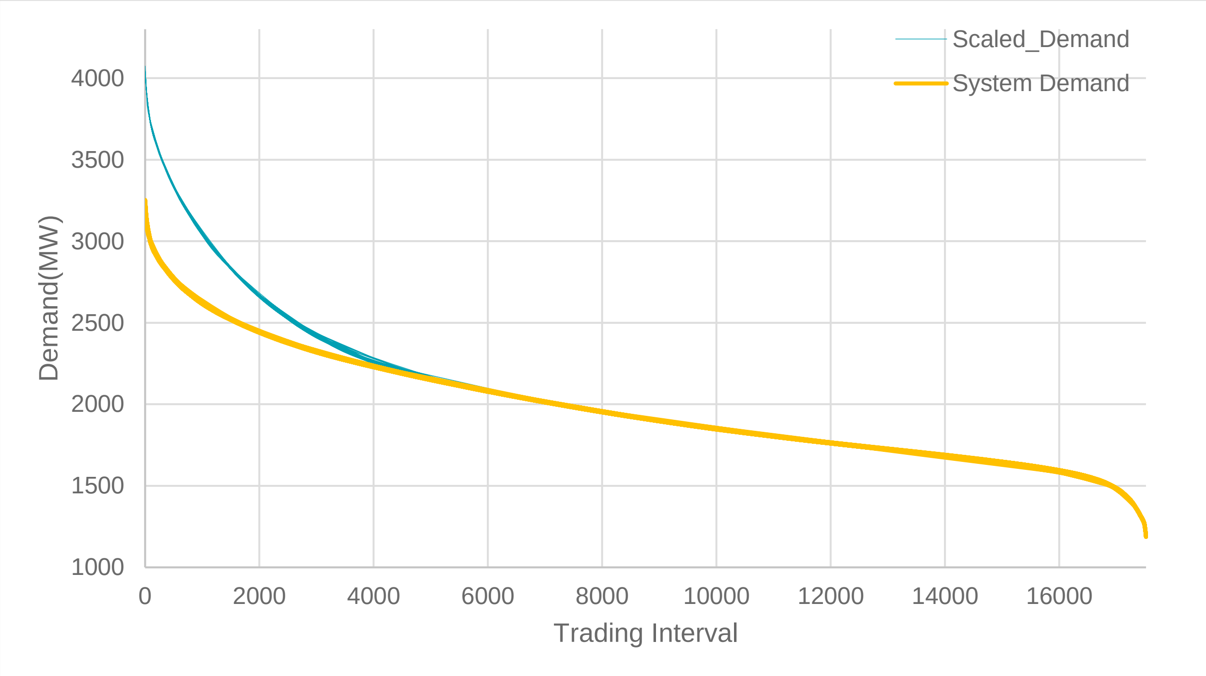
z represents a curvature constant that is adjusted to achieve the expected demand forecast in the resulting scaled system demand,

h denotes the rank of the observed system demand in trading interval t (sorted in descending order) in the sampled year T.

This scaling function is the same as the scaling function AEMO uses to estimate expected demand profiles and subsequently the expected energy shortfall for the target capacity year as part of the publication of the Electricity Statement of Opportunity.[42]

Section 2 in appendix 4 demonstrates the effect of the scaling function introduced above on the results of the proposed method. Figure 1 shows the general effect of the scaling function on the observed load duration curve for the sample period 2018/19 used for the 2019 reserve capacity cycle capacity valuation.

Figure 1. Scaled and observed demand for the 2018/19 sampled year



Results show that the application of the scaling function in the tested scenarios contributes to a small (12 MW or 3.6 per cent) decrease in the capacity value of the fleet of intermittent generators based on a target LOLE of 24 hours in 10 years. For this scenario, the minimum of the sampled capacity value of intermittent generators also increases from 238 MW to 262 MW. At the target LOLE of four hours in 10 years, the capacity value of the fleet of intermittent generators decreases to 274 MW (a 58 MW decrease) and the minimum of the sampled capacity values increases to 250 MW.

The proposed enhancements for the calculation of capacity values at a target LOLE and scaling system demand to expected system demand decreases the difference between the minimum of the sampled capacity values and the set fleet capacity value. Without the improvements the difference between the set fleet capacity value and minimum capacity value was 304-176=128 MW. After the improvements implemented this reduced to 274-250=24 MW.

[42] AEMO, 2019, *Final report: 2019 assessment of system reliability (expected unserved energy), development of availability curve and DSM dispatch quantity forecasts for the South West Interconnected System*, Report prepared by Robinson Bowmaker Paul, pp. 21-23, (online).

3.3 Network Access Quantity framework

RCP Support is concerned that the proposed RLM will interact with the NAQ assignment process and is currently unsure if the effect will be material. This section details how the ERA developed the new RLM to avoid adverse interactions with the NAQ. The ERA's sensitivity analyses showed no material interaction. As a result, no changes will be made to the pre-rule change proposal in response to the concerns raised by RCP Support on the possible interaction with the NAQ assignment process.

The effect of network constraints is deliberately removed from the calculation of both the proposed and current RLM. Network constraints can influence the capacity value of resources in the system.

EPWA's October 2020 release of the principles for the assignment of capacity credits under constrained network access is consistent with the principles anticipated by the ERA during the 2018 RLM review. The ERA considered that the proposed RLM should exclude the effect of network constraints, similar to that in the existing RLM, otherwise the effect of network constraints would be double-counted: once through the RLM and once during the model that accounts for the effect of network constraints.

EPWA's proposal uses the CRC of resources as input to the calculation of the effect of network constraints on the capacity value of generators and assigns capacity credits. This ensures the inputs to calculation of CRC for intermittent generators will be free from the effect of network constraints.

In the MAC meeting on 20 October 2020, RCP Support indicated that it has concerns about this aspect of the proposed RLM. RCP Support considered that:

> the outlined NAQ process creates interaction issues for the proposed RLM. This is because:
>
> (1) one of the input factors for the proposed RLM is the expected fleet of Intermittent and Scheduled Generators (**expected generator fleet**);
>
> (2) the RLM provides CRC values for every Intermittent Generator in the expected generator fleet;
>
> (3) the CRC values from the RLM are one of the input factors in the NAQ process;
>
> (4) as output the NAQ process provides Capacity Credit quantities for every Scheduled and Intermittent Generator under network constraints providing the actual generator fleet; and
>
> (5) the actual generator fleet will most likely be different from the expected generator fleet, which means that the outcome of the RLM may be incorrect.
>
> At this point, RCP Support is unsure whether the impact of the difference between the expected and actual generation fleet on the outcome of the RLM is material. [43]

In its review of the RLM, the ERA explained how in principle the capacity value of some resources, particularly some intermittent generators such as wind and solar generation, depended on the resource mix available in the system.

[43] RCP Support, 2020, Email sent to the Secretariat of the ERA summarising the RCP's support feedback provided to the ERA in the Market Advisory Committee meeting on 20 October 2020 (available in appendix 5).

RCP Support has identified a problem for any capacity valuation method that seeks to account for the effect of the resource mix on the capacity value of resources. This includes the proposed and previous RLM.

The current RLM ignores this interaction between the capacity value of generators by:

- Separating the capacity valuation of new and existing facilities. For the purpose of the RLM, any generator that has come to full operation or has had a significant upgrade or major maintenance over the past five years is considered to be a new facility. For the 2019 reserve capacity cycle 17 out of 30 intermittent generators were new or upgraded facilities. The current relevant level method effectively ignores the effect of new facilities on the occurrence of high reliability stress in the system when estimating the capacity value of existing facilities.
- Incorrectly calculating one of the parameters in the calculation (parameter K).
- Ignoring the possible effect of the availability of electric storage resources in the system during periods of high reliability stress.

The proposed RLM rectifies these problems and estimates the capacity value of resources having regard for the expected generation mix in the capacity year for which the calculation is being conducted.

The expected resource mix, however, can vary after the calculation of the CRC and accordingly the capacity value of resources might vary. The resource mix in the system can vary after the estimation of capacity values through the RLM till to the end of target capacity year for which the capacity values are being calculated, for example:

- Some resources may withdraw their application for certification of reserve capacity after the assignment of CRC.
- Some resources may cancel their project after receiving capacity credits.
- Some resources might be on extended forced or planned outage during the capacity year.
- AEMO may procure additional capacity through the supplementary reserve capacity procurement process closer to the target capacity year.[44]

Existing or proposed changes to the market rules since July 2019 add other scenarios where changes to the resource mix can happen after the certification of reserve capacity through the RLM:

- Some new resources might not receive capacity credits despite having certified reserve capacity. This is because changes to the market rules now define a priority order for the assignment of capacity credits and some resources with low priority might not receive capacity credits when AEMO procures sufficient capacity credits from higher priority resources.
- Some new resources may withdraw their application for receiving capacity credits if the assigned capacity credit is below the amount they are willing to accept to enter the market. EPWA's proposed changes now allow resources to specify the minimum amount of capacity credits they are willing to accept to enter the market.

44 Wholesale Electricity Market Rules (WA), 7 August 2020, Clause 4.24.

The ERA investigated the extent of the effect of changes in the resource mix by conducting two modelling scenarios. The scenarios replicated the assignment of CRC to intermittent generators in the 2018 and 2019 reserve capacity cycles through the proposed RLM.

In the 2018 reserve capacity cycle, four solar generators (with combined installed capacity of 110 MW) left the resource mix after the assignment of CRC. Results of the analysis showed that the effect of their exit from the resource mix on the capacity value of the remaining intermittent generators was approximately 10 MW.

The second scenario assumed all wind farms in the North Country region (excluding the small Kalbarri wind farm) exited the set of candidate facilities for the 2019 reserve capacity cycle, which is an extremely unlikely scenario to happen. The effect of the exit of North Country wind farms on the capacity value of remaining candidate facilities was approximately 12 MW (the capacity value of remaining facilities would have been larger by 12 MW if their capacity valuation had been conducted excluding North Country wind farms).

The results of the two scenarios also indicate the highest possible, but extremely unlikely, effect of network constraints. For example, the second scenario reflects the highest possible effect of network constraints that would influence the output of North Country wind farms on the capacity value of other candidate facilities. This is because the scenario can be interpreted as network constraints limiting the available capacity of North Country wind farms to zero at any period when loss of load probability is material.

RCP Support considered that “the actual generator fleet will most likely be different from the expected generator fleet [after conducting the NAQ process], which means that the outcome of the RLM may be incorrect.”

The RLM forecasts the capacity value of generators two years in advance of a capacity delivery year and, like any other forecast, contains forecast errors. The proposed RLM seeks to minimise these errors, and to do so, uses the best available information at the time of producing the forecast.

The risk of changes in generation mix should be managed to the extent possible having consideration for practicality, transparency and cost. Possible options for managing this risk are:

- Using the best available information at the time of running the RLM, including the expected resource in the system at the target capacity year.
- Repeating, and possibly reiterating, the calculation of the CRC and NAQ assignment process.

Only the first option is viable or reasonable because:

- For the sensitivity scenarios conducted, the effect of changes in the resource mix – due to the exit of some new generators – on the capacity value of resources was small. For an extreme scenario tested, the effect on the capacity value of resources from the influence of network constrains on the available capacity of other resources was small.
- EPWA’s proposed design for the assignment of capacity credits does not contemplate repeating or reiterating the calculation of network access quantities after the assignment of CRC. Option 2 is not a viable option for the ERA because it requires changes to the proposed NAQ process and timing of provision of reserve capacity security to AEMO, which both are outside the scope of the review of the RLM for the ERA.
- EPWA considered that the main principles guiding the design of the NAQ framework were simplicity, transparency, and ease of implementation in the WEM with minimal changes to

existing processes. EPWA stated "consistent with this key design principle, new requirements have been kept to the minimum necessary to facilitate the new NAQ assignment process." It is not clear if option 2 above can be chosen while maintaining simplicity, transparency and ease of implementation. The ERA informed EPWA about the possible interaction between the capacity value of resources, the design of proposed RLM and EPWA consulted with the ERA on the proposed RLM.[45]

- EPWA has indicated the principles for the calculation of NAQ.[46] A new market procedure and capacity allocation tool (the NAQ Model) is yet to be developed by AEMO to account for the transfer capability of the network as part of the NAQ and capacity credit assignment process.[47] At this stage it is not possible to determine if repeating and reiterating the calculation of CRC through the RLM and the NAQ process is viable.
- Existing resources in the mix are not likely to withdraw their application after the assignment of CRC, because their capital cost is sunk. New resources applying for CRC would not be interested to apply for the certification of reserve capacity and assignment of capacity credits and avoid the required costs if they expect they would not receive capacity credits above the minimum quantity they require to enter the market. The resource mix at the time of certification of reserve capacity is a reasonable indication of the expected resource mix.

3.4 Capacity valuation of aggregated facilities

This section details two methods for calculating the capacity of components of aggregated facilities and explains why the pre-rule change proposal has been amended to use one of the two options available. The change will improve the assignment of fleet-wide capacity value to aggregated facilities and ensure that no undue discrimination applies to assigning the fleet-wide capacity value to individual facilities with similar technology.

To make the change, the ERA considered the concerns raised by RCP Support that calculating the capacity of components could be impractical and expensive for aggregated or hybrid facilities.

By design, the proposed RLM is robust and can be used to estimate the capacity contribution of any resource including intermittent generators and or any other hypothetical supply technology. This requires an estimate of the expected available capacity of a resource during the target capacity year.

The proposed RLM uses the historical output of intermittent generators as a proxy for their expected available capacity in the target capacity year. For new or upgraded facilities with no historical data, an estimate of the available capacity is required. Consistent with the current RLM, the proposed method relies on estimated outputs before full operational date for those facilities that are new or upgraded.

Aggregated facilities might contain several components the capacity valuation for which is to be conducted through the RLM. In principle, the ownership of facilities is irrelevant to the

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45 Energy Transformation Taskforce, 2020, *Explanatory Memorandum: Proposed amending rules to the Wholesale Electricity Market Rules – Tranche 3*, p. 3, (online).

46 EPWA, 2020, 'Draft amending rules for reserve capacity mechanism and the network access quantity framework (ME V09)', clause 4.15, (online).

47 Energy Transformation Taskforce, 2020, *Explanatory Memorandum: Proposed amending rules to the Wholesale Electricity Market Rules – Tranche 3*, p. 6, (online).

capacity value of resources. That is, the capacity value of an aggregated facility is equal to the sum of the capacity value of its individual components. Facility ownership might influence the economic incentives for facilities, and hence, the way owners operate a facility. It is important the RLM uses the best indication of the available capacity of these resources.

Aggregated facilities might not have separate metering devices to measure their historical output. This does not create any problem for estimating the capacity value of the fleet of intermittent generators, because these facilities would have a metering device for market settlement, equivalent to that for non-aggregated facilities.

The proposed method apportions the fleet-wide capacity value of intermittent generators to facility groups and then individual facilities. The proposed allocation method is consistent with the relevant practice in other jurisdictions. This allocation process requires an estimate of the observed or estimated output of facilities.

At the MAC meeting on 20 October 2020 RCP Support stated that:

> RCP Support is concerned that the proposed RLM does not allow for hybrid Facilities that combine solar and wind generation in particular, as Facilities of this type already exist in the WEM. RCP Support understands that the ERA intends to amend the proposed method to account for such hybrid Facilities by assessing the wind and solar component separately. RCP Support is concerned that such an approach could be impractical and expensive for the affected participants, as they would have to either install additional meters or produce the relevant expert reports. In addition, this may disadvantage such Facilities by sharing the solar wind interaction effect of the Facility with all other solar and wind generators.

The ERA considered the possible lack of metering data for the components of aggregated facilities and how it might influence the allocation of fleet-wide capacity value to facility groups and individual facilities.

The capacity value of aggregated facilities, combining several technologies, can be estimated using the proposed method in two ways, as explained below:

Method 1 (recommended)

The proposed RLM allows AEMO to split the aggregated facilities into their component facilities and place each component in the respective facility group. For instance, for an aggregated solar-wind facility group AEMO is to place the solar component in the solar facility group and the wind component in the wind facility group. This method is recommended because this ensures that no undue discrimination applies to assigning the fleet-wide capacity value to individual facilities with similar technology.

This is important because the capacity value of large aggregated facilities that, for example, contain solar and wind facilities, would interact with other wind and solar facilities. When placed in a standalone facility group, the aggregated facility’s interaction with other facilities would be mostly shared with other facility groups with large installed capacity.

This calculation approach, of course, requires estimates of the available capacity of each component of the aggregated facility separately: either using metered data or estimated data.

There are options for breaking down the output of aggregated facilities to determine the output of each component: for example, using existing or installing new Western Power meters for each component.[48]

Low-cost options include the use of Western Power supervisory control and data acquisition points for generators that are connected to the transmission network, use of data recorded by programmable logic controller systems, or use of meters installed on facilities by participants for operational reasons.

Use of such data, however, requires an appropriate audit process to ensure the meter data is reliable. For example, solar and wind facilities have supervisory control and data acquisition or programmable logic controller systems that record the output of each component separately. This data can be used subject to an appropriate audit and clearing process, for example, to rectify any errors or replace any missing values. The cost and responsibility of producing this data is to be covered by facility owners, rather than AEMO. Facility owners typically have commercial incentives for measuring the output of each component of their facility and the cost of such meters or monitoring systems is already sunk.

The ERA's updated RLM proposal uses the estimated data for each component of aggregated facilities registered as semi-scheduled facilities. Aggregated non-scheduled facilities are proposed to be treated as single facilities for the purpose of the RLM, equal to that in the current RLM. Non-scheduled generators would be small facilities with no material capacity value interaction effect with other facilities.

For those facilities having any existing meters discussed above, the cost of producing audited data is expected to be lower than producing estimated data for new facilities. For such facilities the cost would be for removing any possible errors only. For new facilities, estimated output data is to be produced based on, for example, solar irradiance, wind speed during each historical period and technological characteristics and thus the associated cost would be larger than auditing and clearing metered data. If audit costs are prohibitively large, facility owners can opt to install audited meters.

Method 2 (not recommended)

AEMO can create a new facility class for all or each aggregated facility registered as semi-scheduled facility. The incremental computation time for each added facility group would be 10 to 15 minutes when the model is run on a typical desktop computer. This method is not recommended because it can lead to discrimination in the approach to assigning capacity credits as explained above.

The capacity value of an aggregated facility comprising solar and wind facilities would interact with the capacity value of other wind and solar facilities, because typically solar facilities shift the periods with the high probability of loss of load to later in the afternoon when wind generation is typically higher.

The proposed method requires the placement of each component of the solar-wind aggregated facility to wind and solar facility groups.

48 The metering protocol – including audit, error filtering process and dispute resolution process – for such meters is stipulated in Chapter 8 of the market rules.

4. Stakeholders' feedback since the MAC meeting on 17 November 2020

On 10 November 2020 the ERA provided a copy of the updated rule change proposal to the MAC for feedback.

At the MAC meeting on 17 November 2020, the ERA Secretariat provided the MAC with a summary of the updated rule change proposal and asked stakeholders to provide feedback by 30 November 2020.

In a submission to the ERA, Alinta Energy stated that it was concerned that the additional consultation being conducted on the ERA's preliminary rule change proposal disrupted the rule change process and risked further delaying the ERA's urgent reforms to the RLM.[49] Alinta Energy considered that "any further consultation duplicates the rule change process and does so in a less rigorous and transparent manner." Alinta considered "this is unnecessary, and risks issues and proposed amendments raised by stakeholders not being appropriately captured, considered and actioned. Ultimately, this could impact the effectiveness of the final rule change". Alinta Energy strongly recommended the ERA to not conduct any further consultation outside the rule change process and submit its rule change proposal as soon as possible.

The ERA agrees with Alinta Energy that any consultation on the proposed RLM should be transparent and provide an opportunity for stakeholders to respond to feedback provided by other stakeholders. Any feedback the ERA has received from stakeholders is captured and discussed in this proposal to ensure transparency. Stakeholders can respond to views expressed by other stakeholders during the rule change assessment process.

The ERA sought feedback from stakeholders to improve the rule change proposal and to help expedite the rule change assessment process. Given the MAC's feedback on the urgency of the submission and assessment of the proposal the ERA prioritised the development and submission of the proposed RLM to ensure the proposal will be submitted to the Rule Change Panel for assessment as soon as possible.

After the MAC meeting on 17 November 2020, AEMO and RCP Support requested meetings with the ERA Secretariat to provide feedback. The ERA Secretariat met with AEMO and RCP Support on 30 November 2020 and 2 December 2020. The main feedback received is summarised and addressed in this section. All other feedback received is summarised and addressed in Table 8. No change to the preliminary rule change proposal was needed after considering AEMO's or RCP Support's feedback.

Where necessary the ERA has included explanatory notes in the proposed changes to the market rules (in appendix 2) to ensure the intention of the proposed change is clear.

4.1 Interpretation of the planning criterion

At the MAC meeting on 17 November 2020 RCP Support explained that it has concerns about the ERA's proposal. RCP Support stated:

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49 Alinta, 2020, *Submission to the ERA's request for further feedback*, 30 November 2020.

> After considering the explanation provided by the ERA in Appendix 3 of the Pre-Rule Change Proposal, RCP Support continued to hold concerns that the proposed Relevant Level Methodology (RLM) might not be consistent with the Planning Criterion.
>
> RCP Support also held some concerns about the proposed scaling of observed demand for use in the RLM.[50]

The ERA Secretariat met with RCP Support to better understand RCP Support's concerns. In subsequent discussion between the ERA Secretariat, AEMO and RCP Support, RCP Support explained how the planning criterion in the SWIS had been interpreted in the past.

Definition of terms used

The market rules use the term available capacity when describing the planning criterion. RCP Support has interpreted this as the planning criterion setting the amount of capacity credits AEMO has to procure assuming capacity certification methods for resources exist in the market rules.

The terms "reserve capacity", "certified reserve capacity" and "capacity credit" are three distinct and different defined terms under the market rules. However, the market rules do not use any of these terms in describing the planning criterion. The ERA suggests the available capacity referenced in the planning criterion has its conventional meaning as in electricity industry practice, which is the amount of generation capacity available to the system expressed in megawatts.

At the meeting on 17 November 2020 RCP Support explained its concern:

> … was that the proposed RLM may assign more CRC [certified reserve capacity] to some intermittent generators than they would actually be expected to make available with a 90% certainty during such a one-in-ten-year peak demand event.[51]

The market rules do not require AEMO to limit certified reserve capacity assigned to any intermittent generator to the amount that is expected to be delivered with a 90 per cent certainty.

Additionally, available capacity during a trading interval and certified reserve capacity are not comparable terms as explained in detail in section 3.2.1.

Certified reserve capacity indicates the forecast contribution of resources to meeting the reliability planning criterion and is an absolute value determined for a period of one year. Forecast available capacity of resources during periods of high reliability stress determines their certified reserve capacity.

No change to the proposed method was made after considering RCP Support's feedback. As explained in detail in section 3.2, the ERA's proposed method is consistent with the explicit requirements of the planning criterion in the market rules and system reliability management principles that are widely used in practice.

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50 At the time of writing this paper a draft of minute for the Committee meeting was available. The meeting minute will be available on the ERA website shortly (online).

51 Rule Change Panel, 2020, *Meeting minutes for the Market Advisory Committee meeting on 20 October 2020*, p. 8, (online).

Setting the planning criterion

At the meeting on 2 December 2020, RCP Support explained that, based on their understanding of the last review of the planning criterion in 2012, the reserve margin and the planning criterion are meant to be, and are, deterministic or absolute.

Power system reliability is a probabilistic concept, because the factors that drive the reliability of the power systems are variable and uncertain in nature, and thus probabilistic. For example, both system demand and available capacity of resources are variable and uncertain, and therefore probabilistic.

A market operator or policy agency needs to run a probabilistic assessment of system reliability and determine the level of reliability risk that is acceptable before developing a deterministic criterion for system reliability management. For example, after accounting for the variability of the available capacity of resources and system demand a market operator can set an absolute (or deterministic) amount of installed capacity required to meet the reliability target of the system.

The probabilistic nature of power system reliability is discussed in many references. For example, Newberry and Grubb (2014) stated that:

> Contrary to common perception, security of supply is not an absolute, but a statistical goal. As noted, the GB standard for reliability is a Loss of Load Expectation (LoLE) of 3 hours per year on average, allowing for the probabilities of mild and also very cold winters. Ofgem (2014) defines LOLE as “the average number of hours in a year where we expect NG [National Grid] may need to take action that goes beyond normal market operations…
>
> LoLE is thus a stochastic measure, to be derived from an analysis of statistics of all the factors that lead to variations in supply and demand. National Grid and Ofgem take account of the probabilistic deviations about the level of demand in any half-hour, and the reliability of each plant on the system, including the amount of wind energy produced in any half-hour.[52]

4.2 Administrative cost of using the proposed RLM

At the MAC meeting, RCP Support asked the members about possible increased administrative costs flowing from the proposed rule change. RCP Support noted its concern that the proposed RLM required aggregated facilities, such as a combined wind and solar farm, to provide estimates of available capacity for their component facilities. RCP Support explained that this may increase costs and the administrative burden for participants because of the need for meters and expert reports. The RCP Support asked the MAC to advise on the implementation costs and administrative burden of the proposed method.

In response, Mr Timothy Edwards (Market Customer) stated that he was able to provide feedback on the costs of obtaining independent experts’ report for the available capacity of hybrid facilities, because his company had recently completed a certification process involving the addition of storage to a small solar facility.

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52 Newberry D. and Grubb M., 2014, ‘*The final hurdle?: Security of supply, the capacity mechanism, and the role of interconnectors*’, *University of Cambridge Energy Policy Research Group*, Working Paper 1412, (online) [accessed 29 October 2020].

Mr Edwards explained that the proposed method required estimated data for seven years, compared to the current method requiring five years of historical or estimated data. Mr Edwards explained the incremental cost of producing estimated output for aggregated facilities, when compared to the current RLM, was in the order of $1,000 to $2,000. Mr Edwards explained that aggregated facilities paid for the same amount of data regardless of an aggregated facility being treated separate or combined. Mr Edwards did not expect the additional costs would be material for facilities with capacities exceeding 10 MW.

The ERA's assessment is that the incremental cost of producing estimated data for the proposed RLM is small. The ERA does not recommend any change to the proposed method in response to RCP Support's concern about the cost of producing estimated data or administrative burdens.

4.3 Transparency of the proposed method

At the MAC meeting, AEMO asked stakeholders if they had any concerns about the transparency of the proposed method when compared to the current method. No stakeholders raised any concerns about the transparency of the proposed method.

The ERA considers the proposed method is transparent because:

- It is based on common reliability assessment principles and modelling frequently used in many jurisdictions. AEMO will soon use similar probabilistic models, to those included in the proposed RLM for short-term and medium-term projected assessment of system adequacy as part of the reforms proposed by EPWA.
- All steps of the proposed method are specified in the proposed market rule and stakeholders can replicate the proposed method using a computer.

The proposed method is robust to changes in the SWIS because it is directly linked with reliability assessment principles and would not be exposed to the risk of fundamental changes such as a change to the requirement of the planning criterion, or changes in the resource mix or demand in the future.

In comparison the current RLM is opaque because:

- It does not specify the steps in the calculation of parameters used in the market rules. Instead it requires the ERA to review these parameters periodically without any guidance on how these parameters should be calculated.
- The formula used in the current method contains fundamental problems and the value of the constant parameters used in the formula is unsound.

Alinta Energy stated that the ERA's rule change proposal "aims to correct significant issues in the current RLM, which can lead to 'excessive errors' in the accreditation of intermittent generators and impact investment signals".[53]

[53] Alinta, 2020, *Submission to the ERA's request for further feedback*, 30 November 2020.

4.4 Possible change in the reliability planning criterion

At the MAC meeting, RCP Support stated that Energy Transformation Implementation Unit (ETIU) is reviewing the planning criterion and they will consult with ETIU to determine if ETIU's review of the planning criterion will overlap with and so affect the proposed RLM and EPWA's proposed changes to the WEM rules.

Ms Wendy Ng (Market Generator) asked if a change in the planning criterion of the SWIS would require a change in the proposed RLM.

The ERA Secretariat explained that the proposed method was based on system reliability assessment principles and so was robust to changes in the reliability planning criterion. The calculation of capacity values in the proposed method is based on effective load carrying capability, which can be estimated based on any reliability metric used to date or to be developed in the future. For example, effective load carrying capability can be calculated based on loss of load hours, expected unserved energy and loss of load expectation.[54] Effective load carrying capability is a technology-neutral measure of capacity contribution and could for example be applied to measure the capacity value of coal and gas generators.[55]

If in the future, the SWIS relies on expected unserved energy criteria – the currently non-dominant criterion of the planning criterion – only a minor change will need to be implemented in the proposed method to account for such change. This would require the calculation of expected unserved energy, rather than loss of load expectation, based on the capacity outage probability table.[56] If the SWIS adopts an explicit loss of load expectation target, the proposed RLM would only require a minor change to insert the specified target in place of the proposed target of four hours loss of load expectation in 10 years.

At a subsequent meeting with the ERA Secretariat, AEMO explained its concerns that the ERA's proposed method may not be applicable if the reserve capacity requirement was set by part (b) of the planning criterion. AEMO explained that under the 'Techtopia' scenario in the 2020 Whole of System Plan, more than 3,000 MW of new large-scale renewable generation (wind and solar) was forecast to be required by 2030. In this scenario, part (b) of the Planning Criterion was likely to set the reserve capacity requirement.

AEMO explained that a solution to this issue could be to link the review of the RLM to the planning criterion so that a review would be required should part (b) ever set the reserve capacity requirement. AEMO noted the review should be carried out to capture this possibility prior to part (b) of the planning criterion being triggered, given the timeframe needed to conduct and finalise a review.

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54 PJM, 2020, *Effective load carrying capability*, p. 4, (online).

55 It can be shown mathematically that the effective load carrying capability of a thermal generator is $ELCC = Temperature\ rated\ capacity\ at\ the\ time\ of\ system\ stress \times (1 - outage\ probability\ at\ the\ time\ of\ system\ stress)$. The outage probability at the time of system stress can be measured using equivalent demand forced outage rate (EFORd) as per the IEEE Standard Definition for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity, (online). Also refer to PJM, 2020, *Effective load carrying capability*, p. 8, (online).

56 Several resources explain how capacity outage probability table can be used to determine expected unserved energy in a power system. For example, refer to Billinton R. and Allan R., 1996, *Reliability Evaluation of Power Systems*, New York, Springer Science, p. 38–39.

The ERA is of the view that no change to the proposed RLM is required in response to AEMO's feedback. This is because:

- In its 2020 electricity statement of opportunity, AEMO explained that it did not expect the second requirement of the planning criterion to dominate the first requirement over the next decade.[57]
- The scenarios developed for the Whole of System Plan show plausible future scenarios in the SWIS. The Techtopia scenario is not contemplated as the most likely scenario to happen nor is it a forecast of future demand and generation mix in the SWIS. Currently, there is no evidence to suggest that even if such a scenario occurs, part (b) of the planning criterion would be triggered.
- The market rules do not prohibit the ERA from conducting reviews of the RLM more than once every three years. If it appears that, in the future, part (b) of the planning criterion is to take effect, the ERA can propose changes to the RLM, if required. The changes required would be minor and could be accommodated through a fast-track rule change proposal.[58]

4.5 Urgency of the rule change proposal assessment

At the MAC meeting, Alinta Energy considered that the RLM rule change proposal should have a high urgency rating for assessment for four reasons:

- The ERA's review showed that the current RLM resulted in excessive forecast errors leading to intermittent generators capacity value being overvalued and undervalued.
- The review showed how increasing the intermittent generation share of the resource mix exacerbated these forecasting errors. It is important to correct these errors before they become worse and disrupt investment signals.
- If these errors are not corrected before the next reserve capacity cycle, they will distort the NAQ assigned to resources for years to come.
- The previous basis for delaying the rule change proposal was the possibility for interference with NAQ reforms. However, there will be no interference as the RLM will be an input in the NAQ model like it is in the current Constrained Access Entitlement model.

MAC members agreed with Alinta Energy and recommended a high urgency rating for the assessment of the ERA's rule change proposal.[59]

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[57] Refer to AEMO, 2020, *Final report: 2020 assessment of system reliability, development of availability curve and DSM dispatch quantity forecasts for the South West Interconnected System*, Report prepared by RBP, pp. 10–11, (online).

[58] Only two changes are needed to accommodate part (b) of the planning criterion: (1) scaling demand to 50% PoE forecast peak demand rather than 10% PoE forecast peak demand, and (2) calculating expected unserved energy using the capacity outage probability table, rather than LOLE.

[59] Committee members Patrick Peake (Market Customer), Peter Huxtable (Contestable Customer), Daniel Kurz (Market Generator), Timothy Edwards (Market Customer), Zahra Jabiri (Network Operator) and Geoff Gaston (Market Customer).

4.6 Available capacity of intermittent generators during extremely high air temperatures

In response to the ERA's pre-rule change proposal submitted to the MAC, Mr Patrick Peake (Market Customers), AEMO and RCP Support provided feedback to the ERA on the available capacity of intermittent generators during extremely high demand periods on hot summer days in the SWIS.

Mr Peake explained that the summer peak occurred after a series of very hot days and it was reasonable to assume that during such periods there would be intense sunshine so all solar systems, both in front of and behind the meter, should be producing.

Mr Peake asked what capacity would be expected from wind farms on such peak demand days and queried if the ERA had conducted any assessment of wind generation expected on peak demand days. Mr Peake asked if it were possible that on peak demand days, the wind speed would be low over all of the south west region and consequently all windfarms would produce very little output. Mr Peake also queried if it was more likely that when there was a strong easterly wind blowing all wind farms would be generating more than expected.

AEMO explained that:

> Intermittent generators perform differently at 10% POE peak demand conditions compared to the profile captured in the seven-year historical data set. However, the [ERA's proposed] method does not include an adjustment to account for this difference, which AEMO considers to be an omission.

AEMO also explained:

> Empirical evidence demonstrates that intermittent generators' performance degrades on higher peak demand days.

RCP Support stated:

> We are concerned that by scaling the demand in the model for Trading Intervals that do not show the characteristics of the one in ten year peak demand (high max daily temperature for consecutive days, low wind in the afternoon/evening, Business Day) will not reflect the contribution of the Intermittent Generators during an actual one in ten year peak demand. In particular we believe that it is likely that the expected weather characteristics during such a one in ten year peak demand would result in a lower contribution of most Intermittent Generators.

Any objective capacity valuation method requires information about the available capacity of resources during periods when the reliability stress in the system is the highest. It is the available capacity of a resource during such periods that determines its contribution to meeting the reliability planning criterion of the system.

In the near future, the periods of high reliability stress in the SWIS are most likely to happen when demand is extremely high. It is reasonable to consider that demand would be extremely high when a series of extremely hot days occurs.

It is important to ensure that the calculation of capacity values uses the best information about the available capacity of resources during periods of high reliability stress. In response to Mr Peake's comments, it is possible that, on a hot summer day when the probability of loss of load in the SWIS is high, wind speed could be very low across the state. However, given the large geographical size of the SWIS this would be very unlikely. Further, it is also possible that as the easterly wind increases, wind generation would increase more than average on hot days.

The geographical diversity of wind farm sites also decreases the likelihood that all wind farms across the SWIS would have very low amount of wind resource during an extremely hot day in Perth. AEMO's analysis of wind generation in the National Electricity Market shows how the outputs of wind farms become less correlated as their geographical distance increases.[60]

There is always the possibility that a period of very low wind speed across the SWIS might coincide with very high demand in the SWIS. However, if the likelihood of this occurring is less than one event in 10 years then it is outside of the requirements of the planning criterion. Although a loss of load event would be likely if such an event happened, the planning criterion does not require sufficient available capacity to meet demand during such period.

It is important to assess whether historical data contains enough information about the available capacity of wind resources during extremely hot periods that would coincide with periods of highest demand consistent with that specified in the planning criterion.

The ERA Secretariat requested AEMO and RCP Support to provide the ERA with their reasoning and evidence for their expectation of intermittent generation performance degradation during extremely high demand periods or one-in-10 year peak demand periods and how this expectation would reduce the capacity value of intermittent generators.

AEMO provided three reasons in support of its comments above:

- In the 2014 review of the RLM the Independent Market Operator found "a strong positive relationship between peak demand and maximum daily temperature and a negative relationship between intermittent generators' output and maximum daily temperature".
- AEMO stated that there was an "observed decrease in the output of Collgar wind farm during historical peak demand days."
- AEMO stated that "historically, the SWIS has not yet experienced any 10% PoE peak demand days."[61]

The ERA considers that AEMO's statement that the proposed RLM does not contain an adjustment in the historical output of intermittent generators, and that this is an omission, is incorrect. The ERA considered this matter when deciding to propose a new RLM and provided details in the final decision paper.[62]

None of the reasons AEMO provided can justify applying an adjustment to the historical output of intermittent generators when calculating their capacity value as recommended by AEMO. AEMO and the Independent Market Operator's observations about the decrease in the output of wind farms during hot periods may be correct but this does not mean that historical wind output data should be adjusted based on these observations. The concern about the lack of data is not about generally hot periods but for extremely hot periods. Any observed correlation

60 For the analysis conducted for the National Electricity Market, the Pearson correlation coefficient between the output of wind farms more than 250 kilometre apart generally decrease below 0.5. The Pearson correlation coefficient measures the strength of the linear relation between two variables. It ranges between -1 and 1, where a coefficient of 1 indicates a perfect upward linear relationship. AEMO, 2020, *Renewable integration study stage 1 Appendix C: managing variability and uncertainty*, pp. 22–23 , (online).

61 AEMO summarised its points and provided the summary to the ERA through email correspondence on 7 December 2020.

62 ERA, 2019, *Relevant method review 2018 – Capacity valuation for intermittent generators*, (online).

between the output of wind farms and system demand in hot or very hot periods is already captured in historical data.

As discussed in detail below, the Independent Market Operator's statistical analysis to derive the correlation between wind generation and air temperature during extremely high air temperature periods was flawed.

Whatever the shape of observed correlation between the output of Collgar wind farm and system demand in the SWIS, it is captured in historical data used in the calculation of capacity value for Collgar.

AEMO stated that observed demand in the SWIS had never been as high as that expected to occur with a probability of exceedance of 10 per cent. This would not necessarily mean that an adjustment to the historical output of intermittent generators is needed.

Before making the decision to propose the new RLM, the ERA reviewed the capacity valuation practice in other jurisdictions and academic studies. In its decision paper, the ERA explained that one challenge in valuing the capacity of renewable generators was that their output was statistically correlated with system demand and the output of other renewable generators in the system. Accounting for this correlation is important when calculating their capacity contribution.

This correlation is complex and cannot be reliably modelled in practice. All studies and practices the ERA reviewed relied on historical data as the best indicator of future performance because modelling the relevant correlations would be subject to several assumptions about meteorological variables such as wind speed and air temperature. To date historical data has been the best source of information available about the correlation between the output of intermittent generators and system demand.

The proposed RLM uses historical data as the input to the calculation, consistent with the practice in other jurisdictions. The ERA conducted additional analyses to assess possible problems from using historic data on the output of intermittent generators.

In the decision paper, the ERA explained its concern about the possible effect of the lack of data on the available capacity of intermittent generators during extremely hot days.[63] The ERA considered to what extent the capacity valuation method could rely on historical output of wind farms when assessing their capacity contribution in two years' time.

In the previous review of the RLM, the Independent Market Operator presented some analysis, conducted by its consultant, Sapere, to investigate how the available capacity of wind resources changed when air temperature increases. Figure 2, from Sapere's report, shows the relation between air temperature and wind speed on historical days with low surplus capacity over demand in the SWIS.[64]

Sapere argued that there was a statistically significant negative relationship between air temperature and wind speed. This was based on fitting a regression model to the data points shown in Figure 2. In the same report Sapere stated that the one in 10-year peak demand in

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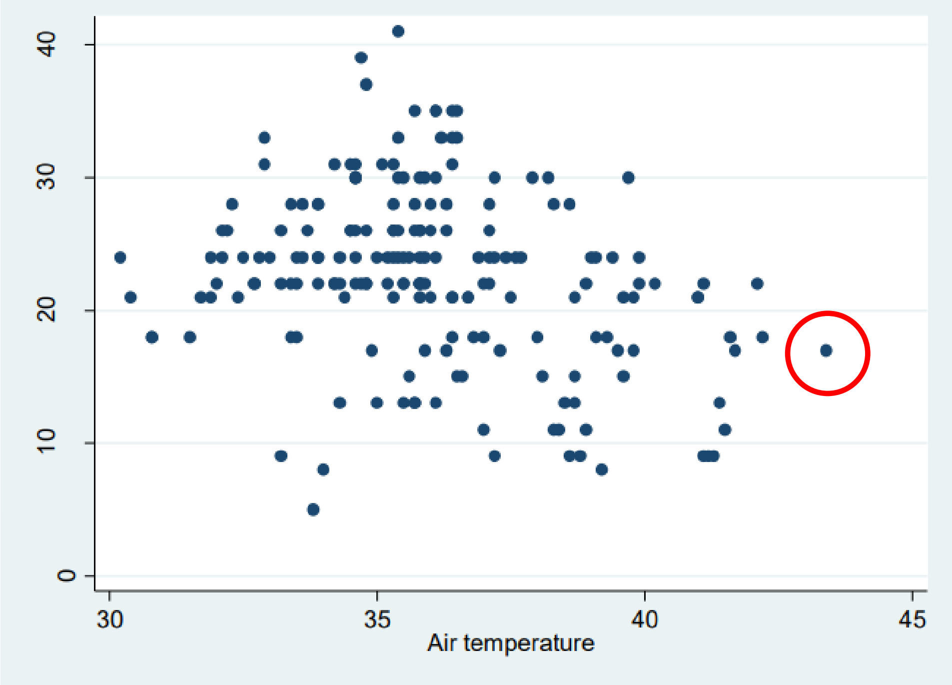
[63] ERA, 2019, *Relevant level method review 2018: technical appendix*, p. 53, (online).

[64] Independent Market Operator. 2014, *2014 Relevant Level Methodology Review Final Report*, Report prepared by Sapere Research Group, pp. 51-52, (online).

the SWIS was most likely to happen when air temperature was approximately 43.8 degrees Celsius.

Figure 2: Relationship between wind speed and air temperature at historically high reliability stress periods



Note: Points represent the air temperature and wind speed on peak LSG days (i.e. top 12 days per year) taken from the Perth Airport weather station.

Source: Sapere, 2014.

There is only one data point in the figure above (circled) that reflects a trading interval with an air temperature close to 43.8 degrees. Any statistical model applied to assess the correlation between air temperature and wind speed *for periods of extremely high demand periods* should be based on data points of measured wind speed when there is extremely high air temperature consistent with that is expected to occur on very high demand trading intervals.

Sapere's analysis is flawed in its assessment of the correlation between wind speed and air temperature during extremely high air temperature. There is no reliable evidence in Sapere's research to explain the direction of correlation between air temperature in Perth (reflecting system demand) and wind speed across wind farms (reflecting their available capacity) during extremely hot intervals.

Sapere applied a regression model to the entire sample points above. The sample contains many air temperature periods below 42 degrees Celsius. Historical data contains many trading intervals with such air temperature but only a few with extremely high air temperature close to 43.8 degrees Celsius. The statistical power of any model fitted to the above data to predict wind speed at extremely high air temperature would be low due the lack of data.

Given the observed limitation of the statistical analyses conducted by the Independent Market Operator, the ERA concluded that it was not reasonable to use the regression model the Independent Market Operator developed to scale the historical output of intermittent generators.

If there was a fitted regression model that included data on wind speed at extremely high temperature, it could be used to scale the historical available capacity of wind farms when estimating the relevant levels using the proposed method. However, the ERA's review of capacity valuation of intermittent generators in other jurisdictions showed that none of these used any scaling function to adjust the historical output of intermittent generators when assessing their capacity value.

The ERA considered other possible ways to investigate the correlation between wind generation and extremely high air temperature. For example, the ERA found academic studies that aimed to address this question.[65] However, those studies were based on numerous assumptions about modelling weather patterns, which, if applied in practice, could not provide any additional benefit given the degree of uncertainty introduced by the underlying assumptions. The computational burden of such analyses could also prohibit their implementation in practice. The ERA also found that other jurisdictions assumed no correlation between wind generation and system demand when there was a lack of historical data during extreme weather events.[66]

The ERA is less concerned about the possible lack of data on wind speeds at extremely high air temperature periods. This is because there is evidence suggesting that periods of highest demand in the SWIS are less likely to happen during extremely hot ambient temperature periods close to 43.8 degrees Celsius.

At the time Sapere conducted the review of the RLM, the penetration of behind-the-meter solar systems in the SWIS was small. The expectation that the highest demand in the SWIS was mostly likely to happen on a very hot day with 43.8 degrees Celsius appeared to be reasonable.

There is evidence that the uptake of behind-the-meter solar panels has shifted the periods of the highest demand in the SWIS towards later in the afternoon when air temperature is high but not the highest that has been observed on the day. For example, AEMO provided the following information in 2020 WEM Electricity Statement of Opportunity.[67] Table 2 shows the occurrence of annual peak demand days in the SWIS.

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65 Zachary S. and Dent C., 2014, *Estimation of Joint Distribution of Demand and Available Renewables for Generation Adequacy Assessment*, (online).

66 Ofgem, 2013, *Electricity Capacity Assessment Report 2013 – Report to the Secretary of State*, (online).

67 AEMO, 2020, *2020 Electricity Statement of Opportunities – A report for the Wholesale Electricity Market*, p. 24, (online).

Table 2. Comparison of annual peak demand days, 2012-13 to 2019-20

Capacity Year	Date	Trading Interval of peak demand	Peak demand (MW)	Daily maximum temperature (°C)	Time of temperature peak	Rank of day[A]
2019-20	4 February 2020	17:30	3,919	43.3	14:30	1
2018-19	7 February 2019	17:30	3,256	35.8	15:00	21
2017-18	13 March 2018	17:30	3,616	38.5	14:00	2
2016-17	21 December 2016	17:00	3,543	42.8	14:30	2
2015-16	8 February 2016	17:30	4,004	42.6	15:00	3
2014-15	5 January 2015	15:30	3,744	44.2	13:30	1
2013-14	20 January 2014	17:30	3,702	38.7	15:00	7
2012-13	12 February 2013	16:30	3,739	41.1	13:00	2

A. A rank of 1 indicates the hottest day in the Capacity Year, 2 indicates the second hottest day, and so on.
Source: AEMO, Solcast and BOM.

Over time, periods of the highest demand have shifted from 15:30 or 16:30 to 17:30. This shift in the timing of the occurrence of peak demand is most likely to be the result of the uptake of behind-the-meter solar photovoltaics generation. Air temperature later in the afternoon is likely to be below the daily peak temperature. Historical peak demand in the SWIS has also occurred during such periods when air temperature is high but not the highest on the day, comparing the timing of the occurrence of peak demand and daily peak temperature in Table 7.

In its decision paper, the ERA explained that the air temperature in Perth was higher than or equal to 38 degrees Celsius during 448 trading intervals in the five-year period between 1 April 2012 and 1 April 2017. The ERA concluded that this sample of trading intervals, if used in the proposed RLM, could provide a reasonable indication of the output of intermittent generators during periods of the highest demand in the SWIS because these periods would most likely to have high air temperature above 38 degrees - but not necessarily extremely high at around 43 or 44 degrees Celsius. Any possible correlation between air temperature and wind speed is already reflected in historical data used in the calculation of capacity values for intermittent generators and the proposed RLM captures this correlation.

Given the observations above, the ERA has introduced measures in the proposed RLM to best address the observed changes in the system and possible lack of data.

The proposed method uses seven years of historical performance as input to the calculation. When compared to a five-year sample, this seven-year sample would include a larger set of data points for the available capacity of wind resources during high air temperature periods. A larger sample would include a larger sample of trading intervals with high air temperature above 38 degrees. It is also possible to increase the sample size to 10 years to ensure more information is captured in the analysis and this could be explored through the rule change process. For example, Mid-continent Independent System Operator in the United States uses the past 15 years of data to collect most weather information available in the analysis of the capacity valuation of wind farms. PJM recently adopted use of ELCC for the capacity valuation of resources. PJM has proposed to use 10 years of historical data.

The proposed method scales historical demand timeseries and forecasts the timeseries of demand in the target capacity year. This scaling function adjusts historical demand to ensure:

- The time series of demand used in the calculation reflects the shift in occurrence of peak demand to later in the afternoon given the expected uptake of behind-the-meter solar generation.
- The profile (load duration curve) of the time series of demand reflects AEMO's expectation of 10 per cent probability of exceedance (PoE) peak demand and expected energy consumption for the target capacity year. This will provide a forecast for system demand in the SWIS in the target capacity year having consideration for AEMO's forecast of 10 per cent probability of exceedance (PoE) peak demand, energy consumption and the uptake of distributed energy resources in the SWIS.

RCP Support expressed concern that in the proposed RLM when demand is scaled up to reflect AEMO's expectation of 10 per cent PoE peak demand there is no corresponding downward scaling of the output of intermittent generators to capture their expected lower output at extremely high temperatures. RCP Support was concerned that the use of demand scaling could exacerbate the omission of scaling of observed available capacities. The ERA does not share RCP Support's concerns. By scaling demand the approach adds more weight to the observed available capacity of intermittent generators during higher air temperature periods in summer when estimating the effective load carrying capability of intermittent generators.

Without adjusting historical demand, for example, it is more likely that available capacity of intermittent generators during high demand periods in winter will unduly influence the capacity value estimated for intermittent generators. This is possible because on a historical cold winter day with high demand, intermittent generators could have low available capacity and loss of load probability could be very high – thus contributing to the estimate of capacity value for intermittent generators. Available capacity of intermittent generators could be low during such winter days but still higher than that could typically happen during a one-in-10 year peak demand period on a summer day. Adjusting the historical demand now limits such possible distortion in the capacity valuation of intermittent generators particularly due to observed mild summers. After scaling demand, the capacity value calculated for wind (and other resources) would be mostly determined by their available capacity during historically hot trading intervals.

Another possible approach to give more weight to the available capacity of intermittent generators during hot summer days would be to discard all historical demand and available capacity data below a certain air temperature or demand level and determine the capacity values based on the remaining historical data.[68] However, this could eliminate information about the available capacity of intermittent generators during high reliability stress periods in winter or any other period with high demand and very low available capacity from intermittent generators. The application of the proposed scaling function takes account of distributed energy resources generation and scales historical demand while keeping information about the available capacity of intermittent generators during extremely high demand periods in winter leading to high probability of loss of load.

Currently the ERA has no reliable evidence on the output of intermittent generators during very high air temperature periods (exceeding 43 degrees Celsius). There is also no evidence that such high air temperature periods would be very likely to happen during a one-in-10 year peak demand period. The ERA is not aware of a reliable model used in practice to forecast the available capacity of wind resources that also considers the correlation between the output of each wind resource and system demand.

[68] This approach would effectively assign a weight of zero to the historical data discarded and one to the remaining historical data used in the capacity valuation.

AEMO has acknowledged the problem with the lack of data for assessing the available capacity of renewable generators. In its 2020 ancillary services report, AEMO stated that “the correlation between output of the various facilities is a key consideration when determining the LFAS [load following ancillary service] requirements and can only be understood through operational experience.”[69] AEMO explained that it intended to use weather forecasting as a guide to determine the amount of load following ancillary service required.

There is an opportunity to review this aspect of the method in the next review of the RLM after further reviewing the progress in capacity valuation of intermittent generators in academic studies and in other jurisdictions. AEMO’s progress in forecasting weather and intermittent generation available capacity may also provide improvement opportunities for the RLM. Any possible increase in the sample of extremely hot days would also provide additional information.

In the next review of the RLM, the ERA will focus on using any available meteorological models to explain the possible effect of the available capacity of intermittent generators during very high air temperature periods on their capacity value.

4.7 Reserve margin used in the planning criterion

AEMO asked two questions in discussions with the ERA Secretariat, these are considered separately below.

Consistency between the loss of load expectation target and the planning criterion

AEMO asked “Is the proposed target LOLE level of four hours in 10 years consistent with the level of reserve margin required under part (a) (or 10.5 per cent of the 10 per cent PoE peak demand) of the planning criterion?”

The target level of system adequacy in the SWIS is having sufficient available capacity to limit the expectation of loss of load to one event in 10 years as explained in section 3.2. This criterion also requires AEMO to add to the forecast 10 per cent PoE peak demand a reserve margin equal to the greater of:

- 7.6 per cent of the forecast peak demand (including transmission losses and allowing for Intermittent Loads); and
- the maximum capacity, measured at 41°C, of the largest generating unit.

The inclusion of reserve margin, in principle, is not to decrease the expectation of loss of load events below one event in 10 years. The reserve margin has been historically included in the planning criterion to ensure generator outages would not increase the expected loss of load above one event in 10 years.

The Independent Market Operator last reviewed the planning criterion in the SWIS in 2012. The Independent Market Operator’s consultant, Market Reform, noted:

> The current Planning Criterion has its genesis in the system planning methodology developed by Western Power Corporation (WPC) before the Wholesale Electricity Market commenced. WPC published a Generation Status Review report each year that

69 AEMO, 2020, *Ancillary services report for the WEM 2020*, p. 16, (online).

> estimated an 8 to 10 per cent required reserve margin over and above the capacity required to supply 10% Probability of Exceedance (POE) demand.

Market Reform explained:

> A reserve criterion is required to maintain at least enough energy to ensure demand can be supplied after the failure of the largest generating unit. The present Market Rule therefore combines a margin [of 8.2 per cent] over 10% POE demand, largest generating unit capacity and an unserved energy standard.

At the time Market Reform conducted the review of the planning criterion, the reserve margin was set at the larger of 8.2 per cent of the forecast 10 per cent PoE peak demand and the maximum capacity of the largest generating unit. In its review of the reserve margin Market Reform considered the costs and benefits of increasing or decreasing the reserve margin above and below the specified 8.2 per cent target at the time and found that a margin of 7.6 per cent of 10 per cent PoE peak demand was optimal for the SWIS.

Market Reform used the actual generator outages in the period between 2007 and 2011 and the central forecast demand for the SWIS to determine the reserve margin.[70]

A common practice in managing the power system adequacy risk was to plan for having sufficient available capacity to meet a target forecast demand, commonly set at 10 per cent PoE forecast peak demand. In the past all generation resources in the system were conventional scheduled generators such as coal and gas generators. System operators counted the rated capacity of scheduled generators at the time of highest demand in the system and ensured that the total amount of rated capacity was sufficient to meet the 10 per cent PoE peak demand in the system. However, they also accounted for the risk of generator outages and demand forecasting error by adding a reserve margin on top of the target forecast demand. They ensured total rated capacity available was equal to the sum of 10 per cent PoE peak demand and the reserve margin. This ensured the expected frequency of loss of load events was limited to one event in 10 years after accounting for the effect of outages or possible spikes in demand.

This was historically the case at the time SECWA or Western Power operated the SWIS. This approach was carried through to the WEM after its commencement in 2006 and to date has remained generally constant.

The reserve margin in the planning criterion is a historic approach to account for the effect of demand forecasting uncertainty and generator outages to plan for system adequacy.

Several references for the reliability assessment of power systems also confirm the application of reserve margins in managing system reliability risk. For example, Billinton and Allen (1996) explain the application of the reserve margin. They stated that:

> The static [system adequacy] requirement can be considered as the installed capacity that must be planned and constructed in advance of the system requirements. The static reserve must be sufficient to provide for the overhaul of generating equipment,

70 Although Market Reform developed other scenarios based on different outage rate and demand scenarios it did not use those scenarios to account for uncertainty in estimating expected outage rates and demand forecasting in the system. The reserve margin in the SWIS currently does not include any allowance for uncertainty in estimating expected outages or forecasting demand. Estimating the percentage reserve margin based on cost-benefit analysis is also incorrect and not consistent with system reliability management principles. The ERA will discuss these matters with EPWA. Refer to Market Reform, *Review of the Planning Criterion used within the South West Interconnected System: Final report*, pp. 7–8, (online).

> outages that are not planned or scheduled and load growth requirements in excess of the estimates.[71]

They further explained "a practice that has developed over many years is to measure the adequacy of both the planned and installed capacity in terms of a percentage reserve." They further explained two approaches to determining this reserve and their advantages and disadvantage in comparison with each other:

- Percentage reserve margin: the percentage reserve margin has tendency to compare the relative adequacy of capacity requirements for different systems on the basis of peak demand. They explained in principle two systems with equal peak demand might require different percentage margin and therefore the percentage reserve margin might not be an optimal choice. Also the percentage reserve criterion attaches no penalty to a unit because of size.
- Largest unit reserve: this reserve criteria requires larger reserve requirements with the addition of larger units to the system.[72]

One approach was to set a reserve margin above the target peak demand in the system to be met by choosing the larger of the two criteria above. This has been the case in setting the reserve margin in the SWIS. As explained above, the aim of including a reserve margin is not to decrease the likelihood of loss of load events below the target level of system adequacy risk in the system but mainly to account for the effect of generator outages when installing or scheduling capacity installations and keeping the expectation of loss of load at the target level.

Current system adequacy standards in many power systems around the world also confirm the explanations above. For instance, the North American Electric Reliability Corporation (NERC) develops and enforces power system reliability standards for north American power systems, including those in the United States and Canada.[73] Current system adequacy standard developed by NERC specifies that:

> **R1** The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall […] :
>
> 1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).
>
> …
>
> 1.1.2. The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).[74]

The PJM Interconnection power system operates an energy plus capacity procurement wholesale electricity market similar to that in the SWIS. PJM follows the system adequacy planning standards specified by the NERC and annually assesses system adequacy for the PJM Interconnection:

71 Billinton R. and Allan R., 1996, *Reliability Evaluation of Power Systems*, New York, Springer Science, p. 18.

72 Ibid, pp. 18-29.

73 NERC, 2020, Website: *About NERC*, (online), [accessed 5 December 2020].

74 NERC, 2020, *Planning resource adequacy analysis, assessment and documentation, BAL-502-RF-03*, (online).

> The PJM Reserve Requirement is defined to be the level of installed reserves needed to maintain the desired reliability index of ten years, on average, per occurrence (loss of load expectation of one occurrence every ten years) after emergency procedures to invoke load management.[75]

PJM uses a probabilistic system adequacy assessment model to determine the PJM reserve requirement, or installed reserve margin:

> The Installed Reserve Margin is the installed capacity percent above the forecasted peak load required to satisfy a Loss of Load Expectation (LOLE) of, on average, 1 Day / 10 Years.[76]

The calculation of installed reserve margin in the PJM system adequacy planning is to maintain the loss of load expectation at the specified target of 0.1 day per year. The probabilistic model PJM uses to determine the installed reserve margin is equal in principle to that the ERA has developed for the proposed RLM.[77]

Recently PJM adopted the use of effective load carrying capability for the capacity valuation of intermittent generators and storage. PJM has proposed to use a very similar capacity valuation method to that the ERA has proposed in this rule change proposal.[78]

Sensitivity of capacity value to a change in the loss of load expectation target

AEMO asked "What is the impact of a different target LOLE (higher or lower) on the forecast capacity value of intermittent generators (i.e. how sensitive is the result to this assumption)?"

Section 3.2.3 explained small variations to the target level of LOLE used for the calculation of capacity values would not have a large effect on the capacity value of many intermittent generators. This is because the effective load carrying capability of a resource is dependent on its contribution to reducing the LOLE in the system after adding the resource to the system. This capacity value is not generally sensitive to small variations in the target LOLE of the system.[79]

Table 3. Other feedback received from stakeholders

Issue	Comment/Question/Effect/Solution	ERA's response
AEMO - Planning Criterion The proposed method uses scaled demand and observed output of	AEMO is concerned that using the observed output of Intermittent Generators which is not consistently adjusted to the 10% POE peak demand conditions may result in overestimating the capacity value of Intermittent Generators' (particularly wind) and lead to reliability issues. • AEMO understands that the proposed method intends to scale demand to	Addressed in section 4.6. No change to the proposed market rules is required given this feedback.

[75] PJM, 2019, *PJM manual 20: PJM resource adequacy analysis, revision: 10*, p. 14, (online).

[76] Ibid, p.13.

[77] Ibid, pp. 30–32.

[78] PJM, 2020, *Webpage: effective load carrying capability (ELCC)*, (online), [accessed 5 December 2020].

[79] Nevertheless, this effect might be large for storage technology depending on the expected duration and length of expected loss of load events in the system. EPWA has proposed to determine the certified reserve capacity of electric storage resources through a linear derating method. For a discussion of the sensitivity of effective load carrying capability to the target risk level in the system refer to Garver L., 1966, *Effective load carrying capability of generating units, IEEE Transactions on Power Apparatus and Systems*, issue 8, pp. 910-919.

Issue	Comment/Question/Effect/Solution	ERA's response
Intermittent Generators.	meet the forecast 10% POE peak demand to capture the impact of DER uptake on load profiles. AEMO would like to further understand how the effect of DER uptake on load profiles will be accounted for in the proposed method. • AEMO notes an inconsistency within the proposed method: - In 10% POE peak demand conditions, the load profile will be different to the load profile captured in the seven-year historical data set. The method attempts to adjust for this difference. - Intermittent Generators perform differently at 10% POE peak demand conditions compared to the profile captured in the seven-year historical data set. However, the method does not include an adjustment to account for this difference, which AEMO considers to be an omission. • Empirical evidence demonstrates that Intermittent Generators' performance degrades on higher peak demand days. Evaluating Intermittent Generators' contribution to the scaled demand based on observed output may result in overestimating their capacity values, which may lead to reliability issues and undermine the purpose of the RCM: - The periodic Planning Criterion review is a cost-benefit analysis, with the objective of recalibrating the Planning Criterion at the level of capacity where the last MW of capacity provides more benefit (in reduced expected unserved energy) than cost (through capacity payments). - If Intermittent Generators' capacity values are overestimated, this balance could shift such that the Planning Criterion is just met, and no further capacity is procured, when in fact additional capacity may deliver more benefit than cost. • Overestimating capacity values for Intermittent Generators will devalue dispatchable capacity: - The Reserve Capacity Price (RCP) provides a signal for investment in capacity (noting that it operates alongside the signals provided by other market prices), particularly to maintain sufficient dispatchable	

Issue	Comment/Question/Effect/Solution	ERA's response
	capacity to ensure reliability is maintained. - All else being equal, an increase to Intermittent Generators' valuations will reduce the RCP. - This reduces the investment signal for dispatchable capacity.	
AEMO - Certification of Reserve Capacity timeline The inputs for the proposed method include: • Facilities that will receive Certified Reserve Capacity (CRC); and • CRC quantities for Facilities that are not assessed via the Relevant Level (RL) method (Scheduled, Semi-Scheduled, Electric Storage Resources, and Demand Side Programmes). Therefore, CRC assessments must be completed for these Facilities before the RL calculation can be performed.	AEMO is concerned that the proposed method will constrict the CRC assessment timeframe significantly and will be extremely challenging to implement without: - Amendments to section 4.9 of the WEM Rules to allow AEMO to assess all Facilities that have applied for CRC prior to carrying out the RL calculation. - An extension to the current CRC assessment timeline under section 4.1 of the WEM Rules for a minimum of 10 Business Days to account for the RL calculation and finalisation. Additional time is required for the 2021 Reserve Capacity Cycle to account for the Constrained Access Entitlement calculation before the Network Access Quantity framework commences for the 2022 Reserve Capacity Cycle. Processes that could previously be performed in parallel must now occur sequentially because CRC assessments must be completed before running the RL calculations. The proposed method requires more inputs and calculation steps compared to the current method. AEMO will require more time to verify inputs, carry out the calculation, validate the results, troubleshoot and resolve any issues that may arise while addressing any queries Market Participants may have on the implementation of the rule change.	The ERA considers that when compared to the current RLM the incremental work-load to run the proposed RLM is small. The proposed method can be run on a desktop computer over two to three hours without manual intervention. With access to parallel or cluster computing facilities the run time can be substantially reduced. All input data required for the proposed method is similar to that for the current method except for a few items. AEMO prepares and validates this additional data as part of other processes either before or during the reserve capacity certification process. AEMO might require some additional time for the first few runs of the proposed method to address any possible error in information technology systems required for the proposed RLM. AEMO can use its discretion under the market rules to extend the reserve capacity cycle or can draw on additional resources to complete the proposed RLM within default time frames for capacity certification. AEMO's incremental workload can also be discussed and assessed in detail as part of the rule change assessment process. No change to the proposed market rules is required given this feedback.
AEMO - Planning Criterion (part b) The proposed method forecasts the expected capacity value of resources based on their contribution to meeting part (a) of	AEMO is concerned that this proposed method may not be applicable if the Reserve Capacity Requirement is set by part (b) of the Planning Criterion. - Under the 'Techtopia' scenario in the 2020 Whole of System Plan, more than 3,000 MW of new large-scale renewable generation (wind and solar) is forecast to be required by 2030. In this scenario, part (b) of the Planning	Addressed in sections 4.4 and 4.7. No change to the proposed market rules is required given this feedback.

Issue	Comment/Question/Effect/Solution	ERA's response
the Planning Criterion.	Criterion is likely to set the Reserve Capacity Requirement. A solution to this issue is to link the RL review to the Planning Criterion such that a review is required should part (b) ever sets the Reserve Capacity Requirement. Note the review should be carried out to capture this possibility prior to part (b) being triggered, given the timeframe needed to conduct and finalise a review. AEMO has the following questions: - Is the target LOLE level of four hours in 10 years consistent with the level of reserve margin required under part (a) (~10.5%)? - What is the impact of a different target LOLE (higher or lower) on the forecast capacity value of Intermittent Generators (i.e. how sensitive is the result to this assumption)?	
CRC assignment The proposed method assigns CRC based on an average of the RL values assigned to the Facility using the proposed method and any available CRC quantities from the two preceding Reserve Capacity Cycles.	AEMO is concerned that this approach may introduce bias between existing and new Facilities. This may result in an inaccurate assignment of CRC and, subsequently, Capacity Credits to meet the Reserve Capacity Requirement. If the quantity of Capacity Credits assigned is incorrect, the RCP will also be incorrect, sending an inefficient signal for capacity investment.	The proposed clause is now removed. The intention of the proposed clause was to dampen any possible sudden change in the assignment of certified reserve capacity from the implementation of the proposed method. This was in response to previous stakeholder feedback to manage any possible financial implications of the change proposed to the RLM. Many stakeholders now consider that the proposed RLM is to be implemented in the market rules to rectify over- and under-estimation of the capacity value of intermittent generators because of the use of the current RLM. They consider this is important to ensure intermittent generators receive Network Access Quantities consistent with their expected capacity value to the system based on the ERA's proposed method.
Conditional and Early CRC assessment It is unclear how the proposed method will be applied to applications for Conditional CRC or Early CRC.	AEMO considers that there is insufficient detail about how the proposed method can be applied for Conditional and Early CRC assessment. As a result, AEMO may be unable to process Intermittent Generators' Conditional or Early CRC applications.	EPWA has proposed any eligible application for the early certification of reserve capacity is to be assessed as part of the certification of reserve capacity after the submission of application. The ERA's proposed method is to be applied using the same principle specified by EPWA in draft amending rules (note

Issue	Comment/Question/Effect/Solution	ERA's response
		EPWA's proposed changes to clause 4.28C.7).[80] No change to the proposed market rules is required given this feedback. Drafting might be improved to ensure this requirement specified by EPWA is clear. For conditional certification of reserve capacity AEMO can use the most recent run of the proposed RLM completed in the preceding reserve capacity cycle and include the application for conditional CRC as a Candidate Facility in that model to determine CRC. The proposed changes to the market rules now include this requirement.
Allocation of the Facility Groups' Relevant Level values The allocation is based on the average performance level of all Facilities over 84 peak demand Trading Intervals.	AEMO would like to confirm the ERA's intention is to remove the set of Trading Intervals based on the peak Residual Demand (scheduled generation) from the allocation of the Facility Groups' RL values. The peak Residual Demand intervals are times when the risk of loss of load is high and capacity is most valuable (especially when there is a high-level penetration of Intermittent Generation).	The ERA confirms the allocation of facility group relevant level to individual facilities based on average performance during peak scaled demand periods only was intended. The previous version of the rule change proposal required an allocation based on peak demand and peak residual demand periods. After the introduction of scaled demand periods of peak scaled demand and peak residual demand (calculated based on scaled demand) would mostly coincide. Keeping the requirement to calculate average performance during peak demand and peak residual demand would not create any problem (provided that both are calculated based on scaled demand). The updated rule change proposal reverted the design back to its previous state to ensure robustness of the proposed method to increased penetration of intermittent generators.
Implementation of the proposed method in the WEM Rules	AEMO suggests that the implementation of the proposed method should include a Market Procedure and AEMO should be the custodian. AEMO understands that the ERA agrees to this approach in principle. AEMO requests further information on how it will be included in the proposed method.	It is out of scope for the ERA to propose a change to the governance of the review of the RLM. The ERA Secretariat considers there are merits in developing an AMEO market procedure detailing the application of the method. AEMO would be able to draw on its experience with short-term and medium-term projected assessment of system adequacy to improve the computation of relevant levels. Nevertheless, to ensure transparency the principles of capacity valuation for

80 EPWA, 2020, *Draft amending rules for reserve capacity mechanism and the network access quantity framework (ME V0.9) (consolidated master)*, p. 170 , (online).

Issue	Comment/Question/Effect/Solution	ERA's response
		intermittent generators will be specified in the market rules. It might be better to delay the development of AEMO's market procedure until after stakeholders have confidence about the application of the proposed method and AEMO's application of the method in practice. No change to the proposed market rules is required given this feedback.
RCP Support – scaling historical demand	We are concerned that by scaling the demand in the model for Trading Intervals that do not show the characteristics of the one in ten year peak demand (high max daily temperature for consecutive days, low wind in the afternoon/evening, Business Day) will not reflect the contribution of the Intermittent Generators during an actual one in ten year peak demand. In particular we believe that it is likely that the expected weather characteristics during such a one in ten year peak demand would result in a lower contribution of most Intermittent Generators. Therefore, we are concerned that the proposed scaling may result in a higher capacity value for Intermittent Generators than they would be expected to deliver during a one in ten year peak demand event.	Addressed in section 4.6. No change to the proposed market rules is required given this feedback.
RCP Support – DER adjustment	From the presentation at the MAC meeting we understand that the ERA intends to include a DER adjustment in the proposed RLM – we would like to understand how that is intended to be included.	The rule change proposal presented to the MAC already included a requirement to account for Distributed Energy Resources generation when estimating scaled demand. The ERA explained that this is based on AEMO's scaling function applied to calculate expected unserved energy for the purpose of part (b) of the planning criterion and provided a reference to AEMO's report that clearly explains how the scaling function is applied and accounts for the uptake of distributed energy resources. Emphasis was added in the relevant rule change proposed to ensure it is clear that distributed energy resources is accounted for. An explanation box also now explains the intention of the proposed clause. The ERA will support the RCP Support to improve drafting (if required) during the rule change assessment process.
AEMO and RCP Support	Both AEMO and RCP Support provided feedback on the ERA's drafting of the proposed changes to the market rules.	The ERA has addressed AEMO's and RCP Support's drafting feedback to ensure proposed drafting captures the ERA's intention of the proposed changes.

Issue	Comment/Question/Effect/Solution	ERA's response
		Some of the feedback received is about EPWA's drafting of the proposed changes to the market rules. Apart from typographical changes needed, the ERA considers EPWA is best placed to address this feedback.
Dr Adnan Hayat – basing the RLM on peak demand periods	Dr Adnan Hayat noted that the principle of basing the RLM on peak demand periods that typically occur during summer may not give a true sense of what Intermittent Generators, and particularly solar facilities, can produce during most of the year.	What determines the contribution of resources to meeting system adequacy requirements is their available capacity during periods of high reliability stress: when surplus of available capacity over demand is small and, therefore, loss of load probability is high. The proposed RLM measures the capacity contribution of resources based on their available capacity during high system stress periods. For this the proposed method considers the available capacity and demand in the system during all trading intervals, but not peak demand periods during summer only. Nevertheless, at the current level of penetration of renewables in the system periods of the highest loss of load probability are most likely to happen during very hot summer days with very high demand. This would not be necessarily the case with increased penetration of renewables. The proposed method is robust to changes in the resource mix in the system.
Mr Patrick Peake – Similarity of the target LOLE proposed and historical LOLE used in the SWIS	Mr Patrick Peake (Market Customer) explained that the proposed target LOLE for the proposed RLM is similar to historical loss of load expectation used when the State Energy Commission of Western Australia (SECWA) operated the SWIS.[81]	The planning criterion of the SWIS has not changed since the commencement of the market and has origins in the planning criterion Western Power used to manage the reliability of the system. In general approach the planning criterion of the SWIS is consistent with the practice in many other jurisdictions and conventional system reliability management principles. The specified target in the planning criterion appears to be too stringent, requiring a very high level of reliability when compared to the reliability standard in other jurisdictions.

81 Patrick Peake, 2020, *Email sent to the ERA Secretariat on 12 December 2020*.

5. Summary of RCP Supports main concerns about the Relevant Level Method proposed in RC_2019_03

At the 20 October 2020 MAC meeting, the ERA presented an update on the progress of its Pre-Rule Change Proposal: Method used for the assignment of Certified Reserve Capacity to Intermittent Generators (RC_2019_03). At the same meeting, RCP Support shared its main concerns with the proposed Relevant Level Method (**RLM**) with the MAC. These concerns together with some additional details are outlined below.

All of the feedback received below has been addressed in sections 3 and 4.

Issue 1: Interaction of the RLM with the Network Access Quantity Framework

Draft NAQ Framework

ETIU is currently working on the Network Access Quantity (**NAQ**) framework to address how Capacity Credits are assigned to Facilities under a constrained network access regime. ETIU provided a confidential draft of the proposed Amending Rules to implement the NAQ framework to the ERA on 31 July 2020 and the ERA shared the information with RCP Support.

Based on the draft Amending Rules, the assignment of Capacity Credits will work as follows:

- AEMO will assign Certified Reserve Capacity (**CRC**) to Facilities:
  - for generators other than Intermittent Generators, this will be based on the maximum sent out capacity of the Facility that can be guaranteed at 41 degree Celsius; and
  - for Intermittent Generators, this will be the outcome of the RLM.
- AEMO will determine the NAQ for each Facility based on a Network Access Model, which is to be developed by AEMO. The model is to take into account the constraint equations (which AEMO will develop based on the Limit Advice provided by Western Power) and the NAQs assigned to individual facilities must not exceed the level of network access expected to be available to the Facility in at least 95% of the generation dispatch scenarios, based on:
  - modelling the generation dispatch for a range of peak demand scenarios developed by AEMO – the scenarios must assume peak demand at the estimated one in ten year peak demand estimated in the Long Term PASA;
  - the CRC of all Facilities;
  - the minimum quantity of Capacity Credits required to be assigned to a Facility for the Facility to participate in the Reserve Capacity Mechanism;[82] and
  - the priority in which Facilities will be assigned available NAQ where the NAQ is not sufficient to cover the CRC of all Facilities' behind a constraint.
- AEMO will assign Capacity Credits to a Facility up to the Facility's NAQ, which cannot exceed the Facility's CRC.

82 This value is proposed to be introduced as part of the introduction of the NAQ framework.

Interaction issue between the RLM and NAQ Processes

RCP Support considers that the outlined NAQ process creates interaction issues for the proposed RLM. This is because:

- one of the input factors for the proposed RLM is the expected fleet of Intermittent and Scheduled Generators (**expected generator fleet**);
- the RLM provides CRC values for every Intermittent Generator in the expected generator fleet;
- the CRC values from the RLM are one of the input factors in the NAQ process;
- as output the NAQ process provides Capacity Credit quantities for every Scheduled and Intermittent Generator under network constraints providing the actual generator fleet; and
- the actual generator fleet will most likely be different from the expected generator fleet, which means that the outcome of the RLM may be incorrect.

At this point, RCP Support is unsure whether the impact of the difference between the expected and actual generation fleet on the outcome of the RLM is material. RCP Support is aware that the ERA engaged a consultant to assess the materiality of this issue and that the outcome of the assessment will be reflected in the Rule Change Proposal.

RCP Support considers that if the Rule Change Panel is convinced that the impact of the interaction issue is not expected to be material at the moment, then the issue can be ignored when progressing the Rule Change Proposal.

At this point RCP Support sees the following high-level options if the issue is expected to have a material impact:

- the Rule Change Panel rejects the proposal; or
- the Rule Change Panel approves the proposal in amended form by:
  - including an iteration(s) that accounts for the interaction of the RLM and NAQ, which will most likely significantly increase cost and reduce the practicality of the process; or
  - replacing the proposed method with a rule of thumb method.

Issue 2: Possible Inconsistency of the RLM with The Planning Criterion and Reserve Margin

The current Planning Criterion of the Reserve Capacity Mechanism requires AEMO to ensure that there is sufficient Certified Reserve Capacity so demand can be met in a 1 in 10 year peak demand scenario including a reserve margin of 7.6% to account for the likelihood that not all Certified Reserve Capacity will be available.

RCP Support is concerned that the proposed RLM is not consistent with the current Planning Criterion and as a result could present a risk to Power System Reliability. AEMO has also raised this concern. The concern is based on the following observations about the proposed RLM:

- The expected load carrying capability (**ELCC**) for the fleet of Intermittent Generators is based on the fleet's expected contribution to the reduction of the loss of load expectation (**LOLE**) over all Trading Interval in each of the Capacity Years in the reference period. RCP support is concerned that this ELCC may be higher than the expected contribution of the fleet during a 1 in 10 year peak demand scenario.

- The capacity value of the fleet is determined by taking the median of the fleet's ELCCs for each Capacity Year in the reference period. RCP Support is concerned that this implies that the fleet would be expected to be able to contribute less than the CRC, which would be inconsistent with the Planning Criterion and the reserve margin.

RCP Support understands that the ERA considers that the RLM is consistent with the Planning Criterion and will not provide any further analysis beyond those already provided as part of the final report of the RLM review. RCP Support is currently assessing this issue.

At this point RCP Support sees the following high-level options if the issue the Panel comes to the conclusion that the proposed RLM is inconsistent with the Planning Criterion:

- the Rule Change Panel rejects the proposal; or
- the Rule Change Panel approves the proposal in amended form which may include a change to the Trading Intervals considered for the ELCC determination of the fleet and/or a change from using the median to using an adequate percentile of the fleets ELLCs over the reference period.

Issue 3: Accounting for Storage Facilities and Hybrid Facilities Combining Wind and Solar

RCP Support notes that Storage Facilities are currently not reflected in the assumptions about available capacity. RCP Support understands that the ERA is currently working on a solution to account for Storage Facilities.

RCP Support is concerned that the proposed RLM does not allow for hybrid Facilities that combine solar and wind generation in particular, as Facilities of this type already exist in the WEM. RCP Support understands that the ERA intends to amend the proposed method to account for such hybrid Facilities by assessing the wind and solar component separately. RCP Support is concerned that such an approach could be impractical and expensive for the affected participants, as they would have to either install additional meters or produce the relevant expert reports. In addition, this may disadvantage such Facilities by sharing the solar wind interaction effect of the Facility with all other solar and wind generators.

The Rule Change panel will assess the issue when processing the Rule Change Proposal.

Appendix 4 Sensitivity analyses (part 1)

The appendix summarises the findings of sensitivity scenarios the ERA conducted to demonstrate the application of the proposed method and assess possible alternative designs.

These sensitivity scenarios replicate the capacity valuation for intermittent generators that applied for the certification of reserve capacity in the 2017 to 2019 reserve capacity cycles. These scenarios were developed with incremental improvements in the model and unless stated results may not be directly comparable.

Section 1 outlines those scenarios already presented to stakeholders during the review period or subsequently in December 2019 and are based on the 2017 and 2018 reserve capacity cycle data. The explanations provided are based on the previous version of the rule change proposal but are generally consistent with the updated version of the rule change proposal. Section 4.5 explains the improvement about assignment of fleet capacity value to individual facilities.

Section 2 presents the application of scaled demand in the proposed method, as discussed in section 3.2.6 in Appendix 3.

Appendix 5 presents the additional scenarios the ERA conducted in October 2020 to update the previous rule change proposal consistent with changes proposed by EPWA and improve the calculation. These scenarios are based on the 2019 reserve capacity cycle data. For conducting these scenarios, the ERA engaged Lantau Group.

1. Sensitivity analyses and example calculation

The ERA conducted several sensitivity analysis scenarios to explore the effect of different factors on the outcomes of the proposed method. Additionally, the ERA analysed possible variation in capacity value results from year to year for both the intermittent generation fleet capacity value and individual facility capacity values.

Sensitivity analyses presented in this section are based on the sample model the ERA developed during its review of the relevant level method. Further details about the sample model can be found in the ERA's final report on the review of the relevant level method.[1]

The calculation of the sample model is explained in detail and in conjunction with the calculation steps in the proposed relevant level method. This provides a detailed example calculation to facilitate the interpretation of the changes proposed and the assessment of the rule change proposal. The incremental steps taken to improve the model are also presented to inform the reasoning for improvements identified.

Although the proposed calculation in Appendix 9 uses a seven-year sample period (Step 1(a)), the analysis provided in this report is based on a sample period of five years. This is because the available estimated output of New Candidate Facilities currently covers a maximum of five years only. The proposed changes to the Relevant Level Method are based on a sample

[1] ERA, 2019, *Relevant level method review 2018, Capacity Valuation for intermittent generators, Final report,* (online).

period of seven years to reduce the variability of results between years and provide a more reliable estimate of the capacity value of candidate facilities.

1.1 2017 reserve capacity cycle (progressed applications only)

In its review of the relevant level method, the ERA developed a sample model to illustrate the application of the proposed relevant level method. The model calculated the Relevant Level of Candidate Facilities for the 2017 Reserve Capacity Cycle (the 2019/20 Capacity Year) using their observed (or estimated) output from 1 April 2012 to 1 April 2017.[2] AEMO used the current relevant level method to estimate Relevant Levels for the same capacity year.

The sample model calculated several estimates of Relevant Level for the fleet of Candidate Facilites, including:

- Relevant Level based on system demand and generation data for each year in the five-year period between 2012 and 2017. This provided a sample of five Annual_Relevant_Level_Candidate_Facilities (Step 10(a)). Results showed that the Relevant Level of the fleet of intermittent generators varied from year to year.
- A longer-term estimate of the Relevant Level of the fleet of Candidate Facilities based on the time series of demand and output of intermittent generators for the whole five-year period between 2012 and 2017 (Full_Period_Relevant_Level_Candidate_Facilities_Fleet as in Step 10(b)).

The ERA improved the sample model and remedied one error in the input data to the model.[3] Results of the enhanced sample model are presented in Table 1. The improvements to the sample model provided results that are generally consistent with that presented in the ERA's review report.

For comparison, AEMO's estimate of the total capacity value of intermittent generators in the SWIS for the capacity year 2019/20 was approximately 183 MW.

[2] This calculation only considers those Candidate Facilities that eventually received capacity credits in the 2017 Reserve Capacity Cycle.

[3] The error in input data was due to using actual sent out generation for New Candidate Facilities before the Full Operation Date.

Table 1. Relevant Level of the fleet of Candiate Facilities (2017 Reserve Capacity Cycle – progressed applications)

Relevant_Period	Relevant Level (MW) (published in the ERA's review report)	Relevant Level (MW), enhanced sample model
2012/13	200	214
2013/14	377	403
2014/15	190	196
2015/16	253	266
2016/17	180	193
2012–17 (full period)	250	264

The proposed method sets the relevant level for the fleet of candidate facilities as the smaller of the median of the annual relevant levels and the full period relevant level (Step 11(a)):

$$\begin{aligned} Relevant\_Level\_Candidate\_Facilities\_Fleet &= \min\{median(214{,}403{,}196{,}266{,}193), 264\} \\ &= 214\ MW \end{aligned}$$

The fleet Relevant Level in this sample model is set by the observed (or estimated) output of Candidate Facilities in the 2012/13 period. Step 11(a) specifies that the Selected_Period is 2012/13, because the fleet Relevant Level is set by the annual Relevant Level in the 2012/13 period. This Selected_Period is used in the calculation specified in Step 11(b).

Table 2 shows the Relevant Level of facilities in each Technology Class as a group calculated based on Step 11(b). Using the results in Table 2 and the calculation Steps 11(c), the amount of interaction between solar and wind technology classes is:

$$\begin{aligned} Solar\_Wind\_Interaction\_Effect &= 214 - (14.7 + 39 + 159) \\ &= 1.3\ MW \end{aligned}$$

In the sample model presented in the ERA's review of the relevant level method, the amount of interaction between solar and wind generators was evenly allocated to each of the solar and wind technology classes. Sensitivity analysis results showed that the amount of interaction between solar and wind generators can be large and is variable. To dampen the variability of results between years, the proposed method allocates the interaction effect in proportion to technology class relevant levels (Step 11(d)).

Based on the calculation in Step 11(d), the adjusted technology class capacity values are presented in Table 3. The table also includes additional data to indicate the Relevant Level as a percentage of installed capacity of each technology class. This data is shaded grey to indicate that it is not part of the calculation in the proposed method. For the rest of this appendix, all shaded columns in tables represent information that is not used in the proposed calculation of relevant level.

Table 2. Technology Class relevant level for the selected period 2012/13 (2017 Reserve Capacity Cycle – progressed applications)

Technology_Class_ Relevant_Level	Net_Demand data	Relevant_Period	Relevant Level (MW)
Technology_Class_Relevant_Level (Biogas Technology Class)	System Demand-CF_Generation(Biogas Technology Class)x2	2012/13 (Selected_Period)	14.7*
Technology_Class_Relevant_Level (Solar Technology Class)	System Demand-CF_Generation(Solar Technology Class)x2	2012/13 (Selected_Period)	39
Technology_Class_Relevant_Level (Wind Technology Class)	System Demand-CF_Generation(Wind Technology Class)x2	2012/13 (Selected_Period)	159

**Note: the amount of Relevant Level for the Biogas Technology Class was determined used a linear interpolation. For instance, with a Net_Demand offset of 15 MW, LOLE calculated for Step 18(c) was 0.00026825, whereas at a Net_Demand offset of 14 MW, LOLE was 0.00026449. The target LOLE (estimated in Step 18(a)) was 0.000267. A linear interpolation between 14 and 15 MW point estimates, yielded a Relevant Level of 14.7 MW at the target LOLE of 0.00026825.*

Table 3. Technology class relevant levels (2017 Reserve Capacity Cycle – progressed applications)

Adjusted_Technology_ Class_Relevant_Level	Relevant Level (MW)	Total installed capacity of technology class (MW)	Relevant Level of technology class as % of total installed capacity
Adjusted_Technology_Class _Relevant_Level(Biogas)	14.7	21.598	68
Adjusted_Technology_Class _Relevant_Level(Solar)	39.25	120	33
Adjusted_Technology_Class _Relevant_Level(Wind)	160.04	606.57	26
Total (all Candidate Facilities)	214	748.168	29

Although not required by the proposed method, this analysis repeated the calculation in Step 11(b) using data from 2013/14, 2014/15, 2015/16, 2016/17 and 2012 to 2017 as the Relevant_Period. The results of this analysis provided insights about the variation in technology class Relevant Levels from year to year, as presented in Table 4.

Table 4. Technology class relevant level for different Relevant_Period used in Step 11(b) and Solar_Wind_Interaction_Effect (Step 11(c)) (2017 Reserve Capacity Cycle – progressed applications)

Technology_Class_Relevant_Level	Relevant_Period used in Step 11(b), MW				
	2013/14	2014/15	2015/16	2016/17	2012 to 2017
Technology_Class_Relevant_Level (Biogas Technology Class)	16	14	15	15	15
Technology_Class_Relevant_Level (Solar Technology Class)	44	69	44	57	45
Technology_Class_Relevant_Level (Wind Technology Class)	326	97	207	130	203
Solar_Wind_Interaction_Effect	17	16	0	-9	1

Table 4 shows that most of the variation in the intermittent generation fleet capacity value is due to the variation of the capacity value of wind technology class followed by solar technology class. The biogas technology class has relatively stable capacity contribution to the reliability of the SWIS.

The solar and wind interaction effect is an indicator of the effect of capacity value of generators on each other. For example, the interaction effect in 2013/14 period is 17 MW. This, for example, shows if all solar facilities had withdrawn their application for Certified Reserve Capacity, wind generators would have had 17 MW less capacity value than the 326 MW estimated. For the 2016/17 period, if all solar facilities had withdrawn their application, wind facilities would have had 9 MW more capacity value than the 130 MW estimated.

Table 5 presents the results of the allocation method specified in Steps 12 and 13. Many Candidate Facilities for the 2017 Reserve Capacity Cycle could have earned more Certified Reserve Capacity if AEMO used the proposed Relevant Level Method instead of the current Relevant Level Method for that Reserve Capacity Cycle.

All biogas facilities received a lower Relevant Level than that estimated by the current Relevant Level Method. When compared to the results of the current method, the largest increase in Relevant Level was for Collgar Wind Farm (+12.2 MW) followed by Badgingarra Wind Farm (10.94 MW). The largest decrease in Relevant Level was for Emu Downs Wind Farm (-4.3 MW).

Table 5. Allocated Relevant Level to Candidate Facilities (2017 Reserve Capacity Cycle progressed applications)

Facility	Maximum Capacity (MW)	Facility_Average_Performance_Level in Step 12(b) (MW)	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Capacity Credits assigned based on the current Relevant Level Method (MW)	Difference between proposed and current methods (MW)
ALBANY_WF1	21.6	10.36	8.330	39	6.611	1.719
ALINTA_WWF	89.1	34.72	27.925	31	24.753	3.172
BADGINGARRA_WF1	130	58.03	46.682	36	35.625	11.057
BIOGAS01	2	1.65	1.532	77	1.654	-0.122
BLAIRFOX_KARAKIN_WF1	5	1.06	0.849	17	0.739	0.110
BREMER_BAY_WF1	0.6	0.29	0.234	39	0.201	0.033
DCWL_DENMARK_WF1	1.44	0.79	0.634	44	0.512	0.122
EDWFMAN_WF1	80	32.11	25.830	32	30.079	-4.249
GRASMERE_WF1	13.8	7.22	5.808	42	4.511	1.297
GREENOUGH_RIVER_PV1	10	2.57	1.949	19	1.995	-0.046
HENDERSON_RENEWABLE_IG1	3	1.92	1.781	59	1.852	-0.071
INVESTEC_COLLGAR_WF1	206	38.71	31.135	15	18.854	12.281
KALBARRI_WF1	1.6	0.47	0.382	24	0.343	0.039
MERSOLAR_PV1	100	45.31	34.344	34	29.317	5.027
MWF_MUMBIDA_WF1	55	14.24	11.452	21	9.968	1.484
NORTHAM_SF_PV1	10	3.91	2.963	30	3.749	-0.786
RED_HILL	3.64	2.86	2.648	73	2.785	-0.137
ROCKINGHAM	4	2.22	2.053	51	2.119	-0.066
SKYFRM_MTBARKER_WF1	2.43	0.97	0.784	32	0.693	0.091
SOUTH_CARDUP	4.158	3.03	2.803	67	2.941	-0.138
TAMALA_PARK	4.8	4.19	3.883	81	4.169	-0.286

**Note: The quantity of Scaling_Factor calculated for each Technology Class was: Scaling_Factor(Biogas)=0.9263, Scaling_Factor(Solar)=0.7579, Scaling_Factor(Wind)=0.8044.*

1.2 2018 Reserve capacity cycle (progressed applications only)

The sample model was also run for the 2018 Reserve Capacity Cycle. Four facilities withdrew their application of the certification of reserve capacity in the 2018 cycle. Those four facilities are not included in the calculation presented in this section. To assess possible impact of changes to the generation mix on the capacity value of generators, section 1.4 includes those four facilities in the calculation.

The capacity value results for the fleet of Candidate Facilities in 2018 are presented in Table 6. For comparison, AEMO's estimate of the total capacity value of intermittent generators in the SWIS for the same capacity year 2020/21 was approximately 258 MW.

Table 6. Relevant Level of the fleet of Candidate Facilities (2018 Reserve Capacity Cycle – progressed applications)

Relevant_Period	Relevant Level (MW)
2013/14	587
2014/15	310
2015/16	352
2016/17	336
2017/18	292
2013–18 (full period)	**352**

The proposed method sets the relevant level for the fleet of candidate facilities as the smaller of the median of the annual relevant levels and the full period relevant level (Step 11(a)):

$$Relevant\_Level\_Candidate\_Facilities\_Fleet = 336$$

The fleet Relevant Level in this sample model is set by the observed (or estimated) output of Candidate Facilities in the 2016/17 period.

Table 7 shows the Relevant Level of facilities in each Technology Class as a group calculated based on Step 11(b). Using the results in Table 7 and the calculation Steps 11(c), the amount of interaction between solar and wind technology classes is negative 33.7 MW.

Based on the calculation in Step 11(d), the adjusted technology class capacity values are presented in Table 8. The table also includes additional data to indicate the Relevant Level as a percentage of installed capacity of each technology class.

Similar to that presented for the 2017 Reserve Capacity Cycle, the analysis repeated the calculation in Step 11(b) using data from 2013/14, 2014/15, 2015/16, 2017/18 and 2013 to 2018 as the Relevant_Period. The results of this analysis provided insights about the variation in technology class Relevant Levels from year to year, as presented in Table 9. Similar to that observed in the 2017 Reserve Capacity results, most of the variation in the intermittent generation fleet capacity value is due to the variation of the capacity value of wind technology class followed by solar technology class. The biogas technology class has relatively stable capacity contribution to the reliability of the SWIS.

However, with increased installation of solar and wind generators the magnitude of variation in technology class capacity values has increased. The interaction between solar and wind technology class capacity values has also increased.

For example, the interaction effect in 2013/14 period is 55.4 MW. This, for example, shows if all solar facilities had withdrawn their application for Certified Reserve Capacity, wind generators would have had 55.4 MW less capacity value than the 461 MW estimated. Or for the 2015/16 period, if all solar facilities had withdrawn their application, wind facilities would have had 35.5 MW more capacity value than the 308 MW estimated.

Table 7. Technology Class relevant level for the selected period 2016/17 (2018 Reserve Capacity Cycle – progressed applications)

Technology_Class_Relevant_Level	Net_Demand data	Relevant_Period	Relevant Level (MW)
Technology_Class_Relevant_Level (Biogas Technology Class)	System Demand-CF_Generation(Biogas Technology Class)x2	2016/17 (Selected_Period)	15.7
Technology_Class_Relevant_Level (Solar Technology Class)	System Demand-CF_Generation(Solar Technology Class)x2	2016/17 (Selected_Period)	70
Technology_Class_Relevant_Level (Wind Technology Class)	System Demand-CF_Generation(Wind Technology Class)x2	2016/17 (Selected_Period)	284

Table 8. Technology class relevant levels (2018 Reserve Capacity Cycle – progressed applications)

Adjusted_Technology_Class_Relevant_Level	Relevant Level (MW)	Total installed capacity of technology class (MW)	Relevant Level of technology class as % of total installed capacity
Adjusted_Technology_Class_Relevant_Level(Biogas)	15.7	21.598	73
Adjusted_Technology_Class_Relevant_Level(Solar)	63.3	150.96	42
Adjusted_Technology_Class_Relevant_Level(Wind)	257.0	1021.87	25
Total (all Candidate Facilities)	**336**	**1194.428**	**28**

Table 10 presents the results of the allocation method specified in Steps 12 and 13. Many Candidate Facilities for the 2018 Reserve Capacity Cycle could have earned more Certified Reserve Capacity if AEMO used the proposed Relevant Level Method instead of the current Relevant Level Method.

Table 9. Technology class relevant level for different Relevant_Period used in Step 11(b) and Solar_Wind_Interaction_Effect (Step 11(c)) (2018 Reserve Capacity Cycle – progressed applications)

Technology_Class_Relevant_Level	Relevant_Period used in Step 11(b), MW				
	2013/14	2014/15	2015/16	2017/18	2013 to 2018
Technology_Class_Relevant_Level (Biogas Technology Class)	16.6	14.5	15.5	16.6	15.5
Technology_Class_Relevant_Level (Solar Technology Class)	54	83	64	33	64
Technology_Class_Relevant_Level (Wind Technology Class)	461	220	308	242	307
Solar_Wind_Interaction_Effect	55.4	-7.5	-35.5	0.4	-34.5

Table 10. Allocated Relevant Level to Candidate Facilities (2018 Reserve Capacity Cycle – progressed applications)

Facility	Maximum Capacity (MW)	Facility_Average_Performance_Level in Step 12(b)	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Capacity Credits assigned based on the current Relevant Level Method (MW)	Difference between proposed and current methods (MW)
ALBANY_WF1	21.6	9.94	8.052	37%	6.434	1.618
ALINTA_WWF	89.1	28.62	23.191	26%	22.035	1.156
AMBRISOLAR_PV1	0.96	0.28	0.352	37%	0.270	0.082
BADGINGARRA_WF1	130	48.24	39.093	30%	36.428	8.221
BADGINGARRA_WF1_UPG_1	17.5	6.85	5.555	32%		
BIOGAS01	2	1.57	1.517	76%	1.551	-0.034
BLAIRFOX_KARAKIN_WF1	5	0.80	0.649	13%	0.736	-0.087
BREMER_BAY_WF1	0.6	0.28	0.230	38%	0.190	0.040
DCWL_DENMARK_WF1	1.44	0.69	0.563	39%	0.414	0.149
EDWFMAN_WF1	80	24.02	19.467	24%	26.317	-6.850
GRASMERE_WF1	13.8	6.67	5.402	39%	4.329	1.073
GREENOUGH_RIVER_PV1	10	1.69	2.089	21%	9.905	5.560
GREENOUGH_RIVER_PV1_UPG_1	30	10.80	13.376	45%		
HENDERSON_RENEWABLE_IG1	3	1.83	1.775	59%	1.761	0.014
INVESTEC_COLLGAR_WF1	206	41.74	33.826	16%	22.894	10.932
KALBARRI_WF1	1.6	0.37	0.302	19%	0.287	0.015
MERSOLAR_PV1	100	35.49	43.950	44%	22.500	21.45
MWF_MUMBIDA_WF1	55	11.74	9.513	17%	8.943	0.570
NORTHAM_SF_PV1	10	2.88	3.569	36%	2.568	1.001
RED_HILL	3.64	2.98	2.885	79%	2.868	0.017
ROCKINGHAM	4	2.39	2.311	58%	2.286	0.025

Facility	Maximum Capacity (MW)	Facility_Average_Performance_Level in Step 12(b)	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Capacity Credits assigned based on the current Relevant Level Method (MW)	Difference between proposed and current methods (MW)
SKYFRM_MTBARKER_WF1	2.43	0.91	0.741	30%	0.606	0.135
SOUTH_CARDUP	4.158	3.14	3.040	73%	3.009	0.031
TAMALA_PARK	4.8	4.31	4.173	87%	4.292	-0.119
WARRADARGE_WF1	183.6	63.32	51.316	28%	36.124	15.192
YANIDN_WF1	214.2	72.88	59.062	28%	40.932	18.130

**Note: The quantity of Scaling_Factor calculated for each Technology Class was: Scaling_Factor(Biogas)=0.9682, Scaling_Factor(Solar)=1.2384, Scaling_Factor(Wind)=0.8104.*

1.3 Assignment of Certified Reserve Capacities based on the proposed clause 4.11.2(c)

The proposed changes to the market rules include an additional clause 4.11.2(c). The purpose of this clause is to dampen possible variations in capacity value results between years and provide a glide path for the transition to the proposed Relevant Level Method. Clause 4.11.2(c) specifies that AEMO must assign a quantity of Certified Reserve Capacity to the relevant Facility for that Reserve Capacity Cycle equal to the average of the Relevant Level assigned to the Facility using the relevant level method in Appendix 9 and any available Certified Reserve Capacity assigned to the relevant Facility in the three preceding Reserve Capacity Cycles.

This clause does not apply to a Facility that is yet to re-enter service after significant maintenance or is to re-enter service after having been upgraded since the date and time specified in clause 4.1.12(b), or otherwise modified or extended under clause 4.1.32, for the preceding Reserve Capacity Cycle to the relevant Reserve Capacity Cycle.

Results in sections 1.1 and 1.2 are used to assess the effect of clause 4.11.2(c) on the amount of Certified Reserve Capacity that would have been assigned to Facilities, if AEMO had used the proposed Relevant Level Method in the 2017 and 2018 Reserve Capacity Cycles. Results are presented in Table 11.

Table 11. Assignment of Certified Reserve Capacity based on the proposed clause 4.11.2(c)

Candidate_Facility	2016/17	2017/18	2018/19	Appendix 9 results (2019/20)	Appendix 9 results (2020/21)	2019/20 Certified Reserve Capacity assigned based on proposed clause 4.11.2(c)	2020/21 Certified Reserve Capacity Assigned based on proposed clause 4.11.2(c)
ALBANY_WF1	8.223	7.809	7.757	8.330	8.052	8.030	7.912
ALINTA_WWF	21.699	23.203	26.096	27.925	23.191	24.731	24.305
AMBRISOLAR_PV1			-		0.352		0.352
BADGINGARRA_WF1				46.682	39.093	46.682	42.888
BADGINGARRA_WF1_UPG_1					5.555		5.555
BIOGAS01	0.93	1.795	1.654	1.532	1.517	1.478	1.611
BLAIRFOX_KARAKIN_WF1	0.97	0.838	0.824	0.849	0.649	0.870	0.795
BREMER_BAY_WF1	0.078	0.112	0.151	0.234	0.230	0.144	0.159
DCWL_DENMARK_WF1	1.118	0.845	0.695	0.634	0.563	0.823	0.731
EDWFMAN_WF1	17.734	17.8	28.037	25.830	19.467	22.350	21.914
GRASMERE_WF1	5.23	4.957	5.074	5.808	5.402	5.267	5.175
GREENOUGH_RIVER_PV1	3.833	3.086	2.528	1.949	2.089	2.849	2.638
GREENOUGH_RIVER_PV1_UPG_1					13.376		13.376
HENDERSON_RENEWABLE_IG1	2.272	2.104	1.938	1.781	1.775	2.024	1.960
INVESTEC_COLLGAR_WF1	15.048	20.105	20.567	31.135	33.826	21.714	24.053
KALBARRI_WF1	0.272	0.283	0.323	0.382	0.302	0.315	0.306
MERSOLAR_PV1				34.344	43.950	34.344	39.147
MWF_MUMBIDA_WF1	14.9	13.828	10.631	11.452	9.513	12.703	11.669
NORTHAM_SF_PV1			4.101	2.963	3.569	3.532	3.734
RED_HILL	2.93	2.876	2.776	2.648	2.885	2.807	2.836
ROCKINGHAM	2.682	2.576	2.022	2.053	2.311	2.333	2.311
SKYFRM_MTBARKER_WF1	0.935	0.806	0.766	0.784	0.741	0.823	0.784
SOUTH_CARDUP	2.446	2.486	2.954	2.803	3.040	2.672	2.788
TAMALA_PARK	3.933	3.962	4.213	3.883	4.173	3.998	4.086
WARRADARGE_WF1					51.316		51.316
YANDIN_WF1					59.062		59.062

1.4 Sensitivity of results to the changes in the intermittent generation mix

As discussed in the Final Report for the review of the relevant level method, the capacity value of a facility is dependent on the contribution of other available facilities to the reliability of the system. It is important that the calculation of capacity values includes all facilities that are expected to be available in the target capacity year. If, for instance, some applicants withdraw their application for the certification of reserve capacity, the capacity credit assigned to other resources would be affected.

The case study provided in this section evaluates the effect of such changes to the generation mix on the capacity value of generators. The study is based on applications for the certification of reserve capacity in the 2018 Reserve Capacity Cycle.

In the 2018 Reserve Capacity Cycle four solar generators – with a total installed capacity of approximately 110 MW – withdrew their application for the certification of capacity:

[redacted]

- The analysis provided in section 1.2 included all progressed applications for the certification of capacity in 2018 and excluded the above four facilities from the process.
- This section emulates the outcomes of AEMO's capacity certification process based on the application of the proposed relevant level method. If AEMO had used the proposed relevant level method in the 2018 Reserve Capacity Cycle, it would have included the above four facilities in the calculation of relevant levels. The difference between the results in this case study and that provided in section 1.2 will provide an indication of the sensitivity of results to the changes in the generation mix.

Results for the whole applications scenario

Table 12 shows the results of the method based on whole and progressed applications for the certifications of reserve capacity in the 2018 Reserve Capacity Cycle. Adding the four withdrawn applications to the list of progressed applications increases the intermittent generation fleet capacity value by 6 to 49 MW over the five-year sample period.

Table 12. Relevant Level of the fleet of Candiate Facilities (2018 Reserve Capacity Cycle – whole applications)

Relevant_Period	Relevant Level (MW) – Progressed applications	Relevant Level (MW) – Whole applications	Difference (MW)
2013/14	587	636	49
2014/15	310	346	36
2015/16	352	363	11
2016/17	336	342	6
2017/18	292	298	6
2013–18 (full period)	**352**	**363**	**11**

** Shaded cells represent the selected fleet capacity value – which are the median of the annual results.*

Using the proposed method, the relevant level for the fleet of candidate facilities is 346 MW, which is 10 MW larger than that calculated for the progressed applications scenario. The fleet capacity value is set by the estimated output of Candidate Facilities in the 2014/15 period, which in the proposed method is referred to as the selected period. This is different to the selected period for the progressed applications scenario – that is the 2016/17 period.

Table 13 shows the Relevant Level of facilities in each facility class. The amount of interaction between solar and wind technology classes is negative 5.5 MW. The inclusion of the four additional solar facilities in the calculation increases the capacity value of the solar facility class by 47 MW and decreases that for the wind facility class by 64 MW.

Table 13. Technology Class relevant level for the selected period 2014/15 (2018 Reserve Capacity Cycle – whole applications)

Technology_Class_Relevant_Level	Relevant Level (MW) – progressed applications	Relevant Level (MW) – whole applications	Difference (MW)
Biogas	15.7	14.5	-1.2
Solar	70	117	47
Wind	284	220	-64
Solar-Wind interaction effect (MW)	-33.7	5.5	

As discussed in the previous section, the capacity contribution of wind and solar facilities is variable between years. The change in the selected period from 2016/17 to 2014/15 creates a substantial change in the composition of solar and wind class capacity values. This variation in also driven by the small sample used in the calculation.

An increase in the sample period from five to seven years can partly, but not completely, dampen the variation in the results. An improvement to the calculation of class capacity values, as discussed in section 1.4, can mitigate the variation in the results.

The technology class capacity values after adjustment for the interaction effect are presented in Table 14.

Table 14. Adjusted technology class relevant levels (2018 Reserve Capacity Cycle – whole applications)

Adjusted relevant level	Relevant Level (MW) – progressed applications	Relevant Level (MW) – whole applications	Difference (MW)
Biogas	15.7	14.5	-1.2
Solar	63.3	115.1	51.8
Wind	257.0	216.4	-40.6
Total (all Candidate Facilities)	**336**	**346**	**10**

Had AEMO run the capacity certification based on all applications it received in 2018, it would have calculated approximately 52 MW more capacity credits for solar facilities and 41 MW fewer capacity credits for wind facilities.

After the application of the proposed clause 4.11.2(c), as depicted in Table 15, AEMO would have calculated 355.2 MW to be assigned to the candidate facilities. After deducting the capacity value of those facilities that withdrew their application (a total of 43.6 MW) all remaining facilities would have received 311.6 MW. This is approximately 20 MW smaller than the amount of credits assigned to intermittent generators, had AEMO decided to repeat the calculation based on all progressed applications (331.5 MW).

The effect of the withdrawn applications on the capacity value of other facilities is summarised as below:

- They reduce the amount of credits to wind facilities by approximately 25 MW. The inclusion of withdrawn applications mostly influences new or recently upgraded wind facilities.
- They increase the amount of credits to other solar facilities by 5 MW.
- They have a minor effect (of negative 0.3 MW) on the capacity credits assigned to biogas facilities.

Table 15. Calculated assigned capacity credits after the application of the proposed clause 4.11.2(c) – progressed and whole applications for the certification of reserve capacity in 2018

Candidate Facilities	Assigned capacity credit – progressed applications (MW)	Assigned capacity credit – whole applications (MW)	Difference (MW)
ALBANY_WF1	7.9	7.6	-0.3
ALINTA_WWF	24.3	23.3	-1.0
AMBRISOLAR_PV1	0.4	0.4	0.0
BADGINGARRA_WF1	42.9	39.8	-3.1
BADGINGARRA_WF1_UPG_1	5.6	4.3	-1.3
BIOGAS01	1.6	1.6	0.0
BLAIRFOX_KARAKIN_WF1	0.8	0.8	0.0
BREMER_BAY_WF1	0.2	0.1	0.0
DCWL_DENMARK_WF1	0.7	0.7	0.0
EDWFMAN_WF1	21.9	21.1	-0.9
GRASMERE_WF1	5.2	4.9	-0.2
GREENOUGH_RIVER_PV1	2.6	2.7	0.1
GREENOUGH_RIVER_PV1_UPG_1	13.4	15.5	2.1
HENDERSON_RENEWABLE_IG1	2.0	1.9	0.0
INVESTEC_COLLGAR_WF1	24.1	22.8	-1.3
KALBARRI_WF1	0.3	0.3	0.0
MERSOLAR_PV1	39.1	41.8	2.7
MWF_MUMBIDA_WF1	11.7	11.2	-0.4
NORTHAM_SF_PV1	3.7	3.9	0.1
RED_HILL	2.8	2.8	-0.1
ROCKINGHAM	2.3	2.3	0.0
[redacted]			
SKYFRM_MTBARKER_WF1	0.8	0.8	0.0
SOUTH_CARDUP	2.8	2.7	-0.1
TAMALA_PARK	4.1	4.0	-0.1
WARRADARGE_WF1	51.3	44.3	-7.0
[redacted]			
YANDIN_WF1	59.1	50.1	-9.0
Total	**331.5**	**355.2**	**23.7**

** Shaded rows indicate those facilities that withdrew their application for the certification of capacity in the 2018 Reserve Capacity Cycle.*

1.5 Improvement to the calculation of facility class capacity values

The analysis provided in section 1.4 shows the main drivers of the effect of changes to the generation mix. Two factors influence the variation in results:

- The effect of interaction between the capacity contribution of wind and solar technologies
- The annual variation in the capacity contribution of wind and solar technologies

It is not possible to separate these effects because of significant changes to the capacity contribution of solar and wind facilities and their interaction. However, it appears that the proposed method for allocating the fleet capacity value to facility classes will cause unnecessary variation in the results. This is particularly due to large variations in the facility class contributions between sample years and the relatively small sample size used in the calculation.

An increase in the sample size to seven or 10 years can dampen the variation in results. However, given the large level of variability in facility class results, the outcomes are likely to be highly variable and therefore sensitive to changes in the generation mix.

The assignment of relevant level for technology classes can be improved to dampen the variation of results and their sensitivity to the changes in the generation mix. The proposed changes in this section, along with the use of a larger sample size of seven or 10 years, may eliminate the need to repeat the calculation of capacity credits when facilities withdraw their application for the certification of capacity credits. Alternatively, should AEMO decide to repeat the calculation upon any changes to the applications, changes to the capacity values for the remaining facilities will be more limited to the effect of interaction between the capacity contribution of facilities.

The basis of the proposed improvement is to use the full-period facility class capacity values for the assignment of capacity value to solar and wind facility classes. This is to replace the current method which uses the sample year results that set the intermittent generation fleet capacity value (or the ‘selected period’). The advantages of using the full-period results for the assignment to facility classes are as below:

- The full-period results better represent the long-term contribution of technology classes to the adequacy of the system.
- The full-period results are likely to be less variable over subsequent reserve capacity cycles. Also changes to the mix of a technology class (either wind or solar), will influence other technology class through the interaction effect only and the annual variation in the facility class results will not influence the results.

This proposed change is presented using the numerical example below. Table 16 shows the technology class capacity values and the solar-wind interaction effect estimated based on the proposed steps 11(b) and 11(c). The current method, in Step 11(a), allocates the fleet capacity value based on the results in the 2014/15 sample year, because it represents the median of annual results.

The composition of solar and wind class capacity values differs significantly across the two scenarios:

- For the progressed applications scenario the selected period was 2016/17. Results in Table 7 show that solar and wind facilities respectively have 70 and 284 MW capacity value.
- For the whole applications scenario the selected period shifts to 2014/15, where the share of solar is significantly larger than that in the 2016/17 period. For this scenario the method respectively assigns 117 and 220 MW to solar and wind facilities.
- The shift in the selected period causes a significant change to the composition of solar and wind facility class capacity contributions, as listed in Table 16.

Table 16. Technology class relevant level for different Relevant_Period used in Step 11(b) and Solar_Wind_Interaction_Effect (Step 11(c)) (2018 Reserve Capacity Cycle – whole applications)

Technology_Class_Relevant_Level	Relevant_Period used in Step 11(b), MW					
	2013/14	2014/15	2015/16	2016/17	2017/18	2013 to 2018
Technology_Class_Relevant_Level (Biogas Technology Class)	16.6	14.5	15.5	15.7	16.6	15.5
Technology_Class_Relevant_Level (Solar Technology Class)	92	117	87	81	42	88
Technology_Class_Relevant_Level (Wind Technology Class)	461	220	308	284	242	307
Solar_Wind_Interaction_Effect	66.4	-5.5	-47.5	-38.7	-2.6	-47.5

Assignment of facility class capacity values based on full-period results

The assignment of facility class capacity values can be improved by using the full-period capacity value results. For both scenarios, the full-period facility class capacity values and the relative share of solar and wind capacity values is presented in Table 17.

The inclusion of the four withdrawn applications in the model only changes the capacity value of solar facility class from 64 to 88 MW. When adjusted for the solar-wind interaction effect, the change to the capacity value of wind facilities is approximately 8 MW.

The relative share of solar and wind facility class capacity values can be used for assigning technology class capacity values. For instance, for the whole applications scenario, the capacity values of solar and wind classes are determined as below:

- $solar\ class\ capacity\ value = 0.22 \times (IG\ fleet\ capacity\ value - full\text{–}period\ biogas\ capacity\ value) = 0.22(346 - 15.5) = 73.6\ MW$
- $wind\ class\ capacity\ value = 0.78 \times (IG\ fleet\ capacity\ value - full\text{–}period\ biogas\ capacity\ value) = 0.78(346 - 15.5) = 256.9\ MW$

The biogas facility class has a capacity contribution that is largely independent from that for solar and wind facilities. The calculation above deducts the relevant level of the biogas facility class from the fleet relevant level and allocates the remainder to solar and wind facility classes.

Table 17. Full period facility class capacity values (Whole and progressed applications, 2018 Reserve Capacity Cycle)

Technology Class	Relevant Level (MW)		Interaction adjusted Relevant Level (MW)	
	Full-period results for progressed applications	Full-period results for whole applications	Full-period results for progressed applications	Full-period results for whole applications
Biogas	15.5	15.5	15.5	15.5
Solar	64	88	58.0 (17%)	77.4 (22%)
Wind	307	307	278.5 (83%)	270.1 (78%)
Solar-Wind Interaction	-34.5	-47.5	-	-

The allocated facility class relevant levels based on the improved method are summarised in Table 18.

Table 18. Improved calculation of facility class relevant levels (2018 Reserve Capacity Cycle – whole and progressed applications)

Allocated relevant level (improved method)	Relevant Level (MW) – progressed applications	Relevant Level (MW) – whole applications	Difference (MW)
Biogas	15.5	15.5	0.0
Solar	55.3	73.6	18.3
Wind	265.2	256.9	-8.3
Total (all Candidate Facilities)	**336**	**346**	**10**

The improved facility class capacity values are then used to calculate the Relevant Level of individual facilities. Results of the model after the application of the proposed clause 4.11.2(c) are presented in Table 19.

Table 19. Facility relevant levels based on the improved calculation of facility class capacity values (Reserve Capacity Cycle 2018 – whole and progressed applications)

Candidate Facilities	Relevant Level (MW) - progressed applications	Relevant Level (MW) - Whole applications
ALBANY_WF1	8.0	7.9
ALINTA_WWF	24.5	24.2
AMBRISOLAR_PV1	0.3	0.3
BADGINGARRA_WF1	43.9	43.3
BADGINGARRA_WF1_UPG_1	5.7	5.1
BIOGAS01	1.6	1.6
BLAIRFOX_KARAKIN_WF1	0.8	0.8
BREMER_BAY_WF1	0.2	0.2
DCWL_DENMARK_WF1	0.7	0.7
EDWFMAN_WF1	22.1	21.8
GRASMERE_WF1	5.2	5.2
GREENOUGH_RIVER_PV1	2.6	2.5
GREENOUGH_RIVER_PV1_UPG_1	11.7	9.9
HENDERSON_RENEWABLE_IG1	2.0	2.0
INVESTEC_COLLGAR_WF1	24.4	24.2
KALBARRI_WF1	0.3	0.3
MERSOLAR_PV1	35.0	31.6
MWF_MUMBIDA_WF1	11.8	11.6
NORTHAM_SF_PV1	3.5	3.4
RED_HILL	2.8	2.8
ROCKINGHAM	2.3	2.3
[redacted]		
SKYFRM_MTBARKER_WF1	0.8	0.8
SOUTH_CARDUP	2.8	2.8
TAMALA_PARK	4.1	4.1
WARRADARGE_WF1	53.0	52.6
[redacted]		
YANDIN_WF1	61.0	59.4
Total	**331.0**	**349.1**

After the application of the proposed clause 4.11.2(c), AEMO would have calculated 349.1 MW to be assigned to the candidate facilities. After deducting the capacity value of those facilities that withdrew their application (a total of 27.9 MW) all remaining facilities would have received 321.1 MW. This is approximately 10 MW smaller than the amount of credits assigned to intermittent generators, had AEMO decided to repeat the calculation based on all progressed applications (331.0 MW).

The effect of the withdrawn applications on the capacity value of other facilities, based on the improved facility assignment method, is summarised as below:

- They reduce the amount of credits to wind facilities by approximately 4 MW.
- They decrease the amount of credits to other solar facilities by 5.5 MW.
- They do not have any effect on the capacity credits assigned to biogas facilities.

1.6 Sensitivity of results to the changes in the scheduled generation mix

Available capacity of scheduled generators does not have any significant correlation with system demand or the availability of other generators in the system. The entry or exit of scheduled generator does not have a significant effect on the capacity contribution of other generators.

This effect is assessed using a hypothetical scenario in this section. For this scenario the calculation excludes the BW2_BLUEWATERS_GT1 from the calculation of the capacity outage probability table. This facility has a large capacity credit of 217 MW and a high (average) forced outage rate of 0.1756. The larger a scheduled generators' capacity credits and its forced outage rate, the larger its effect on the capacity contribution of other generators.

Table 20 shows the results of the analysis. The exclusion of BW2_BLUEWATERS_GT1 has a small effect on the annual results. The capacity value of the intermittent generation fleet does not change from that calculated for all progressed applications, because the median year result (2016/17) does not change.

Table 20. Annual relevant level results excluding BW2_BLUEWATERS_GT1 (2018 Reserve Capacity Cycle)

Relevant_Period	Relevant Level (MW) – all progressed applications	Relevant level (MW) - excluding BW2_BLUEWATERS_GT1	Difference (MW)
2013/14	587	588	1
2014/15	310	311	1
2015/16	352	358	6
2016/17	336	336	0
2017/18	292	292	0
2013–18 (full-period)	**352**	**357**	**5**

Results for facility class contribution also show that the allocation of fleet capacity value to facility classes does not change.

Therefore, the exclusion of BW2_BLUEWATERS_GT1 from the modelling does not have any effect on the capacity value of intermittent generators.

2. Effect of using scaled demand in the calculation

As explained in section 3.2.6 in appendix 3, a modelling scenario was investigated based on scaling the observed demand in the SWIS to the expected system demand in the target capacity year. This scenario repeats the 2019 reserve capacity cycle scenario but uses a scaled time series of demand based on the application of the scaling function introduced in section 3.2.6 in appendix 3.

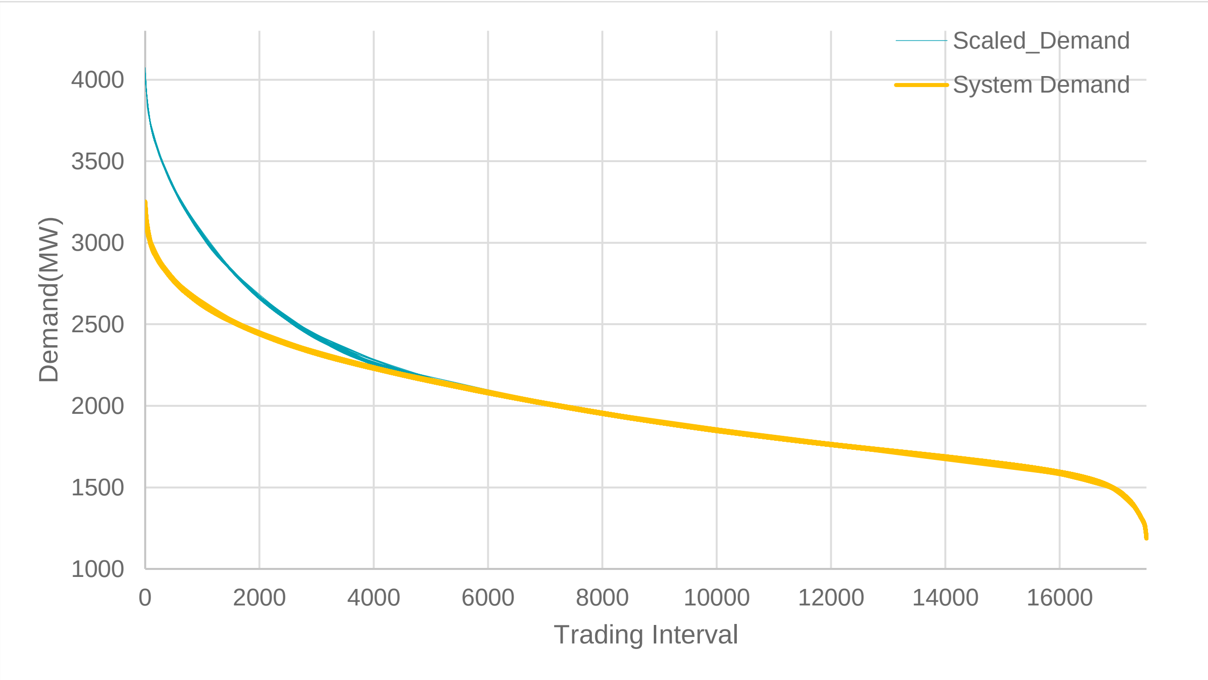
Among all scaled demands for the sampled years, Figure 2 depicts the scaled and observed load duration curve in the 2018/19 sampled year used in the modelling scenario. The highest demand in the scaled load duration curve is consistent with AEMO expectation of 10% PoE peak demand in the SWIS for the 2021/22 capacity year. This scenario is for demonstrating the application of the model and includes simplifications that are not likely to influence the results materially.

To scale the observed demand the scenario used the following parameters in Table 2 for the scaling function $f(t)$ introduced in section 3.2.6, appendix 3.

Table 21. Scaling function parameters used in the scenario

Parameter	Value	Description
10% PoE peak demand (MW)	4075	AEMO's forecast of 10% PoE peak demand for the 2021/22 capacity year.
e	Assumed 1 for simplicity	
m	Used RBP's estimate of m values for respective capacity years (typically 2650x2)	Refer to RBP's report, p. 21–22, (online).
z	Assumed 1 for simplicity	

Figure 1. Scaled and observed demand for the 2018/19 sampled year



Results of the calculation of for the fleet-wide capacity value are presented in Table 22.

Scenario with LOLE=24 hours in 10 years

Results for the LOLE target of 24 hours in 10 years show that in four out of six sampled periods the capacity value of the fleet of intermittent generators based on the scaled demand scenario would be larger than in the observed demand scenario. These results indicate that in many years intermittent generators have generally higher available capacity during periods of high demand when compared to periods with lower levels of demand, when forecast at the target LOLE level of 24 hours in 10 years.

The full-period capacity value results, however, is smaller in the scaled demand scenario. Based on the proposed RLM the assigned capacity value of the fleet in the scenarios tested would be as below:

- Observed demand scenario's fleet capacity value: the median of the annual results (332 MW) is smaller than the full period result. The fleet capacity value would be set at 332 MW.

- Scaled demand scenario's fleet capacity value: the median of the annual results (328 MW) is larger than the full period result (320 MW). The fleet capacity value would be set at 320 MW.

These results indicate that use of scaled demand in the calculation has a small effect (of 12 MW) on the capacity value of intermittent generators as a fleet, when the target LOLE is equal to 24 hours in 10 years.

Scenario with LOLE=4 hours in 10 years

When compared to the target LOLE level of 24 hours, the capacity value of the fleet of facilities estimated at the LOLE target of four hours in 10 years is smaller. This is consistent with the findings of the scenario with the target LOLE of three hours explained in appendix 4. The full-period capacity value decreases to 274 MW. Based on the proposed RLM the assigned capacity value of the fleet in the scenario tested would be as below:

- The median of the annual results (328 MW) is smaller than the full period result (274 MW). The fleet capacity value would be set at 274 MW.

These results indicate that use of scaled demand in the calculation has a small effect (of 12 MW) on the capacity value of intermittent generators as a fleet, when the target LOLE is equal to 24 hours in 10 years. However, this effect is large when an extremely low target LOLE level is used.

Table 22. Fleet-wide ELCC values for the scaled demand scenarios

Relevant level scenario	Relevant Level based on observed demand (MW) (LOLE=24 hours in 10 years)	Relevant Level based on scaled demand) (MW) (LOLE=24 hours in 10 years)	Relevant Level based on scaled demand) (MW) (LOLE=4 hours in 10 years)
2014/15	332	328	328
2015/16	422	456	390
2016/17	293	320	281
2017/18	366	382	360
2018/19	238	262	250
2014-19 (full-period)	384	320	274

Results for facility groups are presented in Table 23.

Table 23. Facility group ELCC values for the scaled demand scenarios

Technology Class	Relevant Level (MW)		Interaction adjusted Relevant Level (MW)	
	LOLE=24	LOLE=4	LOLE=24	LOLE=4
Biogas	16	16	16	16
Solar	54	46	45.9	43.6
Wind	304	226	258.1	214.4
Solar-Wind Interaction	10	-14	-	-

The assigned capacity values to individual facilities are presented Table 24 and Table 25. For emphasis, sensitivity analyses are to demonstrate the application of the proposed RLM and this may not necessarily reflect future certified reserve capacity of facilities if the proposed RLM is approved to replace the current RLM. Future capacity values will be determined by the future resource mix, demand and available capacity of facilities in the system.

Table 24. Allocated Relevant Level to Candidate Facilities (2019 Reserve Capacity Cycle – LOLE target = 24 hours in 10 years, scaled demand)

Facility	Facility average performance level in Step 11(b) (MW)	Relevant Level in Step 13 (MW)	Relevant Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
ALBANY_WF1	8.99	5.162	24%	5.29	-0.132
ALINTA_WWF	40.58	23.311	26%	17.19	6.126
AMBRISOLAR_PV1	0.29	0.261	27%	0.20	0.063
BADGINGARRA_WF1	72.15	41.447	28%	26.87	14.573
BIOGAS01	1.28	1.309	65%	1.18	0.129
BLAIRFOX_KARAKIN_WF1	1.09	0.626	13%	0.49	0.140
BREMER_BAY_WF1	0.27	0.155	26%	0.17	-0.011
DCWL_DENMARK_WF1	0.67	0.386	27%	0.36	0.022
EDWFMAN_WF1	33.87	19.457	24%	16.21	3.248
GRASMERE_WF1	6.26	3.597	26%	3.71	-0.115
GREENOUGH_RIVER_PV1	12.00	10.800	27%	7.38	3.423
HENDERSON_RENEWABLE_IG1	1.69	1.725	58%	1.63	0.093
INVESTEC_COLLGAR_WF1	62.14	35.698	17%	15.82	19.875
KALBARRI_WF1	0.49	0.282	18%	0.26	0.023
MERSOLAR_PV1	35.96	32.370	32%	16.32	16.050
MWF_MUMBIDA_WF1	19.19	11.021	20%	7.03	3.992
NORTHAM_SF_PV1	2.69	2.424	24%	1.80	0.626
RED_HILL	2.94	3.003	82%	2.84	0.161
ROCKINGHAM	2.42	2.471	62%	2.32	0.148
SKYFRM_MTBARKER_WF1	0.99	0.566	23%	0.52	0.045
SOUTH_CARDUP	2.99	3.051	73%	2.97	0.085
TAMALA_PARK	4.35	4.441	93%	4.35	0.090
WARRADARGE_WF1	92.64	53.215	29%	30.22	22.992
YANIDN_WF1	110.06	63.224	30%	36.20	27.028

Table 25. Allocated Relevant Level to Candidate Facilities (2019 Reserve Capacity Cycle – LOLE target = 4 hours in 10 years, scaled demand)

Facility	Facility average performance level in Step 11(b) (MW)	Relevant Level in Step 13 (MW)	Relevant Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
ALBANY_WF1	8.99	4.286	20%	5.29	-1.008
ALINTA_WWF	40.58	19.358	22%	17.19	2.173
AMBRISOLAR_PV1	0.29	0.248	26%	0.20	0.050
BADGINGARRA_WF1	72.15	34.418	23%	26.87	7.544
BIOGAS01	1.28	1.309	65%	1.18	0.129
BLAIRFOX_KARAKIN_WF1	1.09	0.520	10%	0.49	0.034
BREMER_BAY_WF1	0.27	0.129	21%	0.17	-0.037
DCWL_DENMARK_WF1	0.67	0.320	22%	0.36	-0.044
EDWFMAN_WF1	33.87	16.157	20%	16.21	-0.052
GRASMERE_WF1	6.26	2.987	22%	3.71	-0.725
GREENOUGH_RIVER_PV1	12.00	10.277	26%	7.38	2.900
HENDERSON_RENEWABLE_IG1	1.69	1.725	58%	1.63	0.093
INVESTEC_COLLGAR_WF1	62.14	29.644	14%	15.82	13.821
KALBARRI_WF1	0.49	0.235	15%	0.26	-0.024
MERSOLAR_PV1	35.96	30.801	31%	16.32	14.481
MWF_MUMBIDA_WF1	19.19	9.152	17%	7.03	2.123
NORTHAM_SF_PV1	2.69	2.306	23%	1.80	0.508
RED_HILL	2.94	3.003	82%	2.84	0.161
ROCKINGHAM	2.42	2.471	62%	2.32	0.148
SKYFRM_MTBARKER_WF1	0.99	0.470	19%	0.52	-0.051
SOUTH_CARDUP	2.99	3.051	73%	2.97	0.085
TAMALA_PARK	4.35	4.441	93%	4.35	0.090
WARRADARGE_WF1	92.64	44.191	24%	30.22	13.968
YANIDN_WF1	110.06	52.502	25%	36.20	16.306

Appendix 5 Sensitivity analyses (part2)

Amend and Evaluate the Model for Capacity Valuation of Intermittent Generators

Final Report

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1. INTRODUCTION

The Economic Regulation Authority (ERA) engaged the support of The Lantau Group (TLG) for modelling, analysis, and quality assurance to assist the ERA in preparing a rule change proposal to amend the Relevant Level methodology (RLM). The RLM is the method for estimating the capacity contribution of intermittent generators to the Reserve Capacity Mechanism (RCM).

In March 2019, the ERA completed its review of the RLM as specified in Appendix 9 of the Wholesale Electricity Market (WEM) Rules. In its review the ERA concluded the RLM satiability for the WEM could be improved by changing the method through which the RLM was determined. After receiving feedback from stakeholders, the ERA recommended changing the method.

The market rules require the ERA to propose a rule change if it recommends changes to the method following a review. In July 2019, the ERA commenced the rule change process with the development of a pre-rule change proposal, which was presented to the Market Advisory Committee (MAC).

At the same time the ERA was developing the RLM rule change proposal, Energy Policy WA (EPWA) was developing a policy for assigning capacity credits to resources in a constrained network access regime – the details of which were unclear at the time. Given the overlap with the EPWA's reform process, the ERA delayed the submission of the rule change proposal until there was more clarity on the details of EPWA's changes to the assignment of capacity credits.

EPWA has published the details of changes to the market rules in late October 2020 and the ERA has commenced updating its existing rule change proposal for the RLM based on a set of draft amending rules developed by EPWA.

Since the ERA developed its preliminary rule change proposal in July 2019, there have been several changes to the market rules, including changes to the assignment of capacity credits. EPWA has also provided the Secretariat with drafts of the upcoming amendments to the reserve capacity mechanism, registration of facilities including storage technology, and capacity valuation of aggregated facilities and storage facilities all of which have some interplay with the RLM.

As part of our engagement, we are required to provide the following services:

1. Amend the existing model the ERA has developed based on the instructions provided by the ERA (detailed in section 2) and audit the fleet capacity value assignment spreadsheet model to ensure it works as intended; and
2. Use the amended model to run several scenarios based on input data provided by the ERA (detailed in section 4).
3. Conduct quality assurance on the ERA's marked-up changes to the market rules to ensure consistency with the ERA's proposed method and model developed.

2. AMENDMENT OF EXISTING MODEL

ERA requested that TLG make some minor adjustments to the existing RLM model. This model is written in Python 3.0 and includes 2 separate scripts for each Reserve Capacity Cycle (RCC). This includes the COPT.py file, which calculates a capacity outage probability table (COPT) using historical data, and the LOLP_Table.py file which uses the COPT output file and historical intermittent generator output to calculate a loss of load probability (LOLP) table.

The prescribed amendments to the existing model were:

1. Amend the Python module for the calculation of Loss of Load Probability (LOLP) to store the datetime tag for the LOLP in each historical trading interval. This amendment is to allow for further investigation of the periods with the highest LOLP by the ERA.
2. Amend the Python module for the calculation of the COPT to ensure the table produced completes the process up to the total capacity in the system. The current code exits the calculation loop when the cumulative probability gets extremely close to zero.

Both changes were successfully made and documented to the respective Python modules.

2.1. ADDITIONAL AMENDMENTS

In addition to the above prescribed amendments, ERA also requested that TLG provide advice on any additional amendments that could be made to the existing model to enhance useability and efficiency. TLG found two such amendments to be made to the LOLP script which increases the ease of use of the model and decreases the need for significant user interaction.

1. A **user input function** was added to allow the user to select the net demand data to be used for the model run. This selection determines for which technology class the relevant level is to be calculated. Previously, the Python module required the user to manually change a variable that selected the demand data. The need for manual input, and hence the risk of failure due to human error, has been removed.
2. A **root-finding algorithm** was implemented to find the required offset (and hence, relevant level) automatically. Previously, the script would have to be run multiple times, with the user manually choosing a value for the offset and using trial and error until the correct value was found. While the amount of time saved due to this improvement will vary, we estimate that 1-2 hours are saved over the course of a full model run. Furthermore, this automation means a modelling run can be performed now *in the background* and without constant user inputs.

2.2. AMENDED MODEL PERFORMANCE

ERA requested that the total runtime for the RLM model be estimated, given the above amendments to the model code. Although the 2019 RCC and related scenarios were conducted using a five-year assessment period, ERA intends to extend this period to 7-years and thus is interested in the model runtime given this requirement. Table 1 below summarises the runtime estimates.

Table 1: Estimated Runtime for Amended RLM Model

Python Module	Runtime (Estimate)	Comments
7x COPT calculation for each of the seven yearly periods	15 – 20 minutes	These can be run in parallel
1x COPT calculation for the full 7-year period	10 – 15 minutes	
7x LOLP calculation to find an adjustment to reach target LOLE for each of the seven yearly periods	25 – 30 minutes	These can be run in parallel
7x LOLP calculation to find relevant level for each of the seven yearly periods	25 – 30 minutes	These can be run in parallel
5x LOLP calculation of the full 7-year period to find an adjustment to reach target LOLE, the fleet RL and the RL for each technology class (assuming solar, wind and biogas technology classes)	60 – 90 minutes	These can be run in parallel by making copies of the LOLP module
Total	**2.25 – 3 Hours**	

Several points should be noted when evaluating the results in Table 1:

- Due to the nature of the root-finding algorithm, it is impossible to say with complete certainty how long any given run of the LOLP module will take. For example, the correct relevant level could be found after only 2-3 iterations of the algorithm loop, or 10-12, depending on the technology class and the actual relevant level value. This would make a material difference to the runtime.
- Many of these modules can be run in parallel, significantly reducing the overall runtime. However, this may require making copies of the scripts, increasing manual work and overall time.
- These runtimes are based on running the model on a computer with an Intel Core processor with guaranteed processor speed of 1.80GHz. Running the model on a machine with a faster or slower processor will influence the overall runtime significantly.
- Any additional technology classes (i.e. storage) would increase the runtime of the model. The most material difference would be in the need to run the LOLP module an additional time to find the RL for that new technology class. Although this could also be run in parallel with determining the RL for other technology classes, it could add an estimated 10 – 15 minutes to the overall runtime.

- Although the runtime for the LOLP module may be slower than simply using trial and error, depending on how quickly the user can find the correct relevant level, the automated process may increase accuracy and overall working efficiency as it does not require constant user attention.
- Finally, further improvements to reduce and optimise the run time may be possible, and we would be happy to assist ERA in investigating any such improvements in a separate engagement.

3. DATA PREPARATION

To carry out the modelling tasks, TLG was provided several data files by ERA. Most of this data was originally sourced from AEMO and is summarised below:

- **Scheduled Facilities**: A list of all scheduled facilities in the WEM region, including their maximum installed capacity (MW) was provided. These were used in conjunction with each facility's forced outage rate for the calculation of the COPT.
- **Forced Outage Rates**: The forced outage rates for all scheduled facilities for the years 2017, 18 and 19 were provided. These were used for calculating the forced outage rates for 2019 RCC (section 3.1).
- **Existing Facility LSG (EFLSG)**: EFLSG data was provided for the years 2014 to 2019, as per Equation 2 in section 3.2. The EFLSG data was provided to TLG having already been adjusted for DSP Reduction, Interruptible Reduction, and Involuntary Reduction. This was used for the calculation of consumption data (section 3.2).
- **Candidate Facilities**: A list of all candidate facilities, and rejected candidate facilities, was provided with their maximum capacity (MW). These were used to allocate technology class capacity credits to individual facilities.
- **Candidate Facility Output**: The half-hourly output data was provided for all candidate and rejected candidate facilities. For time periods before a new or upgraded facility's full operation date, estimated output data was provided. This data was used for the calculation of consumption data (section 3.2) and intermittent generation data (section 3.3).
- **2019 Relevant Level Results**: The results for the existing relevant level calculation for 2019 was provided, showing the capacity credits allocated to each candidate facility. These were used for the purpose of comparison between the exiting RLM and the proposed amended RLM. This comparison can be found in the appendices.

3.1. Forced Outage Rates

ERA provided TLG with the forced outage rates for all scheduled generating facilities for the three years preceding the RCC. In accordance with the RLM, these were averaged to determine the forced outage rates applicable to the 2019 RCC.

3.2. Consumption Data

Consumption data was calculated as per the RLM as follows:

Eqn. 1

$$Consumption\ (MWh) = EFLSG + CF\ Generation$$

Eqn. 2

$$EFLSG\ (MWh) = (Total\ Generation + DSP\ Reduction + Interruptible\ Reduction + Involuntary\ Reduction) - CF\ Generation$$

Candidate generation (CF Generation) was calculated by summing the output data provided by ERA for all candidate facilities for the period April 1, 2014 to April 1, 2019. Only candidate facilities with full operation dates prior to April 1, 2018 were included for the purposes of calculating consumption.

EFLSG (adjusted for DSP Reduction, Interruptible Reduction, and Involuntary Reduction) was provided by ERA for the full assessment period. This was done in accordance with the RLM.

This calculation was varied slightly as needed for different modelling scenarios. For example, for the scenario wherein North Country Wind Farms were excluded, their output was excluded from the calculation.

3.3. Intermittent Generation Data

The total generation for candidate facilities was calculated using the output data described above. However, for facilities with a full operation date after April 1, 2014, an estimated generation value was used for the summation. In the case of any overlap between estimated and actual generation, actual generation was used if the full operation date had passed.

This data was included for the model run both as a total, and as separate totals for each technology class. This is to allow for the calculation of a fleet relevant level, as well as technology-specific relevant levels.

As was the case for consumption data, this calculation was amended slightly if required for a different modelling scenario.

3.4. Identification of Peak Periods

To allocate capacity credits to individual facilities, their performance in peak demand and peak LSG periods must be known. 12 peak periods (of both demand and LSG) for each year in the assessment period (provided they are all on separate days) are required for this component of the model. That entails identifying a total of 120 peak periods over a five-year period. These periods were found by ranking the system demand and LSG values and identifying the appropriate periods. These were then aligned with the individual facility outputs to determine their performance in these periods.

4. MODELLING RESULTS

ERA requested that TLG use the amended model to run several scenarios. TLG was to provide all modelling results in spreadsheets and a summary of the main findings suitable for inclusion in the ERA's rule change proposal. The modelling results include the estimate of fleet capacity value, technology class capacity values, and individual facility capacity values to be assigned to candidate facilities.

The full input and output files of each modelling scenario have been made available to ERA via a SharePoint folder.

4.1. SCENARIO 1: 2019 RCC

The 2019 RCC scenario calculates the capacity value of intermittent generators that applied for the certification of capacity in the 2019 Reserve Capacity Cycle (RCC). This was done without setting a specific target LOLE.

4.1.1. Results

Table 2: Summary of Fleet Relevant Levels for Scenario 1

Relevant Period	LOLE (TIs)	Relevant Level (MW)
2014 to 2019	1.18e-02	347
2014/15	2.12e-04	304
2015/16	1.14e-02	350
2016/17	1.14e-05	239
2017/18	2.08e-04	328
2018/19	1.05e-07	176
2019 RCC		**304**

Table 3: Summary of Technology-Specific Relevant Levels for Scenario 1

Technology Class	Adjusted Technology Class Relevant Level	Total Installed Capacity of Technology Class	Relevant Level of Technology Class as % of Total Installed Capacity
Biogas	16.0	21.598	74%
Solar	46.7	150.96	31%
Wind	241.3	1021.87	24%
Total	**304.0**	**1194.428**	**25%**

More detailed results can be found in the appendices.

4.2. Scenario 2: 2019 RCC Scenario at Target Level of LOLE = 24Hrs

The 2019 RCC scenario was repeated, however a target level of LOLE equal to 24 hours in 10 years was used when calculating the capacity value of intermittent generators.

4.2.1. Results

Table 4: Summary of Fleet Relevant Levels for Scenario 2

Relevant Period	LOLE (TIs)	Relevant Level (MW)
2014 to 2019	24.00	384
2014/15	4.80	332
2015/16	4.80	422
2016/17	4.80	293
2017/18	4.80	366
2018/19	4.80	238
2019 RCC		**332**

Table 5: Summary of Technology-Specific Relevant Levels for Scenario 2

Technology Class	Adjusted Technology Class Relevant Level	Total Installed Capacity of Technology Class	Relevant Level of Technology Class as % of Total Installed Capacity
Biogas	16.0	21.598	74%
Solar	47.7	150.96	32%
Wind	268.3	1021.87	26%
Total	**332.0**	**1194.428**	**28%**

More detailed results can be found in the appendices.

4.3. Scenario 3: 2019 RCC Scenario at Target Level of LOLE = 3Hrs

The 2019 RCC scenario was repeated, however a target level of LOLE equal to 3 hours in 10 years was used when calculating the capacity value of intermittent generators.

4.3.1. Results

Table 6: Summary of Fleet Relevant Levels for Scenario 3

Relevant Period	LOLE (TIs)	Relevant Level (MW)
2014 to 2019	3.00	370
2014/15	0.60	324
2015/16	0.60	402
2016/17	0.60	280
2017/18	0.60	355
2018/19	0.60	217
2019 RCC		**324**

Table 7: Summary of Technology-Specific Relevant Levels for Scenario 3

Technology Class	Adjusted Technology Class Relevant Level	Total Installed Capacity of Technology Class	Relevant Level of Technology Class as % of Total Installed Capacity
Biogas	14.0	21.598	65%
Solar	50.5	150.96	33%
Wind	259.5	1021.87	25%
Total	**324.0**	**1194.428**	**27%**

More detailed results can be found in the appendices.

4.4. Scenario 4: 2019 RCC Including a Hypothetical Large-Scale Battery as a Candidate Facility Included in a Storage Technology Class

The 2019 RCC scenario was repeated and included in the list of candidate facilities a 100 MW installed battery storage with four-hour duration. This was regarded as a candidate facility, placed in a storage technology class.

A. Assume the battery storage installed capacity is available during the four-hour period between 4:30pm and 8:30pm. Assume the capacity available from the battery storage during all other periods is zero.

B. Investigate if the battery storage has any interaction effect with other candidate facilities (Similar to that the ERA conducted to investigate if the capacity value of biogas has any interaction with solar and wind facilities).

As the inclusion of a hypothetical battery storage facility altered the LSG profile, the peak LSG periods were identified given this change, and individual facility performance during these periods was found. As this change did not affect demand, peak demand periods did not change. The specified output of the hypothetical battery was used to determine what its performance would have been during these periods.

Any interaction effects between the storage technology class and solar, wind and biogas technology classes were evaluated and is discussed in section 4.4.2.

For scenario 4 through 6, a LOLE target of 24 hours in 10 years was used, in accordance with ERA's guidance.

4.4.1. Results

Table 8: Summary of Fleet Relevant Levels for Scenario 4

Relevant Period	LOLE (TIs)	Relevant Level (MW)
2014 to 2019	24.00	458
2014/15	4.80	404
2015/16	4.80	486
2016/17	4.80	381
2017/18	4.80	450
2018/19	4.80	330
2019 RCC		**404**

Table 9: Summary of Technology-Specific Relevant Levels for Scenario 4

Technology Class	Adjusted Technology Class Relevant Level	Total Installed Capacity of Technology Class	Relevant Level of Technology Class as % of Total Installed Capacity
Biogas	16.0	21.598	74%
Solar	49.9	150.96	33%
Wind	280.8	1021.87	27%
Battery Storage	57.3	100	57%
Total	404.0	1294.428	31%

More detailed results can be found in the appendices.

4.4.2. Interaction Effect

TLG analysed the existence of any interaction effect between the storage technology class and the other technology classes. This was done in a similar fashion to the examination of an interaction effect between solar and wind technology classes, previously conducted by ERA. The results of this analysis are shown below.

Table 10: Interaction Effect Between Storage and (Biogas + Solar + Wind)

Combination	Relevant Level (MW)
Biogas + Solar + Wind	384
Battery Storage	62
Sum	446
(Biogas + Solar + Wind) + Battery Storage	458
Interaction Effect	**12**

The results in Table 10 indicate the presence of an interaction effect between the storage technology class and the biogas, solar and wind technology classes, when considered as a whole.

Table 11: Interaction Effect Between Storage and (Biogas + Solar)

Combination	Relevant Level (MW)
Biogas + Solar	69
Battery Storage	62
Sum	131
(Biogas + Solar) + Battery Storage	148
Interaction Effect	**17**

The results in Table 11 indicate the presence of an interaction effect between the storage technology class and the biogas and solar technology classes, when considered as a whole.

Table 12: Interaction Effect Between Storage and (Biogas + Wind)

Combination	Relevant Level (MW)
Biogas + Wind	320
Battery Storage	62
Sum	382
(Biogas + Wind) + Battery Storage	376
Interaction Effect	**-6**

The results in Table 12 indicate the presence of an interaction effect between the storage technology class and the biogas and wind technology classes, when considered as a whole.

The allocation of capacity credits to each technology class was extended to the storage technology class to reflect the above results.

4.5. Scenario 5: 2019 RCC Scenario Assuming a Demand Net of the Available Capacity of a Hypothetical Large-Scale Battery

The 2019 RCC scenario was repeated, however a timeseries of system demand net of the available capacity of storage during the availability window specified in the previous scenario was used.

In this scenario a battery storage technology class was not included. Furthermore, the design of this scenario did not require a re-calculation of peak periods; all peak demand and LSG periods remained consistent with those in scenarios 1 through 3.

4.5.1. Results

Table 13: Summary of Fleet Relevant Levels for Scenario 5

Relevant Period	LOLE (TIs)	Relevant Level (MW)
2014 to 2019	24.00	396
2014/15	4.80	364
2015/16	4.80	412
2016/17	4.80	308
2017/18	4.80	364
2018/19	4.80	244
2019 RCC		**364**

Table 14: Summary of Technology-Specific Relevant Levels for Scenario 5

Technology Class	Adjusted Technology Class Relevant Level	Total Installed Capacity of Technology Class	Relevant Level of Technology Class as % of Total Installed Capacity
Biogas	12.0	21.598	56%
Solar	68.5	150.96	45%
Wind	283.5	1021.87	28%
Total	**364.0**	**1194.428**	**30%**

More detailed results can be found in the appendices.

4.5.2. LOLE Adjustments

To account for the effect of storage available capacity, an additional adjustment to system demand is required. LOLE_Adjustment_1 lifts system demand until the target LOLE is reached (24 hours in ten years). LOLE_Adjustment_2 further lifts system demand to account for storage available capacity. These adjustments are summarised below.

Table 15: LOLE Adjustments Made for Scenario 5

Period	LOLE (TIs)	LOLE_Adjustment_1 (MW)	LOLE_Adjustment_2 (MW)
2014-2019	24	738	62
14-15	4.8	802	40
15-16	4.8	542	74
16-17	4.8	969	73
17-18	4.8	796	86
18-19	4.8	1196	86

4.6. Scenario 6: 2019 RCC Scenario Excluding North Country Region Wind Farms

The 2019 RCC scenario was repeated, however any existing or new north country wind farm facility was excluded from the model. These facilities were specified by ERA and are listed below.

Table 16: List of Facilities Excluded from the Model for Scenario 6

Market Participant	Excluded Facility
Alinta Sales Pty Ltd	ALINTA_WWF
Alinta Sales Pty Ltd	BADGINGARRA_WF1
EDWF Manager Pty Ltd	EDWFMAN_WF1
SRV GRSF Pty Ltd as Trustee for GRSF Trust	GREENOUGH_RIVER_PV1
Mumbida Wind Farm Pty Ltd	MWF_MUMBIDA_WF1
BEI WWF Pty Ltd ATF WWF Trust	WARRADARGE_WF1
Alinta Sales Pty Ltd	YANDIN_WF1

4.6.1. Results

Table 17: Summary of Fleet Relevant Levels for Scenario 6

Relevant Period	LOLE (TIs)	Relevant Level (MW)
2014 to 2019	24.00	146
2014/15	4.80	120
2015/16	4.80	164
2016/17	4.80	104
2017/18	4.80	134
2018/19	4.80	74
2019 RCC		**120**

Table 18: Summary of Technology-Specific Relevant Levels for Scenario 6

Technology Class	Adjusted Technology Class Relevant Level	Total Installed Capacity of Technology Class	Relevant Level of Technology Class as % of Total Installed Capacity
Biogas	16.0	21.598	74%
Solar	42.5	110.96	38%
Wind	61.5	252.47	24%
Total	**120.0**	**385.028**	**31%**

More detailed results can be found in the appendices.

5. QUALITY ASSURANCE OF SPREADSHEET MODEL

ERA also requested that the RCC Results Progressed spreadsheet be audited for alignment with the RLM. This spreadsheet apportions the estimated fleet capacity value to technology classes and individual facilities.

The intended methodology for this component of the RLM model is described in Appendix 9 of the Wholesale Electricity Market Rules. This document is currently undergoing revision. The most recent version available to TLG, and hence used for this audit, is dated 28 October 2020. This spreadsheet is specifically responsible for Steps 9 through 13 of the Appendix.

5.1. CALCULATION OF RELEVANT LEVEL FOR THE FLEET OF CANDIDATE FACILITIES AND FACILITY GROUPS

Steps 9 and 10 of Appendix 9 deal specifically with the determination of the final relevant level for the entire fleet of candidate facilities, and for each technology class of candidate facilities for the given RCC. These are the first steps of the RLM that the RCC Results Progressed spreadsheet is used. Calculations for all previous steps are undertaken in other components of the model and have been outlined in Sections 1 through 4. Step 9 outlines the first part of this process:

> Step 9: Determine
>
> a. For each 12-month period identified in Step 1(b) as the *Relevant_Period,* the *Annual_RL_Fleet* (in MW) using the calculation in Step 18, and the corresponding *Net_Demand* data defined in Table 1; and
>
> b. For the period identified in Step 1(a), as the *Relevant_Period,* the *Full_Period_RL_Fleet* (in MW) using the calculation in Step 18, and the corresponding *Net_Demand* data defined in Table 1
>
> c. For the period identified in Step 1(a), as the *Relevant_Period,* for each facility group *c* the *Facility_Group_RL(c),* using the calculation in Step 18 and corresponding *Net_Demand* data defined in Table 1.
>
> d. The *RL_Fleet* as the smaller of
>
> - The median of the *Annual_RL_Fleet* determined in paragraph a, and
> - The *Full_Period_RL_Fleet* estimated in paragraph b.

The values described in Step 9(a) through (c), are determined using the LOLP_Table.py component of the model. These values are then entered into the RCC Results Progressed spreadsheet model, in cells G3 to G7, G2, and J18 to J20, respectively. The value of *RL_Fleet* is then determined correctly as per the methodology shown in Step 9(d) and is stored in cell C14. In addition to these steps, cell C11 confirms that the sum of the LOLE in each of the 12-month periods, equals that of the entire period. An error here would indicate a problem upstream in the model.

Due to the interaction effect between different candidate facility technology classes, the values found in Step 9(c) must be scaled to account for interaction between different technology classes. Step 10 outlines the methodology to do this, which is executed in the spreadsheet.

Step 10: Determine for each facility group c the value of $Adjusted\_Facility\_Group\_RL(c)$ using the calculation steps below:

a. For each facility group with interaction index *i(c)* equal to zero, the value of *Adjusted_Facility_Group_RL(c)* is equal to *Facility_Group_RL(c)* calculated in Step 9(c). The interaction index *i(c)* is equal to one for Wind Facility Group and Solar Facility Group, or any New Facility Group that contains wind or solar generation, and zero otherwise.

b. Calculate the *Facility_Group_IE*, representing the interaction effect between facility groups with *i(c)* equal to one, as:

$$Full\_Period\_RL\_Fleet - \sum_{c} Facility\_Group\_RL(c)$$

where the expression $\sum_c Facility\_Group\_RL(c)$ represents the sum of all $Facility\_Group\_RL(c)$ for all facility groups estimated in **Error! Reference source not found.**;

c. Calculate the *AFP_Facility_Group_RL(c)* for each facility group c, with interaction index *i(c)* equal to one, as:

$$Facility\_Group\_RL(c) + \frac{Facility\_Group\_RL(c)}{\sum_c (Facility\_Group\_RL(c)) \times i(c))} \times Facility\_Group\_IE$$

where the *Facility_Group_RL(c)* is determined in Step 9(c).

d. Calculate the *Adjusted_Facility_Group_RL(c)* for each facility group c, with interaction index *i(c)* equal to one, as:

$$\frac{AFP\_Facility\_Group\_RL(c)}{\sum_c AFP\_Facility\_Group\_RL(c)} \times (RL\_Fleet - \sum_{c\in\{\forall c|i(c)=0\}} Facility\_Group\_RL(c))$$

where the expression $\sum_{c\in\{\forall c|c(i)=0\}} Facility\_Group\_RL(c)$ represents the sum of $Facility\_Group\_RL(c)$ for all facility groups c estimated in **Error! Reference source not found.** with interaction index $i(c)$ equal to zero.

As stated in Step 10(a), any facility class with an interaction index equal to zero, has an adjusted relevant level equal to the facility group relevant level found in Step 9(c). This is the case for the Biogas facility class and hence the adjusted relevant level is unchanged and is stored in cell L18.

The *Facility_Group_IE,* as defined in Step 10(b), is calculated, and stored in cell J21 of the spreadsheet. The values in cells J18 to J21, as well as the interaction indices for each technology class (stored in cells K18 to K20) are used to calculated the *AFP_Facility_Group_RL* as shown in Step10(c), and these values are stored in cells L18 to L20.

Finally, the calculation shown in Step 10(d) is completed across column M as well as cells C25 to C27, such that the *Adjusted_Facility_Group_RL* values are stored in cells C25 to C27. Auditing all the calculations mentioned to this point found that the spreadsheet correctly implements the methodology laid out in Appendix 9 of the rules.

5.2. Allocation of Facility Group Relevant Level to Individual Candidate Facilities

The audit to this point has pertained to the 'ELCC' tab of the spreadsheet. This tab calculates the technology class relevant levels. The apportionment of these values to individual facilities is done across the remaining four tabs in the spreadsheet.

Step 11: For each Candidate Facility *f* within a facility group *c:*

a. Determine the quantities of:

$$Actual\_CF\_Generation(f) + Estimated\_CF\_Generation(f)$$

As calculated in Step 7(c), during the Trading Intervals identified in Step 8, multiplied by two to convert to units of MW, and

b. Determine the *Facility_Average_Performance_Level(f)* as the mean of the quantities determined for Facility *f* in Stepp 11(a).

The quantities defined in Step 11(a) were previously found for all Candidate Facilities in the data preparation stage of the model, as described above, and are placed in the 'Peak LSG periods' and 'Peak demand periods' tabs of the spreadsheet.

At this point it is important to again note that these rules are currently under review. One potential amendment is to remove the need for both peak demand and peak LSG periods to determine facility performance. This change has not yet been reflected in the spreadsheet component of the model, however a future change to this effect would be trivial and would not impact the correct performance of the spreadsheet.

Below each column of values corresponding to a particular facility, a mean is found as described in Step 11(b). These mean performance values are then stored in columns D and E of the 'Facilities' tab. It is in this tab where the individual facility relevant levels are calculated.

Step 12: For each facility group *c* determine the *Scaling Factor(c)* as:

$$\frac{Adjusted\_Facility\_Group\_RL(c)}{\sum_{f \in c} Facility\_Average\_Performance\_Level(f)}$$

Where the denominator represents the sum of *Facility_Average_Performance_Level* for all Facilities *f* in the facility group *c.*

Scaling factors for each of the facility groups are calculated in the 'Facilities' tab in cells B29 to B31, using the formula set out in Step 12.

Step 13: Determine for each Candidate Facility *f* in the facility group *c* the Relevant Level (in MW) as:

$$max\ (0, Scaling\_Factor(c) \times Facility\_Average\_Performance\_Level(f))$$

The relevant level of each facility is calculated, as per Step 13, in column H of the 'Facilities' tab of the spreadsheet. The audit of the spreadsheet component of the RLM model has determined the spreadsheet operates correctly and efficiently in accordance with the relevant steps of Appendix 9 of the Whole Electricity Market rules.

In addition to the steps laid out in the Appendix, the spreadsheet has some functionality that does not directly relate to the rules. For example, in column I of the 'Facilities' tab, the relevant level of each facility is shown as a percentage of that facility's maximum capacity. In columns J and K of the same tab, a comparison between this allocation methodology and the existing relevant level method is shown. These steps are not laid out in the rules but operate correctly and provide additional insight.

Furthermore, in the 'Capacity credits' tab of the spreadsheet, a slightly different proposed methodology of using a rolling average of the last three relevant levels for each facility as the final assigned capacity credits is sown. Again, this is not laid out in the rules.

Finally, when using the RCC Results Progressed spreadsheet it is important to note that some areas (such as row A of the 'Facilities' tab) use outdated nomenclature. This does not have a bearing on the correct function of the spreadsheet but should be borne in mind to avoid confusion.

APPENDIX A: DETAILED MODELLING RESULTS

A.1 Scenario 1

Facility	Technology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
ALBANY_WF1	Wind	21.6	8.99	8.05	8.52	0.7717	6.572	30%	5.29	1.278
ALINTA_WWF	Wind	89.1	40.58	14.59	27.59	0.7717	21.289	24%	17.19	4.104
AMBRISOLAR_PV1	Solar	0.96	0.29	0.11	0.20	1.3263	0.267	28%	0.20	0.069
BADGINGARRA_WF1	Wind	147.5	72.15	25.43	48.79	0.7717	37.654	26%	26.87	10.780
BIOGAS01	Biogas	2	1.28	1.35	1.32	1.0122	1.334	67%	1.18	0.154
BLAIRFOX_KARAKIN_WF1	Wind	5	1.09	0.39	0.74	0.7717	0.571	11%	0.49	0.085
BREMER_BAY_WF1	Wind	0.6	0.27	0.24	0.26	0.7717	0.198	33%	0.17	0.032
DCWL_DENMARK_WF1	Wind	1.44	0.67	0.61	0.64	0.7717	0.494	34%	0.36	0.130

Facility	Technology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_ Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
EDWFMAN_WF1	Wind	80	33.87	10.49	22.18	0.7717	17.117	21%	16.21	0.908
GRASMERE_WF1	Wind	13.8	6.26	5.43	5.85	0.7717	4.511	33%	3.71	0.799
GREENOUGH_RIVER_PV1	Solar	40	12.00	4.84	8.42	1.3263	11.168	28%	7.38	3.791
HENDERSON_RENEWABLE_IG1	Biogas	3	1.69	1.77	1.73	1.0122	1.750	58%	1.63	0.118
INVESTEC_COLLGAR_WF1	Wind	206	62.14	32.55	47.34	0.7717	36.537	18%	15.82	20.714
KALBARRI_WF1	Wind	1.6	0.49	0.28	0.38	0.7717	0.297	19%	0.26	0.038
MERSOLAR_PV1	Solar	100	35.96	13.47	24.71	1.3263	32.778	33%	16.32	16.458
MWF_MUMBIDA_WF1	Wind	55	19.19	6.10	12.64	0.7717	9.755	18%	7.03	2.726
NORTHAM_SF_PV1	Solar	10	2.69	1.00	1.84	1.3263	2.447	24%	1.80	0.649
RED_HILL	Biogas	3.64	2.94	3.04	2.99	1.0122	3.025	83%	2.84	0.183

Facility	Technology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
ROCKINGHAM	Biogas	4	2.42	2.43	2.43	1.0122	2.456	61%	2.32	0.133
SKYFRM_MTBARKER_WF1	Wind	2.43	0.99	0.69	0.84	0.7717	0.647	27%	0.52	0.126
SOUTH_CARDUP	Biogas	4.158	2.99	3.03	3.01	1.0122	3.044	73%	2.97	0.078
TAMALA_PARK	Biogas	4.8	4.35	4.33	4.34	1.0122	4.392	91%	4.35	0.041
WARRADARGE_WF1	Wind	183.6	92.64	35.19	63.91	0.7717	49.323	27%	30.22	19.100
YANIDN_WF1	Wind	214.2	110.06	36.05	73.05	0.7717	56.377	26%	36.20	20.181

A.2 SCENARIO 2

Facility	Technology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_ Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
ALBANY_WF1	Wind	21.6	8.99	8.05	8.52	0.8580	7.308	34%	5.29	2.014
ALINTA_WWF	Wind	89.1	40.58	14.59	27.59	0.8580	23.670	27%	17.19	6.485
AMBRISOLAR_PV1	Solar	0.96	0.29	0.11	0.20	1.3548	0.273	28%	0.20	0.075
BADGINGARRA_WF1	Wind	147.5	72.15	25.43	48.79	0.8580	41.865	28%	26.87	14.991
BIOGAS01	Biogas	2	1.28	1.35	1.32	1.0122	1.334	67%	1.18	0.154
BLAIRFOX_KARAKIN_WF1	Wind	5	1.09	0.39	0.74	0.8580	0.634	13%	0.49	0.148
BREMER_BAY_WF1	Wind	0.6	0.27	0.24	0.26	0.8580	0.221	37%	0.17	0.055
DCWL_DENMARK_WF1	Wind	1.44	0.67	0.61	0.64	0.8580	0.549	38%	0.36	0.185
EDWFMAN_WF1	Wind	80	33.87	10.49	22.18	0.8580	19.031	24%	16.21	2.822

Facility	Technology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
GRASMERE_WF1	Wind	13.8	6.26	5.43	5.85	0.8580	5.016	36%	3.71	1.304
GREENOUGH_RIVER_PV1	Solar	40	12.00	4.84	8.42	1.3548	11.409	29%	7.38	4.032
HENDERSON_RENEWABLE_IG1	Biogas	3	1.69	1.77	1.73	1.0122	1.750	58%	1.63	0.118
INVESTEC_COLLGAR_WF1	Wind	206	62.14	32.55	47.34	0.8580	40.623	20%	15.82	24.800
KALBARRI_WF1	Wind	1.6	0.49	0.28	0.38	0.8580	0.330	21%	0.26	0.071
MERSOLAR_PV1	Solar	100	35.96	13.47	24.71	1.3548	33.484	33%	16.32	17.164
MWF_MUMBIDA_WF1	Wind	55	19.19	6.10	12.64	0.8580	10.846	20%	7.03	3.817
NORTHAM_SF_PV1	Solar	10	2.69	1.00	1.84	1.3548	2.499	25%	1.80	0.701
RED_HILL	Biogas	3.64	2.94	3.04	2.99	1.0122	3.025	83%	2.84	0.183
ROCKINGHAM	Biogas	4	2.42	2.43	2.43	1.0122	2.456	61%	2.32	0.133

Facility	Technology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
SKYFRM_MTBARKER_WF1	Wind	2.43	0.99	0.69	0.84	0.8580	0.720	30%	0.52	0.199
SOUTH_CARDUP	Biogas	4.158	2.99	3.03	3.01	1.0122	3.044	73%	2.97	0.078
TAMALA_PARK	Biogas	4.8	4.35	4.33	4.34	1.0122	4.392	91%	4.35	0.041
WARRADARGE_WF1	Wind	183.6	92.64	35.19	63.91	0.8580	54.840	30%	30.22	24.617
YANIDN_WF1	Wind	214.2	110.06	36.05	73.05	0.8580	62.683	29%	36.20	26.487

A.3 Scenario 3

Facility	Technology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
ALBANY_WF1	Wind	21.6	8.99	8.05	8.52	0.8298	7.067	33%	5.29	1.773

Facility	Technology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
ALINTA_WWF	Wind	89.1	40.58	14.59	27.59	0.8298	22.890	26%	17.19	5.705
AMBRISOLAR_PV1	Solar	0.96	0.29	0.11	0.20	1.4356	0.289	30%	0.20	0.091
BADGINGARRA_WF1	Wind	147.5	72.15	25.43	48.79	0.8298	40.486	27%	26.87	13.612
BIOGAS01	Biogas	2	1.28	1.35	1.32	0.8857	1.167	58%	1.18	-0.013
BLAIRFOX_KARAKIN_WF1	Wind	5	1.09	0.39	0.74	0.8298	0.613	12%	0.49	0.127
BREMER_BAY_WF1	Wind	0.6	0.27	0.24	0.26	0.8298	0.213	36%	0.17	0.047
DCWL_DENMARK_WF1	Wind	1.44	0.67	0.61	0.64	0.8298	0.531	37%	0.36	0.167
EDWFMAN_WF1	Wind	80	33.87	10.49	22.18	0.8298	18.404	23%	16.21	2.195
GRASMERE_WF1	Wind	13.8	6.26	5.43	5.85	0.8298	4.851	35%	3.71	1.139
GREENOUGH_RIVER_PV1	Solar	40	12.00	4.84	8.42	1.4356	12.089	30%	7.38	4.712

Facility	Technology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
HENDERSON_RENEWABLE_IG1	Biogas	3	1.69	1.77	1.73	0.8857	1.531	51%	1.63	-0.101
INVESTEC_COLLGAR_WF1	Wind	206	62.14	32.55	47.34	0.8298	39.285	19%	15.82	23.462
KALBARRI_WF1	Wind	1.6	0.49	0.28	0.38	0.8298	0.319	20%	0.26	0.060
MERSOLAR_PV1	Solar	100	35.96	13.47	24.71	1.4356	35.480	35%	16.32	19.160
MWF_MUMBIDA_WF1	Wind	55	19.19	6.10	12.64	0.8298	10.488	19%	7.03	3.459
NORTHAM_SF_PV1	Solar	10	2.69	1.00	1.84	1.4356	2.648	26%	1.80	0.850
RED_HILL	Biogas	3.64	2.94	3.04	2.99	0.8857	2.647	73%	2.84	-0.195
ROCKINGHAM	Biogas	4	2.42	2.43	2.43	0.8857	2.149	54%	2.32	-0.174
SKYFRM_MTBARKER_WF1	Wind	2.43	0.99	0.69	0.84	0.8298	0.696	29%	0.52	0.175
SOUTH_CARDUP	Biogas	4.158	2.99	3.03	3.01	0.8857	2.663	64%	2.97	-0.303

Facility	Technology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
TAMALA_PARK	Biogas	4.8	4.35	4.33	4.34	0.8857	3.843	80%	4.35	-0.508
WARRADARGE_WF1	Wind	183.6	92.64	35.19	63.91	0.8298	53.033	29%	30.22	22.810
YANIDN_WF1	Wind	214.2	110.06	36.05	73.05	0.8298	60.618	28%	36.20	24.422

A.4 Scenario 4

Facility	Technology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
ALBANY_WF1	Wind	21.6	8.99	8.05	8.52	0.898	7.648	35%	5.29	2.354
ALINTA_WWF	Wind	89.1	40.58	14.59	27.59	0.898	24.773	28%	17.19	7.588

Facility	Technology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
AMBRISOLAR_PV1	Solar	0.96	0.29	0.11	0.20	1.418	0.285	30%	0.20	0.087
BADGINGARRA_WF1	Wind	147.5	72.15	25.43	48.79	0.898	43.816	30%	26.87	16.942
BIOGAS01	Biogas	2	1.28	1.35	1.32	1.012	1.334	67%	1.18	0.154
BLAIRFOX_KARAKIN_WF1	Wind	5	1.09	0.39	0.74	0.898	0.664	13%	0.49	0.178
BREMER_BAY_WF1	Wind	0.6	0.27	0.24	0.26	0.898	0.231	38%	0.17	0.065
DCWL_DENMARK_WF1	Wind	1.44	0.67	0.61	0.64	0.898	0.574	40%	0.36	0.210
EDWFMAN_WF1	Wind	80	33.87	10.49	22.18	0.898	19.918	25%	16.21	3.709
GRASMERE_WF1	Wind	13.8	6.26	5.43	5.85	0.898	5.249	38%	3.71	1.537
GREENOUGH_RIVER_PV1	Solar	40	12.00	4.84	8.42	1.418	11.940	30%	7.38	4.563
HENDERSON_RENEWABLE_IG1	Biogas	3	1.69	1.77	1.73	1.012	1.750	58%	1.63	0.118

Facility	Technology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_ Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
INVESTEC_COLLGAR_WF1	Wind	206	62.14	32.55	47.34	0.898	42.516	21%	15.82	26.693
KALBARRI_WF1	Wind	1.6	0.49	0.28	0.38	0.898	0.346	22%	0.26	0.087
MERSOLAR_PV1	Solar	100	35.96	13.47	24.71	1.418	35.044	35%	16.32	18.724
MWF_MUMBIDA_WF1	Wind	55	19.19	6.10	12.64	0.898	11.351	21%	7.03	4.322
NORTHAM_SF_PV1	Solar	10	2.69	1.00	1.84	1.418	2.616	26%	1.80	0.818
RED_HILL	Biogas	3.64	2.94	3.04	2.99	1.012	3.025	83%	2.84	0.183
ROCKINGHAM	Biogas	4	2.42	2.43	2.43	1.012	2.456	61%	2.32	0.133
SKYFRM_MTBARKER_WF1	Wind	2.43	0.99	0.69	0.84	0.898	0.753	31%	0.52	0.232
SOUTH_CARDUP	Biogas	4.158	2.99	3.03	3.01	1.012	3.044	73%	2.97	0.078
TAMALA_PARK	Biogas	4.8	4.35	4.33	4.34	1.012	4.392	91%	4.35	0.041

Facility	Technology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_ Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
WARRADARGE_ WF1	Wind	183.6	92.64	35.19	63.91	0.898	57.395	31%	30.22	27.172
YANIDN_WF1	Wind	214.2	110.06	36.05	73.05	0.898	65.603	31%	36.20	29.407
BATTERY	Storage	100	95	95	95.00	0.603	57.276	57%		

A.5 Scenario 5

Facility	Technology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_ Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
ALBANY_WF1	Wind	21.6	8.99	8.05	8.52	0.9065	7.721	36%	5.29	2.427
ALINTA_WWF	Wind	89.1	40.58	14.59	27.59	0.9065	25.008	28%	17.19	7.823
AMBRISOLAR_P V1	Solar	0.96	0.29	0.11	0.20	1.9470	0.392	41%	0.20	0.194

Facility	Technology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
BADGINGARRA_WF1	Wind	147.5	72.15	25.43	48.79	0.9065	44.232	30%	26.87	17.358
BIOGAS01	Biogas	2	1.28	1.35	1.32	0.7592	1.001	50%	1.18	-0.179
BLAIRFOX_KARAKIN_WF1	Wind	5	1.09	0.39	0.74	0.9065	0.670	13%	0.49	0.184
BREMER_BAY_WF1	Wind	0.6	0.27	0.24	0.26	0.9065	0.233	39%	0.17	0.067
DCWL_DENMARK_WF1	Wind	1.44	0.67	0.61	0.64	0.9065	0.580	40%	0.36	0.216
EDWFMAN_WF1	Wind	80	33.87	10.49	22.18	0.9065	20.107	25%	16.21	3.898
GRASMERE_WF1	Wind	13.8	6.26	5.43	5.85	0.9065	5.299	38%	3.71	1.587
GREENOUGH_RIVER_PV1	Solar	40	12.00	4.84	8.42	1.9470	16.395	41%	7.38	9.018
HENDERSON_RENEWABLE_IG1	Biogas	3	1.69	1.77	1.73	0.7592	1.312	44%	1.63	-0.320
INVESTEC_COLLGAR_WF1	Wind	206	62.14	32.55	47.34	0.9065	42.920	21%	15.82	27.097

Facility	Technology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
KALBARRI_WF1	Wind	1.6	0.49	0.28	0.38	0.9065	0.349	22%	0.26	0.090
MERSOLAR_PV1	Solar	100	35.96	13.47	24.71	1.9470	48.119	48%	16.32	31.799
MWF_MUMBIDA_WF1	Wind	55	19.19	6.10	12.64	0.9065	11.459	21%	7.03	4.430
NORTHAM_SF_PV1	Solar	10	2.69	1.00	1.84	1.9470	3.592	36%	1.80	1.794
RED_HILL	Biogas	3.64	2.94	3.04	2.99	0.7592	2.269	62%	2.84	-0.573
ROCKINGHAM	Biogas	4	2.42	2.43	2.43	0.7592	1.842	46%	2.32	-0.481
SKYFRM_MTBARKER_WF1	Wind	2.43	0.99	0.69	0.84	0.9065	0.760	31%	0.52	0.239
SOUTH_CARDUP	Biogas	4.158	2.99	3.03	3.01	0.7592	2.283	55%	2.97	-0.683
TAMALA_PARK	Biogas	4.8	4.35	4.33	4.34	0.7592	3.294	69%	4.35	-1.057
WARRADARGE_WF1	Wind	183.6	92.64	35.19	63.91	0.9065	57.939	32%	30.22	27.716

Facility	Technology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_ Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
YANIDN_WF1	Wind	214.2	110.06	36.05	73.05	0.9065	66.226	31%	36.20	30.030

A.6 Scenario 6

Facility	Tech-nology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_ Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
ALBANY_WF1	Wind	21.6	9.60	8.53	9.07	0.9900	8.976	42%	5.29	3.682
AMBRISOLAR_PV1	Solar	0.96	0.27	0.21	0.24	1.3438	0.321	33%	0.20	0.123
BIOGAS01	Biogas	2	1.32	1.32	1.32	1.0168	1.344	67%	1.18	0.164
BLAIRFOX_KARAKIN_WF1	Wind	5	0.84	0.68	0.76	0.9900	0.755	15%	0.49	0.269
BREMER_BAY_WF1	Wind	0.6	0.27	0.25	0.26	0.9900	0.259	43%	0.17	0.093

Facility	Tech-nology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
DCWL_DENMARK_WF1	Wind	1.44	0.65	0.59	0.62	0.9900	0.615	43%	0.36	0.251
GRASMERE_WF1	Wind	13.8	6.49	5.83	6.16	0.9900	6.095	44%	3.71	2.383
HENDERSON_RENEWABLE_IG1	Biogas	3	1.69	1.72	1.70	1.0168	1.733	58%	1.63	0.101
INVESTEC_COLLGAR_WF1	Wind	206	55.80	32.21	44.01	0.9900	43.566	21%	15.82	27.743
KALBARRI_WF1	Wind	1.6	0.43	0.36	0.39	0.9900	0.390	24%	0.26	0.131
MERSOLAR_PV1	Solar	100	33.62	24.88	29.25	1.3438	39.309	39%	16.32	22.989
NORTHAM_SF_PV1	Solar	10	2.43	1.81	2.12	1.3438	2.849	28%	1.80	1.051
RED_HILL	Biogas	3.64	3.04	2.89	2.96	1.0168	3.012	83%	2.84	0.170
ROCKINGHAM	Biogas	4	2.46	2.46	2.46	1.0168	2.499	62%	2.32	0.176
SKYFRM_MTBARKER_WF1	Wind	2.43	0.91	0.83	0.87	0.9900	0.864	36%	0.52	0.343
SOUTH_CARDUP	Biogas	4.158	2.97	2.91	2.94	1.0168	2.993	72%	2.97	0.027

Facility	Tech-nology Class	Maximum Capacity (MW)	Average sent out generation at peak demand periods in Step 9 (MWh)	Average sent out generation at peak LSG periods in Step 9 (MWh)	Average at all selected periods in Step 9(a) and 9(b)	Scaling_ Factor in Step 13	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Current method Relevant Level (MW)	Difference between proposed and current methods (MW)
TAMALA_PARK	Biogas	4.8	4.38	4.31	4.35	1.0168	4.419	92%	4.35	0.068