RCP | Rule Change Panel
Market Advisory Committee

Meeting Agenda

Meeting Title:	Market Advisory Committee
Date:	Tuesday 11 February 2020
Time:	9:30 AM – 11:45 AM
Location:	Training Room No. 1, Albert Facey House 469 Wellington Street, Perth

Item	Item	Responsibility	Duration
1	Welcome	Chair	5 min
2	Meeting Apologies/Attendance	Chair	5 min
3	Minutes of Meeting 2019_11_26	Chair	5 min
4	Actions Items	Chair	10 min
5	MAC Market Rules Issues List	Chair	5 min
6	Update on the Energy Transformation Strategy (no paper)	ETIU	15 min
7	AEMO Procedure Change Working Group Update	AEMO	5 min
8	Rule Changes		
	(a) Overview of Rule Change Proposals	Chair	5 min
	(b) North Country Spinning Reserve Issue (no paper)	ETIU	25 min
	(c) RC_2014_03: Administrative Improvements to the Outage Process – Consequential Outages and Non-Scheduled Generator commitment and decommitment	RCP Support	25 min

Item	Item	Responsibility	Duration
	(d) RC_2017_02: Implementation of 30-Minute Balancing Gate Closure – enhancement of information used in trading decisions	RCP Support	10 min
	(e) RC_2020_02: Adding a Criteria for Acceptance of a Non-Temperature Dependent Load	RCP Support	15 min
9	General Business	Chair	5 min
Next Meeting: 24 March 2020			

Please note, this meeting will be recorded.

RCP Rule Change Panel
Market Advisory Committee

Minutes

Meeting Title:	Market Advisory Committee (**MAC**)
Date:	26 November 2019
Time:	9:30 AM – 11:35 AM
Location:	Training Room No. 2, Albert Facey House 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	
Sara O'Connor	Economic Regulation Authority (**ERA**) Observer	
Andrew Everett	Synergy	
Shane Duryea	Network Operator	Proxy for Margaret Pyrchla
William Street	Market Generators	Proxy for Jacinda Papps
Wendy Ng	Market Generators	
Daniel Kurz	Market Generators	
Patrick Peake	Market Customers	
Geoff Gaston	Market Customers	
Tim McLeod	Market Customers	
Chayan Gunendran	Market Customers	
Peter Huxtable	Contestable Customers	

Apologies	Class	Comment
Margaret Pyrchla	Network Operator	
Jacinda Papps	Market Generators	
Andrew Stevens	Market Generators	

Also in Attendance	From	Comment
Aden Barker	Energy Transformation Implementation Unit (**ETIU**)	Presenter to 10:55 AM
Jenny Laidlaw	RCP Support	Minutes
Noel Schubert	ERA	Observer
Kei Sukmadjaja	Western Power	Observer
Nicole Markham	AEMO	Observer
Dimitri Lorenzo	Bluewaters Power	Observer
Jo-Anne Chan	Synergy	Observer
Erin Stone		Observer
Ian Porter	Sustainable Energy Now	Observer
Laura Koziol	RCP Support	Observer
Natalie Robins	RCP Support	Observer
Sandra Ng Wing Lit	RCP Support	Observer

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:30 AM and welcomed members and observers to the 26 November 2019 MAC meeting.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above.	
3(a)	**Minutes of Meeting 2019_10_15** Draft minutes of the MAC meeting held on 15 October 2019 were circulated on 29 October 2019. The MAC accepted the minutes as a true and accurate record of the meeting. **Action: RCP Support to publish the minutes of the 15 October 2019 MAC meeting on the Rule Change Panel's (Panel's) website as final.**	**RCP Support**
3(b)	**Minutes of Workshop 2019_10_18 re RC_2017_02** Draft minutes of the MAC workshop held on 18 October 2019 to discuss Rule Change Proposal: Implementation of 30-Minute Balancing Gate Closure (RC_2017_02) were circulated on 1 November 2019. The Chair noted that a revised draft showing suggested tracked changes on page 9 was distributed in the meeting papers. Subject to these changes, the MAC accepted the minutes as a true and accurate record of the workshop.	

Item	Subject	Action
	Action: RCP Support to publish the minutes of the 18 October 2019 MAC workshop on Rule Change Proposal: Implementation of 30-Minute Balancing Gate Closure (RC_2017_02) on the Panel's website as final.	**RCP Support**
3(c)	**Minutes of Workshop 2019_10_25 re RC_2014_03** Draft minutes of the MAC workshop held on 25 October 2019 to discuss Rule Change Proposal: Administrative Improvements to the Outage Process (RC_2014_03) were circulated on 11 November 2019. The MAC accepted the minutes as a true and accurate record of the workshop.	
	Action: RCP Support to publish the minutes of the 25 October 2019 MAC workshop on Rule Change Proposal: Administrative Improvements to the Outage Process (RC_2014_03) on the Panel's website as final.	**RCP Support**
4	**Action Items** The closed action items were taken as read. **Action 19/2019:** Ms Sara O'Connor was uncertain whether the conflict between the Relevant Level Methodology and the early and conditional certification of Intermittent Generators would be addressed by the ERA's Rule Change Proposal or by the Minister as part of changes to the allocation of Capacity Credits to support constrained network access. The ERA intended to hold a workshop with ETIU and AEMO to discuss the proposed changes and report back to the MAC once a decision was reached. **Action 22/2019:** The Chair noted that this action item would be discussed under agenda item 8(b).	
5	**MAC Market Rules Issues List (Issues List) Update** The MAC noted the recent updates to the Issues List. The MAC conducted its annual review of the Issues List and agreed to the following actions: • Issue 31 (LFAS Report): Close the issue, based on advice from Mr Andrew Everett that AEMO no longer requires Synergy to provide it with the relevant information. • Issue 45 (Transfer of responsibility for setting document retention requirements) and Issue 46 (Transfer of responsibility for setting confidentiality statuses): Ms O'Connor agreed to raise the issues within the ERA and report back to the MAC on whether the ERA considered it should take on these functions.	

Item	Subject	Action
	• Issue 53 (TES Recalculation): Close the issue following the submission of Rule Change Proposal: Administrative Improvements to Settlement (RC_2019_04). • Remove “Review of roles in the market” from the list of preliminary reviews in Table 3. • Update the notes for the preliminary review “The Reserve Capacity Mechanism (excluding the pricing mechanism)” to clarify that the preliminary discussion should address outstanding customer-side issues. • Issue 22 (Prepayments and Credit Limits): Keep the issue on hold pending the completion of AEMO’s Reduction of Prudential Exposure 2 project (scheduled for Q2 in 2020). • Issue 27/54 (Review of Protected Provisions): Mr Matthew Martin agreed to work with RCP Support to develop principles for identifying which rules should be Protected Provisions. • Issue 50 (Minimum STEM Price): Close the issue following the submission of Rule Change Proposal: Amending the Minimum STEM Price definition and determination (RC_2019_05). • Issue 53 (Provisions relating to generator models): Mr Dean Sharafi agreed to provide an update to the MAC on the arrangements for generator performance models proposed by the Foundation Regulatory Frameworks work stream.	
	Action: The ERA to advise the MAC on whether the ERA considered it should be assigned responsibility under the Market Rules for setting document retention requirements and confidentiality statuses.	**ERA**
	Action: RCP Support and Energy Policy WA (EPWA) to develop principles for identifying which rules should be Protected Provisions for presentation and discussion by the MAC.	**RCP Support/ EPWA**
	Action: AEMO to provide an update to the MAC on the arrangements for generator performance models proposed by the Foundation Regulatory Frameworks work stream.	**AEMO**
6	**Update on the Energy Transformation Strategy (ETS)** Mr Aden Barker provided the following updates on the ETS. • ETIU was nearing completion of its one-on-one meetings on the Capacity Credits rights proposal, and intended to submit a detailed design to the Energy Transformation Taskforce (**Taskforce**) for approval in late January 2020. ETIU	

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	intended to provide an update on the Capacity Credits rights proposal at the 17 December 2019 meeting of the Transformation Design and Operation Working Group. • The Taskforce was on track for submission of the Distributed Energy Resources (**DER**) Roadmap to the Minister in December 2019, following extensive consultation that included one-on-one meetings and workshops. • The public release of the Assumptions and Methodology for the Whole of System Plan (**WOSP**) was scheduled for early December 2019. Mr Barker expected that an update on initial findings of the modelling would be provided to the MAC in the first quarter of 2020. • Nine papers had been released to date for the Delivering the Future Power System work stream, with two further papers due for release. The first paper was an information paper confirming previous discussions and decisions on frequency operating standards and the treatment of islands. ETIU intended to implement these decisions in the Market Rules in the New Year. The second paper was a more detailed information paper on Technical Rules change management. The paper would be accompanied by draft amendments to the Market Rules and Electricity Network Access Code 2004 (**Access Code**), for stakeholder comment prior to the formal Ministerial consultation period on the Access Code changes sometime in the New Year. • ETIU intended to hold a workshop on 11 December 2019 to review the draft Amending Rules for the governance framework for constraint equations. ETIU planned to release the draft Amending Rules and an explanatory memorandum in early December for formal consultation until the end of January 2020. • The Taskforce was meeting just before Christmas to consider decisions on Essential System Services (**ESS**) Scheduling and Dispatch, along with various market settlement matters including the implementation of five-minute settlement, uplift payments and ESS settlement. ETIU expected that the associated information papers would be published during the following week. The following points were discussed: • In response to a question from Mr Chayan Gunendran, Mr Barker advised that there will be an element of locationality in the initial allocation of Capacity Credits, in	

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	that it will be based on modelling that takes network constraints into account. • Mr Gunendran noted that from a customer's viewpoint 55 percent of costs were network-related, and asked whether the Taskforce would be considering whole of system cost and not just focus on generation costs. Mr Barker replied that this was being considered across all work streams. • Mr Ian Porter asked whether the submissions to the Minister for the DER Roadmap and the WOSP would be made public. Mr Barker replied that the Taskforce would follow the usual processes for advice to the Minister, and that ultimately the WOSP would be what the Minister approved. • In response to a question from Mr Porter, Mr Barker explained that modelling for the WOSP had already commenced, and that the intent was to publish the WOSP assumptions and methodology, except for those assumptions that cannot be disclosed because they are confidential. • In response to a question from Mr Patrick Peake, Mr Barker confirmed that work on the new dispatch engine was running to schedule, although the timeframes continued to be extremely tight. Mr Barker noted that ETIU was seeking to include as much detail as possible in the information papers, and to issue draft rule packages as early as possible. However, Mr Barker warned that to remain on track for a 1 October 2022 implementation, the consultation periods for the draft rule packages might be shorter than ideal. • Mr Daniel Kurz noted that Market Participants would need as much time as possible to build their systems. Mr Barker replied that he was keen to meet with Market Participants to discuss their timing issues; and noted that extending the consultation periods for either high-level principles or rule drafting would delay the provision of a complete market design that Market Participants could use for their system development. • Mr William Street asked when a set of constraint equations that could be used for the purposes of a market trial would become available. Mr Sharafi replied that Western Power would provide limit equations to AEMO, and AEMO would use the limit equations to develop the required constraint equations. AEMO was in the process of recruiting staff to	

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	undertake the work, which would begin once the recruitment process was complete. Mr Barker noted that constraint equations were also required for the purposes of Capacity Credit allocation, although they might not be exactly the same as those that will be used for dispatch. Market Participants would be able to seek more information about the constraint equations used for Capacity Credit allocation from the ETIU staff working on the Capacity Credit rights proposal. • Mr Geoff Gaston asked what checks and balances would exist for the limit advice provided by Western Power and the constraint equations developed by AEMO. Mr Barker provided a brief summary of the arrangements proposed in the recent information paper on constraints governance; and noted that ETIU was considering how it might audit or provide some due diligence around the initial set of constraint equations.	
7	**AEMO Procedure Change Working Group (APCWG) Update** Mr Sharafi noted that the next meeting of the APCWG was scheduled for 12 December 2019 and would deal with changes to the Power System Operation Procedure: Facility Outages arising from Rule Change Proposal: Outage Planning Phase 2 – Outage Process Refinements (RC_2013_15). The MAC noted the update on AEMO's Market Procedures.	
8(a)	**Overview of Rule Change Proposals** The MAC noted the overview of Rule Change Proposals (**Overview**). The Chair noted a new table in the Overview, which listed the expected activities of the Panel until the next MAC meeting. The MAC agreed that RCP Support should continue to provide this table in the Overview.	
8(b)	**North Country Spinning Reserve Issue** <u>Update on North Country Connection Arrangements</u> The Chair noted that during the last few MAC presentations on the North Country Spinning Reserve issue there was some confusion about when NewGen Neerabup and the new Generator Interim Access (**GIA**) generators (Yandin and Warradarge) will form a single contingency. RCP Support met with Western Power after the last MAC meeting to seek clarity on the question.	

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Ms Jenny Laidlaw gave an overview of the relevant North Country connection arrangements. Ms Laidlaw noted that Neerabup Terminal was usually connected to the 132 kV network by a 132 kV transformer. NewGen Neerabup would only be part of the same contingency as Yandin and Warradarge when the connection to the 132 kV network was not in operation. This could occur if:

- the 132 kV transformer was out of service due to a Planned or Forced Outage;
- the connection needed to be open to comply with network limits created by an outage of another item of network equipment; or
- the connection needed to be open under certain rare, extreme peak conditions to avoid overloading the 132 kV network.

The following points were discussed:

- Ms Laidlaw noted that AEMO raised a question about the Capacity Credit implications of the Spinning Reserve issue at the 15 October 2019 MAC meeting. RCP Support's understanding was that the allocation of Capacity Credits would only be affected if the generators could not run concurrently during the peak demand periods contemplated by the Reserve Capacity Mechanism.
- Mr Street questioned how often the 132 kV transformer was out of service, and how likely it would be for the transformer to be subject to an outage at the time of a one-in-ten year peak demand event. Ms Wendy Ng noted that events of this type had never affected the operation of NewGen Neerabup. Ms Laidlaw clarified that the Capacity Credit-related concerns only applied to situations where all the relevant network equipment was available for service, but the 132 kV connection needed to be open to avoid overloading the 132 kV network.
- After some discussion, Mr Shane Duryea and Mr Noel Schubert agreed that opening the connection between Neerabup Terminal and the 132 kV network to avoid overloading the latter during a peak load period would not constitute an outage.
- Ms Laidlaw questioned whether, in a scenario where demand was at a one-in-ten year peak level and all network equipment was available for service, all of the relevant generators with Capacity Credits (including NewGen Neerabup, Yandin, Warradarge, Pinjar, Emu Downs and all other North Country Intermittent Generators) could generate

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	to their Capacity Credit level without creating a security issue; and if so whether this would require opening the connection between Neerabup Terminal and the 132 kV network. Mr Martin Maticka offered to investigate the question in consultation with Western Power and report back to the MAC with the answer. Ms Laidlaw noted that the issue had potential implications for the ETS Capacity Credit rights proposal. <u>RCP Support update and rules interpretation</u> The Chair noted that RCP Support had attended the following meetings on the North Country Spinning Reserve issue since the 15 October 2019 MAC meeting: • A meeting on 31 October 2019 with Western Power to discuss the network configuration in the North Country. During this meeting, Western Power indicated that although other examples existed of generators sharing a single line contingency under system normal conditions, none of these were likely to form the largest single contingency in the SWIS. • A meeting on 13 November 2019, organised by AEMO and attended by AEMO, RCP Support, Western Power, Bright Energy, Alinta and ERM Power, where AEMO provided a briefing on some operational matters, and held a discussion on the potential Rule Change Proposals. At this meeting, RCP Support raised some questions about Western Power's obligations under clause 2.2.1(d) of the Technical Rules, and the impact of these on the Spinning Reserve issue. • A meeting on 19 November 2019, organised by AEMO and attended by AEMO, RCP Support and EPWA, to discuss some open design questions relating to the proposed rule changes. At this meeting, RCP Support reiterated its questions about the impact of clause 2.2.1(d) of the Technical Rules. • A meeting on 25 October 2019 with Western Power to discuss Western Power's interpretation of clause 2.2.1(d). The Chair noted that at the 31 October 2019 and 13 November 2019 meetings, AEMO and Western Power advised that AEMO will provide Western Power with a maximum contingency MW size number in real time, and Western Power will use the GIA tool to ensure that Yandin and Warradarge do not generate at a level that causes a single contingency exceeding this size. RCP Support reviewed the relevant	

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	Technical Rules and Market Rules, and based on its interpretation had asked how Western Power interprets its obligations. The Chair advised that RCP Support's interpretation was that if Yandin and Warradarge are connected as proposed, the new connections will be compliant with the Technical Rules if Western Power ensures that their combined output, plus NewGen Neerabup's output when it is part of the same contingency, does not exceed the standard for Spinning Reserve prescribed in clause 3.10.2 of the Market Rules. Clause 2.2.1(d) of the Technical Rules appeared to place this obligation on Western Power, irrespective of whether AEMO can support a higher Spinning Reserve requirement. The Chair considered that the requirement in the Technical Rules appeared to exist not just to support power system security, but also to avoid excessive Spinning Reserve costs which would eventually be borne by consumers. The ERA added this clause to the initial Technical Rules, which the Chair considered supported the view that it existed to avoid inefficient levels of Spinning Reserve. The Chair suggested that the Market Rules were drafted on the assumption that the requirement in clause 2.2.1(d) of the Technical is met. For example, the full runway Spinning Reserve cost allocation method appeared to be based on this assumption, as was the allowance for the maximum capacity of the largest generating unit (rather than the largest contingency) in the Planning Criterion. The Chair was unaware of any cost-benefit analysis to justify removal of the obligation in clause 2.2.1(d) of the Technical Rules, or to increase the Spinning Reserve standard in clause 3.10.2 of the Market Rules. The Chair noted that Western Power and AEMO appeared to be proposing an arrangement that would allow Western Power to continue to meet its obligations under clause 2.2.1(d) by taking the maximum contingency number provided by AEMO and using the GIA tool to ensure the new wind farms do not create a single contingency that exceeded this size. However, it appeared that AEMO intended to supply Western Power with the size of the largest contingency it was expecting, except where it could not enable enough Spinning Reserve to support a contingency of that size, in which case it would provide the size of the contingency that it could support. RCP Support was not clear how this would ensure that Western Power continued to comply with the Technical Rules.	

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	The Chair considered that if RCP Support's interpretation was correct and Western Power constrained the output of Yandin and Warradarge to ensure its compliance with the Technical Rules, then any Rule Change Proposal would likely need to focus on whether increasing the Spinning Reserve standard in clause 3.10.2 to accommodate the new generators would better achieve the Wholesale Market Objectives; and if so, what consequential changes should be made to other features in the Market Rules, such as the Spinning Reserve cost allocation rules, and what transitional arrangements might be needed.	
	The Chair considered that the issue was fairly urgent because AEMO's margin value submission for the 2020/21 financial year was due in four days, with the ERA's final decision due by 31 March 2020.	
	Mr Duryea considered it was fairly disappointing that RCP Support had taken what he considered was a very bureaucratic interpretation of the Technical Rules. Mr Duryea considered that in the worst case this interpretation would prevent the connection of renewable energy to the network, or the connection of renewable generators that were bigger than the largest coal-fired generator.	
	Ms Laidlaw noted that a Rule Change Proposal could be used to increase the Spinning Reserve standard if it was inefficiently low (e.g. if the energy savings arising from an increase in the standard outweighed the likely increase in Spinning Reserve costs).	
	The Chair considered that the alternative interpretation was that there was no limit on Spinning Reserve, which could result in greatly increased costs for consumers. Mr Everett added that it may not always be possible to meet a materially increased Spinning Reserve requirement, particularly in times of very low system demand.	
	Mr Duryea questioned the way forward on the issue. Mr Barker considered the issue would be largely resolved by the new market arrangements, so the question was what the impact of the issue would be over the intervening period. Noting there had been no cost-benefit analysis, Mr Barker questioned whether it would be beneficial to the market as a whole to have a higher Spinning Reserve requirement (given that it might only need to be in place for a certain period) versus curtailing zero marginal cost energy. Accepting the current agreement that had been worked out in terms of the interpretation of the rules, it remained an open question as to what the actual impact of that was on the market as a whole.	

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	Mr Schubert suggested that modelling be undertaken to determine the most efficient outcome. Mr Schubert noted that the preliminary indication from the recent margin values modelling was that the benefit of the lower-cost energy would be much greater than the increase in Spinning Reserve costs. Mr Porter suggested that storage should be used to reduce Spinning Reserve costs. Mr Duryea considered that the immediate problem related to the period before the implementation of new market arrangements that would facilitate the introduction of new technologies such as storage. Mr Barker considered that the new market would incentivise investment in new technologies like storage if it was appropriate. Mr Barker reiterated that the focus was on the next 18 months, noting that a cost-benefit analysis would need to be conducted with some rigour. If warranted by the cost-benefit analysis, the rule changes would then need to be developed and made, which could potentially involve the use of the Minister's rule making powers for the purposes of expediency. Mr Street asked who should undertake the cost-benefit analysis. Mr Barker questioned who was in the best position to undertake the analysis (i.e. who had access to the necessary data). Mr Schubert suggested that the margin values model developed by EY could be applicable to a cost-benefit analysis. Ms O'Connor did not consider herself in a position to comment on EY's modelling until AEMO made its margin values submission to the ERA. Mr Maticka indicated that the margin values model was very complex, and while AEMO could investigate its use for a cost-benefit analysis the work would be difficult, incur additional costs, and could easily take until February 2020 or longer. Mr Maticka also noted that the model was developed for a specific purpose and questioned whether it was the best model to use for the cost-benefit analysis. Mr Street advised that based on Alinta's preliminary calculations the value of lost energy would be about four or five times the likely increase in Spinning Reserve costs, with a likely net benefit in the order of $10 million per year. There was some discussion about whether using a dynamic tool to determine the optimal level of Spinning Reserve in real time would eliminate the need for any more general limits on the Spinning Reserve requirement. Ms Laidlaw suggested that while the tool might select the most efficient option from those available at the time, if those options were restricted by network infrastructure limitations the outcome could still be inefficient.	

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	Mr Street noted that if the 132 kV transformer was in operation, the new wind farms would create a maximum contingency of 390 MW, which was only 60 MW greater than the size of the largest generator. Mr Sharafi noted that the largest single contingency at night was currently much less than 330 MW.	
	Ms Laidlaw considered that given Mr Street's comments it might be in Alinta's interest to submit a Rule Change Proposal to increase the standard. There was some discussion about what should be included in such a Rule Change Proposal. The Chair suggested that a Rule Change Proposal would need to address changes to the Spinning Reserve standard, the Spinning Reserve cost allocation methodology and any transitional requirements.	
	Mr Sharafi advised that AEMO still proposed to develop a Rule Change Proposal to implement AEMO's Options 2(a) and 2(b), if the MAC wanted these options to proceed. Mr Maticka noted that Options 2(a) and 2(b) did not include changes to increase the Spinning Reserve standard. There was further discussion about the Spinning Reserve standard and Western Power's obligations under clause 2.2.1(d) of the Technical Rules.	
	Mr Peake asked whether, if a causer-pays approach was applied to the new wind farms, both would be treated equally or whether the additional costs would be allocated to the second generator connected.	
	Mr Barker asked whether the MAC's request to AEMO to develop a Rule Change Proposal included changes to increase the Spinning Reserve standard. Mr Maticka expressed concern about the time and effort needed for a cost-benefit analysis to support a change to the standard.	
	Ms Laidlaw suggested that AEMO might not be obliged to undertake a full cost-benefit analysis since the Panel would probably need to carry out its own independent analysis of the changes.	
	Mr Maticka advised that AEMO would need to consider whether it was able to extend the Rule Change Proposal to include a change to the Spinning Reserve standard, and would report back to the MAC as soon as possible. The Chair noted that this would allow other interested parties, such as Alinta or Bright Energy, to decide whether they wished to develop a Rule Change Proposal if AEMO could not.	
	Mr Daniel Kurz expressed sympathy for the generators affected by the Spinning Reserve issue, noting the significant impact on Bluewaters of the five-year delay of reforms to the Spinning Reserve cost allocation method.	

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	Action: AEMO, in consultation with Western Power, to investigate and report back to the MAC on whether, in a scenario where demand was at a one-in-ten year peak level and all network equipment was available for service, all generators with Capacity Credits (including NewGen Neerabup, Yandin, Warradarge, Pinjar, Emu Downs and all other North Country Intermittent Generators) could generate to their Capacity Credit level without creating a security issue; and if so whether this would require opening the connection between Neerabup Terminal and the 132 kV network.	**AEMO**
	Action: AEMO to advise the MAC on whether it could include changes to the Spinning Reserve standard to accommodate the output of Yandin and Warradarge in a Rule Change Proposal to implement AEMO's Options 2(a) and 2(b).	**AEMO**
8(c)	**Market Participant Fee calculation manifest error** The Chair noted that AEMO had identified what it considered to be a manifest error in the calculation of Market Participant Fees under clause 9.13.1 of the Market Rules. The clause as drafted required AEMO to pay Market Participant Fees to Market Customers for Loads instead of charging them. In response to a question from Mr Peter Huxtable, Mr Maticka confirmed that AEMO was compliant with the intent of the rules and charged the fee to Market Customers. The MAC agreed that the problem was a manifest error in the Market Rules. The MAC asked the Panel to develop a Rule Change Proposal to correct the error and progress it as quickly as possible under the Fast Track Rule Change Process, provided this did not adversely affect the progression of other high-urgency Rule Change Proposals.	
8(d)	**Data and IT Procedure Options** Mr Maticka gave a presentation on potential changes to clause 2.36.5 of the Market Rules, which requires AEMO to document the data and IT interface requirements, including security standards required for Market Participants to operate in the Wholesale Electricity Market (**WEM**), in the relevant procedure to which the system pertains. A copy of AEMO's presentation is available in the meeting papers. The following points were discussed: • Mr Maticka questioned whether Market Participants obtained any value from the current Market Procedure: Data	

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	and IT Interface Requirements. Mr Kurz considered that if the procedure's upkeep costs were low it should be retained, as it provided a point of reference for Market Participants and was useful to justify their IT capital expenditure. Mr Kurz agreed with Mr Maticka that an obligation to repeat the relevant information in each Market Procedure was not warranted. • Ms Laidlaw suggested that a single Market Procedure could be useful if it contained basic information such as a high level overview of AEMO's WEM systems, a summary of the available IT documentation and where to find it, details of the change management process used for IT documentation not contained in Market Procedures, and details of the processes used to manage system outages and software upgrades. • The MAC agreed that AEMO should maintain a single Market Procedure with updated content of value to Market Participants (option 1 in AEMO's presentation). Mr Maticka asked Ms Laidlaw to send him her suggestions for the content of the Market Procedure. Ms Laidlaw agreed and proposed to seek additional suggestions from MAC members. • The MAC expressed general support for AEMO to develop a Rule Change Proposal to implement the preferred option 1. **Action: RCP Support to prepare a list of suggested topics for inclusion in a Market Procedure to replace the Market Procedure: Data and IT Interface Requirements, and to circulate the list to the MAC for comment and additional suggestions.**	 **RCP Support**
9	**General Business** <u>MAC Call for Nominations 2020</u> The Chair noted that the Panel would shortly publish a call for nominations to fill four positions that will be vacated early in 2020. The members whose appointments were ending were Market Generator representatives Andrew Stevens and Daniel Kurz, and Market Customer representatives Tim McLeod and Chayan Gunendran. The Chair thanked these members for their contribution to the MAC and invited them to re-nominate for their positions.	

Item	Subject	Action
	<u>Issues receiving emails from RCP Support</u> The Chair noted that a few MAC members appeared to have had some issues with receiving emails from RCP Support, and asked members to notify RCP Support of any further issues they experience. In response to a question from Mr Peake, attendees expressed no concerns about visible email addresses in MAC communications issued by RCP Support.	

The meeting closed at 11:35 AM.

RCP Rule Change Panel
Market Advisory Committee

Agenda Item 4: MAC Action Items

Meeting 2020_02_11

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

Item	Action	Responsibility	Meeting Arising	Status
19/2019	The Economic Regulation Authority (**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	**Closed** The Market Rules governing the early and conditional certification of intermittent generation may be addressed by the rule changes that the Energy Transformation Implementation Unit (**ETIU**) are developing to assign Capacity Credits under the constrained network access model. The ERA will liaise with ETIU as it develops these rule changes. The ERA intends to base RC_2019_03 on the revised Market Rules developed by ETIU and approved by the Minister.

Item	Action	Responsibility	Meeting Arising	Status
22/2019	AEMO to develop a Pre-Rule Change Proposal for AEMO's 'option 2' (i.e. option 2a and 2b) to address the North Country Spinning Reserve issue, as discussed at the 29 July 2019 MAC meeting), for discussion at the 26 November 2019 MAC meeting.	AEMO	2019_10_15	**Closed** This matter was discussed at the MAC meeting on 26 November 2019 – see Agenda Item 8(b). Further action items were allocated at that MAC meeting – see Action items 30/2019 and 31/2019.
24/2019	RCP Support to publish the minutes of the 15 October 2019 MAC meeting on the Rule Change Panel's (**Panel**) website as final	RCP Support	2019_11_26	**Closed** The minutes were posted on the Panel's website on 26 November 2019.
25/2019	RCP Support to publish the minutes of the 18 October 2019 MAC workshop on Rule Change Proposal: Implementation of 30-Minute Balancing Gate Closure (RC_2017_02) on the Panel website as final.	RCP Support	2019_11_26	**Closed** The minutes were posted on the Panel's website on 17 December 2019.
26/2019	RCP Support to publish the minutes of the 25 October 2019 MAC workshop on Rule Change Proposal: Administrative Improvements to the Outage Process (RC_2014_03) on the Panel website as final.	RCP Support	2019_11_26	**Closed** The minutes were posted on the Panel's website on 26 November 2019.
27/2019	The ERA to advise the MAC on whether the ERA considered it should be assigned responsibility under the Market Rules for setting document retention requirements and confidentiality statuses.	ERA	2019_11_26	**Open** The ERA is considering its position regarding this action item and will provide a response to the MAC as soon as possible.

Item	Action	Responsibility	Meeting Arising	Status
28/2019	RCP Support and EPWA to develop principles for identifying which rules should be Protected Provisions for presentation and discussion by the MAC.	RCP Support and EPWA	2019_11_26	**Open** RCP Support and EPWA have commenced discussions on the principles for determining which rules should be Protected Provisions and will present them to the MAC for discussion in the near future.
29/2019	AEMO to provide an update to the MAC on the arrangements for generator performance models proposed by the Foundation Regulatory Frameworks work stream.	AEMO	2019_11_26	**Open** ETIU is still in the process of finalising the Generator Performance Standards and AEMO or ETIU will be in a position to advise on this matter once ETIU has completed this work.
30/2019	AEMO, in consultation with Western Power, to investigate and report back to the MAC on whether, in a scenario where demand was at a one-in-ten year peak level and all network equipment was available for service, all generators with Capacity Credits (including NewGen Neerabup, Yandin, Warradarge, Pinjar, Emu Downs and all other North Country Intermittent Generators) could generate to their Capacity Credit level without creating a security issue; and if so whether this would require opening the connection between Neerabup Terminal and the 132 kV network.	AEMO	2019_11_26	**Open** AEMO and Western Power will provide a verbal update on this action item at the MAC meeting on 11 February 2020.

Item	Action	Responsibility	Meeting Arising	Status
31/2019	AEMO to advise the MAC on whether it could include changes to the Spinning Reserve standard to accommodate the output of Yandin and Warradarge in a Rule Change Proposal to implement AEMO's Options 2(a) and 2(b).	AEMO	2019_11_26	**Open** This action item will be discussed under Agenda Item 8(b) at the MAC meeting on 11 February 2019.
32/2019	RCP Support to prepare a list of suggested topics for inclusion in a Market Procedure to replace the Market Procedure: Data and IT Interface Requirements, and to circulate the list to the MAC for comment and additional suggestions.	RCP Support	2019_11_26	**Closed** RCP Support sent an email to the MAC on 31 January 2020 suggesting that the following IT-related information may be suitable for inclusion in a Market Procedure: • a high-level overview of AEMO's WEM systems; • a summary of the important IT-related documentation provided by AEMO (i.e. documentation that Rule Participants need to build their systems, participate in the market and comply with their obligations under the Market Rules and Market Procedures); • details of the change management processes used for important IT-related documentation that is not contained in Market Procedures; • details of the processes used to manage IT system outages (planned and unplanned); and • details of the processes used to manage software upgrades, including the provision of specifications and other essential

Item	Action	Responsibility	Meeting Arising	Status
				information to Rule Participants, testing arrangement, and change control. RCP Support asked MAC members to provide comments by COB 7 February 2020, after which RCP Support would collate the comments and send them to AEMO for consideration.

RCP Rule Change Panel
Market Advisory Committee

Agenda Item 5: MAC Market Rules Issues List Update

Meeting 2020_02_11

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;
- provide any further updates to existing issues; and
- indicate whether there are any new issues to be raised.

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 November 2018	**LFAS Report** 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 **MAC ratings:** Low: Alinta, Bluewaters Medium: Geoff Gaston, AEMO High: Peter Huxtable **Status:** **Closed** Synergy has advised that AEMO no longer requires Synergy to provide it with the relevant information, so a Rule Change Proposal is no longer required to address issue 31 and the MAC agreed to close issue 31 at its meeting on 26 November 2019.
45	AEMO May 2018	**Transfer of responsibility for setting document retention requirements** 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 **MAC ratings:** Low **Status:** The ERA is to provide its position on this proposal at the MAC meeting on 11 February 2020.

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
46	AEMO May 2018	**Transfer of responsibility for setting confidentiality statuses** 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 **MAC ratings:** Low **Status:** The ERA is to provide its position on this proposal at the MAC meeting on 11 February 2020.
47	AEMO September 2018	**Market Procedure for conducting the Long Term PASA (clause 4.5.14)** 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. 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 **MAC ratings:** Low **Status:** This issue has not been progressed.
52	MAC February 2019	**North Country Spinning Reserve** 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 **MAC ratings:** High **Status:** The MAC discussed this issue at its meetings on 11 June and 29 July 2019. AEMO has proposed three options to address this issue. The MAC further discussed this issue at its meeting on 3 September 2019, where the MAC supported option 3. AEMO agreed to develop a

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
			Pre-Rule Change Proposal for option 3 for presentation to the MAC at its meeting on 26 November 2019. The MAC further discussed this issue at its meeting on 15 October 2019, where the MAC changed its view to instead support option 2. AEMO, RCP Support, ERM Power, Alinta and Synergy met on 13 November 2019; and AEMO, RCP Support and EPWA met on 18 November 2019 to discuss the North Country Spinning Reserve issue. AEMO was to develop a Pre-Rule Change Proposal for option 2 for presentation to the MAC at its meeting on 26 November 2019. The MAC further discussed this issue at its meeting on 26 November 2019 and agreed on some further actions by AEMO to progress the matter. However, EPWA, AEMO and Western Power subsequently held further discussions on this issue and EPWA will advise the MAC on outcomes from these discussions at the MAC meeting 11 February 2020 – see Agenda Item 8(b).
53	Alinta February 2019	**TES Recalculation** Alinta is seeking a rule change to allow the recalculation of TES after the current 15 Business Day deadline.	**Panel rating:** Low **MAC ratings:** Low

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
			Status: Closed Pre-Rule Change Proposal: Administrative Improvements to Settlement (RC_2019_04) includes changes to allow AEMO to recalculate TES values after the 15 Business Day deadline if it identifies an error in the input values. The MAC discussed RC_2019_04 at its meeting on 15 October 2019, where the MAC confirmed that it did not consider there was any need for additional changes to the calculation of TES beyond those proposed in RC_2019_04 (e.g. broader changes to require recalculation of values using interval meter data). The MAC agreed at its meeting on 26 November 2019 to close issue 53 following submission of RC_2019_04.
55	MAC April 2019	**Conflict between Relevant Level Methodology and the early and conditional certification of Intermittent Generators** 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 **MAC ratings:** Low **Status:** 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**).

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
			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: • An early certification application may be submitted at any time before 1 January of Year 1 of the Reserve Capacity Cycle to which the application relates [clause 4.28C.2]. • 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: o which Scheduled Generators, DSPs, and Non-Scheduled Generators would apply for certification; or o what level of CRC would be assigned to these Scheduled Generators and DSPs.

			AEMO also stated that: • Neither a complete set of system demand and Facility actual meter data is available nor are the expected capacity estimates of new Candidate Facilities. • 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. The MAC discussed this issue at its meeting on 3 September 2019 where it was noted that the 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. The Market Rules governing the early and conditional certification of intermittent generation may be addressed by the rule changes that ETIU is developing to assign Capacity Credits under the constrained network access model. The ERA will liaise with ETIU as it develops these rule changes. The ERA intends to base RC_2019_03 on the revised Market Rules developed by ETIU and approved by the Minister.

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
56	Perth Energy July 2019	**Issues with Reserve Capacity Testing** • 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. • There is a discrepancy between the number of Trading Intervals for self-testing vs. AEMO testing. • There is ambiguity in the timing requirements for a second test when the relevant generator is on an outage. • There is ambiguity on the number of Capacity Credits that AEMO is to assign when certain test results occur.	**Panel rating:** TBD **MAC ratings:** TBD **Status:** 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 November 2017	**IRCR calculations and capacity allocation** 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 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 November 2017	Penalties for outages.	To be considered in the preliminary review of the Reserve Capacity Mechanism.
4	Shane Cremin November 2017	Incentives for maintaining appropriate generation mix.	To be considered in the preliminary review of the Reserve Capacity Mechanism.
9	Community Electricity 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 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. Therefore, the non-BTM Market Participants are subsiding the BTM generation in the WEM. Subsidy does not promote efficient economic outcome. Rapid growth of BTM generation will only exacerbate this inefficiency if not promptly addressed. 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. 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. 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 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. 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. Recommendations: to review the Market Fees structure including the cost recovery mechanism for a reform program. The cost saving from improved economic efficiency can be passed on to the end consumers, hence promoting the Wholesale Market Objectives.	
30	Synergy November 2017	**Reserve Capacity Mechanism** 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: • assessment of reserve capacity requirement criteria, reserve capacity capability and reserve capacity obligations; • IRCR assessment; • Relevant Demand determination; • determination of NTDL status; • Relevant Level determination; and • assessment of thermal generation capacity. 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 November 2017	**BTM generation and apportionment of Market Fees, ancillary services, etc.** 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. 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 November 2017	**Commissioning Test Process** 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. 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: • withdraw the Commissioning Test Plan; or • 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. **Specific Issues:** 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. **Examples for improvements are:** • allowing participants to manage delays to the start of an approved plan; and • allowing participants to repeat tests and push the remainder of the Commissioning Test Plan out. 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): o 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. o 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): o 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. **Status:** Review deferred until Issues 11 and 12 are reopened following completion of the Energy Transformation Strategy. **Status:** Preliminary discussion is not yet scheduled. The MAC agreed at its meeting on 26 November 2019 to remove this item from Table 3.
(2) Behind-the-meter issues	**Issues:** 2, 16, 35. **Status:** Preliminary discussion is not yet scheduled. The MAC noted that EPWA was currently working on its DER Roadmap, which will address behind-the-meter issues (amongst other things). The MAC agreed to defer a preliminary discussion of behind-the-meter issues until the DER Roadmap is published and then consider whether a discussion is still required.
(3) Forecast quality	**Issues:** 9. **Status:** Preliminary discussion is not yet scheduled.
(4) Commissioning Tests	**Issues:** 39. **Status:** Preliminary discussion is not yet scheduled.
(5) The basis of allocation of Market Fees	**Issues:** 2, 16, 23 and 35. **Status:** Preliminary discussion is not yet scheduled.
(6) The Reserve Capacity Mechanism (excluding the pricing mechanism)	**Issues:** 1, 3, 4, and 30. **Status:** Preliminary discussion is not yet scheduled. The preliminary discussion should address outstanding customer-side issues.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
7	Community Electricity 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 November 2017	Review of participant and facility classes to address current and looming issues, such as: • incorporation of storage facilities; • distinction between non-scheduled and semi-scheduled generating units; • reconsideration of potential for Dispatchable Loads in the future (which were proposed for removal in RC_2014_06); • whether to retain Interruptible Loads or to move to an aggregated facility approach (like Demand Side Programmes); and • whether to retain Intermittent Loads as a registration construct or to convert to a settlement construct. 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). Treatment of storage facilities was considered under the preliminary review of the treatment of storage facilities in the market.
11	AEMO November 2017	**Whole-of-system planning oversight:** As explained in AEMO's submission to the ERA's review of the WEM, AEMO considers the necessity of the production of an	This issue was initially flagged for consideration as part of the preliminary review of roles in the market.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		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 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). This function would support the achievement of power system security and reliability, in line with Wholesale Market Objective (a).	However, ETIU has advised that the issue will be covered as part of the Energy Transformation Strategy, so the issue has been put on hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020). ETIU is currently developing a Whole of System Plan (**WOSP**) to be delivered to Government and published in mid-2020. ETIU has indicated that the intent is to develop and publish updated Whole of System Plans on an ongoing, regular basis. The MAC agreed to keep issue 11 open pending publication of the WOSP.
12	AEMO November 2017	**Review of institutional responsibilities in the Market Rules.** 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). EPWA 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

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
			Regulatory Frameworks workstream are known (mid-2020).
14/36	Bluewaters and ERM Power November 2017	**Capacity Refund Arrangements:** The current capacity refund arrangement is overly punitive as Market Participants face excessive capacity refund exposure. This refund 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: • 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 • excessive insurance premiums and cost for meeting prudential support requirements. 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: • 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 • unnecessary excessive insurance premium and prudential support costs, the saving of which can be passed on to consumers.	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 agreed that this issue has a low priority and should remain on hold for another 12 months.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
17	Bluewaters 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. This can result in under reporting of Forced Outages, and as a consequence, use of incorrect information used in WEM settlements. 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. Accurately reporting outages will enable the WEM to function as intended and will help meet the Wholesale Market Objectives.	On hold pending a final decision on RC_2014_03: Administrative Improvements to the Outage Process.
18	Bluewaters 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. Bluewaters recommended amending the Market Rules to allow Market Participants to respond to the draft margin values determination by altering its Spinning Reserve offer. 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	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**
		to lead to a more efficient economic outcome and in turn promote the Wholesale Market Objectives.	
19	Bluewaters November 2017	The Spinning Reserve margin values evaluation process is deficient for the following reasons: • shortcomings in the process for reviewing assumptions; • inability to shape load profile; • lack of transparency: (a) modelling was a "black box"; (b) confidential information limits stakeholders' ability to query the results; and • lack to retrospective evaluation of spinning reserve margin values. As a result, the margin values have been volatile, potentially inaccurate and not verifiable. Recommendation: conduct a review on the margin values evaluation process and propose rule changes to address any identified deficiencies. 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: • promoting transparency – better informed Market Participants would be able to better respond to Spinning Reserve requirement in the WEM; and	On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020). Also, AEMO and the ERA to consider whether any options exist to improve transparency of the current margin values process.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		• 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.	
22	Bluewaters 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). 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). 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). 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. This unnecessary duplication is likely to give rise to higher-than-necessary prudential cost burden in the WEM; which creates	On hold pending completion of AEMO's 'Reduction of Prudential Exposure 2' project scheduled for the second quarter of 2020.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		economic inefficiency that is ultimately passed on the end consumers. Recommendation: amend the Market Rules and/or procedures to eliminate the duplication of prudential burden on Market Participants. 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 November 2017 MAC August 2018	Review what should constitute a Protected Provision of the Market Rules, to provide greater clarity over the role of the Minister for Energy. 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 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.	On hold pending the outcome of an EPWA review of the current Protected Provisions in the Market Rules, with timing dependent on Energy Transformation Strategy. EPWA and RCP Support are to develop principles for identifying which rules should be Protected Provisions for presentation and discussion by the MAC.
28	Kleenheat 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 November 2017	**Logging of Forced Outages** The market systems do not currently allow Forced Outages to be amended once entered. This can have the distortionary effect of	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**
		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. 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.	
42	ERA November 2017	**Ancillary Services approvals process** 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: • 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; • 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);	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**
		• 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; • 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 • 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. 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)).	
49	MAC November 2018	Should the method used to calculate constrained off compensation be amended to better reflect the actual costs incurred by Market Generators?	The Amending Rules from RC_2018_07 commenced on 1 July 2019. The MAC agreed to keep this issue on hold until 1 July 2020 to see if the issue requires further consideration.
50	MAC 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

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
			Limits under clause 2.26.3 of the Market Rules. The MAC agreed to close this issue at its meeting on 26 November 2019 because the issue will be addressed by Rule Change Proposal: Amending the Minimum STEM Price definition and determination (RC_2019_05), which was submitted by Synergy on 25 October 2019.
51	MAC 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 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)*: • 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. • Western Power is only required to comply with a request from System Management for updated models "as soon as	On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020). AEMO agreed to provide an update to the MAC on the proposed arrangements for generator performance models proposed as part of the Energy Transformation Strategy.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		reasonably practicable", leaving a Market Generator potentially subject to a Forced Outage for an extended period with no control over the situation. • 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.	
57	MAC October 2019	**Identification of services subject to outage scheduling** 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 schedule outages in respect of both sent out energy and each contracted Ancillary Service but did not seek to address the broader issue. (See section 7.2.2.5 of the Final Rule Change Report for RC_2013_15.)	The MAC agreed that this issue should be placed 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**
58	MAC October 2019	**Outage scheduling for dual-fuel Scheduled Generators** '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 can 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. (See section 7.2.2.5 of the Final Rule Change Report for RC_2013_15.)	The MAC agreed that this issue should be placed on hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020).
59	MAC October 2019	**Ancillary Service outage scheduling anomalies** 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;	The MAC agreed that this issue should be placed 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**
		• 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. (See section 7.2.2.5 of the Final Rule Change Report for RC_2013_15.)	
60	MAC October 2019	**Outage scheduling obligations for Interruptible Loads** 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	The MAC agreed that this issue should be placed 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**
		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. (See section 7.2.3.1 of the Final Rule Change Report for RC_2013_15.)	
61	MAC October 2019	**Direction of Self-Scheduling Outage Facilities** 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.	The MAC agreed that this issue should be placed 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**
		(See section 7.2.3.2 of the Final Rule Change Report for RC_2013_15.)	
62	MAC October 2019	**Outage scheduling obligations for non-intermittent Non-Scheduled Generators** 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 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	The MAC agreed that this issue should be placed 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**
		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. (See section 7.2.3.4 of the Final Rule Change Report for RC_2013_15.)	

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.

MARKET ADVISORY COMMITTEE MEETING, 11 FEBRUARY 2020

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	12 Dec 2019	February/March 2020 (TBC)
Market Procedures for discussion	• PSOP: Outages (due to RC_2013_15)	Agenda likely to include: • Market Procedure: Certification of Reserve Capacity • Market Procedure: Balancing Market Forecast

3. AEMO PROCEDURE CHANGE PROPOSALS

The status of AEMO Procedure Change Proposals is described below, current as at 3 February 2020. 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_11: Market Procedure: Prudential Requirements	The proposed amendments predominantly arise from Rule Change RC_2015_03 (Formalisation of the Process for Maintenance Applications)	No submissions received. Procedure Change Report published 9 Dec 2019. Procedure commenced.	-	9 Dec 2019
AEPC_2019_10: PSOP: Facility Outages	The proposed amendments predominantly arise from Rule Change RC_2013_15 (Outage Planning Phase 2 - Outage Process Refinements)	Procedure Change Proposal published 19 Dec 2019. Submissions closed 21 Jan 2020. One submission received. Procedure Change Report published 31 Jan 2020. Procedure commenced.	-	1 Feb 2020

RCP Rule Change Panel
Market Advisory Committee

Agenda Item 8(a): Overview of Rule Change Proposals (as at 4 February 2020)

Meeting 2020_02_11

- Changes to the report provided at the previous Market Advisory Committee 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 (**Panel**) or the Minister.

Indicative Rule Change Panel Activity Until the Next MAC Meeting

Reference	Title	Events	Indicative Timing
RC_2018_05	ERA Access to market information and SRMC investigation process	Publication of revised Final Rule Change Report	17/02/2020
		Minister's decision on the revised Amending Rules[1]	17/03/2020
RC_2019_04	Administrative Improvements to Settlement	Publication of Draft Rule Change Report	28/02/2020
RC_2019_05	Amending the Minimum STEM Price definition and determination	Publication of Draft Rule Change Report	03/03/2020
		Close of second submission period	31/03/2020

[1] The Minister decided under clause 2.8.5(c) of the Market Rules to send the Amending Rules back to the Panel with some proposed revisions that the Minister considers are required to ensure that the Market Rules, as amended by the Amending Rules, are consistent with the Wholesale Market Objectives. The Panel published a notice of the Minister's decision on 10/01/2020 and invited submissions on the proposed revised Amending Rules, with submissions due 03/03/2020. The Panel is to publish a revised Final Rule Change Report and will submit the revised Final Rule Change Report to the Minister for approval on 17/02/2020. The due date for the Minister's decision on the revised Amending Rules will be 17/03/2020.

Reference	Title	Events	Indicative Timing
RC_2020_01	Market Participant Fee calculation manifest error	Close of consultation period	17/02/2020
		Publication of Final Rule Change Report	24/02/2020
NA	Market Advisory Committee (**MAC**) Composition Review 2020	Panel appointment of new MAC members	28/02/2020

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

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

Approved Rule Change Proposals Awaiting Commencement

Reference	Submitted	Proponent	Title	Commencement
None				

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

Reference	Submitted	Proponent	Title	Rejected
RC_2014_09	13/03/2015	IMO	Managing Market Information	13/12/2019

Rule Change Proposals Awaiting Approval by the Minister

Reference	Submitted	Proponent	Title	Approval Due Date
None				

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						
RC_2020_01	24/01/2020	Panel	Market Participant Fee manifest error	High	Close of fist submission period	17/02/2020
Standard Rule Change Proposals with Second Submission Period Closed						
RC_2018_05	27/09/2018	ERA	ERA access to market information and SRMC investigation process	Medium	Publication of revised Final Rule Change Report[1]	17/02/2020
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	Publication of Draft Rule Change Report	30/04/2020
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	31/12/2020
RC_2017_02	04/04/2017	Perth Energy	Implementation of 30-Minute Balancing Gate Closure	Medium	Publication of Draft Rule Change Report	30/04/2020
RC_2018_03	01/03/2018	Collgar Wind Farm	Capacity Credit Allocation Methodology for Intermittent Generators	Medium	Publication of Draft Rule Change Report	31/12/2020

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
RC_2019_01	21/06/2019	Enel X	The Relevant Demand calculation	Medium	Publication of Draft Rule Change Report	30/06/2020
RC_2019_04	AEMO	AEMO	Administrative Improvements to Settlement	Medium	Publication of Draft Rule Change Report	28/02/2020
RC_2019_05	25/10/2019	Synergy	Amending the Minimum STEM Price definition and determination	High	Publication of Draft Rule Change Report	13/03/2020
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
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

Rule Changes Made by the Minister

Gazette	Date	Title	Commencement
None			

Rule Change Panel

MAC Meeting Agenda Item 8(c)

RC_2014_03: Consequential Outages and Non-Scheduled Generator Commitment and Decommitment

MAC Meeting 11 February 2020

Background

RC_2014_03: Administrative Improvements to the Outage Process

- Call for further submissions discussion of late changes to triggering outages
- RCP Support to schedule MAC discussion about
  - How Non-Scheduled Generator (**NSG**) capacity is removed from service at the start of a Consequential Outage and returned to service at the end of any type of outage
  - The implications in terms of Consequential Outages, constraint payments and the estimation of output for certification
- Seeking advice from the MAC to assist development of the Draft Rule Change Report

RCP Rule Change Panel

Questions for discussion (1)

Scenario for discussion

- A Market Generator (>10 MW) is notified that its NSG will be unable to generate from 9:00 AM to 5:00 PM on a Trading Day due to a planned triggering outage
- The triggering outage takes place as scheduled

Before the start of the triggering outage

- What Balancing Submission quantities for the periods before, during and after the triggering outage?
- Does the Market Generator shut the NSG down or does System Management control the shutdown?
- If System Management controls the shutdown, when should this occur and is the shutdown 'Out of Merit'?

Questions for discussion (2)

Before the start of the triggering outage (cont.)

- "**Out of Merit:** Means the dispatch of a Balancing Facility for a quantity different to that specified for the Facility in the BMO taking into account the Ramp Rate Limit and the Relevant Dispatch Quantity in the applicable Trading Interval for the Balancing Facility"
- For the Trading Interval(s) over which the ramp down occurs
  - Should the NSG be eligible for constraint payments?
  - Should a retrospective Operating Instruction be issued?
  - Should the NSG be eligible for a Consequential Outage?
  - Should the output of the NSG be estimated for the purposes of determining Certified Reserve Capacity,
    and if so under what trigger?

RCP Rule Change Panel

Questions for discussion (3)

After the triggering outage ends

- How should the NSG be returned to full operation, i.e. who controls the ramp up of the NSG and how?
- If System Management determines that the ramp up of the NSG needs to be controlled to limit the LFAS impact, and issues one or more Dispatch Instructions that limit the energy output of the NSG, then for the affected Trading Intervals
  - Is the NSG being dispatched Out of Merit?
  - Should the NSG be eligible for constraint payments?
  - Should a retrospective Operating Instruction be issued?
  - Should the NSG be eligible for a Consequential Outage?
  - Should the output of the NSG be estimated for the purposes of determining Certified Reserve Capacity,
    and if so under what trigger?

RCP Rule Change Panel

Questions for discussion (4)

- What differences if the NSG is taking a Planned Outage?
- What differences if the NSG is returning from a Forced Outage?
- What differences if the NSG experiences a Consequential Outage due to a network Forced Outage?
- What differences if the NSG is shut down and returned to service by the GIA tool?
- Generally, if System Management needs to dispatch Scheduled Generators or NSGs out of merit to prevent an unmanageable ramp rate discrepancy, when should the Facilities receive constrained on/off compensation?

RCP Rule Change Panel

MAC Meeting Agenda Item 8(d)

RCP Rule Change Panel

RC_2017_02: Implementation of 30-Minute Balancing Gate Closure

Enhancement of Information used in Trading Decisions

MAC Meeting 11 February 2020

RC_2017_02 Workshop 18 October 2019

- Is there any other information that would be useful for Market Participants to help to improve the accuracy of their trading decisions?
- "One option to increase the accuracy of information available to Market Participants would be for AEMO to re-run and publish the Forecast BMO every 5 minutes
    - o Five or six IPPs may change their position slightly in a half-hour period, and if one of the IPPs is marginal, a Market Participant may get caught out due to sudden changes in price."

AEMO to re-run and publish Forecast BMO every 5 minutes for whole horizon

- Task of performing this calculation more frequently is relatively simple
- However, storing BMO for whole balancing horizon increases data requirements 6 fold, with knock on effects on performance (such as extraction of BMO)
- With more data, queries inherently run slower

RCP Rule Change Panel

AEMO to re-run and publish Forecast BMO every 10 minutes for whole horizon

- Estimate of cost of assessing implications of increasing frequency of BMO calculation for whole horizon = $20K
    - BMO calculated 3 times more often for whole of balancing horizon
    - BMO used to calculate Balancing Price and provided to dispatch systems
    - BMO, Balancing Price and Load Forecast published using existing mechanisms
- Estimate does not consider remediation work to address identified issues
- Collection of about 3 months of data, total elapsed time **~4 months** (3 months based off historic performance degradation and size of dataset but may need to be revising depending on how investigation progresses)

AEMO to re-run and publish Forecast BMO every 10 minutes for next interval

- Estimate of calculating the ‘gate-closure’ BMO only for the Trading Interval for which gate closure is about to occur = $90K
  - Still provides Forecast BMO every 10 minutes leading up to gate closure of relevant Trading Interval.
  - Avoids data and performance issues associated with providing Forecast BMO more frequently for whole horizon.

AEMO to publish the 5-minute balancing load forecast in a new report

- Estimate to publish the 5-minute balancing load forecast in a new report = $20K
  - Currently, the only balancing load forecast published is the one that is used to calculate the Balancing Price

Summary

Description of Estimate	Order of Magnitude Estimate
Estimated cost to assess the implications of increasing the frequency of the BMO calculation to every ten-minutes for the whole horizon.	$20k
Estimated cost to implement calculation of the forecast BMO every ten minutes only for the Trading Interval for which gate closure is about to occur	$90k
Estimate for cost to publish the 5-minute balancing load forecast in a new report	$20k

RCP Rule Change Panel

RCP Rule Change Panel
Market Advisory Committee

Agenda Item 8(e): RC_2020_02: Adding a Criteria for Acceptance of a Non-Temperature Dependent Load

Meeting 2020_02_11

1. Background

On 31 January 2020, Edna May Operations provided the Rule Change Panel with a Pre-Rule Change Proposal for discussion at the 11 February 2020 meeting of the Market Advisory Committee (**MAC**).

Edna May Operations' Pre-Rule Change Proposal: Adding a Criteria for Acceptance of a Non-Temperature Dependent Load (RC_2020_02) is attached for the MAC's review and feedback.

The Market Rules allow a Market Customer to apply to AEMO to disregard a Trading Interval for the purposes of determining the Load's status as a Non-Temperature Dependent Load (**NTDL**) for several reasons, such as where a load operated below its usual consumption due to maintenance.

In RC_2020_02, Edna May Operations proposes to allow a market Customer to apply to AEMO to disregard a Trading Interval for the purposes of determining the Load's status as a NTDL where a load operated below its usual consumption due to pre-planned operational throughput reduction strategies.

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:

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
3	**Medium:** Net benefit either: • may be large but needs more analysis to determine; or • material but not large enough to warrant a High rating	May delay up to 3 months if budgeted resources unavailable

Urgency	Description	Resourcing Implications
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 Edna May Operations regarding Pre-Rule Change Proposal RC_2020_02; and
2. recommends an urgency rating for RC_2020_02 (Edna May Operations has recommended a High urgency rating in the Pre-Rule Change Proposal).

Attachments

1. RC_2020_02 – Pre-Rule Change Proposal

RCP | Rule Change Panel

Wholesale Electricity Market Rule Change Proposal

Rule Change Proposal ID: **RC_2020_02**
Date received: **TBA**

Change requested by:

Name:	Donna Kretschmer
Phone:	0419 416 198
Email:	donnakretschmer@rameliusresources.com.au
Organisation:	*Edna May Operations Pty Ltd*
Address:	22 Wolfram Street Westonia WA 6423
Date submitted:	*TBA*
Urgency:	*2-high*
Rule Change Proposal title:	ADDING A CRITERIA FOR ACCEPTANCE OF A NON-TEMPERATURE DEPENDENT LOAD
Market Rule(s) affected:	Appendix 5A – Non-Temperature Dependent Load Requirements Step 1(b)

DRAFT

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.

DRAFT

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:

This Rule Change Proposal seeks to add an item to the criteria contained within Step 1(b) of Appendix 5A: Non-Temperature Dependent Load Requirements.

Issue

The Applicant is a small gold mining operation which operates a 24-hour processing plant. The Applicant has successfully achieved non-temperature dependent load (NTDL) status for many years as the majority of its electricity consumption is constant and does not fluctuate due to ambient temperature. Annual evidence is provided by the Applicant for each interval of ↓10% that the source of the consumption was operating at below capacity due to maintenance activities as required under Step 1(b) of Appendix 5A.

Due to a prolonged delay in a clearing application for a new ore source the Applicant needed to amend its standard business operational strategy to allow for a period of restricted high-grade feed. It was estimated that a 15-month period of reduced throughput was required due to only having low grade feed. The lowest cost option for the business was to convert to a campaign milling schedule where the plant would operate at full capacity for 12 days, then switch off for 9 days. During the 9 days off period a skeleton operating crew would be on site and all maintenance activities would be carried out. This was the most cost-effective use of resources and lowest impact on overheads to the business.

The proposed new pit permit has recently been approved and the Applicant is in the process of planning to return the plant to full operation in early March 2020. Unfortunately, the reduced electricity consumption linked with the planned campaign milling schedule does not fall within the scope of Step 1(b) and the Applicant will lose its NTDL status during the next NTDL application period. This is due to the exceptions (i) to (iii) contained within Step 1(b) do not include pre-planned operational downtime.

Proposed Solution

To include pre-planned operational throughput reduction strategies that are chosen by Market Customers to meet business requirements as being an acceptable inclusion in the exceptions listed in Step 1(b) for NTDL status.

Proposed Evidentiary Process

The decision to move to a campaign milling schedule in October 2019 was made by the Applicant during the budgeting process held in May 2019 the outcome of which was included in our official budget documents. The Applicant has appended a copy of the campaign milling schedule that was published as part of the budget book prepared in July 2019. The schedule was shared with the Applicant's electricity retailer on the 13th August to allow for efficient management of electricity requirements.

Rationale

As it can be proven that the schedule causing the reduction in electricity consumption was decided well ahead of the time it was implemented, then it can be concluded that the change in consumption was not driven by ambient temperature. The removal of the ability to maintain NTDL status on this basis does not reflect the actual cause, and therefore reduces the intention behind the Step 1(b) exceptions.

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2. Explain the reason for the degree of urgency:

The applicant is required to re-apply for the annual NTDL status in August 2020. The applicant will be finalizing budget requirements for the 2020/2021 financial year by May / June 2020. The loss of NTDL status has a significant impact on the business and will need to be reflected in the budget models.

The timing specified in Section 2.7 Standard Rule Change Process should be adequate to meet the applicant's requirements as well as allow the Board to follow due process.

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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 <u>underline</u> words added)*

Appendix 5A: Non-Temperature Dependent Load Requirements

AEMO must perform the following steps in deciding whether to accept, in accordance with clause 4.28.9, a load measured by an interval meter nominated in accordance with clauses 4.28.8(a) or 4.28.8C(a) as a Non-Temperature Dependent Load:

Step 1:

- If, in accordance with clause 4.28.8(a), AEMO is provided by a Market Customer in Trading Month n-2 with the identity of an interval meter associated with that Market Customer that it wants AEMO to treat as a Non-Temperature Dependent Load from Trading Month n; and

- If the identity of the interval meter is provided by the date and time specified in clause 4.1.23; and
- If the load was treated as a Non-Temperature Dependent Load in Trading Month n-8,

then AEMO must accept the load as a Non-Temperature Dependent Load if:

(a) the median value of the metered consumption for that load was in excess of 1.0 MWh, calculated over the set of Trading Intervals defined as the 4 Peak SWIS Trading Intervals in each of the Trading Months starting from the start of Trading Month n-11 to the end of Trading Month n-3; and

(b) the load did not deviate downwards from the median consumption in paragraph (a) by more than 10% for more than 10% of the time during the period from the start of Trading Month n-11 to the end of Trading Month n-3 except during Trading Intervals where:

i. the consumption was 0 MWh; or

ii. consumption was reduced at the request of System Management; or

iii. evidence is provided by the Market Customer that the source of the consumption was operating at below capacity due to maintenance or a Saturday, Sunday or a public holiday throughout Western Australia.; <u>or</u>

<u>iv. evidence is provided by the Market Customer that the source of the consumption was operating at below capacity due to forward planned operational throughput reductions to meet business requirements.</u>

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

- The additional non-temperature dependent criterium is consistent with promoting economically efficient supply of electricity as planned business throughput reductions driven by constraints other than ambient temperature do not place additional pressure on electricity supply and related services.

- The outcome of including the proposed exception would be to not disadvantage Market Customers who are proven successful NTDL applicants by retaining their NTDL status as it can be proven their electrical consumption is not driven by ambient temperature.

- The proposed additional criterium is aligned with the intention behind the inclusion of the exceptions already defined in Step 1(b).

- It will contribute to the better optimisation and planning for the SWIS system as intermittent load accounts are more closely defined, which should assist with minimising the long-term cost of electricity for all customers.

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

Costs:

- The electrical pricing for Market Customers whose consumption patterns are based on ambient temperature will better reflect actual usage.

Benefits:

- The Wholesale Electrical Market intermittent load accounts will more closely reflect actual status.
- Market Customers able to produce evidence of planned operation throughput reductions not driven by ambient temperature will continue to receive the discount applied by keeping their NTDL status.

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Appendix A – Campaign Milling Schedule

Edna May FY20
Processing Shutdown & Production Days

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SHUTDOWN & PRODUCTION DAYS

	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
	31	31	30	16	18	18	17	19	14	21	13	21
	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
PLANT PI	Full	Full	Full	Reduced	Reduced	Reduced	Reduced	Reduced	Reduced	Reduced	Reduced	Reduced
1	Reline	Mill	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Mill	Mill	Mill
2	Reline	Mill	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Mill	Offline	Mill
3	Reline	Mill	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Mill	Offline	Mill
4	Reline	Mill	Mill	Mill	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Mill
5	Mill	Mill	Mill	Offline	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Mill
6	Mill	Mill	Mill	Offline	Mill	Mill	Mill	Mill	Offline	Mill	Offline	Mill
7	Mill	Mill	Mill	Offline	Mill	Offline	Mill	Mill	Offline	Mill	Offline	Mill
8	Mill	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Offline	Mill	Offline	Mill
9	Other	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Mill	Mill	Offline	Mill
10	Mill	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Mill	Mill	Offline	Mill
11	Mill	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Mill	Offline	Mill	Mill
12	Mill	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Mill	Offline	Mill	Mill
13	Mill	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Mill	Offline	Mill	Offline
14	Mill	Mill	Mill	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Mill	Offline
15	Mill	Mill	Mill	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Mill	Reline
16	Mill	Mill	Mill	Mill	Offline	Mill	Mill	Offline	Mill	Offline	Mill	Reline
17	Mill	Mill	Mill	Mill	Offline	Mill	Mill	Mill	Mill	Offline	Mill	Reline
18	Mill	Mill	Mill	Mill	Reline SM	Mill	Offline	Mill	Mill	Offline	Mill	Reline
19	Mill	Mill	Mill	Mill	Reline SM	Mill	Offline	Mill	Mill	Offline	Mill	Offline
20	Mill	Mill	Mill	Mill	Reline SM	Mill	Offline	Mill	Mill	Mill	Mill	Offline
21	Mill	Mill	Mill	Mill	Reline SM	Mill	Offline	Mill	Offline	Mill	Mill	Offline
22	Mill	Mill	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Mill	Mill	Mill
23	Mill	Mill	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Mill	Offline	Mill
24	Mill	Mill	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Mill	Offline	Mill
25	Mill	Mill	Mill	Mill	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Mill
26	Mill	Mill	Mill	Offline	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Mill
27	Mill	Mill	Mill	Offline	Mill	Mill	Mill	Mill	Offline	Mill	Offline	Mill
28	Mill	Mill	Mill	Offline	Mill	Offline	Mill	Mill	Offline	Mill	Offline	Mill
29	Mill	Mill	Mill	Offline	Mill	Offline	Mill	Offline	Offline	Mill	Offline	Mill
30	Mill	Mill	Mill	Offline	Mill	Offline	Mill		Mill	Mill	Offline	Mill
31	Mill	Mill		Offline		Offline	Mill		Mill		Offline	