RCP Rule Change Panel
Market Advisory Committee

# Meeting Agenda

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| **Meeting Title:** | Market Advisory Committee |
| **Date:** | Tuesday 15 October 2019 |
| **Time:** | 9:30 AM – 12:00 PM |
| **Location:** | Training Room No. 2, Albert Facey House<br>469 Wellington Street, Perth |

| Item | Item | Responsibility | Duration |
|---|---|---|---|
| **1** | Welcome | Chair | 5 min |
| **2** | Meeting Apologies/Attendance | Chair | 5 min |
| **3** | **(a)** Minutes of Meeting 2019_09_06 | Chair | 5 min |
| | **(b)** Minutes of Workshop 2019_09_06 re RC_2017_02 | Chair | 5 min |
| **4** | Actions Items | Chair | 5 min |
| **5** | MAC Market Rules Issues List | Chair | 25 min |
| **6** | **(a)** Update on the Energy Transformation Strategy (no paper) | ETIU | 15 min |
| | **(b)** Update on the Whole of System Plan | ETIU | 20 min |
| **7** | AEMO Procedure Change Working Group Update | AEMO | 5 min |
| **8** | Rule Changes | | |
| | **(a)** Overview of Rule Change Proposals | Chair | 5 min |
| | **(b)** Update on the North Country Spinning Reserve Issue | AEMO | 20 min |
| | **(c)** Pre-Rule Change Proposal: Administrative Improvements to Settlement | AEMO | 20 min |

| Item | Item | Responsibility | Duration |
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| **9** | Review of the Framework for Rule Change Proposal Prioritisation and Scheduling | Chair | 10 min |
| **10** | General Business | Chair | 5 min |
| | **(a)** Workflow Reporting (no paper) | Chair | 5 min |

Next Meeting: 26 November 2019

Please note, this meeting will be recorded.

RCP | Rule Change Panel
Market Advisory Committee

# Minutes

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|---|---|
| **Meeting Title:** | Market Advisory Committee (**MAC**) |
| **Date:** | 3 September 2019 |
| **Time:** | 9:30 AM – 11:00 AM |
| **Location:** | Training Room No. 1, Albert Facey House<br>469 Wellington Street, Perth |

| Attendees | Class | Comment |
|---|---|---|
| Stephen Eliot | Chair | |
| Matthew Martin | Minister's Appointee – Small-Use Consumer Representative | |
| Martin Maticka | Australian Energy Market Operator (**AEMO**) | |
| Dean Sharafi | System Management | |
| Noel Schubert | Economic Regulation Authority (**ERA**) Observer | Proxy for Sara O'Connor |
| Daniel Kurz | Market Generators | |
| Andrew Stevens | Market Generators | |
| Patrick Peake | Market Customers | |
| Geoff Gaston | Market Customers | |
| Tim McLeod | Market Customers | |
| Chayan Gunendran | Market Customers | |
| Geoff Down | Contestable Customers | Proxy for Peter Huxtable |

| Apologies | Class | Comment |
|---|---|---|
| Sara O'Connor | ERA Observer | |
| Peter Huxtable | Contestable Customers | |
| Wendy Ng | Market Generators | |
| Jacinda Papps | Market Generators | |

| Also in Attendance | From | Comment |
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| Kate Ryan | Energy Transformation Implementation Unit (**ETIU**) | Presenter to 9:55 AM |
| Aden Barker | ETIU | Presenter to 9:55 AM |

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| Jenny Laidlaw | RCP Support | Minutes |
| Dimitri Lorenzo | Bluewaters Power | Observer |
| Scott Davis | Australian Energy Council | Observer |
| Erin Stone | Point Economics | Observer |
| Ian Porter | Sustainable Energy Now | Observer |
| Richard Cheng | RCP Support | Observer |
| Natalie Robins | RCP Support | Observer |
| Sandra Ng Wing Lit | RCP Support | Observer |

| Item | Subject | Action |
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| 1 | **Welcome**<br>The Chair opened the meeting at 9:30 AM and welcomed members and observers to the 3 September 2019 MAC meeting. | |
| 2 | **Meeting Apologies/Attendance**<br>The Chair noted the attendance as listed above. | |
| 3 | **Minutes of Meeting 2019_07_29**<br>Draft minutes of the MAC meeting held on 29 July 2019 were circulated on 19 August 2019. The MAC accepted the minutes as a true and accurate record of the meeting.<br>**Action: RCP Support to publish the minutes of the 29 July 2019 MAC meeting on the Rule Change Panel's (Panel's) website as final.** | **RCP Support** |
| 4 | **Action Items**<br>The Chair noted that the agenda item reference listed for action items 15/2019 and 16/2019 should be agenda item 8(b) rather than agenda item 9.<br>All action items were closed and taken as read. | |
| 5 | **MAC Market Rules Issues List (Issues List) Update**<br>The MAC noted the recent updates to the Issues List.<br><u>Issue 52 (Multiple generating units on a single line constituting the largest credible contingency)</u>:<br>The Chair noted that the agenda item reference listed for issue 52 should be agenda item 8(b) rather than agenda item 9. | |

| Item | Subject | Action |
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| | Issue 55 (Conflict between Relevant Level Methodology and the early and conditional certification of Intermittent Generators): | |
| | The Chair noted that Mr Martin Maticka had provided an amendment to RCP Support on the comments he made regarding this issue at the 30 April 2019 MAC meeting. The amendment was circulated to MAC members with the draft minutes of the 29 July 2019 meeting and was also provided in the Issues List. | |
| | The Chair noted that the issue could be addressed as a standalone Rule Change Proposal or, at the ERA's discretion, as part of the Rule Change Proposal being developed by the ERA to replace the Relevant Level Methodology (RC_2019_03). | |
| | In response to a query from the Chair, Mr Noel Schubert advised that the ERA was not currently considering this particular issue; but was considering other feedback provided by AEMO in relation to RC_2019_03 and what further work it should undertake before it submits the Rule Change Proposal. Ms Jenny Laidlaw noted that the ERA suggested addressing the issue as part of RC_2019_03 at the 30 April 2019 MAC meeting. | |
| | The Chair suggested that the MAC wait for the ERA to decide whether it wanted to address the issue as part of RC_2019_03. If the ERA decided not to include the issue in RC_2019_03, then RCP Support would bring the issue back to the MAC for further discussion on how it should be dealt with. | |
| | Issue 15/34 (Criteria for approval of extension outages): | |
| | The MAC agreed to close issue 15/34 following the publication of the Final Rule Change Report for Rule Change Proposal: Outage Planning Phase 2 – Outage Process Refinements (RC_2013_15), because the Amending Rules for RC_2013_15, which commence on 1 February 2020, will resolve the issue. | |
| | Issue 56 (Issues with Reserve Capacity Testing): | |
| | In response to a question from the Chair, Mr Patrick Peake advised that Perth Energy's development of a Pre-Rule Change Proposal to address issue 56 will be delayed for two months due to staff unavailability. | |
| | **Action: The ERA to advise the MAC whether it intends to address the conflict between the Relevant Level Methodology and the early and conditional certification of Intermittent Generators as part of Rule Change Proposal: Method used for the assignment of Certified Reserve Capacity for Intermittent Generators (RC_2019_03).** | **ERA** |

| Item | Subject | Action |
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| 6 | **Update on the Energy Transformation Strategy (ETS)** | |

Ms Kate Ryan provided the following updates on the ETS.

- The Energy Transformation Taskforce (**Taskforce**) had met five times and published eight information papers relating to the Foundation Regulatory Frameworks work stream.
- The Taskforce had approved the four demand scenarios that will form the basis of modelling for the first Whole of System Plan (**WOSP**) and published an information paper on those scenarios.

  The four scenarios were the same as those presented at the 12 July 2019 Industry Forum for the WOSP. Stakeholders were invited to contact ETIU if they wanted to have a one-on-one session with ETIU about the WOSP assumptions or modelling.
- The Taskforce was receiving regular progress updates on the Distributed Energy Resources (**DER**) Roadmap, which was due to be delivered to the Minister by Christmas 2019.

  On 30 July 2019, ETIU held a workshop on the DER Roadmap, which was attended by about 70 stakeholders. The workshop provided good insights and ideas about the importance and priority of certain DER elements.

  While ETIU intended to hold further stakeholder workshops on the DER Roadmap, it was not yet clear what the topics of those workshops would be. ETIU intended to identify any DER issues that require additional consultation before the finalisation of the DER Roadmap and may hold the next DER workshop in October 2019.
- The Taskforce was considering how to implement constrained access and had given in principle approval to the use of Capacity Credit rights to allocate Capacity Credits in a constrained access environment. This proposal was presented briefly at the first Transformation Design and Operation Working Group (**TDOWG**) meeting; and is to grandfather Capacity Credits for existing generators for a period of time and to lock in a Capacity Credit right for new generators to provide some investment certainty into the future.

  The proposal is to apply to all generators and has the benefit of dealing with part of the transitional issue of moving to a constrained access environment for incumbent generators. The detailed design would be presented at a future TDOWG meeting.

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| | • ETIU intended to commence one-on-one discussions with stakeholders on the transition to constrained access towards the end of September 2019. The purpose of the initial discussions was to gain an understanding of stakeholder issues so that the Taskforce could take these into account.<br>• The Taskforce was to meet for the sixth time on 20 September 2019 to discuss foundation settings for settlements in the Wholesale Electricity Market (**WEM**) and various elements of the DER Roadmap. An information paper on WEM settlements was expected to be published shortly after this meeting.<br><br>Mr Geoff Gaston asked how detailed the WOSP price and cost forecasts were expected to be. Ms Ryan replied that the dispatch modelling for the WOSP was expected to produce forecasts of wholesale costs such as balancing prices, capacity prices, and essential system service costs for each scenario. Retail tariffs were neither an explicit input nor an explicit output.<br><br>Mr Ian Porter considered that because the retail tariff structure will dictate consumer behaviour, which in turn will affect generation requirements, the absence of tariff structures in the scenarios could be a problem. Ms Ryan replied that the four scenarios demonstrate different customer behaviours which in part will be driven by theoretically or potentially different tariff scenarios. Rather than prescribe specific tariffs, the scenarios prescribed the customer behaviours that would follow (e.g. how much DER and demand growth resulted). In this way the scenarios captured a range of potential tariff inputs without explicitly defining what those inputs were.<br><br>In response to a question from Mr Daniel Kurz, Ms Ryan advised that the work of the three ETIU work streams was progressing well. The Taskforce was proving to be an efficient and effective decision-making body, as indicated by the publication of information papers, and Ms Ryan was confident that the mechanisms were now in place to meet the overall program timelines.<br><br>Mr Aden Barker provided the following updates on the TDOWG:<br>• The first TDOWG meeting was held on 12 August 2019 and had 45 attendees. Mr Barker noted the future TDOWG meetings were likely to be held at an alternative venue, with both AEMO and Western Power offering the use of their facilities.<br>• The next TDOWG meeting was scheduled for 9 September 2019. The meeting agenda was to include | |

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| | WEM settlement, outage planning, an update on the changes to the Reserve Capacity Mechanism (**RCM**) to support constrained access, and a brief update on the proposed WEM Regulation changes relating to the Minister's temporary rule-making powers and the publication of Amending Rules.<br>• The third TDOWG meeting was scheduled for 27 September 2019 and was to focus on the RCM changes to support constrained access. ETIU intends to hold one-on-one meetings and small workshops over the four weeks following the TDOWG meeting.<br>• ETIU would also present on non-frequency essential system services (formally labelled locational essential system services) at the 27 September 2019 meeting.<br>• ETIU had commenced work on drafting instructions for the proposed changes to the Technical Rules change management process and would be publishing more information for stakeholder comment in due course.<br>• ETIU was happy to meet with individual stakeholders to discuss the detail provided in the published information papers and how it would be translated to more detailed market design and rule drafting.<br>Ms Ryan noted that the PUO and ETIU are moving from the Department of Treasury into a new sub-department of the Department of Mines, Industry Regulation and Safety on 5 September 2019. This would result in a change of website domain to "energy.wa.gov.au", with a corresponding change to email addresses. An email containing the relevant email and website details would be sent to all stakeholders on the ETIU and PUO email lists.<br>Mr Barker noted that several of the papers previously published by the Taskforce contained links to other Taskforce papers or to papers previously published by the PUO. ETIU was planning to update these links to ensure they remained stable and current with the new website. Ms Ryan asked MAC members to notify ETIU if they found any broken links in Taskforce publications.<br>In response to a question from Ms Laidlaw, Mr Matthew Martin advised that the PUO hoped to be able to send final drafts of the RCM pricing rule changes to the Minister for approval by the end of September 2019, with the intent that the new rules take effect from 1 October 2019 or shortly thereafter. The PUO had met with various stakeholders regarding the rule changes and intended to provide updated drafts to those stakeholders for comment before preparing the final version for the Minister. | |

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| | Mr Martin noted that the intent was to implement the RCM pricing changes from the 2019 Reserve Capacity Cycle, rather than the 2020 Reserve Capacity Cycle as previously discussed. However, the PUO did not expect AEMO would extend any RCM processes for the 2019 Reserve Capacity Cycle, apart from delaying the publication of the Reserve Capacity Price until after the Minister's changes were made.<br><br>Mr Martin noted that some of the standalone provisions, such as the proposed notice of closure provisions, would take effect as soon as the new rules were made. However, other changes would commence later, such as those relating to settlement changes for the 2021 Capacity Year onwards. | |
| **7** | **AEMO Procedure Change Working Group (APCWG) Update**<br><br>The MAC noted the update on AEMO's Market Procedures. | |
| **8(a)** | **Overview of Rule Change Proposals**<br><br>The Chair noted that:<br>• the Amending Rules for Rule Change Proposal: Full Runway Allocation of Spinning Reserve Costs (RC_2018_06) commenced on 1 September 2019;<br>• the Minister had extended the deadline for making his decision on Rule Change Proposal: ERA Access to market information and SRMC investigation process (RC_2018_05) until 20 September 2019;<br>• RCP Support was holding a MAC workshop to discuss Rule Change Proposal: Implementation of a 30-Minute Balancing Gate Closure (RC_2017_02) on 6 September 2019; and had circulated the slide packs for the workshop on 2 September 2019.<br><br>Ms Laidlaw noted that the proposed workshop for Rule Change Proposal: Administrative Improvements to the Outage Process (RC_2014_03) would be held in late September 2019.<br><br>The MAC noted the overview of Rule Change Proposals. | |
| **8(b)** | **North Country Spinning Reserve Issue**<br><br>The Chair noted the meeting paper for this agenda item contained a summary of the views provided by MAC members in response to action item 15/2019 (MAC members to send RCP Support their views on the North Country Spinning Reserve issue (and specifically their views on the three options presented by AEMO at the 29 July 2019 MAC meeting)). The Chair sought the views of the MAC on the feedback received. | |

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| | Mr Kurz reiterated his view that while option 2 appeared to provide the more holistic resolution of the issue, option 3 may be the preferable solution given the likely timeframe to implement option 2. Mr Kurz recognised that option 3 may not provide the lowest energy price outcome, but considered this reflected the fact that providing secure, reliable energy has a cost associated with it (although an assessment should be made of whether that cost was acceptable). Mr Peake supported the views expressed by Mr Kurz.<br><br>Mr Dean Sharafi noted that AEMO was seeking the opinion of MAC members on which whether it would progress with option 2 or 3 in the Rule Change Proposal. Mr Sharafi considered that, while option 2 deals with the problem holistically, option 3 would provide a good start to deal with the problem, and would be quick to implement because it would not affect many AEMO IT systems.<br><br>Mr Gaston agreed that option 2 seemed the most correct, efficient option, but considered the priority was to guard against excessively high ancillary service costs and the perverse outcome of windfall profits to the generators that were causing the problem. Mr Gaston considered that if option 3, including the removal of constrained off compensation, could be implemented faster (ideally before the new generators commenced operations) then that option should be progressed.<br><br>Mr Maticka asked the Chair to summarise the MAC's position for the benefit of the minutes, noting that AEMO would also be seeking some level of endorsement from an energy policy viewpoint from Mr Martin. Mr Martin noted that he had not considered the issue in depth but, if the intention was to implement a solution as soon as possible, option 3 seemed to be a more cost efficient, effective outcome than implementing something more material in advance of the major market reforms.<br><br>Mr Maticka requested clarification on whether the guidance from the MAC was that AEMO should develop a Rule Change Proposal for option 3 or that AEMO should consider both options; noting that while some members had expressed support for option 3 it was not clear that this view was unanimous.<br><br>The Chair noted that irrespective of which Rule Change Proposal was submitted, the Panel was likely to need to consider both options. In response to a question from the Chair, attendees expressed support for the progression of option 3, but noted that no Synergy or Alinta Energy representatives were present at the meeting and that these participants had not | |

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| | provided a response for action item 15/2019. No attendee expressed a preference for AEMO to progress option 2. | |
| | The Chair asked AEMO whether and when it could develop a Rule Change Proposal to implement option 3. Mr Maticka replied that AEMO would need to find a resource to undertake the work but hoped to present a Pre-Rule Change Proposal to the MAC at its 26 November 2019 meeting. | |
| | Mr Schubert supported the development of a Rule Change Proposal for option 3 but noted that there may be an opportunity to compare the economics of the two options as an extension to the work being undertaken to determine the margin values for the 2020/21 Financial Year. Mr Maticka advised that AEMO would not undertake an analysis of this type until after November 2019, to avoid risking the delivery of its margin values proposal to the ERA by 30 November 2019. However, AEMO would be happy to support another party that wished to undertake that work. | |
| | Ms Laidlaw noted that the margin values modelling would require assumptions about the whether the two generators would be allowed to form the largest contingency, and that these assumptions could have a material impact on Spinning Reserve costs. Ms Laidlaw suggested that it may be possible for the ERA to determine margin values that are conditional on the outcome of a Rule Change Proposal. | |
| | There was some discussion about the Spinning Reserve cost impacts of using an incorrect assumption about the size of the largest contingency to determine the margin values; whether the ERA had previously issued a conditional margin values determination; and how difficult it would be to modify the margin values model to use a different assumption about the treatment of the two new generators. | |
| | Mr Maticka noted that AEMO supported the development of a Rule Change Proposal to implement option 3. | |
| | **Action: AEMO to develop a Pre-Rule Change Proposal for AEMO's 'option 3' to address the North Country Spinning Reserve issue (as discussed at the 29 July 2019 MAC meeting), which includes the removal of constrained off payments when the relevant generators are constrained down to reduce the Spinning Reserve requirement, for presentation at the 26 November 2019 MAC meeting.** | **AEMO** |

| Item | Subject | Action |
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| **9** | **Rule Change Panel and RCP Support KPIs for 2018/19** | |

The Chair led a discussion of the questions raised in the report titled 'Rule Change Panel and RCP Support KPIs for 2018/19' (**report**). The following points were discussed.

Approach to deciding whether to progress a Rule Change Proposal:

The Chair noted that some respondents to the Panel's 2018/19 stakeholder satisfaction survey (**survey**) suggested that the Panel had decided to progress some underdeveloped Rule Change Proposals that should not have been progressed.

The Chair asked the MAC if it had any concerns about the approach used by the Panel to decide whether to progress Rule Change Proposals. Mr Kurz replied that Bluewaters Power had no such concerns and was supportive of the approach used by the Panel.

Structure and content of rule change reports:

The Chair noted that the Panel had modified the structure of its rule change reports over the previous year, and now included the decision and a summary of the reasons for the decision at the front of the report.

Mr Martin considered the explanation of the reasons for a decision was sometimes fairly short and it was left to the reader to work back through the earlier documents to piece together the Panel's reasoning for its decisions. Mr Martin noted that the current rule change reports could not be read as standalone documents, and considered they occasionally appeared slightly too dismissive of stakeholder concerns, as it was not clear where those concerns had been addressed.

The Chair noted that including all the relevant details in each rule change report would allow the reports to be read as standalone documents but materially increase their size and complexity. The Chair asked attendees which structure they would prefer.

- Mr Sharafi preferred a structure that provided links to the minutes or submissions in the reports, and minimised cross-referencing within the body of reports to make them more readable.
- Mr Kurz, Mr Maticka, Mr Andrew Stevens and Mr Peake expressed a preference for concise reports with appropriate links to the relevant historical documents; agreed that a reader should be expected to have read the relevant historical documents (e.g. a person reading a Final Rule Change Report should be expected to have read the

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| | relevant Rule Change Proposal and Draft Rule Change Report); and suggested that the Panel list and provide links to any documents it assumes the reader has previously read at the start of each report. | |
| | Splitting of Rule Change Proposals: | |
| | The Chair noted that the Panel had received legal advice that it was unable to split a Rule Change Proposal it receives into multiple Rule Change Proposals for separate progression. | |
| | Mr Martin asked whether the prohibition on splitting a Rule Change Proposal was in the WEM Regulations or the Market Rules. The Chair replied that he thought the prohibition came from the Market Rules, which only allowed the Panel to accept, accept in an amended form or reject a Rule Change Proposal. | |
| | Mr Kurz asked whether the proponent of a Rule Change Proposal, if it decided that it wanted to reduce the scope of that proposal, could withdraw the proposal and submit a new one. Mr Maticka replied that the proponent of a Rule Change Proposal had no control over the progression of that proposal once it was submitted. | |
| | Mr Maticka suggested that the practical solution was to use the informal Pre-Rule Change Proposal process where the MAC discusses proposals before their formal submission and considers whether the issues raised should be addressed together or separately. The Chair considered this approach had worked well with some of the more recent Rule Change Proposals, such as Rule Change Proposal: Removal of constrained off compensation for Outages of network equipment (RC_2018_07). | |
| | Ms Laidlaw considered that in some cases it may be efficient to combine issues in a single Rule Change Proposal, if this reduced the overheads associated with multiple changes to the same IT systems and processes. Mr Maticka agreed that bundling changes could reduce implementation costs but did not consider that issues should be combined for this reason, because of the risk that consideration of the more complex changes might delay the progression of the other changes. | |
| | MAC meetings: | |
| | The Chair noted that some survey respondents considered that the MAC occasionally lacked a sense of purpose and direction, and that the Chair needed to take more accountability in ensuring that MAC discussions were valuable and less of a ‘talk-fest’. | |
| | The Chair noted that to date he had allowed discussions to continue because not all attendees had the same views on what | |

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| | matters were of interest, and because it sometimes takes time for a person to express their thoughts clearly. However, the Chair was willing to take steps to more tightly control MAC discussions, such as cutting short or setting time limits for discussions. The Chair sought the views of MAC members as to what types of actions he should take. | |
| | Mr Kurz did not think the MAC should adopt a strict rule on this matter because at times the MAC discussion is very valuable. Mr Kurz suggested that the Chair monitor discussions to assess whether they are useful, and if a discussion is no longer useful ask the participants to summarise their positions and seek to wrap up the discussion. | |
| | Mr Maticka suggested that the Chair should intervene when the discussion shifts off-topic or becomes repetitive. Mr Gaston suggested that the Chair act to tighten the discussion where this is necessary to keep the discussion moving. | |
| | Mr Sharafi considered that some participants may have valuable opinions but be less inclined to talk than others, so it was beneficial to the MAC meeting to request opinions and ensure that all the opinions are heard. As an example, Mr Sharafi noted that Dr Steve Gould, a previous MAC member, had not spoken often but had very valuable opinions on many things. Mr Gaston did not consider that members should be explicitly asked for their opinions, because in many cases a member may not have an opinion of a specific issue. Mr Kurz agreed, noting that some issues had no impact on Market Generators. Mr Maticka considered that members should offer opinions that reflect the interests of the class they represent at the MAC. | |
| | Mr Martin considered that it was often hard to understand the contribution made by members versus observers. Mr Martin did not suggest that MAC observers should not be allowed to speak but questioned the point of MAC membership if anyone is permitted to attend a MAC meeting and participate in the discussion. | |
| | Mr Stevens noted that observers, if permitted to attend a MAC meeting, have always been entitled to fully participate in the discussion. Mr Kurz noted that while the MAC was supposed to be representational of industry, some parties that are affected by issues discussed at the MAC may not be fully represented by the MAC members. | |
| | Mr Martin suggested that an imbalance of one industry group (e.g. generators) at a meeting might influence the tone of the discussion and provide a distorted picture of the MAC's position on an issue. Mr Stevens suggested that rule change reports should document the numbers of MAC members that supported | |

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| | or opposed each of the proposal considered by the MAC. The Chair noted that the Panel did not base its decisions on the popularity of the Rule Change Proposal. | |
| | The Chair acknowledged Mr Martin's point but noted that the MAC is an advisory committee and what the Panel wanted was advice from the market. The Chair preferred to allow observers to speak as this gives the Panel the benefit of their advice. The MAC meeting minutes provide the Panel with a detailed record of the advice received and the sources of that advice. | |
| | Mr Peake agreed with the Chair's position, considering that one of the strengths of the group was that all attendees were allowed to speak, and that observers often provided good ideas that could strengthen the Panel's decisions. Mr Stevens agreed that the input of observers was often very valuable and considered that the Chair could always intervene if observers acted as a lobby group or dominated the meeting discussion. | |
| | The Chair reminded observers that they were required to request permission from the Chair to attend a MAC meeting. | |
| | <u>MAC meeting papers</u>: | |
| | The Chair noted that some survey respondents had raised concerns about the late provision of MAC meeting papers. The Chair advised that he had taken the approach that if a late paper is provided on an issue, and the issue is sufficiently important that the MAC should consider it, or does not require extensive effort to assess, then the MAC should have the opportunity to discuss the issue. The Chair noted that if the MAC decides it has not had enough preparation time to discuss an issue then the issue can be deferred to a later meeting; but considered it was better for the MAC, rather than the Chair, to make such decisions. | |
| | Mr Kurz considered this was another matter for which a hard and fast rule could potentially lead to perverse outcomes. Mr Sharafi agreed, noting that the slides for AEMO's 29 July 2019 presentation on the North Country Spinning Reserve issue were provided to RCP Support after the meeting papers were circulated. Mr Sharafi thanked the Chair for accepting the slides and scheduling the discussion of what was an important issue. | |
| | Mr Sharafi also thanked the Chair for giving MAC members additional time to provide their feedback on the North Country Spinning Reserve issue after the 29 July 2019 meeting. Mr Kurz, Mr Peake and Mr Maticka all supported the concept of allowing the discussion of late papers while allowing MAC members to | |

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| | request additional time to consider the issues and provide their feedback. | |
| | The Chair also considered, and the MAC agreed, that it was preferable for ETIU to provide up-to-date verbal updates on ETS progress at each MAC meeting than to require them to provide a written summary in the MAC meeting papers that was prepared a week in advance of the meeting. | |
| | <u>Prioritisation of Rule Change Proposals</u>: | |
| | The Chair noted that the Gas Advisory Board (**GAB**) had not yet discussed the Panel's framework for Rule Change Proposal Prioritisation and Scheduling (**framework**). | |
| | RCP Support had reviewed the framework in preparation for its discussion at the 26 September 2019 GAB meeting and considered that changes could be made to make the framework more robust and easier for the Panel, RCP Support, the MAC and the GAB to use. RCP Support intended to discuss the proposed revisions with the GAB and the Panel before bringing them back to the MAC before the end of 2019. | |
| | The Chair noted that the framework included a set of questions to be asked when considering the urgency rating for a Rule Change Proposal. On some occasions the MAC had been asked to recommend an urgency rating for a Rule Change Proposal without considering those questions. | |
| | The Chair noted that the survey responses included comments that there appears to be a lack of clarity about the Panel's priorities. The Chair sought the views of the MAC on whether the priorities of the Panel were unclear and whether there was a better way for the Panel to communicate with stakeholders regarding its priorities. | |
| | In response to a question from Mr Stevens, the Chair confirmed that the Panel's priorities were informed by the urgency ratings provided by the MAC. Mr Stevens considered that it would be strange for the MAC to have concerns with the Panel's priorities because it was largely responsible for setting those priorities. | |
| | Mr Martin considered it might be useful to provide a Gantt chart indicating the expected timeframes for processing each Rule Change Proposal. This would allow stakeholders to understand the sequence in which Rule Change Proposals with the same urgency rating were likely to be progressed. | |
| | The Chair advised that the RCP Support work program (which listed the expected timeframes for each Rule Change Proposal) was updated regularly, usually at least every 1-2 weeks. | |

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| | Mr Tim McLeod asked if would be worthwhile to publish the RCP Support work program in the MAC meeting papers. The Chair expressed concern that stakeholders might rely on dates in the published work program that are subsequently modified.<br>Mr Kurz considered this would not be a problem if it was clarified that the work program was indicative and subject to change.<br>Ms Laidlaw noted that some dates could be published with a greater level of certainty than others. Mr McLeod considered that some transparency was better than no transparency at all.<br><br><u>Other matters</u>:<br><br>Mr Sharafi suggested that when a Rule Change Proposal touches on policy matters there should be discussions with the PUO and ETIU prior to the discussion at the MAC.<br><br>Mr Martin considered that the GAB was unlikely provide much comment on the framework given that only two Rule Change Proposals for the Gas Services Information (**GSI**) Rules had been processed since the Panel commenced operations.<br><br>Mr Martin and Mr Maticka considered that the Panel should allocate resources to a Rule Change Proposal for the GSI Rules rather than making it compete for resources with Rule Change Proposals for the Market Rules.<br><br>The Chair noted that the response rate for the survey was around 8% and encouraged stakeholders to participate in future surveys conducted by the Panel. The Chair also invited stakeholders to contact him at any time if they had any concerns or suggestions about the operations of the Panel and RCP Support. | |
| **10** | **Revised MAC Schedule for 2020**<br><br>The MAC raised no concerns with the revised MAC meeting schedule for 2020. The Chair asked MAC members to reserve the proposed meeting dates in their calendars for 2020.<br><br>Several members noted that they had not received a meeting invitation for this MAC meeting. The Chair agreed to ensure that Outlook meeting invitations were issued to members for future MAC meetings. | |
| **11** | **General Business**<br><br>Mr Kurz noted that Bluewaters Power had found it difficult to update and test its systems in time for the recent changes to the Energy Price Limits, due to the limited time provided by AEMO to undertake this work. | |

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| | Mr Martin and Mr Schubert encouraged MAC members and observers to register for the 2019 Energy in WA Conference, which will be held on 18-19 September 2019. | |

**The meeting closed at 11:00 AM.**

Rule Change Panel
Market Advisory Committee

# Minutes

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| **Meeting Title:** | RC_2017_02 Implementation of 30-minute Balancing Gate Closure Workshop |
| **Date:** | 6 September 2019 |
| **Time:** | 10:00 AM – 12:30 PM |
| **Location:** | Training Room 1, Albert Facey House<br>469 Wellington Street, Perth |

| Attendees | Class | Comment |
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| Stephen Eliot | RCP Support | |
| Jenny Laidlaw | RCP Support | |
| Natalie Robins | RCP Support | |
| Richard Cheng | RCP Support | |
| Sandra Ng Wing Lit | RCP Support | |
| Matthew Fairclough | Australian Energy Market Operator (AEMO) | |
| Martin Maticka | AEMO | |
| Dean Sharafi | AEMO | |
| Aditi Varma | Energy Policy of Western Australia (EPWA) | |
| Patrick Peake | Perth Energy | |
| John Nguyen | Perth Energy | |
| Brad Huppatz | Synergy | |
| Wendy Ng | ERM Power | |
| Quentin Jeay | Kleenheat | |
| Noel Schubert | Economic Regulation Authority (ERA) | |
| Daniel Kurz | Bluewaters Power | |
| Paul Arias | Bluewaters Power | Conference call |
| Tim McLeod | Amanda Energy | |
| Geoff Down | Water Corporation | |
| Jacinda Papps | Alinta Energy | |
| Adam Stephen | Alinta Energy | |
| Erin Stone | Perth Energy | Conference call |

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| 1-5 | **Introduction to Workshop and RC_2017_02**<br>Ms Natalie Robins introduced the purpose of the workshop, the purpose of Rule Change Proposal RC_2017_02, the assessment criteria for the proposal, and its context within a market that is evolving with an increased penetration of variable renewable generation. | |
| 6-7 | **Issue 1: Comparing Options**<br>Ms Robins noted that shortening the time horizon of power system operation can help to reduce the unpredictability of wind and solar, but System Management needs a reasonable time period to maintain system security given that it still relies on some manual processes. Ms Robins noted that System Management has indicated that a 30-minute Balancing Gate Closure (**BGC**) is not feasible, but it can do 90-minutes, and can do 60-minutes most of the time, but it would experience some difficulties in some Trading Intervals. Ms Robins explained that AEMO had noted in 2017 that it needed a longer lead time to effect the chosen Balancing Portfolio Dispatch Plan, and to position slow ramping coal units to provide the required energy, aggregate ramp rate or Ancillary Services. In extreme cases, if the Balancing Portfolio could not be moved in time, this would lead to the potential for increased constrained on and off compensation, which is not in the interests of consumers. | |
| 8-9 | **Existing Issue – Aggregate Ramping**<br>Ms Robins considered that one of System Management's main issues from the AEMO submission related to aggregate ramping of IPPs in the early minutes of the Trading Interval, which requires preparatory scheduling of the Balancing Portfolio to offset the IPP ramping, without materially eroding the Ancillary Service quantities. Load Rejection Reserve (**LRR**) is provided by Synergy's slow ramping Muja unit, and System Management dispatches according to Synergy's guidelines and is obligated to minimize changes to Synergy's dispatch plan. Ms Robins noted that the time horizon of power system operation and outcomes in the market are determined by the 'must run' of Synergy's coal plant. Ms Robins questioned whether this was because of an economic decision by Synergy, or by System Management to | |

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| | maintain system security; and whether it is appropriate that the timeframe cannot be shortened for this reason?<br><br>Mr Patrick Peake considered that Synergy should just accelerate its ramp rate but conceded that this was not a practical proposition.<br><br>Mr Brad Huppatz considered that coal ramp rates in the interval are not necessarily the issue, but rather a combination of the Synergy Balancing Portfolio operating at its minimum, and its balancing capabilities being used to accommodate the ramp rates, not clearing the load following.<br><br>Mr Huppatz considered that the coal ramp rate would be more of an issue at a 60-minute BGC than at a 90-minute BGC.<br>Mr Huppatz explained that, as a Portfolio, Synergy are increasingly at minimum volumes to provide the energy and Ancillary Services that they have cleared for, and to accommodate the ramp rate when they are not marginal, they have to back their coal plant down in the interval so that gas plant can respond and then bring them back up to a net zero position. Mr Huppatz considered that Synergy do not have the ability to respond at minimum volumes and that the market should move to accommodate the ramp in this situation, not Synergy.<br><br>Mr Huppatz questioned whether the issue is because of slow coal ramp rates or because Synergy's Balancing Portfolio is being asked to ramp at a higher ramp rate than Synergy have bid in its submission.<br><br>Mr Noel Schubert questioned whether increased participation of IPPs in providing ancillary services so that the market is not so reliant on the Balancing Portfolio would relieve some of this issue. Mr Schubert considered that IPPs could provide more Ancillary Services if there was a concerted effort to understand what they can and cannot do, what their restrictions are, and to encourage them to tender for provision of the Ancillary Services. Mr Schubert noted that one of the respondents in an expression of interest for an Ancillary Service did not understand what was required to provide the service, which suggested that the information provided and the timeframe to absorb it was insufficient to enable them to offer something of value.<br><br>Ms Jacinda Papps advised that consideration must be given to the cost, and to whether the Margin Values, or providing a discount to that, would attract IPPs, which is a broader problem than just talking to the participants. Ms Papps considered that System Management had talked to Market Participants quite a lot about providing Ancillary Services.<br><br>Mr Dean Sharafi explained that the use of LFAS as a means of facilitating the market was a mistake in the market design, and | |

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| | that LFAS is to keep the system secure, not to enable the market to run. Mr Sharafi noted that Synergy's Balancing Portfolio is also used to facilitate the market, with the ramping of IPPs compensated by moving Synergy in the opposite direction to keep the balance between load and generation. Accordingly, Mr Sharafi considered that LFAS is the focus of discussion, not other Ancillary Services.<br><br>Ms Robins considered that this was different to what she understood, which was that System Management had been eating into LRR and LFAS to address the aggregate ramp issue. Mr Schubert questioned whether Spinning Reserve and LRR are constraining System Management's ability to use the Balancing Portfolio for LFAS and to solve this problem. Mr Sharafi acknowledged that the way System Management dispatches Synergy makes balancing and LFAS a bit mixed, and that System Management uses some LRR but considered that the focus should be on LFAS and how it is used to enable the market.<br><br>Mr Daniel Kurz questioned whether the 28 August 2019 change to the LFAS quantities were incorporated into AEMO's current views or whether that changed the dynamic even further.<br>Mr Martin Maticka and Mr Huppatz noted that increasing the LFAS limit would make it increasingly difficult to manage the situation.<br><br>Mr Peake considered that Perth Energy would like to see the gate closure as short as possible, but that it is aware of the significant issues faced by Synergy and System Management, so it would be reluctant to see the BGC pushed beyond what can be accommodated on a regular basis and under difficult situations. Mr Peake did not want to be in a position where System Management cannot organize themselves within 60 or 90 minutes.<br><br>Ms Robins noted that AEMO reported in 2016 that the aggregate ramp problem occurred less than 4% of the time and questioned whether System Management knew how frequently this is occurring now. Mr Fairclough suggested that the frequency depends on a lot of factors as an outcome of bidding and that this was the next thing that AEMO will work through. | |
| **10** | **Existing Issue – Aggregate Ramping**<br><br>Ms Robins noted that the aggregate ramp issue already exists outside of the Rule Change Proposal but must be considered if reducing the BGC exacerbates the issue, leading to risks to system security. Accordingly, it's important to understand the options. Synergy is required to provide Ancillary Services to a | |

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| | standard sufficient to enable System Management to meet its obligations. Noting that the slow ramping coal had been sufficient to meet the market requirements, Ms Robins questioned whether slow ramping coal was still sufficient.<br><br>Mr Huppatz considered that Synergy's plant can and does sufficiently meet the Ancillary Services requirements, it provides the LRR when it is on and while its ramp is slow, it is sufficient to meet individual targets. Mr Huppatz considered that the question is whether Synergy is being asked to do more than meet the Ancillary Services. Synergy may not be capable of meeting intra interval movements that are in excess of its average ramp rate.<br><br>Ms Robins noted that System Management must procure adequate Ancillary Services and asked whether the market had evolved to the point where System Management needs to ask IPPs to provide more Ancillary Services, or for Synergy to provide more from another plant. Ms Robins noted further that System Management has other options: it can monitor and increase the Ancillary Service requirements or use a Dispatch Support Service (**DSS**). However, there was no mention of an increase in LFAS to address the aggregate ramping issue in the annual Ancillary Services report for this year, so it is not clear whether this will be required if the BGC is reduced. There was also no mention of a DSS to address the aggregate ramp issue, although there was mention of a possible DSS for inertia, leading to the question of just how much of an issue the aggregate ramping really is. Finally, Ms Robins noted that System Management had employed LRR and LFAS previously to address the aggregate ramping issue, but its reading of the rules had changed recently so that only uninstructed fluctuations can be addressed using LFAS, rather than instructed fluctuations. Ms Robins provided the example that a movement is 'instructed' if System Management dispatches a plant and it is an 'instructed fluctuation' if the plant overshoots demand.<br><br>Mr Sharafi agreed that the market design is to allow LFAS to enable aggregate ramp but considered that LFAS is supposed to be used to balance changes in demand and supply in real time. Ms Jenny Laidlaw considered that, when explaining how the real time dispatch engine (**RTDE**) works, it had been acknowledged from the start of the Balancing Market up until last week that load following would account for the difference when someone ramped faster than System Management would like. This is because of how the RTDE and the Theoretical Energy Schedule (**TES**) work. Ms Laidlaw questioned whether the change in approach was due to an event, a degeneration in performance, an increased security risk, or whether System Management was running out of LFAS.<br><br>Mr Sharafi considered that there are more recent instances of sudden changes in the system and provided an example from | |

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| | the previous weekend where the system went to 52 Hz because a cloud front came and disappeared in a very short period, requiring 400 MW of ramp, and causing one facility to trip on over frequency as if it were a contingency. Mr Fairclough stated that uninstructed events that disrupt power system security are happening more frequently and with greater magnitude, but System Management had not yet undertaken an analysis to show this. Mr Fairclough considered that that the effectiveness of LFAS is reduced if it is used to address aggregate ramping or an instructed issue at any point in time. The environment is changing such that the need for LFAS has increased and there is no longer as much flexibility. Additionally, the rules require System Management to set the LFAS requirement in a way that does not include instructed deviations, which leaves System Management stuck on both fronts.<br><br>Ms Laidlaw noted that the LFAS requirement had never been set according to the Market Rules because there would never be enough, but that this is probably a separate issue.<br><br>Ms Robins questioned whether DSS was being considered. Mr Sharafi indicated that System Management is not considering DSS because it cannot get through the current Ancillary Service mechanism or definitions. Mr Sharafi noted that a DSS could be used soon for inertia because there is no Ancillary Service for inertia, but there is a defined Ancillary Service that System Management can use to procure LFAS.<br><br>Ms Robins sought clarification on the 'defined service' given the position that LFAS cannot be used for instructed fluctuations.<br><br>Mr Fairclough explained that AEMO only considers DSS to address issues when it has no other tools to address the issue. AEMO would not look at DSS to address aggregate ramping unless it had exhausted all other options and, at this stage, AEMO had not exhausted everything. | |
| 11 | **Options to Address Aggregate Ramping**<br><br>Ms Robins presented a checklist of principles that can be used to assess whether the mechanisms developed to address the aggregate ramping issue are appropriate, noting that the list was not exhaustive and could include other things, such as the causer pays principle. | |
| 12 | **Option – Linear Ramping**<br><br>Ms Robins noted that in 2017, AEMO suggested that either linear or staggered ramping may allow for a move to 60-minute BGC. AEMO has now suggested that it will implement linear ramping irrespective of this Rule Change Proposal. Some of the | |

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| | benefits are that System Management currently uses linear ramping in Emergency Operating States, this approach is consistent with where the Energy Transformation Implementation Unit (**ETIU**) market reforms are headed, and it removes any concerns that System Management has about aggregate ramping.<br><br>Ms Papps noted that ETIU is moving toward linear ramping but that it will be over a five-minute period, which is quite a different concept to linear ramping over 30 minutes. | |
| | **Presentation by AEMO on Linear Ramping**<br><br>**AEMO SLIDE 2:**<br><br>Mr Fairclough explained that the WEM rules are designed to balance generation and demand at the end of the Trading Interval, which is not required at any other point in the Trading Interval. AEMO tries to balance the system to maintain frequency, but there is always imbalance during the Trading Interval and the question is about the nature of the imbalance and how AEMO deals with it. Any movement of a facility during the interval can affect that balance, whether the movement is scheduled or unscheduled. A scheduled movement is what AEMO says in a Dispatch Instruction or a Dispatch Order to Synergy. Load following is set to cover unscheduled movements of generation to maintain that balance (i.e. LFAS is to balance the system if the wind moves or clouds come over). Ramping of any generator is a scheduled movement.<br><br>However, Ms Laidlaw noted that LFAS can be used to address the aggregate ramping issue, and that it has been used for that purpose for the last seven years.<br><br>Mr Fairclough agreed with Miss Laidlaw. Mr Fairclough considered that, if there is a scheduled movement that impacts the balance, and nothing else happens, then the LFAS facility will move to take up that slack, and its ability to then respond to anything else is reduced. This can have consequential impacts on Spinning Reserve and LRR because LFAS is used for those facilities, though it is generally no longer a problem for LRR.<br><br>Ms Laidlaw questioned whether it was AEMO's choice to double LFAS down and LRR. Mr Fairclough confirmed that it was AEMO's choice.<br><br>Mr Fairclough considered that the availability of LFAS is now more important because of the increased frequency and magnitude of unscheduled events, with three back-up LFAS events occurring in the last three weeks, even before next year when another 400 MW of wind will join the system. | |

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| | Mr Fairclough cautioned that even with the increased requirement for LFAS, there have been LRR events caused by cloud cover and events are occurring that AEMO has never seen before.<br><br>**AEMO SLIDE 3:**<br><br>Mr Fairclough explained that AEMO excludes any machines that are providing LFAS when it considers the capability of the Balancing Portfolio, because these machines cannot respond to an unscheduled movement if they are responding to a scheduled movement. This generally limits the Balancing Portfolio ramp rate, so it is often easy for scheduled non-Synergy movements to exceed the Balancing Portfolio ramp rate, leading to the aggregate ramping issue. AEMO's tools to respond to aggregate non-scheduled movements in a normal operating state are to:<br><br>(1) displace the Balancing Portfolio to offset it, if it is in the interval and the Balancing Portfolio is available to move within the interval;<br><br>(2) dispatch the Balancing Portfolio in advance of the interval to reduce the impact and duration on use of LFAS facilities; and<br><br>(3) constrain non-Synergy facilities.<br><br>Mr Peake considered that all these options have a cost.<br>Mr Fairclough agreed, and indicated that a move to a 60-minute BGC will preclude the second option, which would limit AEMO to either dispatching the Balancing Portfolio or issuing dispatch instructions.<br><br>In response to a question from Ms Laidlaw, Mr Fairclough confirmed that a move to a 60-minute BGC would preclude the second option, not just reduce it, because AEMO would not have time to implement option (2).<br><br>Ms Laidlaw questioned what exactly AEMO does with dispatch in advance and when it does it. It was explained that AEMO rearranges the position of coal and gas within the Balancing Portfolio so that it has a faster ramp rate than it would otherwise have during that Trading Interval, and it can move upward or downwards, or sometimes upwards and downwards, as required in that Trading Interval.<br><br>**AEMO SLIDE 4:**<br><br>Mr Fairclough presented a chart indicating the impact on the Balancing Portfolio when one IPP ramps up and another ramps down at a different ramp rate. It was noted that there is no change in the generation by the Balancing Portfolio at the end of the Trading Interval, but that it needs to move within the Trading Interval to account for the differing ramp rates for the IPPs. | |

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| | It was noted that there is an error in the chart and that the blue and red lines should be inverted.<br>**AEMO SLIDE 5:**<br>Mr Fairclough presented a chart showing the Balancing Portfolio's ramp up capability over time and explained that AEMO had analysed a year's worth of data for every facility in the portfolio to determine the ramp rate of the facilities for every four seconds. A facility was excluded from the analysis if it was operating near its maximum or minimum so that it did not have the ability to move to the necessary ramp rate in the next minute or if it was providing LFAS.<br>Mr Fairclough showed that the Balancing Portfolio has a ramp rate less than 20 MW/minute in about 20% of the Trading Intervals and indicated that the Balancing Portfolio may have insufficient ramp up capability in these intervals. Mr Fairclough also showed that the ramp rate for the Balancing Portfolio varies substantially from year-to-year.<br>**AEMO SLIDE 6:**<br>Mr Fairclough presented a chart like the chart in slide 5 but showing the Balancing Portfolio's ramp down capability.<br>Mr Fairclough noted that the ramp is less than 20 MW/minute for almost 40% of the time.<br>Ms Laidlaw noted that Synergy's Balancing Submissions normally have a 15 MW/minute ramp rate and questioned how often the ramp rate was below this value. Mr Fairclough explained that it is virtually always greater than 15 MW/minute if every facility in the Balancing Portfolio is considered, but not if LFAS facilities were excluded.<br>Ms Laidlaw questioned the rationale for removing of the LFAS facilities, explaining that two different things were being considered. Firstly, if NewGen or Alinta is providing LFAS, they get sent to a set point and that set point can change. They can be rebalanced and move to different places in a Trading Interval and then they provide LFAS around that. Secondly, if the Balancing Portfolio has notional dispatch instructions, if nothing else happened but the demand went down and Synergy was a marginal unit, it would be dispatched down and the RTDE would think that it is going at 15 MW/minute. Ms Laidlaw questioned whether, if Synergy did not have 15 MW/minute, AEMO would use LFAS to pick that up. Mr Fairclough confirmed that this would be the case.<br>Mr Huppatz considered that this comes down to how the facilities are dispatched and noted that Synergy had moved from clearing 70 MW of LFAS to zero. Ms Laidlaw clarified that she was not suggesting that there are no issues for Synergy, but that the Balancing Portfolio provides a balancing function, including a | |

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| | rebalancing at 10 and 20 minutes notionally, as well as providing LFAS and Spinning Reserve. The dispatch mechanism dispatches other people up/down to certain levels based on the assumption that this notional big generator (i.e. Synergy) can go at 15 MW/minute. Part of why the other participants get sent long distances is because the RTDE thinks that it has something (i.e. Synergy) that can go the other way.<br>**AEMO SLIDE 7:**<br>Mr Fairclough highlighted differences between January and February of this year in the ramp up and down rates of the Portfolio, noting that the participation of the Balancing Portfolio in the LFAS market changed significantly at the start of February, which means that AEMO's ability to use the Balancing Portfolio for intra-interval balancing is increasing.<br>**AEMO SLIDE 8:**<br>Mr Fairclough noted that more analysis needs to be done, but AEMO's preliminary conclusion is that the ramp rate has varied over time due to changes over the years in the total quantity that is being cleared by the Balancing Portfolio and to dramatic changes in the clearance of LFAS. Currently, AEMO is faced with:<br>• downward ramp less than 20 MW/minute about 38% of the time and less than 10 MW/minute about 3% of the time; and<br>• upward ramp less than 20 MW/minute about 25% of the time and less than 10 MW/minute about 2% of the time.<br>Mr Fairclough explained that AEMO will next come up with methods to forecast the Balancing Portfolio capability.<br>**AEMO SLIDE 9:**<br>Mr Fairclough considered that up to now, AEMO has used the ramp rates specified in Balancing Submissions and only varies the ramp rates as a last resort, when there is a High-Risk Operating State, because doing so will result in constrained off payments.<br>Mr Fairclough explained that the aggregate ramp issue arises because generators ramp at different rates to how the load is moving. With linear ramping, there still could be mismatches if Synergy's Balancing Portfolio does not ramp at its expected ramp rate, but they should net out in most cases and there will be no aggregate ramp issue.<br>To do linear ramping, when the BMO finishes, AEMO will assess the forecast ramping capability of the Balancing Portfolio, and the demand and other factors, and if the aggregate ramping exceeds the capability of the Balancing Portfolio, then AEMO will set the ramp rates to linear. AEMO will issue every non-Synergy facility a Dispatch Instruction to go to a point at the end of the | |

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| | interval via a ramp rate determined by AEMO. To match the linear ramping of the non-Synergy facility, AEMO will also linear ramp the Balancing Portfolio.<br><br>The ramp rates in the Dispatch Instructions for Non-Portfolio facilities may be less than their ramp rate limits and will be calculated by taking the changing quantity over the interval and dividing it by the number of minutes left in the interval, whenever the instruction is given. AEMO will average the solution so that the resulting ramp rates do not have decimals.<br><br>Mr Fairclough noted that AEMO had reviewed the Market Rules and concluded it can do linear ramping now, without the dispatch being out of merit. However, any change to the ramp rates from the ramp rate limits would result in constrained off payments, resulting in costs.<br><br>Mr Huppatz asked Mr Fairclough to elaborate on why AEMO considers a scenario where the Balancing Portfolio ramp rate is exceeded, rather than what Synergy has bid for the Balancing Portfolio. Mr Fairclough noted that the Balancing Portfolio is used where possible to allow the market to function and that there are occasions within the interval when AEMO have no other tools to ensure a good outcome, so it moves the Balancing Portfolio up and down, but still meets the required outcome at the end of the interval.<br><br>Mr Fairclough indicated that AEMO would like to implement linear ramping now because it has had to use back-up LFAS three times in a week. Mr Peake sought clarification on whether it had to be linear ramping for a full 30-minutes, noting that there's re-dispatch at 10 and 20 minutes. It was Mr Fairclough's understanding that AEMO was looking at this and that it would have to determine exactly what the process is and when it would be used. Mr Fairclough considered that linear ramping would generally always be a last option and that, while AEMO is thinking about linear ramping for its current operations, AEMO is not going to introduce linear ramping tomorrow. However, Mr Fairclough considered that if there is a move to 60-minute BGC, AEMO will need to be able to implement linear ramping from that date.<br><br>Mr Fairclough noted that the distinction was that AEMO would need to automate linear ramping for 60-minute BGC but could implement it manually for a 90-minute BGC. Mr Fairclough considered that additionally, a move to an automated process would require a more conservative formula.<br><br>Ms Papps expressed concern that it may cause instability if the ramp rates could be anything up to the ramp rate limit because governors can be tuned to specific ramp rates but there are limits to the variability in the ramp rates that can be used. | |

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| | Mr Sharafi considered that AEMO may not have visibility of this, which may create issues for generators.<br><br>Ms Laidlaw questioned whether linear ramping would be built into the RTDE as part of the automated solution. Mr Fairclough considered that there was no need to change the RTDE, as AEMO could simply change the ramp rate that it feeds into the RTDE. Mr Sharafi considered that the controller can manually override what goes into the RTDE.<br><br>Ms Laidlaw questioned how AEMO would work out what the units are going to be dispatched to, and therefore, who's going where, and at what speed, if AEMO does not look at it through the RTDE. Mr Fairclough considered that this would have to be considered in how AEMO implements linear ramping, as AEMO had not worked out exactly how it was going to work yet.<br><br>Mr Eliot noted that there are costs and timing implications associated with implementing an automatic process. Ms Robins questioned whether, if linear ramping is something planned in the longer term, the Rule Change Proposal should be held off while AEMO implements linear ramping or should proceed with some other option. Ms Robins noted that 400 MW of wind and 200 MW of residential solar will be added by mid-next year, so Market Participants may want to shorten the BGC now, rather than waiting to implement an aggregate ramping solution.<br><br>Ms Papps noted that Participants may need time to implement control system and governor changes to implement linear ramping, which requires outage planning, outages, testing, commissioning, and finding a supplier. There is not enough information and Participants don't have an outage plan or an outage scheduled, which makes it difficult to provide a timeframe.<br><br>Ms Robins considered that if work cannot start on implementing linear ramping until the end of next year, then the time frame is too close to when the market reforms will be implemented. The decision could be made to not implement linear ramping but to hold off for the reforms.<br><br>Mr Sharafi noted that AEMO had avoided making wholesale changes to the RTDE because it knew that the reforms would address most of the issues, with a different dispatch period and different structure to the Ancillary Services. Mr Sharafi considered that implementing linear ramp rates is a change that requires ~~significant~~ system changes, and consideration needs to be given to the efficiency of the solution and what can be gained from it.<br><br>Ms Laidlaw noted that the difference between the BGC options is that the advanced dispatch option is available for 90-minute BGC but not for 60-minute BGC and considered that, in a | |

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| | situation where Synergy has not got anything more to give, AEMO would have nothing left to shift around and it would not matter what the BGC is.<br><br>Ms Laidlaw further considered that there is an equity issue when AEMO advance dispatches some units to increase Synergy's ramp rate to higher than 15 MW/minute, as AEMO is moving Synergy above what it puts in its Balancing Submissions and Synergy is not being compensated for providing the additional ramp. Ms Laidlaw considered that shifting around Synergy's dispatch arrangement to provide additional ramp sounds like LFAS. Mr Huppatz considered that it's not viable for Synergy to be at its minimum, which is often the case, and where it has zero clearing volume, and then being asked to move again. Synergy do not want to prop up the market, and the market should see the costs that are involved and should seek to minimise the total costs, not cross-subsidise them.<br><br>Ms Laidlaw explained that the RTDE sends Synergy to a point 30 minutes away, 20 minutes away and 10 minutes away; and that Synergy is also being moved up and down. It is very hard to distinguish between movement of the Balancing Portfolio and LFAS because of the way the Balancing Portfolio is dispatched and because it is often the same machine being used, but it becomes a bit clearer if Synergy is not providing any LFAS. Ms Laidlaw questioned whether the machines are still on in load following mode, even if they are not providing load following. Mr Sharafi confirmed that the machines are still on in load following mode and noted that AEMO dispatch Synergy every four seconds.<br><br>Mr Huppatz noted that Synergy is not always marginal and clearing for Ancillary Services. Mr Huppatz considered that he was not sure how the ramp rate minimum comes in, because if Synergy has cleared at minus $1000/MWh, it is not expecting to move. Synergy might not have the down ramp at that point, because it cannot go lower, and it's not expected to, and is still compliant. Ms Laidlaw considered that it sounded as if the advanced dispatch would not work in these situations and questioned whether the number of these situations is growing.<br><br>Mr Huppatz considered the number is growing and noted that there will be circumstances where, because of increasing the Ancillary Service cap, regardless of the 90-minutes, Synergy will not be able to provide the necessary ramp. There were higher loads in the past, and Synergy was not at the floor, so AEMO could move its plant around to do that.<br><br>Mr Peake noted that, with linear ramping, he would hate to see a situation where plants are at less than their minimum as it will lead to issues with the ERA. | |

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| | Mr Adam Stephen question whether using linear ramping to solve the instructed output fluctuation problem might cause more uninstructed fluctuation issues. Ms Robins considered that if AEMO are going to moderate a generator's ramp rate and there is a loss of revenue associated with generating less, then this would provide an incentive for Participants to increase their ramp rates to the maximum so that they will not lose as much if they are moderated, which will make the aggregate ramp issue worse.<br><br>There was some discussion about whether participants are required to ramp at their maximum ramp rates. Mr Fairclough clarified that participants are required to be able to ramp at the ramp rate indicated in their Balancing Submissions, which is not necessarily always the facility's maximum ramp rate. | |
| 13 | **Option – Linear Ramping**<br><br>Ms Robins questioned whether the simple solution is a change to the Market Rules for LFAS to reflect 'instructed' output fluctuations, and to continue to address the aggregate ramping issue using LFAS.<br><br>Mr Fairclough noted that AEMO's next step is to assess the maximum capability of the Balancing Portfolio in every interval last year and determine how often the aggregate ramp issue occurred. However, Mr Fairclough considered that past behaviour is not necessarily a good indicator of the future.<br><br>Ms Laidlaw questioned whether AEMO's concern with including instructed fluctuations in the LFAS requirement was that it might be breaching the Rules. Mr Fairclough questioned whether, if AEMO decided to include instructed output fluctuations in the LFAS requirement, even though this is not in the rules, it would be efficient for the LFAS requirement to be a lot more than it currently is. Ms Robins noted that the LFAS has been used to address this issue in the past. Mr Fairclough considered that AEMO had more LFAS available in the past, so it was okay. Mr Sharafi stated that LFAS should not be used but, if there is an imbalance, the LFAS kicks in and resolves the issue because of Automatic Generation Control.<br><br>Ms Robins noted that the Annual Ancillary Services Report presents a figure that says that frequency is maintained 99.998% of the time. Ms Robins questioned how close the market is to affecting that figure, based on what AEMO had said today. Mr Sharafi considered that the performance of frequency relates to LFAS to some extent, but it also relates to other things like the response of the generators in the system (such as droop | |

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| | control), so a direct connection cannot be made between frequency performance and LFAS.<br><br>Mr Sharafi considered that AEMO would need to implement automated linear ramping to move to a 60-minute BGC, because it is beyond the capacity of a human being to deal with that issue in that short period of time.<br><br>Mr Stephens offered that linear ramping is employed in the NEM, but that it's a five-minute interval, not a half hour interval, and ramping occurs at the ramp rates in the bidding, which doesn't get moderated. Ms Laidlaw considered that in three years' time, there won't necessarily need to be linear ramping because LFAS can pick up small imbalances with a 5-minute dispatch cycle. This means that the cost to make everyone switch to linear ramping would be required for a short-term solution. Ms Papps considered that the cost to implement the linear ramping for 30 minutes might be quite different, and that the solution is quite different, from five minutes. Ms Varma considered that a different world is being contemplated in 2022 and that there is no consideration of a 30-minute BGC in the future.<br><br>Mr Eliot noted that questions of cost and practicality cannot be answered if we do not know how the linear ramping model is going to work. Mr Fairclough considered that AEMO would have to come up with a formula for how it would implement linear ramping and that this formula would apply whether AEMO did it manually or used an automated process. Mr Fairclough noted that the requirement to ramp linearly would be lower with a 90-minute BGC, leading to a difference in the amount of constrained off payments between the two scenarios.<br>Mr Fairclough considered that AEMO could give an indication of the difference between constrained off payments, based on last year, and then consider the cost of creating the system.<br><br>Ms Robins questioned whether AEMO needed to implement linear ramping regardless of a reduction in the BGC. Mr Sharafi considered that AEMO may have to implement it, but it has not yet completed its analysis. AEMO is witnessing much more volatility on the grid, so it sometimes needs to limit the ramp rate of generators, but it can currently do this by manual intervention. AEMO will not change its systems to implement automatic linear ramping if 60-minute BGC is not implemented. With manual intervention, the controller sees that it cannot respond to a fast movement of generators so he or she limits the ramp rate of some of the units. The other option is to constrain the generator, which is done under not normal conditions.<br><br>There was discussion on whether an understanding of how linear ramping would work and its costs to AEMO and Market Participants would be required prior to publishing a Draft Rule | |

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| | Change Report and Attendees agreed that that would be quite a large process.<br><br>Mr Sharafi urged attendees to consider the Rule Change Proposal in of the reform program and its time frames and noted that System Management does not have any resources to focus on other things.<br><br>Ms Laidlaw questioned what AEMO would do if a shorter BGC was not implemented, whether it would continue to use the combination of pre-advanced dispatch and LFAS, and whether AEMO would have the same concerns about using LFAS and its effect on system security. Mr Sharafi confirmed that this was the case and that AEMO would still have these concerns.<br><br>Mr Fairclough considered that if there is a greater frequency and impost of unscheduled movements, AEMO are likely to get into the situation of constraining IPPs more often. AEMO do not want to introduce linear ramping now because it knows that it costs everyone but considers that this is the way things are heading. Mr Fairclough considered that the change to BGC had not instigated AEMO's view on the use of LFAS.<br><br>Ms Laidlaw sought clarification on whether AEMO is removing LFAS as an option to deal with the aggregate ramp issue. Mr Fairclough confirmed that this was the case. Ms Laidlaw questioned whether AEMO therefore needed to set up the first part of the automated system, to check every Trading Interval to see whether it will use LFAS, and therefore need to use one of the remaining options to address the aggregate ramp issue. Mr Fairclough considered that AEMO already have the tools to do this, to a degree, so it doesn't need to build something to get the information.<br><br>Ms Laidlaw sought clarification on whether AEMO knows when it needs to linear ramp and questioned whether it was just that more often than not, AEMO are moving the Balancing Portfolio around to solve the problem. Mr Fairclough considered that AEMO uses the Balancing Portfolio on 99% of occasions.<br><br>Ms Laidlaw questioned whether AEMO were only rarely using LFAS, as it was her understanding that it would been the tool most commonly used by AEMO. Mr Fairclough considered that if AEMO did not do anything else, it would default to LFAS.<br><br>Ms Laidlaw questioned whether AEMO were proposing that, in the frequent set of situations when the imbalance was only small, it was going to use linear ramping rather than LFAS. Mr Fairclough considered that AEMO was not thinking about the times when there was a little impost, which would be business as usual, but more the times when there is a 10 MW/minute or higher impost. | |

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| | Ms Laidlaw questioned whether AEMO would have a threshold of LFAS usage that it would determine, and beyond that threshold would then go to linear ramping? Mr Fairclough considered that there wouldn't be an LFAS threshold, but that the automation would be based on AEMO's assumptions about what the Balancing Portfolio could do.<br><br>**Action: RCP Support to hold a second workshop.**<br><br>**Action: MAC Members to advise the Panel on what they want them to do regarding linear ramping.** | <br><br><br><br><br><br>**RCP Support**<br><br>**MAC Members** |
| **14-15** | **Option – Staggered Ramping**<br><br>Ms Robins noted that many of the same issues that must be considered for linear ramping will need to be considered for aggregate ramping and that information would be sought from Market Participants on this topic in a follow up email to the workshop. | |
| **16** | **Issue 2: Synergy's Gate Closure**<br><br>Ms Robins noted that the forecast is 10.5 hours ahead of the first Trading Interval and 16 hours ahead of the last Trading Interval in the related LFAS block. There was some confusion around when Synergy's LFAS gate closure occurs under the Market Rules, with most Participants assuming that the LFAS gate closure was the same for Synergy as for IPPs. Attendees agreed to address this question outside of the workshop.<br><br>Ms Robins considered that, if the gate closure is reduced for IPPs, then it would seem reasonable to also reduce Synergy's gate closure but cautioned that Synergy is the dominant player in the market and there is a need to avoid infeasible dispatch.<br><br>Mr Huppatz noted that Synergy had indicated in its submission that it should be treated on a level playing field and should have the same gate closure as IPPs.<br><br>Mr Sharafi considered that AEMO does not mind if Synergy's gate closure is the same as everyone else's, so long as LFAS gate closure is before that. The attendees agreed that there was no need to disrupt the order of gate closures, with Synergy gate closure following LFAS gate closure.<br><br>Mr Peake and Ms Papps considered that Synergy's gate closure should be as close as possible to the BGC but should not be the same, as this would be most efficient for the market. Ms Papps noted there are probably still some things about the Balancing | |

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| | Portfolio that are different than for IPPs, which requires a different gate closure for Synergy.<br><br>Ms Robins noted that consideration needed to be given to what IPPs need to do in the time between Synergy's gate closure and when they bid, and how long they need to do it. Ms Papps considered that IPPs need to wait for the information to come out of AEMO and then respond to that information. Mr Stephens noted that the information on the BMO is provided at the start of every half-hour. At one-minute past the half hour Synergy must make their submission, AEMO's system processes Synergy's submission, and then IPPs can see the result and decide if they must change their submission and make their submission.<br><br>Mr Eliot questioned whether it was a long period between when Synergy makes its submission and when the BMO is in IPP's hands and considered that if it was an automated process it would take less than a minute. Ms Papps noted that if the BMO comes out at 8.01 then IPPs would not want to have to make a submission before 8:30. Ms Papps considered that 30 minutes was too short. Mr Stephens noted that if the IPP makes its Balancing Submission within the last two minutes before the start of interval, it is not reflected in the BMO for the following interval, only in the next one.<br><br>Mr Maticka noted the design of the market was to allow IPPs to respond to the market dominance of Synergy and considered that, from a technical point of view, it makes no difference to the power system. Mr Maticka posed the question of whether it is a correct lever for addressing market power.<br><br>Ms Laidlaw considered that one of the IPP's biggest risks is infeasible dispatch, and that this risk increases if they do not have some forewarning of what the Balancing Portfolio is doing. The Balancing Portfolio doesn't have the same kind of risk of infeasible dispatch. However, Mr Huppatz considered that Synergy also face infeasible dispatch because of the forecasting inaccuracy, and the long gate closure.<br><br>Ms Varma noted that the intent in the planned reform is that the Synergy Balancing Portfolio will no longer exist, which creates opportunities to harmonise the gate closure of Synergy and IPPs, if there is a gate closure.<br><br>Ms Robins questioned whether anyone had any concerns or could see issues with Synergy having a rolling gate closure instead of block bidding, as this would reduce the time frame of operation between the last forecast and the bid for the start of the Trading Interval.<br><br>Mr Huppatz considered that the shorter the gate closure, the better in terms of efficiency for the market. Increasingly, Synergy needs to have the ability to get its plant in or out. This might | |

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| | mean making a decommitment decision but if that is left too late, Synergy might be able to de-commit the plant but it's too late to bid it out, so that volume stays in the market. Similarly, Synergy have some slow start plants, which is problematic if they must come on at short notice. For example, if AEMO wanted to request that Coburn comes on because of a security issue, it cannot provide that volume because it needs to start early in the day to be on that night. Mr Huppatz considered that the shorter the gate closure, the more accurately Synergy can reflect what is required, which is efficient for the market. On that basis, Mr Huppatz indicated that Synergy advocates for a rolling gate closure.<br><br>Ms Ng noted that when the rules were developed, the block bidding and time frames were developed just to manage market power issues. Ms Ng questioned whether everyone was comfortable that the market power issues had disappeared, before going down the path of introducing a rolling gate closure for Synergy. Ms Ng considered that everyone needs to be comfortable with the change, given that there is a new world that the market is going to that will have facility bidding and potentially 30-minute gate closure, with everyone on the same time frames.<br><br>Ms Laidlaw questioned how block bidding mitigates market power, noting that there is no difference for the first trading interval in the block, but there is a half-hour delay for the second interval. Ms Laidlaw questioned what the purpose of that delay is and how it mitigates market power. Mr Maticka recalled that the idea of the design was to provide a mechanism to encourage Synergy to pull facilities out of the Balancing Portfolio. Mr Peake considered that there was also a reluctance to make the changes too big from the word go. Mr Maticka considered further that there could have been another reason to do with resource plans but that it was an outdated concept, and that Ms Ng's point was correct, that block bidding should not just be removed without checking whether some of the logic around it is still valid.<br><br>Mr Huppatz added that the market has changed and that there is inefficiency and additional risk to the market by Synergy not going to a rolling gate closure. Mr Huppatz questioned the logic of a requirement that by 10:00 AM, Synergy cannot adjust what it is going to do or provide a signal to the market for what Synergy is doing over the evening peak. Mr Huppatz considered that this is unworkable<br><br>Mr Maticka considered that if Synergy is sitting at a mid-low point, it would end up having to decommit some coal and then it might have to bring it back on very quickly, within a half an hour or an hour. Mr Maticka considered that this could present some | |

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| | horrendous problems for the management of the fleet and that Synergy cannot respond if it has such forward blocks.<br><br>Mr Huppatz added that Synergy can manage base load plant with a fixed gate closure but as soon as it starts becoming mid-merit, trying to manage with a block that is 10 hours in advance is not ideal.<br><br>Mr Eliot noted that RCP support was looking for feedback from everybody on the following questions:<br><br>1. whether there are any concerns with a rolling gate closure for Synergy;<br><br>2. if there is a reason why Synergy should have a longer BGC than everybody else; and<br><br>3. if the answer to number two, is yes, how much time do IPPs need and why?<br><br>**Action MAC Members to provide feedback to the Panel on the above questions.** | <br><br><br><br><br><br><br><br><br><br><br><br><br><br>**MAC Members** |
| **17-19** | **Issue 3: Load Following Gate Closure, Current Gate Closure Timeframes and Strawman Options**<br><br>Ms Robins noted that she would ask participants the same questions about the LFAS gate closure as for Synergy's gate closure.<br><br>Regarding the strawman options, a possible reduction in the LFAS blocks from six to four hours was suggested, due to Market Participant concerns that a rolling gate closure may necessitate employing another trader, and that it could increase the risk of penalties if Participants do not realise that they have been cleared to provide LFAS and do not reposition themselves in the balancing market.<br><br>Mr Fairclough questioned whether a change to the LFAS gate closure was within the scope of this Rule Change. Ms Robins considered that it is within scope, as it is about creating efficiencies through increased forecasting accuracy. | |
| | **Next Steps**<br><br>RCP Support will send an email with the date for a follow up workshop, and with follow up questions to address the Action Items for response within two weeks. | |

RCP Rule Change Panel
Market Advisory Committee

# Agenda Item 4: MAC Action Items

Meeting 2019_10_15

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| Shaded | Shaded action items are actions that have been completed since the last 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 |
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| 18/2019 | RCP Support to publish the minutes of the 29 July 2019 MAC meeting on the Rule Change Panel (**Panel's**) website as final. | RCP Support | 2019_09_03 | **Closed**<br>The minutes were published on the Panel's website on 3 September 2019. |
| 19/2019 | The ERA to advise the MAC whether it intends to address the conflict between the Relevant Level Methodology and the early and conditional certification of Intermittent Generators as part of Rule Change Proposal RC_2019_03: Method used for the assignment of Certified Reserve Capacity for Intermittent Generators. | ERA | 2019_09_03 | **Open**<br>The ERA is still considering its this matter and will advise the MAC in due course. |

| Item | Action | Responsibility | Meeting Arising | Status |
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| 20/2019 | AEMO to develop a Pre-Rule Change Proposal for AEMO's 'option 3' to address the North Country Spinning Reserve issue (as discussed at the 29 July 2019 MAC meeting), which is to include the removal of constrained off payments when the relevant generators are constrained down to reduce the Spinning Reserve requirement, for presentation at the 26 November 2019 MAC meeting. | AEMO | 2019_09_03 | **Open**<br>AEMO is in the process of developing the Pre-Rule Change Proposal and will provide the MAC with an update on progress at its meeting on 15 October 2019 – see Agenda Item 8(b). |

RCP Rule Change Panel
Market Advisory Committee

# Agenda Item 5: MAC Market Rules Issues List Update

Meeting 2019_10_15

The latest version of the Market Advisory Committee (**MAC**) Market Rules Issues List (**Issues List**) is available in Attachment 1 of this paper.

The MAC maintains the Issues List to track and progress issues that have been identified by Wholesale Electricity Market (**WEM**) stakeholders. A stakeholder may raise a new issue for discussion by the MAC at any time by emailing a request to the MAC Chair.

Updates to the Issues List are indicated in red font, while issues that have been closed since the last publication are shaded in grey.

## Recommendation:

RCP Support recommends that the MAC:

- note the updates to the Issues List;
- discuss the seven outage issues indicated below:
    - should any of the outage issues to be included in the Issues List;
    - for each of the outage issue that should be included in the Issues List:
        - where should it be included – as a potential Rule Change Proposal, placed on hold or treated as a broader issue requiring further discussion/review; and
        - what urgency rating should the issue have?

## Outage Issues for Potential Inclusion on the Issues List

Several outage-related issues were raised during consultation on Rule Change Proposal RC_2013_15: Outage Planning Phase 2 – Outage Process Refinements that did not fall within the scope of either RC_2013_15 or Rule Change Proposal RC_2014_03: Administrative Improvements to the Outage Process. The Rule Change Panel suggested in the Final Rule Change Report for RC_2013_15 that the MAC consider whether any of these issues should be included in the Issues List.

### 1. Identification of services subject to outage scheduling[1]

The Market Rules do not clearly define the 'services' that should be subject to outage scheduling (e.g. what services are provided by different items of network equipment, Intermittent Load facilities, dual-fuel Scheduled Generators, etc), and how the 'availability' of these services should be measured for each Outage Facility. This can lead to ambiguity about what constitutes an Outage for certain Outage Facilities.

Additionally, if a Facility or item of network equipment can provide multiple services that require outage scheduling, then this concept should be clearly reflected in the Market Rules. The Amending Rules for RC_2013_15 clarified that a Scheduled Generator or Non-Scheduled Generator that is subject to an Ancillary Service Contract is required to

[1] See section 7.2.2.5 of the Final Rule Change Report for RC_2013_15, available on the Panel's website.

schedule outages in respect of both sent out energy and each contracted Ancillary Service, but did not seek to address the broader issue.

## 2. Outage scheduling for dual-fuel Scheduled Generators[2]

'0 MW' outages are currently used to notify System Management when a dual-fuel Scheduled Generator is unable to operate on one of its nominated fuels. There is no explicit obligation in the Market Rules or the Power System Operation Procedure: Facility Outages to request/report outages that limit the ability of a Scheduled Generator to operate using one of its fuels. In terms of the provision of sent out energy (the service used to determine Capacity Cost Refunds), it is questionable whether this situation qualifies as an outage at all.

More generally, the Market Rules lack clarity on the nature and extent of a Market Generator's obligations to ensure that its Facility is able to operate on the fuel used for its certification, what (if anything) should occur if these obligations are not met, and the implications for outage scheduling and Reserve Capacity Testing.

## 3. Ancillary Service outage scheduling anomalies[3]

Currently Registered Facilities that provide Ancillary Services under an Ancillary Service Contract must be included on the Equipment List. This creates the following potential anomalies:

- some Ancillary Service Contracts may include outage reporting provisions that are specific to the service and may differ from the standard outage scheduling provisions for Equipment List Facilities;
- Market Participants are not required to schedule outages in relation to the availability of their LFAS Facilities to provide LFAS;
- Synergy is not required to schedule outages in relation to the availability of its Facilities to provide uncontracted Ancillary Services; and
- a contracted Ancillary Service may not always be provided by a Registered Facility.

A review of the outage scheduling requirements relating to Ancillary Services may be warranted to resolve any anomalies and ensure that the obligations on Rule Participants to schedule outages for Ancillary Services are appropriate and consistent.

## 4. Outage scheduling obligations for Interruptible Loads[4]

The Market Rules require all Registered Facilities that are subject to an Ancillary Service Contract to be included on the Equipment List. This includes the Interruptible Loads that are used to provide Spinning Reserve Service. However, the Market Rules do not explicitly state who is responsible for outage scheduling for Interruptible Loads.

This is a problem because the counterparty to an Interruptible Load Ancillary Service Contract may be an Ancillary Service Provider, and not the Market Customer (usually a retailer) to whom the Interruptible Load is registered. An Ancillary Service Provider is not subject to obligations placed on a 'Market Participant or Network Operator', while the retailer for an Interruptible Load may not have any involvement with the Interruptible Load arrangement or the management of outages for that Load.

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2 See section 7.2.2.5 of the Final Rule Change Report for RC_2013_15.

3 See section 7.2.2.5 of the Final Rule Change Report for RC_2013_15.

4 See section 7.2.3.1 of the Final Rule Change Report for RC_2013_15.

## 5. Direction of Self-Scheduling Outage Facilities[5]

An apparent conflict exists in the Market Rules between clauses that appear to allow System Management to reject or recall Planned Outages of Self-Scheduling Outage Facilities (e.g. clauses 3.4.3(a), 3.4.3(b), 3.4.4 and 3.5.5(c)) and clauses that appear to exempt Planned Outages of Self-Scheduling Outage Facilities from rejection or recall, such as:

- clause 3.18.2A, which explicitly exempts Self-Scheduling Outage Facilities from obligations under section 3.20;
- clause 3.19.5, which allows System Management to reject an approved Scheduled Outage or Opportunistic Maintenance but fails to mention Planned Outages of Self-Scheduling Outage Facilities (which are neither Scheduled Outages nor Opportunistic Maintenance); and
- clause 3.19.6(d), which sets out a priority order for System Management to consider when it determines which previously approved Planned Outage to reject, but does not include any reference to Planned Outages of Self-Scheduling Outage Facilities.

## 6. Coordination of network and generation outages[6]

When a network outage is likely to unduly impact the operation of one or more Market Participant Registered Facilities, clause 3.18.5C of the Market Rules allows System Management to require that, in developing their Outage Plans, the relevant Network Operator and affected Market Participants coordinate the timing of their outages to minimise the impact of the network outage on the operation of the Market Participant Registered Facilities.

In its second period submission for RC_2013_15, Alinta suggested that while clause 3.18.5C ensures that there is some coordination of outages where both network and generation participants want outages, the Market Rules should require either:

- greater coordination of network outages where they are likely to unduly impact the operation of one or more Market Participant Registered Facilities (whether or not the participant wants or needs a corresponding outage); and/or
- the Network Operator should have to consider the Wholesale Market Objectives when planning network outages to ensure that least cost and efficient outcomes are achieved for the market as a whole.

## 7. Outage scheduling obligations for non-intermittent Non-Scheduled Generators [7]

Under the Market Rules:

- a non-intermittent generation system with a rated capacity between 0.2 MW and 10 MW may be registered as a Non-Scheduled Generator; and
- a non-intermittent generation system with a rated capacity less than 0.2 MW can only be registered as a Non-Scheduled Generator.

To date, no non-intermittent generation systems have been registered as Non-Scheduled Generators. However, if a non-intermittent Non-Scheduled Generator was registered it would

5 See section 7.2.3.2 of the Final Rule Change Report for RC_2013_15.

6 See Appendix D, Issue 34 of the Final Rule Change Report for RC_2013_15.

7 See section 7.2.3.4 of the Final Rule Change Report for RC_2013_15.

be able to apply for Capacity Credits, and if assigned Capacity Credits would also be assigned a non-zero Reserve Capacity Obligation Quantity (**RCOQ**).

While this would make the Non-Scheduled Generator subject to the same RCOQ-related Scheduling Day obligations as a Scheduled Generator, the Non-Scheduled Generator's Balancing Market obligations are more uncertain and were not considered in the development of RC_2013_15. The Balancing Submissions for a Non-Scheduled Generator comprise a single Balancing Price-Quantity Pair with a MW quantity equal to the Market Generator's "best estimate of the Facility's output at the end of the Trading Interval". There is no clear obligation to make the Facility's RCOQ available for dispatch or to report an outage for capacity not made available, because new section 7A.2A, which will clarify these obligations for Scheduled Generators, does not apply to Non-Scheduled Generators.

The need to cater for non-intermittent, Non-Scheduled Generators also affects the determination of capacity-adjusted outage quantities and outage rates, and is likely to increase IT costs and the complexity of the Market Rules.[8]

8 To assist with the progression of RC_2014_03, RCP Support has requested advice from the Energy Transformation Implementation Unit (**ETIU**) regarding:

- whether ETIU intends that small (i.e. <10 MW) non-intermittent generation systems will still be eligible to register as Non-Scheduled Generators under the new market arrangements; and
- if so, whether ETIU intends that these non-intermittent, Non-Scheduled Generators will still be eligible for Capacity Credits; and
- if so, what mechanism will be used to ensure that these Facilities actually make their capacity available when it is required.

# Agenda Item 5 – Attachment 1 – MAC Market Rules Issues List

| Table 1 – Potential Rule Change Proposals | | | |
|---|---|---|---|
| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| 31 | Synergy<br>November 2018 | **LFAS Report**<br>Under clauses 7A.2.9(b) and 7A.2.9(c) of the Market Rules, Synergy is obligated to compile and send the LFAS weekly report to AEMO based on the LFAS data for each Trading Interval supplied to Synergy by System Management. Given that System Management is now part of AEMO, it seems reasonable to remove this obligation on Synergy to reduce administrative burden. This rule change supports Wholesale Market Objective (a). | **Panel rating:** Low, but OK to progress using the Fast Track Rule Change Process<br>**MAC ratings:**<br>Low: Alinta, Bluewaters<br>Medium: Geoff Gaston, AEMO<br>High: Peter Huxtable<br>**Status:**<br>This issue has not been progressed. |
| 45 | AEMO<br>May 2018 | **Transfer of responsibility for setting document retention requirements**<br>AEMO suggested that responsibility for setting document retention requirements (clauses 10.1.1 and 10.1.2 of the Market Rules) should move from AEMO to the ERA. AEMO considers that it is not the best entity to hold this responsibility as it no longer maintains the broader market development and compliance functions of the IMO. | **Panel rating:** Low<br>**MAC ratings:** Low<br>**Status:**<br>Waiting on the ERA to provide its position on the proposal, but this is a low priority issue for the ERA. |
| 46 | AEMO<br>May 2018 | **Transfer of responsibility for setting confidentiality statuses**<br>AEMO suggested that responsibility for setting confidentiality statuses (clauses 10.2.1 and 10.2.3 of the Market Rules) should move from AEMO to the ERA. AEMO considers that it is not the best entity to hold this responsibility as it no longer maintains the broader market development and compliance functions of the IMO. | **Panel rating:** Low<br>**MAC ratings:** Low<br>**Status:**<br>Waiting on the ERA to provide its position on the proposal, but this is a low priority issue for the ERA. |

| Table 1 – Potential Rule Change Proposals | | | |
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| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| 47 | AEMO<br>September 2018 | **Market Procedure for conducting the Long Term PASA (clause 4.5.14)**<br>The scope of this procedure currently includes describing the process that the ERA must follow in conducting the five-yearly review of the Planning Criterion and demand forecasting process.<br>AEMO considers that its Market Procedure should not cover the ERA's review, and the ERA should be able to independently scope the review. As such, AEMO recommends removing this requirement from the head of power in clause 4.5.14 of the Market Rules. | **Panel rating:** Low<br>**MAC ratings:** Low<br>**Status:**<br>This issue has not been progressed. |
| 52 | MAC<br>February 2019 | **North Country Spinning Reserve**<br>How should potential future scenarios be managed where multiple generating units that are connected to the same line constitute the largest credible contingency, without imposing excessive constraint payment costs on Market Customers? | **Panel rating:** TBD<br>**MAC ratings:** High<br>**Status:**<br>The MAC discussed this issue at its meetings on 11 June and 29 July 2019. AEMO has proposed three options to address this issue.<br>The MAC further discussed this issue at its meeting on 3 September 2019, where the MAC supported option 3. AEMO agreed to develop a Pre-Rule Change Proposal for option 3 for presentation to the MAC at its meeting on 26 November 2019.<br>This issue will be further discussed at the MAC meeting on 15 October 2019 – see Agenda Item 8(b). |

| Table 1 – Potential Rule Change Proposals | | | |
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| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| 53 | Alinta<br>February 2019 | **TES Recalculation**<br>Alinta is seeking a rule change to allow the recalculation of TES after the current 15 Business Day deadline. | **Panel rating:** Low<br>**MAC ratings:** Low<br>**Status:**<br>This issue has not been progressed. |
| 55 | MAC<br>April 2019 | **Conflict between Relevant Level Methodology and the early and conditional certification of Intermittent Generators**<br>There is a conflict between the current and proposed Relevant Level Methodologies and the early and conditional certification of new Intermittent Generators, because the methodologies depend on information that is not available before the normal certification time for a Reserve Capacity Cycle. | **Panel rating:** TBD<br>**MAC ratings:** Low<br>**Status:**<br>On 15 August 2019, Mr Maticka advised RCP Support that AEMO has revised its position and is now of the view that there is an opportunity as part of RC_2019_03 to remove Clause 4.28C.7 that relates to Early Certification of Reserve Capacity (**CRC**).<br>The draft proposal states that AEMO "must reject the early certification application if it has cause to believe that it cannot reliably set the Early CRC…"; otherwise, AEMO must set Early CRC within 90 days of receiving the application. It appears that it is almost certain that AEMO cannot reliably set the Early CRC for an early certification application if an intermittent Facility nominates to use clause 4.11.2(b) for the assessment. This is because:<br>• An early certification application may be submitted at any time before 1 January of |

| Table 1 – Potential Rule Change Proposals | | | |
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| Id | Submitter/Date | Issue | Urgency and Status |
| | | | Year 1 of the Reserve Capacity Cycle to which the application relates [clause 4.28C.2].<br>• This means that when AEMO receives an application under 4.11.2(b), it can't calculate a reliable Relevant Level value for the Facility, as it is not certain:<br>o which Scheduled Generators, DSPs, and Non-Scheduled Generators would apply for certification; or<br>o what level of CRC would be assigned to these Scheduled Generators and DSPs.<br>AEMO also stated that:<br>• Neither a complete set of system demand and Facility actual meter data is available nor are the expected capacity estimates of new Candidate Facilities.<br>• It almost implies that in fact only Scheduled Generators can apply and be certified for Early Certification. Noting an application of this nature has not been provided in the past years, AEMO suggests removal of this clause completely.<br>The MAC discussed this issue at its meeting on 3 September 2019 where it was noted that the |

| Table 1 – Potential Rule Change Proposals | | | |
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| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| | | | issue could be addressed as a standalone Rule Change Proposal or as part RC_2019_03. The ERA is considering whether it wants to address the issue as part of RC_2019_03, and if not, then RCP Support will bring the issue back to the MAC for further discussion. |
| 56 | Perth Energy<br>July 2019 | **Issues with Reserve Capacity Testing**<br>• Market Generators that fail a Reserve Capacity Test may prefer to accept a small shortfall in a test (and a corresponding reduction in their Capacity Credits) than to run a second test.<br>• There is a discrepancy between the number of Trading Intervals for self-testing vs. AEMO testing.<br>• There is ambiguity in the timing requirements for a second test when the relevant generator is on an outage.<br>• There is ambiguity on the number of Capacity Credits that AEMO is to assign when certain test results occur. | **Panel rating:** TBD<br>**MAC ratings:** TBD<br>**Status:**<br>Perth Energy has indicated that it will develop a Pre-Rule Change Proposal for consideration by the MAC. |

Notes:

- The Potential Rule Change Proposals are well-defined issues that could be addressed through development of a Rule Change Proposal.
- If the MAC decides to add an issue to the Potential Rule Change Proposals list, then RCP Support will seek a preliminary urgency rating from MAC members/observers and from the Rule Change Panel (**Panel**) and will include this information in the list.
- Potential Rule Change Proposals will be closed after a Pre-Rule Change Proposal is presented to the MAC or a Rule Change Proposal is submitted to the Panel.

| Table 2 – Broader Issues | | | |
|---|---|---|---|
| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| 1 | Shane Cremin<br>November 2017 | IRCR calculations and capacity allocation<br>There is a need to look at how IRCR and the annual capacity requirement are calculated (i.e. not just the peak intervals in summer) along with recognising behind-the-meter solar plus storage. The incentive should be for retailers (or third-party providers) to reduce their dependence on grid supply during peak intervals, which will also better reflect the requirement for conventional 'reserve capacity' and reduce the cost per kWh to consumers of that conventional 'reserve capacity'. | To be considered in the preliminary review of the Reserve Capacity Mechanism. |
| 2 | Shane Cremin<br>November 2017 | Allocation of market costs – who bears Market Fees and who pays for grid support services with less grid generation and consumption? | To be considered in the preliminary reviews of behind-the-meter issues and the basis for allocation of Market Fees. |
| 3 | Shane Cremin<br>November 2017 | Penalties for outages. | To be considered in the preliminary review of the Reserve Capacity Mechanism. |
| 4 | Shane Cremin<br>November 2017 | Incentives for maintaining appropriate generation mix. | To be considered in the preliminary review of the Reserve Capacity Mechanism. |
| 9 | Community Electricity<br>November 2017 | Improvement of AEMO forecasts of System Load; real-time and day-ahead | To be considered in the preliminary review of forecast quality. |

| Table 2 – Broader Issues | | | |
|---|---|---|---|
| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| 16 | Bluewaters<br>November 2017 | Behind the Meter (**BTM**) generation is treated as reduction in electricity demand rather than actual generation. Hence, the BTM generators are not paying their fair share of the network costs, Market Fees and ancillary services charges.<br>Therefore, the non-BTM Market Participants are subsiding the BTM generation in the WEM. Subsidy does not promote efficient economic outcome.<br>Rapid growth of BTM generation will only exacerbate this inefficiency if not promptly addressed.<br>Bluewaters recommends changes to the Market Rules to require BTM generators to pay their fair share of the network costs, Market Fees and ancillary services charges.<br>This is an example of a regulatory arrangement becoming obsolete due to the emergence of new technologies. Regulatory design needs to keep up with changes in the industry landscape (including technological change) to ensure that the WEM continues to meet its objectives.<br>If this BTM issue is not promptly addressed, there will be distortion in investment signals, which will lead to an inappropriate generation facility mix in the WEM, hence compromising power system security and in turn not promoting the Wholesale Market Objectives. | To be considered in the preliminary reviews of behind-the-meter issues and the basis for allocation of Market Fees. |
| 23 | Bluewaters<br>November 2017 | Allocation of Market Fees on a 50/50 basis between generators and retailers may be overly simplistic and not consider the impacts on economic efficiency.<br>In particular, the costs associated with an electricity market reform program should be recovered from entities based on the benefit they | To be considered in the preliminary review of the basis for allocation of Market Fees. |

| Table 2 – Broader Issues | | | |
|---|---|---|---|
| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| | | receive from the reform. This is expected to increase the visibility of (and therefore incentivise) prudence and accountability when it comes to deciding the need and scope of the reform.<br>Recommendations: to review the Market Fees structure including the cost recovery mechanism for a reform program.<br>The cost saving from improved economic efficiency can be passed on to the end consumers, hence promoting the Wholesale Market Objectives. | |
| 30 | Synergy<br>November 2017 | **Reserve Capacity Mechanism**<br>Synergy would like to propose a review of Market Rules related to reserve capacity requirements and reserve capacity capability criteria to ensure alignment and consistency in determination of certain criteria. For instance:<br>• assessment of reserve capacity requirement criteria, reserve capacity capability and reserve capacity obligations;<br>• IRCR assessment;<br>• Relevant Demand determination;<br>• determination of NTDL status;<br>• Relevant Level determination; and<br>• assessment of thermal generation capacity.<br>The review will support Wholesale Market Objectives (a) and (d). | To be considered in the preliminary review of the Reserve Capacity Mechanism. |

| Table 2 – Broader Issues | | | |
|---|---|---|---|
| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| 35 | ERM Power<br>November 2017 | **BTM generation and apportionment of Market Fees, ancillary services, etc.**<br>The amount of solar PV generation on the system is increasing every year, to the point where solar PV generation is the single biggest unit of generation on the SWIS. This category of generation has a significant impact on the system and we have seen this in terms of the daytime trough that is observed on the SWIS when the sun is shining. The issue is that generators that are on are moving around to meet the needs of this generation facility but this generation facility, which could impact system stability, does not pay its fair share of the costs of maintaining the system in a stable manner. That is, they are not the generators that receive its fair apportionment of Market Fees and pay any ancillary service costs but yet they have absolute freedom to generate into the SWIS when the fuel source is available. There needs to be equity in this equation. | To be considered in the preliminary reviews of behind-the-meter issues and the basis for allocation of Market Fees.<br>The MAC recognised that the Minister has commenced work on BTM issues and flagged that issue 35 should be considered as part of the Energy Transformation Strategy. |
| 39 | Alinta Energy<br>November 2017 | **Commissioning Test Process**<br>The commissioning process within the Market Rules and PSOP works well for known events (i.e. the advance timings of tests). However, the Market Rules and PSOP do not work for close to real time events. There is limited flexibility in the Market Rules and PSOP to deal with the practical and operational realities of commissioning facilities.<br>The Market Rules and PSOP require System Management to approve a Commissioning Test Plan or a revised Commissioning Test Plan by 8:00 AM on the Scheduling Day on which the Commissioning Test Plan would apply. | To be considered in the preliminary review of the Commissioning Tests. |

| Table 2 – Broader Issues | | | |
|---|---|---|---|
| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| | | If a Market Participant cannot conform to its most recently approved Commissioning Test Plan, the Market Participant must notify System Management; and either:<br>• withdraw the Commissioning Test Plan; or<br>• if the conditions relate to the ability of the generating Facility to conform to a Commissioning Test Schedule, provide a revised Commissioning Test Plan to System Management as soon as practicable before 8:00 AM on the Scheduling Day prior to the commencement of the Trading Day to which the revised Commissioning Test Plan relates.<br>**Specific Issues:**<br>This restriction to prior to 8:00 AM on the Scheduling Day means that managing changes to the day of the plan are difficult. Sometimes a participant is unaware at that time that it may not be able to conform to a plan. Amendments to Commissioning Tests and schedules need to be able to be dealt with closer to real time.<br>**Examples for improvements are:**<br>• allowing participants to manage delays to the start of an approved plan; and<br>• allowing participants to repeat tests and push the remainder of the Commissioning Test Plan out.<br>Greater certainty is needed for on the day changes (i.e. there is uncertainty as to what movements/timing changes acceptable within the “Test Window” i.e. on the day). | |

**Wholesale Market Objective Assessment:**

A review of the Commissioning Test process, with a view to allowing greater flexibility to allow for the technical realities of commissioning, will better achieve:

- Wholesale Market Objective (a):
  - Allowing generators greater flexibility in undertaking commissioning activities will allow the required tests to be conducted in a more efficient and timely manner, which should result in the earlier availability of approved generating facilities. This contributes to the efficient, safe and reliable production of energy in the SWIS.
  - Productive efficiency requires that demand be served by the least-cost sources of supply, and that there be incentives for producers to achieve least-cost supply through a better management of cost drivers. Allowing for a more efficient management of commissioning processes, timeframes and costs in turn promotes the economically efficient production and supply of electricity.
- Wholesale Market Objective (b): improvements to the efficiency of the Commissioning Test process may assist in the facilitation of efficient entry of new competitors.
- Wholesale Market Objective (d):
  - Balancing appropriate flexibility for generators with appropriate oversight and control for System Management should ensure that the complex task of commissioning is not subject to unnecessary red tape, adding to the cost of projects. This contributes to the achievement of Wholesale Market Objective (d) relating to the long-term cost of electricity supply.

| Table 2 – Broader Issues | | | |
|---|---|---|---|
| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| | | o Impacts on economic efficiency and efficient entry of new competitors (as outlined above) will potentially lead to the minimisation of the long-term cost of electricity supplied. | |

Notes:

- Some issues require further discussion/review before specific Rule Change Proposals can be developed. For these issues, the MAC will:
  - group the issues together where appropriate;
  - determine the order of priority for the grouped Broader Issues;
  - conduct preliminary reviews to scope out the Broader Issues; and
  - refer the Broader Issues to the appropriate body for consideration/development.
- RCP Support will aim to schedule preliminary reviews at the rate of one per MAC meeting, unless competing priorities prevent this.
- Broader Issues will be closed (or moved onto another sub-list) following the completion of the relevant preliminary review and any agreed follow-up discussions on the issue.
- The current list of preliminary reviews is shown in Table 3.

| Table 3 – Preliminary Reviews | |
|---|---|
| **Review** | **Status** |
| (1) Review of roles in the market | **Issues:** 11 and 12.<br>**Status:** Review deferred until Issues 11 and 12 are reopened following completion of the Energy Transformation Strategy. |
| (2) Behind-the-meter issues | **Issues:** 2, 16, 35.<br>**Status:** Preliminary discussion is not yet scheduled. |
| (3) Forecast quality | **Issues:** 9.<br>**Status:** Preliminary discussion is not yet scheduled. |
| (4) Commissioning Tests | **Issues:** 39.<br>**Status:** Preliminary discussion is not yet scheduled. However, on 22 May 2018 AEMO held a workshop on Commissioning Test issues in connection with its proposed changes to the Power System Operation Procedure: Commissioning and Testing. |
| (5) The basis of allocation of Market Fees | **Issues:** 2, 16, 23 and 35.<br>**Status:** Preliminary discussion is not yet scheduled. |
| (6) The Reserve Capacity Mechanism (excluding the pricing mechanism) | **Issues:** 1, 3, 4, and 30.<br>**Status:** Preliminary discussion is not yet scheduled. |

| Table 4 – Issues on Hold | | | |
|---|---|---|---|
| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| 7 | Community Electricity<br>November 2017 | Improved definition of the quantity of LFAS (a) required and (b) dispatched. | On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020), with potential input from work on RC_2017_02: Implementation of 30-Minute Balancing Gate Closure. |
| 10 | AEMO<br>November 2017 | Review of participant and facility classes to address current and looming issues, such as:<br>• incorporation of storage facilities;<br>• distinction between non-scheduled and semi-scheduled generating units;<br>• reconsideration of potential for Dispatchable Loads in the future (which were proposed for removal in RC_2014_06);<br>• whether to retain Interruptible Loads or to move to an aggregated facility approach (like Demand Side Programmes); and<br>• whether to retain Intermittent Loads as a registration construct or to convert to a settlement construct.<br>Would support new entry, competition and market efficiency; particularly supporting the achievement of Wholesale Market Objectives (a) and (b). | On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020).<br>Treatment of storage facilities was considered under the preliminary review of the treatment of storage facilities in the market. |
| 11 | AEMO<br>November 2017 | Whole-of-system planning oversight:<br>As explained in AEMO's submission to the ERA's review of the WEM, AEMO considers the necessity of the production of an annual, independent Integrated Grid Plan to identify emerging issues and opportunities for investment at different locations in the network to support power system security and reliability. This role would support | This issue was initially flagged for consideration as part of the preliminary review of roles in the market.<br>However, the Energy Transformation Implementation Unit has advised that the issue will be covered as part of the Energy |

| Table 4 – Issues on Hold | | | |
|---|---|---|---|
| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| | | AEMO's responsibility for the maintenance of power system security and will be increasingly important as network congestion increases and the characteristics of the power system evolve in the course of transition to a predominantly non-synchronous future grid with distributed energy resources, highlighting new requirements (e.g. planning for credible contingency events, inertia, and fast frequency response).<br>This function would support the achievement of power system security and reliability, in line with Wholesale Market Objective (a). | Transformation Strategy, so the issue has been put on hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020). |
| 12 | AEMO<br>November 2017 | Review of institutional responsibilities in the Market Rules.<br>Following the major changes to institutional arrangements made by the Electricity Market Review, a secondary review is required to ensure that tasks remain with the right organisations, e.g. responsibility for setting confidentiality status (clause 10.2.1), document retention (clause 10.1.1), updating the contents of the market surveillance data catalogue (clause 2.16.2), content of the market procedure under clause 4.5.14, order of precedence of market documents (clause 1.5.2). This will promote efficiency in market administration, supporting Wholesale Market Objectives (a) and (d). | Potential changes to responsibilities for setting document retention requirements and confidentiality statuses have been listed as Potential Rule Change Proposals (issues 45 and 46). Potential changes to clause 4.5.14 have also been listed as a Potential Rule Change Proposal (issue 47).<br>The PUO has advised that the remaining issues will be covered as part of the Energy Transformation Strategy, so the remaining issues have been put on hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020). |
| 14/36 | Bluewaters and ERM Power | Capacity Refund Arrangements:<br>The current capacity refund arrangement is overly punitive as Market Participants face excessive capacity refund exposure. This refund | On 29 May 2018, the MAC agreed to place this issue on hold for 12 months (until June 2019) to allow time for historical data on dynamic refund rates to accumulate. On 29 July 2019, the MAC |

| Table 4 – Issues on Hold | | | |
|---|---|---|---|
| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| | November 2017 | exposure is well more than what is necessary to incentivise the Market Participants to meet their obligations for making capacity available. Practical impacts of such excessive refund exposure include:<br>• compromising the business viability of some capacity providers - the resulting business interruption can compromise reliability and security of the power system in the SWIS; and<br>• excessive insurance premiums and cost for meeting prudential support requirements.<br>Bluewaters recommended imposing seasonal, monthly and/or daily caps on the capacity refund. Bluewaters considered that reviewing capacity refund arrangements and reducing the excessive refund exposure is likely to promote the Wholesale Market Objectives by minimising:<br>• unnecessary business interruption to capacity providers and in turn minimising disruption to supply availability; which is expected to promote power system reliability and security; and<br>• unnecessary excessive insurance premium and prudential support costs, the saving of which can be passed on to consumers. | agreed that this issue has a low priority and should remain on hold for another 12 months. |
| 15/34 | Bluewaters and ERM Power<br>November 2017 | An interpretation of clause 3.18.7 of the Market Rules is that System Management will not approve a Planned Outage for a generator unless it was available at the time the relevant Outage Plan was submitted. This gives rise to the following issues:<br>• Operational inefficiency for the generators – it is not uncommon for minor problems to be discovered during a Planned Outage and addressing these problems may require the Planned Outage period | The MAC discussed this issue at its meeting on 3 September 2019 and agreed to close the issue because it was addressed in RC_2013_15. |

| Table 4 – Issues on Hold | | | |
|---|---|---|---|
| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| | | to be marginally extended (by submitting an additional Outage Plan). However, System Management has taken an interpretation of clause 3.18.7 that it is not allowed to approve the Planned Outage period extension because the relevant generator was not available at the time the extension application was submitted. To meet this rules requirement, the generator will need to bring the unit online, apply for a Planned Outage while the unit is online, and subsequently take the unit off-line again only to address the minor problems. Such operational inefficiency could have been avoided if System Management can approve such Planned Outage extension (as long as there is sufficient reserve margin available in the power system during the extended Planned Outage period).<br>• Driving perverse incentives in the WEM and compromising market efficiency – to get around the issue discussed above, generators are likely to overestimate their Planned Outage period requirements in their outage applications. This results in higher than necessary projected plant unavailability, which does not promote accurate price signals for guiding trading decisions. This misinformation is expected to lead to an inefficient outcome which in turn does not promote the Wholesale Market Objectives.<br>Bluewaters recommendation: clarify in the Market Rules so that System Management can approve a Planned Outage extension application. | |
| 17 | Bluewaters<br>November 2017 | Under clause 3.21.7 of the Market Rules, a Market Participant is not allowed to retrospectively log a Forced Outage after the 15-day deadline; even if the Market Participant is subsequently found to be in breach of the Market Rules for not logging the Forced Outage on time. | On hold pending a final decision on RC_2014_03: Administrative Improvements to the Outage Process. |

| Table 4 – Issues on Hold | | | |
|---|---|---|---|
| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| | | This can result in under reporting of Forced Outages, and as a consequence, use of incorrect information used in WEM settlements.<br>Bluewaters recommend a rule change to enable Market Participants to retrospectively log a Forced Outage after the 15-day deadline. If a Market Participant is found to be in breach of the Market Rules by not logging the Forced Outage by the deadline, it should be required to log the outage.<br>Accurately reporting outages will enable the WEM to function as intended and will help meet the Wholesale Market Objectives. | |
| 18 | Bluewaters<br>November 2017 | The Spinning Reserve procurement process does not allow Market Participants to respond to the draft margin values determination by altering its Spinning Reserve offer.<br>Bluewaters recommended amending the Market Rules to allow Market Participants to respond to the draft margin values determination by altering its Spinning Reserve offer.<br>Allowing a Market Participant to respond to the draft margin values determination, can serve as a price signal to enable a price discovery process for Spinning Reserve capacity. This is expected to lead to a more efficient economic outcome and in turn promote the Wholesale Market Objectives. | On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020). |
| 19 | Bluewaters<br>November 2017 | The Spinning Reserve margin values evaluation process is deficient for the following reasons:<br>• shortcomings in the process for reviewing assumptions;<br>• inability to shape load profile; | On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020). |

| Table 4 – Issues on Hold | | | |
|---|---|---|---|
| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| | | • lack of transparency:<br>(a) modelling was a "black box";<br>(b) confidential information limits stakeholders' ability to query the results; and<br>• lack to retrospective evaluation of spinning reserve margin values.<br>As a result, the margin values have been volatile, potentially inaccurate and not verifiable.<br>Recommendation: conduct a review on the margin values evaluation process and propose rule changes to address any identified deficiencies.<br>Addressing the deficiencies in the margin values evaluation process can promote the Wholesale Market Objectives by enhancing economic efficiency in the WEM. This can be achieved through:<br>• promoting transparency – better informed Market Participants would be able to better respond to Spinning Reserve requirement in the WEM; and<br>• allowing a better-informed margin values determination process, which is likely to give a more accurately priced margin values to promote an efficient economic outcome. | Also, AEMO and the ERA to consider whether any options exist to improve transparency of the current margin values process. |
| 22 | Bluewaters<br>November 2017 | Prudential arrangement design issue: clause 2.37.2 of the Market Rules enables AEMO to review and revise a Market Participant's Credit Limit at any time. It is expected that AEMO will review and increase Credit Limit of a Market Participant if AEMO considers its credit exposure has increased (for example, due to an extended plant outage event). | On hold pending AEMO's proposed review of its process for Credit Limit determination. |

| Table 4 – Issues on Hold | | | |
|---|---|---|---|
| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| | | In response to the increase in its credit exposure, clause 2.40.1 of the Market Rules and section 5.2 of the Prudential Procedure allow the Market Participant to make a voluntary prepayment to reduce its Outstanding Amount to a level below its Trading Limit (87% of the Credit Limit).<br>Under the current Market Rules and Prudential Procedure, AEMO can increase the Market Participant's Credit Limit (hence increasing its prudential support requirement) despite that a prepayment has already been paid (it is understood that this is AEMO's current practice).<br>The prepayment would have already served as an effective means to reduce the Market Participant's credit exposure to an acceptable level. Increasing the Credit Limit in addition to this prepayment would be an unnecessary duplication of prudential requirement in the WEM.<br>This unnecessary duplication is likely to give rise to higher-than-necessary prudential cost burden in the WEM; which creates economic inefficiency that is ultimately passed on the end consumers.<br>Recommendation: amend the Market Rules and/or procedures to eliminate the duplication of prudential burden on Market Participants.<br>The resulting saving from eliminating this unnecessary prudential burden can be passed on to end consumers. This promotes economic efficiency and therefore the Wholesale Market Objectives. | |
| 27/54 | Kleenheat<br>November 2017 | Review what should constitute a Protected Provision of the Market Rules, to provide greater clarity over the role of the Minister for Energy.<br>A review of the Protected Provisions in the Market Rules is required to identify any that they no longer need to be Protected Provisions. This is | On hold pending the outcome of a PUO review of the current Protected Provisions in the Market Rules, with timing dependent on Energy Transformation Strategy. |

| Table 4 – Issues on Hold | | | |
|---|---|---|---|
| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| | MAC<br>August 2018 | because shifting the rule change function to the Panel has removed some of the potential conflicts of interest that led to the original classification of some Protected Provisions. | |
| 28 | Kleenheat<br>November 2017 | Appropriate rule changes to allow for battery storage. Consultation to decide how the batteries will be treated and classified as generators or not, whether batteries can apply for Capacity Credits and the availability status when the batteries are charging. | On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020). |
| 33 | ERM Power<br>November 2017 | **Logging of Forced Outages**<br>The market systems do not currently allow Forced Outages to be amended once entered. This can have the distortionary effect of participants not logging an Outage until it has absolute certainty that the Forced Outage is correct, hence participants could take up to 15 days to submit its Forced Outages.<br>If a participant could cancel or amend its Forced Outage information, it will likely provide more accurate and transparent signals to the market of what capacity is really available to the system. This should also assist System Management in generation planning for the system. | On hold pending a final decision on RC_2014_03: Administrative Improvements to the Outage Process. |
| 42 | ERA<br>November 2017 | **Ancillary Services approvals process**<br>Clause 3.11.6 of the Market Rules requires System Management to submit the Ancillary Services Requirements in a report to the ERA for audit and approval by 1 June each year, and System Management must publish the report by 1 July each year. The ERA conducted this process for the first time in 2016/17. In carrying out the process it became apparent that: | On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020). |

| Table 4 – Issues on Hold | | | |
|---|---|---|---|
| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| | | • there is no guidance in the rules on what the ERA's audit should cover, or what factors the ERA should consider in making its determination on the requirements;<br>• there are no documented Market Procedures setting out the methodology for System Management to determine the ancillary service requirements (the preferable approach would be for the methodologies to be documented in a Market Procedure, and for the ERA to audit whether System Management has followed the procedure);<br>• the timeframe for the ERA's audit and approval process (less than 1 month) limits the scope of what it can achieve in its audit;<br>• the levels determined by System Management are a function of the Ancillary Service standards, but the standards themselves are not subject to approval in this process; and<br>• the value of the audit and approval process is limited because System Management has discretion in real time to vary the levels from the set requirements.<br>The question is whether the market thinks this approvals process is necessary/will continue to be necessary (particularly in light of co-optimised energy and ancillary services). If so, then the issues above will need to be addressed, to reduce administrative inefficiencies and, if more rigour is added to the process, provide economic benefits (Wholesale Market Objectives (a) and (d)). | |

| Table 4 – Issues on Hold | | | |
|---|---|---|---|
| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| 49 | MAC<br>November 2018 | Should the method used to calculate constrained off compensation be amended to better reflect the actual costs incurred by Market Generators? | The MAC agreed to include this issue in the Issues List and place it on hold until a decision is made on RC_2018_07, and if the Rule Change Proposal is approved, the changes have been in place for 12 months. |
| 50 | MAC<br>November 2018 | Should the Minimum STEM Price (currently -$1,000/MWh) be increased to reduce the potential magnitude of constrained off compensation (e.g. by restoring the former practice of setting the Minimum STEM Price to the Maximum STEM Price multiplied by -1): | The MAC agreed to include this issue in the Issues List and place it on hold pending the outcomes of the ERA's next review of the methodology for setting the Energy Price Limits under clause 2.26.3 of the Market Rules. |
| 51 | MAC<br>November 2018 | There is a need to provide Market Customers with timely advance notice of their upcoming constraint payment liabilities. | The MAC agreed to place this issue on hold pending implementation of AEMO's proposed changes to the Outstanding Amount calculation in 2019. |
| 53 | MAC<br>August 2018 | MAC members have identified the following issues with the provisions relating to generator models that were Gazetted by the Minister on 30 June 2017 in the *Wholesale Electricity Market Rules Amending Rules 2017 (No. 3)*:<br>• The provisions allow for System Management, where it deems that the performance of a Generator does not conform to its models, to request updated models from Western Power and constrain the output of the Generator until these were provided, placing the Generator on a new type of Forced Outage and making it liable for Capacity Cost Refunds. | On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020). |

| Table 4 – Issues on Hold | | | |
|---|---|---|---|
| **Id** | **Submitter/Date** | **Issue** | **Urgency and Status** |
| | | • Western Power is only required to comply with a request from System Management for updated models "as soon as reasonably practicable", leaving a Market Generator potentially subject to a Forced Outage for an extended period with no control over the situation.<br>• The generator model information is assigned a confidentiality status of System Management Confidential, so that System Management is not permitted under the Market Rules to tell the Network Operator what model information it needs or explain the details of its concerns to the Market Generator. | |

Notes:

- These are issues that the MAC will consider following some identified event. Issues on Hold will be reviewed by the MAC once the identified event has occurred, and then closed or moved to another sub-list.

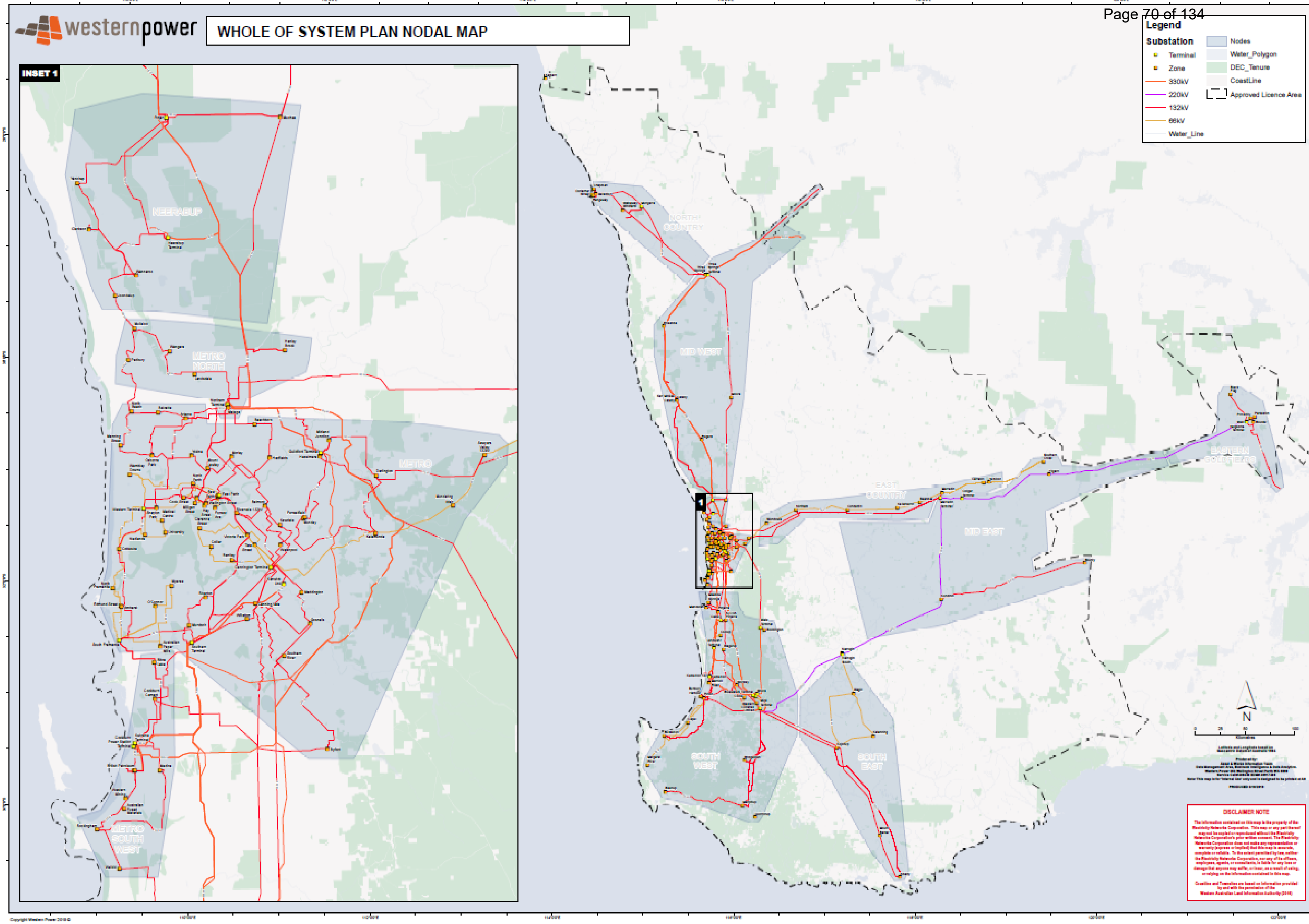
GOVERNMENT OF WESTERN AUSTRALIA
Energy Transformation Implementation Unit

Agenda Item 6(b)

# Whole of System Plan

## Modelling Methodology, Inputs and Assumptions

15 October 2019


westernpower
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Terminal
Zone
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66kV
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Nodes
Water_Polygon
DEC_Tenure
CoastLine
Approved Licence Area
NEERABUP
METRO NORTH
METRO
METRO SOUTH WEST
NORTH COUNTRY
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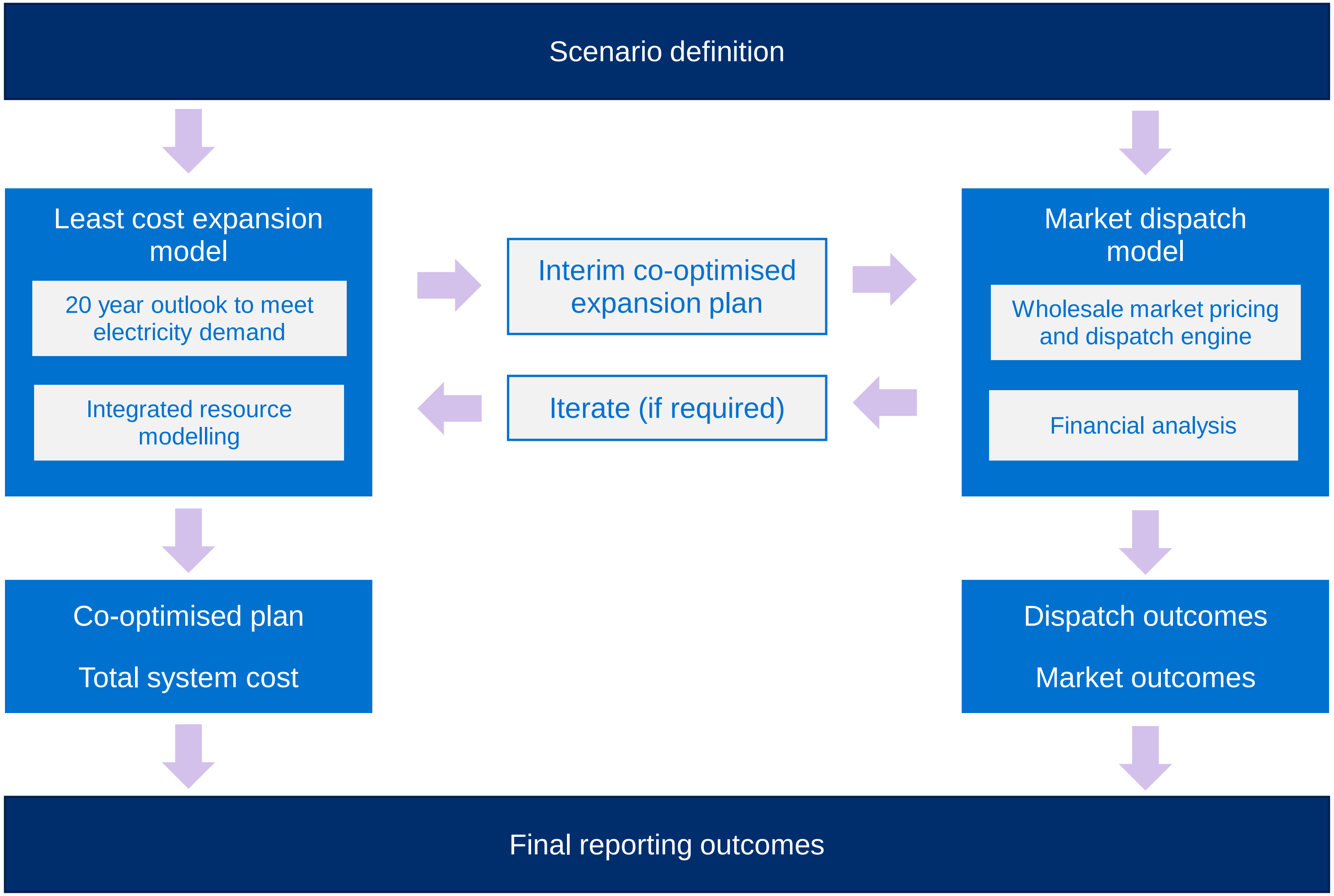
DISCLAIMER NOTE

# Modelling overview



# Inputs and assumptions

**Customer demand**
Scenarios have been broken down into half-hourly demand profiles on a customer segment basis in each of the 11 nodes over 20 years

**Network augmentation**
Western Power are estimating network transfer limits between the nodes and providing approximate costs for network augmentation options

**Generator costs**
Cost assumptions of both existing and potential new facilities have been collated in collaboration with a wide range of industry participants

**Essential system services**
System constraints are assessed in the modelling and examine frequency regulation (load following) and frequency contingency reserves (spinning reserve and load rejection reserve)

# Next steps

**Update Energy Transformation Taskforce on modelling methodology, inputs and assumptions**

18 October 2019

**Publish high-level modelling methodology, inputs and assumptions information paper**

October/November 2019

**Conduct least cost expansion modelling**

October 2019 – January 2020

**Provide modelling update to the Market Advisory Committee**

Early 2020

# Thank you

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# MARKET ADVISORY COMMITTEE MEETING, 15 OCTOBER 2019

FOR NOTING

SUBJECT: UPDATE ON AEMO'S MARKET PROCEDURES

AGENDA ITEM: 7

## 1. PURPOSE

Provide a status update on the activities of the AEMO Procedure Change Working Group and AEMO Procedure Change Proposals.

## 2. AEMO PROCEDURE CHANGE WORKING GROUP (APCWG)

| | **Most recent meeting** | **Next meeting** |
|---|---|---|
| Date | 8 Aug 2019 | 21 Oct 2019 |
| Market Procedures for discussion | Procedures related to RC_2015_03 (Formalisation of the Process for Maintenance Applications):<br>• Market Procedure: Individual Reserve Capacity Requirements<br>• Market Procedure: Consumption Deviation Applications | Market Procedure: Prudential Requirements |

## 3. AEMO PROCEDURE CHANGE PROPOSALS

The status of AEMO Procedure Change Proposals is described below, current as at 7 October 2019. Changes since the previous MAC meeting are in red text. A procedure change is removed from this report after its commencement has been reported or a decision has been taken not to proceed with a potential Procedure Change Proposal.

| ID | Summary of changes | Status | Next steps | Date |
|---|---|---|---|---|
| AEPC_2019_09:<br>Market Procedure: Individual Reserve Capacity Requirements<br>Market Procedure: Consumption Deviation Applications | The proposed amendments predominantly arise from Rule Change RC_2015_03 (Formalisation of the Process for Maintenance Applications) | No submissions received.<br>Procedure Change Report published 30 Sep 2019. Procedure commenced. | - | 1 Oct 2019 |

RCP Rule Change Panel
Market Advisory Committee

# Agenda Item 8(a): Overview of Rule Change Proposals (as at 8 October 2019)

Meeting 2019_10_15

- Changes to the report provided at the previous MAC meeting are shown in red font.
- The next steps and the timing for the next steps are provided for Rule Change Proposals that are currently being actively progressed by the Rule Change Panel or the Minister.

## Rule Change Proposals Commenced since Report presented at the last MAC Meeting

| Reference | Submitted | Proponent | Title | Commenced |
|---|---|---|---|---|
| RC_2015_03 | 27/03/2015 | IMO | Formalisation of the Process for Maintenance Applications | 01/10/2019 |
| RC_2018_06 | 26/11/2018 | PUO | Full Runway Allocation of Spinning Reserve Costs | 01/09/2019 |

## Approved Rule Change Proposals Awaiting Commencement

| Reference | Submitted | Proponent | Title | Commencement |
|---|---|---|---|---|
| RC_2013_15 | 24/12/2013 | IMO | Outage Planning Phase 2 – Outage Process Refinements | 01/02/2020 |

## Rule Change Proposals Rejected since Report presented at the last MAC Meeting

| Reference | Submitted | Proponent | Title | Rejected |
|---|---|---|---|---|
| None | | | | |

## Rule Change Proposals Awaiting Approval by the Minister

| Reference | Submitted | Proponent | Title | Approval Due Date |
|---|---|---|---|---|
| RC_2018_05 | 27/09/2018 | ERA | ERA access to market information and SRMC investigation process | 21/10/2019 |

## Formally Submitted Rule Change Proposals

| Reference | Submitted | Proponent | Title | Urgency | Next Step | Date |
|---|---|---|---|---|---|---|
| **Fast Track Rule Change Proposals with Consultation Period Closed** | | | | | | |
| None | | | | | | |
| **Fast Track Rule Change Proposals with Consultation Period Open** | | | | | | |
| None | | | | | | |
| **Standard Rule Change Proposals with Second Submission Period Closed** | | | | | | |
| None | | | | | | |
| **Standard Rule Change Proposals with Second Submission Period Open** | | | | | | |
| None | | | | | | |
| **Standard Rule Change Proposals with First Submission Period Closed** | | | | | | |
| RC_2014_03 | 27/11/2014 | IMO | Administrative Improvements to the Outage Process | High | MAC Workshop | 24/10/2019 |
| RC_2014_05 | 02/12/2014 | IMO | Reduced Frequency of the Review of the Energy Price Limits and the Maximum Reserve Capacity Price | Medium | Publication of Draft Rule Change Report | 31/12/2019 |
| RC_2014_09 | 13/03/2015 | IMO | Managing Market Information | Low | Publication of Draft Rule Change Report | 31/10/2019 |

| Reference | Submitted | Proponent | Title | Urgency | Next Step | Date |
|---|---|---|---|---|---|---|
| RC_2017_02 | 04/04/2017 | Perth Energy | Implementation of 30-Minute Balancing Gate Closure | Medium | Second MAC Workshop | 18/10/2019 |
| RC_2018_03 | 01/03/2018 | Collgar Wind Farm | Capacity Credit Allocation Methodology for Intermittent Generators | Medium | Publication of Draft Rule Change Report | 31/12/2019 |
| RC_2019_01 | 21/06/2019 | Enel X | The Relevant Demand calculation | Medium | Publication of Draft Rule Change Report | 30/06/2020 |
| **Standard Rule Change Proposals with the First Submission Period Open** | | | | | | |
| None | | | | | | |

## Pre-Rule Change Proposals

| Reference | Proponent | Description | Next Step | Submitted |
|---|---|---|---|---|
| RC_2019_03 | ERA | Method used for the assignment of Certified Reserve Capacity to Intermittent Generators | Submit Rule Change Proposal | TBD |
| RC_2019_04 | AEMO | Administrative Improvements to Settlement | Submit Rule Change Proposal | TBD |
| TBD | Perth Energy | Issues with Reserve Capacity Testing | Submit Pre-Rule Change Proposal | TBD |
| TBD | AEMO | North Country Spinning Reserve | Submit Pre-Rule Change Proposal | TBD |

Agenda Item 8(b)

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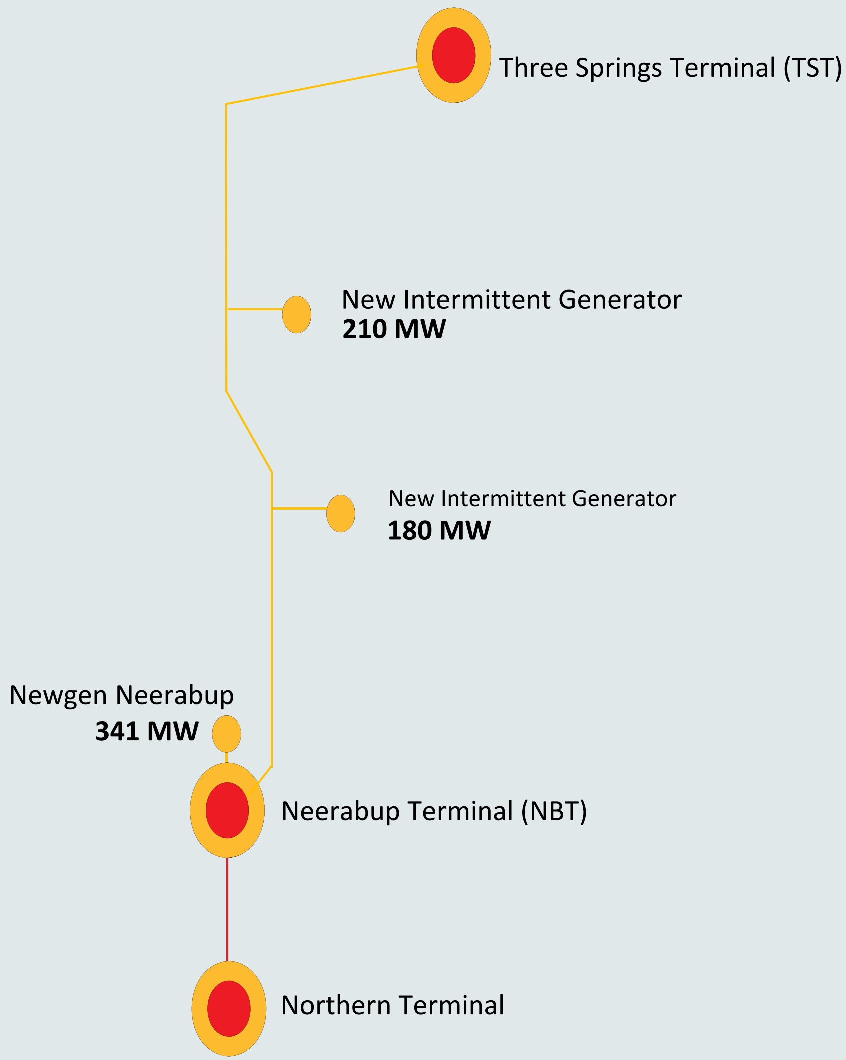
# MAC Meeting discussion on option 3 (to resolve the largest generation contingency; action item 10/2019)

15 October 2019
Feedback on action 10/2019

# Review: Scenario

- Connection of two new intermittent generators on the single 330 kV line between Neerabup Terminal (NBT) and Three Springs Terminal (TST) in first half of 2020
- A network fault on NT-NBT-TST 330 kV line will trip both generators
  - This will become the largest SWIS generation contingency
  - Will occur when the combined output of both generators is in excess of the output of the largest single generator
- In certain outage conditions, a network fault between Northern Terminal and NBT will also trip Newgen Neerabup
  - Up to 730 MW generation could be lost
- Network Operator will reduce the maximum size of the contingency to ensure that under-frequency load-shedding is not triggered given sufficient Spinning Reserve



# Implications on current WEM design from NT-NBT-TST 330 kV contingency

- Power system security can be maintained
  - AEMO is investigating operationalising this
  - Options include obtaining additional Spinning Reserve
  - Constraining the size of the contingency to avoid a high risk state (not to avoid cost)
- Market implications
  - Likely increase in SR requirements and hence higher cost
  - Full runway methodology doesn't account for a Transmission constraint being the largest contingency
  - Potential additional constrained off costs that will be paid to the generators contributing to the SR contingency (causer paid)
  - Reduction in Balancing Price due to low-cost generation

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# Options discussed (MAC meeting 3 Sept 2019)

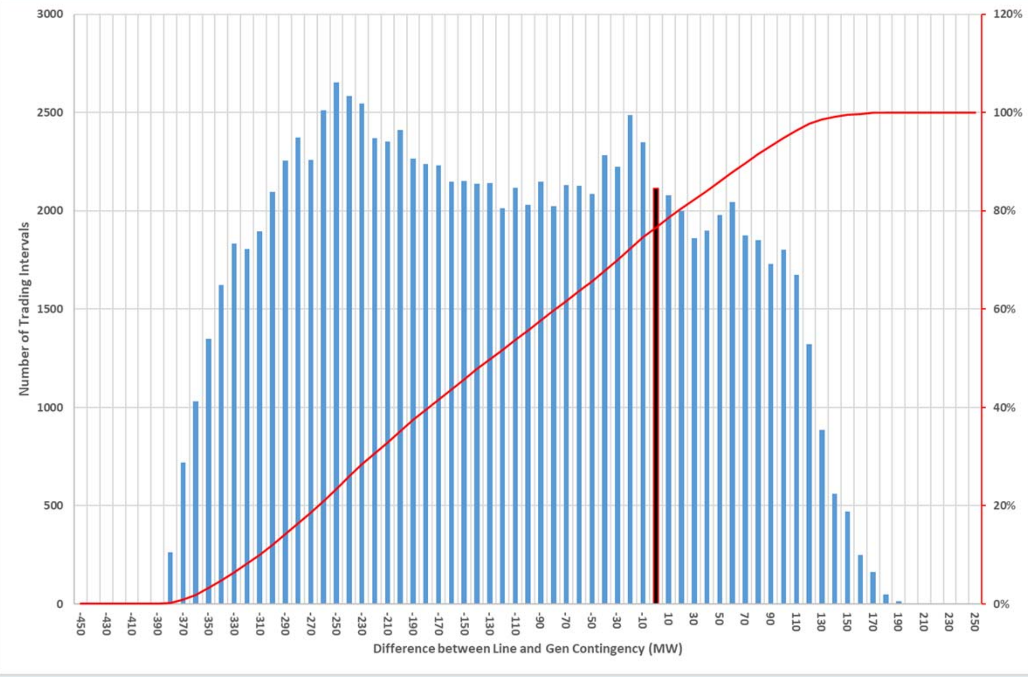
| Option | Pros | Cons |
|---|---|---|
| 1. Manage within existing framework (adjust SR to a level required considering the largest contingency or constrain down to avoid HR state) | As per current Rules<br>Less work is required<br>No process or system changes<br>Likely to be addressed by reform | Market issues not addressed.<br>The extra cost (at least 2 years) is pushed to the market players who didn't have any role in this issue and can't change the situation. |
| 2a. Amend full runway methodology to take account of transmission contingencies | The cost is pushed to the parties who created the demand for extra Spinning Reserve (Causer Pay) | Extra work is required in putting together a Rule Change.<br>System changes are required to capture these situation and settle the market accordingly<br>Not all market inefficiencies are resolved without 2b. |
| 2b. Remove constrained off payments for these generators when constrained due to impact on Spinning Reserve | Causers are not paid | Extra work required to put together a Rule Change.<br>Not all market inefficiencies are resolved if done without 2a. |
| 3. Amend AEMO powers to constrain generators to prevent a transmission contingency exceeding the size of the largest single generator | Costs will not be shifted to other players.<br>Spinning reserve costs not increased. | Market inefficiencies.<br>The cost of energy will go up as these are low cost generators<br>Constrained Off payment may apply |

# MAC request and implications

- The MAC requested AEMO prepare a Rule Change based on option 3
  - Preclude further Spinning Reserve costs by curtailing generators that form part of NT-NBT-TST 330 kV when this contingency exceeds the generator with the largest output
    - Note the largest generator overnight is 180 MW
- However, even assuming no constrained-off payments, option 3 has several implications:
  - Extent of curtailment of new low-cost Non-Scheduled Generators (NSG)
    - And consequential constrained-on generation
  - WEM Rules require AEMO to curtail using BMO
    - Impacts which NSG is curtailed
    - Will prevent Newgen Neerabup from operating when part of the contingency
      - Capacity Credit implications
  - Power System Security conflict where extra generation is required

# Extent of curtailment

- Many possible scenarios, however:
  - NT-NBT-TST 330 kV will be the largest contingency for 20-40% of the time
  - NT-NBT-TST 330 kV will exceed the largest generator by more than 100 MW for 3-30% of the time
  - Does not consider Newgen Neerabup
- In the graphed scenario, NT-NBT-TST 330 kV exceeds the largest generator contingency for 23% of the time, with the exceedance being greater than 100 MW for 5% of the time
- Therefore, significant amounts of low-cost generation would be curtailed
  - Increases Balancing Price
- In addition, often will require other generation to be constrained-on
  - Increases market costs even if no constrained-off payments



# BMO curtailment requirements

- WEM Rule 7.6.1C requires AEMO to dispatch in accordance with the BMO
- BMO order determined by WEM Rule 7A.3.2:
  - Loss-factor adjust all prices except the Balancing Portfolio
  - Sort lowest to highest by loss-factor adjusted price
  - Where there is a tie, rank by a random number assigned to each Facility each day
- Therefore:
  - If both NSGs offer at the Minimum STEM Price, then the NSG with the higher loss-factor will always be curtailed to zero first
  - Newgen Neerabup likely to be constrained whenever they are part of the contingency
    - Based on BMO, would need to curtailed to minimum generation before the first NSG constrained
    - This may have Capacity Credit implications

# Power System Security conflict where extra generation is required

- When increasing generation, AEMO must determine whether the next generator in the BMO will increase the NT-NBT-TST 330 kV contingency
  - If so, skip that generator
- Increases complexity of manual dispatch
- Requires changes to the RTDE

# Conclusion on option 3

- Implications of option 3
  - Will result in increased market costs even if constrained-off payments do not apply
    - Higher Balancing Price than otherwise
    - Significant constrained-on costs
  - This may exceed costs of further Spinning Reserve under option 1 or option 2
  - Lengthy implementation timeframe as requires changes to RTDE
  - Increased complexity of manual dispatch
  - Penalises Newgen Neerabup and the NSG with the worse loss-factor in all cases
- Propose further consideration of option 2a/2b
  - Amend full runway methodology to take account of transmission contingencies
    - Requires AEMO to identify which Facilities form part of the largest contingency
    - Requires changes to settlement system
  - Remove constrained off payments for these generators when constrained due to impact on Spinning Reserve
    - Extend Rules introduced in RC_2018_07 to include this circumstance
    - Note this may also result in constrained-on requirements – however not expected to be frequent

# Option 2a - Settlement

- Amend methodology introduced by RC_2018_06 by calculating SR cost allocation by contingency, rather than by facility. This includes changes to the prudential monitoring system.
- Each facility within a contingency will be allocated in proportion to its applicable capacity relative to other facilities within the same contingency
- This approach will require AEMO to define and manage which facilities make up the contingencies within the network.
- Intermittent generators will be apportioned cost based on their actual generation for the interval rather than their average (as per current rules) over the month.
- Based on RC_2018_06 and RoPe:
  - Implementation costs estimated between $350-$500k
  - Require approximately 5-7 months to implement

# Option 2a – Example

| | | Output (MW) | | Facility SR Share (FSRS) | | | |
|---|---|---|---|---|---|---|---|
| | | | | By Facility (current) | By Contingency (proposed) | | Delta |
| Contingency | Facility | By Facility | By Contingency | | Contingency | Facility | |
| C1 | A | 101 | 451 | 1.47% | 24.52% | 5.49% | 4.02% |
| | B | 150 | | 2.60% | | 8.15% | 5.55% |
| | C | 200 | | 4.40% | | 10.87% | 6.48% |
| C2 | D | 220 | 430 | 5.63% | 19.86% | 10.16% | 4.54% |
| | E | 210 | | 4.90% | | 9.70% | 4.80% |
| C3 | F | 400 | 400 | 40.63% | 16.54% | 16.54% | -24.09% |
| C4 | G | 300 | 300 | 15.63% | 9.15% | 9.15% | -6.48% |
| C5 | H | 85 | 270 | 1.18% | 7.48% | 2.36% | 1.17% |
| | I | 60 | | 0.80% | | 1.66% | 0.87% |
| | J | 125 | | 1.96% | | 3.46% | 1.50% |
| C6 | K | 215 | 215 | 5.21% | 5.04% | 5.04% | -0.17% |
| C7 | L | 195 | 195 | 4.19% | 4.30% | 4.30% | 0.12% |
| C8 | M | 155 | 155 | 2.76% | 3.04% | 3.04% | 0.28% |
| C9 | N | 145 | 145 | 2.46% | 2.76% | 2.76% | 0.30% |
| C10 | O | 120 | 120 | 1.85% | 2.14% | 2.14% | 0.29% |
| C11 | P | 110 | 110 | 1.64% | 1.92% | 1.92% | 0.28% |
| C12 | Q | 80 | 80 | 1.10% | 1.32% | 1.32% | 0.22% |
| C13 | R | 70 | 70 | 0.94% | 1.13% | 1.13% | 0.19% |
| C14 | S | 50 | 50 | 0.66% | 0.79% | 0.79% | 0.13% |

# Option 2b – Overview

- Propose to utilise the Operating Instruction mechanism to remove constrained off payments, as recently used in RC_2018_07.
- AEMO to issue retrospective Operating Instructions to Facilities that have been constrained to reduce the size of the contingency.
- Operating Instruction will set the Facility's out of merit quantity to zero (which sets the constraint payment to zero) in accordance with Section 6.16A of the WEM Rules.
- Based on RC_2018_07:
  - Implementation costs estimated between $50-$70k
  - Require approximately 1.5 months to implement

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# Conclusion on Option 2a & 2b

- No increase in constrained off payments
- Enables AEMO to manage network constraint being the largest contingency
- Extension of the current full runway cost allocation methodology to account for multiple facilities contributing to single constraint
- Remove constraint payments from generators who are causing the largest contingency

RCP | Rule Change Panel
Market Advisory Committee

# Agenda Item 8(c): RC_2019_04: Administrative Improvements to Settlement

Meeting 2019_10_15

## 1. Background

At the 20 November 2018 meeting of the Market Advisory Committee (**MAC**), AEMO consulted with the MAC about the development of Rule Change Proposal to correct several issues AEMO had identified with the non-STEM settlement adjustment process.[1] The MAC agreed that AEMO should develop a Pre-Rule Change Proposal to address the issues raised by AEMO in its presentation.

AEMO's Pre-Rule Change Proposal: Administrative Improvements to Settlement (RC_2019_04) is attached for the MAC's review and feedback.

In RC_2019_04, AEMO proposes changes to:

- allow AEMO to use updated input data for settlement, including data produced by AEMO and Theoretical Energy Schedule (**TES**) values;
- provide more time for Rule Participants to lodge a Notice of Disagreement in relation to a Non-STEM Settlement Statement and subsequent adjusted Settlement Statements;
- include Ancillary Service Providers (who are not Market Participants) in the settlement process; and
- remove unnecessary operational and procedural administration detail from the Market Rules.

## 2. Urgency Rating

The MAC is to recommend an urgency rating for this Rule Change Proposal. The urgency ratings from the Framework for Rule Change Proposal Prioritisation and Scheduling are presented below:

| Urgency | Description | Resourcing Implications |
|---|---|---|
| **1** | **Essential:** e.g. legal necessity, unacceptable market outcomes or a serious threat to power system security and reliability. | Do not delay – acquire additional resources, request increase to the ERA budget from Treasury if necessary |
| **2** | **High:** Compelling proposal, and either large net benefit or else necessary to avoid serious perverse market outcomes. | Do not delay – acquire additional resources if available subject to overall ERA budget limitations |

[1] This consultation was consistent with AEMO's obligations under clause 2.5.1A of the Market Rules.

| Urgency | Description | Resourcing Implications |
|---|---|---|
| 3 | **Medium:** Net benefit either:<br>• may be large but needs more analysis to determine; or<br>• material but not large enough to warrant a High rating. | May delay up to 3 months if budgeted resources unavailable |
| 4 | **Low:** Minor net benefit (e.g. reduced administration costs). | May delay up to 6 months if budgeted resources unavailable |
| 5 | **Housekeeping:** Negligible market benefit, e.g. just improves the readability of the Market/GSI Rules | May delay up to 12 months if budgeted resources unavailable |

## 3. Recommendation

That the MAC:

1. provides feedback to AEMO regarding Pre-Rule Change Proposal RC_2019_04;
2. discusses AEMO's proposed changes relating to the calculation and use of TES values and whether any further changes (such as the recalculation of TES values using interval meter readings) are warranted; and
3. recommends an urgency rating for RC_2019_04 (AEMO has recommended a High urgency rating in the Pre-Rule Change Proposal).

## Attachments

1. RC_2019_04 – Pre-Rule Change Proposal

RCP | Rule Change Panel

# Wholesale Electricity Market [PRE] 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:**

| | |
|---|---|
| **Name:** | [TBC] |
| **Phone:** | [TBC] |
| **Email:** | [TBC] |
| **Organisation:** | Australian Energy Market Operator (AEMO) |
| **Address:** | Level 45, 152 St Georges Terrace, Perth WA |
| **Date submitted:** | [TBC] |
| **Urgency:** | High |
| **Rule Change Proposal title:** | Administrative Improvements to Settlement |
| **Market Rule(s) affected:** | Clauses 6.15.4, 9.2.1, 9.16.2, 9.16.3, 9.16.3A, 9.16.4, 9.18.1, 9.18.2, 9.18.3, 9.18.4, 9.19.1, 9.19.3, 9.19.5, 9.19.6, 9.19.7, 9.20.3, 9.20.4, 9.20.5, 9.20.7, 9.20.7A (new), 9.20.7B (new), 9.20.8 9.21.1 and 9.22.2. |

## 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:**

**Overview of proposed amendments**

This Rule Change Proposal addresses a number of administrative matters related to the settlement of the Wholesale Electricity Market (WEM). The amendments proposed by AEMO will result in more accurate market settlements, reducing the potential for windfall gains and losses. AEMO considers the proposed Amending Rules will therefore improve the efficiency and effectiveness of the market and therefore better meet Wholesale Market Objective (a).

AEMO proposes to amend:

- clauses 6.15.4, 9.16.3, 9.16.3A and 9.19.1 of the WEM Rules to allow AEMO to use updated input data for settlement, including data produced by AEMO and TES values;
- clauses 9.16.2, 9.16.4, 9.19.5, 9.19.6, 9.19.7, 9.20.7A (new), 9.20.7B (new) and 9.20.7 of the WEM Rules to provide more time for Rule Participants to lodge a Notice of Disagreement in relation to a Non-STEM Settlement Statement and subsequent adjusted Settlement Statements;
- clauses 9.16.2, 9.18.1, 9.18.2, 9.18.3, 9.18.4, 9.19.3, 9.20.7, 9.21.1 and 9.22.2 of the WEM Rules to correct an oversight, to include Ancillary Service Providers who may not be Market Participants, in the settlement process; and
- clauses 9.2.1, 9.20.3, 9.20.4 and 9.20.5 of the WEM Rules to remove unnecessary operational and procedural administration detail from the WEM Rules.

AEMO has also taken the opportunity to propose a number of administrative changes to the clauses it proposes to amend to improve the integrity of the WEM Rules.

Each of these proposed changes are discussed in the following sections.

**Allowing updated input data for settlement**

AEMO proposes to amend clauses 6.15.4, 9.16.3, 9.16.3A and 9.19.1 of the WEM Rules to allow it to adjust Settlement Statements to account for updated, more accurate input data where it becomes available.

The settlement process in the WEM includes the ability for AEMO to make adjustments to Settlement Statements to reflect updated, more accurate input data where it becomes available. Clause 9.16.3 of the WEM Rules states:

*9.16.3. AEMO must undertake a process for adjusting settlements ("**Adjustment Process**") in accordance with clause 9.19. The purpose of the process is to review the Relevant Settlement Statements which were issued in the nine months prior to the commencement of the Adjustment Process ("**Relevant Settlement Statements**") to facilitate corrections, as applicable, resulting from:*

*(a) Notices of Disagreement;*

*(b) the resolution of disputes;*

*(c) revised metering data provided by Metering Data Agents;*

*(d) any revised Market Fee rate, System Management Fee rate or Regulator Fee rate (as applicable);*

*(e) any determinations made in accordance with clauses 6.16A.1(b)(i), 6.16A.2(b)(i), 6.16B.1(b)(i) or 6.16B.2(b)(i); and*

*(f) any adjustment required for GST purposes under clause 9.1.2.*

*Adjustments may only be made to Relevant Settlement Statements. Adjustments may not be made to Settlement Statements outside of an Adjustment Process.*

In the 2018/19 Financial Year AEMO transacted approximately $4.7M in relation to settlement adjustments to ensure the correct market outcomes are achieved. The majority of these adjustments relate to updated metering data.

Clause 9.19.1 of the WEM Rules specifies each type of information AEMO may take into account in the Adjustment Process:

*9.19.1. When undertaking an Adjustment Process AEMO must:*

*(a) recalculate the amounts included in the Relevant Settlement Statements in accordance with this Chapter but taking into account any:*

*i. revised metering data which has been provided by Metering Data Agents;*

*iA. adjustment to Non-Balancing Dispatch Instruction Payments under clause 9.19.1A;*

*ii. actions arising from a Notice of Disagreement;*

*iii. the resolution of any Dispute;*

*iv. determinations made in accordance with clauses 6.16A.1(b)(i), 6.16A.2(b)(i), 6.16B.1(b)(i) or 6.16B.2(b)(i);*

> *v.* *revised Market Fee rate, System Management Fee rate or Regulator Fee rate; and*
>
> *vi.* *any adjustment required for GST purposes under clause 9.1.2;*
>
> *…*

The list specified in clause 9.19.1 of the WEM Rules does not include a number of key data sources used in settlements which may, from time-to-time be required to be updated or corrected to achieve accurate and efficient market outcomes. Specifically, it does not include data developed by AEMO.

AEMO expects when the WEM Rules were drafted, any error in settlements resulting from data developed by the then IMO (now AEMO) would have been expected to be captured as an action arising from a Notice of Disagreement or Notice of Dispute. However, this does not account for those circumstances where AEMO may itself identify the need for updated input data it created.

AEMO routinely performs a thorough verification and validation process throughout the settlement process. This can result in AEMO identifying inaccurate, out-of-date or missing data which if not updated would result in incorrect settlement outcome.

Over the past two years, there were seven instances where AEMO identified issues with data it developed that affected settlements and therefore efficient market outcomes.

- For three of these instances, the affected party lodged a Notice of Disagreement under clause 9.20.1 of the WEM Rules. This allowed AEMO to reflect the updated data through the settlement Adjustment Process under clause 9.19.1(a)(ii).
- In each of the other four instances AEMO proactively identified inaccurate, out-of-date or missing data and took into account revised information in the settlement process. This ensured accurate and efficient market outcomes. However, it resulted in non-compliances with clause 9.19.1 of the WEM Rules. These instances are discussed in AEMO's annual audit reports[1] (the 2018/19 report is currently in draft) and are as follows:
  - 18WEM1.19 in relation to incorrect Ancillary Service parameters
  - 18WEM1.19 in relation to missing Ancillary Service settlement amounts
  - 18WEM1.20 and 19WEM1.54 in relation to incorrect generation data and recalculation of TES

AEMO considers the settlement Adjustment Process should allow the recalculation of settlements using the best data available to it at the time, including any data developed by AEMO. AEMO therefore proposes to amend clause 9.19.1(a) of the WEM Rules to expand the list of data for which AEMO may adjust settlements to include "any revised value that AEMO considers to be in compliance with these Market Rules and accurate"[2].

In the 2017/18 market audit, the auditor supported the resolution of the issue, recommending AEMO progresses "a rule change proposal to extend the list of data changes that can trigger

[1] Refer to the 2017/18 and 2018/19 (the 2018/19 report will be published on 28/10/2019) market audit reports available at: https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Compliance-and-audit.
[2] This drafting is consistent with clause 9.20.6 of the WEM Rules, under which settlements may be adjusted for updates to information developed by AEMO in response to a Notice of Disagreement.

a settlement adjustment”[3].

AEMO proposes two associated amendments:

1. **Removing the prohibition for AEMO to alter TES in response to a Notice of Disagreement or Notice of Dispute** – Clause 6.15.4 of the WEM Rules currently prevents AEMO from correcting or replacing data used in the calculation of TES. AEMO considers the broader ability to recalculate TES to be beyond the scope of this Rule Change Proposal. However, in line with AEMO’s aim to improve the accuracy and efficiency of market outcomes through settlements, it considers it should use the most accurate and up-to-date data and therefore adjust TES (and settlements) where data is found to be missing or incorrect, for example due to erroneous or missing SCADA data. AEMO therefore proposes to delete clause 6.15.4 of the WEM Rules.
2. **Amending the definition of a Relevant Settlement Statement** – Clause 9.16.3A of the WEM Rules currently defines a Relevant Settlement Statement for Non-STEM Settlement Statements by referencing the receipt of revised metering data or out of merit generation quantities. To facilitate the proposed amendment to broaden the ability for AEMO to adjust settlements to reflect more accurate or up-to-date data, AEMO proposes to remove this detail and simply refer to “revised data”.

**Change to the deadline for Notices of Disagreement relating to Non-STEM Settlement Statements**

In line with AEMO’s aim to improve the accuracy and efficiency of market outcomes through settlements, it has reviewed the timelines in relation to Notices of Disagreement.

Currently under clauses 9.16.2(f) and 9.16.4(e) of the WEM Rules, a Rule Participant may only lodge a Notice of Disagreement relating to a Non-STEM Settlement Statement within 20 Business Days of the statement being issued. Clause 9.19.7 specifies an additional deadline where a Notice of Disagreement with respect to an adjusted Settlement Statement may not be issued more than nine months after the issuance of the original Settlement Statement. These deadlines can conflict and create confusion.

Moreover, under clause 9.19.6 of the WEM Rules, a Rule Participant may only issue a Notice of Disagreement in relation to the most recently issued statement, and where information included in that statement varies from the most recently issued version.

The tight deadline can often be too restrictive for Rule Participants to effectively validate all of the information within the Settlement Statement. Moreover, AEMO highlights that, within a 20-day period a Rule Participant could receive up to eight Settlement Statements to review and validate. Should a Rule Participant not identify an issue prior to the issuance of the next version of the Settlement Statement, clause 9.16.2 of the WEM Rules may prevent the issue from being resolved and the correct market outcome may not be achieved.

AEMO considers that, should a Rule Participant find an error in a Settlement Statement, it should be corrected at any point before AEMO makes the final adjustment to ensure accurate market outcomes. AEMO therefore proposes to extend the timeframe for a Rule Participant to review, and where necessary, lodge a Notice of Disagreement (on any issued Settlement Statement for the Trading Month) until the first Business Day of the tenth month following the Trading Month being settled.

[3] Audit findings 18WEM1.19 and 18WEM1.20 of the WEM Audit Report refer, available at: https://www.aemo.com.au/-/media/Files/Electricity/WEM/Compliance/RBP--AEMO--WEM-Audit-Report-v10--Public--2018-10-12.pdf

AEMO proposes to amend the WEM Rules as follows:

- Amend the Non-STEM Settlement Disagreement Deadline in clauses 9.16.2(f) and 9.16.4(e) from 5:00 PM on the twentieth Business Day following the date on which a Non-STEM Settlement Statement was issued, to 5:00 PM on the first Business Day of the tenth month following the Trading Month being settled.

- Remove clause 9.19.6 which only allows Rule Participants to issue a Notice of Disagreement in relation to information that has been amended since the previous version of the Settlement Statement.

- Introduce a new obligation in clause 9.19.5 requiring Rule Participants to review Settlement Statements and raise a Notice of Disagreement, as necessary, as soon as practicable.

- Remove clause 9.19.7 which, for the avoidance of doubt, places a final deadline of nine months on Notices of Disagreement relating to a Non-STEM Settlement Statement to allow the final/third settlement Adjustment Process to occur. This is now redundant as there is only one deadline rather than three.

- Amend clause 9.20.7 to reduce the period for AEMO to respond to Notices of Disagreement relating to a Non-STEM Settlement Statement from three months to 20 Business Days to facilitate the extended Non-STEM Settlement Disagreement Deadline.

- Introduce two new clauses (9.19.7A and 9.19.7B) to allow AEMO to extend the deadline to respond to Notices of Disagreement if required, but to no later than the ten months after the Non-STEM Settlement Statement Date for the initial settlement (specified in clause 9.16.2(c)). This will ensure a response is provided before the Non-STEM Settlement Statement Date for the final/third settlement Adjustment Process.

AEMO assessed the potential impact of removing the strong incentive for Rule Participants to review Settlement Statements earlier in the process. As settlement is a zero-sum game, there will always be at least one party negatively affected, and therefore they have a financial incentive to review and raise any issue with Settlement Statements as soon as practical. On this basis, AEMO considers the proposed amendments should have little impact on the timing of settlement adjustments and therefore certainty of settlement outcomes for Rule Participants.

**Use of the term Rule Participant to include Ancillary Service Providers in settlements**

Ancillary Service Providers are Rule Participants, but may not be Market Participants. Various settlement related clauses of the WEM Rules refer to Market Participants, thereby excluding these provisions from applying to some Ancillary Service Providers.

AEMO considers this to be an oversight and proposes to replace the term Market Participant with Rule Participant in clauses 9.16.2(f), 9.18.1, 9.18.3, 9.18.4, 9.19.3, 9.20.7, 9.21.1 and 9.22.2 of the WEM Rules.

AEMO also proposes to amend clause 9.18.2 of the WEM Rules to include Ancillary Service Providers on the list of participant types to which AEMO must provide a Non-STEM Settlement Statement.

**Remove unnecessary detail from the WEM Rules**

The WEM Rules currently include the detail on the operational and procedural administration of Notices of Disagreement. AEMO considers many of the obligations currently included in the WEM Rules are overly prescriptive and are often redundant, and therefore should be removed, and as required included in the relevant Market Procedure.

AEMO therefore proposes the following changes to the WEM Rules:

- Clause 9.20.3 of the WEM Rules currently places an obligation for a Market Participant to notify AEMO if a receipt for a Notice of Disagreement is not received. AEMO considers this step to be redundant as the Market Participant has sufficient incentive to ensure the notice was received. AEMO therefore considers clause 9.20.3 of the WEM Rules should be deleted.

- Clause 9.20.4 of the WEM Rules specifies the information a Notice of Disagreement must include. AEMO highlights that the information required by a Notice of Disagreement may vary on a case-by-case basis and considers some level of discretion could be applied by AEMO. It therefore considers clause 9.20.4 of the WEM Rules should be amended to require AEMO to specify the form and content of a Notice of Disagreement in the relevant Market Procedure. AEMO also proposes to make the obligation to document these processes in a Market Procedure explicit by amending the head of power for the Market Procedure: Settlement in clause 9.2.1 of the WEM Rules.

- Clause 9.20.5 of the WEM Rules requires AEMO to notify the Metering Data Agent or Network Operator within 5 Business Days of the receipt of a Notice of Disagreement, specifying a date not later than 60 days after, if the Notice of Disagreement relates to data provided by their service. AEMO considers it should only be required to notify the Metering Data Agent or Network Operator of a Notice of Disagreement if the issue requires that party to assist in the resolution of the issue. Moreover, AEMO considers such administrative detail should be included in the relevant Market Procedure as required, rather than the WEM Rules. AEMO therefore considers clause 9.20.5 of the WEM Rules should be removed.

**Administrative changes**

AEMO has also taken the opportunity to propose a number of administrative changes to the clauses it proposes to amend to improve the integrity of the WEM Rules. This includes clauses 9.16.2, 9.16.3, 9.16.3A, 9.16.4, 9.18.4, 9.19.1, 9.19.5, 9.20.7 and 9.20.8 of the WEM Rules.

**Consultation**

In accordance with clause 2.5.1A of the WEM Rules, AEMO is required to consult with the MAC in relation to the matters to be addressed, the options available, and whether AEMO should progress a Rule Change Proposal. AEMO presented a paper at the November 2018 MAC meeting[4] and received support from MAC members to progress a Rule Change Proposal to allow it to make settlement adjustments for all updated input data[5].

At the MAC meeting, members asked whether AEMO could consider proposing amendment to allow TES quantities to be recalculated[6]. AEMO agreed to consider whether updates to TES should be included in this Rule Change Proposal. AEMO considers that such changes to the

[4] Papers are available at: https://www.erawa.com.au/cproot/19905/2/MAC%202018_11_20%20--%20Agenda%20Item%208(e)%20--%20AEMO%20presentation.pdf
[5] See Agenda Item 8(e) of the MAC meeting minutes, available at: https://www.erawa.com.au/cproot/20085/2/MAC%202018_11_20%20--%20Minutes%20FINAL.PDF
[6] More information is included in the papers related to RC_2012_19: Constrained On/Off Compensation for Non-Scheduled Generators, including minutes of the 14 November 2012 MAC meeting.

design of the market and associated systems are beyond the scope of the operational process related issues addressed in this Rule Change Proposal. AEMO has therefore not included a broad ability to recalculate TES quantities in this proposal. However, it has made changes to allow it to replace incorrect or missing input data (see page 5).

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**2. Explain the reason for the degree of urgency:**

The proposed changes are critical to allow AEMO to accurately settle the WEM in compliance with the WEM Rules. In the past two years, there have been four such instances where AEMO has been non-compliant with the WEM Rules due to these issues.

AEMO considers the matters addressed in this Rule Change Proposal should be addressed as a priority to avoid any further non-compliances with the WEM Rules.

The proposed changes are operational and administrative in nature, and do not change fundamental principles of the current market design. Moreover, AEMO's proposed amendments are not inconsistent with the direction on the State Government's reform agenda.

On this basis, AEMO considers this Rule Change Proposal should be progressed prior to the new market arrangements being implemented.

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**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)*

AEMO proposes the following amendments to the WEM Rules:

~~6.15.4 The Maximum Theoretical Energy Schedules and Minimum Theoretical Energy Schedules calculated by AEMO in accordance with clause 6.15.3 cannot be altered by:~~

~~(a) disagreement under clause 9.20.6; or~~

~~(b) disputes under clause 9.21.1.~~

…

9.2.1. AEMO must document the settlement process, including the application of taxes and interest, and processes related to Notices of Disagreement and Notices of Dispute in a Market Procedure.

…

9.16.2. ~~For all Financial Years other than the first Financial Year of energy market operations, the~~The settlement cycle timeline for settlement of other amounts payable under these Market Rules for all Trading Days within a Financial Year must be published by AEMO at least one calendar month prior to the commencement of that Financial Year. ~~For the first Financial Year of energy market operation, the settlement cycle timeline must be published one calendar~~

~~month prior to Energy Market Commencement.~~ This settlement cycle timeline must include for each settlement cycle:

(a) The Interval Meter Deadline, being the Business Day by which Meter Data Submissions for a Trading Month must be provided to AEMO. This date must be the first Business Day of the second month following the month in which the Trading Month commenced.

(b) The Capacity Credit Allocation Submission and Capacity Credit Allocation Acceptance timeline, including:

i. the earliest date and time at which Capacity Credit Allocation Submissions and Capacity Credit Allocation Acceptances for a Trading Month can be submitted, where this is to be not less than 10 Business Days prior to the start of the relevant Trading Month; and

ii. the latest date and time at which Capacity Credit Allocation Submissions and Capacity Credit Allocation Acceptances for a Trading Month can be submitted, where this is the Interval Meter Deadline as specified in clause 9.16.2(a) for the relevant Trading Month.

(c) The Non-STEM Settlement Statement Date, being the Business Day by which Non-STEM Settlement Statements for a Trading Month must be issued by AEMO. This date must be not less than three Business Days and not more than five Business Days after the Interval Meter Deadline defined in clause 9.16.2(a).

(d) The Invoicing Date being the Business Day by which AEMO must issue Invoices for Non-STEM Settlement Statements for a Trading Month. This date must be the sixth Business Day of the second month following the month in which the Trading Month being settled commenced.

(e) The Non-STEM Settlement Date being the Business Day on which the transactions covered by a Non-STEM Settlement Statement are settled. This date must be the eighth Business Day of the second month following the month in which the Trading Month being settled commenced.

(f) The Non-STEM Settlement Disagreement Deadline, being 5:00 PM~~pm~~ on the ~~twentieth~~ first Business Day of the tenth month following the commencement of the Trading Month being settled. ~~date on which a Non-STEM Settlement Statement was issued.~~ A ~~Market~~ Rule Participant has until this time to lodge a Notice of Disagreement with AEMO in relation to any amount included in the Non-STEM Settlement Statement.

9.16.3. AEMO must undertake a process for adjusting settlements ("**Adjustment Process**") in accordance with ~~clause~~ section 9.19. The purpose of the process is to review the Relevant Settlement Statements which were issued in the nine months prior to the commencement of the Adjustment Process ("**Relevant Settlement Statements**") to facilitate corrections, as applicable, resulting from:

(a) Notices of Disagreement;

(b) the resolution of disputes;

(c) revised metering data provided by Metering Data Agents;

(cA) any revised value, that AEMO considers to be in compliance with these Market Rules and accurate;

(d) any revised Market Fee rate, System Management Fee rate or Regulator Fee rate (as applicable);

(e) any determinations made in accordance with clauses 6.16A.1(b)(i), 6.16A.2(b)(i), 6.16B.1(b)(i) or 6.16B.2(b)(i); and

(f) any adjustment required for GST purposes under clause 9.1.2.

Adjustments may only be made to Relevant Settlement Statements. Adjustments may not be made to Settlement Statements outside of an Adjustment Process.

9.16.3A. A Relevant Settlement Statement is:

(a) any STEM Settlement Statement or Non-STEM Settlement Statement that requires correction as the result of the resolution of a dispute raised under clause 2.19, where AEMO has indicated under clause 9.20.7 that it will revise information in response to a Notice of Disagreement, or where an adjustment is required in accordance with clause 9.1.2; and

(b) any Non-STEM Settlement Statement for which the Invoicing Date occurred in the month that is three, six or nine months prior to the start of the Adjustment Process, and for which AEMO has ~~received~~ revised ~~metering data from a Metering Data Agent or any determinations in accordance with clauses 6.16A.1(b)(i), 6.16A.2(b)(i), 6.16B.1(b)(i) or 6.16B.2(b)(i)~~.

9.16.4. The following dates for each Adjustment Process to be undertaken during a Financial Year must be published by AEMO at least one calendar month prior to the commencement of that Financial Year~~ or, only in the case of the first Financial Year of energy market operation, one calendar month prior to Energy Market Commencement~~:

(a) the commencement date for the settlement ~~a~~Adjustment ~~p~~Process~~,~~;

(b) the date by which adjusted STEM Settlement Statements and Non-STEM Settlement Statements will be released, where this must be not less than 20 Business Days after the date set for the purposes of clause 9.16.4(a);

(c) the date by which Invoices reflecting the adjusted STEM Settlement Statements and Non-STEM Settlement Statements will be released, where this must be not less than two Business Days after the date set for the purposes of clause 9.16.4(b);

(d) the settlement date for the Invoices described in clause 9.16.4(c), where this must be not less than two Business Days after the date set for the purposes of clause 9.16.4(c); and

(e) ~~subject to clause 9.19.7,~~ the deadline for Notices of Disagreement pertaining to an adjusted Settlement Statement, where this must be ~~not more than 20 Business Days after the adjusted Settlement Statement is released~~ the first Business Day of the tenth month following the commencement of the Trading Month being settled.

…

9.18.1. AEMO must provide Non-STEM Settlement Statements to ~~Market~~ Rule Participants in accordance with the settlement cycle timeline published under clause 9.16.2.

9.18.2. AEMO must provide a Non-STEM Settlement Statement to each:

(a) Market Generator; ~~and~~

(b) Market Customer; and

(c) Ancillary Service Provider.

9.18.3. A Non-STEM Settlement Statement must contain the following information:

(a) details of the Trading Days covered by the Non-STEM Settlement Statement;

(b) the identity of the ~~Market~~ Rule Participant to which the Non-STEM Settlement Statement relates;

(c) for each Trading Interval of each Trading Day:

i. the Bilateral Contract quantities for that ~~Market~~ Rule Participant;

ii. the Net Contract Position of the ~~Market~~ Rule Participant;

iiA. the MWh quantity of energy scheduled from each of the ~~Market~~ Rule Participant's Facilities;

iii. [Blank]

iv. the Maximum Theoretical Energy Schedule and the Minimum Theoretical Energy Schedule data for each of the ~~Market~~ Rule Participant's Registered Facilities;

v. the meter reading for each Registered Facility associated with the ~~Market~~ Rule Participant;

vi. [Blank]

vii. in the case of Synergy:

1. Notional Wholesale Meter values; and

2. the total quantity of energy deemed to have been supplied by its Registered Facilities;

viii. the value of the Balancing Price; and

viiiA. any ConQN, CoffQN, PConQN, PCoffQN, Non Qualifying Constrained On Generation and Non Qualifying Constrained Off Generation under Chapter 6;

viiiB. details of any Non-Balancing Facility Dispatch Instruction Payment;

viiiC. the Metered Balancing Quantity for the ~~Market~~ Rule Participant;

ix. details of amounts calculated for the ~~Market~~ Rule Participant under sections 9.7 to 9.14 with respect to:

1. Reserve Capacity settlement;
2. Balancing Settlement;
3. Ancillary Services settlement;
4. Outage compensation settlement;
5. Reconciliation settlement;
6. [Blank]
7. Fee settlement; and
8. Net Monthly Non-STEM Settlement Amount;

(cA) details of any Capacity Credits allocated to the ~~Market~~ Rule Participant from another ~~Market~~ Rule Participant in accordance with sections 9.4 and 9.5;

(cB) details of any Capacity Credits allocated to another ~~Market~~ Rule Participant from the ~~Market~~ Rule Participant in accordance with sections 9.4 and 9.5;

(cC) details of any reductions in payments in the preceding Trading Month under clause 9.24.3A as a result of a ~~Market~~ Rule Participant being in default;

(cD) details of any payments to the ~~Market~~ Rule Participant as a result of AEMO recovering funds not paid to the ~~Market~~ Rule Participant in previous Trading Months under clause 9.24.3A as a result of a ~~Market~~ Rule Participant being in default;

(cE) in regard to Default Levy re-allocations, as defined in accordance with clause 9.24.9:

i. the total amount of Default Levy paid by that ~~Market~~ Rule Participant during the Financial Year, with supporting calculations;

ii. the adjusted allocation of those Default Levies to be paid by that ~~Market~~ Rule Participant, with supporting calculations; and

iii. the net adjustment be made;

(d) whether the statement is an adjusted Non-STEM Settlement Statement and replaces a previously issued Non-STEM Settlement Statement;

(e) in the case of an adjusted Non-STEM Settlement Statement, details of all adjustments made relative to the first Non-STEM Settlement Statement issued for that Trading Month with an explanation of the reasons for the adjustments;

(f) any interest applied in accordance with clause 9.1.3;

(g) the net dollar amount owed by the ~~Market~~ Rule Participant to AEMO for the billing period (i.e. the Trading Days covered by the Non-STEM Settlement Statement) where this may be a positive or negative amount; and

(h) all applicable taxes.

9.18.4. A ~~Market~~ Rule Participant may under ~~clause~~ section 9.20 issue a Notice of Disagreement in respect of a Non-STEM Settlement Statement by the Non-STEM Settlement Disagreement Deadline.

…

9.19.1. When undertaking an Adjustment Process AEMO must:

(a) recalculate the amounts included in the Relevant Settlement Statements in accordance with this Chapter but taking into account any:

i. revised metering data which has been provided by Metering Data Agents;

iA. adjustment to Non-Balancing Dispatch Instruction Payments under clause 9.19.1A;

ii. actions arising from a Notice of Disagreement;

iii. the resolution of any Notice of Dispute;

iv. determinations made in accordance with clauses 6.16A.1(b)(i), 6.16A.2(b)(i), 6.16B.1(b)(i) or 6.16B.2(b)(i);

v. revised Market Fee rate, System Management Fee rate or Regulator Fee rate; ~~and~~

vi. any adjustment required for GST purposes under clause 9.1.2; and

vii. any revised value that AEMO considers to be in compliance with these Market Rules and accurate; and

(b) provide adjusted STEM Settlement Statements and adjusted Non-STEM Settlement Statements to Rule Participants in accordance with the timeline specified under clause 9.16.4 in respect of the relevant Adjustment Process.

9.19.3. An adjusted Settlement Statement must include details of the adjustment to be paid by or to the ~~Market~~ Rule Participant, being:

(a) the adjustment which will need to be paid by or to the ~~Market~~ Rule Participant to put the ~~Market~~ Rule Participant in the position it would have been in at the time payment was made in respect of the original Settlement Statement if the adjusted Settlement Statement had been issued as the original Settlement Statement (but taking into account any adjustments previously made under this clause 9.19); plus

(b) interest on the amount referred to in clause 9.19.3(a) calculated in accordance with clause 9.1.3.

…

9.19.5. A Rule Participant may under section ~~clause~~ 9.20 issue a Notice of Disagreement in respect of an adjusted Settlement Statement as soon as practicable before ~~by~~ the deadline specified under clause 9.16.4(e) in respect of the relevant Adjustment Process.

~~9.19.6. Subject to clause 9.19.7, a Rule Participant may only issue a Notice of Disagreement for an adjusted Settlement Statement with respect to information in the adjusted Settlement Statement which differs from information in the previously released version of that Settlement Statement and which has not been changed in accordance with the resolution of a Notice of Disagreement issued by the relevant Market Participant or a Dispute in relation to which the relevant Market Participant was a Dispute Participant.~~

~~9.19.7. A Notice of Disagreement with respect to an adjusted Settlement Statement may not be issued more than nine months after the issuance of the original Settlement Statement.~~

…

9.20.3. ~~If a Rule Participant fails to receive a confirmation in accordance with clause 9.20.2, then it must contact AEMO within one Business Day of the deadline for receipt of the confirmation described in clause 9.20.2 to appraise AEMO of the failure of AEMO to confirm receipt and, if necessary, to make alternative arrangements for the submission of the Notice of Disagreement.~~[Blank]

9.20.4. A Notice of Disagreement must contain the information set out, and be in the format prescribed by AEMO in the Market Procedure specified in clause 9.2.1.~~include:~~

~~(a) details of the Settlement Statement and Trading Day to which the Notice of Disagreement relates;~~

~~(b) details of the Rule Participant to which the Notice of Disagreement relates; and~~

~~(c) a list of information in the Settlement Statement with which the Market Participant disagrees, including:~~

~~i. the reason for the disagreement; and~~

~~ii. what the Rule Participant believes the correct value should be, if this is known.~~

9.20.5. [Blank]~~If a Notice of Disagreement relates to information provided to AEMO by a Metering Data Agent or SCADA data provided by a Network Operator then as soon as practicable, but not later than five Business Days after AEMO confirms receipt of the Notice of Disagreement, AEMO must;~~

~~(a) notify the Metering Data Agent or Network Operator (as applicable) of any item of information provided by them to which the Notice of Disagreement relates;~~

~~(b) notify the Metering Data Agent or Network Operator (as applicable) of the time and date by which AEMO requires a response, where the date is to be no later than 60 days after the date on which AEMO confirmed receipt of the Notice of Disagreement; and~~

~~(c) require the Metering Data Agent or Network Operator (as applicable) to investigate the accuracy of the item and to provide a response by the time specified under clause 9.20.5(b):~~

~~i. reporting on the actions taken to investigate the accuracy of the item; and~~

~~ii. if applicable, a revised value for the item that the Metering Data Agent or Network Operator (as applicable) considers to be in compliance with these Market Rules and accurate.~~

…

9.20.7. AEMO must, as soon as practicable, but within ~~three months of confirming~~ 20 Business Days of the receipt of a Notice of Disagreement respond to a ~~Market~~ Rule Participant who issued a Notice of Disagreement indicating the actions (if any) AEMO will take in response to the Notice of Disagreement, where such actions may -include:

(a) revising information provided to AEMO by Metering Data Agents and Network Operators (as applicable), and the reasons provided to AEMO for those revisions~~, in accordance with clause 9.20.5~~;

(b) revising information developed by AEMO and used as an input to the settlement process, and the reason for the revision, as determined in accordance with clause 9.20.6; and

(c) whether AEMO considers an error was made in the settlement calculations that has produced an incorrect Settlement Statement.

9.20.7A. AEMO may extend the deadline to respond to the Notice of Disagreement in clause 9.20.7 where it determines additional time is required to respond. This includes where AEMO requires additional time to assess the information or determine the actions it will take. Where AEMO decides to extend the deadline to respond to a Notice of Disagreement, it must notify the Rule Participant:

(a) that it has decided to extend the deadline in clause 9.20.7;

(b) the reasons for its decision to extend the deadline in clause 9.20.7; and

(c) the time by which AEMO will respond to the Notice of Disagreement.

9.20.7B. AEMO must not extend the deadline to respond to a Notice of Disagreement under clause 9.20.7A to a date later than ten months after the Non-STEM Settlement Statement Date specified in clause 9.16.2(c) for the relevant Trading Month.

9.20.8. If a Market Participant is not satisfied with AEMO's response to a Notice of Disagreement given by the Market Participant, it may issue a Notice of Dispute to AEMO in accordance with ~~clause~~ section 9.21.

…

9.21.1. A ~~Market~~ Rule Participant may only issue a Notice of Dispute in regard to a Settlement Statement after:

(a) having raised a Notice of Disagreement with respect to a Settlement Statement; and

(b) AEMO having given a response under clause 9.20.7 in respect of the Notice of Disagreement with which the ~~Market~~ Rule Participant is not satisfied.

…

9.22.2. An Invoice must include:

(a) all Settlement Statements (including adjusted Settlement Statements) to which the Invoice relates;

(b) the net amount to be paid to or by AEMO (including applicable taxes). A positive amount is to be paid by the ~~Market~~ Rule Participant to AEMO and a negative amount is to be paid by AEMO to the ~~Market~~ Rule Participant;

(c) the payment date and time; and

(d) any amounts outstanding from overdue payments in relation to previous Settlement Statements.

…

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

This Rule Change Proposal addresses a number of matters related to the settlement of the WEM. The changes proposed by AEMO will:

- allow AEMO to use updated input data for settlement, including data produced by itself and TES;

- provide more time for Rule Participants to lodge a Notice of Disagreement in relation to a Non-STEM Settlement Statement and subsequent versions of Settlement Statements issued through the settlement Adjustment Process;
- correct an oversight to include Ancillary Service Providers, who may not otherwise be Market Participants, in the settlement process; and
- remove unnecessary procedural detail from the WEM Rules.

AEMO considers each of these changes will result in more accurate settlements and efficient market outcomes, and therefore better meet Wholesale Market Objective (a).

AEMO has also taken the opportunity to propose a number of administrative changes to the clauses it proposes to amend to improve the integrity of the WEM Rules.

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

AEMO has considered the high level impact of this Rule Change Proposal and the subsequent Procedure Change Proposal on the market systems and processes.

AEMO notes the proposed changes do not require AEMO or Market Participants to make amendments to market systems.

The Market Procedure: Settlement will require consequential amendments. AEMO will progress a Procedure Change Proposal in parallel to the consultation on this Rule Change Proposal. This is particularly important as AEMO proposes to move some operational and administrative procedural detail from the WEM Rules to the Market Procedure.

AEMO will make the associated changes to the Settlement Cycle Timeline in parallel to the consultation on the Procedure Change Proposal.

As the proposed changes are primarily related to AEMO's administrative processes, it does not anticipate any issues with the timing of the implementation of the proposed amendments in this Rule Change Proposal.

There are no civil penalty provisions or Reviewable Decisions affected by this Rule Change Proposal. However, clauses 9.16.3 and 9.16.4 of the WEM Rules are Protected Provisions under clause 2.8.13 of the WEM Rules.

Rule Change Panel
Market Advisory Committee

# Agenda Item 9: Review of the Framework for Rule Change Proposal Prioritisation and Scheduling

Meeting 2019_10_15

## 1. Background

The Rule Change Panel (**Panel**) approved the current Rule Change Proposal Prioritisation and Scheduling Framework (**Framework**) on 21 July 2017. The Framework was designed to allow the Panel and the Market Advisory Committee (**MAC**) to prioritise and schedule Rule Change Proposals (**Proposals**) for the Wholesale Electricity Market Rules (**Market Rules**).

The Gas Advisory Board (**GAB**) discussed the Framework at its meeting on 27 September 2018, where the GAB was advised that the Panel also intends:

- for the GAB and Panel to use the Framework to prioritise and schedule Proposals for the Gas Services Information Rules (**GSI Rules**); and
- to undertake a review of the Framework in 2018/19 in consultation with the MAC and GAB (this review was subsequently deferred until 2019/20).

The Framework is intended to provide a means for the Panel to efficiently manage its workload to produce the best outcomes for the energy markets and consumers. The Framework establishes the processes to:

- prioritise each Proposal in a way that offers the greatest benefits in terms of the Wholesale Market Objectives and GSI Objectives; and
- manage the Panel's work program based on its resource availability and priorities, including deciding when additional resources are required to support the Panel.

## 2. Review of the Framework

The Panel has commenced a review of the Framework and has considered feedback provided by the GAB on 27 September 2018 and 26 September 2019 indicating that the Framework:

- uses electricity terminology and should be made more suitable for gas market participants;
- should provide for re-evaluation of the urgency ratings of Proposals if the timelines in the Framework are not reached; and
- using a 'one queue' approach to prioritise Proposals for the Market Rules and GSI Rules may lead to delays in processing Proposals for the GSI Rules that tend to be lower priority.

The Panel has developed changes to the Framework to:

- include referencing to relevant Market Rules and GSI Rules;
- clarify the factors that the Panel must have regard to in developing amendments to the Market Rules and GSI Rules;

- update the Framework to reflect the Panel's current resource allocation;
- re-affirm the questions that should be considered when assigning an urgency rating to Proposals;
- re-affirm the factors that influence the prioritisation and scheduling of Proposals;
- adjust the descriptions of the urgency rating scale to be applicable to gas Proposals; and
- make typographical changes for consistent grammar and clarity.

The Panel intends to continue to use the 'one queue' approach to prioritise Proposals for the Market Rules and GSI Rules because:

- the one queue approach is a more efficient way to manage RCP Support resources;
- there is no evidence that the one queue approach has caused significant delays to the processing of Proposals for the GSI Rules;[1] and
- gas market participants can seek a change to the urgency rating of a Proposal for the GSI Rules if delays in processing the proposal become too long.

## Recommendation

It is recommended that the MAC:

- reviews the Rule Change Proposal Prioritisation and Scheduling Framework – January 2020 (attachment 1); and
- discusses any concerns with the changes to the Framework or if any other factors need to be addressed.

## 3. Next Steps

The next steps for the review of the Framework are:

| Stage | Proposed Time |
|---|---|
| Discuss the proposed changes to the Framework with the MAC | 15 October 2019 |
| Invitation for submissions for the Review of the Framework | 28 October to 8 November 2019 |
| Revise and update the proposed changes to the Framework based on submissions and seek Panel approval | 8 November to 29 November 2019 |
| Panel approval of amendments to the Framework | 5 December 2019 |
| Commencement of the revised Framework | 1 January 2020 |

1 For example:

- it took seven months to process GRC_2018_01 (GBB Zones) even though the Panel made changes to the proposal in response to submissions from gas market participants; and
- it took only one month to process GRC_2017_01 (Amendments to Schedule 2 – GBB Zones).

## Attachments

1. Rule Change Proposal Prioritisation and Scheduling Framework – January 2020
2. Rule Change Proposal Prioritisation and Scheduling Framework – January 2020 (tracked changes) (reference only)

RCP Rule Change Panel

# Framework for Rule Change Proposal Prioritisation and Scheduling

1 January 2020

## 1. Background

On 23 November 2016, the Rule Change Panel (**Panel**) was established to undertake the administration of, and decision-making for changes to the Wholesale Electricity Market Rules (**Market Rules**) and the Gas Services Information Rules (**GSI Rules**). The Panel commenced its rule-making functions on 3 April 2017.

The Panel is responsible for the development of amendments and replacement of the Market Rules and GSI Rules.[1] The Panel must:

- be satisfied that the Amending Rules as proposed to be amended or replaced are consistent with the Wholesale Market Objectives or GSI Objectives;[2]
- have regard to:[3]
    - o any applicable statement of policy principles given to the Panel by the Minister;
    - o the practicality and cost of implementing the Rule Change Proposal (**Proposal**);
    - o the views expressed in submissions on the Proposal;
    - o the views expressed by the Market Advisory Committee (**MAC**) or Gas Advisory Board (**GAB**); and
    - o any technical studies that the Panel considers necessary.

Any person may make a Proposal.[4] The Panel must publish a Rule Change Notice for a Proposal within seven Business Days of receiving it (or any clarification requested by the Panel).[5] The Market Rules and GSI Rules do not allow the Panel to extend this deadline.

Proposals can then be progressed under the Standard Rule Change Process or Fast Track Rule Change Process. The default timeframes are:

- For the Standard Rule Change Process:
    - o at least 30 Business Days from the publication of the Rule Change Notice until the end of the first submission period;[6]

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1 See clause 2.2B.2 of the Market Rules and subrule 125(1) of the GSI Rules.

2 See clause 2.4.2 of the Market Rules and subrule 127 of the GSI Rules. The Wholesale Market Objectives and GSI Objectives are reproduced in the Appendix to this paper.

3 See clause 2.4.3 of the Market Rules and subrule 128(1) of the GSI Rules.

4 See clause 2.5.1 of the Market Rules and subrule 129 of the GSI Rules.

5 See clause 2.5.7 of the Market Rules and subrule 132(2)(b) of the GSI Rules.

6 See clause 2.5.7 of the Market Rules and subrule 132(6) of the GSI Rules.

- no more than 20 Business Days from the closure of the first submission period until publication of the Draft Rule Change Report;[7]
- at least 20 Business Days from the publication of the Draft Rule Change Report until the end of the second submission period;[8] and
- no more than 20 Business Days from the closure of the second submission period until publication of the Final Rule Change Report.[9]

- For the Fast Track Rule Change Process:
  - no more than 15 Business Days from the publication of the Rule Change Notice until the end of the consultation period;[10] and
  - no more than 20 Business Days from the publication of the Rule Change Notice until publication of the Final Rule Change Report.[11]

The Panel may decide to extend these timeframes, but is required to publish a notice of extension explaining the reasons for the delay.[12]

## 2. Overview of the Framework

The purpose of this framework is to manage the Panel's workload in an efficient manner to produce the best outcomes for the market and consumers. This framework establishes the processes to:

- allocate resources to the Panel, including the options to acquire additional resources on a short- or long-term basis if the available resources are insufficient to progress a Proposal within the default timeframes (see section 3); and
- prioritise each Proposal in a way that offers the greatest benefits in terms of the Wholesale Market Objectives and GSI Objectives (see section 4); and
- manage the Panel's work program based on its resource availability and priorities, including deciding when additional resources are required to support the Panel.

## 3. Resources

Ideally, all Proposals will be progressed in accordance with the default timeframes, except for very large or complex Proposals, where additional time for analysis and consultation may be needed regardless of resource availability.

The default timelines cannot be guaranteed because the workload of the Panel, the Executive Officer and RCP Support[13] is not within the control of the Panel and is likely to be highly variable due to:

- variability in the quantity and timing of Proposals; and
- variability in the size, complexity and subject matter of Proposals.

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7 See clause 2.7.6 of the Market Rules and subrule 136(1) of the GSI Rules.

8 See clause 2.7.6(b) of the Market Rules and subrule 136(1)(b) of the GSI Rules.

9 See clause 2.7.7A of the Market Rules and subrule 137(1) of the GSI Rules.

10 See Clause 2.6.3 of the Market Rules and subrule 133(3) of the GSI Rules.

11 See clause 2.6.3A of the Market Rules and subrule 134(1) of the GSI Rules.

12 See clauses 2.5.10 and 2.5.12 of the Market Rules and rule 141 of the GSI Rules.

13 The Economic Regulation Authority (**ERA**) provides the Executive Officer, RCP Support and other resources to support the Panel, in accordance with the subregulation 23(2) of the *Energy Industry (Rule Change Panel) Regulations 2016*.

Due to the complexity of the Market Rules and GSI Rules, the speed at which Proposals are progressed is dependent on the availability of skilled and experienced resources. It would be inefficient for the ERA to permanently employ the necessary experienced analysts to manage any conceivable workload peaks within the default timeframes. On the other hand, there are risks to the Western Australian energy markets if RCP Support is significantly under-resourced.

The budget for rule change activities is addressed in the Government budget estimates for the ERA.

The ERA provides the Executive Officer to the Panel, along with a mixture of dedicated and shared resources to provide the necessary services. The resources allocated to support the Panel as at 31 July 2019 include:

- four full-time staff members;[14]
- a variable share (depending on requirements) of a Principal Analyst; and
- an annual consultancy budget.[15]

If the Panel needs to urgently progress a Proposal, then the ERA may be able to provide additional resources to the Panel, subject to its overall budget limitations, either through the reallocation of internal resources or by procuring external resources with the required skills and experience from consultants or legal firms. However, the costs of such external resources would likely be high and would need to be balanced against the benefits of progressing a Proposal without delay.

The ERA may also, in exceptional circumstances, seek an increase to its budget from Treasury outside of the normal annual budget cycle.

# 4. Prioritising Proposals

The Panel will undertake an assessment process to prioritise each Proposal.

RCP Support will undertake the assessment as soon as possible in the lifecycle of a Proposal, ideally at the Pre-Rule Change Proposal stage. However, the initial priority assessment for a Proposal may need to be revised over time as circumstances change. For example:

- a change in market activity may increase/decrease the financial effects of a design flaw in the Market Rules or GSI Rules, potentially increasing/decreasing the urgency of a Proposal to address the problem;
- the progression of a high urgency Proposal requiring changes to one of AEMO's IT systems may affect the prioritisation of a lower urgency Proposal that depends on the same IT systems, if concurrent processing of the Proposals would result in material cost savings for the market; and
- the assessment of some Proposals is likely to be significantly impacted by Government reform programs (e.g. the Energy Transformation Strategy) or ERA reviews.

14 The full-time staff include the Executive Officer, an Assistant Director, a Principal Analyst and an Assistant Analyst. The ERA had also commenced procuring an additional full-time staff member as of 31 July 2019.

15 The consultancy budget covers legal advice on Proposals (particularly on drafting of Amending Rules) and for any consultants to deal with specific Proposals (e.g. a part-time staff member was employed in 2018/19).

## 4.1 Factors Impacting the Priority of a Proposal

The following factors will impact the priority of a Proposal:

- the urgency rating of the Proposal (see section 4.2);
- the submission date of the Proposal;
- the estimated resource requirements (by resource type and working days) to process the Proposal, including:
  - internal resources (e.g. analyst, the Executive Officer);
  - specialist consultancy requirements (e.g. legal support, consultants);
  - external assistance (e.g. support from AEMO, support from the ERA, MAC or GAB workshops or working groups);
- other factors, including:
  - any specific timing considerations (e.g. the need to align commencement of Amending Rules with the Reserve Capacity Cycle, ERA reviews);
  - IT and process implementation cycles for AEMO and Market Participants; and
  - interdependencies with any Government-led reforms (e.g. the Energy Transformation Strategy).

## 4.2 Urgency Ratings

Each Proposal is assigned an urgency rating to help prioritise the Proposals and to determine the appropriate level of response if available resources are insufficient to progress a Proposal within the default timeframes.

### 4.2.1 Questions to Consider in Assigning an Urgency Rating

The urgency ratings are determined by considering the following questions:

(1) Are the proposed amendments necessitated by external events (e.g. legislative or regulatory changes)?

(2) Is the Proposal seeking to address a market failure or a market improvement (e.g. imperfect competition or information asymmetries)?

(3) How bad, in terms of the Wholesale Market Objectives or GSI Objectives, might the outcomes be if the Proposal is delayed?

(4) How good, in terms of the Wholesale Market Objectives or GSI Objectives, might the outcomes be if the Proposal is progressed promptly?

(5) What are the likely implementation and ongoing operational costs?

(6) What are the likely cost-benefit outcomes from the Proposal?

The Panel will not have started its formal assessment of a Proposal when the Proposal is assessed for its urgency rating. Therefore, consideration of the above questions will be based on rough initial estimates and judgment calls. Assigning a higher urgency rating to a Proposal will not impact the outcome of the Proposal.

### 4.2.2 The Urgency Rating Scale

The urgency rating of a Proposal is a major input to the prioritisation process but is not the only factor considered (see section 4.1). The urgency ratings are specified as follows.

| Urgency | Description | Resourcing Implications |
|---|---|---|
| 1 | **Essential**<br>The Proposal:<br>• is a legal necessity;<br>• addresses unacceptable outcomes for the Wholesale Electricity Market or the gas market; or<br>• addresses a serious threat to:<br>o power system security and reliability; or<br>o 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**<br>The Proposal is compelling and is:<br>• likely to have a large net benefit; and/or<br>• necessary to avoid serious perverse market outcomes. | Do not delay – acquire additional resources if available, subject to overall ERA budget limitations. |
| 3 | **Medium**<br>The net benefit of the Proposal:<br>• may be large but needs more analysis to determine; or<br>• is material but not large enough to warrant a High rating. | Delay up to 3 months if budgeted resources are unavailable. |
| 4 | **Low**<br>The Proposal has minor net benefit (e.g. reduced administration costs). | Delay up to 6 months if budgeted resources are unavailable. |
| 5 | **Housekeeping**<br>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. |

### 4.2.3 The Process to Assign an Urgency Rating

The usual process for assigning an urgency rating to a Proposal is as follows.

(1) the proponent is to suggest an urgency rating for their Proposal, usually at the Pre-Rule Change Proposal stage;

(2) RCP Support is to seek the advice of the MAC or GAB on the urgency rating for the Pre-Proposal or Rule Change Proposal, and in doing so, is to provide the MAC or GAB with the questions listed in section 4.2.1 and the rating scale in section 4.2.2;

(3) the MAC or GAB is to form a consensus view on the urgency rating for the Proposal, usually during discussion of the Pre-Rule Change Proposal at a MAC or GAB meeting, and is to consider the importance of each question listed in section 4.2.1 relative to the Proposal;

(4) RCP Support is to form an independent view of the urgency rating for the Proposal, which may differ from what was suggested by the proponent and/or the MAC or GAB;

(5) RCP Support is to provide the Panel with its recommended urgency rating for the Proposal, the reasons for its recommendation, and the views of the proponent and the MAC or GAB (particularly where these views differ from RCP Support's recommendation); and

- the Panel is to decide on the urgency rating for the Proposal, which RCP Support will then use to prioritise and schedule the Proposal.

RCP Support or the proponent of a Proposal may propose to revise the urgency rating for a Proposal if the timelines indicated in the table above are not met or if circumstances change at any stage during the rule change process. RCP Support will consult with the MAC or GAB before proposing a new urgency rating to the Panel.

### 4.3 Special Cases

Some Proposals need to be treated as 'special cases' because they are or will be affected by interdependencies with Government-led reform programs (such as the Energy Transformation Strategy) or an ERA review:

- Amending Rules made by the Minister may supersede a Proposal, either by implementing the proposed amendments or by rendering them irrelevant. In these cases, the Panel will need to reject the Proposal using the normal rule change process. Although the rejection is effectively only a housekeeping task, it should be processed promptly to avoid any unnecessary confusion.
- Uncertainty about the future of Government reforms may make it impossible for the Panel to assess a Proposal. For example, if a proposed but unconfirmed Government reform would supersede the changes in a Proposal, then it will be difficult to determine what benefits of the Proposal will accrue and for how long, and therefore whether the Proposal will have a positive net benefit. In these cases, it may be appropriate to put the Proposal on hold until the Government's policy direction and implementation plans are better understood. However, a deadline should be set for any extension to ensure that the Proposal is not placed on hold indefinitely.
- Some Proposals may contain multiple components, of which only some are affected by proposed Government reforms. In these cases, the Panel may decide to progress those elements that can be progressed prior to the Government Reform and reject the remaining components, to avoid any unnecessary delay to the former for the sake of the latter. A new Proposal can then be made for the rejected components following the Government reforms, if necessary.

## 5. Scheduling

The Executive Officer is responsible for managing the RCP Support work plan and for any associated reporting to the Panel, MAC and GAB. The work plan will be reviewed and updated:

- whenever new Proposals are submitted;
- whenever resource availability changes;
- periodically to reflect progress made in processing Proposals; and
- in response to changes to the status of the Government's reform programs, ERA reviews or other relevant external events.

## 5.1 Prioritisation of Proposals

In developing the work plan, the Executive Officer will aim to prioritise Proposals by urgency rating and then submission date, subject to consideration of the following qualifying factors:

- resource availability and workflow practicalities – for example:
    - it may sometimes be necessary to progress lower priority Proposals over higher priority Proposals to allocate resources efficiently and avoid resourcing bottlenecks; and
    - it may be practical to work on lower rated Proposals during the consultation periods for higher rated Proposals;
- Panel availability;
- AEMO availability;
- MAC or GAB availability;
- timing for IT and process development and testing by AEMO and Market Participants;
- the need to coordinate with any Government-led reforms or ERA reviews; and
- special timing considerations (e.g. a small delay to a High rated Proposal may be acceptable provided the Amending Rules can be commenced before the relevant Reserve Capacity Cycle deadline).

The Panel may ask the Executive Officer to change the prioritisation and scheduling of Proposals if it considers that the changes are likely to better achieve the Wholesale Market Objectives or GSI Objectives.

## 5.2 Monitoring and Reporting

The Executive Officer is responsible for:

- six weekly reporting to the Panel on the RCP Support work plan via the ‘Workflow Summary’ and the ‘Summary of Rule Change Proposals’;
- regular reporting to the MAC and GAB on the RCP Support work plan via the ‘Overview of Rule Change Proposals’;
- monitoring for potential failures to meet the required processing timeframes for each Proposal (given its urgency rating) and reporting any concerns to the Panel; and
- coordinating any remedial actions under this framework to address resourcing shortfalls.

Remedial action will be required if Proposals cannot be progressed using budgeted resources within the timeframes permitted for their urgency rating. Remedial action may include:

- liaising with the ERA to increase the use of shared resources or to ‘borrow’ other ERA resources;
- engaging consultants to perform specialist tasks, where appropriate;
- procuring additional resources through short-term contracts;
- deferring consideration of some Proposals; and
- if the scale of the problem is large enough (e.g. due to submission of a very large Essential or High urgency Proposal, or a severe and ongoing resource shortage) and it cannot be addressed within the ERA’s overall budget limitations, liaising with the Panel and the ERA to prepare a Treasury submission to procure additional resources.

## 5.3 Interaction with Annual Budgeting Cycle

The ERA commences preparing its annual budget in February each year so that it can seek changes to its budget as part of the Government's annual budget estimates process, which normally occurs in April each year.

The ERA's annual budget process includes an assessment of whether sufficient resources are allocated to the Panel to meet its likely workload. The Panel and the ERA use the outcomes of this assessment to determine if any changes are needed to the resourcing levels for the next financial year.

# Appendix: The Wholesale Market Objectives and the GSI Objectives

## Wholesale Market Objectives

The Wholesale Market Objectives are specified in clause 1.2.1 of the Market Rules as follows:

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.

## GSI Objectives

The GSI Objectives are specified in subrule 2(1) of the GSI Rules as follows:

In accordance with section 6 of the GSI Act, the objectives of the Gas Bulletin Board (the GBB) and the Gas Statement of Opportunities (the GSOO) (the GSI Objectives) are to promote the long term interests of consumers of natural gas in relation to:

(a) the security, reliability and availability of the supply of natural gas in the State;

(b) the efficient operation and use of natural gas services in the State;

(c) the efficient investment in natural gas services in the State; and

(d) the facilitation of competition in the use of natural gas services in the State.

Rule Change Panel

# Framework for Rule Change Proposal Prioritisation and Scheduling

~~21 July 2017~~

1 January 2020

## 1. Background

~~The~~ On 23 November 2016, the Rule Change Panel (**Panel**) was established to undertake the administration of, and decision-making for changes to the Wholesale Electricity Market Rules (**Market Rules**) and the Gas Services Information Rules (~~Market/~~**GSI** **Rules**) ~~specify default timeframes~~). The Panel commenced its rule-making functions on 3 April 2017.

The Panel is responsible for the ~~progression~~development of amendments and replacement of the Market Rules and GSI Rules.[1] The Panel must:

- be satisfied that the Amending Rules as proposed to be amended or replaced are consistent with the Wholesale Market Objectives or GSI Objectives;[2]
- have regard to:[3]
  - any applicable statement of policy principles given to the Panel by the Minister;
  - the practicality and cost of implementing the Rule Change Proposal (**Proposal**);
  - the views expressed in submissions on the Proposal;
  - the views expressed by the Market Advisory Committee (**MAC**) or Gas Advisory Board (**GAB**); and
  - any technical studies that the Panel considers necessary.

Any person may make a Proposal.[4] The Panel must publish a Rule Change Notice for a Proposal within seven Business Days of receiving it (or any clarification requested by the Panel).[5] The Market Rules and GSI Rules do not allow the Panel to extend this deadline.

Proposals ~~(Proposals)~~can then be progressed under the Standard Rule Change Process ~~and~~or Fast Track Rule Change Process. The default timeframes are:

- ~~for~~For the Standard Rule Change Process:

1 See clause 2.2B.2 of the Market Rules and subrule 125(1) of the GSI Rules.

2 See clause 2.4.2 of the Market Rules and subrule 127 of the GSI Rules. The Wholesale Market Objectives and GSI Objectives are reproduced in the Appendix to this paper.

3 See clause 2.4.3 of the Market Rules and subrule 128(1) of the GSI Rules.

4 See clause 2.5.1 of the Market Rules and subrule 129 of the GSI Rules.

5 See clause 2.5.7 of the Market Rules and subrule 132(2)(b) of the GSI Rules.

- o at least 30 Business Days from the publication of the Rule Change Notice until the end of the first submission period;[6]
- o no more than 20 Business Days from the closure of the first submission period until ~~the~~ publication of the Draft Rule Change Report;[7]
- o at least 20 Business Days from the publication of the Draft Rule Change Report until the end of the second submission period;[8] and
- o no more than 20 Business Days from the closure of the second submission period until ~~the~~ publication of the Final Rule Change Report~~; and~~.[9]

- ~~for~~For the Fast Track Rule Change Process:
  - o no more than 15 Business Days from the publication of the Rule Change Notice until the end of the consultation period;[10] and
  - o no more than 20 Business Days from the publication of the Rule Change Notice until ~~the~~ publication of the Final Rule Change Report.[11]

The ~~Rule Change~~ Panel ~~(Panel)~~ may decide to extend these timeframes, but is required to publish a notice of extension explaining the reasons for the delay.[12]

## 2. ~~Regardless~~Overview of the ~~rule change process used~~Framework

The purpose of this framework is to manage the Panel's workload in an efficient manner to produce the best outcomes for the market and consumers. This framework establishes the processes to:

- allocate resources to the Panel ~~must publish the Rule Change Notice for~~ , including the options to acquire additional resources on a short- or long-term basis if the available resources are insufficient to progress a Proposal within ~~7 Business Days of receiving the~~the default timeframes (see section 3); and
- prioritise each Proposal ~~(or any clarification of the Proposal requested by the Panel). The~~ in a way that offers the greatest benefits in terms of the Wholesale Market~~/~~ Objectives and GSI ~~Rules do not allow the Panel to extend this deadline.~~Objectives (see section 4); and
- manage the Panel's work program based on its resource availability and priorities, including deciding when additional resources are required to support the Panel.

## 3. Resources

Ideally, all Proposals ~~are~~will be progressed in accordance with the default timeframes, except for very large or complex Proposals, where additional time for analysis and consultation ~~is~~may be needed regardless of resource availability.

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6 See clause 2.5.7 of the Market Rules and subrule 132(6) of the GSI Rules.
7 See clause 2.7.6 of the Market Rules and subrule 136(1) of the GSI Rules.
8 See clause 2.7.6(b) of the Market Rules and subrule 136(1)(b) of the GSI Rules.
9 See clause 2.7.7A of the Market Rules and subrule 137(1) of the GSI Rules.
10 See Clause 2.6.3 of the Market Rules and subrule 133(3) of the GSI Rules.
11 See clause 2.6.3A of the Market Rules and subrule 134(1) of the GSI Rules.
12 See clauses 2.5.10 and 2.5.12 of the Market Rules and rule 141 of the GSI Rules.

~~However, in practice it is difficult to guarantee this outcome without imposing inefficient costs on the market. The workload of the Panel, and therefore of the executive officer and other RCP Secretariat Support Services provided by the Economic Regulation Authority (ERA) to support the Panel (RCP Support),~~The default timelines cannot be guaranteed because the workload of the Panel, the Executive Officer and RCP Support[13] is not within the control of the Panel and is likely to be highly variable due to:

- variability in the quantity and timing of Proposals; and
- variability in the size, complexity and subject matter of Proposals.

Due to the complexity of the Market~~/~~ Rules and GSI Rules, the ~~rapid processing of many~~ speed at which Proposals are progressed is dependent on the availability of skilled and experienced resources. It would ~~not~~ be ~~efficient~~inefficient for the ERA to permanently employ ~~enough~~the necessary experienced analysts to manage any conceivable ~~work load~~workload peaks within the default timeframes. ~~Further, while it is often possible to procure external resources with the required skills and experience (e.g. from legal firms)~~On the ~~additional costs of such resources are likely to be high and may not always be warranted by the benefits of avoiding a delay in progressing a Proposal.~~

~~The purpose of this framework is to manage the expected peaks and troughs of the Panel's workload in an efficient manner to produce the best outcomes for the market and consumers. Specifically, the framework:~~

- ~~provides a basis for scheduling work that prioritises Proposals offering the greatest benefits in terms of the Wholesale Market Objectives/GSI Objectives (Objectives);~~
- ~~establishes guidelines for determining the appropriate level of response when insufficient budgeted resources are available to progress a Proposal in the default timeframes; and~~
- ~~provides a basis for managing the Panel's work program, assessing performance and deciding when additional resources are required to support the Panel, either in the short term or through a longer-term changes to the Panel's budget.~~

## ~~2. Overview of Framework~~

~~The main features of the framework include:~~

- ~~identification of the resources allocated to support of the Panel and the options to acquire additional resources on a short or long-term basis;~~
- ~~the application of a scheduling assessment process to each Proposal, to determine the factors that inform the prioritisation and scheduling of the Proposal;~~
- ~~the use of a five-level "urgency rating" in the scheduling assessment process;~~

~~the scheduling of Proposals into a coordinated~~other hand, there are risks to the Western Australian energy markets if RCP Support ~~work plan, based on the scheduling assessment factors and the available resources;~~is significantly under-resourced.

- ~~ongoing monitoring, reporting and adjustment of the work plan to reflect progress against targets and account for internal and external changes;~~

[13] The Economic Regulation Authority (**ERA**) provides the Executive Officer, RCP Support and other resources to support the Panel, in accordance with the subregulation 23(2) of the *Energy Industry (Rule Change Panel) Regulations 2016*.

- ~~guidelines around the procurement of additional resources to support the Panel in the short or longer-term; and~~
- ~~provision of feedback to the annual ERA budget processes, which establish the base resource allocation for Panel support for each financial year.~~

## ~~3.1.~~ ~~Resources~~

The budget for rule change activities is ~~contained within the overall expenditure approved~~addressed in the Government budget estimates for the ERA.

~~In addition~~The ERA provides the Executive Officer to the ~~executive officer, the ERA allocates~~Panel, along with a mixture of dedicated and shared resources to provide the ~~secretariat support~~necessary services ~~needed by the Panel. For example, the~~. The resources allocated to support the Panel as at ~~21~~31 July ~~2017~~2019 include:

- ~~three full-time analysts (including a Principal Analyst, Senior Analyst and Assistant Analyst);~~
- four full-time staff members;[14]
- a variable share (depending on requirements) of a ~~Legal Officer, a~~ Principal Analyst ~~and the Executive Director Markets~~; and
- an annual consultancy budget ~~($200,000 for the 2017/18 financial year).~~.[15]

~~The dedicated resources will be assigned to other ERA work during any periods in which they are not required by the Panel.~~

If ~~there is an urgent requirement, the ERA may~~the Panel needs to urgently progress a Proposal, then the ERA may be able to provide additional resources to the Panel, subject to its overall budget limitations, ~~be able to provide additional resources to assist the Panel,~~ either through the reallocation of internal resources or ~~through short-term contractors.~~ by procuring external resources with the required skills and experience from consultants or legal firms. However, the costs of such external resources would likely be high and would need to be balanced against the benefits of progressing a Proposal without delay.

The ERA may also, in exceptional circumstances, seek an increase to its budget from Treasury outside of the normal annual budget cycle.

# 4. ~~Scheduling Assessment of Rule Change~~Prioritising Proposals

~~Each Proposal submitted to the~~ The Panel will ~~undergo a scheduling~~undertake an assessment process~~. This process determines the factors that inform the prioritisation and scheduling of a Proposal.~~ to prioritise each Proposal.

RCP Support will ~~commence~~undertake the ~~scheduling~~ assessment ~~process~~ as soon as possible in the lifecycle of a Proposal, ideally at the Pre~~-~~Rule Change Proposal stage. However, the initial ~~scheduling~~priority assessment for a Proposal may need to be revised over time as ~~new information becomes available.~~circumstances change. For example:

[14] The full-time staff include the Executive Officer, an Assistant Director, a Principal Analyst and an Assistant Analyst. The ERA had also commenced procuring an additional full-time staff member as of 31 July 2019.

[15] The consultancy budget covers legal advice on Proposals (particularly on drafting of Amending Rules) and for any consultants to deal with specific Proposals (e.g. a part-time staff member was employed in 2018/19).

- a change in market activity may ~~either~~ increase ~~or~~ /decrease the financial effects of a design flaw in the Market Rules or GSI Rules, potentially increasing ~~or~~ /decreasing the urgency ~~rating~~ of a Proposal to address the problem;
- the progression of a high urgency Proposal requiring changes to one of AEMO's IT systems may affect the prioritisation of a lower urgency Proposal ~~affecting~~that depends on the same IT ~~system~~systems, if concurrent processing of the Proposals would result in material ~~IT development~~ cost savings for the market; and
- the assessment of some Proposals is likely to ~~change as more information becomes available about~~be significantly impacted by Government reform programs (e.g. the ~~status and timeframes of related Electricity Market Review reforms~~Energy Transformation Strategy) or ERA reviews.

## ~~4.1~~ Factors ~~Considered in a Scheduling Assessment~~

## 4.1 ~~The scheduling assessment~~Impacting the Priority of a Proposal ~~comprises the~~

The following ~~input~~ factors will impact the priority of a Proposal:

- the urgency rating~~, determined in accordance with~~ of the Proposal (see section ~~4.2 below;~~4.2);
- the submission date of the Proposal;
- the estimated resource requirements (by resource type and working days) to process the Proposal, including:
  - internal resources~~,~~ (e.g. analyst, ~~legal support;~~the Executive Officer);
  - specialist consultancy requirements~~; and~~ (e.g. legal support, consultants);
  - external assistance~~,~~ (e.g. support from AEMO~~;~~, support from the ERA, MAC or GAB workshops or working groups);
- ~~qualifying~~other factors, including:
  - any specific timing considerations~~,~~ (e.g. the need to align ~~the~~ commencement of Amending Rules with the Reserve Capacity Cycle~~;~~, ERA reviews);
  - IT and process implementation cycles for AEMO and Market Participants; and
  - interdependencies with any Government-led reforms ~~of which the Panel is aware,~~ (e.g. the ~~Electricity Market Review reforms.~~Energy Transformation Strategy).

## 4.2 Urgency Ratings

Each Proposal is assigned an urgency rating ~~based on the information available at the time of the assessment. The urgency ratings are used to~~to help prioritise the Proposals and to determine the appropriate level of response ~~when insufficient budgeted~~ if available resources are ~~available~~insufficient to progress a Proposal ~~in~~within the default timeframes.

### 4.2.1 Questions to Consider in Assigning an Urgency Rating

The urgency ratings are determined by considering the following questions~~.~~:

(1) Are the proposed amendments necessitated by external events~~,~~ (e.g. legislative or regulatory changes ~~to GST laws or the merger of Synergy and Verve Energy?~~)?

(2) Is the Proposal seeking to address a market failure~~,~~ or a market improvement (e.g. imperfect competition or information asymmetries~~?~~)?

(3) How bad, in terms of the Wholesale Market Objectives or GSI Objectives, might the outcomes be if the Proposal is delayed?

(4) How good, in terms of the Wholesale Market Objectives or GSI Objectives, might the outcomes be if the Proposal is progressed promptly?

(5) What are the likely implementation and ongoing operational costs?

(6) ~~It should be noted that these questions may require~~ What are the ~~use of initial ballpark estimates and judgement calls, as in many cases the~~likely cost-benefit outcomes from the Proposal?

The Panel will not have started its formal assessment of a Proposal when the Proposal~~. This means,~~ is assessed for ~~example, that in some cases a relatively high~~its urgency rating ~~may be assigned to a Proposal that is eventually rejected by the Panel.~~

~~It should also be noted that while the~~. Therefore, consideration of the above questions will be based on rough initial estimates and judgement calls. Assigning a higher urgency rating to a Proposal will not impact the outcome of the Proposal.

### 4.2.2 The Urgency Rating Scale

The urgency rating of a Proposal is a major input to the prioritisation process ~~it~~but is not the only factor considered (see section 1.1). The urgency ratings are specified as follows.

~~The urgency ratings are listed in Table 4.1 below.~~

~~**Table 4.1: Urgency ratings**~~

| Urgency | Description | Resourcing Implications |
|---|---|---|
| **1** | **Essential**~~: e.g.~~<br>The Proposal:<br>• is a legal necessity~~,~~;<br>• addresses unacceptable ~~market~~ outcomes for the Wholesale Electricity Market or the gas market; or<br>• addresses a serious threat to:<br>o power system security and reliability; or<br>o 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**~~: Compelling proposal, and either~~<br>The Proposal is compelling and is:<br>• likely to have a large net benefit; and/~~-~~or ~~else~~<br>• ~~-~~necessary to avoid serious perverse market outcomes. | Do not delay – acquire additional resources if available, subject to overall ERA budget limitations. |
| **3** | **Medium**~~: Net~~<br>The net benefit ~~either~~of the Proposal:<br>• may be large but needs more analysis to determine; or<br>• is material but not large enough to warrant a High rating. | ~~May delay~~Delay up to 3 months if budgeted resources are unavailable. |
| **4** | **Low**~~: Minor~~<br>The Proposal has minor net benefit~~,~~ (e.g. reduced administration costs). | ~~May delay~~Delay up to 6 months if budgeted resources are unavailable. |
| **5** | **Housekeeping**~~: Negligible~~<br>The Proposal has negligible market benefit~~,~~ (e.g. ~~just~~it improves the readability of the Market~~/~~ Rules or GSI Rules~~-~~). | ~~May delay~~Delay up to 12 months if budgeted resources are unavailable. |

### 4.2.3 The Process to Assign an Urgency Rating

The usual process for assigning an urgency rating to a Proposal ~~will be~~is as follows.

(1) ~~The~~the proponent is to suggest~~s~~ an urgency rating for their Proposal, usually at the Pre~~-~~-Rule Change Proposal stage~~.~~;

(2) RCP Support is to seek the advice of the MAC or GAB on the urgency rating for the Pre-Proposal or Rule Change Proposal, and in doing so, is to provide the MAC or GAB with the questions listed in section 4.2.1 and the rating scale in section 4.2.2;

~~(1)~~(3) the MAC~~/~~ or GAB ~~provides its~~is to form a consensus view~~s~~ on the urgency rating for the Proposal, usually during discussion of the Pre~~-~~-Rule Change Proposal at a MAC~~/~~ or GAB meeting, and is to consider the importance of each question listed in section 4.2.1 relative to the Proposal~~.~~;

(4) RCP Support is to form an independent view of the urgency rating for the Proposal, which may differ from what was suggested by the proponent and/or the MAC or GAB;

~~(2)~~(5) RCP Support is to provide~~s~~ the Panel with its ~~(potentially modified)~~ recommended urgency rating~~, along with~~ for the Proposal, the reasons for its recommendation, and ~~details of any dissenting~~the views ~~from~~of the proponent ~~or the MAC/GAB, to the Panel for review and approval.~~and the MAC or GAB (particularly where these views differ from RCP Support's recommendation); and

- ~~The~~the Panel is to decide~~s~~ on the urgency rating for the Proposal, which ~~is then used by~~ RCP Support will then use to prioritise and schedule the Proposal.

RCP Support or the proponent of a Proposal may propose ~~a new~~to revise the urgency rating for a Proposal, if ~~at any stage there is a change to the relevant~~the timelines indicated in the table above are not met or if circumstances~~.~~ change at any stage during the rule change process. RCP Support will consult with the MAC~~/~~ or GAB before proposing a new urgency rating to the Panel ~~for approval~~.

### 4.3 Special Cases ~~with Government-led Reform Interdependencies~~

Some Proposals need to be treated as ~~“~~‘special ~~cases”~~cases’ because they are or ~~have been~~will be affected by interdependencies with Government-led reform programs (such as the ~~Electricity Market Review. Some examples are provided below.~~Energy Transformation Strategy) or an ERA review:

- ~~In some cases~~ Amending Rules made by the Minister may supersede a Proposal, either by implementing the proposed amendments or ~~else~~ by rendering them irrelevant. In these cases, the Panel will need to reject the Proposal ~~needs to be rejected by the Panel~~ using the normal rule change process. Although the rejection is effectively only a housekeeping task,~~function~~ it should ~~still~~ be processed promptly to avoid any unnecessary confusion.
- ~~In some cases uncertainty~~Uncertainty about the future of Government reforms ~~makes~~may make it impossible for the Panel to assess a Proposal. For example, if a proposed but unconfirmed Government reform would supersede the changes in a Proposal, then ~~the “payback period” for the changes cannot be assessed with any confidence.~~ it will be difficult to determine what benefits of the Proposal will accrue and for how long, and therefore whether the Proposal will have a positive net benefit. In these cases ~~the Proposal should~~, it may be ~~placed~~appropriate to put the Proposal on hold ~~for some period~~ until the Government's policy direction and implementation plans are better understood. However, a deadline should be set for any extension to ensure that the Proposal is not placed on hold indefinitely.
- ~~If the Government confirms its support for certain Electricity Market Review reforms then this may reduce the expected payback period for some Proposals, to the extent that their progression would be inconsistent with the Objectives. In these situations the Proposals should be extended until the relevant reforms are either implemented or abandoned.~~
- ~~In some cases a Proposal~~Some Proposals may contain multiple components, of which only some are affected by proposed Government reforms. In these cases, the Panel may decide to progress those elements that can be progressed prior to the Government Reform and reject the remaining components, to avoid any unnecessary delay to the former for the sake of the latter. A new Proposal can then be made for the rejected components following the Government reforms, if necessary.

# ~~5. Work Plan Management~~

# 5. Scheduling

The ~~executive officer~~Executive Officer is responsible for managing the RCP Support work plan and for any associated reporting to the Panel, MAC and ~~the MAC/~~GAB. ~~It is expected that the~~The work plan will ~~need to~~ be reviewed and updated:

- whenever new Proposals are submitted;
- whenever resource availability changes;
- periodically to reflect progress made in processing Proposals; and
- in response to changes to the status of the Government's reform programs, ERA reviews or other relevant external events.

## 5.1 Prioritisation of ~~Rule Change~~ Proposals

In developing the work plan, the ~~executive officer~~Executive Officer will aim to prioritise Proposals by urgency rating and then submission date, subject to consideration of the following qualifying factors:

- resource availability and workflow practicalities – for example:
  - it may sometimes be necessary to ~~amend the default~~progress lower priority ~~order~~Proposals over higher priority Proposals to allocate resources efficiently and avoid resourcing bottlenecks; and
  - it may be practical to work on lower rated Proposals during the consultation periods for higher rated Proposals;
- Panel availability;
- AEMO availability;
- MAC or GAB availability;
- timing for IT and process development and testing by AEMO and Market Participants;
- the need to coordinate with any Government-led reforms or ERA reviews; and
- special timing considerations~~,~~ (e.g. a small delay to a High rated Proposal may be acceptable provided the Amending Rules ~~still have time to commence~~can be commenced before the relevant Reserve Capacity Cycle deadline~~;~~).
- ~~The Panel availability;~~
- ~~MAC/GAB and AEMO availability;~~
- ~~IT and process development timing; and~~
- ~~the need to coordinate with any Government-led reforms.~~

~~Additionally, the~~ Panel may ~~request changes to~~ask the Executive Officer to change the prioritisation and scheduling of Proposals if it considers that the changes are likely to better achieve the Wholesale Market Objectives or GSI Objectives.

## 5.2 Monitoring and Reporting

The ~~executive officer~~Executive Officer is responsible for:

- ~~monthly~~six weekly reporting to the Panel on the RCP Support work plan via the 'Workflow ~~Summary~~Summary' and the 'Summary of Rule Change ~~Proposals standing agenda items~~Proposals';
- regular reporting to the MAC~~/~~ and GAB on the RCP Support work plan via the 'Overview of Rule Change ~~Proposals standing agenda item~~Proposals';
- monitoring for potential failures to meet the required processing timeframes for each Proposal (given its urgency rating) and reporting any concerns to the Panel~~ and the Executive Director, Markets~~; and
- coordinating any remedial ~~action required~~actions under this framework to address resourcing shortfalls.

Remedial action will be required if~~ open~~ Proposals cannot be progressed using budgeted resources within the timeframes permitted for their urgency rating. Remedial action may include:

- liaising with the ~~relevant~~ ERA~~ managers~~ to increase the use of shared resources or to ~~"borrow"~~'borrow' other ERA resources;
- engaging consultants to perform specialist tasks, where appropriate;
- ~~liaising with the relevant ERA managers to procure~~procuring additional resources through short-term contracts;
- deferring consideration of some Proposals; and
- if the scale of the problem is large enough (e.g. due to ~~the~~ submission of a very large Essential or High ~~rated~~urgency Proposal, or a severe and ongoing resource shortage) and it cannot be addressed within the ERA's overall budget limitations, liaising with the Panel and the ERA to prepare a Treasury submission to ~~increase the ERA budget to meet the~~procure additional ~~resource requirement~~resources.

## 5.3 Interaction with Annual Budgeting Cycle

The ERA commences preparing its annual budget ~~preparation~~ in February each year~~. This is to ensure~~ so that ~~if there is any requirement to~~it can seek ~~a change in the~~changes to its budget ~~from Government, it is done~~ as part of the Government's annual budget estimates process, which occurs in April each year.

The ERA's annual budget ~~preparation~~ process ~~will include~~includes an assessment of whether ~~the budgeted~~sufficient resources are allocated to the Panel ~~have been sufficient~~ to meet ~~the actual~~its likely workload. The Panel and the ERA ~~will~~ use the outcomes of this assessment~~, as well as the Panel's expectation of likely changes in workload for the coming financial year,~~ to determine ~~and agree~~if any ~~required~~ changes are needed to the resourcing levels for the next financial year.

# Appendix: The Wholesale Market Objectives and the GSI Objectives

## Wholesale Market Objectives

The Wholesale Market Objectives are specified in clause 1.2.1 of the Market Rules as follows:

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.

## GSI Objectives

The GSI Objectives are specified in subrule 2(1) of the GSI Rules as follows:

In accordance with section 6 of the GSI Act, the objectives of the Gas Bulletin Board (the GBB) and the Gas Statement of Opportunities (the GSOO) (the GSI Objectives) are to promote the long term interests of consumers of natural gas in relation to:

(a) the security, reliability and availability of the supply of natural gas in the State;

(b) the efficient operation and use of natural gas services in the State;

(c) the efficient investment in natural gas services in the State; and

(d) the facilitation of competition in the use of natural gas services in the State.