RCP Rule Change Panel
Market Advisory Committee

Meeting Agenda

Meeting Title:	Market Advisory Committee
Date:	Tuesday 17 November 2020
Time:	9:30 AM – 11:30 AM
Location:	Online meeting Persons who would like to attend the online MAC meeting are asked to register with RCP Support (Support@rcpwa.com.au) by close of business on Friday 13 November 2020. RCP Support will then send an invite to all of the registered attendees on Monday 16 November 2020 with a link to allow attendees to log into the meeting.

Item	Item	Responsibility	Duration
1	Welcome	Chair	2 min
2	Meeting Apologies/Attendance	Chair	3 min
3	Minutes of Meeting 2020_10_20	Chair	5 min
4	Action Items	Chair	5 min
5	RC_2019_03: Method used for the assignment of Certified Reserve Capacity to Intermittent Generators – Pre-Rule Change Proposal	ERA	60 min
6	Rule Change Governance – Consultation on Changes to the WEM Rules and Regulations (late papers)	EPWA	40 min
7	General Business	Chair	5 min

Next Meeting: 1 December 2020

Please note, this meeting will be recorded.

RCP Rule Change Panel
Market Advisory Committee

Minutes

Meeting Title:	Market Advisory Committee (**MAC**)
Date:	20 October 2020
Time:	9:30 AM – 11:05 AM
Location:	Online via Microsoft Teams

Attendees	Class	Comment
Stephen Eliot	Chair	
Matthew Martin	Small-Use Consumer Representative	
Martin Maticka	Australian Energy Market Operator (**AEMO**)	
Dean Sharafi	System Management	
Sara O'Connor	Economic Regulation Authority (**ERA**) Observer	
Kate Ryan	Minister's Appointee – Observer	
Andrew Everett	Synergy	
Jacinda Papps	Market Generators	
Wendy Ng	Market Generators	
Daniel Kurz	Market Generators	
Tom Frood	Market Generators	
Patrick Peake	Market Customers	
Geoff Gaston	Market Customers	
Timothy Edwards	Market Customers	
Peter Huxtable	Contestable Customers	
Zahra Jabiri	Network Operator	To 10:55 AM

Also in Attendance	From	Comment
Jai Thomas	Energy Transformation Implementation Unit (**ETIU**)	Presenter
Matt Shahnazari	ERA	Presenter
Richard Cheng	ERA	Presenter
Jenny Laidlaw	RCP Support	Minutes
Laura Koziol	RCP Support	Observer

Also in Attendance	From	Comment
Adnan Hayat	RCP Support	Observer
Noel Schubert	Independent	Observer
Dimitri Lorenzo	Bluewaters Energy	Observer
Jo-Anne Chan	Synergy	Observer
Graham Pearson	Australian Energy Council	Observer
Erin Stone	Point Global	Observer
Nicole Markham	AEMO	Observer to 10:55 AM
Edwin Ong	AEMO	Observer
Dora Guzeleva	ETIU	Observer
Emma Forrest	ERA	Observer
Julian Fairhall	ERA	Observer

Apologies	From	Comment
<None>		

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:30 AM and welcomed members and observers to the 20 October 2020 MAC meeting.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above.	
3	**Minutes of Meeting 2020_09_08** Draft minutes of the MAC meeting held on 8 September 2020 were circulated on 18 September 2020. The MAC accepted the minutes as a true and accurate record of the meeting. **Action: RCP Support to publish the minutes of the 8 September 2020 MAC meeting on the Rule Change Panel's (Panel) website as final.**	**RCP Support**
4	**Action Items** There were no outstanding action items.	

Item	Subject	Action
5	**MAC Market Rules Issues List (Issues List) Update** The Chair noted that the MAC agreed at its 8 September 2020 meeting to review the Issues List against the Energy Transformation Strategy (**ETS**) reforms in February 2021 to determine which issues have been addressed by the ETS and which remain outstanding. **Issues 45 and 46:** The Chair noted that ETIU has confirmed that it will consider issue 45 (transfer of responsibility for setting document retention requirements) and issue 46 (transfer of responsibility for setting confidentiality statuses) as part its Tranche 5 Amending Rules for the ETS. The MAC supported the Chair's suggestion to place issues 45 and 46 on hold pending the outcome of ETIU's consultation on the Tranche 5 Amending Rules. **Issue 22:** The Chair noted that issue 22 (regarding changes to eliminate duplication of prudential burden on Market Participants) was on hold pending completion of AEMO's Reduction of Prudential Exposure (**RoPE**) 2 project. The RoPE 2 project was now complete and AEMO had suggested that the remaining issues should be left on hold and picked up again following the ETS reforms. Mr Martin Maticka clarified that AEMO considered that the remaining issues were important but of a lower priority than other work currently in progress. The MAC agreed to leave issue 22 on hold pending the planned review of all Issues List issues in February 2021.	
6(a)	**Update on Changes to the Rule Change Governance Structure** Ms Kate Ryan gave a presentation on the Government's proposed changes to the governance of the Western Australian energy sector. A copy of the presentation is available on the Panel's website. Ms Ryan offered to meet with the MAC to discuss the draft Amending Rules for the transition of the Panel's functions to the Coordinator. The Chair noted that he was likely to schedule an additional MAC meeting in November 2020 to discuss the Pre-Rule Change Proposal: Method used for the assignment of certified reserve capacity to intermittent generators (RC_2019_03), and suggested that this might also be an appropriate time to discuss the draft Amending Rules and regulation changes. MAC members welcomed the opportunity to review and comment on the draft Amending Rules and agreed that a special MAC meeting should be held, if necessary.	

The following points were discussed:

- The Chair asked what the effective deadline for regulation changes was before the start of caretaker period for the March 2021 State election. Ms Ryan advised that the caretaker period ~~started~~ was expected to start in the first week of February 2021, which provided the opportunity for some routine government decision-making processes during December 2020 and the start of January 2021. However, the intent was to complete the changes by Christmas 2020.
- Mr Patrick Peake asked whether the MAC or some other industry consultation process would continue. Ms Ryan replied that the MAC would continue and that ETIU was looking at expanding the role of the MAC as part of the changes.

  Ms Ryan ~~noted that~~ acknowledged the perceived conflict of interest, as the Government ~~owned~~ owns assets in the sector and, while the Minister already had the power to make Amending Rules, the proposed amendments entrenched that ~~power~~ further. For this reason, the intent was to try to use the MAC and the Gas Advisory Board (**GAB**) as an important check and balance on the exercise of decision-making power by the Coordinator and the Minister.

  ~~ETIU~~ EPWA was considering elevating the role of the MAC and probably introducing an independent Chair, along with some explicit requirements for the Coordinator to have regard to the advice of the MAC as they go through the decision-making process.
- Mrs Jacinda Papps asked whether Protected Provisions would continue to exist. Ms Ryan replied that the Minister would continue to be the ultimate decision-maker on the kind of rules that were currently Protected Provisions, along with any rules that related to functions of the Coordinator.

  Ms Ryan noted that the Minister will also be required to approve the Amending Rules for any Rule Change Proposal proposed by the Coordinator.
- In response to questions from Ms Wendy Ng, Ms Ryan confirmed that an independent Chair was also being considered for the GAB. The MAC and GAB Chairs would not necessarily be the same person, although it may be convenient for one person to fill both roles.
- Ms Ryan invited MAC members and attendees to contact her or Ms Dora Guzeleva if they wished to discuss the proposed changes to the governance arrangements.

Item	Subject	Action
6(b)	**Update on the Energy Transformation Strategy** Mr Jai Thomas provided the following updates on the ETS: • The Government launched the first Whole of System Plan (**WOSP**) at an Australian Institute of Energy event on 12 October 2020. A range of information on the WOSP was available on the Brighter Energy Future and Energy Policy WA websites. An industry forum to discuss the WOSP was scheduled for 29 October 2020. • The one-week consultation period on the revised Tranche 1 Amending Rules (which include changes relating to Generator Performance Standards) closed on 19 October 2020. • The draft Tranche 2 Amending Rules were released for public consultation on 21 October 2020. ETIU intended to hold five Transformation Design and Operation Working Group (**TDOWG**) meetings to discuss the Tranche 2 Amending Rules, and were also happy to meet with stakeholders on a one-on-one basis. • The draft Tranche 3 Amending Rules, which relate to the Reserve Capacity Mechanism (**RCM**) and the proposed Network Access Quantity (**NAQ**) framework, were expected to be released for public consultation by 23 October 2020. ETIU expected to hold two TDOWG meetings in early to mid-November 2020 to discuss the Tranche 3 Amending Rules. Stakeholders could also contact Mr Ashwin Raj or Ms Guzeleva to arrange a one-on-one discussion. • The *Electricity Networks Access Code Amendments (No. 2) 2020* were gazetted on 18 September 2020. • During September 2020, ETIU consulted on an Issues Paper: Distributed Energy Resources (**DER**) Orchestration Roles and Responsibilities. ETIU received around 12 submissions, which were published on 16 October 2020 (see https://www.wa.gov.au/government/document-collections/previous-consultation-process-distributed-energy-resources). • The first phase of the DER register project commenced, with the transfer from Western Power to AEMO of DER historical records for 180,000 of the approximately 300,000 existing DER installations.	

Item	Subject	Action
7(a)	**AEMO Procedure Change Working Group (APCWG) Update** Mr Maticka provided the following updates on AEMO's Market Procedures: • the amendments to the Market Procedure: Declaration of Bilateral Trades and the Reserve Capacity Auction arising from Procedure Change Proposal: AEPC_2020_10 commenced on 16 October 2020. • AEMO had not held or scheduled any APCWG meetings since the 8 September 2020 MAC meeting.	
7(b)	**BRCP Working Group Update** Ms Sara O'Connor noted that the ERA published Procedure Change Proposal: calculation of benchmark reserve capacity price (EEPC_2020_02) on 15 September 2020. The ERA received one submission during the consultation period, which closed on 14 October 2020. The ERA also held a second and probably final BRCP Working Group meeting on 6 October 2020. The Working Group provided general support for the ERA's proposed changes to the Weighted Average Cost of Capital parameters. The ERA governing body was due to approve the Procedure Change Report on 4 November 2020 and to publish the report within the following two days. This would allow AEMO to use the revised Market Procedure to calculate the Benchmark Reserve Capacity Price for the 2021 Reserve Capacity Cycle.	
8(a)	**Overview of Rule Change Proposals** The paper was taken as read. The Chair provided the following updates: • The Draft Rule Change Report for Rule Change Proposal: Administrative Improvements to the Outage Process (RC_2014_03) was due to be published by the end of October 2020. The proposed submission period was five weeks, but the Panel was aware that this timeframe might be problematic for some Market Participants, given the large volumes of work for the ETS scheduled for November 2020. Stakeholders were welcome to contact RCP Support if they wished to seek an extension. RCP Support also intended to review the recently published draft Tranche 2 Amending Rules and follow up with ETIU regarding any discrepancies between the draft Tranche 2 Amending Rules and the proposed Amending Rules for RC_2014_03.	

Item	Subject	Action
	• The next step for Rule Change Proposal: The Relevant Demand calculation (RC_2019_01) was for RCP Support to develop a straw man proposal for an X of Y dynamic baseline. The Panel had de-prioritised RC_2019_01 in favour of RC_2014_03 and RC_2019_03, but intended to restart work on the proposal as soon as resources were available.	
8(b)	**Capacity valuation method for intermittent generators – ERA's proposed method: Rule Change Proposal** Dr Matt Shahnazari provided an update to the MAC on the ERA's progress in developing Rule Change Proposal: capacity valuation method for intermittent generators (RC_2019_03). A copy of the ERA's presentation is available in the meeting papers. Ms Laura Koziol noted that RCP Support had the following concerns regarding the ERA's proposed changes to the Relevant Level Methodology (**RLM**): • The inputs to the proposed RLM included the expected generation fleet, including intermittent and non-intermittent generators. The RLM produced Certified Reserve Capacity (**CRC**) values for the intermittent generators, which were then used as an input to the NAQ process, which determined the NAQ and Capacity Credits for all generators. A risk existed that the actual generation fleet could be different from the expected fleet, and that the 'incorrect' input values in the RLM could adversely affect the accuracy of the output CRC values. The ERA was investigating whether the potential impact of the difference was material. If the potential impact was not found to be material, then RCP Support considered that the issue could be ignored for now and addressed at a later time. However, if the potential impact was material, then the issue would need to be addressed, either by the ERA in the Rule Change Proposal or by the Panel when it processed the proposal. For the Panel, the options would be to either reject the proposal or approve it in an amended form. The amended form could involve, for example, the inclusion of some form of iteration between the RLM and NAQ processes, or implementation of a 'rule of thumb' method. • RCP Support held a concern that the proposed RLM might be inconsistent with the Planning Criterion and associated reserve margin, and therefore threaten system reliability.	

This was because the current RCM requires AEMO to acquire sufficient Reserve Capacity to meet a one-in-ten-year peak demand, which includes a reserve margin that assumes around 10% of accredited capacity will not be available during peak demand periods.

RCP Support's concern was that the proposed RLM may assign more CRC 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.

If the Panel concluded that this was a material issue and the proposed RLM threatened system reliability, then it would be likely to either reject the Rule Change Proposal or approve it in an amended form. It was likely that an amended method would tend to assign lower CRC values than the proposed RLM.

- The original Pre-Rule Change Proposal for RC_2019_03 did not address the allocation of CRC to hybrid solar/wind facilities or account for the impacts of storage facilities. As noted by Dr Shahnazari, the ERA was revising its Pre-Rule Change Proposal to account for these matters; and the Panel would need to assess the ERA's proposed approach to dealing with these facilities.

The following points were discussed:

- Mr Timothy Edwards noted that Metro Power Company would be interested in testing the proposed RLM to further understand the implications and provide feedback on the issues identified.
- Mr Peake questioned whether assigning CRC to intermittent generators based on their load carrying capacity underestimated the ability of these generators to contribute to system reliability compared with conventional generators, which were assigned CRC based on their absolute capacity. Mr Peake noted that in Ireland all generators were assessed on the basis of their load carrying capacity.

  Dr Shahnazari replied that the effective load carrying capability (**ELCC**) method was technology-agnostic and could be applied to any sort of generator with any technology, provided the necessary input data was available. However, for conventional gas or coal plant the ELCC method produced much the same results as the current absolute capacity method.
- Mr Dean Sharafi noted that AEMO had previously expressed some concerns about the ERA's Pre-Rule Change Proposal and considered that those concerns had

not been addressed. Mr Sharafi advised that AEMO's main concern was about reliability, and that the proposed RLM did not target the peak demand condition, because the Planning Criterion was based on a one-in-ten-year extreme weather event, and RC_2019_03 did not address that requirement.

Mr Sharafi suggested that the observed historical intermittent generation output will probably not align with the extreme weather criteria in the Planning Criterion and questioned how the proposed RLM will account for this.

Mr Sharafi also considered the proposed process was onerous, very iterative and circular with the new NAQ process; and questioned whether the proposal to run the RLM using the expected resource mix in the target Capacity Year would reduce or remove the need for iteration in the process.

- Mr Sharafi advised that, given the likely timing of the Rule Change Proposal, AEMO could implement the proposed RLM for the 2022 Reserve Capacity Cycle.
- Dr Shahnazari noted that the ERA did not intend to propose any form of iteration in RC_2019_03. The proposed RLM was in nature able to account for any possible interaction, for example, due to the effect of network constraints. However, the policy position from Government had been to run the NAQ process after receiving the CRC values from the RLM.

  The ERA did not discuss the impacts of network constraints of the allocation of Capacity Credits with stakeholders during consultation on the RLM in 2018-19, because the future market design was for CRC to be assigned without considering network constraints, as these would be accounted for in a subsequent process. Amendments to change the NAQ process and combine it with the proposed RLM were out of scope for the ERA.

  Dr Shahnazari also noted that the ERA did not really know how material the interaction effect might be. While not wishing to speculate on the matter, Dr Shahnazari suggested that the RLM and NAQ arrangements could be iterated in the future if AEMO considered that the interaction effect was material.

  Dr Shahnazari noted that AEMO recently indicated that it wanted to run short term and medium term projected assessment of system adequacy studies based on system adequacy analysis and loss of load expectation (**LOLE**),

and noted the similarity with the proposed RLM, which involved a system adequacy analysis based on a measure of system reliability (ELCC).

The Chair reiterated that RCP Support was considering whether the impact of the interaction between the RLM and NAQ processes was material. The Chair agreed with Mr Sharafi that it could be difficult and costly to incorporate iterations into the proposed processes.

Dr Shahnazari considered that one would need to develop a method that combined the RLM and NAQ processes to determine if the interaction effect was material. The ERA had run a sensitivity analysis based on what would happen if a few generators withdrew their applications during the CRC process. In one scenario, which was based on the 2018 Reserve Capacity Cycle, with 110 MW of solar facilities withdrawing their applications, the effect on the remaining facilities' capacity value was very small (in the order of 5 MW).

The Chair agreed that the best approach to consider the potential materiality of the issue was a sensitivity analysis.

- Dr Shahnazari questioned what alternatives existed to the proposed RLM, given that the current method contained conceptual errors and was therefore unreliable. The ERA had looked at other jurisdictions that at the time used a rule of thumb method for capacity valuation. However, these jurisdictions still needed to run probabilistic system adequacy analyses every few years to update the parameters used in the rule of thumb method.

  Dr Shahnazari considered that the best practice approach (which was recommended by the Institute of Electrical and Electronics Engineers and the International Energy Agency, and widely adopted across jurisdictions with similar planning criteria based on meeting a one-in-ten year peak demand event) was an ELCC analysis at the target level of LOLE.

- Dr Shahnazari noted that ETIU proposed to require Market Participants to specify a minimum Capacity Credit quantity when seeking CRC for a new facility. If the RLM assigned a level of CRC below the specified minimum quantity the application would be automatically withdrawn. This would partly, but not completely, manage the risk of changes to the expected generator fleet.

- Dr Shahnazari suggested that, in the future, as more intermittent generators enter the Wholesale Electricity Market (**WEM**), the periods of high reliability stress might no

longer be the highest demand periods, but instead periods that have a high demand combined with low intermittent generator availability. The proposed RLM accounted for this development by not restricting its analysis to extreme peak demand periods.

- Dr Shahnazari noted that the ERA was considering whether the specification of a target level of LOLE would have a material effect on RLM outputs. If the ERA found this to be the case, it intended to include a target LOLE level in the Rule Change Proposal.

  Dr Shahnazari noted that different jurisdictions had different interpretations of the one-in-ten-year criterion (e.g. some North American jurisdictions used an LOLE of 24 hours in 10 years, while the United Kingdom used 3 hours ~~in 10 years~~ per year). However, the choice of interpretation was unlikely to materially affect the value of the intermittent fleet ELCC.

- Mr Sharafi indicated that AEMO would follow up with the ERA separately regarding its outstanding concerns.

- In response to a question from Ms Ng, Ms Guzeleva confirmed that the proposed requirement for Market Participants to specify a minimum Capacity Credit level would apply to new generators only.

- Ms O'Connor considered AEMO's suggestion that the ERA had not addressed AEMO's concerns about the proposed RLM was misleading. Ms O'Connor noted that AEMO sat on the stakeholder group when the ERA conducted its review of the current RLM and developed the proposed RLM. AEMO also provided a submission to the draft report for the review that was supportive of the approach suggested by the ERA, and this submission was available on the ERA's website.

  AEMO also provided the ERA with 14 questions outlining its concerns after the ERA presented RC_2019_03 to the MAC in 2019. The ERA had fully responded to each of the questions, with an offer to respond to additional questions or concerns.

  The Chair suggested that AEMO's outstanding questions were probably similar to those noted by Ms Koziol earlier in the meeting.

The Chair noted that the ERA planned to present a revised Pre-Rule Change Proposal to the MAC for discussion in November 2020, and then formally submit the Rule Change Proposal in December 2020. Given the timelines for the

Item	Subject	Action
	Standard Rule Change Process, the Chair questioned whether AEMO would have time to implement the new RLM for the 2021 Reserve Capacity Cycle. RCP Support was already working on the analysis for the Rule Change Proposal to ensure it can be processed as quickly as possible. The Chair suggested that the MAC meet on 17 November 2020 to discuss the revised Pre-Rule Change Proposal and the proposed changes to the energy sector governance arrangements. Mrs Papps, Ms Ng, Ms Ryan, Mr Maticka and Mr Peter Huxtable indicated that they were available on the proposed date, and the Chair asked remaining members to contact RCP Support by 27 October 2020 if they were unavailable on 17 November 2020. **Action: MAC members to advise RCP Support by Tuesday 27 October 2020 if they are unable to attend a MAC meeting on 17 November 2020.**	**All**
9	**2020 Review of Two Market Rules Intended to Incentivise the Availability of Generators** Mr Richard Cheng gave a presentation on the draft report findings of the ERA's 2020 review on two market rules (clauses 4.11.1(h) and 4.26.1C) intended to incentivise the availability of generators. A copy of the ERA's presentation is available in the meeting papers. Mr Cheng noted that the consultation period for the draft report closed at 4:00 PM on 13 November 2020. Due to the 31 December 2020 publication deadline for the final report, the ERA would not be able to grant any extensions to the consultation period. Ms Jenny Laidlaw asked why the ERA proposed to reduce the threshold levels associated with clause 4.11.1(h) to zero, and what the guidance to AEMO on the application of clause 4.11.1(h) would entail. Mr Cheng replied that the reason for the reduction of the thresholds to zero was the relatively arbitrary nature of the figures. The guidance would need to stipulate the factors that AEMO should consider. Several of those factors were already in the Market Rules, but the ERA would need to expand on that information to ensure that Market Participants were fully aware of what was being calculated and how AEMO would decide which generators to assess. For example, if a generator was of a material nature to the WEM and reducing its CRC would not be conducive to the Wholesale Market Objectives, then, as per the current Market Rules, AEMO	

Item	Subject	Action
	would not reduce that generator's CRC. The ERA would put guidance to this effect in the proposed document. There were also questions about how to estimate the likely future output of generators. The ERA would need to determine what it should look at for developing the guidance, in consultation with AEMO and industry. Ms Laidlaw noted that there were two different approaches to assigning Capacity Credits and calculating capacity refunds. For example, under the current Market Rules Scheduled Generators were usually assigned Capacity Credits based on what they could generate at 41 degrees, and the potential for some of them to be unavailable during peak periods was handled through the 7.6% reserve margin. In contrast, many American jurisdictions used an 'unforced capacity' (UCAP) approach, where Capacity Credits were de-rated to reflect some expectation of a generator's forced outages. Generators were still expected to offer their full capacity under a UCAP regime, and the capacity refund arrangements were correspondingly different. Ms Laidlaw was uncertain whether the ERA considered the WEM had a flawed UCAP regime that needed some adjustments, or whether it considered the WEM should change to a UCAP regime. Mr Cheng replied that the review was meant to highlight the differences between the two regimes. The ERA had put forward what it believed was a potentially more efficient, or more accurate regime (i.e. the UCAP regime), but acknowledged that currently the WEM used the reserve margin approach. The ERA considered its proposed changes would act as a foundational stepping-stone towards moving to a UCAP regime. Ms Laidlaw asked what CRC the guidance would propose for a Scheduled Generator with an expected 15% outage rate. Mr Cheng replied that it would be necessary to determine the gap between the expected outage rate and what was already accounted for through the reserve margin, and that the facility's CRC might be reduced to the extent of that gap. However, Mr Cheng noted that AEMO might decide not to reduce the CRC for other reasons. The ERA sought to allow flexibility for AEMO to do what it thought was necessary, but also to allow it to reduce the CRC of generators that are potentially not going to provide the required level of adequacy.	
10	**General Business** No general business was discussed.	

The meeting closed at 11:05 AM

RCP Rule Change Panel
Market Advisory Committee

Agenda Item 4: MAC Action Items

Meeting 2020_11_17

Shaded	Shaded action items are actions that have been completed since the last Market Advisory Committee (**MAC**) meeting.
Unshaded	Unshaded action items are still being progressed.
Missing	Action items missing in sequence have been completed from previous meetings and subsequently removed from log.

Item	Action	Responsibility	Meeting Arising	Status
21/2020	RCP Support to publish the minutes of the 8 September 2020 MAC meeting on the Rule Change Panel's (**Panel**) website as final.	RCP Support	2020_10_20	**Closed** The Minutes were published on the Panel's website on 20 October 2020.
22/2020	MAC members to advise RCP Support by Tuesday 27 October 2020 if they are unable to attend a MAC meeting on 17 November 2020.	RCP Support	2020_10_20	**Closed** No MAC members indicated that they would be unavailable to attend a MAC meeting on 17 November 2020.

RCP Rule Change Panel
Market Advisory Committee

Agenda Item 5: RC_2019_03: Method used for the assignment of Certified Reserve Capacity to Intermittent Generators – Pre-Rule Change Proposal

Meeting 2020_11_17

1. Background

The Market Rules require the Economic Regulation Authority (**ERA**) to undertake regular reviews of the method used for assignment of Certified Reserve Capacity (**CRC**) to Intermittent Generators (the Relevant Level Methodology (**RLM**)). The ERA must undertake these reviews every three years and must submit a Rule Change Proposal (**Proposal**) depending on the outcome of the review.[1]

The ERA completed a 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.[2]

The ERA presented and discussed its review of the RLM at the 30 April 2019 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 (**ETS**).

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 2019 MAC meeting. The ERA noted that:

- it saw no conflict between the proposed RLM and the proposed NAQ framework (based on the draft Amending Rules that ETIU had shared with the ERA) and that the ERA was undertaking sensitivity analysis to assess the impact of the interaction effect;

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1 This function was transferred from the IMO to the ERA on 1 July 2016. The transitional provisions in the Market Rules provided that the ERA did not have to conduct its first review of the RLM before 1 April 2019.

2 https://www.erawa.com.au/cproot/20328/2/Relevant%20level%20method%20review%202018%20-%20Final%20report.pdf.

- it was amending the PRC to account for:
    - the introduction of storage facilities; and
    - hybrid Facilities.

At the 20 October 2020 MAC meeting, RCP Support and AEMO raised several concerns with the PRC, including that the proposed RLM may be inconsistent with the Planning Criterion and the Reserve Margin, as indicated in the minutes from that meeting (see Agenda Item 3).

On 23 October 2020 ETIU published the draft Amending Rules for the NAQ framework.

2. The Pre-Rule Change Proposal

On 10 November 2020, the ERA submitted the attached updated Pre-Rule Change Proposal: Method used for the assignment of Certified Reserve Capacity to Intermittent Generators (RC_2019_03) to RCP Support for presentation to the MAC, including the following supporting documents:

- additional scenario analysis prepared by the Lantau Group (Appendix 4 – Additional modelling scenarios run by Lantau Group);
- an informal summary prepared by RCP Support of the concerns it had raised at the 20 October MAC meeting (Appendix 5 – Summary of RCP Support feedback);
- a document addressing the concerns raised by RCP Support and AEMO and explaining the changes made to accommodate the recently published draft Amending Rules to implement the NAQ framework (Appendix 3 – Changes since the previous version of the proposal)

At the time of writing this cover paper, RCP Support had not had sufficient time to review the documents provided by the ERA in their entirety nor to formulate specific questions for consideration by the MAC.

Based on a preliminary review of Appendix 3 to the PRC, RCP Support believes that the ERA has misunderstood the nature of RCP Support's concerns related to the Planning Criterion and the Reserve Margin. RCP Support will endeavour to clarify this misunderstanding with the ERA before the 17 November MAC meeting.

3. Discussion pf the Pre-Rule Change Proposal

The ERA may submit RC_2019_03 at any time, but is seeking feedback from the MAC prior to submitting the Proposal. The MAC is asked to provide feedback to the ERA to assist the ERA in finalising its Proposal.

4. Urgency Rating of Rule Change Proposal

The ERA suggested in the PRC that RC_2019_03 should be given a 2 – High urgency rating and that it should be implemented before the upcoming 2021 Reserve Capacity Cycle.

The Rule Change Panel (**Panel**) will decide whether to process RC_2019_03 once the ERA formally submits the Proposal, and if the Panel decides to progress the Proposal, will decide what urgency rating to assign to the Proposal. The MAC is asked to recommend to the Panel an urgency rating for RC_2019_03 using the Framework for Rule Change Proposal Prioritisation and Scheduling, as presented in the table below.

Urgency	Description	Resourcing Implications

1	**Essential**
	The Proposal:
	• is a legal necessity;
	• addresses unacceptable outcomes for the Wholesale Electricity Market or the gas market; or
	• addresses a serious threat to:
	  ○ power system security and reliability; or
	  ○ security, reliability or availability of the supply of natural gas in the State.
		Do not delay – acquire additional resources, and request an increase to the ERA budget from Treasury if necessary.

2	**High** The Proposal is compelling and is: • likely to have a large net benefit; and/or • necessary to avoid serious perverse market outcomes.	Do not delay – acquire additional resources if available, subject to overall ERA budget limitations.
3	**Medium** The net benefit of the Proposal: • may be large but needs more analysis to determine; or • is material but not large enough to warrant a High rating.	Delay up to 3 months if budgeted resources are unavailable.
4	**Low** The Proposal has minor net benefit (e.g. reduced administration costs).	Delay up to 6 months if budgeted resources are unavailable.
5	**Housekeeping** The Proposal has negligible market benefit (e.g. it improves the readability of the Market Rules or GSI Rules).	Delay up to 12 months if budgeted resources are unavailable.

Attachments

1. RC_2019_03 – Pre-Rule Change Proposal
2. PRC Appendix 1 – Marked up changes to the market rules
3. PRC Appendix 2 – Updated Wholesale Electricity Market Rules, no tracked changes
4. PRC Appendix 3 – Changes implemented to the previous rule change proposal and modelling scenarios
5. PRC Appendix 4 – Additional modelling scenarios developed in October 2020
6. PRC Appendix 5 – Summary of RCP Support's main concerns about the Relevant Level Method proposed in RC_2019_03

Wholesale Electricity Market Rule Change Proposal

Rule Change Proposal ID: *[to be filled in by the RCP]*
Date received: *[to be filled in by the RCP]*

Change requested by:

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Date submitted:	17 November 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 1.17.5, 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

[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 developed other changes to the existing rule change proposal to enhance the relevant level 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.

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 emerging technologies such as storage.

The current RLM is not technology neutral. For instance, it does not account for the capacity contribution of facilities that shift the periods with high reliability risk from peak demand periods

to other periods when the surplus of capacity in the system is lowest. This is particularly important with the uptake of renewable energy technologies and storage 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 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.

[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).

- 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 3 and 4.

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 Facility").

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

- the full operation date of a Candidate Facility for the Reserve Capacity Cycle ("Full Operation Date") is:
  - 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
  - the date most recently provided for a Reserve Capacity Cycle under clause 4.10.1(k) otherwise; ~~and~~
- a Candidate Facility will be considered to be:
  - a new candidate Facility, if the five 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
  - an existing Candidate Facility ("Existing Candidate Facility"), otherwise.
- each Candidate Facility will be assigned to one of the following facility groups, based on the technology, Facility type and Facility Class of that Candidate Facility, as determined by AEMO based on the information received under clauses 4.10.1 and 2.33.3 and the requirements of clauses 4.11.1(bD)(i) and 4.11.1(bE):

- biogas technology group ("Biogas Facility Group"), or
- solar technology group ("Solar Facility Group"), or
- wind technology group ("Wind Facility Group"), or
- non-scheduled Electric Storage Resources group comprising Facilities to which clause 4.11.1(bD)(i) applies ("Non-scheduled ESR Facility Group"), or
- non-scheduled Facilities group comprising Facilities to which clause 4.11.1(bE) applies ("Other Non-scheduled Facility Group").

- 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 assignment of a Candidate Facility to any other facility group than the new facility group can contribute to a material under-estimation or over-estimation of the Relevant Level for that Candidate Facility or other Candidate Facilities that have applied for the certification of Reserve Capacity under clause 4.11.2(b).
- For the purpose of the calculation in this Appendix 9, the individual Facilities, other than those that are Electric Storage Resource, within an aggregated Facility that is 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.
- The available capacity of a Candidate Facility for a Trading Interval is the amount of capacity available to be sent out (in MW) and, for emphasis, is not on Planned Outage or Forced Outage ("Available Capacity").

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

Determining ~~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) any 12 month period, from 1 April to 31 March, 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 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), that would have been available 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.

(c) for each Candidate Facility that is a component of an aggregated Facility 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~~

~~(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(a)~~ 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 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.~~

Step 7: Determine for each Trading Interval in ~~each 12 month period identified in step 1(b) the Existing Facility Load for Scheduled Generation (in MWh) as~~ Step 1(a):

(a) the Observed Demand (in MW) as:

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

where:

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

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

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);

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) for each 12-month period T identified in Step 1(b), the Scaled Demand 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:

the maximum of $Scaled\ Demand(t)$ for all Trading Intervals during the period T equals AEMO's estimate of one in ten year peak demand assuming expected demand growth, as determined for the purpose of clause 4.5.10(a)iv for the Capacity Year 3 of the relevant Reserve Capacity Cycle;

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 Capacity Year 3 of the relevant Reserve Capacity Cycle; and

the function form of $f(t)$ must be consistent with the scaling function AEMO uses to scale historical demand in the SWIS and forecast the expected energy shortfalls in the SWIS for the purpose of clause 4.5.9(b).

(c) for each Facility Group c, the $CF\_Generation(c)$ 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.

For Existing Candidate Facilities:

- the $Actual\_CF\_Generation(f)$ for the Trading Interval is the Sent Out Generation determined in Step 2(a), or estimated in Step 3(c), Step 5, or half of the quantity determined in Step 2(c), as applicable, and
- the $Estimated\_CF\_Generation$ is zero.

For New Candidate Facilities:

- 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 3(c) or Step 5, or half of the quantity determined in Step 2(c), as applicable, and zero otherwise; and
- 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) 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 will receive Certified Reserve Capacity for the Capacity Year 3 of the relevant Reserve Capacity Cycle, other than those included in the set of Candidate Facilities. For each Electric Storage Facility f_s, $AC\_ESR(f_s)$ (in MW):

- is equal to zero, outside the Electric Storage Resource Obligation Intervals;
- 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;
- is equal to the maximum output AEMO determines for the Facility as per clause 4.11.3, otherwise.
- For each Trading Interval during the Electric Storage Resource Obligation Intervals and each Electric Storage Facility f_s, the value of p should be drawn randomly from a uniform distribution of the range between zero and one.
- For each Electric Storage 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 under clause 4.11.1(h), and otherwise if not available, those values provided to AEMO under 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"):

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

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), the 12 Trading Intervals~~,~~ occurring on separate Trading Days~~, with the highest Existing Facility Load for Scheduled Generation~~ with the highest Scaled 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 18, 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 18, 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 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).

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 2(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) AEMO~~System Management ~~has determined a revised estimate under clause 7.13.7~~of 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:

$$\frac{AFP\_Facility\_Group\_RL(c)}{\sum_c AFP\_Facility\_Group\_RL(c)} \times (RL\ Fleet\ -\ \sum_{c \in \{\forall c | i(c)=0\}} Facility\ Group\ RL(c))$$

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

Step11: ~~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 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, 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 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 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 as Scheduled Facilities, or as part of a Scheduled Facility, and loads registered as Demand Side Programme that will receive Certified Reserve Capacity for the Capacity Year 3 of the relevant Reserve Capacity Cycle, using the method in clause 4.11;

(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 all Facilities identified in Step 14(a), the quantity of Certified Reserve Capacity to be assigned to generation systems in accordance with clause 4.11.1(a) and the quantity of Certified Reserve Capacity to be assigned to Demand Side Programme for the Capacity Year 3 of the relevant Reserve Capacity Cycle;

(c) the forced outage rate, estimated using Power System Operation Procedure: Facility Outages (for the purpose of clause 4.11.1(h)), 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 Step14(a) set the parameter U as the average of the three forced outage rates for the three Reserve Capacity Cycles identified in this clause 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 Demand Side Programme, identified in paragraph (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 Forced Outage Rate U identified in Step 14, 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.

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.

In the equation in this Step 15(a),

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

$P'(X)$ 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 for a Trading Interval with a system load of D MW as ("Loss of Load Probability");

$$P(CC - D)$$

where,

CC is the total Certified Reserve Capacities assigned to Facilities identified in Step 14;

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

(b) the loss of load expectation 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 in the SWIS 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 closest 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 ten years as $LOLE\_adjustment1$.

(c) Calculate the Loss of Load Expectation in the SWIS using the calculation in Step 16(b) and (Scaled Demand – $Storage\ Available\ Capacity$), rounded to the nearest integer, as system load during the $Relevant\_Period$. Increase the system load in this paragraph with increments of whole MW and fixed across all Trading Intervals in the $Relevant\_Period$, until the Loss of Load Expectation is equal or closest to eight Trading Intervals in ten years. Identify the total amount of increase in the system load in this paragraph that makes the Loss of Load Expectation equal to eight Trading Intervals in 10 years as $LOLE\_adjustment2$.

(d) Calculate the Loss of Load Expectation in the SWIS 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 $Relevant\ Period$.

(e) Increase the $Net\ Load$ data in paragraph (d), with increments of whole MW and fixed across all Trading Intervals in the $Relevant\ Period$, and repeat the calculation in Step 17(d) with the increased $Net\ Load$ data until the Loss of Load Expectation calculated in Step 17(d) is equal or closest 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(e) that makes the Loss of Load Expectation calculated in Step 17(d) equal or closest to eight Trading Intervals in 10 years.

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

Step 18: Publish on the Market Web Site by 1 June of Year 1 of the relevant Reserve Capacity Cycle a provisional forecast of the Trading Intervals that may be identified in Step 8.~~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: 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

4.9.5. 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 assigned to the capacity.

(b) 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) 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) 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.

…

4.10.2. ~~[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 Method~~ology~~.

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 part 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 the Relevant Level Method;

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 part 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, or clause 4.10.3B as applicable, must include:

(a) for each Trading Interval during the period identified in step 1(a) of the Relevant Level Method~~ology,~~ 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;

…

...

4.11.2. 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) and 4.11.2(c).

(c) 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 according to paragraph (b) and any available Certified Reserve Capacity assigned to the relevant Facility in the two preceding Reserve Capacity Cycles. This paragraph 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. The effect of this clause ceases on three reserve capacity after this clause first takes effect.

…

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~~;

…

4.11.3C. 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.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 the Relevant Level Method, 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.

…

10.5.1. 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 calculated in Step 7(b) determined for each Trading Interval in the period identified in Step 1(a).

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) determined for each Trading Interval in the period identified in Step 1(a).

3. the Capacity Outage Probability Table calculated in Step 16.

4. the $Annual\_RL\_Fleet$ determined in Step 9(a).

5. the $Full\_Period\_RL\_Fleet$ estimated in Step 9(b).

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

7. For each facility group c determine the $Scaling\_Factor(c)$.

Changes to Chapter 11 (Glossary)

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

Remove the following definitions from the glossary, because they are no longer used in Appendix 9**:**

- **Existing Facility Load for Scheduled Generators**
- **New Facility Load for Scheduled Generation**.

Some new definitions in Appendix 9 may be useful for application in other market rules in the future. Add the following definitions to the glossary:

Observed Demand: is 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 the relevant level method.

Appendix 2 Updated Wholesale Electricity Market Rules, no tracked changes

The following market rules will be the version after the Relevant Level Method rule change and the EPWA's tranches of Amending Rules have been made.

Appendix 9: Relevant Level Determination

This Appendix presents the method 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 Facility").

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

- the full operation date of a Candidate Facility for the Reserve Capacity Cycle ("Full Operation Date") is:
    - 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
    - the date most recently provided for a Reserve Capacity Cycle under clause 4.10.1(k) otherwise;
- a Candidate Facility will be considered to be:
    - a new candidate Facility, if the five 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
    - an existing Candidate Facility ("Existing Candidate Facility"), otherwise.
- each Candidate Facility will be assigned to one of the following facility groups, based on the technology, Facility type and Facility Class of that Candidate Facility, as determined by AEMO based on the information received under clauses 4.10.1 and 2.33.3 and the requirements of clauses 4.11.1(bD)(i) and 4.11.1(bE):
    - biogas technology group ("Biogas Facility Group"), or
    - solar technology group ("Solar Facility Group"), or
    - wind technology group ("Wind Facility Group"), or

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

- 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 assignment of a Candidate Facility to any other facility group than the new facility group can contribute to a material under-estimation or over-estimation of the Relevant Level for that Candidate Facility or other Candidate Facilities that have applied for the certification of Reserve Capacity under clause 4.11.2(b).
- For the purpose of the calculation in this Appendix 9, the individual Facilities, other than those that are Electric Storage Resource, within an aggregated Facility that is 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.
- The available capacity of a Candidate Facility for a Trading Interval is the amount of capacity available to be sent out (in MW) and, for emphasis, is not on Planned Outage or Forced Outage ("Available Capacity").

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

Determining 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) any 12 month period, from 1 April to 31 March, 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 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), that would have been available 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.

(c) for each Candidate Facility that is a component of an aggregated Facility 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)].

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 containing an Electric Storage Resource.

Step 5: [Blank]

Step 6: [Blank]

Step 6A: [Blank]

Step 7: Determine for each Trading Interval in Step 1(a):

(a) the Observed Demand (in MW) as:

(Total_Generation + DSP_Reduction + Interruptible_Reduction + Involuntary_Reduction) x 2

where:

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

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

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

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

(b) for each 12-month period T identified in Step 1(b), the Scaled Demand 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:

the maximum of $Scaled\ Demand(t)$ for all Trading Intervals during the period T equals AEMO's estimate of one in ten year peak demand assuming expected demand growth, as determined for the purpose of clause 4.5.10(a)iv for the Capacity Year 3 of the relevant Reserve Capacity Cycle;

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 Capacity Year 3 of the relevant Reserve Capacity Cycle; and

the function form of $f(t)$ must be consistent with the scaling function AEMO uses to scale historical demand in the SWIS and forecast the expected energy shortfalls in the SWIS for the purpose of clause 4.5.9(b).

(c) for each Facility Group c, the $CF\_Generation(c)$ 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.

For Existing Candidate Facilities:

- the $Actual\_CF\_Generation(f)$ for the Trading Interval is the Sent Out Generation determined in Step 2(a), or estimated in Step 3(c), Step 5, or half of the quantity determined in Step 2(c), as applicable, and
- the $Estimated\_CF\_Generation$ is zero.

For New Candidate Facilities:

- 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 3(c) or Step 5, or half of the quantity determined in Step 2(c), as applicable, and zero otherwise; and
- 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) 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 will receive Certified Reserve Capacity for the Capacity Year 3 of the relevant Reserve Capacity Cycle, other than those included in the set of Candidate Facilities. For each Electric Storage Facility f_S, $AC\_ESR(f_S)$ (in MW):

- is equal to zero, outside the Electric Storage Resource Obligation Intervals;
- 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;
- is equal to the maximum output AEMO determines for the Facility as per clause 4.11.3, otherwise.
- For each Trading Interval during the Electric Storage Resource Obligation Intervals and each Electric Storage Facility f_S, the value of p should be drawn randomly from a uniform distribution of the range between zero and one.
- For each Electric Storage 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 under clause 4.11.1(h), and otherwise if not available, those values provided to AEMO under 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"):

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

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), the 12 Trading Intervals occurring on separate Trading Days with the highest Scaled Demand.

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

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).

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 2(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:

(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:

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

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

Step11: 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 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:

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

Calculation of Capacity Outage Probability Table

Step 14: Identify:

(a) all generation systems registered as Scheduled Facilities, or as part of a Scheduled Facility, and loads registered as Demand Side Programme that will receive Certified Reserve Capacity for the Capacity Year 3 of the relevant Reserve Capacity Cycle, using the method in clause 4.11;

(b) For all Facilities identified in Step 14(a), the quantity of Certified Reserve Capacity to be assigned to generation systems in accordance with clause 4.11.1(a) and the quantity of Certified Reserve Capacity to be assigned to

Demand Side Programme for the Capacity Year 3 of the relevant Reserve Capacity Cycle;

(c) the forced outage rate, estimated using Power System Operation Procedure: Facility Outages (for the purpose of clause 4.11.1(h)), 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 Step14(a) set the parameter U as the average of the three forced outage rates for the three Reserve Capacity Cycles identified in this clause 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 Demand Side Programme, identified in paragraph (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 Forced Outage Rate U identified in Step 14, 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.

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.

In the equation in this Step 15(a),

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

$P'(X)$ 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 for a Trading Interval with a system load of D MW as ("Loss of Load Probability");

$$P(CC - D)$$

where,

CC is the total Certified Reserve Capacities assigned to Facilities identified in Step 14;

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

(b) the loss of load expectation 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

(a) Calculate the Loss of Load Expectation in the SWIS 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 within 0.1 Tranding Interval of the eight Trading Intervals in 10 years. Identify the total amount of increase in Scaled Demand that makes the Loss of Load Expectation closest to eight Trading Intervals in ten years as $LOLE\_adjustment1$.

(c) Calculate the Loss of Load Expectation in the SWIS using the calculation in Step 16(b) and (Scaled Demand – $Storage\_Available\_Capacity$), rounded to the nearest integer, as system load during the $Relevant\_Period$. Increase the system load in this paragraph with increments of whole MW and fixed across all Trading Intervals in the $Relevant\_Period$, until the Loss of Load Expectation is within 0.1 Trading Interval of the eight Trading Intervals in ten years. Identify the total amount of increase in the system load in this paragraph that makes the Loss of Load Expectation closest to eight Trading Intervals in 10 years as $LOLE\_adjustment2$.

(d) Calculate the Loss of Load Expectation in the SWIS 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 $Relevant\_Period$.

(e) Increase the Net_Load data in paragraph (d), with increments of whole MW and fixed across all Trading Intervals in the $Relevant\_Period$, and repeat the calculation in Step 17(d) with the increased Net_Load data until the Loss of Load Expectation calculated in Step 17(d) is within 0.1 Trading Interval of 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(e) that makes the Loss of Load Expectation calculated in Step 17(d) closest to eight Trading Intervals in 10 years.

Publication of information

Step 18: Publish on the Market Web Site by 1 June of Year 1 of the relevant Reserve Capacity Cycle a provisional forecast of the Trading Intervals that may be identified in Step 8.

Step 19: [Blank]

Changes to other market rules

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 assigned to the capacity.

(b) 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) 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

(d) 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.

…

4.10.2. 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 the Relevant Level Method.

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 part 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 the Relevant Level Method;

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 part 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, or clause 4.10.3B as applicable, must include:

(a) for each Trading Interval during the period identified in step 1(a) of the Relevant Level Method 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;

…

...

4.11.2. 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), 4.11.1(i) and 4.11.2(c).

(c) 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 according to paragraph (b) and any available Certified Reserve Capacity assigned to the relevant Facility in the two preceding Reserve Capacity Cycles. This paragraph 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. The effect of this clause ceases on three reserve capacity after this clause first takes effect.

…

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 41°C;

(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;

…

4.11.3C. 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.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 the Relevant Level Method, 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.

…

10.5.1. 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 calculated in Step 7(b) determined for each Trading Interval in the period identified in Step 1(a).
2. the Residual Demand calculated in Step 7(e) determined for each Trading Interval in the period identified in Step 1(a).
3. the Capacity Outage Probability Table calculated in Step 16.
4. the $Annual\_RL\_Fleet$ determined in Step 9(a).
5. the $Full\_Period\_RL\_Fleet$ estimated in Step 9(b).
6. for each facility group c the $Facility\_Group\_RL(c)$ calculated in Step 9(c).
7. For each facility group c determine the $Scaling\_Factor(c)$.

Changes to Chapter 11 (Glossary)

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

Remove the following definitions from the glossary, because they are no longer used in Appendix 9**:**

- **Existing Facility Load for Scheduled Generators**
- **New Facility Load for Scheduled Generation**.

Some new definitions in Appendix 9 may be useful for application in other market rules in the future. Add the following definitions to the glossary:

Observed Demand: is 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 the relevant level method.

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

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. A rule change proposal is now being progressed after a delay to address possible interactions between the proposed RLM rule change 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 and outlines the amendments made to the pre-rule change proposal, now that there is more clarity on EPWA's proposal for allocating capacity credits in a constrained network environment. To draft these changes, the ERA has worked from draft amending rules provided by EPWA, assuming that no major changes to EPWA's proposal arise following its consultation process, which closes in late November 2020.

The ERA has implemented changes to improve the application of the proposed method. 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] The results of modelling scenarios based on the enhanced method indicate that the current RLM underestimates the capacity value of intermittent generators in the SWIS.

2. Background

In March 2019, the ERA's final report on its review of the RLM established 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]

In July 2019, the Market Advisory Committee 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 the Minister for Energy's changes to the market rules were published. The delay would allow the

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.

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).

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.[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 Market Advisory Committee, 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 Market Advisory Committee Meeting and feedback received from stakeholders from July 2019.

3. Amendments to the pre-rule change proposal

The minor amendments in response to EPWA's proposed changes are discussed in 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.[7] 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

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

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

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.[8] 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.[9]

EPWA has proposed a new framework for the registration and participation of facilities in the WEM.[10] 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. The ERA is of the view that this concern may be based on a misunderstanding of available capacity and

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

9 EPWA's proposed amendments to the rules define:

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".

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

certified reserve capacity (CRC). These concepts are explained below. No changes to the pre-rule change proposal are necessary based on 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 difference between the capacity value set for the fleet of intermittent generators and the minimum of the capacity value sample produced. 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 Market Advisory Committee 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 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 demand scenario including a reserve margin of 7.6% to account for the likelihood that not all Certified Reserve Capacity will be available.[11]

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.[12][13]

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

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11 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 will be published on the ERA website in due course (online).

12 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.

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

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 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.[14] 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

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

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.[15] The proposed method estimates 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.[16]

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.[17] 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

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15 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 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).

16 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.

17 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].

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, 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.[18]

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.

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

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 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 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.[19] 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 hour per 10 year (or eight hours per year).[20]
- France's electricity system targets LOLE=3 hours per year.
- The Netherlands' electricity system targets LOLE=4 hours per year.[21]

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 seek to avoid the occurrence of loss of load. This expectation of the duration of a typical loss of load event

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19 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.

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

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

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.

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.[22]

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

[22] 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).

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.

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.[23] 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

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

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 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, they calculated 14 annual wind-fleet ELCC values (one for each year between 2005 and 2018). They set the wind-fleet ELCC equal to the average of the 14 values.[24]
- The Southwest Power Pool in the United States uses the historical output of solar and wind in the past five year 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.[25]
- Recently, the PJM Interconnection adopted the use of ELCC for the capacity valuation of intermittent generators and storage. PJM proposed to use ten 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.[26] 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

[24] PJM Interconnection, 2020, *Effective load carrying capability (ELCC)*, p. 14, (online).

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

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

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.[27] 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.

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.[28]
- 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.[29]
- 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.[30]

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

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

28 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).

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

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

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.[31] 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.

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.[32]

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 that 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 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.

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

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

The ERA's expectation was that this potential bias would be small and 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.[33]

In the Market Advisory Committee 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 considered in the planning criterion.[34] 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.[35] 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.

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33 Ibid, p. 61.

34 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 will be published on the ERA website in due course (online).

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

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.[36]

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 related to 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 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.[37]

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.[38] 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).[39]

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.[40] The implementation of the new

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

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

38 Ibid.

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

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

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 in the system in the sampled period to that AEMO expects to reflect the system demand profile that would 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 equal to 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.

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:

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

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,

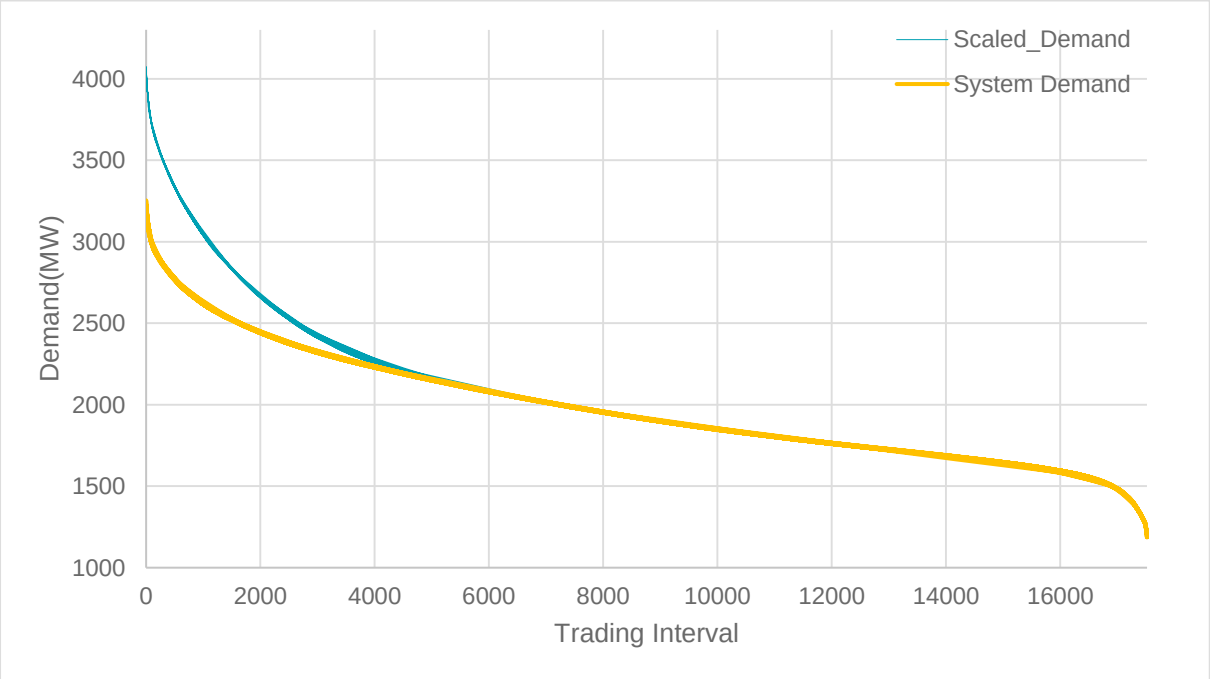
n denotes the total number of trading intervals in a year,

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

This scaling function is equal to 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.[41]

Section 5 demonstrates the effect of the scaling function introduced above on the results of the proposed method. Figure 2 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



[41] 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).

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.

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 impact 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 Market Advisory Committee 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. [42]

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.

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.[43]

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:

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[42] 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).

[43] Wholesale Electricity Market Rules (WA), 7 August 2020, Clause 4.24.

- 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.

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:

1. Using the best available information at the time of running the RLM, including the expected resource in the system at the target capacity year.

2. 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 principle guiding the design of the NAQ framework was 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 consulted with the ERA on the proposed RLM.[44]
- EPWA has indicated the principles for the calculation of NAQ.[45] 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.[46] 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.

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44 Energy Transformation Taskforce, 2020, *Explanatory Memorandum: Proposed amending rules to the Wholesale Electricity Market Rules – Tranche 3*, p. 3, (online).

45 EPWA, 2020, 'Draft amending rules for reserve capacity mechanism and the network access quantity framework (ME V09)', clause 4.15, (online).

46 Energy Transformation Taskforce, 2020, *Explanatory Memorandum: Proposed amending rules to the Wholesale Electricity Market Rules – Tranche 3*, p. 6, (online).

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 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 the market settlement purpose, equal 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.

In the Market Advisory Committee 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.[47]

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 either of 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.

[47] The metering protocol – including audit, error filtering process and dispute resolution process – for such meters is stipulated in Chapter 8 of the market rules.

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. The rest of this paper 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.

Section 4 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 5 presents the application of scaled demand in the proposed method, as discussed in section 3.2.6.

Appendix 4 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.

4. 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.[48]

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

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

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 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.

4.1 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.[49] 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.[50] Results of the enhanced sample model are presented in Table 2. 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.

[49] This calculation only considers those Candidate Facilities that eventually received capacity credits in the 2017 Reserve Capacity Cycle.

[50] The error in input data was due to using actual sent out generation for New Candidate Facilities before the Full Operation Date.

Table 2. 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)):

$$Relevant\_Level\_Candidate\_Facilities\_Fleet = \min\{median(214,403,196,266,193), 264\} = 214\ MW$$

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 3 shows the Relevant Level of facilities in each Technology Class as a group calculated based on Step 11(b). Using the results in Table 3 and the calculation Steps 11(c), the amount of interaction between solar and wind technology classes is:

$$Solar\_Wind\_Interaction\_Effect = 214 - (14.7 + 39 + 159) = 1.3\ MW$$

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 4. 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 3. 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 4. 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 5.

Table 5. 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 5 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 6 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 6. 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

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)
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.*

4.2 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 4.4 includes those four facilities in the calculation.

The capacity value results for the fleet of Candidate Facilities in 2018 are presented in Table 7. 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 7. 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 8 shows the Relevant Level of facilities in each Technology Class as a group calculated based on Step 11(b). Using the results in Table 8 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 9. 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 10. 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 8. 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 9. 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 11 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 10. 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 11. 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

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)
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
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.*

4.3 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 4.1 and 4.2 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 12.

Table 12. 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

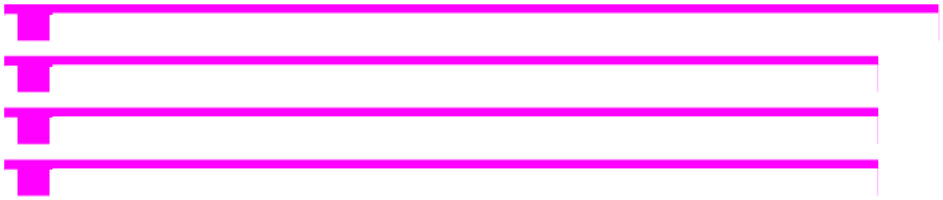
Candidate_Facility	2016/17	2017/18	2018/19	Appendix 9 results (2019/20)	Appendix 9 results (2020/21)	2019/20 Certified Reserve Capacity assigned based on proposed clause 4.11.2(c)	2020/21 Certified Reserve Capacity Assigned based on proposed clause 4.11.2(c)
INVESTEC_COLLGAR_WF1	15.048	20.105	20.567	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

4.4 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:



- The analysis provided in section 4.2 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 4.2 will provide an indication of the sensitivity of results to the changes in the generation mix.

Results for the whole applications scenario

Table 13 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 13. 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 14 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 14. 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 4.4, can mitigate the variation in the results.

The technology class capacity values after adjustment for the interaction effect are presented in Table 15.

Table 15. 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 16, 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 16. 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]			
[redacted]			
[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.*

4.5 Improvement to the calculation of facility class capacity values

The analysis provided in section 4.4 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 17 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 significantly differs across the two scenarios:

- For the progressed applications scenario the selected period was 2016/17. Results in Table 8 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 17.

Table 17. 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 18.

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 18. 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 19.

Table 19. 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 20.

Table 20. 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]		
[redacted]		
[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.

4.6 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 21 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 21. 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.

5. Effect of using scaled demand in the calculation

As explained in section 3.2.6, 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.

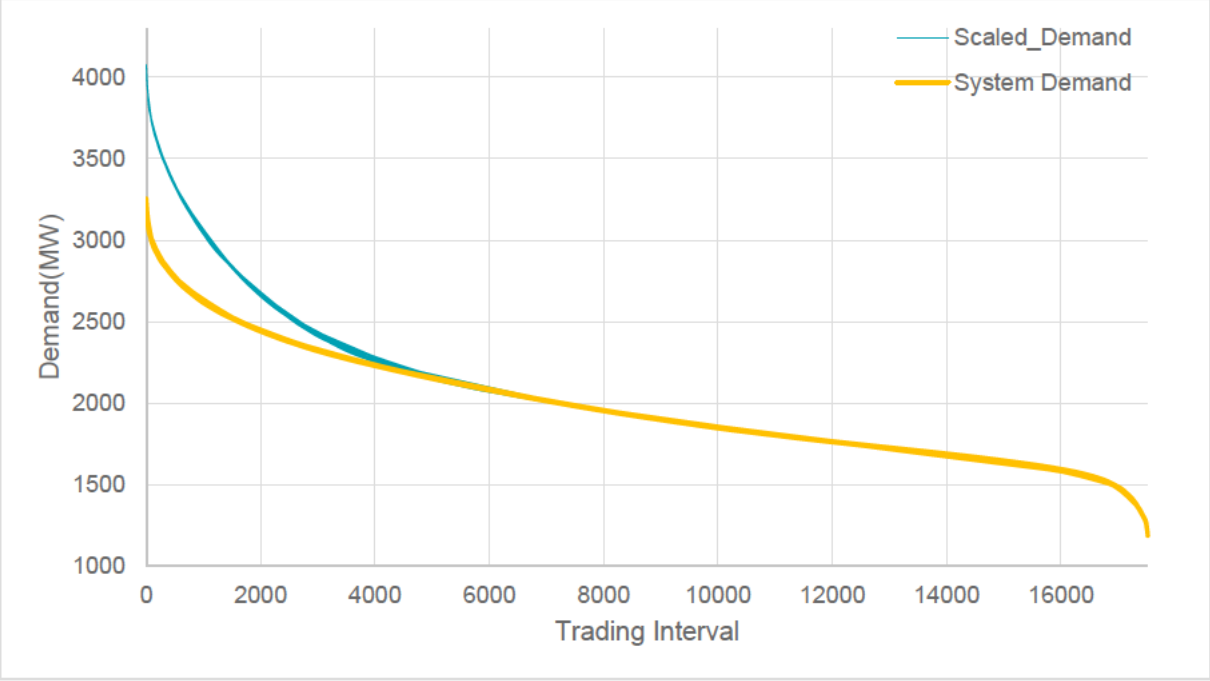
Among all scaled demands for the sampled years, Figure 2 depicts the scaled and observed load duration curve in the 2018/19 sampled year used in the modelling scenario. The highest demand in the scaled load duration curve is consistent with AEMO expectation of 10% PoE peak demand in the SWIS for the 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 22 for the scaling function $f(t)$ introduced in section 3.2.6.

Table 22. 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 2. 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 23.

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 23. 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 24.

Table 24. 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 in Table 25 and Table 26. 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 25. Allocated Relevant Level to Candidate Facilities (2019 Reserve Capacity Cycle – LOLE target = 24 hours in 10 years, scaled demand)

Facility	Maximum Capacity (MW)	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	21.6	8.99	5.162	24%	5.29	-0.132
ALINTA_WWF	89.1	40.58	23.311	26%	17.19	6.126
AMBRISOLAR_PV1	0.96	0.29	0.261	27%	0.20	0.063
BADGINGARRA_WF1	147.5	72.15	41.447	28%	26.87	14.573
BIOGAS01	2	1.28	1.309	65%	1.18	0.129
BLAIRFOX_KARAKIN_WF1	5	1.09	0.626	13%	0.49	0.140
BREMER_BAY_WF1	0.6	0.27	0.155	26%	0.17	-0.011
DCWL_DENMARK_WF1	1.44	0.67	0.386	27%	0.36	0.022
EDWFMAN_WF1	80	33.87	19.457	24%	16.21	3.248
GRASMERE_WF1	13.8	6.26	3.597	26%	3.71	-0.115
GREENOUGH_RIVER_PV1	40	12.00	10.800	27%	7.38	3.423
HENDERSON_RENEWABLE_IG1	3	1.69	1.725	58%	1.63	0.093
INVESTEC_COLLGAR_WF1	206	62.14	35.698	17%	15.82	19.875
KALBARRI_WF1	1.6	0.49	0.282	18%	0.26	0.023

Facility	Maximum Capacity (MW)	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)
MERSOLAR_PV1	100	35.96	32.370	32%	16.32	16.050
MWF_MUMBIDA_WF1	55	19.19	11.021	20%	7.03	3.992
NORTHAM_SF_PV1	10	2.69	2.424	24%	1.80	0.626
RED_HILL	3.64	2.94	3.003	82%	2.84	0.161
ROCKINGHAM	4	2.42	2.471	62%	2.32	0.148
SKYFRM_MTBARKER_WF1	2.43	0.99	0.566	23%	0.52	0.045
SOUTH_CARDUP	4.158	2.99	3.051	73%	2.97	0.085
TAMALA_PARK	4.8	4.35	4.441	93%	4.35	0.090
WARRADARGE_WF1	183.6	92.64	53.215	29%	30.22	22.992
YANIDN_WF1	214.2	110.06	63.224	30%	36.20	27.028

Table 26. Allocated Relevant Level to Candidate Facilities (2019 Reserve Capacity Cycle – LOLE target = 4 hours in 10 years, scaled demand)

Facility	Maximum Capacity (MW)	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	21.6	8.99	4.286	20%	5.29	-1.008
ALINTA_WWF	89.1	40.58	19.358	22%	17.19	2.173
AMBRISOLAR_PV1	0.96	0.29	0.248	26%	0.20	0.050
BADGINGARRA_WF1	147.5	72.15	34.418	23%	26.87	7.544
BIOGAS01	2	1.28	1.309	65%	1.18	0.129
BLAIRFOX_KARAKIN_WF1	5	1.09	0.520	10%	0.49	0.034
BREMER_BAY_WF1	0.6	0.27	0.129	21%	0.17	-0.037
DCWL_DENMARK_WF1	1.44	0.67	0.320	22%	0.36	-0.044
EDWFMAN_WF1	80	33.87	16.157	20%	16.21	-0.052
GRASMERE_WF1	13.8	6.26	2.987	22%	3.71	-0.725
GREENOUGH_RIVER_PV1	40	12.00	10.277	26%	7.38	2.900
HENDERSON_RENEWABLE_IG1	3	1.69	1.725	58%	1.63	0.093
INVESTEC_COLLGAR_WF1	206	62.14	29.644	14%	15.82	13.821
KALBARRI_WF1	1.6	0.49	0.235	15%	0.26	-0.024

Facility	Maximum Capacity (MW)	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)
MERSOLAR_PV1	100	35.96	30.801	31%	16.32	14.481
MWF_MUMBIDA_WF1	55	19.19	9.152	17%	7.03	2.123
NORTHAM_SF_PV1	10	2.69	2.306	23%	1.80	0.508
RED_HILL	3.64	2.94	3.003	82%	2.84	0.161
ROCKINGHAM	4	2.42	2.471	62%	2.32	0.148
SKYFRM_MTBARKER_WF1	2.43	0.99	0.470	19%	0.52	-0.051
SOUTH_CARDUP	4.158	2.99	3.051	73%	2.97	0.085
TAMALA_PARK	4.8	4.35	4.441	93%	4.35	0.090
WARRADARGE_WF1	183.6	92.64	44.191	24%	30.22	13.968
YANIDN_WF1	214.2	110.06	52.502	25%	36.20	16.306

Appendix 4. Additional modelling scenarios developed in October 2020

THE LANTAU GROUP

Amend and Evaluate the Model for Capacity Valuation of Intermittent Generators

Modelling Results

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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.

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
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

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)
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
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

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	0.7717	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

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)
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
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

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	0.8580	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
ALINTA_WWF	Wind	89.1	40.58	14.59	27.59	0.8298	22.890	26%	17.19	5.705

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	1.4356	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
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

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)
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
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
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

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	1.012	1.750	58%	1.63	0.118
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
WARRADARGE_WF1	Wind	183.6	92.64	35.19	63.91	0.898	57.395	31%	30.22	27.172

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	0.898	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_PV1	Solar	0.96	0.29	0.11	0.20	1.9470	0.392	41%	0.20	0.194
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

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)
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
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

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	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
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

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)
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
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

Appendix 5 Summary of RCP Support's 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.

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;[1] 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.

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:

[1] This value is proposed to be introduced as part of the introduction of the NAQ framework.

- 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 understands that the ERA has 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.

Government of **Western Australia**
Energy Policy WA

Energy Sector Governance: Proposed Changes to the Regulatory Framework

Consultation Paper

10 November 2020

An appropriate citation for this paper is: Energy Sector Governance: Proposed Changes to the Regulatory Framework

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Contents

Abbreviations

The following table provides a list of abbreviations and acronyms used throughout this document. Defined terms are identified in this document by capitals.

Term	Definition
AEMO	Australian Energy Market Operator
ERA	Economic Regulation Authority
ESS	Essential System Services
Coordinator	The Coordinator of Energy
GSI	Gas Services Information
RCP	Rule Change Panel
RLM	Relevant Level Methodology
STEM	Short Term Energy Market
Taskforce	Energy Transformation Taskforce
the Act	*Electricity Industry Act 2004*
WEM	Wholesale Electricity Market
WOSP	Whole of System Plan

1. Introduction

The Western Australian energy sector is experiencing an unprecedented change, which is re-shaping every aspect of the sector, and the rate of this change is increasing. New technologies and business models are rapidly displacing the traditional means of producing and consuming energy, which requires dynamic response by the governance arrangements.

In recognition of the changes underway and the need to modernise Western Australia's electricity market and regulatory arrangements, in May last year the Government established the Energy Transformation Taskforce, which will be in place until May 2021.

While the Taskforce is delivering a substantial package of reforms within its two-year remit, the need for the market and regulatory arrangements to evolve will continue well beyond the Taskforce's life.

This evolution will require careful coordination and management, to ensure the energy transformation delivers effective reforms that enable a secure, reliable, sustainable and affordable energy supply for all customers.

Stakeholders have continued to raise concerns about the potential gap in the development and evolution of the market beyond the Taskforce, which Government is now looking to address.

Alongside the work of the Taskforce, Government has considered the overall governance of the energy sector and has decided to make some modifications to ensure it is up to the ongoing reform challenge. The changes seek to rationalise and clarify governance roles to reduce existing overlaps and address ongoing gaps.

These changes will also make better use of the different skills across the governance bodies by clarifying their focus, and seek to ease the pressure on administration costs across the sector as a whole over the medium to longer term.

The changes are about addressing the deficiencies in the current governance arrangements, they are not a reflection on the performance of any of the existing governance bodies.

They also acknowledge the need for strategic leadership and coordination by Government, beyond the life of the Taskforce, in the delivery of essential energy services.

The Government has agreed to clarify and enhance the governance arrangements whereby:

- the Coordinator of Energy (the Coordinator), supported by Energy Policy WA, will undertake policy, market development, strategic planning and overall coordination;
- the Economic Regulation Authority (ERA) will undertake economic regulation and price setting, licencing and compliance; and
- the Australian Energy Market Operator (AEMO) will undertake system operation, market operation and associated market administration (e.g. registration, settlement etc.).

1.1 Proposed changes

To give effect to this, as a first step, Government has agreed to:

- transfer responsibility for administration of the Wholesale Electricity Market (WEM) Rules and Gas Services Information (GSI) Rules from the Rule Change Panel (RCP), as well as allocate responsibility for the new rules for the North West Interconnected System, to the Coordinator;
- transfer responsibility for WEM and GSI market development functions, in particular some reviews of a policy or technical nature, from the ERA to the Coordinator; and

- allocate responsibility for the development of future, periodic Whole of System Plans (WOSPs) to the Coordinator.

Government has supported 1 July 2021 as the proposed commencement date for these changes, with this date to be confirmed as part of implementation planning by Energy Policy WA in consultation with the ERA and RCP.

[Note to stakeholders: In the proposed draft rules at appendices A and C we have not replicated changes related to the generator performance standards (Tranche 1 Rules) administrative changes being proposed as part of the Energy Transformation Strategy. These will be incorporated at a later date as necessary to suit the timing of the various rules packages]

1.2 Further review

Over the coming 12 months, Energy Policy WA will also review the energy governance framework more broadly and consider other improvements, including those that may require legislative change.

This will likely consider, for example:

- the development of an objective for the *Electricity Industry Act 2004* (the Act), which will guide the development and operation of all subordinate instruments made under the Act;
- the licensing and exemptions framework, to develop a robust framework for emerging business models and address deficiencies in compliance with exemptions (work has been underway on this for some time[1]);
- the allocation of the costs of administering and operating the State's energy markets, including to new business models;
- the arrangements relating to disputes, reviews and compliance matters heard by the Energy Disputes Arbitrator and Electricity Review Board; and
- the change management processes for the various subordinate instruments made under the Act (in particular) to identify opportunities for more consistent and coordinated development of those instruments.

Some further changes may be proposed to the allocation of governance responsibilities as a result of this work, consistent with the general governance approach outlined above.

Planning for this work is underway, including how and when consultation, with both the existing governance bodies and stakeholders more broadly, will occur. More information will be made available in 2021.

[1] See the information on Energy Policy WA's *Review of licensing and exemption regulatory framework* at https://www.wa.gov.au/organisation/energy-policy-wa/review-of-licensing-and-exemption-regulatory-framework

2. Transfer of responsibility for administration of the WEM and GSI Rules from the RCP

Amendments to the WEM and GSI Rules are proposed to implement necessary modifications to the rule change and review processes to accommodate the transfer of functions from the RCP to the Coordinator as outlined in section 1.1 above.

Appendix A contains the proposed changes to the WEM Rules and Appendix B contains the proposed changes to the GSI Rules.

There are also some proposed changes to the role and composition of the Market Advisory Committee (MAC) and Gas Advisory Board (GAB) to enable these to operate more independently from the rule maker. It is important to enhance the role of industry participants to inform and influence the decision making by the Coordinator, as doing so will provide greater confidence in both decision making and the fair operation of the sector.

The following proposed changes to the current arrangements for the MAC and the GAB are aimed at achieving this:

- The Minister will appoint independent chairpersons of the MAC and the GAB, who in the opinion of the Minister, must be demonstrably free of conflicts of interest. Currently, these two bodies are not chaired independently from the rule maker.
- It is also proposed that the independent chairperson recommends to the Coordinator the members who should be appointed to the MAC and the GAB. Currently, the RCP appoints members at its discretion.
- It is proposed that the MAC and the GAB must endeavour to provide a consensus position and note any dissenting views when providing advice to the Coordinator on the evolution of the market, and the Coordinator must take these views into account. This is a new requirement.
- It is also proposed that the Coordinator must have regard to any advice received from the MAC and GAB regarding matters concerning the evolution of the WEM Rules.
- It is proposed that the independent chairpersons of the MAC and the GAB may make Rule Change Proposals based on advice received from the MAC and the GAB regarding matters concerning the evolution of the WEM Rules or the GSI Rules.
- It is proposed that the Coordinator must, before commencing the development of a Rule Change Proposal, consult with the MAC and the GAB, respectively, and take into account any advice, comments or objections provided by the MAC and the GAB. All Rule Changes commenced by the Coordinator must be approved by the Minister for Energy.

Protected Provisions will continue to be a feature of the WEM and GSI Rules, meaning the Minister will be responsible for approving certain changes to the rules, including those relating to the functions of the Coordinator.

The funding for the administration of the WEM Rules and the GSI Rules, will continue to be collected from market participants by the AEMO, and will be transferred to the Coordinator.

The proposed amendments also implement a number of consequential changes to facilitate the transfer of functions.

3. Transfer of reviews of a policy or technical nature from the ERA to the Coordinator

Appendix C contains proposed changes to transfer a number of reviews of a policy or technical nature, from the ERA to the Coordinator. In summary, the intent of the proposed changes is to:

- provide for reviews of a technical (power system related) or policy nature to be undertaken by the Coordinator, with reviews of an economic nature, including for setting various prices in the WEM, to be undertaken by the ERA;
- remove the requirement for some price related reviews to be undertaken by AEMO and then approved by the ERA – with the ERA to be responsible for the review and AEMO's role removed; and
- implement a number of consequential changes to facilitate the transfer of functions.

Other reviews are being proposed and modified as part of the Energy Transformation Strategy. The above principles are also expected to apply to these reviews, that is, reviews of a technical or policy nature will be undertaken by the Coordinator, and reviews of an economic nature will be undertaken by the ERA. The proposed provisions for these have been, or will be, included in draft rules released for consultation by the Taskforce.

3.1 Reviews to be conducted by the ERA

Following the implementation of the proposed changes, the following reviews will be undertaken by the ERA:

- Monitoring market behaviour – The ERA will continue to have responsibility for investigating any market behaviour if it considers that the behaviour has resulted in the market not functioning effectively. It must provide to the Minister a report dealing with the matters identified in its investigations where the ERA considers that any specific events, or systemic behaviour or matters have impacted on the effectiveness of the market.
- Essential System Services (ESS) procurement – The ERA will also review the criteria and processes used by AEMO for the procurement of ESS through the Real-Time Market, the Supplementary ESS Mechanism, and under any contracts entered into by AEMO.
- Network Operator Outages – At least once in every five years, the ERA must conduct an economic study on the impact of Network Operator Outages on the market.
- Energy and reserve capacity prices – At least once in every five years, the ERA must review the methodology for setting the Benchmark Reserve Capacity Price (as well as the Reserve Capacity Price Factors) and the Energy Price Limits.
    - To avoid duplication of functions, the ERA will assume the responsibility, from AEMO, for the annual review of the Benchmark Reserve Capacity Price as well as the values of the Maximum Short Term Energy Market (STEM) Price and Alternative Maximum STEM Price.
- Relevant Level Methodology (RLM) – For each three-year period, beginning with the period commencing on 1 January 2015, the ERA must, by 1 April of the first year of that period, conduct a review of the RLM.

Under section 128 of the Act, every three years the ERA also reviews the operation of the market to assess the extent to which the Market Objectives are being achieved. However, if in the performance of its functions the ERA identifies a market design problem or inefficiency, the ERA may provide to the Coordinator and the Minister a report describing the problem or inefficiency.

3.2 Reviews to be conducted by the Coordinator

Following the implementation of the proposed changes, the following reviews will be undertaken by the Coordinator:

- Monitoring the market – To support its market development role, the Coordinator will be responsible for monitoring the market for design problems or inefficiencies. The Coordinator must provide to the Minister a report at least once in every three years and the report must contain any recommended measures to increase the effectiveness of the market in meeting the Wholesale Market Objectives to be considered by the Minister.
    - As part of its market development role, the Coordinator must also monitor the effectiveness of: (i) the Coordinator's WEM Rule change process, and ERA, AEMO and Coordinator's Procedure Change Processes; (ii) the effectiveness of the compliance monitoring and enforcement measures; and (iii) the effectiveness of AEMO in carrying out its functions.
- ESS standards and requirements – At least once in every three years, the Coordinator, with the assistance of AEMO, must carry out a review on the ESS Standards and the basis for setting ESS requirements.
- Outage Planning and Planning Criterion – At least once in every five-year period, starting from 1 July 2021, the Coordinator, with the assistance of AEMO, must conduct a review of the outage planning process and the Planning Criterion (including the process by which AEMO forecasts SWIS peak demand). These two reviews do not need to be done at the same time.

Stakeholder views are sought, in particular, on whether the proposed arrangements regarding the ERA's economic study of the impact of Network Operator Outages on the market and the Coordinator's review of the outage planning process would be expected to be efficient and effective. The intent is to separate the economic aspects of this review (to be undertaken by the ERA), from the technical aspects (to be undertaken by the Coordinator), consistent with the Government's decision on roles and responsibilities.

4. Responsibility for the development of WOSPs

Given the role that the WOSP will play in informing future policy and market evolution in Western Australia, as well as the fact that the South West Interconnected System has just one network to model, the Government has decided that responsibility for developing future periodic WOSPs should be undertaken by the Coordinator.

Government will continue to meet some of the cost of developing the WOSP, with Energy Policy WA's costs to be shared between Government and industry fees, at least initially.

Both AEMO and Western Power have very important roles to play in providing information and expertise in the development of the WOSP and will be required to support the development of WOSPs. The Taskforce is undertaking a separate public consultation on the overall regulatory framework for future WOSPs[2].

[2] https://www.wa.gov.au/government/publications/tranche-3-amending-rules-and-explanatory-memorandum

5. Drafting instructions – changes to relevant regulations

Appendix D contains the drafting instructions for changes the relevant regulations to give effect the transfer of functions from the RCP to the Coordinator and other related changes.

5.1 Electricity Industry (Rule Change Panel) Regulations

The proposed drafting instructions are to repeal the Electricity Industry (Rule Change Panel) Regulations 2016 with effect as of 1 July 2021, and make such other amendments to regulations under the Act as may be necessary or desirable to provide for the orderly winding up of the RCP.

Despite the repeal, the obligation on members and former members of the panel in relation to confidential information (regulation 34) is to continue to apply.

Energy Policy WA is continuing to liaise with the ERA and RCP Support team on transitional arrangements that may be required to support the orderly transfer of the functions and further provisions may be incorporated in the regulations as they are drafted.

5.2 Electricity Industry (Wholesale Electricity Market) Regulations)

5.2.1 WEM Rules may confer functions on Coordinator.

Proposed changes have already been progressed to the Electricity Industry (Wholesale Electricity Market) Regulations 2004 (WEM Regulations) [3] through the transitional arrangement for arbitration of Generator Performance Standards related disputes. The functions that may be conferred on the Coordinator are not confined to the making of Rules as was done in relation to the Panel under regulation 12B. These recent changes also provide for the ability of the Coordinator to recover fees.

5.2.2 Other amendments to the WEM Regulations

It is proposed to amend the WEM Regulations to remove the ability of the WEM Rules to confer functions on the RPC (e.g. under regulation 12B) and make such other changes as are necessary or desirable to reflect the abolition of the RCP.

It is also proposed to amend the WEM Regulations to continue the ability of the Minister to make market rules in relation to the wholesale electricity market until 31 March 2023. This proposed change is not directly related to the transfer of powers to the Coordinator. It is aimed at continuing the ability of the Minister to make rules for six months after the planned commencement of the rules for the new security constrained, economic dispatch energy market so that any necessary amendments identified in the implementation of the new market can be progressed in a timely manner.

The drafting instructions also include some administrative amendments to the WEM Regulations – principally to replace references to System Management with AEMO. This will improve consistency with how AEMO is proposed to be referred to with respect to its other functions under the WEM Rules, with similar amendments to the WEM Rules being developed by the Energy Transformation Taskforce.

[3] The Electricity Industry (Wholesale Electricity Market Amendment) Regulations 2020 are available at https://www.legislation.wa.gov.au/legislation/prod/filestore.nsf/FileURL/mrdoc_43341.pdf/$FILE/Electricity%20Industry%20(Wholesale%20Electricity%20Market)%20Amendment%20Regulations%202020%20-%20%5B00-00-00%5D.pdf?OpenElement

Other amendments also deal with related matters such as the treatment of confidential information by the Coordinator and the requirement for the Coordinator to make available a copy of the WEM Rules.

5.3 Gas Services Information Regulations

5.3.1 Minister to make rules

It is proposed to amend the Gas Services Information Regulations 2012 (GSI Regulations) to give the Minister for Energy an ability to make rules to amend the GSI Rules. It is proposed that the Minister's rule making power commences as soon as practicable after gazettal (i.e. the day after) and continue until a sunset date in line with that proposed under the WEM Regulations (see section 5.2.2 above).

The amendment should be comparable to the relevant portions of regulations 6 and 7 of the WEM Regulations that enable the Minister to make rules in relation to the WEM.

The Gas Services Information Amendment Regulations (No. 3) 2015 might also serve as an example of the type of amendment to the GSI Regulations that is desired.

5.3.2 GSI Rules to confer functions on Coordinator

It is proposed to amend the GSI Regulations to enable the GSI Rules to confer functions on the Coordinator and enable the recovery of fees by the Coordinator for the performance of functions under the Act. The form of these amendments will generally follow and correspond with the comparable amendments made to the WEM Regulations (to the extent relevant or applicable).

The GSI Regulations are to provide that any GSI Rules made, amended or repealed that confer functions on the Coordinator must be approved by the Minister for Energy before they are made.

Other amendments also deal with related matters such as the treatment of confidential information by the Coordinator and the requirement for the Coordinator to make available a copy of the GSI Rules.

6. Next Steps

Energy Policy WA welcomes feedback on the proposed changes the regulatory framework outlined in this consultation paper and its Attachments. Feedback can be submitted in any of the following ways:

1. Email your written submission to submissions@energy.wa.gov.au
2. Contact info@energy.wa.gov.au to arrange a one-on-one discussion
3. Post your written submission to Energy Policy WA at Locked Bag 11, Cloisters Square, WA 6850

Consultation on this paper closes at **5.00pm (AWST), 11 December 2020**. Late submissions may not be considered.

In the interests of transparency and to promote informed discussion, submissions will be made publicly available on www.energy.wa.gov.au unless requested otherwise. Accordingly, stakeholders should clearly specify if the information they provide is confidential and, where possible, should separate confidential information from non-confidential information.

Persons making any claim for confidentiality should familiarise themselves with the provisions of the *Freedom of Information Act 1992* (Western Australia), which imposes obligations on Energy Policy WA in respect to the release of documents.

Following consultation, Energy Policy WA proposes to finalise the proposed amendments to the rules and regulations for consideration by the Minister for Energy in December 2020. Subject to approval, it is proposed that the changes commence from 1 July 2021, with transitional provisions commenced earlier as required.

Appendix A

Draft WEM Rules Amendments– Transfer of Functions from the RCP to the Coordinator

Appendix A

DRAFT WEM RULES AMENDMENTS

TRANSFER FROM RCP TO COE

[Note to stakeholders: In the proposed draft rules at appendices A and C we have not replicated changes related to the generator performance standards (Tranche 1 Rules) administrative changes being proposed as part of the Energy Transformation Strategy. These will be incorporated at a later date as necessary to suit the timing of the various rules packages]

Disclaimer

This copy of the Wholesale Electricity Market Rules is provided in accordance with regulation 8 of the *Electricity Industry (Wholesale Electricity Market) Regulations 2004*. Every attempt has been made to ensure that it is accurate. However, no warranty is given that it is free from error or omission nor as to the accuracy of any information in it. The ~~Economic Regulation Authority, Rule Change Panel~~Coordinator and each of its officers and employees disclaim any responsibility for, or liability arising from, any act or omission done in reliance on the document or for any consequences of any such act or omission.

1.4. Other rules of interpretation

1.4.1. In these Market Rules, unless the contrary intention appears:

…

(n) (**amendments**): if the ~~Rule Change Panel~~Coordinator, AEMO, System Management, the Economic Regulation Authority or a Network Operator has the power to make, prescribe, determine, compile, establish or develop a document, instrument, matter or thing, then the ~~Rule Change Panel~~Coordinator, AEMO, System Management, the Economic Regulation Authority or the Network Operator, as applicable, also has the power to amend, replace or revoke the whole or part of that document, instrument, matter or thing exercisable in like manner and subject to like conditions (if any);

…

1.4.2. In these Market Rules, unless the contrary intention appears, any notice or confirmation required to be issued by the ~~Rule Change Panel~~Coordinator, AEMO or the Economic Regulation Authority may be issued by an automated software system employed by the ~~Rule Change Panel~~Coordinator, AEMO or the Economic Regulation Authority, as applicable~~,~~.

…

1.5. Subservient Documents

1.5.1. The following documents are subservient to the Market Rules:

(a) Market Procedures; and

(b) any other document or instrument issued, made or given by the ~~Rule Change Panel~~Coordinator, AEMO, the Economic Regulation Authority or a Network Operator under the Market Rules.

1.5.2. In the event of conflict between the Market Rules and other documents, then the order of precedence is to be, in the following order:

…

(dC) any other document or instrument issued, made or given by the ~~Rule Change Panel~~Coordinator under these Market Rules.

…

1.6. Notices

1.6.1. The ~~Rule Change Panel~~Coordinator must develop a Market Procedure which sets out the method by which notices and communications required under, contemplated by or relating to, these Market Rules are to be given to or by the ~~Rule Change Panel~~Coordinator.

…

1.7.3. Where the Economic Regulation Authority ~~or the Rule Change Panel~~ is required by these Market Rules to publish or release a document or information, then:~~—~~

(a) the Economic Regulation Authority must make that document or information available on its web site, in a place which is generally accessible by members of the class of persons entitled to access that document or information given AEMO's determination of its confidentiality status in accordance with clause 10.2; and

(b) if these Market Rules require that document or information to be published on the Market Web Site—

i. the Economic Regulation Authority must promptly notify AEMO when the document or information is published on the Economic Regulation Authority's web site; and

ii. AEMO must, at a minimum, promptly publish a link to the relevant area of the Economic Regulation Authority's web site on the Market Web Site; and

iii. the Economic Regulation Authority ~~or the Rule Change Panel (as appropriate)~~ is deemed to have published or released the document or information once the Economic Regulation Authority has

published the document or information on its own web site, and has notified AEMO.

1.7.3A. Where the Coordinator is required by these Market Rules to publish or release a document or information, the Coordinator must make that document or information available on the Coordinator's Website, in a place which is generally accessible by members of the class of persons entitled to access that document or information given its confidentiality status in accordance with section 10.2.

…

~~1.14 Transition of functions to AEMO~~

~~1.14.1. On and from the AEMO Transition Date:~~

~~(f) the Market Procedure that the IMO developed under clause 1.6.1 prior to the AEMO Transition Date is deemed to be both the Market Procedure —~~

~~i. that the Rule Change Panel is required to develop under clause 1.6.1; and~~

…

1.18 [Note to stakeholders: Section 1.18 will remain as is.]

1.18A. Transition of ~~certain IMO~~Rule Change Panel functions to the ~~Rule Change Panel~~Coordinator

[Note to stakeholders: The transition from RCP to the Coordinator will be effected by a new rule 1.18A. This will be modelled on existing rule 1.18, which effected the transfer from the IMO to the RCP.]

1.18A.1. On and from the Coordinator Transfer Date:

(a) where the Coordinator is required to do an act, matter or thing under a provision of these Market Rules, and that act, matter or thing was done by the Rule Change Panel prior to the Coordinator Transfer Date, then the act, matter or thing is deemed to have been done by the Coordinator in accordance with the relevant provision;

(b) where the Coordinator is required to do an act, matter or thing under a provision of a Market Procedure, and that act, matter or thing was done by the Rule Change Panel prior to the Coordinator Transfer Date, then the act, matter or thing is deemed to have been done by the Coordinator in accordance with the relevant provision;

(c) notwithstanding the operation of clauses 1.18A.1(a) and 1.18A.1(b), the Coordinator is not liable for any act, matter or thing done by the Rule Change Panel prior to the Coordinator Transfer Date in breach of these Market Rules or any Market Procedure;

(d) where the Coordinator is required to develop or maintain a Market Procedure, and that Market Procedure was developed or maintained by the Rule Change Panel prior to the Coordinator Transfer Date, then—

i. the Market Procedure is deemed to have been developed or maintained by the Coordinator in accordance with these Market Rules;

ii. a reference to the Rule Change Panel in that Market Procedure that should be a reference to the Coordinator having regard to the Coordinator's functions, powers, rights and obligations under these Market Rules and the other Market Procedures is deemed to be a reference to the Coordinator;

iii. the Coordinator may amend the Market Procedure to refer to the Coordinator instead of the Rule Change Panel (where appropriate) and make any necessary consequential amendments without undertaking the Procedure Change Process; and

iv. any Market Procedure which is amended by the Coordinator in accordance with this clause 1.18A.1(d) may commence operation on the date and time determined by the Coordinator and published on the Market Web Site;

(e) where the Coordinator is required to publish or release any information or document (other than a Market Procedure) (including, without limitation, a form, protocol, instrument or other thing) and that information or document was published or released by the Rule Change Panel prior to the Coordinator Transfer Date, then—

i. the information or document is deemed to have been published or released by the Coordinator in accordance with these Market Rules; and

ii. any reference to the Rule Change Panel in that information or document that should be a reference to the Coordinator having regard to the Coordinator's functions, powers, rights and obligations under these Market Rules and the Market Procedures is deemed to be a reference to the Coordinator;

(f) where a person (including, without limitation, a Rule Participant) is required to provide information to, or do an act, matter or thing for the Coordinator under these Market Rules or a Market Procedure and the person has provided that information to, or done that act, matter or thing for the Rule Change Panel prior to the Coordinator Transfer Date, then the information, act, matter or thing, is deemed to have been provided to, or done for, the Coordinator in accordance with the relevant Market Rules or Market Procedure; and

(g) if, by operation of this clause 1.18A.1, the Coordinator is deemed to have made a Reviewable Decision that was made by the Rule Change Panel,

then, on and from the Coordinator Transfer Date any application to the Electricity Review Board for a review of the Reviewable Decision that might have been brought or continued by a Rule Participant against the Rule Change Panel may be brought or continued against the Coordinator as if all references to the Rule Change Panel as the relevant decision-maker are references to the Coordinator.

~~[~~**[Note: No equivalent is needed for clause 1.18.2.]**

1.18A.2~~3~~. On and from the ~~Rule Change Panel~~Coordinator Transfer Date:~~—~~

(a) any Rule Change Proposal that has, prior to the ~~Rule Change Panel~~Coordinator Transfer Date, been developed by or submitted to the ~~IMO~~Rule Change Panel (and in respect of which the rule change process under ~~clause~~ sections 2.4~~, and clauses 2.5~~ to 2.8~~.13~~ is not, as at the ~~Rule Change Panel~~Coordinator Transfer Date, complete) will be deemed to have been developed by or submitted to the ~~Rule Change Panel~~Coordinator; and

(b) notwithstanding any other provision of these Market Rules, a Market Procedure or any document referred to in these Market Rules or a Market Procedure (including a Draft Rule Change Report), the normal timeframes for the ~~Rule Change Panel~~Coordinator or any other person to do any act, matter or thing in relation to a Rule Change Proposal referred to in clause 1.18A.2~~3~~(a) (including any extended timeframe determined by the ~~IMO~~Rule Change Panel under clause 2.5.10 in respect of any such proposal) will be automatically extended for such period as determined by the ~~Rule Change Panel~~Coordinator (which determination may be made at a date after the date of the expiry of the normal, or previously extended, timeframe).

1.18A.3~~4~~. The ~~Rule Change Panel~~Coordinator must publish a notice of the extended timeframe(s) determined in accordance with clause 1.18A.2~~3~~(b), and must update any information already published in accordance with clause 2.5.7(f) (if applicable).

1.18A.4. Notwithstanding clause 2.24.6A, the date by which the Coordinator must notify AEMO of the dollar amount that the Coordinator may recover under clause 2.24.5B in the Financial Year beginning on 1 July 2021, is 15 July 2021.

1.19. Amendments to Market Procedures to reflect transfer of functions

1.19.1. In addition to the amendments to Market Procedures referred to in clauses 1.14.1, 1.16.1, 1.16.2, 1.17.1, 1.18.1 ~~and~~, 1.18.2 and 1.18A.1, AEMO, System Management, the Economic Regulation Authority or the ~~Rule Change Panel~~Coordinator (as applicable) (each a **Transferee**) may make the minimum necessary amendments to a Market Procedure required to be developed or maintained by the Transferee to:~~—~~

(a) reflect the transfer of functions, powers, rights and obligations from the IMO, Western Power ~~or,~~ AEMO or the Rule Change Panel to the Transferee or another Transferee; or

(b) maintain consistency between the Market Procedure and these Market Rules,

without undertaking the Procedure Change Process.

…

1.19.3. Until such time as the relevant Transferee makes the amendments referred to in clause 1.19.1, any reference in any Market Procedure:~~—~~

…

(d) … ; ~~and~~

(e) … ~~.~~; and

(f) ~~to the IMO, AEMO or~~ Rule Change Panel that should be a reference to the Coordinator having regard to the Coordinator's functions, powers, rights and obligations under these Market Rules and the other Market Procedures is deemed to be a reference to the Coordinator.

…

2.1A. Australian Energy Market Operator

…

2.1A.2 …

…

(lA) to contribute to the development and improve the effectiveness of the operation and administration of the Wholesale Electricity Market, by:

…

iii. providing information to the ~~Rule Change Panel~~Coordinator as required to support the ~~Rule Change Panel~~Coordinator's functions under the Market Rules; and

…

2.2A. The Economic Regulation Authority

2.2A.1. The following functions are conferred on the Economic Regulation Authority under these Market Rules:~~—~~

…

(bA) [blank]~~to provide the RCP Secretariat Support Services to the Rule Change Panel in accordance with the Panel Regulations~~;

(bB) to contribute to the development and improve the effectiveness of the operation and administration of the Wholesale Electricity Market, by developing Rule Change Proposals;

…

2.2B. [Blank]~~Rule Change Panel~~

~~2.2B.1. The Rule Change Panel is conferred functions in respect of the Wholesale Electricity Market under the WEM Regulations and the Panel Regulations.~~

~~2.2B.2. The WEM Regulations also provide for the Market Rules to confer functions on the Rule Change Panel. Subject to clause 2.2B.3, the functions conferred on the Rule Change Panel are to—~~

~~(a) administer these Market Rules;~~

~~(b) develop amendments to these Market Rules and replacements for them;(c) develop Market Procedures, and amendments and replacements for them, where required by these Market Rules;~~

~~(d) do anything that the Rule Change Panel determines to be conducive or incidental to the performance of the functions set out in this clause 2.2B.2; and~~

~~(e) carry out any other functions conferred, and perform any obligations imposed, on it under these Market Rules.~~

~~2.2B.3. Clause 2.2B.2(b) of these Market Rules commences operation on and from 08:00AM on 3 April 2017, in accordance with regulation 2(b) of the *Electricity Industry (Wholesale Electricity Market) Amendment Regulations (No.2) 2016.*~~

…

2.2D. Coordinator of Energy

2.2D.1. The Coordinator is conferred functions in respect of the Wholesale Electricity Market under the WEM Regulations.

2.2D.2. The WEM Regulations also provide for the Market Rules to confer functions on the Coordinator. Subject to clause 2.2D.3, the functions conferred on the Coordinator are to:

(a) administer these Market Rules;

(b) develop amendments to these Market Rules and replacements for them;

(c) develop Market Procedures, and amendments and replacements for them, where permitted or required by these Market Rules;

(d) consider and, in the Coordinator's discretion and in consultation with the Market Advisory Committee, progress the development of the Wholesale Electricity Market and these Market Rules;

(e) provide MAC Secretariat services to the Market Advisory Committee and support its independent Chair;

(f) undertake reviews and consultation as required under these Market Rules;

(g) do anything that the Coordinator determines to be conducive or incidental to the performance of the functions set out in this clause 2.2D.2; and

(h) carry out any other functions conferred, and perform any obligations imposed, on it under these Market Rules.

…

2.3. The Market Advisory Committee

2.3.1. The Market Advisory Committee is a committee of industry representatives convened by the ~~Rule Change Panel~~Coordinator:

(a) to advise the ~~Rule Change Panel~~Coordinator regarding Rule Change Proposals;

(b) to advise the ~~Rule Change Panel~~Coordinator, AEMO ~~(including in its capacity as System Management)~~ and the Economic Regulation Authority regarding Procedure Change Proposals;

(c) to advise the Coordinator, AEMO and the Economic Regulation Authority on the development of Rule Change Proposals where requested by the Coordinator, AEMO or the Economic Regulation Authority in accordance with clauses 2.5.1A or 2.5.1B or 2.5.1C; ~~and~~

(d) to advise the Coordinator ~~Rule Change Panel~~ regarding matters concerning, and the Coordinator's plans for, the evolution of the Wholesale Electricity Market and these Market Rules; and

(e) to provide assistance to the Coordinator in its monitoring role under clauses 2.16.13A and 2.16.13B.

2.3.1A. The Market Advisory Committee is a non-voting committee.

2.3.1B. The Market Advisory Committee must endeavour where practicable to reach a consensus position on any issue before it.

2.3.1C If, after allowing a reasonable time for discussion, the independent Chair of the Market Advisory Committee determines that a consensus position either will not be achieved, or is unlikely to be achieved within a time which is reasonable in the circumstances, then the independent Chair must provide advice to the Coordinator

which reflects any majority view and which includes or is accompanied by the dissenting views.

2.3.2. The ~~Rule Change Panel~~Coordinator must develop and publish a constitution for the Market Advisory Committee detailing:

(a) the process for convening the Market Advisory Committee;

(b) the terms of reference of the Market Advisory Committee;

(c) the membership terms of Market Advisory Committee members;

(d) the process for appointing and replacing Market Advisory Committee members by the ~~Rule Change Panel~~Coordinator;

(e) the conduct of Market Advisory Committee meetings;

(f) the role of the ~~RCP~~ MAC Secretariat in respect of the Market Advisory Committee;

(g) the interaction between the Market Advisory Committee and the ~~Rule Change Panel~~Coordinator;

(h) the ability of the Market Advisory Committee to delegate any of the roles described in clause 2.3.1 to a Working Group; and

(i) the governance arrangements to apply between the Market Advisory Committee and any Working Groups where the Market Advisory Committee delegates any of the roles described in clause 2.3.1 to a Working Group.

2.3.3. The constitution of the Market Advisory Committee must be consistent with the Market Rules.

2.3.4. The ~~Rule Change Panel~~Coordinator must invite public submissions when developing or amending the constitution of the Market Advisory Committee.

2.3.5. Subject to clause 2.3.13, the Market Advisory Committee must comprise:

(a) at least ~~three~~ six and not more than eight~~four~~ members representing Market ~~Generators~~Participants, excluding Synergy;

(b) at least one member representing Contestable Customers;

(c) at least one and not more than two members representing Network Operators, of whom one must represent Western Power;

(d) [blank]~~at least three and not more than four members representing Market Customers;~~

(e) at least two~~one~~ members nominated by the Minister to represent small-use consumers;

(f) [blank]~~one member representing System Management;~~

(g) ~~one~~ two members representing AEMO;

(h) one member representing Synergy; and

(i) an independent C~~c~~hair~~person~~, ~~who must be a person~~ to be appointed by the ~~chairperson of the Rule Change Panel~~Minister under clause 2.3.8A.

2.3.5A. Subject to clause 2.3.13, when appointing or removing members of the Market Advisory Committee of the class described in clause 2.3.5(a), the ~~Rule Change Panel~~Coordinator must use its reasonable endeavours to ensure equal representation of Market Generators and Market Customers.

2.3.5B The same organisation cannot be represented by more than one member on the Market Advisory Committee simultaneously.

2.3.5C Candidates for appointment under clause 2.3.5(c), (g) and (h) may be proposed to the Coordinator by Western Power, AEMO and Synergy respectively.

2.3.6. The Minister may appoint a representative to attend Market Advisory Committee meetings as an observer.

2.3.7. The Economic Regulation Authority may appoint a representative to attend Market Advisory Committee meetings as an observer.

2.3.7A The Coordinator or the independent Chair of the Market Advisory Committee may invite a person to attend Market Advisory Committee meetings as an observer, either for a specified meeting or meetings or until further notice.

2.3.8. The ~~Rule Change Panel~~Coordinator may appoint and remove members of the Market Advisory Committee in consultation with the independent Chair appointed in accordance with clause 2.3.8A.

2.3.8A. The Minister must appoint an independent Chair of the Market Advisory Committee, who in the opinion of the Minister:

(a) is free from any business or other relationship that could materially interfere with the independent exercise of the independent Chair's judgment; and

(b) has the skills and experience necessary to carry out the responsibilities and functions of the independent Chair of the Market Advisory Committee.

2.3.8B. The Minister may remove an independent Chair of the Market Advisory Committee at any time in the following circumstances:

(a) the person becomes an undischarged bankrupt; or

(b) the person becomes of unsound mind or his or her estate is liable to be dealt with in any way under law relating to mental health; or

(c) in the Minister's opinion the person no longer adequately meets the criterion in clause 2.3.8A.

2.3.9. The ~~Rule Change Panel~~Coordinator must annually review the composition of the Market Advisory Committee in consultation with the independent Chair of the Market Advisory Committee and may remove and appoint members following the review.

2.3.10. When appointing and removing members of the Market Advisory Committee, the ~~Rule Change Panel~~Coordinator must consult with the independent Chair of the Market Advisory Committee, and take nominations from Rule Participants and industry groups, that it considers relevant to the Wholesale Electricity Market, and, if practicable, must choose members from persons nominated.

2.3.11. The ~~Rule Change Panel~~Coordinator may remove a member of the Market Advisory Committee at any time in the following circumstances:

(a) the person becomes an undischarged bankrupt;

(b) the person becomes of unsound mind or his or her estate is liable to be dealt with in any way under law relating to mental health; or

(c) an event specified for this purpose in the constitution for the Market Advisory Committee occurs; or

(d) in the ~~Rule Change Panel~~Coordinator's opinion the person no longer adequately represents the person or class of persons that they were appointed to represent in accordance with clause 2.3.5.

2.3.12. A member of the Market Advisory Committee may resign by giving notice to the ~~Rule Change Panel~~Coordinator in writing.

2.3.13. Where a position on the Market Advisory Committee is vacant at any time, the ~~Rule Change Panel~~Coordinator must use its reasonable endeavours to appoint a person to fill the position, but the Market Advisory Committee may continue to perform its functions under this clause 2.3 despite any vacancy.

2.3.14. [Blank]

2.3.15. The ~~RCP~~ MAC Secretariat must convene the Market Advisory Committee:

(a) on any occasion where these Market Rules require a meeting to discuss a Rule Change Proposal;

(aA) on any occasion where these Market Rules require a meeting to discuss a Procedure Change Proposal;

(b) [Blank]; and

(c) on any occasion when ~~two or more members~~the independent Chair of the Market Advisory Committee has~~ve~~ informed the ~~RCP~~ MAC Secretariat in writing that ~~they~~ she or he wishes to bring a matter regarding~~,~~ the evolution of these Market Rules or the operation of these Market Rules before the Market Advisory Committee for discussion.

2.3.16. Subject to ~~its~~ her or his obligations of confidentiality under these Rules and otherwise ~~and the Panel Regulations~~, the ~~Rule Change Panel~~Coordinator must use reasonable endeavours to provide ~~the members of~~ the Market Advisory Committee any information in ~~its~~ the Coordinator's possession obtained in the course of performing a function under these Market Rules that is pertinent to the issues being addressed by the Market Advisory Committee.

2.3.17. The Market Advisory Committee may:

(a) establish one or more Working Groups comprising Representatives of Rule Participants and other interested ~~stakeholders~~persons, to assist the Market Advisory Committee in advising the ~~Rule Change Panel~~Coordinator, Economic Regulation Authority and AEMO on any of the matters listed in clause 2.3.1 of these Market Rules; and

(b) disband any Working Groups where it considers that the Working Group is no longer required, or will no longer be required, to assist the Market Advisory Committee in advising the ~~Rule Change Panel~~Coordinator, Economic Regulation Authority and AEMO on any of the matters listed in clause 2.3.1 of these Market Rules.

Market Documents

2.4. Market Rules made by the ~~Rule Change Panel~~Coordinator

2.4.1. The ~~Rule Change Panel~~Coordinator:

(a) is responsible for maintaining and publishing the Market Rules; and

(b) is responsible for ensuring the development of amendments of, and replacements for, the Market Rules; and

(c) may make amending rules (as defined in the Regulations) ("**Amending Rules**") in accordance with this Chapter.

2.4.1A. [blank] ~~This clause 2.4, clauses 2.5 to 2.8.13 (inclusive) and clause 3.8.4 of these Market Rules commence on and from 08:00AM on 3 April 2017, being the date on which the Rule Change Panel is conferred the function to develop amendments of and replacements for these Market Rules in accordance with regulation 2(b) of the Electricity Industry (Wholesale Electricity Market) Amendment Regulations (No.2) 2016.~~

2.4.2. The ~~Rule Change Panel~~Coordinator must not make Amending Rules unless it is satisfied that the Market Rules, as proposed to be amended or replaced, are consistent with the Wholesale Market Objectives.

2.4.3. In deciding whether ~~or not~~ to make Amending Rules, the ~~Rule Change Panel~~Coordinator must have regard to the following:

(a) any applicable statement of policy principles given to the ~~Rule Change Panel~~Coordinator under clause 2.5.2;

(aA) any views expressed by the Market Advisory Committee regarding the development of the Wholesale Electricity Market or these Market Rules;

(b) the practicality and cost of implementing the Rule Change Proposal;

(c) the views expressed in any submissions on the Rule Change Proposal;

(d) the views expressed by the Market Advisory Committee where the Market Advisory Committee met to consider the Rule Change Proposal; ~~and~~

(dA) in connection with clauses 2.4.3(aA) and 2.4.3(d), whether the advice from the Market Advisory Committee reflects a consensus view or a majority view, and, if the latter, any dissenting views included in or accompanying the advice;

(e) any technical studies that the ~~Rule Change Panel~~Coordinator considers are necessary to assist in assessing the Rule Change Proposal.

2.4.3A. Without limiting clause 2.4.3, in deciding whether or not to make Amending Rules, the ~~Rule Change Panel~~Coordinator may ~~request the RCP Secretariat to~~ seek advice, and the ~~Rule Change Panel~~Coordinator may have regard to that advice, from any person that the ~~Rule Change Panel~~Coordinator considers is appropriate to assist it in assessing the relevant Rule Change Proposal.

2.4.4. The ~~Rule Change Panel~~Coordinator must maintain on the ~~Market Web Site~~Coordinator's website a Rule Change Proposal form which must include:

(a) contact details for proposing rule changes; and

(b) information that must be provided in proposing a change, including:

i. the name of the person submitting the Rule Change Proposal, and where relevant, details of the organisation that person represents;

ii. the issue to be addressed;

iii. the degree of urgency of the proposed change;

iv. any proposed specific changes to particular rules;

v. a description of how the rule change would allow the Market Rules to better address the Wholesale Market Objectives; and

vi. any identifiable costs and benefits of the change.

2.5. Rule Change Proposals

2.5.1. Any person may make a Rule Change Proposal by completing a Rule Change Proposal form and submitting it to the ~~Rule Change Panel~~Coordinator.

2.5.1A. AEMO must, before commencing the development of a Rule Change Proposal or providing material support or assistance to another party to develop a Rule Change Proposal, consult with the Market Advisory Committee on:

(a) the matters to be addressed by the Rule Change Proposal and if applicable the nature and scope of the support or assistance requested by the other party;

(b) what options exist to resolve the matters to be addressed by the Rule Change Proposal;

(c) AEMO's estimated costs of developing the Rule Change Proposal or providing the support or assistance requested by the other party;

(d) whether and when AEMO should develop the Rule Change Proposal or if AEMO should provide the support or assistance requested by the other party; and

(e) whether and how the Market Advisory Committee will be consulted during the development of the Rule Change Proposal,

and take into account any advice, comments or objections provided by any member or observer of the Market Advisory Committee in deciding whether, when and how to develop the Rule Change Proposal or provide material support or assistance to another party to develop the Rule Change Proposal.

2.5.1B. The Economic Regulation Authority must, before commencing the development of a Rule Change Proposal or providing material support or assistance to another party to develop a Rule Change Proposal, consult with the Market Advisory Committee on:

(a) the matters to be addressed by the Rule Change Proposal and if applicable the nature and scope of the support or assistance requested by the other party;

(b) what options exist to resolve the matters to be addressed by the Rule Change Proposal;

(c) the Economic Regulation Authority's estimated costs of developing the Rule Change Proposal or providing the support or assistance requested by the other party;

(d) whether and when the Economic Regulation Authority should develop the Rule Change Proposal or if the Economic Regulation Authority should provide the support or assistance requested by the other party; and

(e) whether and how the Market Advisory Committee will be consulted during the development of the Rule Change Proposal,

and take into account any advice, comments or objections provided by any member or observer of the Market Advisory Committee in deciding whether, when and how to develop the Rule Change Proposal or provide material support or assistance to another party to develop the Rule Change Proposal.

2.5.1C. The Coordinator must, before commencing the development of a Rule Change Proposal or providing material support or assistance to another party to develop a Rule Change Proposal, consult with the Market Advisory Committee on:

(a) the matters to be addressed by the Rule Change Proposal and if applicable the nature and scope of the support or assistance requested by the other party;

(b) what options exist to resolve the matters to be addressed by the Rule Change Proposal;

(c) the Coordinator's estimated costs to be recovered through Coordinator Fees of developing the Rule Change Proposal or providing the support or assistance requested by the other party;

(d) whether and when the Coordinator should develop the Rule Change Proposal or if the Coordinator should provide the support or assistance requested by the other party; and

(e) whether and how the Market Advisory Committee will be consulted during the development of the Rule Change Proposal,

and take into account any advice, comments or objections provided by any member or observer of the Market Advisory Committee in deciding whether, when and how to develop the Rule Change Proposal or provide material support or assistance to another party to develop the Rule Change Proposal.

2.5.2. The Minister may issue a statement of policy principles to the ~~Rule Change Panel~~Coordinator with respect to the development of the market. The statement of policy principles must not be inconsistent with the Wholesale Market Objectives. Before giving a statement of policy principles, the Minister may provide a draft of the proposed statement to the ~~Rule Change Panel~~Coordinator and seek the ~~Rule Change Panel~~Coordinator's views on it.

~~2.5.3. The Rule Change Panel must have regard to any statement of policy principles given by the Minister in making Amending Rules in accordance with this Chapter.~~

2.5.3A The Coordinator must have regard to any advice received from the Market Advisory Committee regarding the evolution of the Wholesale Electricity Market or these Market Rules.

2.5.3B The independent Chair of the Market Advisory Committee may develop and submit Rule Change Proposals based on advice received from the Market Advisory Committee regarding the development of the Wholesale Electricity Market or these Market Rules.

2.5.4. Where the ~~Rule Change Panel~~Coordinator considers that a change to the Market Rules is:~~—~~

~~(a) required to correct a manifest error in the Market Rules; or~~

~~(b) of a minor or procedural nature,~~

the ~~Rule Change Panel~~Coordinator may develop a Rule Change Proposal and must publish it in accordance with clause 2.5.7.

2.5.5. Where necessary, the ~~Rule Change Panel~~Coordinator may contact the person submitting a Rule Change Proposal and request clarification of any aspect of the Rule Change Proposal. Any clarification received is to be deemed to be part of the Rule Change Proposal.

2.5.6. Within five Business Days of the later of:

(a) receiving the Rule Change Proposal; and

(b) any clarification under clause 2.5.5,

the ~~Rule Change Panel~~Coordinator must:

(c) decide whether or not to progress the Rule Change Proposal any further; and

(d) notify the person who submitted the Rule Change Proposal whether or not the ~~Rule Change Panel~~Coordinator will progress the Rule Change Proposal any further.

2.5.7. When it has developed a Rule Change Proposal, or within seven Business Days of receiving a Rule Change Proposal under clause 2.5.1, the ~~Rule Change Panel~~Coordinator must publish notice of the Rule Change Proposal on the ~~Market Web Site~~Coordinator's Website. The notice must include:

(a) the date that the Rule Change Proposal was submitted, if applicable;

(b) the name, and where relevant, the organisation, of the person who made the Rule Change Proposal;

(c) details of the Rule Change Proposal, including relevant references to clauses of the Market Rules and any proposed specific changes to those clauses;

(d) the description of how the rule change would allow the Market Rules to better address the Wholesale Market Objectives given by the person submitting the proposed rule change;

(e) whether the Rule Change Proposal will be progressed and the reason why the Rule Change Proposal will or will not be progressed; and

(f) if the Rule Change Proposal will be progressed further:

i. whether the Rule Change Proposal is to be subject to the Fast Track Rule Change Process in accordance with clause 2.5.9 and the reasons for this decision;

ii. if the Rule Change Proposal is subject to the Fast Track Rule Change process, and the Rule Change Proposal did not include proposed specific changes to clauses, the ~~Rule Change Panel~~Coordinator's proposed Amending Rules to implement the Rule Change Proposal; and

iii. if the Rule Change is not subject to the Fast Track Rule Change process, a call for submissions in relation to the Rule Change Proposal. The due date for submissions must be:

1. 30 Business Days after the notification; or
2. if a longer timeframe is determined in accordance with clause 2.5.10, at a time that is consistent with that timeframe.

2.5.8. Where a Rule Change Proposal that will be progressed relates to a Protected Provision the ~~Rule Change Panel~~Coordinator must notify the Minister at the same time as it gives the notice described in clause 2.5.7.

2.5.8A. All rule changes resulting from a Rule Change Proposal initiated by the Coordinator must be approved by the Minister.

2.5.9. The ~~Rule Change Panel~~Coordinator may subject a Rule Change Proposal to the Fast Track Rule Change Process if, in its opinion, the Rule Change Proposal:

(a) is of a minor or procedural nature; or

(b) is required to correct a manifest error; or

(c) is urgently required and is essential for the safe, effective and reliable operation of the market or the SWIS.

2.5.10. Subject to clause 2.5.12, the ~~Rule Change Panel~~Coordinator may at any time after deciding to progress a Rule Change Proposal decide to extend the normal timeframe for processing Rule Change Proposals. If the ~~Rule Change Panel~~Coordinator decides to do so, then it may modify the times and time periods under ~~clauses~~ sections 2.6 or 2.7 in respect of the Rule Change Proposal and publish details of the modified times and time periods.

2.5.11. If a Rule Change Proposal was subject to the Fast Track Rule Change Process, and the ~~Rule Change Panel~~Coordinator decides to extend the timeframe, it must either:

(a) extend the timeframe by no more than 15 Business Days; or

(b) reclassify the Rule Change Proposal as not being subject to the Fast Track Rule Change Process, and must progress it in accordance with ~~clause~~ section 2.7.

2.5.12. The ~~Rule Change Panel~~Coordinator must publish a notice of an extension determined in accordance with clause 2.5.10, and must update any information already published in accordance with clause 2.5.7(f).

2.5.13. A notice of extension must include:

(a) the reasons for the proposed extension;

(b) the views of any Rule Participants consulted on the extension;

(c) the proposed length of any extension; and

(d) the proposed work program.

2.5.14. A Rule Change Proposal that the ~~Rule Change Panel~~Coordinator decides is subject to the Fast Track Rule Change Process is to be progressed in accordance with ~~clause~~ section 2.6, and ~~clause~~ section 2.7 does not apply.

2.5.15. A Rule Change Proposal that the ~~Rule Change Panel~~Coordinator decides is not subject to the Fast Track Rule Change Process is to be progressed in accordance with ~~clause~~ section 2.7, and ~~clause~~ section 2.6 does not apply.

2.6. Fast Track Rule Change Process

2.6.1. Within five Business Days of publishing the notice referred to in clause 2.5.7, the ~~Rule Change Panel~~Coordinator must notify those Rule Participants that it considers have an interest in the Rule Change Proposal of its intention to consult with them concerning the Rule Change Proposal.

2.6.2. Within five Business Days of publishing the notice referred to in clause 2.5.7, a Rule Participant may notify the ~~Rule Change Panel~~Coordinator that they wish to be consulted concerning the Rule Change Proposal.

2.6.3. Within 15 Business Days of publishing the notice referred to in clause 2.5.7, the ~~Rule Change Panel~~Coordinator must have completed such consultation as the ~~Rule Change Panel~~Coordinator considers appropriate in the circumstances with the Rule Participants described in clauses 2.6.1 and 2.6.2.

2.6.3A. Within 20 Business Days of publishing the notice referred to in clause 2.5.7, the ~~Rule Change Panel~~Coordinator must:

(a) decide whether to:

i. accept the Rule Change Proposal in the proposed form; or

ii. accept the Rule Change Proposal in a modified form; or

iii. reject the Rule Change Proposal; and

(b) prepare and publish a Final Rule Change Report on the Rule Change Proposal.

2.6.4. The Final Rule Change Report must contain:

(a) the information in the notice of the Rule Change Proposal under clause 2.5.7;

(b) any analysis of the Rule Change Proposal that the ~~Rule Change Panel~~Coordinator has carried out;

(c) the identities of Rule Participants that were consulted;

(d) information on any objections expressed by the Rule Participants consulted, and the ~~Rule Change Panel~~Coordinator's response to the objections;

(e) the ~~Rule Change Panel~~Coordinator's assessment of the Rule Change Proposal in light of clauses 2.4.2 and 2.4.3;

(f) the decision made by the ~~Rule Change Panel~~Coordinator under clause 2.6.3A(a) on the Rule Change Proposal;

(g) the ~~Rule Change Panel~~Coordinator's reasons for the decision; and

(h) if the ~~Rule Change Panel~~Coordinator decides to make Amending Rules arising from the Rule Change Proposal:

i. the wording of the Amending Rules; and

ii. the proposed date and time that the Amending Rules will commence.

2.7. Standard Rule Change Process

2.7.1. Any person may make a submission to the ~~Rule Change Panel~~Coordinator relating to a Rule Change Proposal within the time frame specified under clause 2.5.7(f)(iii).

2.7.2. Subject to its obligations of confidentiality under these Rules and ~~the Panel Regulations~~ otherwise, the ~~Rule Change Panel~~Coordinator must release to the public all information submitted under clause 2.7.1 ~~to the public~~.

2.7.3. The ~~Rule Change Panel~~Coordinator may hold public forums or workshops concerning a Rule Change Proposal.

2.7.4. Within one Business Day after the publication of a notice of a Rule Change Proposal in accordance with clause 2.5.7, the ~~Rule Change Panel~~Coordinator must notify the members and observers of the Market Advisory Committee as to whether the ~~Rule Change Panel~~Coordinator considers the Rule Change Proposal requires convening a meeting of the Market Advisory Committee and the reasons why.

2.7.5. The ~~Rule Change Panel~~MAC Secretariat must convene a meeting of the Market Advisory Committee concerning a Rule Change Proposal before the due date for submissions in relation to the Rule Change Proposal if:

(a) the ~~Rule Change Panel~~Coordinator considers that advice on the Rule Change Proposal is required from the Market Advisory Committee; or

(b) ~~two or more members~~the independent Chair of the Market Advisory Committee ~~have~~ has informed the ~~Rule Change Panel~~Coordinator in writing that ~~they~~ she or he considers that advice on the Rule Change Proposal is required from the Market Advisory Committee.

2.7.6. Within 20 Business Days following the close of submissions, the ~~Rule Change Panel~~Coordinator must:

(a) prepare and publish a Draft Rule Change Report on the Rule Change Proposal; and

(b) publish a deadline for further submissions in relation to the Rule Change Proposal, where that deadline must be at least 20 Business Days after the date the deadline is published.

2.7.7. The Draft Rule Change Report must contain:

(a) the information in the notice of the Rule Change Proposal under clause 2.5.7;

(b) all submissions received before the due date for submissions, a summary of those submissions, and the ~~Rule Change Panel~~Coordinator's response to issues raised in those submissions (and the report may in the Coordinator's discretion contain any or all of this material in respect of a submission received after the due date);

(c) a summary of any public forums or workshops held;

(d) a summary of the views expressed by the members of the Market Advisory Committee where the Market Advisory Committee met to consider the Rule Change Proposal and, if the Market Advisory Committee has delegated its role to consider the Rule Change Proposal to a Working Group under clause 2.3.17(a), a summary of the views expressed by that Working Group;

(e) the ~~Rule Change Panel~~Coordinator's assessment of the Rule Change Proposal in light of clauses 2.4.2 and 2.4.3;

(f) a proposal as to whether the Rule Change Proposal should be accepted in the form proposed. The proposal may be that:

i. the Rule Change Proposal be accepted in the proposed form; or

ii. the Rule Change Proposal be accepted in a modified form; or

iii. the Rule Change Proposal be rejected; and

(g) if the ~~Rule Change Panel~~Coordinator proposes to make Amending Rules arising from the Rule Change Proposal:

i. the wording of the proposed Amending Rules; and

ii. a proposed date and time the proposed Amending Rules will commence.

2.7.7A. Within 20 Business Days of the deadline specified under clause 2.7.6(b), the ~~Rule Change Panel~~Coordinator must:

(a) decide whether to:

i. accept the Rule Change Proposal in the proposed form; or

ii. accept the Rule Change Proposal in a modified form; or

iii. reject the Rule Change Proposal; and

(b) prepare and publish a Final Rule Change Report on the Rule Change Proposal.

2.7.8. The Final Rule Change Report must contain:

(a) the information in the Draft Rule Change Report;

(b) all submissions received before the deadline for submissions specified in relation to the relevant Draft Rule Change Report under clause 2.7.6(b), a summary of those submissions, and the ~~Rule Change Panel~~Coordinator's response to the issues raised in those submissions (and the report may in the Coordinator's discretion contain any or all of this material in respect of a submission received after the deadline);

(c) any further analysis or modification to the Rule Change Proposal;

(d) the ~~Rule Change Panel~~Coordinator's assessment of the Rule Change Proposal in light of clauses 2.4.2 and 2.4.3;

(e) the decision made by the ~~Rule Change Panel~~Coordinator under clause 2.7.7A(a) on the Rule Change Proposal;

(f) the ~~Rule Change Panel~~Coordinator's reasons for the decision; and

(g) if the ~~Rule Change Panel~~Coordinator decides to make Amending Rules arising from the Rule Change Proposal:

i. the wording of the Amending Rules; and

ii. the proposed date and time that the Amending Rules will commence.

2.8. Review of ~~Rule Change Panel~~Coordinator Rule Amendment Decisions, Ministerial Approval and Coming into Force of Rule Amendments

2.8.1. A Rule Participant may apply to the Electricity Review Board for a Procedural Review of a decision by the ~~Rule Change Panel~~Coordinator contemplated by clause 2.5.6(c), 2.5.9, 2.6.3A(a) or 2.7.7A(a) within the time specified in regulation 44 of the WEM Regulations, on the grounds that the ~~Rule Change Panel~~Coordinator has not followed the rule change process set out in ~~clauses~~ sections 2.5, 2.6 and 2.7.

2.8.2. Following an application for a Procedural Review under clause 2.8.1, if the Electricity Review Board finds that the ~~Rule Change Panel~~Coordinator has not followed the rule change process set out in ~~clauses~~ sections 2.5, 2.6 and 2.7 the Electricity Review Board may set aside the ~~Rule Change Panel~~Coordinator's decision and direct the ~~Rule Change Panel~~Coordinator to reconsider the relevant Rule Change Proposal in accordance with the process set out in ~~clauses~~ sections 2.5, 2.6 and 2.7.

2.8.3. The ~~Rule Change Panel~~Coordinator must submit a Rule Change Proposal, together with the Final Rule Change Report, to the Minister for approval where Amending Rules in the Final Rule Change Report:

(a) amend or replace a Protected Provision, or, in the ~~Rule Change Panel~~Coordinator's opinion, would have the effect of changing the meaning or effect of one or more Protected Provisions;

(b) are subject to the requirements in clause 2.5.8A.

2.8.4. Subject to clause 2.8.6, the Minister must consider the Rule Change Proposal within 20 Business Days and decide whether the Market Rules, as amended or replaced by the proposed Amending Rules, are consistent with the Wholesale Market Objectives.

2.8.5. Where a Rule Change Proposal is submitted under clause 2.8.3, the Minister may:

(a) approve the proposed Amending Rules;

(b) not approve the proposed Amending Rules; or

(c) send back to the ~~Rule Change Panel~~Coordinator the proposed Amending Rules with any revisions the Minister considers are required to ensure the Market Rules, as amended or replaced by the proposed Amending Rules, are consistent with the Wholesale Market Objectives.

2.8.6. The Minister may extend the time for a decision on a Rule Change Proposal under clause 2.8.4 by a further period of up to 20 Business Days by notice to the ~~Rule Change Panel~~Coordinator. The Minister may extend the time for a decision in respect of a Rule Change Proposal more than once.

2.8.7. The ~~Rule Change Panel~~Coordinator must publish notice of any extension under clause 2.8.6 on the Market Web Site.

2.8.8. Where the Minister does not make a decision by the original date determined in accordance with clause 2.8.4, or by an extended date determined in accordance with clause 2.8.6, as applicable, then the proposed Amending Rules will be taken to have been approved by the Minister.

2.8.9. Where the Minister does not approve the proposed Amending Rules or sends proposed Amending Rules back to the ~~Rule Change Panel~~Coordinator under clause 2.8.5(c), the Minister must give reasons, and the ~~Rule Change Panel~~Coordinator must publish a notice of the Minister's decision and the reasons given by the Minister.

2.8.10. Where the Minister sends proposed Amending Rules back to the ~~Rule Change Panel~~Coordinator in accordance with clause 2.8.5(c), the ~~Rule Change Panel~~Coordinator must:

(a) publish the revised Amending Rules and call for submissions on the revised Amending Rules within 15 Business Days of publication; and

(b) provide a revised Final Rule Change Report, including any submissions received on the Minister's revised Amending Rules to the Minister within 25 Business Days of the close of the consultation period and clauses 2.8.4 to this clause 2.8.10 apply to the revised Final Rule Change Report.

2.8.11. Amending Rules are made:

(a) for Rule Change Proposals to which clause 2.8.3 applies, when the Minister has either approved, or is taken by clause 2.8.8 to have approved, the Amending Rules; and

(b) for Rule Change Proposals to which clause 2.8.3 does not apply, when the ~~Rule Change Panel~~Coordinator has decided to make the Amending Rules as notified under clause 2.6.3A(b) or clause 2.7.7A(b).

2.8.12. Subject to clause 2.8.2, ~~-~~Amending Rules commence at the time and date determined by the ~~Rule Change Panel~~Coordinator. The ~~Rule Change Panel~~Coordinator must publish notice of the time and date Amending Rules commence.

2.8.13. The following clauses are Protected Provisions:

(a) clauses 1.1 to 1.3 and 1.5 to 1.9, 1.17A~~-~~;

(b) clauses 2.1 to 2.25, 2.28, 2.31.1, 2.31.3, 2.31.6, 2.34.1 and 2.36.1;

(c) clauses 3.8.4, 3.15, 3.18.18 and 3.18.19;

(d) clauses 4.1.4 to 4.1.12, 4.1.15 to 4.1.19, 4.1.21, 4.1.24, 4.5.10, 4.5.11, 4.5.15 to 4.5.20, 4.5A, 4.13.10, 4.13.10A, 4.13.10B, 4.13.11, 4.13.11A, 4.13A.15, 4.13A.16 4.16, 4.24.1, 4.24.2 and 4.24.12, 4.24.19;

(e) [Blank]

(f) clauses 9.13.1, 9.16.3, 9.16.4 and 9.20.2;

(g) clauses 10.1.1, 10.1.2, 10.2.1, 10.2, 10.3 and 10.4.; and

(h) any other clauses of these Market Rules that must not be amended, repealed or replaced without the approval of the Minister in accordance with the WEM Regulations.

2.9. Market Procedures

…

2.9.2C. The ~~Rule Change Panel~~Coordinator must manage the development of, amendment of, and replacement for Market Procedures which these Market Rules require be developed by the ~~Rule Change Panel~~Coordinator.

…

2.9.5. The ~~Rule Change Panel~~Coordinator must develop a Market Procedure setting out the procedure for developing and amending Market Procedures.

. . .

2.9.7C. The ~~Rule Change Panel~~Coordinator must comply with Market Procedures applicable to it.

2.10. Procedure Change Process

2.10.1. The ~~Rule Change Panel~~Coordinator, AEMO, System Management, the Economic Regulation Authority or a Network Operator, as applicable, may initiate the Procedure Change Process by developing a Procedure Change Proposal.

2.10.2. Rule Participants may notify the ~~Rule Change Panel~~Coordinator, AEMO, System Management, the Economic Regulation Authority or the relevant Network Operator, as applicable, where they consider an amendment to or replacement of a Market Procedure would be appropriate.

2.10.2A. Within 20 Business Days of receipt of a notification under clause 2.10.2, the ~~Rule Change Panel~~Coordinator, AEMO, System Management, the Economic Regulation Authority or the Network Operator, as applicable, must:

(a) determine whether the suggested amendment to or replacement of a Market Procedure is appropriate; and

(b) publish on the Market Web Site details of whether a Procedure Change Proposal will be progressed with respect to the suggested amendment to or replacement of a Market Procedure and the reasons for that decision.

2.10.3. If an Amending Rule requires the ~~Rule Change Panel~~Coordinator, AEMO, System Management, the Economic Regulation Authority or a Network Operator to develop new Market Procedures or to amend or replace existing Market Procedures, then the ~~Rule Change Panel~~Coordinator, AEMO, System Management, the Economic Regulation Authority or the Network Operator, as applicable, is responsible for the development of, amendment of or replacement for, Market Procedures so as to comply with the Amending Rule.

2.10.4. [Blank]

2.10.5. [Blank]

2.10.5A. AEMO must publish Procedure Change Proposals that AEMO develops (including in its capacity as System Management).

2.10.5B. The Economic Regulation Authority must publish Procedure Change Proposals that the Economic Regulation Authority develops.

2.10.5C. The ~~Rule Change Panel~~Coordinator must publish Procedure Change Proposals that the ~~Rule Change Panel~~Coordinator develops.

2.10.5D. A Network Operator must publish Procedure Change Proposals that the Network Operator develops.

2.10.6. A Procedure Change Proposal must include:

(a) a proposed Market Procedure or an amendment to or replacement for a Market Procedure~~.~~, indicating the proposed amended words, or a proposed Market Procedure; and

(b) the reason for the proposed Market Procedure or an amendment to or replacement for a Market Procedure or proposed Market Procedure.

2.10.7. At the same time as it publishes a Procedure Change Proposal notice, the ~~Rule Change Panel~~Coordinator, AEMO, the Economic Regulation Authority or the Network Operator, as applicable, must publish a call for submissions on that proposal. The due date for submissions must be 20 Business Days from the date the call for submissions is published. Any person may make a submission to the ~~Rule Change Panel~~Coordinator, AEMO, the Economic Regulation Authority or the Network Operator, as applicable, relating to a Procedure Change Proposal. A Procedure Change Submission may be made using the Procedure Change Submission form maintained on the Market Web Site in accordance with clause 2.9.4.

2.10.8. [blank]

2.10.9. The ~~Rule Change Panel~~Coordinator must convene a meeting of the Market Advisory Committee concerning any Procedure Change Proposal before the due date for submissions in relation to the Procedure Change Proposal if:

(a) the ~~Rule Change Panel~~Coordinator, AEMO or the Economic Regulation Authority considers that advice on the Procedure Change Proposal is required from the Market Advisory Committee;

(aA) a Network Operator considers that advice on the Procedure Change Proposal prepared by a Network Operator is required from the Market Advisory Committee; or

(b) ~~two or more members~~the independent Chair of the Market Advisory Committee ~~have~~ has informed the ~~Rule Change Panel~~Coordinator in writing that ~~they~~ she or he considers that advice on the Procedure Change Proposal is required from the Market Advisory Committee.

2.10.10. Following the closing date for submissions, the ~~Rule Change Panel~~Coordinator, AEMO, System Management or the Economic Regulation Authority, as applicable, must prepare a Procedure Change Report on the Procedure Change Proposal.

2.10.11. [Blank]

2.10.12. [Blank]

2.10.12A. AEMO must publish Procedure Change Reports that AEMO prepares (including in its capacity as System Management).

2.10.12B. The Economic Regulation Authority must publish Procedure Change Reports that the Economic Regulation Authority prepares.

2.10.12C. The ~~Rule Change Panel~~Coordinator must publish Procedure Change Reports that the ~~Rule Change Panel~~Coordinator prepares.

2.10.12D. A Network Operator must publish Procedure Change Reports that the Network Operator prepares.

2.10.13. The Procedure Change Report must contain:

(a) the wording of the proposed Market Procedure or amendment to or replacement for the Market Procedure;

(b) the reason for the proposed Market Procedure or amendment to or replacement for the Market Procedure;

(c) all submissions received before the due date for submissions, a summary of those submissions, and the response of the ~~Rule Change Panel~~Coordinator, AEMO, System Management or the Economic Regulation Authority, as applicable, to the issues raised in those submissions;

(d) a summary of the views expressed by the Market Advisory Committee and, if the Market Advisory Committee has delegated its role to consider the Procedure Change Proposal to a Working Group under clause 2.3.17(a), a summary of the views expressed by that Working Group;

(dA) whether any advice from the Market Advisory Committee regarding the Procedure Change Proposal reflects a consensus view or a majority view, and, if the latter, any dissenting views included in or accompanying the advice;

(e) [Blank]

(f) in the case of a Procedure Change Proposal developed by the ~~Rule Change Panel~~Coordinator, a proposed date and time for the Market Procedure or amendment or replacement to commence, which must, in the ~~Rule Change Panel~~Coordinator's opinion, allow sufficient time after the date of publication of the Procedure Change Report for Rule Participants to implement changes required by it;

(g) in the case of a Procedure Change Proposal developed by AEMO (including in its capacity as System Management), a proposed date and time for the Market Procedure or amendment or replacement to commence, which must, in AEMO's opinion, allow sufficient time after the date of publication of the Procedure Change Report for Rule Participants to implement changes required by it;

(h) in the case of a Procedure Change Proposal developed by the Economic Regulation Authority, a proposed date and time for the Market Procedure or amendment or replacement to commence, which must, in the Economic Regulation Authority's opinion, allow sufficient time after the date of publication of the Procedure Change Report for Rule Participants to implement changes required by it; and

(i) in the case of a Procedure Change Proposal developed by a Network Operator, a proposed date and time for the Market Procedure or amendment or replacement to commence, which must, in the Network Operator's opinion, allow sufficient time after the date of publication of the Procedure Change Report for Rule Participants to implement changes required by it.

2.10.14. [Blank]

2.10.15. [Blank]

2.10.16. [Blank]

2.10.17. If the ~~Rule Change Panel~~Coordinator, AEMO, the Economic Regulation Authority or a Network Operator, as applicable, considers, at any time after publishing a Procedure Change Proposal, that it is necessary to extend the normal timeframes for processing the Procedure Change Proposal because:

(a) issues of sufficient complexity or difficulty have been identified relating to the Procedure Change Proposal; or

(b) further public consultation on an issue associated with the Procedure Change Proposal is required; or

(c) the Procedure Change Proposal cannot be dealt with adequately without an extension because of any other special circumstance,

then the ~~Rule Change Panel~~Coordinator, AEMO, the Economic Regulation Authority or the Network Operator, as applicable, may modify the times and time periods under clause 2.10.7 in respect of the Procedure Change Proposal and publish details of the modified times and time periods.

2.10.18. The ~~Rule Change Panel~~Coordinator, AEMO, the Economic Regulation Authority or a Network Operator, as applicable, must publish a notice of an extension determined in accordance with clause 2.10.17 and must update any information already published in accordance with clause 2.10.7.

2.10.19. A notice of extension under clause 2.10.18 must include:

(a) the reasons for the proposed extension;

(b) the views of any Rule Participant consulted on the extension;

(c) the proposed length of any extension; and

(d) the proposed work program.

2.11. Coming into Force of Procedure Amendments

2.11.1. A Rule Participant may apply to the Electricity Review Board for a Procedural Review of a decision by the ~~Rule Change Panel~~Coordinator, AEMO, System Management, the Economic Regulation Authority or a Network Operator, as applicable, contemplated by clauses 2.10.2A(a) or 2.10.13 within the time specified in regulation 44 of the WEM Regulations, on the grounds that the ~~Rule Change Panel~~Coordinator, AEMO, System Management, the Economic Regulation Authority or the Network Operator, as applicable, has not followed the process set out in section 2.10 or the Market Procedure specified in clause 2.9.5.

2.11.2. Following an application for a Procedural Review under clause 2.11.1, if the Electricity Review Board finds that the ~~Rule Change Panel~~Coordinator, AEMO, System Management, the Economic Regulation Authority or a Network Operator has not followed the process set out in section 2.10 or the Market Procedure specified in clause 2.9.5, the Electricity Review Board may set aside the ~~Rule Change Panel~~Coordinator's decision, AEMO's decision, System Management's decision, the Economic Regulation Authority's decision or the Network Operator's decision and direct the ~~Rule Change Panel~~Coordinator, AEMO, System Management, the Economic Regulation Authority or the Network Operator to reconsider the relevant Procedure Change Proposal in accordance with section 2.10 and the Market Procedure specified in clause 2.9.5.

2.11.3. Subject to clauses 2.11.2 and 2.11.4, a Market Procedure or an amendment of or replacement for a Market Procedure commences at the time and date specified under clauses 2.10.13(f), 2.10.13(g), 2.10.13(h) or 2.10.13(i) (as applicable).

2.11.4. If at any time, the ~~Rule Change Panel~~Coordinator, AEMO, the Economic Regulation Authority or a Network Operator considers that Rule Participants will not have sufficient time to implement any necessary changes required by the Market Procedure that the ~~Rule Change Panel~~Coordinator, AEMO, the Economic Regulation Authority or the Network Operator, as applicable, are required to publish, or amendment or replacement of the Market Procedure, then the ~~Rule Change Panel~~Coordinator, AEMO, the Economic Regulation Authority or the Network Operator, as applicable, may extend the time and date when that Market Procedure, amendment or replacement commences by publishing notice of the revised time and date when the amendment of or replacement for that Market Procedure commences.

. . .

2.16. Monitoring the Effectiveness of the Market

. . .

2.16.2. AEMO must develop a Market Surveillance Data Catalogue, which identifies data to be compiled concerning the market. The Market Surveillance Data Catalogue must identify the following data items:

...

(o) the number of Rule Change Proposals received, and details of Rule Change Proposals that the ~~Rule Change Panel~~Coordinator has decided not to progress under clause 2.5.6; and

(p) such other items of information as AEMO considers relevant to the functions of the ~~Rule Change Panel~~Coordinator, AEMO and the Economic Regulation Authority under this ~~clause~~ section 2.16.

...

2.16.6. Where the Economic Regulation Authority considers that it is necessary or desirable for the performance of its functions, or the functions of AEMO under this ~~clause~~ section 2.16, the Economic Regulation Authority may collect additional information from Rule Participants or the ~~Rule Change Panel~~Coordinator as follows:

(a) the Economic Regulation Authority may issue a notice to one or more Rule Participants or the ~~Rule Change Panel~~Coordinator requiring them to provide specified data to the Economic Regulation Authority by a date (which the Economic Regulation Authority considers to be reasonable);

(b) Market Participants ~~or the Rule Change Panel (as applicable)~~ must provide any information requested by the Economic Regulation Authority by the date specified in the notice; and

(bA) subject to its obligations of confidentiality under these Rules or otherwise, the Coordinator must use reasonable endeavours to provide any information requested by the Economic Regulation Authority by the date specified in the notice; and

(c) the Economic Regulation Authority must provide this information to AEMO where the Economic Regulation Authority considers that it is necessary or desirable for the performance of AEMO's functions under this ~~clause~~ section 2.16.

...

2.17. Reviewable Decisions

2.17.1. Decisions by the ~~Rule Change Panel~~Coordinator, AEMO, System Management, the Economic Regulation Authority or a Network Operator, as applicable, made under the following clauses are Reviewable Decisions:

...

2.17.2. Decisions by the ~~Rule Change Panel~~Coordinator, AEMO, System Management, the Economic Regulation Authority or a Network Operator, as applicable, made under the following clauses may be subject to a Procedural Review:

(a) clauses 2.5.6(c), 2.5.9, 2.6.3A(a) and 2.7.7A(a); and

(b) clauses 2.10.2A(a) and 2.10.13.

...

2.18. Disputes

2.18.1. The dispute process set out in clauses 2.18, 2.19 and 2.20 applies to any dispute concerning:

(a) the application or interpretation of these Market Rules;

(b) the failure of Rule Participants to reach agreement on a matter where these Market Rules require agreement or require the Rule Participants to negotiate in good faith with a view to reaching agreement;

(c) payment of moneys under, or the performance of any obligation under, these Market Rules,

but does not apply to:

(d) any matter that is identified as a Reviewable Decision or is subject to Procedural Review; or

(e) a matter that arises under a contract between Rule Participants, unless AEMO is a party to the contract and the contract provides that the dispute process applies.

…

2.18.3. At any time during the course of resolving a dispute a Dispute Participant may refer a question of law to a court of competent jurisdiction.

...

2.21. Market Consultation

…

2.21.7. The ~~Rule Change Panel~~Coordinator must consult on such matters with such persons and over such timeframes as are specified in these Market Rules.

2.21.8. The ~~Rule Change Panel~~Coordinator must—

(a) conduct its consultation processes in good faith; and

(b) ensure that these consultation processes allow a reasonable opportunity for relevant stakeholders to present their views.

...

2.22A Determination of AEMO's budget

2.22A.1. For the purposes of this section 2.22A, the services provided by AEMO are:

...

(c) market administration services, including AEMO's performance of the Procedure Change Process, support for the ~~Rule Change Panel~~Coordinator in carrying out its functions under these Market Rules, participation in the Market Advisory Committee and other consultation, support for monitoring and reviews by the Economic Regulation Authority, audit, registration related functions and other functions under these Market Rules;

. . .

2.24. Determination of Market Fees

2.24.1. The fees charged by AEMO are:

(a) Market Fees, System Management Fees, Coordinator Fees and Regulator Fees determined in accordance with clause 2.24.2;

(b) Application Fees described in clauses 2.33.1(a), 2.33.2(a), 2.33.3(a), 2.33.4(a), 2.33.5(a), 4.9.3(c), 4.26.2CC and 4.28.9B; and

(c) a Reassessment Fee described in clause 4.11.11.

2.24.2. Before 30 June each year, AEMO must determine and publish the level of the Market Fee rate, System Management Fee rate, Coordinator Fee rate and Regulator Fee rate, and the level of each of the Application Fees, and the level of the Reassessment Fee to apply over the year starting 1 July in accordance with AEMO's budget published under clause 2.22A.4, ~~and~~ information provided by the Economic Regulation Authority under clause 2.24.6 (if any) and information provided by the Coordinator under clause 2.24.6A (if any). Where the Economic Regulation Authority has not provided AEMO with the information required under clause 2.24.6 by the date which is five Business Days prior to 30 June, AEMO will determine and publish the expected level of Regulator Fee rate based on the most recent information provided to AEMO by the Economic Regulation Authority under clause 2.24.6. Where the Coordinator has not provided AEMO with the information required under clause 2.24.6A by the date which is five Business Days prior to 30 June, AEMO will determine and publish the expected level of Coordinator Fee rate based on the most recent information provided to AEMO by the Coordinator under clause 2.24.6A.

2.24.2A. AEMO must determine and publish a level of revised Market Fee rate, System Management Fee rate, Coordinator Fee rate ~~,~~ or Regulator Fee rate (as applicable) within five Business Days of making any adjustment to AEMO's budget and receiving the information, if in any year the Economic Regulation Authority provides AEMO with the information required under clause 2.24.6 later than the date which is five Business Days prior to 30 June or the Coordinator provides AEMO with the information required under clause 2.24.6A later than the date which is five Business Days prior to 30 June.

2.24.2B A revised Market Fee rate, System Management Fee rate, Coordinator Fee rate and Regulator Fee rate will supersede any expected Market Fee rate, System Management Fee rate, Coordinator Fee rate and Regulator Fee rate and are recoverable from Market Participants in arrears with effect from the start of the Financial Year to which they apply.

2.24.3. At the same time as AEMO publishes a level of revised Market Fee rate, System Management Fee rate. Coordinator Fee rate or Regulator Fee rate (as applicable), AEMO must also publish an estimate of the total amount of revenue to be earned from—

(a) Market Fees collected for—

i. [Blank]

ii. AEMO's—

1. market operation services;

2. system planning services; and

3. market administration services,

where the amounts to be earned for each service is equal to the relevant costs in AEMO's budget published in accordance with clause 2.22A.4 or as adjusted under clause 2.24.2A;

(b) System Management Fees collected for AEMO's system management services where the amount to be earned is equal to the relevant costs in AEMO's budget published in accordance with clause 2.22A.4 or as adjusted under clause 2.24.2A; ~~and~~

~~(c)~~ Regulator Fees collected for~~—~~

~~i.~~ the Economic Regulation Authority's monitoring, compliance, enforcement and regulation services ~~and RCP Secretariat Support Services; and~~

~~ii. the Rule Change Panel's market administration services, where the amount to be earned for those services is equivalent to the costs identified by the Economic Regulation Authority as costs incurred in the performance of the Rule Change Panel's functions under these Market Rules or the WEM Regulations,~~

~~and in each case,~~ where the amount must be consistent with the relevant amount notified in accordance with clause 2.24.6; and

(d) Coordinator Fees collected for:

i. the Coordinator's functions under these Market Rules; and

ii. the costs associated with the remuneration and other expenses for the independent Chair of the Market Advisory Committee,

where the amount to be earned for those services is equivalent to the costs identified by the Coordinator as costs incurred in the performance of the Coordinator's functions under these Market Rules or the WEM Regulations, where

the amount must be consistent with the relevant amount notified in accordance with clause 2.24.6A.

2.24.4. The Market Fee rate, System Management Fee rate, the Coordinator Fee rate and Regulator Fee rate should be set at a level that AEMO estimates will earn revenue equal to the relevant estimate of revenue under clause 2.24.3.

2.24.5. The Economic Regulation Authority may recover a portion of its budget determined by the Minister responsible for the Economic Regulation Authority which corresponds to the costs of the Economic Regulation Authority in undertaking its Wholesale Electricity Market related functions and other functions under these Market Rules, the WEM Regulations and the Electricity Industry Act ~~Panel Regulations~~ from the collection of Regulator Fees under these Market Rules. The Economic Regulation Authority must identify in its budget the proportion of its costs that relate to the performance of its Wholesale Electricity Market related functions and its other functions.

2.24.5A Where the revenue earned via Regulator Fees in the previous Financial Year is greater than or less than the Economic Regulation Authority expenditure related to the functions described in clause 2.24.5 for that Financial Year, the current year's budget must take this into account by decreasing the budgeted revenue by the amount of the surplus or adding to the budgeted revenue the amount of any shortfall, as the case may be.

2.24.5B. The Coordinator may recover a portion of its budget determined by the Minister responsible for the Coordinator which corresponds to the costs of the Coordinator in undertaking its functions under these Market Rules from the collection of Coordinator Fees under these Market Rules. The Coordinator must identify in its budget the proportion of its costs that relate to the performance of its functions under these Market Rules.~~The Economic Regulation Authority may recover, on behalf of the Rule Change Panel, the costs identified by the Economic Regulation Authority as costs incurred in the performance of the Rule Change Panel's functions under these Market Rules or the WEM Regulations, from the collection of Regulator Fees under these Market Rules.~~

2.24.5C Where the revenue earned via Coordinator Fees in the previous Financial Year is greater than or less than the Coordinator expenditure related to the functions described in clause 2.24.5B for that Financial Year, the current year's budget must take this into account by decreasing the budgeted revenue by the amount of the surplus or adding to the budgeted revenue the amount of any shortfall, as the case may be.

2.24.6. By the date which is five Business Days prior to 30 June each year, the Economic Regulation Authority must notify AEMO of—

~~(a)~~ the dollar amount that the Economic Regulation Authority may recover under clause 2.24.5.~~; and~~

~~(b) the dollar amount that the Economic Regulation Authority may recover under clause 2.24.5B (to the extent such amount is not already included in the dollar amount referred to in clause 2.24.6(a)).~~

2.24.6A. By the date which is five Business Days prior to 30 June each year, the Coordinator must notify AEMO of the dollar amount that the Coordinator may recover under clause 2.24.5B.

2.24.7. The level of each Application Fee:

(a) must reflect the estimated average costs to AEMO of processing that type of application;

(b) must be consistent with the Allowable Revenue approved by the Economic Regulation Authority; and

(c) may be different for different classes of Rule Participant and different classes of facility.

2.25. Payment of Market Participant Fees

2.25.1. AEMO must charge a Market Participant the relevant payment amount for Market Fees, System Management Fees, Coordinator Fees and Regulator Fees for a Trading Month in accordance with clause 9.13.

2.25.1A. AEMO is an agent for the collection of Coordinator Fees and Regulator Fees payable by Market Participants to AEMO.

2.25.1B. The Economic Regulation Authority must, if requested by AEMO, do all things reasonably necessary (including entering into any agreements) to enable AEMO to give effect to clause 2.25.1A.

2.25.1C. The Coordinator must, if requested by AEMO, use reasonable endeavours to cooperate with AEMO, as AEMO endeavours to give effect to clause 2.25.1A.

2.25.2. Each Market Participant must pay the relevant payment amount for Market Fees, System Management Fees, Coordinator Fees and Regulator Fees in accordance with Chapter 9.

2.25.3. Following receipt of a payment contemplated by clause 2.25.2, AEMO must:

(a) pay to the Economic Regulation Authority in accordance with Chapter 9 an amount corresponding to the part of the payment received multiplied by the relevant proportionality factor; and

(aA) pay to the Coordinator in accordance with Chapter 9 an amount corresponding to the part of the payment received multiplied by the relevant proportionality factor; and

(b) transfer to the fund established under clause 9.22.9 in accordance with Chapter 9 an amount corresponding to the part of the payment received multiplied by the relevant proportionality factor.

2.25.4. The relevant proportionality factor for AEMO, AEMO in its capacity as System Management, the Coordinator or the Economic Regulation Authority for a Financial Year is:

(a) the estimate of the total amount to be earned from Market Fees, System Management Fees, Coordinator Fees or Regulator Fees (as applicable) in respect of the relevant services published for the relevant year under clause 2.24.3; divided by

(b) the estimate of the total amount to be earned from Market Fees, System Management Fees, Coordinator Fees and Regulator Fees in respect of all services published for the relevant year under clause 2.24.3.

~~2.25.4A. The Economic Regulation Authority recovers the proportion of the payment referred to in clause 2.25.3(a) that relates to the costs contemplated in clause 2.24.5B on behalf of the Rule Change Panel.~~

. . .

9.1.2. With respect to the treatment of GST:

…

(g) if AEMO determines that:

i. a party is entitled to payment of any costs or expenses by way of reimbursement or indemnity; or

ii. a price, fee or other charge payable under these Market Rules (other than System Management Fees, the Coordinator Fees and Regulator Fees) is calculated with reference to a cost or expense incurred by a party,

then the payment or cost or expense (as the case may be) must exclude any part of the cost or expense which is attributable to GST for which the party (or a representative member of any GST group of which the party is a member) is entitled to an input tax credit.

…

9.13. The Market Participant Fee Settlement Calculations for a Trading Month

9.13.1. The applicable Market Participant Fee settlement amount for Market Participant p for Trading Month m is:

MPFSA(p,m) = (-1) x (Market Fee rate + System Management Fee rate
+ Coordinator Fee rate + Regulator Fee rate) x
(Monthly Participant Load(p,m) + Monthly Participant Generation(p,m))

Where

. . .

Coordinator Fee rate is the charge per MWh for funding the Coordinator's activities under these Market Rules determined in accordance with clause 2.24.2 for the year in which Trading Month m falls;

Regulator Fee rate is the charge per MWh for funding the Economic Regulation Authority's ~~and the Rule Change Panel's~~ activities with respect to the Wholesale Electricity Market and other functions under these Market Rules and the Regulations determined in accordance with clause 2.24.2 for the year in which Trading Month m falls;

. . .

10.2. Information Confidentiality Status

. . .

10.2.2. The classes of confidentiality status are:

. . .

(c) Rule Participant Market Restricted, in which case the relevant information or documents may only be made available to:

. . .

iiC. the ~~Rule Change Panel~~Coordinator;

. . .

(d) Rule Participant Dispatch Restricted, in which case the relevant information or documents may only be made available to:

. . .

iiC. the ~~Rule Change Panel~~Coordinator;

. . .

(e) System Management Confidential, in which case the relevant information or documents may only be made available to:

. . .

iiA. the ~~Rule Change Panel~~Coordinator;

. . .

(f) AEMO Confidential, in which case the relevant information or documents may only be made available to:

…

iiB. the ~~Rule Change Panel~~Coordinator;

…

iv. … ; ~~and~~

(g) Rule Participant Network Restricted, in which case the relevant information or documents may only be made available to:

…

ivA. the ~~Rule Change Panel~~Coordinator;

…

vii. … ~~.~~; and

(h) Coordinator Restricted, in which case the relevant information or documents may only be made available with the Coordinator's written consent.

. . .

10.2.3. In setting the confidentiality status of a type of market related information or document under clause 10.2.1, and subject to clauses 10.3.2B and 10.3.2BA, AEMO must have regard to the following principles:

. . .

(cb) the ~~Rule Change Panel~~Coordinator may make available to a person information if the ~~Rule Change Panel~~Coordinator is required or permitted to do so by law or these Market Rules;

. . .

10.2.3A. AEMO must consult with the Economic Regulation Authority and obtain the Economic Regulation Authority's consent, prior to setting the confidentiality status of a type of market related information or document under clause 10.2.1 relating to functions of the Economic Regulation Authority under these Market Rules.

10.2.3B. AEMO must consult with the ~~Rule Change Panel~~Coordinator and obtain the ~~Rule Change Panel~~Coordinator's written consent, prior to setting the confidentiality status of a type of market related information or document under clause 10.2.1 relating to functions of the ~~Rule Change Panel~~Coordinator under these Market Rules, and in the absence of such consent must set its confidentiality status as Coordinator Restricted.

10.2.3BA To the extent information or a document relates to the Coordinator's functions under any written law other than these Market Rules, AEMO must set its confidentiality status as Coordinator Restricted unless the Coordinator in her or his absolute discretion agrees otherwise in writing.

. . .

10.3.2. Subject to clause 10.4.2, the ~~Rule Change Panel~~Coordinator, AEMO, the Economic Regulation Authority or a Network Operator must not require a fee for information or documents released or published by the ~~Rule Change Panel~~Coordinator, AEMO, the Economic Regulation Authority or the Network

Operator via the Market Web Site, or via AEMO's web site, the Coordinator's Website, the Economic Regulation Authority's web site or the Network Operator's web site in accordance with the Market Rules or Market Procedures.

. . .

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:

. . .

(r) public reports pertaining to the Wholesale Electricity Market issued by:

i. the ~~Rule Change Panel~~Coordinator;

. . .

(v) summary information pertaining to the account maintained by AEMO for market settlement for the preceding 24 calendar months, including:

i. the end of month balance;

ii. the total income received for transactions in each of the Reserve Capacity Mechanism, the STEM, Balancing Settlement, Market Fees, System Management Fees, Regulator Fees and a single value for all other income;

iii. the total outgoings paid for transactions in each of the Reserve Capacity Mechanism (excluding Supplementary Capacity Contracts), Supplementary Capacity Contracts, the STEM, Balancing Settlement and a single value for all other expenses; and

iv. Service Fee Settlement Amount paid to AEMO and the Economic Regulation Authority;

. . .

Coordinator: The Coordinator referred to in section 4 of the Energy Coordination Act 1994.

Coordinator Fees: The fees determined by AEMO in accordance with section 2.24, and payable by Market Participants to AEMO for the services provided by the Coordinator in undertaking its functions under these Market Rules.

Coordinator's Website: A website or portion of a website maintained by, or on behalf of, the Coordinator**.**

Coordinator Transfer Date: Means 08:00AM on the date the amending rules made under the *Electricity Industry (Wholesale Electricity Market) Regulations 2004* (WA), regulation 7(4)

giving effect to the transfer of functions from the Rule Change Panel to the Coordinator commence operation.[1]

Draft Rule Change Report: The draft report described in clause 2.7.7 and published by the ~~Rule Change Panel~~Coordinator under clause 2.7.6(a) in relation to a Rule Change Proposal.

. . .

Final Rule Change Report: In respect of a Rule Change Proposal to which the Fast Track Rule Change Process applies, the report described in clause 2.6.4 and published by the ~~Rule Change Panel~~Coordinator in accordance with clause 2.6.3A(b). In respect of a Rule Change Proposal to which the Standard Rule Change Process applies, the report described in clause 2.7.8 and published by the ~~Rule Change Panel~~Coordinator in accordance with clause 2.7.7A(b).

. . .

MAC Secretariat: The services, facilities and assistance made available by the Coordinator to the Market Advisory Committee.

…

Market Advisory Committee: An advisory body to the ~~Rule Change Panel~~Coordinator, Economic Regulation Authority and AEMO comprising industry representatives established under clause 2.3.1.

. . .

Market Procedure: The procedures developed by the ~~Rule Change Panel~~Coordinator, AEMO, System Management, the Economic Regulation Authority and a Network Operator, as applicable, in accordance with section 2.9 (including the Power System Operation Procedures developed by System Management) as amended in accordance with the Procedure Change Process.

. . .

Panel Regulations: Means the *Energy Industry (Rule Change Panel) Regulations 2016*.

. . .

Procedure Change Proposal: A proposal developed by the ~~Rule Change Panel~~Coordinator, AEMO, System Management, the Economic Regulation Authority or a Network Operator to initiate a Procedure Change Process.

Procedure Change Report: A final report prepared by the ~~Rule Change Panel~~Coordinator, AEMO, System Management, the Economic Regulation Authority or a Network Operator in relation to a Procedure Change Proposal, containing the information described in clause 2.10.13.

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[1] The amending rules referred to in this definition commenced operation on 26 November 2016.

...

~~**RCP Secretariat**: Means the executive officer of the Rule Change Panel made available by the Economic Regulation Authority in accordance with the Panel Regulations.~~

~~**RCP Secretariat Support Services**: Means the RCP Secretariat and such staff members, services, facilities and assistance as are made available by the Economic Regulation Authority to the Rule Change Panel in accordance with the Panel Regulations.~~

...

Regulations: Any regulations made under the *Electricity Industry Act 2004* (WA) including the WEM Regulations, AEMO Regulations~~, the Panel Regulations~~ and the *Electricity Industry (Independent Market Operator) Repeal Regulations 2018*.

...

Regulator Fees: The fees determined by AEMO in accordance with clause 2.24, and payable by Market Participants to AEMO for the services provided by the Economic Regulation Authority ~~and the Rule Change Panel~~ in undertaking ~~their respective~~its Wholesale Electricity Market related functions and other functions under these Market Rules.

...

Reviewable Decision: Decisions made by the ~~Rule Change Panel~~Coordinator, AEMO, the Economic Regulation Authority or a Network Operator, in respect of which an eligible person may apply to the Electricity Review Board in accordance with section 125 of the Electricity Industry Act and the Regulations, and does not include any decisions of a class specified for this purpose in the Regulations under section 125 of that Act.

Rule Change Panel: Has the meaning given to it in the Panel Regulations.

~~**Rule Change Panel Transfer Date**: Means 08:00AM on the date the amending rules made under the *Electricity Industry (Wholesale Electricity Market) Regulations 2004* (WA), regulation 7(4) giving effect to the transfer of functions from the IMO to the Rule Change Panel commence operation.[2]~~

Rule Change Proposal: A proposal made in accordance with clause 2.5 proposing that the ~~Rule Change Panel~~Coordinator make~~s~~ Amending Rules.

~~[2] The amending rules referred to in this definition commenced operation on 26 November 2016.~~

Appendix B

Draft GSI Rules Amendments– Transfer of Functions from the RCP to the Coordinator

Appendix B

DRAFT GSI RULES AMENDMENTS

TRANSFER FROM RCP TO COE

…

3 Duty to act in good faith

(1) A Gas Market Participant must perform the obligations imposed by the Rules in good faith.

(2) The ~~Rule Change Panel~~Coordinator, AEMO and the ERA must exercise their powers and discharge their duties under the Rules in good faith.

3A ~~GSI Website~~ Publication

(1) [Blank]

(2) Where the ERA ~~or the Rule Change Panel~~ is required by the Rules to publish or release a document or information or maintain a document or information on the GSI Website, then—

(a) the ERA must make that document or information available on its website;

(b) the ERA must promptly notify AEMO when the document or information is published on the ERA's website;

(c) AEMO must, as a minimum, promptly publish a link to the relevant area of the ERA's website on the GSI Website; and

(d) the ERA ~~or the Rule Change Panel (as applicable)~~ is deemed to have published or released the document or information, and maintained it on the GSI Website, once the ERA has published or released the document or information on its own website, and has notified AEMO.

(3) Where the Coordinator is required by the Rules to publish or release a document or information the Coordinator must make that document or information available on the Coordinator's Website.

…

5 Single documentation

(1) This rule applies if the ~~Rule Change Panel~~Coordinator, AEMO or the ERA is authorised to prepare a document under the GSI Act, the GSI Regulations~~, the Panel Regulations~~ or the Rules for a purpose and is also authorised to prepare a document for the same or a similar, related or corresponding purpose, under the Electricity Laws.

(2) The ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) may satisfy the requirements of the GSI Act, the GSI Regulations~~, the Panel Regulations~~ and the Rules regarding the document under the GSI Act, the GSI Regulations~~, the Panel Regulations~~ or the Rules, by preparing and making (and where relevant, publishing) a single document.

…

Division 3 Procedure for consultation

7 GSI Consultation Procedure

(1) If the Rules require the ~~Rule Change Panel~~Coordinator, AEMO or the ERA to make an instrument (however described) in accordance with the GSI Consultation Procedure, the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) must proceed in accordance with this rule.

(2) The ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) must proceed as follows:

(a) the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) must, after such consultation (if any) as the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) considers appropriate, prepare a draft instrument;

(b) the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) must publish, on the GSI Website and in any other way the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) considers appropriate, the draft instrument together with a notice:

(i) stating why the instrument is required;

(ii) giving reasonable details of the context in which the draft instrument has been prepared, the issues involved and the possible effects of the instrument; and

(iii) inviting written submissions on the draft instrument within a period (at least 20 Business Days) stated in the notice;

(c) the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) must publish submissions received on the GSI Website, subject to the requirements relating to Protected Information; and

(d) the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) must, as soon as reasonably practicable after the end of the period allowed for making submissions on the draft instrument, consider all relevant submissions made within the time allowed and make the instrument in its final form.

(3) The ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) must prepare a written notice stating the reasons for making the instrument in its final form.

(4) After making an instrument, the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) must, without delay, publish the instrument and the written notice under subrule (3) relating to it on the GSI Website.

(5) Subject to any other provisions in the Rules, an instrument made in accordance with this rule takes effect on the date provided for its commencement under the terms of the instrument or, if no date is so provided, 10 Business Days after the date the instrument was made.

Division 4 Functions and powers of the ~~Rule Change Panel~~Coordinator, AEMO and ERA

8 Functions and powers of the ~~Rule Change Panel~~Coordinator, AEMO and ERA

(1) AEMO has the following functions and powers—

(a) to establish, operate and maintain the GBB;

(b) to register certain Gas Market Participants as Registered Participants;

(c) to register certain Facilities as Registered Facilities, and to exempt certain facilities from the requirement to be registered;

(d) to prepare and publish the GSOO;

(e) [blank];

(f) Procedure making functions, to the extent to which the Procedures relate to its functions under the Rules;

(g) [blank];

(h) [blank];

(i) [blank];

(j) information gathering and disclosure functions, to the extent to which the information gathering and disclosure functions relate to its other functions conferred on AEMO under the GSI Regulations and the Rules;

(ja) to support—

(i) the ERA's monitoring of persons' compliance with the Rules or Procedures;

(ii) the ERA's investigation of breaches or possible breaches of the Rules or the Procedures (including by reporting possible breaches to the ERA); and

(iii) any enforcement action taken by the ERA under the GSI Regulations or Rules;

(jb) to provide information to and assist the Coordinator as required to support the Coordinator's functions under the Rules; and

(k) any other functions conferred on AEMO under the GSI Act, the GSI Regulations and the Rules.

(1A) [Blank]

(1B) The ERA has the following functions and powers—

(a) Procedure making functions, to the extent to which the Procedures relate to its functions under the Rules;

(b) to monitor compliance by persons with the Rules or Procedures;

(c) to investigate breaches or possible breaches of the Rules or the Procedures;

(d) to take enforcement action under the GSI Regulations and Rules;

(e) information gathering and disclosure functions, to the extent to which the information gathering and disclosure functions relate to its other functions conferred on the ERA under the GSI Regulations and the Rules;

(f) [Blank]

(fa) [blank]~~to provide the RCP Secretariat Support Services to the Rule Change Panel in accordance with the Panel Regulations~~; and

(g) any other functions conferred on the ERA under the GSI Act, the GSI Regulations~~, the Panel Regulations~~ and the Rules.

(1C) Subject to subrule (1D), the ~~Rule Change Panel~~Coordinator has the following functions and powers—

(a) r~~R~~ule making functions;

(aA) to consider, and in the Coordinator's discretion and in consultation with the Gas Advisory Board, progress the evolution of the Rules;

(b) Procedure making functions, to the extent to which the Procedures relate to ~~its~~ the Coordinator's functions under the Rules;

(c) information gathering and disclosure functions, to the extent to which the information gathering and disclosure functions relate to its other functions conferred on the ~~Rule Change Panel~~Coordinator under the GSI Regulations~~, the Panel Regulations~~ and the Rules; and

(d) any other functions conferred on the ~~Rule Change Panel~~Coordinator under the GSI Act, the GSI Regulations~~, the Panel Regulations~~ and the Rules.

(1D) [blank]~~Subrule (1C)(a) commences operation on and from 08:00AM on 3 April 2017, in accordance with regulation 2(b) of the *Gas Services Information Amendment Regulations (No.2) 2016*.~~

(2) Each of the ~~Rule Change Panel~~Coordinator, AEMO and the ERA has the power to do all things necessary or convenient to be done for or in connection with the performance of its respective functions as specified in subrule (1), subrule (1B) and subrule (1C) (as applicable).

Division 5 Information provision and disclosure

9 Provision of information to ~~Rule Change Panel~~Coordinator, AEMO and ERA

Where the Rules require a Gas Market Participant to submit information to the ~~Rule Change Panel~~Coordinator, AEMO or the ERA, the participant must do so in the manner and form (including by the date or dates) specified by the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable).

10 [Blank]Use and disclosure of information by Coordinator

(1) The Coordinator must take all reasonable measures to protect Confidential Information from unauthorised use or disclosure.

(2) The Coordinator is authorised to use any information, including Confidential Information, obtained in the course of performing a function under these Rules for the purposes of performing any function conferred on the Coordinator under these

Rules, the GSI Regulations, s4A of the *Energy Coordination Act 1994* (WA) or another written law.

(3) For the purposes of subrule (1), authorised disclosure of Confidential Information includes the following—

(a) disclosure with the written consent of the person to whom the information relates;

(b) disclosure that is authorised or required under —

(i) these Rules; or

(ii) the GSI Regulations; or

(iii) a written law; or

(c) disclosure required for the purposes of —

(i) civil or criminal proceedings; or

(ii) proceedings before a tribunal or review body established under a written law or a law of the Commonwealth, a State or a Territory;

(d) disclosure of statistical or other information that could not reasonably be expected to lead to the identification of any person to whom the information relates;

(e) disclosure of information if the information is in the public domain;

(f) disclosure of information to the Minister responsible for administering the GSI Act.

Division 6 Gas Advisory Board

11 ~~Rule Change Panel~~Coordinator to establish Gas Advisory Board

(1) The ~~Rule Change Panel~~Coordinator must establish a non-voting advisory board to be known as the Gas Advisory Board.

(2) The role of the Gas Advisory Board is to advise—

(a) the ~~Rule Change Panel~~Coordinator in relation to Rule Change Proposals and the ~~Rule Change Panel~~Coordinator, AEMO and the ERA in relation to Procedure Change Proposals;

(b) the ~~Rule Change Panel~~Coordinator in relation to matters concerning the development of the Rules and the ~~Rule Change Panel~~Coordinator, AEMO and the ERA in relation to matters concerning the development of Procedures; and

(ba) the Coordinator regarding matters concerning, and the Coordinator's plans for, the evolution of these Rules.

(c) [Blank]; and

(d) [Blank].

(3) The ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) must, subject to applicable requirements relating to Protected Information under the GSI Act , the GSI Regulations and these Rules ~~Panel Regulations~~, provide the members of the Gas Advisory Board with any information in its possession that is pertinent to the issues being addressed by the Gas Advisory Board.

(4) Subject to subrule (5), the Gas Advisory Board must endeavour to provide a consensus position and note any dissenting views when providing advice to the Coordinator.

(5) If, after allowing a reasonable time for discussion, the Chair of the Gas Advisory Board determines that a consensus position either will not be achieved, or is unlikely to be achieved within a time which is reasonable in the circumstances, then the Chair must provide advice to the Coordinator which reflects any majority view and which includes or is accompanied by the dissenting views.

12 Composition of the Gas Advisory Board

(1) The Gas Advisory Board must consist of:

(a) an independent ~~chairperson~~Chair, who must be a person appointed by the ~~chairperson of the Rule Change Panel~~Minister in accordance with subrule (3);

(b) one person from AEMO;

(c) ~~one~~ two persons nominated by the Minister representing small end use customers;

(d) a representative of the Coordinator in the capacity of Hazard Management Agency under the Emergency Management Regulations 2006; and

(e) persons appointed by the ~~Rule Change Panel~~Coordinator, ~~such persons to include~~including:

(i) two persons representing pipeline operators and owners;

(ii) two persons representing gas producers;

(iii) two persons representing gas shippers; and

(iv) two persons representing gas users.

(2) The Minister and the ERA may each appoint a representative to attend meetings of the Gas Advisory Board as an observer.

(3) The Minister must appoint an independent Chair of the Gas Advisory Board, who in the opinion of the Minister:

(a) is free from any business or other relationship that could materially interfere with the independent exercise of the Chair's judgment; and

(b) has the skills and experience necessary to carry out the responsibilities and functions of the Chair of the Gas Advisory Board.

(4) The Minister may remove an independent Chair of the Gas Advisory Board at any time in the following circumstances:

(a) the person becomes an undischarged bankrupt; or

(b) the person becomes of unsound mind or his or her estate is liable to be dealt with in any way under law relating to mental health; or

(c) in the Minister's opinion the person no longer adequately meets the criterion in subrule (3).

(5) The same organisation cannot be represented by more than one member on the Gas Advisory Board simultaneously.

(6) The Coordinator or the Chair of the Gas Advisory Board may invite a person to attend Gas Advisory Board meetings as an observer, either for a specified meeting or meetings or until further notice.

13 Appointment matters for the Gas Advisory Board

(1) The ~~Rule Change Panel~~Coordinator may appoint and remove members of the Gas Advisory Board in accordance with the Rules and the Constitution, and in consultation with the independent Chair.

(2) When appointing members of the Gas Advisory Board, the ~~Rule Change Panel~~Coordinator must consult with the independent Chair, and take nominations from~~,~~ Gas Market Participants and gas industry groups that it considers have an interest in the information published on the GBB and in the GSOO, and, if practicable, must choose members from persons nominated.

(3) The ~~Rule Change Panel~~Coordinator must ~~annually~~ review the composition of the Gas Advisory Board every two years in consultation with the independent Chair and may remove and appoint members following the review.

(4) The ~~Rule Change Panel~~Coordinator may remove a member of the Gas Advisory Board at any time in the following circumstances:

(a) the person becomes an undischarged bankrupt;

(b) the person becomes of unsound mind or his or her estate is liable to be dealt with in any way under a law relating to mental health;

(c) an event specified for this purpose in the Constitution for the Gas Advisory Board occurs; or

(d) in the ~~Rule Change Panel~~Coordinator's opinion the person no longer adequately represents the interests of the person or class of persons that he or she was appointed to represent in accordance with rule 12.

(5) A member of the Gas Advisory Board may resign by giving notice to the ~~Rule Change Panel~~Coordinator in writing.

(6) Where a position on the Gas Advisory Board is vacant at any time, the ~~Rule Change Panel~~Coordinator must use its reasonable endeavours to appoint a person to fill the position, but the Gas Advisory Board may continue to perform its functions under the Rules despite any vacancy.

14 Constitution for the Gas Advisory Board

(1) The ~~Rule Change Panel~~Coordinator must, in accordance with the GSI Consultation Procedure, develop and publish on the GSI Website a Constitution for the Gas Advisory Board which is consistent with the Rules.

(2) The Constitution must provide for matters such as:

(a) the process for appointing, replacing or removing members of the Gas Advisory Board by the ~~Rule Change Panel~~Coordinator;

(b) any terms of reference of the Gas Advisory Board;

(c) the terms and conditions for members of the Gas Advisory Board;

(d) the process for convening the Gas Advisory Board;

(e) the conduct of meetings of the Gas Advisory Board; and

(f) any governance matters where the Gas Advisory Board establishes a working group.

15 ~~ERA~~ Coordinator to make available ~~RCP~~ GAB Secretariat for the Gas Advisory Board

(1) The ~~ERA~~ Coordinator must make available the ~~RCP~~ GAB Secretariat, who will provide secretariat and other services to the Gas Advisory Board~~, in accordance with the Panel Regulations~~.

(2) The ~~Rule Change Panel, through the~~ RCP Secretariat~~,~~ must convene the Gas Advisory Board in accordance with the Constitution:

(a) if the Rules require a meeting in relation to a Rule Change Proposal or a Procedure Change Proposal;

(b) [Blank]; ~~and~~

(c) on any occasion when ~~two or more members~~the independent Chair of the Gas Advisory Board ~~have~~ has informed the ~~RCP~~ GAB Secretariat in writing that they wish to bring a matter relating to the matters listed in subrule 11(2) before the Gas Advisory Board for discussion; and

(d) on any occasion when the independent Chair of the Gas Advisory Board or the Coordinator wishes to bring a matter regarding the evolution of these Rules or the operation of these Rules before the Gas Advisory Board for discussion.

16 Gas Advisory Board may establish working groups

(1) The Gas Advisory Board may establish working groups, which may comprise members of the Gas Advisory Board, Registered Participants and other interested persons, to assist it in advising the ~~Rule Change Panel~~Coordinator, AEMO or the ERA on any of the matters arising in the performance of their respective roles under the Rules.

(2) The Gas Advisory Board may disband any working group it considers to be no longer required.

…

Division 2A ERA Regulator Fees

110A Regulator Fees

(1) The ERA may recover a portion of its budget determined by the Minister responsible for the ERA which corresponds to the costs of the ERA in undertaking its functions under the Rules and, the GSI Regulations ~~and the Panel Regulations~~, from the collection of Regulator Fees under these Rules. The ERA must identify in its budget the proportion of its costs that relates to the performance of its functions under the Rules and the GSI Regulations and its other functions.

(2) Where the revenue earned via Regulator Fees in the previous Financial Year is greater than or less than the ERA expenditure related to the functions described in subrule (1) for that Financial Year, the current year's budget must take this into account by decreasing the budgeted revenue by the amount of the surplus or adding to the budgeted revenue the amount of any shortfall, as the case may be.

(2A) [Blank] ~~The ERA may recover, on behalf of the Rule Change Panel, the costs identified by the ERA as costs incurred in the performance of the Rule Change Panel's functions under the Rules or the GSI Regulations, from the collection of Regulator Fees under these Rules.~~

(3) By the date which is five Business Days prior to 30 June each year, the ERA must notify AEMO of—

(a) the dollar amount that the ERA may recover under subrule (1); and

(b) the dollar amount that the ERA may recover under subrule (2A) (to the extent such amount is not already included in the dollar amount referred to in subrule (3)(a)).

(4) AEMO must publish on the GSI Website the amount of the Regulator Fees for each Financial Year by 30 June each year in accordance with the information provided by the ERA under subrule (3).

(5) If the ERA has not provided AEMO with the information required under subrule (3) by the date which is five Business Days prior to 30 June, AEMO will publish on the GSI Website the expected amount of Regulator Fees based on the most recent information provided to AEMO by the ERA under subrule (3).

(6) AEMO must publish on the GSI Website a revised amount for Regulator Fees within five Business Days of receiving the information, if in any year, the ERA

provides AEMO with the information required under subrule (3) later than the date which is five Business Days prior to 30 June.

(7) A revised amount for Regulator Fees will supersede any expected amount for Regulator Fees and is recoverable from Registered Shippers and Registered Production Facility Operators in arrears with effect from the start of the Financial Year to which it applies.

…

Division 2B Coordinator Fees

110B Coordinator Fees

(1) The Coordinator may recover a portion of its budget determined by the Minister responsible for the Coordinator which corresponds to the costs of the Coordinator in undertaking its functions under the Rules and the GSI Regulations, from the collection of Coordinator Fees under these Rules. The Coordinator must identify in its budget the proportion of its costs that relates to the performance of its functions under the Rules and the GSI Regulations and its other functions.

(2) Where the revenue earned via Coordinator Fees in the previous Financial Year is greater than or less than the Coordinator expenditure related to the functions described in subrule (1) for that Financial Year, the current year's budget must take this into account by decreasing the budgeted revenue by the amount of the surplus or adding to the budgeted revenue the amount of any shortfall, as the case may be.

(3) By the date which is five Business Days prior to 30 June each year, the Coordinator must notify AEMO of the dollar amount that the Coordinator may recover under subrule (1).

(4) AEMO must publish on the GSI Website the amount of the Coordinator Fees for each Financial Year by 30 June each year in accordance with the information provided by the Coordinator under subrule (3).

(5) If the Coordinator has not provided AEMO with the information required under subrule (3) by the date which is five Business Days prior to 30 June, AEMO will publish on the GSI Website the expected amount of Coordinator Fees based on the most recent information provided to AEMO by the Coordinator under subrule (3).

(6) AEMO must publish on the GSI Website a revised amount for Coordinator Fees within five Business Days of receiving the information, if in any year, the Coordinator provides AEMO with the information required under subrule (3) later than the date which is five Business Days prior to 30 June.

(7) A revised amount for Coordinator Fees will supersede any expected amount for Coordinator Fees and is recoverable from Registered Shippers and Registered Production Facility Operators in arrears with effect from the start of the Financial Year to which it applies.

…

118A Payment of GSI Fees to ERA

(1) AEMO is an agent for the ERA for the collection of the Regulator Fees each Financial Year and payable by Registered Shippers and Registered Production Facility Operators to AEMO.

(2) The ERA must, if requested by AEMO, do all things reasonably necessary (including entering into any agreements) to enable AEMO to give effect to subrule (1).

(3) Following receipt of a payment of GSI Fees in accordance with rule 118 or rule 119, AEMO must pay to the ERA an amount corresponding to the proportion of the GSI Fees attributable to the Regulator Fees for the relevant Financial Year.

(4) [blank]~~The ERA recovers the proportion of the payment referred to in subrule (3) that relates to the costs contemplated in subrule 110A(2A) on behalf of the Rule Change Panel.~~

118B Payment of GSI Fees to Coordinator

(1) AEMO is an agent for the Coordinator for the collection of the Coordinator Fees each Financial Year and payable by Registered Shippers and Registered Production Facility Operators to AEMO.

(2) The Coordinator must, if requested by AEMO, use reasonable endeavours to cooperate with AEMO, as AEMO endeavours to give effect to subrule (1).

(3) Following receipt of a payment of GSI Fees in accordance with rule 118 or rule 119, AEMO must pay to the Coordinator an amount corresponding to the proportion of the GSI Fees attributable to the Coordinator Fees for the relevant Financial Year.

…

Part 8 Rule Making

Division 1 General

125 Rule making by the ~~Rule Change Panel~~Coordinator

(1) The ~~Rule Change Panel~~Coordinator, in accordance with the GSI Act, the GSI Regulations~~, the Panel Regulations~~ and the Rules, may make Amending Rules for or with respect to any matter or thing referred to in the GSI Act and~~,~~ the GSI Regulations~~ and the Panel Regulations~~, after the initial Rules have been made by the Minister.

(2) The ~~Rule Change Panel~~Coordinator:

(a) is responsible for maintaining the Rules;

(b) is responsible for ensuring the development of amendments of, and replacements for, the Rules; and

(c) may make Amending Rules in accordance with this Part 8.

(3) [not used]~~This rule 125 and the remainder of Part 8 of the Rules (other than rule 125A) commence operation on and from 08:00AM on 3 April 2017X XX XXX, being the date on which the Rule Change Panel is conferred the function to develop amendments of and replacements for the Rules in accordance with regulation 2(b) of the *Gas Services Information Amendment Regulations (No.2) 2016.*~~

~~125A. Rule making by the Minister~~

~~(1) This rule 125A applies from the Rule Change Panel Transfer Date until 08:00AM on 1 July 2017, being the date on which until the Minister's power to make Amending Rules under regulation 7(5) of the GSI Regulations ends.~~

~~(2) Despite anything in the Rules, the Minister may develop and make Amending Rules in accordance with regulation 7(5) of the GSI Regulations.~~

126 Ministerial policy statements

(1) The Minister may issue a statement of policy principles to the ~~Rule Change Panel~~Coordinator with respect to the GBB or the GSOO. The statement of policy principles must not be inconsistent with the GSI Objectives.

(2) The Minister may provide the ~~Rule Change Panel~~Coordinator with a draft of the proposed statement of policy principles and seek the ~~Rule Change Panel~~Coordinator's views on it.

(3) The ~~Rule Change Panel~~Coordinator must have regard to the statement of policy principles given by the Minister in making Amending Rules under this Part.

127 Rule making test

The ~~Rule Change Panel~~Coordinator must not make Amending Rules unless it is satisfied that the Rules, as proposed to be amended or replaced, are consistent with the GSI Objectives.

128 Factors for ~~Rule Change Panel~~Coordinator consideration

(1) In deciding whether ~~or not~~ to make Amending Rules, the ~~Rule Change Panel~~Coordinator must have regard to the following:

(a) any applicable statement of policy principles given to the ~~Rule Change Panel~~Coordinator under rule 126;

(aa) any views expressed by Gas Advisory Board regarding the evolution of these Rules;

(b) the practicality and cost of implementing the Rule Change Proposal;

(c) the relevant views expressed in any submissions received by the ~~Rule Change Panel~~Coordinator on the Rule Change Proposal;

(d) the relevant views expressed at any public forums or workshops, or in other consultation with Gas Market Participants, held by the ~~Rule Change Panel~~Coordinator on the Rule Change Proposal;

(e) the relevant views expressed by the Gas Advisory Board where it met to consider the Rule Change Proposal; and

(ea) in connection with subrules (aa) and (e) of this rule 129(1), whether the advice from the Gas Advisory Board reflects a consensus view or a majority view, and, if the latter, any dissenting views included in or accompanying the advice;

(f) any information that the ~~Rule Change Panel~~Coordinator considers necessary to assess the Rule Change Proposal.

(2) Without limiting subrule (1), in deciding whether or not to make Amending Rules, the ~~Rule Change Panel~~Coordinator may request the ~~RCP~~ GAB Secretariat to seek advice, and the ~~Rule Change Panel~~Coordinator may have regard to that advice, from any person that the ~~Rule Change Panel~~Coordinator considers is appropriate to assist it in assessing the relevant Rule Change Proposal.

Division 2 Initiating changes to the Rules

129 Initiating a Rule Change Proposal

(1) Any person may make a Rule Change Proposal by completing a Rule Change Proposal Form.

(2) A person other than the ~~Rule Change Panel~~Coordinator who wishes to make a Rule Change Proposal must submit a completed Rule Change Proposal Form to the ~~Rule Change Panel~~Coordinator using the contact details provided in the form.

(3) Where the ~~Rule Change Panel~~Coordinator considers it to be necessary, it may contact a person submitting a Rule Change Proposal and request written clarification of any aspect of the proposal.

(4) Information clarifying a Rule Change Proposal received by the ~~Rule Change Panel~~Coordinator forms part of the Rule Change Proposal.

(4a) The Coordinator must, before commencing the development of a Rule Change Proposal or providing material support or assistance to another party to develop a Rule Change Proposal, consult with the Gas Advisory Board on:

(a) the matters to be addressed by the Rule Change Proposal and if applicable the nature and scope of the support or assistance requested by the other party;

(b) what options exist to resolve the matters to be addressed by the Rule Change Proposal;

(c) the Coordinator's estimated costs to be recovered through Coordinator Fees of developing the Rule Change Proposal or providing the support or assistance requested by the other party;

(d) whether and when the Coordinator should develop the Rule Change Proposal or if the Coordinator should provide the support or assistance requested by the other party; and

(e) whether and how the Gas Review Board will be consulted during the development of the Rule Change Proposal,

and take into account any advice, comments or objections provided by any member or observer of the Gas Review Board in deciding whether, when and how to develop the Rule Change Proposal or provide material support or assistance to another party to develop the Rule Change Proposal.

(5) Where the ~~Rule Change Panel~~Coordinator considers that a change to the Rules is:~~—~~

(a) required ~~to correct a manifest error in the Rules; or~~

(b) [blank] ~~of a minor or procedural nature~~,

the ~~Rule Change Panel~~Coordinator may develop a Rule Change Proposal and must publish it in accordance with subrule 132(2)(a).

(6) The Coordinator must have regard to any advice received from the Gas ~~Review~~ Advisory Board regarding the evolution of the Rules.

(7) The independent Chair of the Gas Advisory Board may develop and submit Rule Change Proposals based on advice received from the Gas Advisory Board regarding the evolution of the Rules.

130 Rule Change Proposal Form

(1) The ~~Rule Change Panel~~Coordinator must publish on the GSI Website a Rule Change Proposal Form.

(2) The form must include:

(a) contact details for proposing rule changes; and

(b) information that must be provided in a Rule Change Proposal, including:

(i) the name of the person submitting the Rule Change Proposal and, where relevant, details of the organisation that person represents;

(ii) the issue to be addressed;

(iii) the degree of urgency of the proposed change;

(iv) any proposed specific changes to particular rules;

(v) an explanation of how the proposed rule change would allow the Rules to better address the GSI Objectives; and

(vi) any identifiable costs and benefits of the change.

131 ~~Rule Change Panel~~Coordinator decision to progress a Rule Change Proposal

(1) Within five Business Days of the later of receiving a Rule Change Proposal or any clarification information requested under subrule 129(3), the ~~Rule Change Panel~~Coordinator must:

(a) decide whether ~~or not~~ to progress the Rule Change Proposal any further; and

(b) notify the person who submitted the Rule Change Proposal whether ~~or not~~ the ~~Rule Change Panel~~Coordinator will progress the proposal and the reasons for the decision.

(2) The ~~Rule Change Panel~~Coordinator may decide to progress a Rule Change Proposal under the Fast Track Rule Change Process if, in the opinion of the ~~Rule Change Panel~~Coordinator, the proposal:

(a) is of a minor or procedural nature;

(b) is required to correct a manifest error; or

(c) is urgently required and is essential for the effective operation of the GBB.

132 Rule Change Notice

(1) The ~~Rule Change Panel~~Coordinator must publish notice of a Rule Change Proposal on the GSI Website in accordance with this rule (a Rule Change Notice).

(2) A Rule Change Notice must be published:

(a) in the case where the Rule Change Proposal has been developed by the ~~Rule Change Panel~~Coordinator, as soon as practicable after the proposal is developed; or

(b) in the case where the Rule Change Proposal was submitted by any other person, within seven Business Days of the later of receiving:

(i) the Rule Change Proposal; or

(ii) any information or clarification requested by the ~~Rule Change Panel~~Coordinator under subrule 129(3).

(3) A Rule Change Notice must include:

(a) the date that the Rule Change Proposal was submitted, if applicable;

(b) the name, and where relevant, the organisation, of the person who proposed the Rule Change Proposal;

(c) the Rule Change Proposal, including relevant references to provisions of the Rules and any proposed specific changes to those provisions;

(d) a description of how the person submitting the Rule Change Proposal considers the rule change would allow the Rules to better address the GSI Objectives; and

(e) whether the Rule Change Proposal will be progressed and the reasons why the Rule Change Proposal will or will not be progressed.

(4) Where a Rule Change Proposal will be progressed, the Rule Change Notice must state whether the Rule Change Proposal is subject to the Fast Track Rule Change Process and the reasons for this decision.

(5) Where the Rule Change Proposal will be progressed under the Fast Track Rule Change Process, the Rule Change Notice must include:

(a) an invitation to make written submissions on the Rule Change Proposal and the closing date for making those submissions; and

(b) in the case where the Rule Change Proposal did not include Amending Rules to implement the proposal, the proposed Amending Rules to implement the Rule Change Proposal.

(6) Where the Rule Change Proposal will be progressed under the Standard Rule Change Process, the Rule Change Notice must include an invitation to make written submissions on the Rule Change Proposal and the closing date for making those submissions, which must be at least 30 Business Days after the date the notice is published.

Division 3 Fast Track Rule Change Process

133 Consultation for Fast Track Rule Change Process

(1) Within five Business Days of publishing a Rule Change Notice, the ~~Rule Change Panel~~Coordinator must notify AEMO and those Gas Market Participants that it considers have an interest in the Rule Change Proposal, of its intention to consult with them concerning the Rule Change Proposal.

(2) Within five Business Days of publishing the Rule Change Notice, AEMO or an interested Gas Market Participant may notify the ~~Rule Change Panel~~Coordinator that it wishes to be consulted in relation to the Rule Change Proposal.

(3) The ~~Rule Change Panel~~Coordinator must complete such consultation as the ~~Rule Change Panel~~Coordinator considers appropriate in the circumstances with AEMO and the relevant Gas Market Participants (as applicable) within 15 Business Days of publishing the Rule Change Notice.

134 Final Rule Change Report for Fast Track Rule Change Process

(1) Within 20 Business Days of publishing a Rule Change Notice for a Rule Change Proposal to be progressed under the Fast Track Rule Change Process, the ~~Rule Change Panel~~Coordinator must:

(a) decide whether to:

(i) accept the Rule Change Proposal in the proposed form;

(ii) accept the Rule Change Proposal in a modified form; or

(iii) reject the Rule Change Proposal; and

(b) publish on the GSI Website a Final Rule Change Report.

(2) A Final Rule Change Report must contain:

(a) the decision made by the ~~Rule Change Panel~~Coordinator under subrule (1)(a) on the Rule Change Proposal; and

(b) the reasons of the ~~Rule Change Panel~~Coordinator as to whether ~~or not~~ it should make the proposed Amending Rules, having regard to:

(i) the rule making test in rule 127; and

(ii) the factors for consideration listed in subrule 128(1).

(3) If the ~~Rule Change Panel~~Coordinator decides to make Amending Rules, the Final Rule Change Report must contain:

(a) the Amending Rules; and

(b) the proposed date and time that the Amending Rules will commence.

Division 4 Standard Rule Change Process

135 Gas Advisory Board advice

(1) The ~~Rule Change Panel~~Coordinator must, within one Business Day after the publication of the Rule Change Notice, notify the members and observers of the Gas Advisory Board whether the ~~Rule Change Panel~~Coordinator considers the Rule Change Proposal requires convening a meeting of the Gas Advisory Board and the reasons why.

(2) The ~~Rule Change Panel~~Coordinator must convene a meeting of the Gas Advisory Board concerning a Rule Change Proposal if:

(a) the ~~Rule Change Panel~~Coordinator considers that advice on the Rule Change Proposal is required from the Gas Advisory Board; or

(b) ~~two or more members~~the independent Chair of the Gas Advisory Board has ~~have~~ informed the ~~Rule Change Panel~~Coordinator in writing that ~~they~~ she or he considers that advice on the Rule Change Proposal is required from the Gas Advisory Board.

136 Draft Rule Change Report

(1) Within 20 Business Days after the closing date for making submissions, as set out in the Rule Change Notice, the ~~Rule Change Panel~~Coordinator must publish on the GSI Website:

(a) a Draft Rule Change Report on the Rule Change Proposal; and

(b) an invitation to make written submissions on the Draft Rule Change Report by the closing date which must be at least 20 Business Days after the date of publication of the Draft Rule Change Report.

(2) A Draft Rule Change Report must contain the reasons of the ~~Rule Change Panel~~Coordinator as to whether ~~or not~~ it should make the proposed Amending Rules, having regard to:

(a) the rule making test in rule 127; and

(b) the factors for consideration listed in subrule 128(1).

(3) A Draft Rule Change Report must indicate whether the proposed decision of the ~~Rule Change Panel~~Coordinator is to:

(a) accept the Rule Change Proposal in the proposed form;

(b) accept the Rule Change Proposal in a modified form; or

(c) reject the Rule Change Proposal.

(4) If the ~~Rule Change Panel~~Coordinator is considering the making of Amending Rules, the Draft Rule Change Report must contain:

(a) the draft Amending Rules; and

(b) a proposed date and time on which the draft Amending Rules would commence.

137 Final Rule Change Report

(1) Within 20 Business Days of the closing date for making submissions on the Draft Rule Change Report, the ~~Rule Change Panel~~Coordinator must:

(a) decide whether to:

(i) accept the Rule Change Proposal in the proposed form;

(ii) accept the Rule Change Proposal in a modified form; or

(iii) reject the Rule Change Proposal; and

(b) publish on the GSI Website a Final Rule Change Report.

(2) A Final Rule Change Report must contain:

(a) the decision made by the ~~Rule Change Panel~~Coordinator under subrule (1)(a) on the Rule Change Proposal; and

(b) the reasons of the ~~Rule Change Panel~~Coordinator as to whether ~~or not~~ it should make the proposed Amending Rules, having regard to:

(i) the rule making test in rule 127; and

(ii) the factors for consideration listed in subrule 128(1).

(3) If the ~~Rule Change Panel~~Coordinator decides to make Amending Rules, the Final Rule Change Report must contain:

(a) the Amending Rules; and

(b) a proposed date and time on which the Amending Rules will commence.

Division 5 Submissions and public forums

138 Right to make submissions

(1) Any person or body, within the period specified in a Rule Change Notice or an invitation to make a submission in relation to a Draft Rule Change Report, may make a written submission in relation to the Rule Change Proposal to which the request for submissions relates.

(2) In determining whether ~~or not~~ to make Amending Rules, the ~~Rule Change Panel~~Coordinator:

(a) must take into account all relevant comments in written submissions received by the closing date for submissions; and

(b) may, but is not required to, take into account any comments in written submissions received after that date.

139 ~~Rule Change Panel~~Coordinator must publish submissions

Subject to applicable requirements relating to Protected Information under the GSI Act, the GSI Regulations and these Rules ~~Panel Regulations~~, the ~~Rule Change Panel~~Coordinator must publish all written submissions received under this Part.

140 Public forums or workshops

The ~~Rule Change Panel~~Coordinator may hold public forums or workshops concerning a Rule Change Proposal.

Division 6 Extension of rule change timeframes

141 ~~Rule Change Panel~~Coordinator may extend timeframes

(1) The ~~Rule Change Panel~~Coordinator may at any time after deciding to progress a Rule Change Proposal extend the prescribed timeframe for a Fast Track Rule Change Process or a Standard Rule Change Process in accordance with this rule.

(2) If a Rule Change Proposal is subject to the Fast Track Rule Change Process, and the ~~Rule Change Panel~~Coordinator decides to extend the timeframe, it must either:

(a) extend the timeframe by no more than 15 Business Days; or

(b) reclassify the Rule Change Proposal as not being subject to the Fast Track Rule Change Process, and must progress it in accordance with the Standard Rule Change Process.

(3) The ~~Rule Change Panel~~Coordinator must publish on the GSI Website a notice of extension of timeframe where it has decided to extend the prescribed timeframe, and must update any information already published.

(4) A notice of extension of timeframe must include:

(a) the reasons for the proposed extension;

(b) views of Gas Market Participants (if any) consulted on the extension;

(c) the proposed length of any extension; and

(d) the proposed work program.

(5) The ~~Rule Change Panel~~Coordinator may only extend a prescribed timeframe under this rule before the expiry of that timeframe.

Division 7 Protected Provisions

142 Definition of Protected Provisions

(1) In this Division, “modify” includes an addition, an omission or a substitution or any change that, in the ~~Rule Change Panel~~Coordinator’s opinion, would have the effect of changing the meaning of a Protected Provision.

(2) The following rules are Protected Provisions:

(a) rules 1 to 20, excluding rule 10;

(b) rules 21 to 51;

(c) rules 92 to 95;

(d) rules 107 to 114, and rules 116, 118A, 118B and 120;

(e) rules 125 to 153;

(f) rules 154 to 164;

(g) rules 165 to 174;

(h) rules listed in Schedule 1 of the GSI Regulations as Civil Penalty Provisions;

(i) rules listed in Schedule 2 of the GSI Regulations as Reviewable Decisions; and

(j) any other rules that must not be amended, repealed or replaced without the approval of the Minister in accordance with the GSI Regulations.

143 ~~Rule Change Panel~~Coordinator to notify Minister at start of Rule Change Process

Where the ~~Rule Change Panel~~Coordinator decides to progress a Rule Change Proposal that relates to or affects a Protected Provision or a Rule Change Proposal in accordance with subrule 129(4a), the ~~Rule Change Panel~~Coordinator must notify the Minister at the same time as it publishes the Rule Change Notice under rule 132.

144 Minister must approve changes to Protected Provisions

(1) The Minister must approve Amending Rules that modify a Protected Provision.

(2) The ~~Rule Change Panel~~Coordinator must, as soon as practicable after publishing a Final Rule Change Report that relates to a Protected Provision Amendment, submit to the Minister the following documents:

(a) the relevant Rule Change Proposal; and

(b) the Final Rule Change Report, including the Amending Rules to be made.

(3) Subject to rule 145, the Minister must, within 20 Business Days of the submission of a Protected Provision Amendment by the ~~Rule Change Panel~~Coordinator, decide whether the Amending Rules should be made, having regard to the GSI Objectives.

(4) For a Protected Provision Amendment, the Minister may:

(a) approve the making of the Amending Rules;

(b) not approve the making of the Amending Rules; or

(c) send back to the ~~Rule Change Panel~~Coordinator the proposed Amending Rules with any revisions the Minister considers are required to ensure the Rules, as amended or replaced by the proposed Amending Rules, are consistent with the GSI Objectives.

(5) Where the Minister approves a Protected Provision Amendment, the ~~Rule Change Panel~~Coordinator must publish on the GSI Website the Minister's approval and the date of the decision.

145 Minister may extend time to approve Protected Provision Amendment

(1) The Minister may extend the time for a decision under rule 144 on a Protected Provision Amendment by a further period of up to 20 Business Days by notice to the ~~Rule Change Panel~~Coordinator, and may do so more than once.

(2) The Minister may only extend a timeframe for a decision under subrule (1) before the expiry of that timeframe.

(3) The ~~Rule Change Panel~~Coordinator must publish notice of any extension by the Minister on the GSI Website, as soon as practicable.

146 Approval of Minister may be deemed for Protected Provision Amendment

If the Minister does not make a decision under this Division by the original date or by an extended date, as applicable, then the Protected Provision Amendment is taken to have been approved by the Minister.

147 Minister to give reasons where Protected Provision Amendment not approved

Where the Minister does not approve or sends back a Protected Provision Amendment under subrule 144(4)(c), the Minister must give reasons, and the ~~Rule Change Panel~~Coordinator must publish a notice of the Minister's decision and the reasons given by the Minister on the GSI Website.

148 Consultation where Minister proposes revisions to Protected Provision Amendment

(1) Where the Minister sends a Protected Provision Amendment back to the ~~Rule Change Panel~~Coordinator with revisions in accordance with subrule 144(4)(c), the ~~Rule Change Panel~~Coordinator must publish on the GSI Website the revised Amending Rules and invite written submissions within 15 Business Days of publication.

(2) The ~~Rule Change Panel~~Coordinator must, within 25 Business Days after the close of submissions:

(a) submit to the Minister a revised Final Rule Change Report, including any submissions received on the revised Amending Rules; and

(b) publish on the GSI Website the revised Final Rule Change Report and all submissions received,

and this Division applies to the revised Final Rule Change Report.

Division 7A Coordinator-initiated rule changes

148A Minister to approve Coordinator-initiated rule changes

All rule changes resulting from a Rule Change Proposal initiated by the Coordinator, other than a Rule Change Proposal to which rule 131(2) applies, must be approved by the Minister.

Division 8 Making and commencement of Amending Rules

149 Making of Amending Rules

Amending Rules are made:

(a) in the case where the Final Rule Change Report does not relate to a Protected Provision Amendment, when the ~~Rule Change Panel~~Coordinator publishes the Final Rule Change Report in relation to those Amending Rules; or

(b) in the case where the Final Rule Change Report relates to a Protected Provision Amendment, when the Minister approves, or is taken to approve, the Amending Rules under Division 7.

150 Operation and commencement of Amending Rules

(1) Amending Rules commence operation on the date and time determined by the ~~Rule Change Panel~~Coordinator.

Note: A Final Rule Change Report includes a proposed date and time for commencement of the Amending Rules.

(2) The ~~Rule Change Panel~~Coordinator must, on or before the date on which Amending Rules commence, publish on the GSI Website a notice of the commencement of the Amending Rules.

(3) The ~~Rule Change Panel~~Coordinator may amend a proposed date and time for commencement of Amending Rules as published in a Final Rule Change Report (and may do so on more than one occasion), provided that:

(a) the first amended commencement date and time is published on the GSI Website before the proposed commencement date and time referred to in the Final Rule Change Report;

(b) subsequent amendments to the proposed commencement date and time are published on the GSI Website before the most recently published proposed commencement date and time; and

(c) the ~~Rule Change Panel~~Coordinator publishes reasons for the change.

151 ~~ERA~~ Coordinator to publish up to date version of Rules

The ~~ERA~~ Coordinator must, at all times, maintain on the Coordinator's W~~w~~ebsite maintained by the ERA a copy of the Rules, as in force from time to time.

Note: Regulation 9 of the GSI Regulations contains further requirements for making the Rules available.

152 Evidence of the Rules

A document purporting to be a copy of the Rules endorsed with a certificate to which the seal of the Coordinator~~ERA~~ has been duly affixed, certifying the document is such a copy, is evidence that the document is such a copy.

153 ~~Rule Change Panel~~Coordinator to publish historical Rule Change Proposals

The ~~Rule Change Panel~~Coordinator must publish on the GSI Website documents relevant to previous Rule Change Proposals that are no longer current, whether or not those proposals were accepted or rejected.

Part 9 Procedures

154 ~~Rule Change Panel~~Coordinator, AEMO and ERA may make Procedures

(1) [Blank]

(1A) AEMO may make Procedures to the extent to which the Procedures relate to its functions under the Rules, and must do so in accordance with this Part.

(1B) The ERA may make Procedures to the extent to which the Procedures relate to its functions under the Rules, and must do so in accordance with this Part.

(1C) The ~~Rule Change Panel~~Coordinator may make Procedures to the extent to which the Procedures relate to its functions under the Rules~~,~~ and must do so in accordance with this Part.

(2) Procedures must be consistent with the GSI Objectives.

(3) The ~~Rule Change Panel~~Coordinator, AEMO and the ERA and each person to whom the Procedures are applicable must comply with those Procedures.

155 Matters about which Procedures may be made

(1) Procedures may deal with any subject dealt with under the GSI Act, the GSI Regulations~~, the Panel Regulations~~ or the Rules.

(2) Without limiting subrule (1), the Procedures may deal with the following matters:

(a) the manner in which AEMO maintains, and publishes information on, the GBB including the format of any registers or reports required or permitted by the Rules;

(b) the content, manner and form of a Registration Application and an application to deregister a Registered Participant or a Registered Facility;

(c) the content, manner and form of an application for transfer of a Registered Facility;

(d) the content, manner and form of an Exemption Application;

(e) the time, manner and form for providing AEMO with information in connection with the GBB and the collection and collation of that information;

(f) the content, manner and form of an application for exemption from providing specified information for the GBB;

(g) any terms and conditions of use of the GBB;

(h) the meaning of symbols used for the purposes of the GBB;

(i) the definition of terms or the designation of status for the purposes of the rules governing the operation of the GBB;

(j) the times at which, or frequency by which, AEMO will update the reports and information published on the GBB;

(k) the determination of any matter the ~~Rule Change Panel~~Coordinator, AEMO and the ERA is required or allowed to determine under the Rules including forecasts for the purposes of the GSOO;

(l) the time, manner and form for providing AEMO with information in connection with the GSOO and the collection and collation of that information;

(m) the ERA's and AEMO's monitoring processes for assessing compliance with the Rules and Procedures by Gas Market Participants;

(n) processes for Gas Market Participants to report alleged breaches of the Rules or Procedures;

(o) processes for investigations into alleged breaches of the Rules or Procedures;

(p) guidelines for the ERA when issuing Warning Notices for alleged breaches of the Rules or Procedures to Gas Market Participants;

(q) the procedure for dealing with Category A Civil Penalty Provision breaches;

(r) the procedure for bringing proceedings in respect of alleged breaches of the Rules or Procedures before the Board;

(s) any additional matters or reports that the ERA intends to include in published compliance reports; and

(t) any matter consequential or related to any of the above.

(3) Without limiting subrule (1) and subrule 154(1A), AEMO—

(a) may make Procedures dealing with the matters referred to in subrule 155(2)(a) to (j) (inclusive) and subrule 155(2)(l) and any matter consequential or related to those matters;

(b) may make Procedures dealing with the matters referred to in subrule 155(2)(k) and subrule 155(2)(m), to the extent the Procedures relate to its functions under the Rules; and

(c) must not make Procedures dealing with the matters referred to in subrule 155(2)(n) to (s) (inclusive) and any matter consequential or related to those matters.

(4) [Blank]

(5) Without limiting subrule (1) and subrule 154(1B), the ERA—

(a) may make Procedures dealing with the matters referred to in subrule 155(2)(n) to (s) (inclusive) and any matter consequential or related to those matters;

(b) may make Procedures dealing with the matters referred to in subrule 155(2)(k) and subrule 155(2)(m), to the extent the Procedures relate to its functions under the Rules; and

(c) must not make Procedures dealing with the matters referred to in subrule 155(2)(a) to (j) (inclusive) and subrule 155(2)(l) and any matter consequential or related to those matters.

(6) Without limiting subrule (1) and subrule 154(1C), the ~~Rule Change Panel~~Coordinator—

(a) may make Procedures dealing with the matters referred to in subrule 155(2)(k), to the extent the Procedures relate to its functions under the Rules; and

(b) must not make Procedures dealing with the matters referred to in subrule 155(2)(a) to (j) (inclusive) and subrule 155(2)(l) to (s) (inclusive) and any matter consequential or related to those matters.

156 ~~Rule Change Panel~~Coordinator, AEMO and ERA may initiate a Procedure Change Proposal

(1) The ~~Rule Change Panel~~Coordinator, AEMO or the ERA may initiate a proposal to make a Procedure relating to its functions under these Rules (a Procedure Change Proposal).

(2) A Gas Market Participant may notify in writing the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) where it considers a change to a Procedure or a new Procedure would be appropriate.

(3) Within 20 Business Days of receipt of a notification under subrule (2), the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) must—

(a) determine whether a change to a Procedure or a new Procedure is appropriate; and

(b) publish on the GSI Website details of whether a Procedure Change Proposal will be progressed with respect to the suggested change and the reasons for that decision.

(4) If an Amending Rule requires the ~~Rule Change Panel~~Coordinator, AEMO or the ERA to make changes to Procedures, then the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) must develop an appropriate Procedure Change Proposal consistent with the Amending Rule.

157 Procedure Change Proposal

A Procedure Change Proposal developed by the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) must be published on the GSI Website and must include:

(a) a description of the proposed Procedure (or change to a Procedure);

(b) the reasons for the proposed Procedure (or change to a Procedure);

(c) a draft of the proposed Procedure (or change to a Procedure); and

(d) an invitation to make written submissions on the Procedure Change Proposal and the closing date for making those submissions, which must be at least 20 Business Days after the date the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) publishes the Procedure Change Proposal on the GSI Website.

158 Submissions

(1) Any person may make a submission to the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) in relation to a Procedure Change Proposal in the form published on the GSI Website.

(2) In determining whether or not to make Procedures under the Rules, the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable):

(a) must take into account all relevant comments in written submissions that it receives by the closing date for submissions; and

(b) may, but is not required to, take into account any comments in written submissions that it receives after that date.

159 Gas Advisory Board advice

(1) [Blank]

(2) The ~~Rule Change Panel~~GAB Secretariat must convene a meeting of the Gas Advisory Board concerning a Procedure Change Proposal if—

(a) the Procedure Change Proposal relates to the ~~Rule Change Panel~~Coordinator's functions under the Rules and the ~~Rule Change Panel~~Coordinator considers that advice on the Procedure Change Proposal is required from the Gas Advisory Board;

(b) ~~two or more members~~ the Chair of the Gas Advisory Board has~~ve~~ informed the ~~Rule Change Panel~~Coordinator in writing that ~~they~~ she or he considers that advice on the Procedure Change Proposal is required from the Gas Advisory Board;

(c) AEMO requests the ~~Rule Change Panel~~Coordinator to convene a meeting under subrule (3); ~~or~~

(d) the ERA requests the ~~Rule Change Panel~~Coordinator to convene a meeting under subrule (4)~~;~~ or

(e) the Coordinator requests a meeting of the Gas Advisory Board.

(3) AEMO may request the ~~Rule Change Panel~~Coordinator to convene a meeting of the Gas Advisory Board concerning a Procedure Change Proposal if the Procedure Change Proposal relates to AEMO's functions under the Rules.

(4) The ERA may request the ~~Rule Change Panel~~Coordinator to convene a meeting of the Gas Advisory Board concerning a Procedure Change Proposal if the Procedure Change Proposal relates to the ERA's functions under the Rules.

160 Procedure Change Report

(1) Within 20 Business Days after the closing date for submissions specified in the Procedure Change Proposal, the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) must publish a Procedure Change Report on the GSI Website.

(2) The ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) must decide whether to:

(a) make the proposed Procedure in the proposed form;

(b) make the proposed Procedure in a modified form; or

(c) not make the proposed Procedure.

(3) A Procedure Change Report must contain:

(a) a summary of any comments received on the proposed Procedure, including advice from the Gas Advisory Board and any working groups established by the Gas Advisory Board;

(b) the reasons of the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) for making or not making the proposed Procedure, including an explanation of how the proposed Procedure is consistent with the GSI Objectives;

(c) if the decision is to make the proposed Procedure – the proposed date and time on which the Procedure is to commence operation; and

(d) the proposed Procedure and, if it has been modified, a description of how and why it has been revised.

(4) The date and time for commencement of the new or amended Procedure must be determined by the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable), having regard to the need to allow sufficient time for Gas Market Participants to implement any changes required.

161 Extension of timeframes

(1) The ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) may, at any time after deciding to progress a Procedure Change Proposal, extend the prescribed timeframe for processing a Procedure Change Proposal in accordance with this rule.

(2) The ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) must publish on the GSI Website a notice of extension of timeframe where it has decided to extend the prescribed timeframe, and must update any information already published.

(3) A notice of extension of timeframe must include:

(a) the reasons for the proposed extension;

(b) the views of Gas Market Participants (if any) consulted on the extension;

(c) the proposed length of any extension; and

(d) the proposed work program.

(4) The ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) may only extend a prescribed timeframe under this rule before the expiry of that timeframe.

162 Operation and commencement of Procedures

(1) A Procedure (including an amended Procedure) commences operation on the date and time determined by the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable).

Note: A Procedure Change Report includes a proposed date and time for commencement of the proposed Procedure as determined by the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable).

(2) Where the proposed commencement date and time specified in a Procedure Change Report published on the GSI Website is later than the date of publishing that Procedure Change Report, the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) must, on or before the date on which the new or amended Procedure commences, publish on the GSI Website a notice of the commencement of the new or amended Procedure.

(3) The ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) may amend a proposed date and time for commencement of a new or amended Procedure as published in a Procedure Change Report (and may do so on more than one occasion), provided that:

(a) the first amended commencement date and time is published on the GSI Website before the proposed commencement date and time referred to in the Procedure Change Report;

(b) subsequent amendments to the proposed commencement date and time are published on the GSI Website before the most recently published proposed commencement date and time; and

(c) the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) publishes reasons for the change.

163 ~~Rule Change Panel~~Coordinator, AEMO and ERA to publish up to date version of Procedures

The ~~Rule Change Panel~~Coordinator, AEMO and the ERA (as applicable) must, at all times, maintain on the GSI Website a copy of all Procedures that relate to its functions under the Rules, as in force from time to time.

164 ~~Rule Change Panel~~Coordinator, AEMO and ERA to publish historical Procedure Change Proposals

The ~~Rule Change Panel~~Coordinator, AEMO and the ERA (as applicable) must publish on the GSI Website documents relevant to previous Procedure Change Proposals that relate to its functions under the Rules that are no longer current, whether ~~or not~~ those proposals were accepted or rejected.

…

Confidential Information means information given to the Coordinator under an obligation under a written law or these Rules—

(a) that is specified to be confidential by the person who provided it (unless it is not reasonable in the circumstances to so specify the information); or

(b) that by its nature is confidential; or

(c) that is classified as confidential under these Rules or the GSI Regulations.

…

Coordinator means the Coordinator of Energy referred to in section 4 of the Energy Coordination Act 1994.

Coordinator's Website means a website or portion of a website maintained by, or on behalf of, the Coordinator**.**

…

Draft Rule Change Report means a report prepared by the ~~Rule Change Panel~~Coordinator under rule 136.

…

Final Rule Change Report means—

(a) for a Fast Track Rule Change Process, a report published by the ~~Rule Change Panel~~Coordinator under rule 134 and includes a revised Final Rule Change Report published under subrule 148(2); and

(b) for a Standard Rule Change Process, a report published by the ~~Rule Change Panel~~Coordinator under rule 137, and includes a revised Final Rule Change Report published under subrule 148(2).

…

GAB Secretariat means the services, facilities and assistance made available by the Coordinator to the Gas Advisory Board.

Gas Advisory Board means the board established by the ~~Rule Change Panel~~Coordinator under rule 11.

…

GSI Consultation Procedure means the consultation procedure set out in rule 7 that the ~~Rule Change Panel~~Coordinator, AEMO and the ERA must follow when any of those entities are required to make an instrument (however described) under the Rules in accordance with the GSI Consultation Procedure.

…

Panel Regulations means the *Energy Industry (Rule Change Panel) Regulations 2016* as they were in effect immediately before their repeal.

…

Procedure Change Report means a report published by the ~~Rule Change Panel~~Coordinator, AEMO or the ERA (as applicable) under rule 160.

…

Protected Information has the meaning given in the GSI Act and includes any C~~c~~onfidential I~~i~~nformation ~~as defined in the Panel Regulations~~.

…

~~**RCP Secretariat** means the executive officer of the Rule Change Panel made available by the ERA in accordance with the Panel Regulations.~~

~~**RCP Secretariat Support Services** means the RCP Secretariat and such staff members, services, facilities and assistance as are made available by the ERA to the Rule Change Panel in accordance with the Panel Regulations.~~

…

Rule Change Notice means a notice issued by the ~~Rule Change Panel~~Coordinator in accordance with rule 132.

Rule Change Panel has the meaning given in the Panel Regulations.

…

Rule Change Proposal means a proposal made in accordance with rule 129 requesting that the ~~Rule Change Panel~~Coordinator make Amending Rules.

Rule Change Proposal Form means a form published by the ~~Rule Change Panel~~Coordinator on the GSI Website for the purposes of initiating a Rule Change Proposal (see rule 130).

~~**Rule Change Panel Transfer Date** means 8:00AM on the date the amending rules made under the GSI Regulations, regulation 7(5) giving effect to the transfer of functions from the IMO to the Rule Change Panel commence operation.~~

…

[Note to stakeholders: The transition from RCP to the Coordinator will be implemented by a new rule Part 6 of Schedule 3. This will be modelled on existing Part 4 of Schedule 3, which implemented the transfer from the IMO to the RCP. To assist readers who may be familiar with existing rule Part 4, we have presented the new Part as a markup from that Part.]

Part 4~~6~~—Transitional rules for conferral of functions on ~~Rule Change Panel~~Coordinator

Division 1—Definitions

1 Definitions

In this Part—

~~Rule Change Panel~~Coordinator Transfer Date has the meaning given in Schedule 1.

Division 2—Transitional Rules

2 Validation of acts, instruments and decisions of ~~Rule Change Panel~~Coordinator

(1) On and from the ~~Rule Change Panel~~Coordinator Transfer Date—

(a) where the ~~Rule Change Panel~~Coordinator is required to do an act, matter or thing under a provision of the Rules, and that act, matter or thing was done by the ~~IMO~~Rule Change Panel prior to the ~~Rule Change Panel~~Coordinator Transfer Date, then the act, matter or thing is deemed to have been done by the ~~Rule Change Panel~~Coordinator in accordance with the relevant provision;

(b) where the ~~Rule Change Panel~~Coordinator is required to do an act, matter or thing under a provision of a Procedure, and that act, matter or thing was done by the ~~IMO~~Rule Change Panel prior to the ~~Rule Change Panel~~Coordinator Transfer Date, then the act, matter or thing is deemed to have been done by the ~~Rule Change Panel~~Coordinator in accordance with the relevant provision;

(c) notwithstanding the operation of subrules 2(1)(a) and 2(1)(b), the ~~Rule Change Panel~~Coordinator is not liable for any act, matter or thing done by the ~~IMO~~Rule Change Panel prior to the ~~Rule Change Panel~~Coordinator Transfer Date in breach of the Rules or any Procedure;

(d) where the ~~Rule Change Panel~~Coordinator is required to develop or maintain a Procedure, and that Procedure was developed or maintained by the ~~IMO~~Rule Change Panel prior to the ~~Rule Change Panel~~Coordinator Transfer Date, then—

(i) the Procedure is deemed to have been developed or maintained by the ~~Rule Change Panel~~Coordinator in accordance with the Rules;

(ii) a reference to the ~~IMO~~Rule Change Panel in that Procedure that should be a reference to the ~~Rule Change Panel~~Coordinator having regard to the ~~Rule Change Panel~~Coordinator's functions, powers, rights and obligations under the Rules and the other Procedures is deemed to be a reference to the ~~Rule Change Panel~~Coordinator;

(iii) the ~~Rule Change Panel~~Coordinator may amend the Procedure to refer to the ~~Rule Change Panel~~Coordinator instead of the ~~IMO~~Rule Change Panel (where appropriate) and make any necessary consequential amendments to the Procedure, and the provisions of rules 156 to 162 will not apply to the ~~Rule Change Panel~~Coordinator to the extent to which it amends Procedures in accordance with this subrule 2(1)(d); and

(iv) any Procedure which is amended by the ~~Rule Change Panel~~Coordinator in accordance with this subrule 2(1)(d) may commence operation on the date and time determined by the ~~Rule Change Panel~~Coordinator and published on the GSI Website;

(e) where the ~~Rule Change Panel~~Coordinator is required to publish or release any information or document (other than a Procedure) (including, without limitation, a form, protocol, instrument or other thing and the Constitution) and that information or document was published or released by the

~~IMO~~Rule Change Panel prior to the ~~Rule Change Panel~~Coordinator Transfer Date, then—

(i) the information or document is deemed to have been published or released by the ~~Rule Change Panel~~Coordinator in accordance with the Rules; and

(ii) any reference to the ~~IMO~~Rule Change Panel in such information or document that should be a reference to the ~~Rule Change Panel~~Coordinator having regard to the ~~Rule Change Panel~~Coordinator's functions, powers, rights and obligations under the Rules and the Procedures is deemed to be a reference to the ~~Rule Change Panel~~Coordinator; and

(f) where a person (including, without limitation, a Gas Market Participant) is required to provide information to, or do an act, matter or thing for the ~~Rule Change Panel~~Coordinator under the Rules or a Procedure and the person has provided that information to, or done that act, matter or thing for the ~~IMO~~Rule Change Panel prior to the ~~Rule Change Panel~~Coordinator Transfer Date, then the information, act or thing, is deemed to have been provided to, or done for, the ~~Rule Change Panel~~Coordinator in accordance with the relevant Rules or Procedure.

(2) If, by operation of subrule 2(1), the ~~Rule Change Panel~~Coordinator is deemed to have made a Reviewable Decision that was made by the ~~IMO~~Rule Change Panel, then, on and from the ~~Rule Change Panel~~Coordinator Transfer Date, any application to the Board for a review of the Reviewable Decision that might have been brought or continued by a Gas Market Participant against the ~~IMO~~Rule Change Panel may be brought or continued against the ~~Rule Change Panel~~Coordinator as if all references to the ~~IMO~~Rule Change Panel as the relevant decision-maker are references to the ~~Rule Change Panel~~Coordinator.

3 Coordinator's first budget

Notwithstanding subrule 110B(3) , the date by which the Coordinator must notify AEMO of the dollar amount that the Coordinator may recover under subrule 110B(1) in the Financial Year beginning on 1 July 2021, is 15 July 2021.

Appendix C

Draft WEM Rules Amendments – Transfer of Functions from the ERA to the Coordinator

Appendix C

DRAFT WEM RULES AMENDMENTS

TRANSFER FROM ERA to COE, and AEMO to ERA

[Note to stakeholders: In the proposed draft rules at appendices A and C we have not replicated changes related to the generator performance standards (Tranche 1 Rules) administrative changes being proposed as part of the Energy Transformation Strategy. These will be incorporated at a later date as necessary to suit the timing of the various rules packages]

1.17A. Transition of certain Economic Regulation Authority ~~IMO~~ functions to the ~~Economic Regulation Authority~~ Coordinator

[Note: Section 1.17 will be retained in its current form, and an entirely new section 1.17A will be inserted. However, we have marked-up the new clause to show how it has been adapted from section 1.17]

1.17A.1. On and from the ~~ERA~~ Coordinator Transfer Date:

(a) where the ~~Economic Regulation Authority~~Coordinator is required to do an act, matter or thing under a provision of these Market Rules, and that act, matter or thing was done by the ~~IMO~~Economic Regulation Authority prior to the ~~ERA~~Coordinator Transfer Date, then the act, matter or thing is deemed to have been done by the ~~Economic Regulation Authority~~Coordinator in accordance with the relevant provision;

(b) where the ~~Economic Regulation Authority~~Coordinator is required to do an act, matter or thing under a provision of a Market Procedure, and that act, matter or thing was done by the ~~IMO~~Economic Regulation Authority prior to the ~~ERA~~Coordinator Transfer Date, then the act, matter or thing is deemed to have been done by the ~~Economic Regulation Authority~~Coordinator in accordance with the relevant provision;

(c) notwithstanding the operation of clauses 1.17A.1(a) and 1.17A.1(b), the ~~Economic Regulation Authority~~Coordinator is not liable for any act, matter or thing done by the ~~IMO~~Economic Regulation Authority prior to the ~~ERA~~Coordinator Transfer Date in breach of these Market Rules or any Market Procedure;

~~(d) where the Economic Regulation Authority is required to develop or maintain a Market Procedure (including the Market Procedure that is required to be maintained in accordance with clause 2.15.1), and that Market Procedure was developed or maintained by the IMO prior to the ERA Transfer Date, then:~~

~~i. the Market Procedure is deemed to have been developed or maintained by the Economic Regulation Authority in accordance with these Market Rules;~~

ii. a reference to the IMO in that Market Procedure that should be a reference to the Economic Regulation Authority having regard to the Economic Regulation Authority's functions, powers, rights and obligations under these Market Rules and the other Market Procedures is deemed to be a reference to the Economic Regulation Authority;

iii. the Economic Regulation Authority may amend the Market Procedure to refer to the Economic Regulation Authority instead of the IMO (where appropriate) and make any necessary consequential amendments without undertaking the Procedure Change Process; and

iv. any Market Procedure which is amended by the Economic Regulation Authority in accordance with this clause 1.17.1(d) may commence operation on the date and time determined by the Economic Regulation Authority and published on the Market Web Site;

(ed) where the Economic Regulation AuthorityCoordinator is required to publish or release any information or document (other than a Market Procedure) (including, without limitation, a form, protocol, instrument or other thing) and that information or document was published or released by the IMOEconomic Regulation Authority prior to the ERACoordinator Transfer Date, then—

i. the information or document is deemed to have been published or released by the Economic Regulation AuthorityCoordinator in accordance with these Market Rules; and

ii. any reference to the IMOEconomic Regulation Authority in that information or document that should be a reference to the Economic Regulation AuthorityCoordinator having regard to the Economic Regulation AuthorityCoordinator's functions, powers, rights and obligations under these Market Rules and the Market Procedures is deemed to be a reference to the Economic Regulation AuthorityCoordinator; and

(fe) where a person (including, without limitation, a Rule Participant) is required to provide information to, or do an act, matter or thing for the Economic Regulation AuthorityCoordinator under these Market Rules or a Market Procedure and the person has provided that information to, or done that act, matter or thing for the IMOEconomic Regulation Authority prior to the ERACoordinator Transfer Date, then the information, act, matter or thing, is deemed to have been provided to, or done for, the Economic Regulation AuthorityCoordinator in accordance with the relevant Market Rules or Market Procedure.

1.17.2. [Blank]

~~1.17.3. If, by operation of clause 1.17.1, the Economic Regulation Authority is deemed to have made a Reviewable Decision that was made by the IMO, then, on and from the ERA Transfer Date any application to the Electricity Review Board for a review of the Reviewable Decision that might have been brought or continued by a Rule Participant against the IMO may be brought or continued against the Economic Regulation Authority as if all references to the IMO as the relevant decision-maker are references to the Economic Regulation Authority.~~

~~1.17.4. [Blank]~~

~~1.17.5. The operation of —~~

~~(a) clause 3.15.1 is modified so that the Economic Regulation Authority is not required to conduct the next study on the Ancillary Service Standards and the basis for setting Ancillary Service Requirements before 31 October 2017;~~

~~(b) clause 3.18.18 is modified so that the Economic Regulation Authority is not required to conduct the next review of the outage planning process before 31 October 2017; Chapter 1~~

~~(c) clause 4.5.15 is modified so that the Economic Regulation Authority is not required to conduct a review of the Planning Criterion and the process by which it forecasts SWIS peak demand before 31 October 2017;~~

~~(d) clause 4.11.3C is modified so that the Economic Regulation Authority is not required to conduct the first review of the Relevant Level Methodology before 1 April 2019, and:~~

~~i. the values of the parameters K and U in Step 17 of Appendix 9 to be applied for the 2018 Reserve Capacity Cycle are deemed to be the K and U values determined for the 2017 Reserve Capacity Cycle as published on the Market Web Site; and~~

~~ii. in conducting the first review of the Relevant Level Methodology, the Economic Regulation Authority must determine the values of the parameters K and U to be applied for the 2019 and 2020 Reserve Capacity Cycles; and~~

~~(e) clause 4.16.9 is modified so that the Economic Regulation Authority is not required to carry out the next review of the Market Procedure referred to in clause 4.16.3 (including any public consultation process in respect of the outcome of the review) before 31 October 2017.~~

…

2.1A. Australian Energy Market Operator

…

2.1A.2. The WEM Regulations also provide for the Market Rules to confer additional functions on AEMO. The functions conferred on AEMO are:

…

(k) to support the Economic Regulation Authority in its market surveillance role, including providing any market related information required by the Economic Regulation Authority;

(l) to support the Coordinator and the Economic Regulation Authority in ~~its~~ their roles of monitoring market effectiveness, including providing any market related information required by the Coordinator or the Economic Regulation Authority;

(lA) to contribute to the development and improve the effectiveness of the operation and administration of the Wholesale Electricity Market, by:

i. developing Rule Change Proposals;

ii. providing support and assistance to other parties to develop Rule Change Proposals;

iii. providing information to the Coordinator ~~Rule Change Panel~~ as required to support the Coordinator~~Rule Change Panel~~'s functions under the Market Rules; and

iv. providing information and assistance to the Coordinator and the Economic Regulation Authority as required to support the reviews they carry ~~carried~~ out ~~by the Economic Regulation Authority~~ under the Market Rules;

...

...

[Note: For the readers convenience the mark-up to 2.16 below includes some changes that will not commence until 1 Oct 2022]

2.16. Monitoring the Effectiveness of the Market

2.16.1. AEMO is responsible for collection and primary analysis of data in accordance with this clause 2.16. AEMO must:

(a) compile the data identified in the Market Surveillance Data Catalogue and provide that data to the Coordinator and the Economic Regulation Authority; and

(b) analyse the compiled data in accordance with clause 2.16.4 and provide the results of the analysis to the Coordinator and the Economic Regulation Authority.

2.16.2. AEMO must develop a Market Surveillance Data Catalogue, which identifies data to be compiled concerning the market. The Market Surveillance Data Catalogue must identify the following data items:

(a) the number of Market ~~Generators and Market Customers~~Participants~~-~~ in the market;

(b) [blank]~~the number of participants in each Reserve Capacity Auction;~~

(c) clearing prices in each ~~Reserve Capacity Auction and~~ STEM Auction;

(d) ~~LFAS~~ ESS Submissions;

(dA) [blank]~~all Reserve Capacity Auction offers;~~

(e) all bilateral quantities scheduled;

(f) all STEM Offers and STEM Bids, including both quantity and price terms;

(g) ~~Balancing~~ Real-Time Market Submissions, including associated Real-Time Market~~Balancing~~ Price-Quantity Pairs and Ramp Rate Limits;

(gA) all Fuel Declarations;

(gB) all Availability Declarations;

(gC) ~~all Ancillary Service Declarations~~(blank);

(gD) Offers of Frequency Co-optimised Essential System Services in the Real-Time Market;

(h) any substantial variations in STEM Offer and STEM Bid prices or quantities relative to recent past behaviour;

(hA) any evidence that a Market Customer has significantly over-stated its consumption as indicated by its Net Contract Position with a regularity that cannot be explained by a reasonable allowance for forecast uncertainty or the impact of Loss Factors;

(hB) the information in clause 7A.2.18(c);

(hC) any substantial variations in Real-Time Market ~~Balancing~~ Prices, ~~Non-Balancing Facility Dispatch Instruction~~Constrained On Payments or Metered Real-Time Market ~~Balancing~~ Quantities relative to recent past behaviour;

(i) the capacity available from ~~Balancing~~ Facilities through the Real-Time ~~Balancing~~ Market and from Demand Side Programmes ~~specified in the Non-Balancing Dispatch Merit Order~~;

(j) the frequency and nature of Dispatch Instructions and Operating Instructions to Market Participants;

(k) the number and frequency of outages of Scheduled Generators, Semi-Scheduled Generators and Non-Scheduled Generators, and Market Participants' compliance with the outage scheduling process;

(l) the performance of Market Participants with Reserve Capacity Obligations in meeting their obligations;

(m) details of ~~Ancillary Service~~Supplementary ESS Contracts and any System Restart Service Contracts that it enters into ~~as System Management~~;

(n) all ~~LFAS~~ ESS Prices;

(o) ~~the number of Rule Change Proposals received, and details of Rule Change Proposals that the Rule Change Panel has decided not to progress under clause 2.5.6~~(blank); and

(p) such other items of information as AEMO considers relevant to the functions of the ~~Rule Change Panel~~Coordinator, AEMO and the Economic Regulation Authority under this clause 2.16.

2.16.2A. [Blank]

2.16.3. AEMO must publish the Market Surveillance Data Catalogue~~,~~ and must republish this document whenever it changes.

2.16.4. AEMO must undertake the following analysis of the data identified in the Market Surveillance Data Catalogue to calculate relevant summary statistics:

(a) where applicable, calculation of the means and standard deviations of values in the Market Surveillance Data Catalogue;

(b) monthly, quarterly and annual moving averages of STEM Clearing Prices, Real-Time Market~~Balancing~~ Prices and ~~LFAS~~ ESS Prices;

(c) statistical analysis of the volatility of STEM Clearing Prices, Real-Time Market ~~Balancing~~ Prices and ~~LFAS~~ ESS Prices;

(cA) any consistent or significant variations between the Fuel Declarations, Availability Declarations~~, and Ancillary Service Declarations for~~, and the actual operation of, a Market Participant facility in real-time;

(d) the proportion of time STEM Clearing Prices and Real-Time Market~~Balancing~~ Prices are at each Energy Price Limit;

(e) correlation between capacity offered into the STEM Auctions and the incidence of high STEM Clearing Prices;

(f) correlation between capacity offered into and made available in the Real-Time Market~~Balancing~~ Market and the incidence of high Real-Time Market ~~Balancing~~ Prices;

(fA) correlation between capacity offered into and made available in the ~~LFAS~~ ESS Market and the incidence of high ~~LFAS~~ ESS Prices;

(g) exploration of the key determinants for high STEM Clearing Prices, Real-Time Market~~Balancing~~ Prices and ~~LFAS~~ ESS Prices, including determining correlations or other statistical analysis between explanatory factors that AEMO considers relevant and price movements; and

(h) such other analysis as AEMO considers appropriate or is requested of AEMO by the Coordinator or the Economic Regulation Authority (as applicable).

2.16.5. AEMO must, on request from the Coordinator or the Economic Regulation Authority (as applicable), and in any event at least once each month, provide the

Coordinator or the Economic Regulation Authority (as applicable) with the data identified in the Market Surveillance Data Catalogue and the results of the analysis on that data referred to in clause 2.16.4.

2.16.6. Where the Coordinator or the Economic Regulation Authority (as applicable) considers that it is necessary or desirable for the performance of its functions under these Market Rules, the WEM Regulations or the Electricity Industry Act, or the functions of AEMO under this clause 2.16, the Coordinator or the Economic Regulation Authority (as applicable) may collect additional information from Rule Participants ~~or the Rule Change Panel~~ as follows:

(a) the Coordinator or the Economic Regulation Authority (as applicable) may issue a notice to one or more Rule Participants ~~or the Rule Change Panel~~ requiring them to provide specified data to the Coordinator or the Economic Regulation Authority (as applicable) by a date (which the Coordinator or the Economic Regulation Authority (as applicable) considers to be reasonable);

(b) Market Participants ~~or the Rule Change Panel (as applicable)~~ must provide any information requested by the Coordinator or the Economic Regulation Authority (as applicable) by the date specified in the notice; and

(c) the Coordinator or the Economic Regulation Authority (as applicable) must provide this information to AEMO where the Coordinator or the Economic Regulation Authority (as applicable) considers that it is necessary or desirable for the performance of AEMO's functions under this clause 2.16.

2.16.7. Without limitation, additional information that can be collected by the Coordinator or the Economic Regulation Authority (as applicable) includes:

(a) cost data for Synergy, including actual fuel costs by Trading Interval;

(b) System Management's operational records (whether held by System Management or which System Management may require from another person under these Market Rules), including SCADA records, of the level of utilisation and fuel related data for each of Synergy's Registered Facilities by Trading Interval; and

(c) the terms of Bilateral Contracts entered into by Synergy.

2.16.8. Rule Participants may notify AEMO or the Economic Regulation Authority of behaviour that they consider reduces the effectiveness of the market, including behaviour related to market power, and the Economic Regulation Authority, with the assistance of AEMO, must investigate the behaviour identified in each relevant notification.

2.16.8A. AEMO must notify the Economic Regulation Authority of any behaviour a Rule Participant notifies it about under clause 2.16.8.

2.16.9. The Economic Regulation Authority ~~is responsible for monitoring the effectiveness of the market in meeting the Wholesale Market Objectives and~~ must investigate

any market behaviour if it considers that the behaviour has resulted in the market not functioning effectively. The Economic Regulation Authority, with the assistance of AEMO, must monitor:

[Note: For the readers convenience the mark-up to 2.16.9(a) below includes changes that will not commence until 1 Oct 2022]

(a) the criteria and processes used by AEMO for the procurement of Essential System Services through the Real-Time Market, the Supplementary Essential System Service Mechanism, and under any contracts entered into by AEMO~~Ancillary Service Contracts that System Management enters into and the criteria and process that System Management uses to procure Ancillary Services from other persons~~; and

(b) inappropriate and anomalous market behaviour, including behaviour related to market power and the exploitation of shortcomings in the Market Rules or Market Procedures by Rule Participants. ~~including, but not limited to:~~

~~i. prices offered by a Market Generator in its Portfolio Supply Curve that do not reflect the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity;~~

~~ii. prices offered by a Market Generator in its Balancing Submission that exceed the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity;~~

~~iii. prices offered by a Market Generator in its LFAS Submission that exceed the Market Generator's reasonable expectation of the incremental change in short run marginal cost incurred by the LFAS Facility in providing the relevant LFAS;~~

~~iv. Availability Declarations that may not reflect the reasonable expectation of a Facility's availability, beyond outages of which System Management has been notified;~~

~~v. Ancillary Service Declarations that may not reflect the reasonable expectation of the Ancillary Services to be provided by a Facility; and~~

~~vi. Fuel Declarations that may not reflect the reasonable expectation of the fuel that a Facility will be run on in real-time;~~

~~(c) market design problems or inefficiencies; and~~

~~(d) problems with the structure of the market.~~

2.16.9A. The Economic Regulation Authority must, in carrying out the monitoring activities ~~identified in clauses 2.16.9(b)(i), 2.16.9(b)(ii) and 2.16.9(b)(iii)~~ relating to any prices offered by a Market Generator, examine prices in:

(a) …

...

2.16.10. [Blank]~~The Economic Regulation Authority must also review:~~

~~(a) the effectiveness of the Market Rule change process and Procedure Change Process;~~

~~(b) the effectiveness of the compliance monitoring and enforcement measures in the Market Rules and Regulations; and~~

~~(c) the effectiveness of AEMO (including in its capacity as System Management) in carrying out its functions under the Regulations, the Market Rules and Market Procedures.~~

~~(d) the effectiveness of System Management in carrying out its functions under the Regulations, the Market Rules and Market Procedures.~~

2.16.11. The Economic Regulation Authority must provide to the Coordinator and the Minister a report on the effectiveness of the market and dealing with the matters identified in clause~~s~~ 2.16.9 ~~and 2.16.10:~~ , if the Economic Regulation Authority considers that any specific events, or systemic behaviour or matters have impacted on the effectiveness of the market.

~~(a) at least annually; and~~

~~(b) more frequently where the Economic Regulation Authority considers that the market is not effectively meeting the Wholesale Market Objectives.~~

2.16.12. [Blank]~~A report referred to in clause 2.16.11 must contain but is not limited to the following:~~

~~(a) a summary of the information and data compiled by AEMO and the Economic Regulation Authority under clause 2.16.1;~~

~~(b) the Economic Regulation Authority's assessment of the effectiveness of the market, including the effectiveness of AEMO (including in its capacity as System Management) in carrying out its functions, with discussion of each of:~~

~~i. the Reserve Capacity Mechanism;~~

~~ii. the market for bilateral contracts for capacity and energy;~~

~~iii. the STEM;~~

~~iv. the Balancing Market;~~

~~v. the dispatch process;~~

~~vi. planning processes;~~

~~vii. the administration of the market, including the Market Rule change process; and~~

~~viii. Ancillary Services;~~

~~(c) an assessment of any specific events, behaviour or matters that impacted on the effectiveness of the market; and~~

~~(d) any recommended measures to increase the effectiveness of the market in meeting the Wholesale Market Objectives to be considered by the Minister.~~

2.16.13. In carrying out its responsibilities under clause 2.16.9(b), the Economic Regulation Authority must:

(a) estimate the prevalence of such behaviour;

(b) estimate the cost to end users of such behaviour;

(c) estimate the impact of such behaviour on the effectiveness of the market in meeting the Wholesale Market Objectives;

(d) consult with Market Participants on the impacts of such behaviour;

(e) estimate the benefits and costs of any recommended measure to reduce such behaviour. The Economic Regulation Authority:

i. may use market simulation tools to estimate the benefits and costs;

ii. must give consideration to:

1. the probability of success of the measure in reducing the behaviour;

2. the implications on the efficiency of the market of implementing the measure; and

3. the costs of compliance as a result of implementing the measure;

(f) where the benefits of any change are estimated to exceed the cost, make recommendations to the Coordinator and the Minister for implementing the measures in a report under clause 2.16.11; and

(g) provide details of its findings in a report to the Coordinator and the Minister under clause 2.16.11.

2.16.13A. The Coordinator is responsible for the development of the market, and with the assistance of the Economic Regulation Authority and AEMO, must monitor market design problems or inefficiencies.

2.16.13B. In carrying out its responsibilities under clause 2.16.13A, the Coordinator must also monitor:

(a) the effectiveness of the Market Rule change process and Procedure Change Process;

(b) the effectiveness of the compliance monitoring and enforcement measures in the Market Rules and Regulations;

(c) the effectiveness of AEMO in carrying out its functions under the Regulations, the Market Rules and Market Procedures; and

(d) the effectiveness of Network Operators in carrying out their functions under the Market Rules and Market Procedures.

2.16.13C. If in the performance of its functions under these Market Rules the Economic Regulation Authority identifies a market design problem or inefficiency, the Economic Regulation Authority may provide to the Coordinator and the Minister a report describing the problem or inefficiency and must publish the report on its website.

2.16.13D. The Coordinator must provide to the Minister a report dealing with the matters identified in clause 2.16.13A and 2.16.13B at least once in every three years.

2.16.13E. A report referred to in clause 2.16.13D must contain but is not limited to the following:

(a) market trends, which may include:

(i) a summary of the information and data compiled by AEMO and the Economic Regulation Authority under clause 2.16.1; and

(ii) any other matter or information the Coordinator considers relevant and appropriate to include;

(b) any recommended measures to increase the effectiveness of the market in meeting the Wholesale Market Objectives to be considered by the Minister.

2.16.14. The Coordinator or the Economic Regulation Authority (as applicable) may use any information collected under this section 2.16, including information provided to it by AEMO, for the purpose of carrying out any of its functions under the Market Rules. The Coordinator or the Economic Regulation Authority (as applicable) must treat information collected under this section 2.16 as confidential and must not publish any of that information other than in accordance with this section 2.16 or where required in the performance of the Coordinator or the Economic Regulation Authority's (as applicable) functions under the Market Rules. AEMO must use information provided to it by the Coordinator or the Economic Regulation Authority (as applicable) under clause 2.16.6(c) only for the purpose of carrying out its functions under this section 2.16. AEMO must treat information provided to it by the Coordinator or the Economic Regulation Authority (as applicable) under clause 2.16.6(c) as confidential and must not publish any of that information other than in accordance with this section 2.16.

2.16.15. Where the Economic Regulation Authority provides a report to the Minister in accordance with clause 2.16.11, it must, after consultation with the Minister, publish a version of the report which has confidential or sensitive data aggregated or removed. An assessment of the results of the Economic Regulation Authority's monitoring under clause 2.16.9(b) must be included in the published version of the report.

2.16.15A. Where the Coordinator provides a report to the Minister in accordance with clause 2.16.13C, it must, after consultation with the Minister, publish a version of the report which has confidential or sensitive data aggregated or removed.

2.16.16. In respect of any reports published under this clause 2.16, only aggregate or summary statistics of confidential data may be published. The aggregation must be at a level sufficient to ensure the underlying data cannot be identified. Where aggregated data is derived from confidential data collected from three or less Market Participants, then this data should not be published.

...

Administered Prices and Loss Factors

2.26. Economic Regulation Authority Review of Methodology for Setting~~Approval of~~ Administered Prices

2.26.1. [Blank] ~~Where AEMO has proposed a revised value for the Benchmark Reserve Capacity Price in accordance with section 4.16 or a change in the value of one or both of the Maximum STEM Price and the Alternative Maximum STEM Price in accordance with section 6.20, the Economic Regulation Authority must:~~

~~(a) review the report provided by AEMO, including all submissions received by AEMO in preparation of the report;~~

~~(b) decide whether to approve the revised value for the Benchmark Reserve Capacity Price or any value comprising the Energy Price Limits;~~

~~(c) in making its decision, only consider:~~

~~i. whether the proposed revised value for the Benchmark Reserve Capacity Price or Energy Price Limit proposed by AEMO reasonably reflects the application of the method and guiding principles described in sections 4.16 or 6.20 (as applicable);~~

~~ii. whether AEMO has carried out an adequate public consultation process; and~~

~~(d) notify AEMO whether it has approved the revised or recommended value.~~

2.26.2. [Blank] ~~Where the Economic Regulation Authority rejects a revised Benchmark Reserve Capacity Price or the Energy Price Limits submitted by AEMO it must give reasons and may direct AEMO to carry out all or part of the review process under section 4.16 or 6.20 (as applicable) again in accordance with any directions or recommendations of the Economic Regulation Authority.~~

2.26.3. At least once in every five years, t~~T~~he Economic Regulation Authority must review the methodology for setting the Benchmark Reserve Capacity Price and the Energy Price Limits ~~not later than the fifth anniversary of the first Reserve Capacity Cycle and, subsequently, not later than the fifth anniversary of the completion of the preceding review under this clause 2.26.3~~. A review must examine:

(a) the level of competition in the market;

(b) the level of market power being exercised and the potential for the exercise of market power;

(c) the effectiveness of the methodology in curbing the use of market power;

(d) ~~historical Reserve Capacity Offers and the proportion of Reserve Capacity Offers with prices equal to the Benchmark Reserve Capacity Price, in the case of Reserve Capacity Cycles up to and including the 2014 Reserve Capacity Cycle~~(blank);

(dA) ~~historical Reserve Capacity Offers and the proportion of Reserve Capacity Offers with prices equal to 110 percent of the Benchmark Reserve Capacity Price, in the case of Reserve Capacity Cycles from the 2015 Reserve Capacity Cycle up to and including the 2018 Reserve Capacity Cycle~~(blank);

(dB) ~~historical Reserve Capacity Offers and the proportion of Reserve Capacity Offers with prices equal to 130 percent of the Benchmark Reserve Capacity Price, in the case of Reserve Capacity Cycles from the 2019 Reserve Capacity Cycle onwards~~(blank);

(e) historical STEM Bids and STEM Offers and the proportion of STEM Bids and Offers with prices equal to the Energy Price Limits;

(eA) the Bids and Offers with prices equal to the Energy Price Limits submitted for Facilities which have received Constraint On payments in the Trading Intervals to which the Bids and Offers applied;

(f) the appropriateness of the parameters and methodology in section 4.16 and the Market Procedure referred to in clause 4.16.3 for recalculating the Benchmark Reserve Capacity Price;

(g) the appropriateness of the parameters and methodology in section 6.20 for recalculating the Energy Price Limits;

(h) [blank]~~the performance of Reserve Capacity Auctions, STEM Auctions and the Balancing Market in meeting the Wholesale Market Objectives;~~ and

(i) other matters which the Economic Regulation Authority considers relevant.

2.26.3A. The Economic Regulation Authority must review the Reserve Capacity Price Factors at the same time as each review of the Benchmark Reserve Capacity Price under clause 2.26.3. A review must examine:

(a) whether the Reserve Capacity Price Factors efficiently signal the long-term economic value of incremental or excess Reserve Capacity in the Wholesale Electricity Market;

(b) whether the Reserve Capacity Price calculated using the Reserve Capacity Price Factors is consistent with the Wholesale Market Objectives; and

(c) any other matters the Economic Regulation Authority considers to be relevant.

2.26.4. The Economic Regulation Authority must provide a report to the Minister on the reviews conducted under clauses 2.26.3 and 2.26.3A.

...

2.32. Rule Participant Suspension and Deregistration

…

2.32.7A. ~~The Economic Regulation Authority or~~ AEMO may at any time review whether a Rule Participant registered in the classes outlined in clause 2.28.1(b) or (c) continues to meet all of the criteria specified in clause 2.28.19.

…

...

[Note: For the readers convenience the mark-up to 3.11 below includes some changes that will not commence until 1 Oct 2022]

3.11. Determining & Procuring Ancillary Service Requirements

…

~~3.11.8B System Management must obtain the approval of the Economic Regulation Authority before entering into an Ancillary Service Contract for Dispatch Support Ancillary Services.~~

~~3.11.8C The Economic Regulation Authority must only review whether an Ancillary Service Contract, to which 3.11.8B applies, would achieve the lowest practicably sustainable cost of delivering the services.~~

~~3.11.8D The Economic Regulation Authority may undertake a public consultation process in determining whether to approve the Ancillary Service Contract for Dispatch Support Service. In determining whether to undertake a public consultation process, the Economic Regulation Authority must have regard to the terms of the Ancillary Service Contract, including the length of its intended operation and whether a need exists to expedite the approval process.~~

…

...

[Note: For the readers convenience the mark-up to 3.13 below includes some changes that will not commence until 1 Oct 2022]

3.13. Payment for Ancillary Services

3.13.1. The total payments by AEMO for Ancillary Services in accordance with Chapter 9 comprise:

(a) [Blank]

(aA) for Load Following Service for each Trading Month:

i. a capacity payment LF_Capacity_Cost, calculated in accordance with clause 9.9.2(q) for that Trading Month; and

ii. an amount LF_Market_Cost calculated in accordance with clause 9.9.2(o) for that Trading Month;

(b) an amount SR_Availability_Cost for Spinning Reserve Service for each Trading Month, which is calculated in accordance with clause 9.9.2(m) for that Trading Month; and

(c) Cost_LRD, the monthly amount for Load Rejection Reserve Service and System Restart Service, determined ~~in accordance with the process described in clauses 3.13.3B and 3.13.3C; and Dispatch Support Service determined in accordance with clause 3.11.8B~~

…

~~3.13.3A. For each Financial Year, by 31 March prior to the start of that Financial Year, the Economic Regulation Authority must determine values for the parameters Margin_Peak and Margin_Off-Peak, taking into account the Wholesale Market Objectives and in accordance with the following:~~

~~(a) by 30 November prior to the start of the Financial Year, AEMO must submit a proposal for the Financial Year to the Economic Regulation Authority:~~

~~i. for the reserve availability payment margin applying for Peak Trading Intervals, Margin_Peak, AEMO must take account of:~~

~~1. the margin Synergy could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve Service during Peak Trading Intervals; and~~

~~2. the loss in efficiency of Synergy's Scheduled Generators that System Management has scheduled (or caused to be scheduled) to provide Spinning Reserve Service during Peak Trading Intervals that could reasonably be expected due to the scheduling of those reserves;~~

~~ii. for the reserve availability payment margin applying for Off-Peak Trading Intervals, Margin_Off-Peak, AEMO must take account of:~~

1. the margin Synergy could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve Service during Off-Peak Trading Intervals; and

2. the loss in efficiency of Synergy's Scheduled Generators that System Management has scheduled (or caused to be scheduled) to provide Spinning Reserve Service during Off-Peak Trading Intervals that could reasonably be expected due to the scheduling of those reserves; and

(b) the Economic Regulation Authority must undertake a public consultation process, which must include publishing an issues paper and issuing an invitation for public submissions.

3.13.3B. For each Review Period, by 31 March of the year in which the Review Period commences, the Economic Regulation Authority must determine values for Cost_LR, taking into account the Wholesale Market Objectives and in accordance with the following:

(a) by 30 November of the year prior to the start of the Review Period, System Management must submit a proposal for the Cost_LR parameter for the Review Period to the Economic Regulation Authority. Cost_LR must cover the costs for providing the Load Rejection Reserve Service and System Restart Service and Dispatch Support Service except those provided through clause 3.11.8B;

(b) the Economic Regulation Authority must undertake a public consultation process, which must include publishing an issues paper and issuing an invitation for public submissions.

3.13.3C. For any year within a Review Period if System Management determines Cost_LR for the following Financial Year to be materially different than the costs provided under clause 3.13.3B, then the Economic Regulation Authority must determine the revised values for Cost_LR, taking into account the Wholesale Market Objectives and in accordance with the following:

(a) by 30 November of the year prior to the start of the relevant Financial Year, System Management must submit an updated proposal for the Cost_LR parameter to the Economic Regulation Authority. Cost_LR must cover the costs for providing the Load Rejection Reserve Service and System Restart Service and Dispatch Support Service except those provided through clause 3.11.8B;

(b) the Economic Regulation Authority may undertake a public consultation process and:

i. if a public consultation process is undertaken, the Economic Regulation Authority must publish an issues paper and issue an invitation for public submissions; and

ii. if a public consultation process is not undertaken, the Economic Regulation Authority must publish the reasons behind the decision.

...

[Note: For the readers convenience the mark-up to section3.15 below includes changes that will not commence until 1 Oct 2022]

3.15. Review of Ancillary Essential System Service Requirements Process and Standards

[Note: Grey text shows changes being made in other work streams.]

3.15.1. Economic Regulation AuthorityThe Coordinator, with the assistance of AEMO, must carry out a study review on the Ancillary Essential System Service Standards and the basis for setting Ancillary Essential System Service Requirements requirements. The study must include:

(a) technical analyses determining the relationship between the level of Ancillary Services provided and the SWIS Operating Standards set out in clause 3.1;

(b) identification of the expected costs that would result from an increase in the requirements for Ancillary Services due to additional Facilities connecting to the SWIS;

(c) a cost-benefit study on the effects on stakeholders of providing and using a variety of levels of each Ancillary Service; and

(d) a public consultation process.

3.15.1A. The CoordinatorEconomic Regulation Authority must conduct the first review under clause 3.15.1 within two and a half years of the New WEM Commencement Day and then, subject to clause 3.15.1B, at least once in every three year period from completion of the previous review.

3.15.1B. The CoordinatorEconomic Regulation Authority may conduct a review contemplated by clause 3.15.1 earlier than the time referred to in clause 3.15.1A if it reasonably forms the opinion that any of the metrics developed under clause 3.15.2 are significantly departing from the targets set in the previous review.

3.15.1C. A review conducted pursuant to clause 3.15.1A or clause 3.15.1B must include:

(a) technical analyses determining the relationship between the quantity of Essential System Service scheduled and dispatched against the technical parameters in the Frequency Operating Standards;

(b) economic analyses determining the relationship between technical parameters (including, without limitation, frequency operating bands and Oscillation Control Constraint parameters) and overall cost of supply of energy and Essential System Services;

(c) a cost-benefit study on the effects on the Network and Market Participants of providing and using higher or lower levels of each Essential System Service;

(d) identification of the costs and benefits of changing technical parameters, including the potential for increasing or decreasing the overall cost to supply energy and Essential System Services;

(e) a review of the processes and effectiveness of the SESSM if it was triggered during the review period; and

(f) a public consultation process.

3.15.2. As part of each review under clause 3.15.1A or clause 3.15.1B, the Coordinator~~Economic Regulation Authority~~, with the support of AEMO, must determine and publish a set of metrics to be used for ongoing monitoring of Essential System Services, which must include:

(a) technical outcomes, such as dispatched Essential System Service quantities, number of accredited Facilities, number of capable Facilities and the historical performance of those Facilities;

(b) financial outcomes, such as Market Clearing Prices and Essential System Service costs; and

(c) economic outcomes, such as the overall electricity costs faced by consumers.

3.15.~~2~~3. The Coordinator~~Economic Regulation Authority~~ must publish a report containing:

(a) the inputs and results of the technical reviews conducted pursuant to clause 3.15.1A and clause 3.15.1B and cost-benefit studies;

(b) the submissions received by the Coordinator~~Economic Regulation Authority~~ in the consultation process, a summary of those submissions, and any responses to issues raised in those submissions; ~~and~~

(c) any recommendations for the inclusion of a new Essential System Service, ~~recommended~~ changes to ~~Ancillary~~ Essential System Service Standards and the basis for setting ~~Ancillary~~ Essential System Service ~~Requirements~~ requirements~~.~~; and

(d) the metrics and targets to be used for ongoing monitoring of Essential System Services.

3.15.~~4~~. The Coordinator~~Economic Regulation Authority~~ must publish the report referred to in clause 3.15.3 no later than:

(a) for the first report, two and a half years of the New WEM Commencement Day; and

(b) thereafter, three years after publishing the previous review.

3.15.35. If the CoordinatorEconomic Regulation Authority recommends any changes in a the report published under in clause 3.15.2 3.15.3, the Economic Regulation Authority must, as relevant:

(a) draftmake a Rule Change Proposal in accordance with clause 2.5.1 to implement those changes;

(b) draft a suitable Procedure Change Proposal and progress it using the Procedure Change Process in section 2.10; or

(c) recommend to AEMO that it amend a WEM Procedure which these WEM Rules contemplate will be developed by AEMO, in which case AEMO must draft a suitable Procedure Change Proposal and progress it using the Procedure Change Process in section 2.10.

…

3.18. Outage Scheduling

…

~~3.18.18. From time to time, and at least once in every five year period starting from Energy Market Commencement, the Economic Regulation Authority, with the assistance of System Management, must conduct a review of the outage planning process against the Wholesale Market Objectives. The review must include a technical study of the effectiveness of the criteria in clause 3.18.11 and a broad consultation process with Rule Participants.~~

3.18G. Economic Regulation Authority Study of the Impact of Network Operator Outages on the Market

3.18G.1. At least once in every five year period starting from 1 July 2021, the Economic Regulation Authority must conduct an economic study on the impact of Network Operator Outages on the market.

3.18G.2. At the conclusion of a review under clause 3.18G.1, Economic Regulation Authority must publish:

(a) the inputs and results of the economic study;

(b) all submissions received by Rule Participants as part of a consultation process conducted by the Economic Regulation Authority and any responses to issues raised in those submissions; and

(c) a report containing any recommended changes, formulated as one or more WEM Rule changes, recommended WEM Procedure changes or recommended changes to other relevant instruments (e.g. Access Code).

3.18G.3. If the Economic Regulation Authority recommends any changes to the WEM Rules or WEM Procedures in a report published under clause 3.18G.2(c), the Economic Regulation Authority must either submit a Rule Change Proposal in accordance

with clause 2.5.1 or initiate a Procedure Change Process in accordance with section 2.10 to effect the change, as the case may be.

3.18HG. ~~Economic Regulation Authority~~ Coordinator Review of Outage Planning Process

3.18H~~G~~.1. At least once in every five year period starting the New WEM Commencement Day, the Coordinator ~~Economic Regulation Authority~~, with the assistance of AEMO, must conduct a review of the Outage planning process against the Wholesale Market Objectives. At a minimum, the review must include:

(a) a technical study of the effectiveness of the Outage Evaluation Criteria;

~~(b) an economic study on the impact of Network Operator Outages on the market~~; and

(b~~c~~) a public consultation process with Rule Participants.

3.18H~~G~~.2. At the conclusion of a review under clause 3.18H~~G~~.1, the Coordinator ~~Economic Regulation Authority~~ must publish:

(a) the inputs and results of the technical study ~~and economic study~~;

(b) all submissions received by Rule Participants as part of the consultation process and any responses to issues raised in those submissions; and

(c) a report containing any recommended changes to the Outage planning process, formulated as one or more WEM Rule changes, recommended WEM Procedure changes or recommended changes to other relevant instruments (e.g. Access Code).

3.18H~~G~~.3. If the Coordinator ~~Economic Regulation Authority~~ recommends any changes to the WEM Rules or WEM Procedures in a report published under clause 3.18H~~G~~.2(c), the Coordinator ~~Economic Regulation Authority~~ must either submit a Rule Change Proposal in accordance with clause 2.5.1 or initiate a Procedure Change Process in accordance with section 2.10 to effect the change, as the case may be.

...

4.5. Long Term Projected Assessment of System Adequacy

…

4.5.14. AEMO must document the procedure it follows in conducting the Long Term PASA~~, and which the Economic Regulation Authority must follow in conducting reviews under clause 4.5.15,~~ in a Market Procedure.

4.5.15. From time to time, and at least once in every five year period starting from ~~Energy Market Commencement~~ 1 July 2021, the ~~Economic Regulation Authority~~Coordinator, with the assistance of AEMO, must conduct a review of the

Planning Criterion and the process in the Market Procedure specified in clause 4.5.14 by which AEMO forecasts SWIS peak demand. This review must include:

(a) a review of the technical analysis; and

(b) a cost-benefit study on the effects on stakeholders of a variety of levels of generation adequacy.

4.5.16. In conducting a review under clause 4.5.15, the ~~Economic Regulation Authority~~ Coordinator must invite submissions ~~in accordance with the Market Procedure specified in clause 4.5.14~~ on the performance of the Planning Criterion and the process by which AEMO forecasts SWIS peak demand from Rule Participants, and must specify a reasonable time by which submissions must be lodged. ~~and~~ The Coordinator must take ~~any submissions~~ into account in the review any submissions received within the time specified, and may take into account any late submission.

4.5.17. ~~In accordance with the Market Procedure specified in clause 4.5.14, the Economic Regulation Authority~~ The Coordinator must make available a draft of the report described in clause 4.5.18 to Rule Participants for comment and invite submissions on the draft report. The Coordinator must specify a reasonable time by which submissions must be lodged, and must take into account any submissions received within the time specified, and may take into account any late submission.

4.5.18. After concluding the review described in clause 4.5.15, the ~~Economic Regulation Authority~~ Coordinator must publish a final report containing:

(a) issues identified by the ~~Economic Regulation Authority~~ Coordinator;

(b) assumptions made by the ~~Economic Regulation Authority~~ Coordinator in undertaking the review;

(c) submissions received by the Coordinator ~~Economic Regulation Authority~~ from Rule Participants in accordance with clause 4.5.16;

(d) the Coordinator's ~~Economic Regulation Authority's~~ responses to the issues raised in those submissions;

(e) the results of the technical and cost-benefit studies;

(f) the submissions on the draft report received by the Coordinator ~~Economic Regulation Authority~~ from Rule Participants in accordance with clause 4.5.17;

(g) the Coordinator's ~~Economic Regulation Authority's~~ responses to the issues raised in those submissions; and

(h) any recommended changes to the Planning Criterion.

4.5.19. Where the Coordinator ~~Economic Regulation Authority~~ finds that a change to the process by which AEMO forecasts SWIS peak demand would be beneficial in light of the Wholesale Market Objectives, it must:

(a) make a Rule Change Proposal to implement the change; and/or

(b) make a Procedure Change Proposal to implement the change.

4.5.20. If the Coordinator ~~or Economic Regulation Authority~~ contracts with a third party to conduct ~~the~~ any analysis required under this clause 4.5, then:

(a) the Coordinator ~~Economic Regulation Authority~~ must ensure that the third party is familiar with the methodology employed in conducting the analysis required under this clause 4.5 in previous years; and

(b) the Coordinator ~~Economic Regulation Authority~~ must approve any variations in the process to be used by that third party, ~~where~~ and variations may only be accepted if not inconsistent with the requirements specified in the Market Rules or a Market Procedure.

...

4.11. Setting Certified Reserve Capacity

…

~~4.11.1E. The Economic Regulation Authority, in consultation with AEMO, must undertake a review, to be completed by 31 December 2020, of the operation of clause 4.11.1(h) in which it must consider the appropriate thresholds under clause 4.11.1D for Capacity Years from and including the 2022 Capacity Year. The review must include, at a minimum, an assessment of—~~

~~(a) the availability performance of the generation sector in the Wholesale Electricity Market compared with analogous generating plants in other markets;~~

~~(b) the number of Facilities in the SWIS to which the criteria in clause 4.11.1(h) have applied in each of the previous five Capacity Years; and~~

~~(c) the impact on the Wholesale Electricity Market of decisions made by AEMO under clause 4.11.1(h) in the previous five Capacity Years.~~

~~4.11.1F. If the Economic Regulation Authority recommends a rule change resulting from the review in clause 4.11.1E, the Economic Regulation Authority must submit a Rule Change Proposal to implement the change.~~

…

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

(a) examine the effectiveness of the Relevant Level Methodology 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.

…

...

4.16. The Benchmark Reserve Capacity Price

4.16.1. For all Reserve Capacity Cycles, the Economic Regulation Authority~~AEMO~~ must publish a Benchmark Reserve Capacity Price as determined in accordance with this section 4.16 prior to the time specified in section 4.1.4.

4.16.2. The Benchmark Reserve Capacity Price to apply for the first Reserve Capacity Cycle is $150,000 per MW per year.

4.16.3 The Economic Regulation Authority must develop a Market Procedure documenting~~:~~ the methodology ~~AEMO~~ it must use and the process ~~AEMO~~ it must follow in determining the Benchmark Reserve Capacity Price, and—

(a) the Economic Regulation Authority, AEMO and Rule Participants must follow that documented Market Procedure when conducting any review and consultations in accordance with that Market Procedure and clause 4.16.6; and

(b) the Economic Regulation Authority~~AEMO~~ must follow that documented Market Procedure to annually review the value of the Benchmark Reserve Capacity Price in accordance with this section 4.16 and in accordance with the timing requirements specified in section 4.1.19.

4.16.4. [Blank]

4.16.5. ~~AEMO~~ The Economic Regulation Authority must ~~propose a~~ revised~~d~~ the value ~~for~~ of the Benchmark Reserve Capacity Price using the methodology described in the Market Procedure referred to in clause 4.16.3.

4.16.6. The Economic Regulation Authority~~AEMO~~ must prepare a draft report describing how it has arrived at a proposed revised value for the Benchmark Reserve Capacity Price under clause 4.16.5. The Economic Regulation Authority~~AEMO~~ must publish the report on the Market Web Site and advertise the report in newspapers widely distributed in Western Australia and request submissions from all sectors of the Western Australia energy industry, including end-users.

4.16.7. After considering of the submissions on the draft report described in clause 4.16.6 the Economic Regulation Authority~~AEMO~~ must propose a final revised value for

the Benchmark Reserve Capacity Price and publish that value and its final report, including submissions received on the draft report on the Market Web Site.

4.16.8. A proposed revised value for the Benchmark Reserve Capacity Price becomes the Benchmark Reserve Capacity Price after the Economic Regulation Authority~~AEMO~~ has posted a notice on the Market Web Site of the new value of the Benchmark Reserve Capacity Price with effect from the date and time specified in the Economic Regulation Authority~~AEMO~~'s notice.

4.16.9 At least once in every five year period, the Economic Regulation Authority must review the Market Procedure referred to in clause 4.16.3 and must undertake a public consultation process in respect of the outcome of the review.

4.16.10. If the Economic Regulation Authority recommends changes as a result of the review in clause 4.16.9, the Economic Regulation Authority must either submit a Rule Change Proposal or initiate a Procedure Change Process, as the case may be, to implement those changes.

…

4.24. Supplementary Reserve Capacity

…

4.24.19. Following each call for tenders for supplementary capacity or otherwise acquiring Eligible Services, ~~AEMO~~ the Coordinator must review the Supplementary Reserve Capacity provisions of this section 4.24 of the Market Rules with regard to the Wholesale Market Objectives and must undertake a public consultation process in respect of the outcome of the review.

…

4.26. Financial Implications of Failure to Satisfy Reserve Capacity Obligations

…

~~4.26.1D. The Economic Regulation Authority, in consultation with AEMO, must undertake a review, to be completed by 31 December 2020 of whether the limit for the Refund Exempt Planned Outage Count referred to in clause 4.26.1C should be modified to better address the Wholesale Market Objectives. The review must include, at a minimum, an assessment of—~~

~~(a) variations in Planned Outage rates and Forced Outage rates of Scheduled Generators since the introduction of the limit on Refund Exempt Planned Outages;~~

~~(b) for each Scheduled Generator and each year since the introduction of the limit on Refund Exempt Planned Outages—~~

~~i. the number of Equivalent Planned Outage Hours for which Facility Reserve Capacity Deficit Refunds were payable; and~~

~~ii. the total amount of Facility Reserve Capacity Deficit Refunds associated with Refund Payable Planned Outages; and~~

~~(c) the level of participation by Scheduled Generators in the Reserve Capacity Mechanism in each year since the introduction of the limit on Refund Exempt Planned Outages; and~~

~~(d) changes in the mix of Scheduled Generators that have participated in the Reserve Capacity Mechanism in each year since the introduction of the limit on Refund Exempt Planned Outages.~~

~~4.26.1E. If the Economic Regulation Authority recommends changes in the review in clause 4.26.1D, the Economic Regulation Authority must submit a Rule Change Proposal to implement those changes.~~

…

6.20. Energy Price Limits

…

6.20.6. ~~AEMO~~ The Economic Regulation Authority must annually review the appropriateness of the value of the Maximum STEM Price and Alternative Maximum STEM Price.

6.20.7. In conducting the review required by clause 6.20.6 the Economic Regulation Authority~~AEMO~~:

(a) may propose revised values for the following:

i. the Maximum STEM Price, where this is to be based on AEMO's estimate of the short run marginal cost of the highest cost generating works in the SWIS fuelled by natural gas and is to be calculated using the formula in paragraph (b); and

ii. the Alternative Maximum STEM Price, where this is to be based on the Economic Regulation Authority~~AEMO~~'s estimate of the short run marginal cost of the highest cost generating works in the SWIS fuelled by distillate and is to be calculated using the formula in paragraph (b);

(b) must calculate the Maximum STEM Price or Alternative Maximum STEM Price using the following formula:

(1 + Risk Margin)× (Variable O&M +(Heat Rate × Fuel Cost))/Loss Factor

Where

i. Risk Margin is a measure of uncertainty in the assessment of the mean short run average cost for a 40 MW open cycle gas turbine generating station, expressed as a fraction;

ii. Variable O&M is the mean variable operating and maintenance cost for a 40 MW open cycle gas turbine generating station, expressed in $/MWh, and includes, but is not limited to, start-up related costs;

iii. Heat Rate is the mean heat rate at minimum capacity for a 40 MW open cycle gas turbine generating station, expressed in GJ/MWh;

iv. Fuel Cost is the mean unit fixed and variable fuel cost for a 40 MW open cycle gas turbine generating station, expressed in $/GJ; and

v. Loss Factor is the marginal loss factor for a 40 MW open cycle gas turbine generating station relative to the Reference Node.

Where the Economic Regulation Authority~~AEMO~~ must determine appropriate values for the factors described in paragraphs (i) to (v) as applicable to the Maximum STEM Price and Alternative Maximum STEM Price.

6.20.8. [Blank]

6.20.9. In conducting the review required by clause 6.20.6 the Economic Regulation Authority~~AEMO~~ must prepare a draft report describing how it has arrived at a proposed revised value of one or both of the Maximum STEM Price and Alternative Maximum STEM Price. The draft report must also include details of how the Economic Regulation Authority~~AEMO~~ determined the appropriate values to apply for the factors described in clauses 6.20.7 (b)(i) to 6.20.7(b)(v). The Economic Regulation Authority~~AEMO~~ must publish the draft report on the Market Web Site and advertise the report in newspapers widely published in Western Australia and request submissions from all sectors of the Western Australia energy industry, including end-users, within six weeks of the date of publication.

6.20.9A. Prior to proposing a final revised for one or both of the Maximum STEM Price and Alternative Maximum STEM Price in accordance with clause 6.20.10, the Economic Regulation Authority~~AEMO~~ may publish a request for further submissions on the Market Web Site. Where the Economic Regulation Authority~~AEMO~~ publishes a request for further submissions in accordance with this clause, it must request submissions from all sectors of the Western Australia energy industry, including end-users.

6.20.10. The Economic Regulation Authority must consider in-time~~After considering the~~ submissions on the draft report described in clause 6.20.9, and any in-time submissions received under clause 6.20.9A, and may consider any late submissions, and after considering the submissions ~~AEMO~~ must propose a final revised value for ~~any proposed change to~~ one or both of the Maximum STEM Price and Alternative Maximum STEM Price ~~and submit those values and its final~~

~~report, including any submissions received, to the Economic Regulation Authority for approval~~.

6.20.11. A proposed revised value for the Maximum STEM Price and the Alternative Maximum STEM Price replaces the previous value after~~:~~

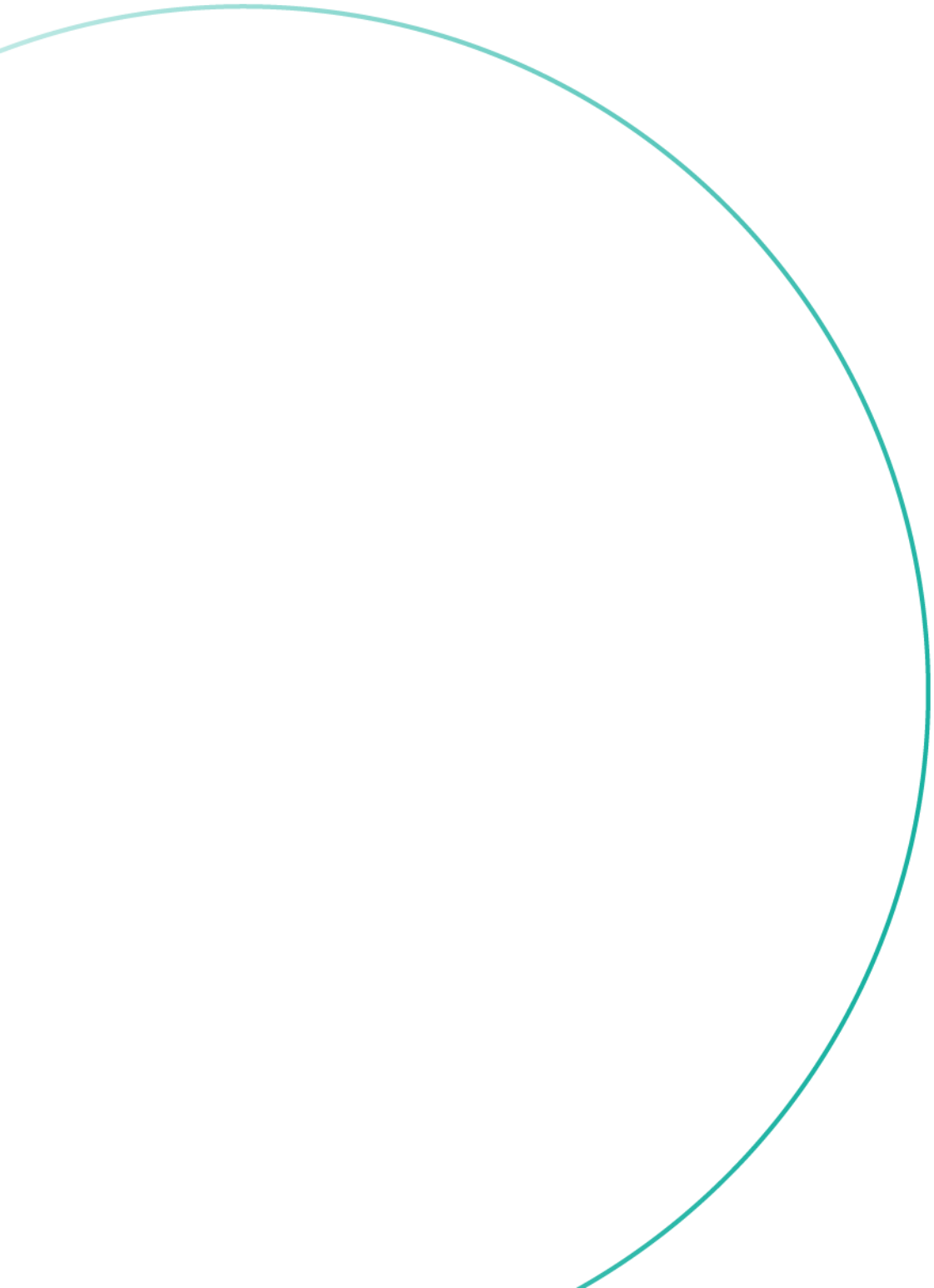
(a) [blank] ~~the Economic Regulation Authority has approved that value in accordance with clause 2.26; and~~

~~(b)~~ AEMO has posted a notice on the Market Web Site of the new value of the applicable Energy Price Limit,

with effect from the time specified in AEMO's notice.

Appendix D

Drafting instructions - Rule change panel abolition and related changes



Appendix D

DRAFTING INSTRUCTIONS

ABOLITION OF RULE CHANGE PANEL AND RELATED CHANGES

Electricity Industry (Rule Change Panel) Regulations

Electricity Industry (Wholesale Electricity Market) Regulations

Gas Services Information Regulations

ELECTRICITY INDUSTRY (RULE CHANGE PANEL) REGULATIONS)

Please repeal the *Electricity Industry (Rule Change Panel) Regulations* (**Panel Regulations**) effective as of 1 July 2021.

On repeal:

a) the Rule Change Panel (**Panel**) is to cease to exist;

b) all members of the Panel are to go out of office;

c) the Executive Officer for the Panel (as defined in these regulations) is to go out of office; and

d) the Economic Regulation Authority (**ERA**) is to no longer have any functions in relation to the Panel, save as to the transitional or consequential arrangement described below.

Despite the repeal, the obligation on members and former members of the Panel in relation to confidential information (regulation 34) is to continue to apply.

It is to be a function of the ERA to undertake such activities as may be necessary or desirable to provide for the orderly wind up of the Panel including, but not limited to:

a) such reporting or other arrangements as may necessary or desirable for the purposes of the *Financial Management Act 2006* or under any other another written law as a consequence of the Panel's cessation; and

b) the provision of all documents, materials and information (in whatever form) relating to the panel and its operations that were held by the Panel or by the ERA on the Panel's behalf, to the Coordinator of Energy.

ELECTRICITY INDUSTRY (WHOLESALE ELECTRICITY MARKET) REGULATIONS)

WEM Rules may confer functions on Coordinator.

This change has already been progressed through regulation 6 of the proposed Electricity Industry (Wholesale Electricity Market) Amendment Regulations 2020.

The following information is provided for context and completeness only (no additional drafting changes required):

"Changes are being sought to also allow functions to be conferred on the Coordinator for Energy under the WEM Rules. Under section 4 of the *Energy Coordination Act 1994*, the Coordinator's functions include performing the functions vested in the Coordinator by or under the *Energy Coordination Act 1994* or any other written law.

The WEM Regulations should allow:

a) WEM Rules to confer functions and impose requirements on the Coordinator of Energy;
b) The Coordinator of Energy to develop, amend and/or replace WEM Procedures that relate to its functions; and
c) The WEM Rules to allow the Coordinator to recover costs associated with its functions from Market Participants.

The Regulations should provide that any Rules made, amended or repealed that confer functions on the Coordinator of Energy must be approved by the Minister for Energy before they are made. [refer regulation 7(3)(b)]."

Abolition of Panel

Please make such amendments to the *Electricity Industry (Wholesale Electricity Market) Regulations* (**WEM Regulations**) as may be necessary or desirable to reflect the abolition of the Panel including, for example:

a) remove the ability of the market rules (**WEM Rules**) to confer functions on the Panel (eg under regulation 12B);

b) inclusion of a provision enabling the WEM Rules to deal with transitional matters relating to the transfer of the functions of the Panel under the WEM Rules to the Coordinator – comparable to regulation 17B, but expressed in slightly broader terms to accommodate not only a situation where the transfer of functions is "like for like", but also a situation where the Coordinator is being given a comparable or similar function;

c) repeal of existing regulation 17B (alternatively, removal of references to the Panel in that clause);

d) removal of references to the Panel in regulation 21:

e) removal of references to the Panel and its regulations (and the ERA in connection with the Panel) and substitution of the Coordinator as relevant (e.g. replace regulation 21(2A) with a provision requiring the Coordinator's costs under this regulation to be kept separate from its GSI costs).

The Panel need not be removed from the list of persons identified in regulation 51 (Persons exempt from 126(3)(a) of the Act).

Confidential information

[Note that the Coordinator has obligations of confidence under s24(1) of the Energy Coordination Act]

a) Please include a provision similar to regulation 33 of the Panel Regulations, such that the Coordinator may use and disclose information obtained in the course of performing functions under the WEM Regulations or WEM Rules as follows:

   i. as authorised or required by the WEM Regulations or the WEM Rules;

   ii. with the consent of the person to whom the information relates;

   iii. as authorised or required by a written law;

iv. for the purposes of court, tribunal or similar (eg Electricity Review Board) proceedings;

v. the information is disclosed in a summary or statistical form, or is combined or aggregated with other information in such a way that the information could not reasonably be ascertained in isolation from the other information (see comparable provision re "trade secrets" in s24AA of the *Energy Coordination Act*);

vi. the information is in the public domain;

vii. for the purposes of performing the Coordinator's functions under s4A of the *Energy Coordination Act*; or

viii. the information is provided to the Coordinator's legal and other professional advisers, consultants and contractors under conditions of confidentiality

b) Please include a provision confirming that functions conferred on the Coordinator under the WEM Rules are to be taken as a function performed under a written law. Alternatively, please include a provision confirming that it is a function of the Coordinator to perform functions conferred on the Coordinator by the WEM Rules.

[Note: the provision described in para (b) is desirable for the purposes of providing clarity in the application of provisions of the Energy Coordination Act, including s24(1): which allows the Coordinator to disclose information obtained in the course of performing functions (duties) "as required or allowed… under a written law."

The WEM Rules are not a written law for the purposes of the Interpretation Act (s123(2) of the Electricity Industry Act). This may also mean they are not a written law for the purposes of the Energy Coordination Act although this matter is not free from all argument. EPWA will provide Parliamentary Counsel with additional information and advice on this issue as may be required.

In any event, WEM Regulations are, beyond any doubt, a written law and certainty on the application of relevant portions of the Energy Coordination Act are desired. The objective is to have the Coordinator's use/disclosure of information obtained under the WEM Rules/WEM Regulations to be recognised as use under a written law for the purposes of the Energy Coordination Act.]

Administrative amendments

Please make the following amendments to allow for removal of System Management.

WEM Regulation	Proposed Action Required	Reason / Comment
Reg 3	Delete the definition of "System Management".	No longer required.
Reg 13	Amend heading to reflect reg 13 is deleted.	No longer required.

WEM Regulation	Proposed Action Required	Reason / Comment
Reg 13(1)	Move reg 13(1) to new reg 12(5).	Regulation 12 sets out AEMO's functions (referred to as "operator" in the WEM Regulations). The function of System Management in reg 13(1) should be moved to reg 12, as new reg 12(5) as a function of the "operator".
Reg 13(2)	Delete reg 13(2).	No longer required.
Reg 13(2a)	Delete reg 13(2a).	No longer required. As AEMO's liability under the civil liability scheme in the Act as a *market governance participant* or a *system management participant* is the same, the continued distinction between the two is redundant.
Reg 13(3)	Delete reg 13(3).	No longer required. Reg 12(1) provides the head of power for the market rules to confer functions and impose requirements on AEMO.
Reg 13(4)	Delete reg 13(4).	No longer required. It is implicit in AEMO's obligations under the WEM Rules that it must act consistently, or not inconsistently, with the Wholesale Market Objectives.
Reg 13(5)	Delete reg 13(5).	No longer required. Reg 12(4) contains a similar head of power for the "operator" i.e. AEMO.
Reg 13(6)	Move reg 13(6) to new reg 12(7).	Move reg 13(6) to new reg 12(7) and amend the wording to refer to the performance of AEMO's functions under the market rules with respect to system operations.
Reg 15(2)	Delete the reference to System Management by deleting the words ", System Management".	No longer required to refer to System Management. AEMO will continue to have a head of power to issue directions pursuant to the regulation.
Reg 19(2)	Delete the reference to System Management by deleting the words "or System Management".	No longer required. AEMO is already excluded from the operation of reg 14(e)
Reg 52(3A)	Delete the reference to System Management by deleting the words "(including in relation to its system management function)".	This proposed amendment is for completeness, as reg 52(3A) is now redundant as the period of 12 months referred to in the regulation has lapsed.

Other amendments

a) Please extend the date in regulation 7(5) for the Minister's transitional rule-making power to 31 March 2023.

b) Please amend the regulations (eg regulation 8) to:

i. remove the obligation on the ERA to make a copy of the WEM Rules available for inspection at its office during working hours; and

ii. confer an obligation on the Coordinator to make a copy of the WEM Rules available on a website maintained by, or on behalf of the Coordinator.

GAS SERVICES INFORMATION REGULATIONS

Minister to make rules.

Please amend the *Gas Services Information Regulations* (**GSI Regulations**) to give the Minister for Energy an ability to make rules to amend the Gas Services Information Rules (**GSI Rules**).

The Minister's rule making power should commence as soon as practicable after gazettal (ie the day after) and continue until a sunset date. The sunset date is 31 March 2023.

The amendment should be comparable to the relevant portions of regulations 6 and 7 of the *Electricity Industry (Wholesale Electricity Market) Regulations* that enable the Minister to make market rules (WEM Rules).

The *Gas Services Information Amendment Regulations (No. 3) 2015* may also serve as a relevant example.

GSI Rules to confer functions on Coordinator

In summary, the form of the following amendments should generally follow and correspond with comparable amendments made to the WEM Regulations (to the extent relevant and applicable).

To this end, please amend the GSI Regulations to allow the:

a) GSI Rules to confer functions and impose requirements on the Coordinator of Energy and those functions are not to be limited just to rule making (cf. the current limitation for the RCP in regulation 8);

b) Coordinator of Energy to develop, amend and/or replace GSI Procedures that relate to its functions (refer regulation 11);

c) GSI Rules to allow the Coordinator to recover costs associated with its functions from Market Participants (refer regulation 8);

The amendments should provide that any Rules made, amended or repealed that confer functions on the Coordinator of Energy must be approved by the Minister before they are made.

Other amendments

In summary, the form of the following amendments should generally follow and correspond with comparable amendments to be made to the WEM Regulations to reflect the abolition of the Panel as described in clause 2.2 above (to the extent relevant and applicable). For example:

a) removal of the ERA's obligation to make a copy of the GSI Rules available for inspection at its office and conferral of an obligation on the Coordinator to make a copy of the GSI Rules available on a website maintained by or on behalf of the Coordinator (regulation 9);

b) inclusion of a provision enabling the GSI Rules to deal with transitional matters relating to the transfer of the functions of the Panel under the WEM Rules to the Coordinator – comparable to regulation 8A but expressed in slightly broader terms as per item 2.2(b) above;

c) repeal of existing regulation 8A (alternatively, removal of references to the Panel in that clause);

d) confirmation that the GSI Rules may deal with the fees and charges to be payable by registered gas market participants in relation to the functions of the Coordinator (see item d) above);

e) removal of references to and provisions relating to the Panel (and the ERA in connection with the Panel) and substitution of the Coordinator as relevant, for example:

   i. regulations 7(4)(b), 8(2)(d)(i) and 11(5) – replace with equivalent provisions for Coordinator;
   ii. regulation 8(2)(c) – remove reference to the Panel;

f) include a provision enabling the Coordinator to use information obtained by the Coordinator in the course of performing functions under the GSI Rules, for the purposes of performing the Coordinator's functions under s4A of the Energy Coordination Act.

g) amend regulation 8(2)(l) to enable the GSI Rules to provide for the use and disclosure of protected information by the Coordinator;

[Note: Section 8(4) of the *Gas Services Information Act 2012* states that "The *Interpretation Act 1984* sections 42 and 43(6) do not apply to the rules." Unlike the position under the *Electricity Industry Act* in relation to the status of the WEM Rules, the GSI Act does not go on to state that the GSI Rules are not subsidiary legislation for the purposes of the Interpretation Act and so the issue described above as to whether or not the WEM Rules are a written law for the purposes of the *Energy Coordination Act* does not arise in relation to the GSI Rules.