RCP Rule Change Panel
Market Advisory Committee

Meeting Agenda

Meeting Title:	Market Advisory Committee
Date:	Tuesday 24 March 2020
Time:	9:30 AM – 11:15 AM
Location:	Online meeting Persons who would like to attend the online MAC meeting are asked to register with RCP Support (Support@rcpwa.com.au) by noon on Friday 20 March 2020. RCP Support will then send an invite to all of the registered attendees that will contain a link to allow you to log into the meeting.

Item	Item	Responsibility	Duration
1	Welcome	Chair	5 min
2	Meeting Apologies/Attendance	Chair	5 min
3	Minutes of Meeting 2020_02_11	Chair	5 min
4	Actions Items	Chair	5 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	10 min
	(b) RC_2019_01: The Relevant Demand calculations – Next Steps	RCP Support	15 min
9	Update on the Whole of System Plan (no paper – presentation at the meeting)	ETIU	15 min

Item	Item	Responsibility	Duration
10	Proposed Changes to the Rule Change Panel Appointment Process	Chair	15 min
11	General Business	Chair	5 min
Next Meeting: 5 May 2020			

Please note, this meeting will be recorded.

RCP Rule Change Panel
Market Advisory Committee

Minutes

Meeting Title:	Market Advisory Committee (**MAC**)
Date:	11 February 2020
Time:	9:30 AM – 11:20 AM
Location:	Training Room No. 1, 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 Zahra Jabiri
Oscar Carlberg	Market Generators	Proxy for Jacinda Papps
Wendy Ng	Market Generators	
Daniel Kurz	Market Generators	
Patrick Peake	Market Customers	
Geoff Gaston	Market Customers	
Peter Huxtable	Contestable Customers	

Apologies	Class	Comment
Zahra Jabiri	Network Operator	
Jacinda Papps	Market Generators	
Andrew Stevens	Market Generators	
Tim McLeod	Market Customers	

Also in Attendance	From	Comment
Aden Barker	Energy Transformation Implementation Unit (**ETIU**)	Presenter to 11:05 AM

Also in Attendance	From	Comment
Jenny Laidlaw	RCP Support	Minutes
Noel Schubert	ERA	Observer
Elizabeth Walters	ERA	Observer
Kei Sukmadjaja	Western Power	Observer
Ben Bristow	Western Power	Observer
Dimitri Lorenzo	Bluewaters Power	Observer
Jo-Anne Chan	Synergy	Observer
Ben Skinner	Australian Energy Council	Observer
Tom Frood	Bright Energy Investments	Observer
John Lorenti	SynergyRED	Observer
Laura Koziol	RCP Support	Observer
Natalie Robins	RCP Support	Observer
Sandra Ng Wing Lit	RCP Support	Observer
Adnan Hayat	RCP Support	Observer

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:30 AM and welcomed members and observers to the 11 February 2020 MAC meeting.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above. The Chair advised that Ms Margaret Pyrchla had resigned her position as Western Power's representative and would be replaced on the MAC by Dr Zahra Jabiri. The Chair thanked Ms Pyrchla for her service to the MAC and wished her the best for her new role in Western Power.	
3	**Minutes of Meeting 2019_11_26** Draft minutes of the MAC meeting held on 26 November 2019 were circulated on 28 January 2020. The MAC accepted the minutes as a true and accurate record of the meeting. **Action: RCP Support to publish the minutes of the 26 November 2019 MAC meeting on the Rule Change Panel's (Panel's) website as final.**	**RCP Support**

Item	Subject	Action
4	**Action Items** The closed action items were taken as read. **Action 27/2019:** Ms Sara O'Connor advised that the ERA had not reached a position on whether it should be assigned responsibility under the Market Rules for setting document retention requirements and confidentiality statuses. **Action 28/2019:** Open. **Action 29/2019:** Open. **Action 30/2019:** Mr Dean Sharafi noted that AEMO had worked with Western Power on this action item. Mr Sharafi confirmed that in a scenario where demand was at a one in ten year peak level, and all network equipment was available for service, all the relevant generators with Capacity Credits, including Yandin, Warradarge, Pinjar, Emu Downs and the other North Country Intermittent Generators could generate to their Capacity Credit level without creating a security issue, but this would require opening the connection between Neerabup Terminal and the 132 kV network. Mr Martin Maticka confirmed that this would increase the Spinning Reserve requirement if all the relevant generators were generating to their Capacity Credit level. There was some discussion about the impact of this increase on the Reserve Capacity Requirement. Action 30/2019 was closed. **Action 31/2019:** The Chair noted that this action item would be discussed under agenda item 8(b). Action 31/2019 was closed.	
5	**MAC Market Rules Issues List (Issues List) Update** The MAC noted the recent updates to the Issues List.	
6	**Update on the Energy Transformation Strategy (ETS)** Mr Aden Barker provided the following updates on the ETS. • Work to refine inputs and run models for the Whole of System Plan (**WOSP**) was currently underway. ETIU was using both a resource planning model and a dispatch model, with some iteration between the two. While the iteration process was expected to continue through to May/June 2020, ETIU expected to give the MAC a presentation on high level outputs in March 2020. • The Energy Transformation Taskforce (**Taskforce**) delivered the Distributed Energy Resources (**DER**) Roadmap to the Minister on 23 December 2019. The DER Roadmap outlines 37 actions to overcome barriers to	

Item	Subject	Action

increasing DER penetration in the SWIS and improve outcomes and opportunities for customers.

ETIU anticipated that the DER Roadmap would be published in March 2020, subject to Cabinet approval. ETIU would be happy to meet with stakeholders to discuss details of the 37 actions once the DER Roadmap is released.

- ETIU held two Transformation Design and Operation Working Group (**TDOWG**) meetings in December 2019:
  - the first discussed outage management and the high-level parameters for the allocation of Capacity Credits under a constrained network access regime; and
  - the second discussed outstanding matters relating to settlement and Essential System Services (**ESS**) scheduling and dispatch.
- The Taskforce published four information papers in November and December 2019:
  - Revising Frequency Operating Standards in the SWIS;
  - ESS – Scheduling and Dispatch;
  - Market Settlement – Implementation of Five-Minute Settlement, Uplift Payments and ESS Settlement; and
  - Technical Rules Change Management Process).
- The Technical Rules Change Management Process information paper provided further details on matters covered in previous papers, along with draft Access Code changes to implement the new framework for Technical Rules change management. While the draft Access Code changes had been released for consideration, this did not constitute the formal consultation required under the Act.

  The Access Code changes were to be packaged with the minor changes associated with the constraint information framework, and some additional content around the timing for Western Power's Access Arrangement 5 (**AA5**) submission to the ERA. The package was expected to be approved by the Minister and released for a formal 30-day consultation period within the next few weeks.

  If substantive issues were raised by stakeholders during the consultation period, a decision might be made to not progress all the changes simultaneously, noting the time sensitivity in relation to Western Power's AA5 submission.
- The Taskforce approved changes to the outage management framework on 7 February 2020, and the associated information paper was due to be published in the

Item	Subject	Action

next two weeks. ETIU indicated that it would meet with stakeholders to discuss any issues relating to this information paper.

- The next Taskforce meeting was scheduled for 28 February 2020 and would consider the framework for market registration and participation, along with operating states and contingency event definitions. The latter included a proposal to provide a clearly articulated reliability standard, and information on how that will work in planning and dispatch. These topics would be covered at the next TDOWG meeting on 12 February 2020.

The following points were discussed:

- Ms Wendy Ng asked whether the Access Code package included changes relating to the proposed governance framework for constraint equations. Mr Barker replied that the package included changes to allow Western Power to recover costs for activities associated with the development of constraint information. The more substantive part of the proposed governance framework would be contained in the Market Rules. The draft Amending Rules were released for public consultation in December 2019 and the consultation period closed on 31 January 2020.

  Mr Barker advised that the draft Amending Rules would be submitted for Taskforce approval during February 2020. Ms Ng reiterated her strong concerns about the proposal to classify limit advice as confidential, questioning how Market Participants would be able to operate efficiently without visibility of the network limits.

  Ms Jenny Laidlaw and Mr Daniel Kurz agreed with Ms Ng that restricting access to limit advice would reduce the effectiveness and value of the proposed framework. Mr Barker noted that stakeholders had consistently expressed this view. Their concerns would be discussed as a specific agenda item at the following week's meeting of the Program Implementation Coordination Group, and would also be raised with the Taskforce.

- Mr Noel Schubert requested an update on the status of the Minister's Reserve Capacity pricing reforms. Mr Matthew Martin replied that Energy Policy WA (**EPWA**) submitted a finalised set of draft rules to the Minister on 24 December 2019. The Minister was on leave over the holiday period, and while he had returned from leave the previous week, EPWA was uncertain when he would approve the draft rules due to competing priorities.

Item	Subject	Action
	• Mr Barker noted that on 16 January 2020, EPWA released a directions paper about the creation of a dynamic customer protection framework for behind the meter electricity services. Mr Martin added that EPWA aimed to introduce codes of practice with heads of power in regulations, which would require changes to the Electricity Industry Act 2004. EPWA's first focus would be on generation and storage services that occur behind the meter. The first code working group meeting was scheduled for 12 February 2020 and would be followed by several further meetings. EPWA intended to publish the presentation materials for the working group and was happy to meet with stakeholders on a one-on-one basis throughout the process. Mr Geoff Gaston asked how the new codes of practice would apply to parties with existing exemptions. Mr Martin replied that EPWA still needed to work through this question, and while the changes would not affect all existing exemptions, some transition process may be needed for parties with existing solar power purchase agreement exemptions. Mr Gaston supported the removal of some existing exemptions. • Mr Barker noted that the first behind-the-meter working group meeting was unfortunately scheduled for the same day as the next TDOWG meeting (12 February 2020). While EPWA could not guarantee that in future there would not be several meetings of this type in a single week, EPWA undertook to ensure that the scheduled meeting times did not overlap.	
7	**AEMO Procedure Change Working Group (APCWG) Update** Mr Sharafi noted that the next meeting of the APCWG was scheduled for 20 February 2020. The topics includes revisions to the Balancing Market tie-breaker process that involved changes to the Market Procedure: Balancing Market Forecast and the Market Procedure: Balancing Facility Requirements; and updates to the Market Procedure: Certification of Reserve Capacity. In response to a question from Ms Ng, Mr Maticka advised that AEMO intended to implement the proposed changes to the Market Procedure: Certification of Reserve Capacity in time for their use in the 2020 Reserve Capacity Cycle. 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.	

Item	Subject	Action
	In response to a question from the Chair, MAC members raised no concerns about the new table of expected Panel activities being ordered by reference number.	
8(b)	**North Country Spinning Reserve Issue** Mr Barker advised that following the 26 November 2019 MAC meeting AEMO undertook a preliminary assessment of whether the benefits of increasing the Spinning Reserve requirement to allow the unconstrained operation of Yandin and Warradarge would outweigh the costs, based on analysis used to determine the margin values for the 2020/21 Financial Year. Mr Barker advised that while the work was in no way final or conclusive, it indicated there was likely to be a material benefit in amending the Spinning Reserve standard. In response, ETIU considered the decisions already made by the Taskforce with respect to how the largest credible contingency might be defined, how the Spinning Reserve standard might be calculated and how settlement might then occur in that context; and formed the view that there may be benefit in bringing forward a rule change that implements part of the new market design early. ETIU intended the rule change to include changes to the Spinning Reserve standard to enable multiple generation facilities to form the largest credible contingency, and consequential changes to how settlement quantities are calculated for such facilities, consistent with the causer pays principle. Mr Barker noted that AEMO previously suggested a third change, to remove constrained off payments when a generator is constrained down to reduce the Spinning Reserve requirement. While ETIU would give that change consideration, Mr Barker questioned whether the first two changes and the implementation of the proposed Generator Interim Access (**GIA**) tool arrangements would obviate the need for it. Mr Barker noted that AEMO would be responsible for development of the rule change proposal, which ETIU and the Taskforce would consider before releasing the proposal for formal public consultation. Mr Barker guaranteed a fulsome process of public consultation before the proposal was presented to the Minister for a decision on whether to make the Amending Rules using his rulemaking powers (on the basis that they were consistent with the direction of the new market design). The following points were discussed: • Mr Kurz suggested that the changes were required by 1 July 2020, to ensure the rules were adequate for the next	

Item	Subject	Action

margin values period to accommodate the larger Spinning Reserve requirement. Mr Barker replied that the changes were needed by the time the Yandin and Warradarge wind farms were commissioned and in operation. However, the consequential settlement changes could have a different implementation timeframe, with an initial indication from AEMO that it may not be able to implement the settlement component until early 2021.

Mr Maticka noted that the potential delay related to AEMO's transition to a new settlement system with a different vendor. AEMO proposed an option whereby settlement outcomes for the first few months would be corrected in a subsequent settlement adjustment, to avoid having to implement the changes in a system that was due to be decommissioned. Mr Maticka noted that this approach was unusual, would require more complex drafting and may have some cashflow implications, but would reduce IT implementation costs.

- Mr Barker noted that key considerations for ETIU in bringing a change forward from the new market design was whether the benefit was material, what the additional incremental cost was likely to be compared with implementation in October 2022, and whether the early implementation could affect the implementation of the broader market reforms by October 2022. ETIU's initial view was that the incremental cost was outweighed by the benefit.
- Mr Kurz noted that the proposed margin values for the 2020/21 Financial Year assumed a higher Spinning Reserve requirement due to the two GIA generators in advance of the rules permitting that requirement. Mr Maticka replied that AEMO's recommendation was based on the current construct of the rules, and the ERA would need to take that into consideration.
- Ms Laidlaw asked what would happen if the rule change was not implemented by the time the two generators were in operation. Mr Sharafi replied that System Management would allow for a higher Spinning Reserve requirement to ensure power system security. Mr Barker advised that he was not going to speak for Western Power or AEMO in respect of their views.
- Ms Laidlaw asked whether AEMO or ETIU was responsible for the groundwork for changes to the Spinning Reserve standard, noting the concerns raised by AEMO about undertaking this work at the 26 November 2019 MAC meeting. Mr Barker replied that in the first instance, ETIU

Item	Subject	Action
	was just looking at multiple generators being able to form the largest credible contingency, rather than 70 percent of the largest single generator. The change would apply generally and not be restricted to the contingency involving Yandin, Warradarge and (occasionally) NewGen Neerabup.	
	• Mr Patrick Peake questioned whether, when a new generator connected to a line with existing generation and increased the size of associated contingency, the additional Spinning Reserve costs should be attributed to the new generator or shared among all generators on that line. Mr Maticka replied that his understanding of what had been requested was that the additional costs would be shared among all the generators on the line.	
	Mr Peake suggested that sharing the cost among all the generators was contrary to the causer-pays concept, as the existing generators would not have caused the increase in Spinning Reserve costs. Mr Barker considered that Mr Peake had raised a good question that raised longer-term questions about network planning and how market costs should be taken into account.	
	• Ms Ng noted that NewGen Neerabup was affected by the proposed changes and asked if a ballpark estimate of the additional costs was available. Mr Sharafi replied that complex market modelling would be needed to estimate the additional costs. AEMO had not undertaken any such modelling.	
	Mr Kurz noted that EY's modelling for the recent margin values submission indicated that Yandin and Warradarge would form the largest contingency 21% of the time, and that the costs of constraining the generators (in terms of increased Balancing Prices) were not the same as the costs of allowing them to run and creating a higher Spinning Reserve requirement and higher margin values.	
	Mr Barker agreed that cost estimates would need to be made available as part of the consultation process, and noted that the bar should be as high for the Minister's consideration of rule changes as it was for the Panel's. Mr Kurz considered that the suggested net benefits presented in the EY report needed to be quantified.	
	Ms Laidlaw noted that it seemed likely that the benefits of increasing the Spinning Reserve requirement would outweigh the costs in the specific case of Yandin and Warradarge. However, the cost/benefit outcomes might be quite different for future scenarios with different	

Item	Subject	Action
	configurations, making a cost benefit analysis for a full removal of the standard much more challenging.	
	• Mr Peake noted that the Federal Government was providing funds to Victoria and New South Wales for transmission projects, and asked whether Western Australia intended to seek funding to resolve the North Country issues. Mr Martin replied that there had been some engagement with the Federal Government to seek monetary assistance for various projects.	
	Mr Peake asked whether it would be helpful if the MAC provided a document in support of the Government's requests. Mr Martin replied that the MAC did not have a role in that regard, as it existed to provide advice to the Panel rather than Government.	
	• Mr Sharafi suggested that any additional costs to the market could be used as input to a business case to upgrade the second North Country line to 330 kV.	
	• Mr Barker suggested that the future connection of additional generators on shared lines was likely to be limited for several reasons, including the expected reduction in capacity revenue for co-located facilities.	
	• Mr Barker asked Ms Laidlaw what she meant by the removal of the Spinning Reserve standard. Ms Laidlaw replied that the proposed standard removed any obligation on Western Power to design the network in a way that avoided excessive Spinning Reserve costs. While in future a dynamic tool might find the efficient balance between constraining dispatch and increasing Spinning Reserve, this did not fully resolve the problem.	
	Ms Laidlaw gave an extreme example of moving the two Bluewaters facilities to a single line. While the dynamic tool might determine the most efficient option for any Trading Interval (i.e. constraining the facilities versus enabling additional Spinning Reserve), neither option was likely to be as efficient as connecting the two facilities on separate lines.	
	Ms Laidlaw also noted that despite the proposed cost allocation changes, increasing the Spinning Reserve requirement could increase Spinning Reserve costs for all generators, because the relationship between the Spinning Reserve requirement and Spinning Reserve costs was not always linear.	
	• Mr Barker noted the need to amend the current framework for system planning and indicated that this was likely to be	

Item	Subject	Action
	addressed in a future WOSP. Given the timeframe for building transmission lines, Mr Barker considered the question was what to do in the intra-planning period, both in terms of the operation of the market and managing real constraints in the network. ETIU had supplied part of the answer in the context of the ESS Project around the supplementary mechanism. ETIU intended to release another paper detailing how the supplementary mechanism will operate and the circumstances under which it will be triggered. ETIU also intended to release an information paper on non-co-optimised ESS. This would cover existing services such as System Restart, but also consider options for when a constraint is starting to bind and cannot be resolved through initial network investment, but might be able to be resolved through a Market Participant changing their behaviour or investing in a particular part of the network within a certain timeframe. Mr Barker advised that the intent was to have the Amending Rules made by August 2020. Mr Barker noted that the responsibility was on AEMO in the first instance in terms of the rule change proposal development, and there was also a potential need for additional modelling to quantify the costs and benefits of the change and its early delivery. ETIU aimed to release the proposal for consultation by April-May 2020. The proposal would be progressed via a Taskforce process and the use of the Minister's rulemaking powers, which are specific to the ETS.	
8(c)	**RC_2014_03: Administrative Improvements to the Outage Process – Consequential Outages and Non-Scheduled Generator commitment and decommitment** Ms Laidlaw sought advice from the MAC on the processes used to decommit a Non-Scheduled Generator (**NSG**) before a triggering outage and return the NSG to full operation at the end of the triggering outage. A copy of the discussion slides is available in the meeting papers. Ms Laidlaw presented the following scenario for discussion: • a Market Generator is notified that its NSG (>10 MW) will be unable to generate from 9:00 AM to 5:00 PM on a Trading Day due to a planned triggering outage; and • the triggering outage takes place as scheduled.	

The following points were discussed:

- MAC members confirmed that a Market Generator in this scenario would usually submit zero quantities in its Balancing Submissions for the period between 8:30 AM and 5:00 PM, but would not amend its offer price to cause the NSG to be dispatched off in merit.
- Ms Laidlaw noted previous advice from AEMO that it usually issued a Dispatch Instruction to shut the NSG down before the start of the triggering outage (normally in the preceding Trading Interval but sometimes earlier). Ms Laidlaw suggested that this Dispatch Instruction would be Out of Merit according to the Market Rules, and no MAC members disagreed with this view.
- Mr Sharafi noted that generally both the Market Generator and System Management were able to control the shutdown and ramp rate of the NSG. System Management's preference was that the Market Generator shut down the NSG itself (i.e. without the issue of Dispatch Instructions). AEMO's current practice was to not calculate estimates or constraint payments for the periods in which the NSG was ramping down at the start of the outage or ramping up at the end of the outage.

  Mr Oscar Carlberg noted that a Market Generator required accurate information about a triggering outage to shut down its NSG at the appropriate time and make its Balancing Submissions consistent with the triggering outage. To date Market Generators had not always had enough information to act in this way.
- In response to a question from Ms Laidlaw, Mr Shane Duryea confirmed that requiring Market Generators to manage the return of their NSGs at the end of a triggering outage (i.e. without the use of Dispatch Instructions) would not create a safety risk because Western Power had controls in place to prevent the NSG from starting up before it was safe to do so.
- There was general agreement that an NSG should not receive constrained off compensation for the Trading Interval(s) in which it was shutting down before the start of a triggering outage.
- Ms Laidlaw questioned whether the shutdown of an NSG before the start of a triggering outage could reduce the energy output of the NSG in the relevant Trading Interval(s) by enough to warrant estimating the NSG's output for certification. Mr Carlberg considered that if an NSG was ramping down because of a network outage then it should receive an estimate, because its level of Certified Reserve

Item	Subject	Action
	Capacity should not be affected by a network outage over which it has no control. • Mr Tom Frood suggested that it was easier for System Management to dispatch the NSGs than for the Market Generators to manage the process, and questioned the reasons for System Management's preference. Mr Sharafi acknowledged that in some situations some Market Generators may not have the means to turn their NSGs off. Mr Frood added that not all NSGs were manned on a 24/7 basis. Mr Duryea considered, and most MAC members agreed, that Market Generators needed to be able to turn off their Facilities. Mr Maticka considered there was also an issue about who should have control over an NSG. Mr Maticka understood that there was some obligation on the Market Generator to actually manage the NSG; otherwise it would be acting only as an investor and leaving the management of the NSG to AEMO, which might not produce the most optimal outcomes for the Market Generator. • Mr Sharafi questioned whether not receiving an estimate for a 10-minute ramp down period would have a material impact on a NSG's certification. Mr Carlberg considered that a material risk existed in terms of certification, but reiterated his view that the NSG should not receive constrained off compensation. Ms Laidlaw noted previous advice from AEMO that the shutdown period can span multiple Trading Intervals. • Ms Laidlaw asked whether an NSG should receive constrained off compensation and/or an estimate for certification if, at the end of a triggering outage, System Management returned the NSG to service using Dispatch Instructions that restricted its ramp rate or target MW to limit the LFAS impact. Mr Sharafi replied that in these situations System Management put a constraint on the ramp rate of the NSG. This was not expected to last for a long period of time, because eventually the NSG would reach the same output level, as if its ramp rate had not been constrained. Mr Sharifi considered that while the purist view of the Market Rules may say that the NSG was entitled to constrained off compensation, practically it was a very short period of time and the conditions under which the NSG was constrained are known because of the triggering outage.	

Item	Subject	Action

Mr Sharafi questioned whether applying the purist view of the rule was warranted.

- Ms Laidlaw noted that the current definition of a Consequential Outage did not cover Trading Intervals beyond the end of the triggering outage, as there was no network-related reason to restrict the output of a generator in those Trading Intervals. Ms Laidlaw asked whether in general (i.e. not just at the end of a Consequential Outage) a generator should receive a constraint payment if System Management restricted its output to address a ramp rate issue; and whether the treatment should be different for Scheduled Generators and NSGs.

  Mr Sharafi noted that the question only applied until the implementation of the new market arrangements.
  Ms Laidlaw agreed that large scale rule changes may not be warranted before October 2022. Mr Maticka considered that neither Scheduled Generators nor NSGs should receive constrained off compensation in these situations.

  Mr Kurz considered that these situations did not occur very often for the Bluewaters Facilities; and that he did not see any reason why an NSG should not receive an estimate in these situations. Mr Gaston did not consider that the cost of the changes required to remove constraint payments in these situations would be warranted, given the short timeframes involved.

  The MAC did not offer any reasons why Scheduled Generators and NSGs should be treated differently in terms of constraint payments.

- There was some discussion about the management of triggering outages affecting GIA generators, and how the current practice of using the GIA tool and Operating Instructions to constrain a GIA generator during a triggering outage meant that the output of the generator was not estimated for the purposes of certification. Mr Carlberg noted that Alinta was keen for estimates to be provided when its GIA generators were subject to a triggering outage.

  Ms Laidlaw noted that the relevant network equipment should be on the Equipment List and asked if there was any reason why the triggering outage processes proposed as part of RC_2014_03 would not work for GIA generators. There was further discussion about why and whether the triggering outage process should be different for GIA generators because of their different contractual relationship with Western Power.

Item	Subject	Action
	Mr Sharafi and Mr Maticka agreed to take the question on notice. Ms Laidlaw noted that clarity on the issue was urgently needed as it could affect the drafting for RC_2014_03. • Ms Laidlaw sought the views of MAC members on Synergy's suggestion that a Scheduled Generator that suffered a Forced Outage in a Trading Interval should be ineligible for constraint payments in that Trading Interval; and in particular whether they would support the idea if it materially reduced implementation costs for RC_2014_03.	
	Action: AEMO to advise RCP Support and the MAC on whether and why the triggering outage processes recently proposed as part of Rule Change Proposal: Administrative Improvements to the Outage Process (RC_2014_03) should be different for GIA generators.	**AEMO**
	Action: MAC members to email any additional feedback on the questions raised in the discussion of Consequential Outages and NSG commitment and decommitment at the 11 February 2020 MAC meeting to RCP Support by 5:00 PM on Thursday 20 February 2020.	**All**
8(d)	**RC_2017_02: Implementation of 30-Minute Balancing Gate Closure – enhancement of information used in trading decisions** Dr Natalie Robins presented the estimated costs of three options to provide additional Balancing Market information to Market Participants to help improve the accuracy of their trading decisions. A copy of Dr Robins' presentation is available in the meeting papers. Dr Robins sought feedback from MAC members on whether the benefits of the additional information provided under each of the three options would outweigh their estimated implementation costs. The following points were discussed: • Mr Kurz noted that while in general more information led to better decision-making, he needed to give further thought to whether the costs of the options presented were justified by the benefits. Mr Carlberg agreed, noting that Alinta would consider the net benefits of the options given how much time remained before the new market arrangements were to begin. • Ms Ng noted AEMO's concerns about the volume of data that would be created if the Forecast BMO was published	

Item	Subject	Action
	every five minutes, and questioned why this would not also be a problem for the proposed security constrained economic dispatch (**SCED**) systems. Mr Maticka explained that the current systems were only designed to support a 30-minute cycle, and would need to be upgraded to support a more frequent cycle. In contrast, the proposed SCED process will use new systems built on a different technology platform, and will be designed and tuned with a five-minute cycle time in mind. • Mr Sharafi observed that none of the options presented was required to facilitate a shorter Balancing Gate Closure. MAC members requested a week to further consider the net benefit of the options and provide their views to RCP Support.	
	Action: MAC members to provide their feedback on whether the three options discussed at the 11 February 2020 MAC meeting to provide additional information to Market Participants to help improve the accuracy of their trading decisions would provide sufficient benefit, given the cost estimates provided by AEMO, by 5:00 PM on Wednesday 19 February 2020.	**All**
8(e)	**RC_2020_02: Adding a Criteria for Acceptance of a Non-Temperature Dependent Load** The Chair noted that Edna May Operations recently raised an issue with RCP Support about the status of its processing plant as a Non-Temperature Dependent Load (**NTDL**). Edna May Operations had provided a Pre-Rule Change Proposal to address their concerns for consideration by the MAC. The Chair asked MAC members for their views on the Pre-Rule Change Proposal, including the urgency rating they would recommend for the proposal. The following points were discussed: • Mr Maticka noted that AEMO had contacted the participant to discuss the issue because the Pre-Rule Change Proposal did not appear to consider that it was fairly easy to reinstate the NTDL status of the Load under the current Market Rules. Mr Maticka also noted that the proposed Amending Rules in the Pre-Rule Change Proposal were based on an old version of the Market Rules. • Mr Carlberg's initial thought was that the rules, as drafted, gave quite a lot of power to the participant to manipulate its NTDL status. Mr Carlberg agreed with Mr Maticka's assessment that the participant could quite easily reapply for NTDL status; and suggested that if this was an isolated	

Item	Subject	Action
	issue affecting a small number of participants then it should not be assigned a very high urgency rating. • Mr Kurz agreed that there already appeared to be enough options in the Market Rules for the participant to manage its NTDL status. • Ms Laidlaw asked MAC members for their views on the proposed additional exemption criterion, leaving aside the question of the urgency of the proposal. The Chair asked members to consider, among other things, whether the drafting opened the way for any gaming opportunities. Mr Carlberg considered that the Load's consumption seemed likely to vary over time, and suggested the participant might be able to manipulate its NTDL status if it knew when those consumption changes were going to occur. Mr Carlberg questioned whether this type of Load should be classified as an NTDL. Mr Gaston questioned whether the NTDL concept was warranted at all, because the Loads were still relying on the market to provide backup even though they had a steady consumption level. Mr Gaston did not consider the issue was very urgent. Mr Peter Huxtable considered that the principle of non-temperature dependence had never been particularly well explained, but was generally supportive of the NTDL concept for Loads with a flat consumption pattern. Mr Huxtable tended to agree with the principle behind the Pre-Rule Change Proposal, but considered there were potential loopholes in the drafting. • Ms Ng considered that, putting aside any drafting issues, the proposal was not urgent but was still worth considering. The MAC generally agreed that the concept behind the Rule Change Proposal was reasonable, but considered further work was needed to address the concerns raised by MAC members. The MAC recommended a Low urgency rating for the Pre-Rule Change Proposal.	
9	**General Business** No general business was discussed.	

The meeting closed at 11:35 AM.

RCP Rule Change Panel
Market Advisory Committee

Agenda Item 4: MAC Action Items

Meeting 2020_03_24

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
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 but will not be in a position to provide a response to the MAC until about September 2020.
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.

Item	Action	Responsibility	Meeting Arising	Status
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	**Closed** ETIU gave a presentation on generator performance standards to the Transformation Design and Operation Working Group (**TDOWG**) meeting on 10 March 2020.[1]
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	**Closed** AEMO provided a verbal update on this action item at the MAC meeting on 11 February 2020 (see the minutes of that meeting).
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	**Closed** This action item was be discussed under Agenda Item 8(b) at the MAC meeting on 11 February 2020 (see the minutes of that meeting).
1/2020	RCP Support to publish the minutes of the 26 November 2019 MAC meeting on the Rule Change Panel's (**Panel**) website as final	RCP Support	2020_02_11	**Closed** The minutes were posted on the Panel's website on 12 February 2020.

[1] The slides for this presentation are available at http://cdn-au.mailsnd.com/26738/xlgos4GSCfJWjbpU3NrBbS3GH7IGa6kwP5U4zC9fHTI/3134432.pdf.

Item	Action	Responsibility	Meeting Arising	Status
2/2020	AEMO to advise RCP Support and the MAC on whether and why the triggering outage processes recently proposed as part of Rule Change Proposal: Administrative Improvements to the Outage Process (RC_2014_03) should be different for GIA generators.	AEMO	2020_02_11	**Open** AEMO advised RCP Support that it does not consider that the triggering outage process should be different for GIA generators. Rather the Triggering Outage Notification proposed rules may need to consider the treatment of GIA generators under the existing outages rules. For example, in the event that the GIA tool constrains a GIA generator under MR 3.21.2A there is no GIA generator outage and therefore no Triggering Outage event in the context of the Rule Change Proposal RC_2014_03. AEMO is happy to discuss this further with RCP Support during the drafting of the rules concerning RC_2014_03. RCP Support is seeking clarification on several aspects of AEMO's response and will provide further feedback at the MAC meeting.
3/2020	MAC members to email any additional feedback on the questions raised in the discussion of Consequential Outages and NSG commitment and decommitment at the 11 February 2020 MAC meeting to RCP Support by 5:00 PM on Thursday 20 February 2020.	MAC	2020_02_11	**Closed** RCP Support received two responses from MAC members and will account for this feedback in the Draft Rule Change Report for RC_2014_03.
4/2020	MAC members to provide their feedback on whether the three options discussed at the 11 February 2020 MAC meeting to provide additional information to Market Participants to help improve the accuracy of their trading decisions would provide	MAC	2020_02_11	**Closed** RCP Support has received responses from some MAC members and will account for this feedback in the Draft Rule Change Report for RC_2017_02.

Item	Action	Responsibility	Meeting Arising	Status
	sufficient benefit, given the cost estimates provided by AEMO, by 5:00 PM on Wednesday 19 February 2020.			

RCP Rule Change Panel
Market Advisory Committee

Agenda Item 5: MAC Market Rules Issues List Update

Meeting 2020_03_24

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;
- advise whether issue 52 (North Country Spinning Reserve) should be closed or remain open while AEMO and the Energy Transformation Implementation Unit (**ETIU**) develop a rule change proposal to address the issue;
- 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**
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 still considering its position on this proposal.
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 still considering its position on this proposal.
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.

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
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 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

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
			some further actions by AEMO to progress the matter. However, EPWA, AEMO and Western Power subsequently held further discussions on this issue. ETIU advised the MAC at its meeting on 11 February 2020 that AEMO will develop a rule change proposal to address North Country Spinning Reserve issue and will submit it to the Minister for approval. The intent is for the rule change proposal to: • allow multiple generators to form the largest contingency; and • change how Spinning Reserve costs are allocated when multiple generators form the largest contingency to maintain the cost causality principle.
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

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
			that relates to Early Certification of Reserve Capacity (**CRC**). 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

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
			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

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
			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.
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) Behind-the-meter issues	**Issues:** 2, 16, 35. **Status:** Preliminary discussion is not yet scheduled. EPWA is working on its DER Roadmap, which will address behind-the-meter issues (amongst other things). A preliminary discussion of behind-the-meter issues is to be deferred until the DER Roadmap is published and then the MAC will consider whether a discussion is still required.
(2) Forecast quality	**Issues:** 9. **Status:** Preliminary discussion is not yet scheduled.
(3) Commissioning Tests	**Issues:** 39. **Status:** Preliminary discussion is not yet scheduled.
(4) The basis of allocation of Market Fees	**Issues:** 2, 16, 23 and 35. **Status:** Preliminary discussion is not yet scheduled.
(5) 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.
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.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
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 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.	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.
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	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**
		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.)	
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)	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**
		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.)	
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; • 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.	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 7.2.2.5 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 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.)	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).
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	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**
		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. (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.	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**
		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 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, 24 MARCH 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	20 February 2020	7 April 2020 (To be confirmed)
Market Procedures for discussion	• Market Procedure: Certification of Reserve Capacity • Market Procedure: Balancing Market Forecast • Market Procedure: Balancing Facility Requirements	• Market Procedure: Reserve Capacity Testing (several changes to clarify process) • Market Procedure: Facility Registration, De-Registration and Transfer (minor changes to correct references)

3. AEMO PROCEDURE CHANGE PROPOSALS

The status of AEMO Procedure Change Proposals is described below, current as at 16 March 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_2020_02 Market Procedure: Certification of Reserve Capacity	The proposed amendments are intended to clarify the process for applying for Certified Reserve Capacity and the supporting documentation required	Procedure Change Proposal published 12 March 2020	Consultation period closes	9 April 2020

RCP Rule Change Panel
Market Advisory Committee

Agenda Item 8(a): Overview of Rule Change Proposals (as at 17 March 2020)

Meeting 2020_03_24

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

Indicative Rule Change Panel Activity Until the Next MAC Meeting

Reference	Title	Events	Indicative Timing
RC_2014_03	Administrative Improvements to the Outage Process	Publication of the Draft Rule Change Report	16/04/2020
RC_2017_02	Implementation of 30-Minute Balancing Gate Closure	Publication of the Draft Rule Change Report	14/04/2020
RC_2018_05	ERA Access to market information and SRMC investigation process	Ministerial approval of the Amending Rules	16/04/2020
RC_2019_04	Administrative Improvements to Settlement	Publication of the Draft Rule Change Report	20/03/2020
		Close of second submission period	21/04/2020
RC_2019_05	Amending the Minimum STEM Price definition and determination	Close of second submission period	14/04/2020
RC_2020_01	Market Participant Fee calculation manifest error	Ministerial approval of the Amending Rules	24/03/2020
		Commencement	30/03/2020

Reference	Title	Events	Indicative Timing
N/A	2020 Review of Market Customers Vacant Positions on the MAC	Close of nominations	03/04/2020
		Panel appointment of new MAC members	30/04/2020

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

Reference	Submitted	Proponent	Title	Commenced
None				

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
None				

Rule Change Proposals Awaiting Approval by the Minister

Reference	Submitted	Proponent	Title	Approval Due Date
RC_2018_05	27/09/2018	ERA	ERA access to market information and SRMC investigation process	16/04/2020
RC_2020_01	24/01/2020	Panel	Market Participant Fee calculation manifest error	24/03/2020

Formally Submitted Rule Change Proposals

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
Fast Track Rule Change Proposals with Consultation Period Closed						
None						
Fast Track Rule Change Proposals with Consultation Period Open						
None						
Standard Rule Change Proposals with Second Submission Period Closed						
None						
Standard Rule Change Proposals with Second Submission Period Open						
RC_2019_05	25/10/2019	Synergy	Amending the Minimum STEM Price definition and determination	High	Close of second submission period	14/04/2020
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
RC_2019_01	21/06/2019	Enel X	The Relevant Demand calculation	Medium	Publication of Draft Rule Change Report	30/06/2020

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
RC_2019_04	18/11/2019	AEMO	Administrative Improvements to Settlement	Medium	Publication of Draft Rule Change Report	20/03/2020
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

Rule Changes Made by the Minister

Gazette	Date	Title	Commencement
2020/24	21/02/2020	Wholesale Electricity Market Amendment (Reserve Capacity Pricing Reforms) Rules 2019	22/02/2020 01/10/2021[1]

[1] The *Wholesale Electricity Market Amendment (Reserve Capacity Pricing Reforms) Rules 2019* will commence in two tranches – the first commenced on 22 February 2020 and the second will commence on 1 October 2021.

RCP | Rule Change Panel
Market Advisory Committee

Agenda Item 8(b): RC_2019_01: The Relevant Demand calculation – Next Steps

Meeting 2020_03_24

1. Background

Enel X submitted Rule Change Proposal RC_2019_01 to the Rule Change Panel (**Panel**) on 29 April 2019. The Panel sought further clarification on some aspects of RC_2019_01 and Enel X provided the clarifications on 21 June 2019.

The Panel decided to progress RC_2019_01 and published the Rule Change Notice and Proposal on its website on 28 June 2019. The first submission period was held between 28 June 2019 and 9 August 2019. The Panel received submissions from AEMO, the Australian Energy Council, Perth Energy, Synergy and Water Corporation.

The Panel has a assigned an urgency rating of 'Medium' to the Rule Change Proposal.

On 26 August 2019, the Panel has extended the timeframe for the publication of the Draft Rule Change Report until 30 June 2020 to give it time to hold workshops to develop drafting for this Rule Change Proposal and to prepare the Draft Rule Change Report while also managing competing priorities.

In Gazette 2020/24, published on 21 February 2020, the Minister has provided that from October 2021 all Demand Side Programmes (**DSP**) will receive the same Reserve Capacity Price for their Capacity Credits as other Facilities. The Panel considers that this change is likely to increase the participation of DSPs in the Reserve Capacity Mechanism, increasing the relevance of RC_2019_01. However, due to the timing of the changes to the Reserve Capacity Price for DSPs, RCP Support considers that the urgency rating of the Rule Change Proposal remains appropriate.

The Rule Change Notice and Proposal are attached for convenience. The submissions received in the first submission period are published on the Panel's website.

2. The Rule Change Proposal

2.1 Definition of Relevant Demand

Enel X proposes to change the definition of Relevant Demand to: An estimate of a DSP's counterfactual demand, when it is dispatched.

2.2 Implementation of a Dynamic Baseline

Enel X proposes to replace the current methodology for calculating a DSPs Relevant Demand with a baseline methodology for DSPs that strikes an appropriate balance between accuracy, simplicity and integrity.[1]

Enel X considers that the current method, using a low, static baseline not only under-calculates and undervalues the potential of DSPs but results in a very inaccurate picture of the DSPs' expected consumption in majority of the hours.

Dynamic baseline methodologies have the potential to measure baseline consumption much more accurately than static approaches because they are capable of taking into account a DSP's variability over whatever hours it is actually dispatched.

Enel X advocates implementing a dynamic baseline methodology for DSPs that accounts for a Load's variability when calculating a DSP's Relevant Demand. Enel X is of the view that an "X of Y"[2] methodology is best suited for the Wholesale Electricity Market (**WEM**). Enel X also suggest that it may not be necessary to settle on one specific approach. Many international markets offer a range of baseline methodologies so that the most accurate one can be chosen for each site.

2.3 Availability monitoring

Enel X notes that most capacity markets worldwide do not impose any obligation on the system operator to monitor availability to gain assurance that capacity providers will be able to deliver the capacity they have been credited for. Therefore, Enel X is of the view that continuous availability monitoring of demand side programmes is not required. Rather, any concerns about a DSP's ability to meet its reserve capacity obligations are better addressed through security, testing and penalty frameworks.

3. Relevant Demand Calculation in the WEM

3.1 Current Methodology

Under the current methodology set out in the Market Rules, AEMO calculates the Relevant Demand for a DSP as follows:

(1) identify the 200 Calendar Hours in the previous Capacity Year with the highest Total Sent out Generation (the Calendar Hours do not have to be contiguous);

(2) identify the metered consumption for each of the DSP's Associated Loads for the two Trading Intervals of each Calendar Hour identified under (1);

(3) for each Calendar Hour, sum the values for each of the DSP's Associated Loads identified under (2);

(4) for each DSP, rank the 200 values determined under (3) from lowest to highest; and

(5) the Demand Side Programme's Relevant Demand is the tenth lowest value.

---

1 Accuracy – customers receive credit for no more and no less than the curtailment that they provide.

Simplicity – the methodology makes baseline and curtailment calculations easy to calculate and easy for customers to understand.

Integrity – the methodology does note encourage irregular consumption, and irregular consumption does not influence he baseline calculations (i.e. protects against the ability to "game the system").

2 The "Y" is a Load's expected demand drawn from data from a number of previous days and "X" is a subset of these "Y days" to obtain a representative sample.

Under the current Market Rules, AEMO calculates the Relevant Demand for each DSP on a daily basis. This means that a DSP's Relevant Demand can change from one Trading Day to the next due to changes in meter data, which may affect the selection of the 200 Calendar Hours under (1) or the consumption of any of the DSP's Associated Loads.

3.2 Previous Methodology

Under the previous methodology, AEMO had to calculate the Relevant Demand for a DSP as follows:

(1) identify the eight consecutive Trading Intervals with the highest aggregate system demand in each month during the Hot Season of the previous Capacity Year;

(2) determine the metered consumption multiplied by two (to convert from MWh to MW) for each of the DSP's Associated Loads for the Trading Intervals identified under (1);

(3) for each Trading Interval determined under (1) sum the values determined under (2) for all of the DSP's Associated Loads; and.

(4) the DSP's Relevant Demand is the median of the 32 values determined under (3).

4. Relevant Dynamic Demand Baseline Types

The Electric Reliability Council of Texas (**ERCOT**) uses the following different baselines for different types of loads providing demand side management:

- **Statistical Regression Model**

  The following formula outlines a generalised form of a Statistical Regression Model used by ERCOT:

  $$kW^{e}_{d,h,\text{int}} = F\left(Weather_d, Calendar_d, Daylight_d\right)$$[3]

  Within this general specification, there is an unlimited number of detailed specifications that involve different types of data (such as hourly versus daily weather variables) and different functional specifications that can be used to capture specific nonlinear relationships and variable interactions. This breakdown allows development of a robust and relatively rich daily energy model that relies primarily on daily weather and calendar information.

- **Meter-Before/Meter-After Model**

  For this model the energy consumption during the trading interval that ends immediately preceding the dispatch instruction is used as the baseline for all subsequent intervals.

[3] Where: **e** is the DSP's ID;
d is a specific day;
h is an hour on day **d;**
int is a 15-minute interval during hour **h**;
kW is the average load for a DSP's ID in a specific interval;
Weather represents weather conditions on the day and preceding days;
Calendar represents the type of day involved; and
Daylight represents solar data, such as the time of sunrise and sunset.

- **Middle X-of-Y Like Days Model**

  This concept is used widely in many jurisdictions, and with numerous variations especially on the number of days to evaluate. ERCOT has concluded using 8-of-10 produces the best results. This approach consists of the following steps:

  (1) identifying the 10 (Y) days having the same day-type as the event day;

  (2) calculating the energy consumption for each of the ten (X) days and eliminating the day with the highest consumption and the day with lowest consumption; and

  (3) averaging the interval consumption for the eight remaining days together for each interval.

  The result of this is the unadjusted baseline. The data selection rules ERCOT uses for choosing the Y days are mostly proximity to the event, similarity of load and/or similarity of weather. Exclusion rules to eliminate some of the Y days can be based on eliminating highest or lowest demand days or choosing middle days. The days left after applying the exclusion rules can be referred to as X days. These X days are averaged to calculate an unadjusted baseline. ERCOT also allows for further adjustment of the baseline (e.g. by applying a factor to the baseline to account for temperature differences).

- **Nearest-20 Like Days Model**

  The load for a demand side management site on 20 days of the same day-type that occur close to a dispatch event is averaged for each interval. The result of this is the unadjusted baseline.

- **Matching Day Pair Mode**

  Intervals for past days (matching days) are matched with the corresponding intervals of the event day. The ten best available matching days are identified and the average for consumption over all matching days is calculated for each interval to determine an unadjusted baseline.

5. Role of Relevant Demand on the Reserve Capacity Mechanism

DSPs can participate in the Reserve Capacity Mechanism and receive Capacity Credits. In the WEM, all Facilities holding Capacity Credits are also subject to reserve capacity testing and the Capacity cost Refund regime. Therefore, not including a form of continuous monitoring if DSPs meet their Reserve Capacity Obligation could:

- increase the risk that the capacity would not be available when it is needed; and
- be against Wholesale Market Objective (c),[4]

Currently a DSP incurs Capacity Cost Refunds for every Trading Interval where the sum of the Relevant Demand of all its Associated Loads does not meet its Reserve Capacity Obligation. This approach will not work if the Relevant Demand is calculated with a dynamic baseline.

---

4 Wholesale Market Objective (c) is:

> 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.

6. Content for Workshop

RCP Support is planning a workshop to develop the design elements and support the development of Amending Rules for this proposal. RCP Support suggests discussing the following content at this workshop:

(1) How should Relevant Demand be defined?

(2) Should the Relevant Demand in the WEM based on a static baseline or a dynamic baseline?

(3) Which methodologies for determining a baseline are appropriate for the WEM?

(4) Should there be a single baseline approach for all DSPs or different baseline approaches for different types of DSPs?

(5) On which basis should Capacity Credits be assigned to DSPs?

(6) How can the availability of DSPs be monitored for Capacity Cost Refunds?

7. Recommendation

That the MAC:

(1) provides feedback to the Panel regarding the proposed content of the planned workshop; in particular if:

   (a) any of the proposed aspects should not be discussed at the workshop;

   (b) if any additional aspects should be discussed at the workshop; and

(2) discusses the possible timing of the workshop.

8. Attachments

(1) RC_2019_01 – Rule Change Notice and Proposal

RCP Rule Change Panel
Market Advisory Committee

Agenda Item 10: Proposed Changes to the Rule Change Panel Appointment Process

Meeting 2020_03_24

Background

On 28 February 2020, Energy Policy WA (**EPWA**) published:[1]

- a paper titled 'Improving the Rule Change Panel appointment process – Directions Report' (**Directions Report**); and
- draft changes to the *Energy Industry (Rule Change Panel) Regulations 2016* (**Panel Regulations**).

The Minister for Energy has endorsed the Directions Report and EPWA is seeking feedback as to any drafting errors or unintended consequences arising from the draft Amendment Regulations. Submissions are to be made to EPWA at submissions@energy.wa.gov.au by 5:00 PM on 26 March 2020.

Summary of Proposed Changes

(1) The Rule Change Panel (**Panel**) is to be increased from three to five members. The quorum for the Panel is to remain at three members.

(2) The Panel Chairperson is to be given a casting vote in the event of a deadlock in deciding a particular matter.

(3) The restrictions on who can be appointed to the Panel are to be amended as follows:

Current Restrictions	Revised Restrictions
o the Executive Officer to the Panel; o a member of the Economic Regulation Authority (**ERA**);[2] o a person employed in the Public Service;[3] o a market participant;[4] and o a person who is employed or engaged by a market participant.[5]	o the Executive Officer to the Panel; o a member of the ERA and ERA staff; o the Coordinator of Energy and EPWA staff; and o a Director of AEMO and AEMO staff.

1 The Directions Report and draft changes to the Panel Regulations are available on EPWA's website at https://www.wa.gov.au/government/announcements/improving-the-rule-change-panel-appointments-process.The Directions Report is dated 14 November 2019 but was published on 28 February 2020.

2 That is, the three members of the ERA's Governing Body.

3 This includes staff from the ERA, EPWA, the Department of Treasury and any other Government department.

4 The term 'market participant' is defined in clause 3 of the Panel Regulations – see Attachment 1 for further information.

5 That is, a staff member of, or a consultant to a market participant.

The revised governance arrangements will make the following persons eligible for appointment to the Panel:

- public servants other than ERA and EPWA staff, which would include staff from the Department of Treasury and any other Government department;
- staff of market participants, which would include staff of any of the parties indicated in Attachment 1; and
- any consultant that has a contract to provide services to a market participant.

(4) The restriction on Panel members being reappointed only once is to be removed.

Discussion

The Panel is seeking advice from the MAC regarding the MAC's views on the changes to the Panel's governance arrangements, and in particular, whether these changes are likely to have any unintended consequences;

Attachment 1: The Definition of 'market participant'

Clause 3 of the Panel Regulations defines a 'market participant' as:

- a 'participant' defined in section 121(3) of the *Electricity Industry Act 2004* (**EI Act**); or
- a 'gas market participant' defined in section 3(1) of the *Gas Services Information Act 2012* (**GSI Act**).

Section 121(3) of the EI Act defines a person as a participant if:

(a) the person is registered in accordance with the market rules as required under the regulations; or

(b) functions are conferred on the person under the regulations or the market rules; or

(c) functions relating to this Part are conferred on the person by another written law.

Section 3(1) of the GSI Act defines a gas market participant as:

(a) a service provider;

(b) a user;

(c) a producer;

(d) a storage provider; and

(e) a person prescribed by the regulations for the purposes of this definition.

The Panel Regulations will also soon be amended to cover the Panel's role with respect to the soon to be established Pilbara Network Rules and will presumably need to expand the definition of 'market participant' in clause 3 to include 'participants' as defined in the Pilbara Network Rules. EPWA is currently consulting on what entities will need to be registered under the Pilbara Network Rules but RCP Support expects these will include:

(a) Network Service Providers;

(b) generators

(c) large customers; and

(d) Essential Systems Services providers.

So in summary, a market participant includes:

Under the Market Rules	Under the GSI Rules	Under the Pilbara Network Rules (likely)
There are currently 87 Rule Participants,[6] including: • large generators (like Alinta, Bluewaters, Synergy, etc.); • smaller generators; • operators of intermittent generators (windfarms, solar farms, etc.); • Market Customers, which includes retailers (like Alinta and Wesfarmers Kleenheat), large self-supplying customers, third party providers of Demand Side Programmes, and Ancillary Service Providers; • network operators (like Western Power); and • persons with functions conferred by the Market Rules (like AEMO).	There are currently 77 registered gas market participants,[7] including: • gas producers (like BHP, Chevron, Woodside, etc.); • pipeline operators (like APA Group and the Dampier to Bunbury Natural Gas Pipeline); • shippers (like Gas Trading Australia); • large industrial gas users (like mining companies); and • users (like Alinta);	It is currently unclear exactly who will be a participant under the Pilbara Network Rules, but it is likely to include: • Alinta; • BHP; • FMG; • Horizon Power; and • Rio Tinto.

6 A list of Rule Participants can be found on AEMO's website at (https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/participate-in-the-market/information-for-current-participants/participants-registered-in-the-wem).

7 A list of registered gas market participants can be found on AEMO's website at (https://www.aemo.com.au/energy-systems/gas/wa-gas-bulletin-board-wa-gbb/participate-in-the-wa-gbb/participants-and-facilities-registered-for-the-wa-gbb).