RCP Rule Change Panel
Market Advisory Committee

Minutes

Meeting Title:	Market Advisory Committee (**MAC**)
Date:	29 July 2019
Time:	09:30 AM – 12:30 PM
Location:	Training Room No. 2, Albert Facey House 469 Wellington Street, Perth

Attendees	Class	Comment
Stephen Eliot	Chair	
Matthew Martin	Minister's Appointee – Small-Use Consumer Representative	
Martin Maticka	Australian Energy Market Operator (**AEMO**)	
Dean Sharafi	System Management	
Sara O'Connor	Economic Regulation Authority (**ERA**) Observer	
Andrew Everett	Synergy	
Margaret Pyrchla	Network Operator	
Jacinda Papps	Market Generators	
Wendy Ng	Market Generators	
Daniel Kurz	Market Generators	
Andrew Stevens	Market Generators	
Patrick Peake	Market Customers	
Geoff Gaston	Market Customers	
Tim McLeod	Market Customers	
Peter Huxtable	Contestable Customers	

Apologies	Class	Comment
Chayan Gunendran	Market Customers	

Also in Attendance	From	Comment
Claire Richards	Enel X	Presenter
Aden Barker	Energy Transformation Implementation Unit (**ETIU**)	Presenter to 12:15 PM
Miles Jupp	ETIU	Presenter

Jenny Laidlaw	RCP Support	Minutes
Kim Phan	ETIU	Observer
Julian Fairhall	ERA	Observer
Noel Schubert	ERA	Observer
Scott Davis	Australian Energy Council	Observer
Erin Stone	Point Economics	Observer
Kei Sukmadjaja	Western Power	Observer
Ian Porter	Sustainable Energy Now	Observer
Richard Cheng	RCP Support	Observer
Natalie Robins	RCP Support	Observer

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1	**Welcome** The Chair opened the meeting at 9:30 AM and welcomed members and observers to the 29 July 2019 MAC meeting.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above.	
3(a)	**Minutes from Previous Meeting** Draft minutes of the MAC meeting held on 11 June 2019 were circulated on 19 June 2019. The MAC accepted the minutes as a true and accurate record of the meeting. **Action: RCP Support to publish the minutes of the 11 June 2019 MAC meeting on the Rule Change Panel's (Panel's) website as final.**	**RCP Support**
3(b)	**Minutes of MAC Workshop 2019_06_10 (RC_2013_15)** The MAC noted the final minutes of the MAC drafting review workshop held on 10 June 2019 for Rule Change Proposal: Outage Planning Phase 2 – Outage Process Refinements (RC_2013_15).	
4	**Action Items** The closed action items were taken as read. **Action 10/2019:** Mr Dean Sharafi gave a presentation on the results of AEMO's modelling of the impact of the two new North Country generators on the Spinning Reserve requirement, and the options that AEMO has identified to address the market	

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	implications. A copy of AEMO's presentation is available on the Panel's website. The following points were discussed. • Mr Sharafi clarified that the two new generators and NewGen Neerabup would not form a single contingency under system normal conditions. • In response to a question from Mr Andrew Stevens, Ms Jenny Laidlaw clarified that Synergy would not receive any compensation for providing additional Spinning Reserve unless the additional requirement was incorporated into the next margin values determination. • Mr Martin Maticka noted that under the current Spinning Reserve cost allocation mechanism, the two generators would not be allocated a Spinning Reserve cost share that reflected their impact on the Spinning Reserve requirement. • Mr Stevens suggested that if the full runway cost allocation method was amended to consider line contingencies, then there would be no need to worry about constrained off payments because the Facilities involved could make a commercial decision on whether to run at a higher level and pay an increased Spinning Reserve cost, or reduce their output to avoid that cost. Mr Sharafi replied that in some situations it may not be possible to enable enough Spinning Reserve, so System Management will have to constrain the output of one or more generators. • Ms Laidlaw questioned why a Facility that connects under the Generator Interim Access (**GIA**) arrangement, with an expectation of operating under a future constrained network access regime, should receive constrained off compensation in these circumstances. No attendee offered a reason why constrained off compensation would be warranted. • No attendee disagreed with the concept that if System Management was to enable additional Spinning Reserve, then Synergy should be appropriately compensated for providing the additional service, and the additional costs should be allocated on a causer-pays basis. • Mr Andrew Everett considered that in future it may not always be possible to enable enough Spinning Reserve, even if the new generators are constrained down to prevent them forming the largest contingency. • Mr Sharafi presented three options to address the problem. There was some discussion about the need for a relatively simple solution and how to assess the economic trade-off	

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	between potentially higher Spinning Reserve costs and potentially lower energy prices. Mr Sharafi noted that AEMO has not undertaken any market modelling regarding which of the three options is the most efficient.	
	• Ms Laidlaw noted that it would be perverse to restrict the output of generators in a Trading Interval where the additional Spinning Reserve requirement could be met without any additional cost to Synergy.	
	• Mr Geoff Gaston asked whether the generators would receive any compensation if they were constrained down by Western Power under their GIA arrangements. Mr Sharafi replied that while generators do not receive compensation if they are constrained down under a GIA arrangement, the GIA arrangements are only used to manage network constraints.	
	• In response to a question from Mr Gaston, Ms Laidlaw confirmed that constrained off payments for Facilities that are constrained off due to a network outage were removed on 1 July 2019 by the Amending Rules for Rule Change Proposal: Removal of constrained off compensation for Outages of network equipment (RC_2018_07).	
	Ms Laidlaw questioned whether it would be appropriate for NewGen Neerabup to be constrained down ahead of a GIA generator if a network outage created a Spinning Reserve requirement that System Management could not meet.	
	• Mr Patrick Peake asked whether the two generators were starting at the same time and, if not, whether any additional Spinning Reserve costs should be borne by the second generator to connect. Mr Sharafi replied that both generators were due to start operations in the first quarter of 2020.	
	• There was further discussion about how the relative efficiency of options 2 (incorporating 2a and 2b) and 3 could be assessed, and how decisions on whether to enable additional Spinning Reserve or constrain generators down might be made in real time. Mr Stevens noted that the modelling results indicated how often the generators would form the largest contingency, but not how often they would create a Spinning Reserve requirement that could not be met.	
	• Mr Stevens considered there was no choice but to agree that the generators should not receive compensation if they are constrained down to reduce the Spinning Reserve	

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	requirement. Mr Stevens expressed a concern that the issue was not identified and addressed earlier. • Mr Sharafi suggested that the issue might provide a case for Western Power to prepare a submission to the ERA to energise the second 330 kV North Country transmission line. • Mr Peake supported option 2 on the basis that it was unacceptable for the additional Spinning Reserve costs to be allocated to the largest generator rather than the responsible wind farms. However, Mr Peake questioned what the relevant Market Generators had been promised by the Government and other parties. Ms Laidlaw noted that the potential for the new generators to increase the Spinning Reserve requirement had been known for several years, so presumably there had been some discussion about the issue. • Mr Stevens questioned whether any other line contingencies might exceed 400 MW. Mr Sharafi replied that the next largest line contingency related to the 220 kV transmission line to the Eastern Goldfields. • Mr Ian Porter considered that demand response could form part of a future solution to the issue. Mr Porter indicated that he would agree with Mr Peake's view on the need to attribute the additional Spinning Reserve liabilities to the wind farms if the liability in future for carbon emissions was attributed to coal-fired power stations. Mr Sharafi noted that Interruptible Loads already provide Spinning Reserve at the transmission level, although there is no distribution-level demand response. Mr Peake noted that the source of the Spinning Reserve Service did not affect the need to pay for that service. • Mr Gaston expressed support for option 2. Mr Daniel Kurz also considered that option 2 would produce the best outcomes but questioned how long it would take to implement the necessary rule changes. Mr Sharafi considered that options 2a and 2b could be part of the same Rule Change Proposal and suggested that the proposal could be progressed using the Fast Track Rule Change Process. Ms Laidlaw considered that the proposal was unlikely to meet the fast track criteria but was likely to be assigned a High urgency rating. • Ms Wendy Ng asked how long it would take to implement the required system changes for option 2. Ms Laidlaw suggested that the changes could be implemented in two	

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	stages, i.e. the simpler changes (to remove constraint payments) first, and the more complex cost allocation changes later. Mr Maticka agreed that such an approach could be workable. • Mr Stevens suggested that the owners of the new Facilities should be advised immediately to ensure that their control system designs can cater for the suggested changes. There was some discussion about whether any material changes to the Facilities' control system designs would be required. • The Chair asked if the MAC supported the development of a Rule Change Proposal to address the issues raised by AEMO. Several members explicitly supported the development of a Rule Change Proposal, and no attendees suggested that a Rule Change Proposal should not be progressed. However, Mrs Jacinda Papps noted that AEMO's presentation was not sent to members until late on the previous Friday afternoon (26 July 2019) and indicated she could not offer any position on the proposal at this meeting. • There was some discussion about next steps and what AEMO is required to do before starting work to develop a Rule Change Proposal. Mr Maticka noted that AEMO had only responded to the action item raised by the MAC; and was presenting options for discussion rather than consulting with the MAC under clause 2.5.1A of the Market Rules about the development of a Rule Change Proposal. • Mr Maticka and Mr Stevens suggested that the MAC needed more time to reach a position on the development of a Rule Change Proposal, because some members had not had enough time to consider the issue. Mr Everett disagreed, considering that MAC members were at the MAC to form a market view, and that the views of Synergy and Alinta should not alter what the MAC chose to do from a market perspective. Mr Everett advised that he was comfortable with the development of a Rule Change Proposal proceeding, noting that individual representatives can express their individual views on that proposal at a later date. • The Chair asked AEMO whether, if the MAC was to support the development of a Rule Change Proposal to address the issues, AEMO would be willing to develop that Rule Change Proposal. Mr Sharafi replied that AEMO lacked resources to undertake the work, but if the MAC wanted AEMO to develop a Rule Change Proposal then AEMO would be happy to discuss this with the Rule Change Panel and see	

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	what could be done. No member raised a concern about AEMO developing a Rule Change Proposal to address the issue. • In response to a question from Ms Ng, Mr Sharafi advised that AEMO had no specific preference for option 3, because the new generators will provide low-cost energy to the market and constraining their output unnecessarily might increase energy costs. Ms Ng questioned whether this could be tolerated until the new market arrangements are implemented in 2022; and suggested that option 3 should be further considered before deciding to proceed with option 2. • Further to Ms Ng's comments, Mr Aden Barker encouraged MAC members to consider the issue of timing and implementation resource availability. Mr Barker noted that some of the issues would be resolved through a combination of the application of constrained network access and co-optimisation in the market, under the new market systems and the revised Essential Systems Services framework. Mr Barker questioned how long it would take to develop, progress and implement the rule changes for options 2a and 2b. However, Mr Barker clarified that he was an observer and therefore not expressing a view on whether a simpler option would be better. **Action 13/2019:** Mr Barker advised he would address the action item under Agenda Item 6(b).	
	Action: MAC members to send RCP Support their views on the North Country Spinning Reserve issue (and specifically their views on the three options presented by AEMO at the 29 July 2019 MAC meeting) by 9 August 2019.	**All**
	Action: AEMO and RCP Support to consider the views provided by MAC members on the North Country Spinning Reserve issue and discuss options for the development of a Rule Change Proposal, and report to the next MAC meeting.	**AEMO/ RCP Support**
5	**MAC Market Rules Issues List (Issues List) Update** The MAC noted the recent updates to the Issues List. <u>Issue 14/36 (Capacity Refund Arrangements):</u> The Chair noted that on 9 May 2018, the MAC placed issue 14/36 on hold for 12 months (until June 2019) to allow time for historical data on dynamic refund rates to accumulate. Mr Kurz	

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	and Ms Ng, who originally raised the issue, agreed that it has a low priority and should remain on hold for another 12 months. <u>Issue 52 (Multiple generating units on a single line constituting the largest credible contingency):</u> The MAC agreed to move issue 52 to table 1 (Potential Rule Change Proposals) and set the preliminary MAC urgency rating to High.	
6(a)-6(d)	**Update on the Energy Transformation Strategy (ETS)** Mr Barker provided the following updates on the ETS. • The Energy Transformation Taskforce (**Taskforce**) had held several meetings since the last MAC meeting. • On 12 July 2019, ETIU held an industry forum to seek feedback on proposed modelling scenarios for the first Whole of System Plan (**WOSP**). Approximately 100 stakeholders attended the industry forum. • The first Program Implementation Coordination Group meeting was held on 19 July 2019. The group comprises the Chair of the Taskforce, the ETIU Program Director and senior level representatives from AEMO and Western Power. • On 22 July 2019, ETIU hosted a presentation by Dr Gabrielle Kuiper on her Churchill Fellowship report "The Future of Electricity Distribution Networks". • During the most recent Taskforce meeting (26 July 2019), the Taskforce approved information papers relating to the change management process for Western Power's Technical Rules, and the high-level regulatory and legislative framework for Power System Security and Reliability standards. • Two meetings of the Taskforce are scheduled for August 2019. The first meeting will consider matters under the Foundation Regulatory Frameworks work stream, including the foundation market parameters discussed at the first Market Design and Operation Working Group (**MDOWG**) meeting, the energy scheduling and dispatch matters discussed at the second MDOWG meeting, and the publication of the GHD paper for the technical framework for Essential System Services. The second Taskforce meeting will include approval of information papers for release on limits information and the first tranche of work on Essential System Services.	

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	• The Taskforce published its first newsletter (for July 2019) and intends to publish newsletters on a monthly basis. • A Distributed Energy Resources (**DER**) Stakeholder Workshop was scheduled for 30 July 2019, with 70 stakeholders registered to attend. • The Strategic Consultative Group was also due to hold its first meeting soon. • The 3 July 2019 MDOWG meeting included a carry-over discussion around scheduling and dispatch of energy (specifically the treatment of fast start facilities and facility aggregation), a discussion of the new technical framework for Essential System Services, and an update on the proposed Reserve Capacity Mechanism (**RCM**) changes to support constrained network access. The next meeting was scheduled for 12 August 2019 and would continue the discussion around Essential System Services (and specifically frequency control). • With respect to action item 13/2019, the Taskforce was aware of the tight timeframes involved, not just in relation to the RCM but more generally in terms of changes to the market. The September 2019 MDOWG meeting would include a discussion around implementation of the RCM changes, including details of the relevant timelines. • Feedback on the proposed changes to the Terms of Reference for the MDOWG and the Power System Operation Working Group (**PSOWG**) had raised some legitimate questions about the distinction between the two working groups. While acknowledging the substantial administrative work that had gone into holding PSOWG meetings, ETIU considered that the two working groups should be abolished and replaced with a single working group, convened by the Taskforce and chaired by ETIU. Mr Barker advised that the new working group, which was likely to be known as the 'TDOWG', would operate in the same way as the former working groups, under new terms of reference that will be published under the Taskforce and ETIU section of the Treasury website. Stakeholders will continue to be able to bring items for discussion to the working group meetings. Mr Barker considered that one of the benefits of the new working group was that it could deal with matters that do not strictly fall under the purview of the MAC, such as matters relating to Western Power's Technical Rules, and any	

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	matters that need to be discussed around the Whole of System Plan and DER Roadmap. The MAC agreed to disband the MDOWG and PSOWG. The Chair asked if ETIU still wished to include a standing item on the MAC agenda for ETS progress updates. Mr Barker and MAC members agreed it would be useful to continue these regular updates. Mr Sharafi noted that AEMO had been working on several subjects for the next PSOWG meeting, including the reliability framework, outage management and frequency regulation, and that these subjects will now be discussed at meetings of the new working group. Mr Noel Schubert supported the working group changes but hoped that they did not adversely affect the momentum of the two former working groups. Mr Barker advised that the work previously assigned to AEMO and Western Power would continue to be undertaken by those parties; and commended the excellent work done by Mr Clayton James in facilitating the PSOWG meetings to date.	
6(e)	**Whole of System Plan** Mr Miles Jupp provided an update to the MAC on the development of the first WOSP. A copy of ETIU's presentation is available in the meeting papers. The following points were discussed. • Ms Ng asked if ETIU had developed the load profiles for the four scenarios. Mr Jupp replied that ETIU was making use of Western Power's forecasts, which considered residential, commercial and industrial loads separately. The load profiles for the four scenarios were developed using different assumptions about the mix of the three sectors. For example, the Castaway scenario assumed a large number of residential customers leaving the grid, so the load profile reflected the expected loss of some peak residential loads. • Mr Sharafi asked if ETIU had consulted with the AEMO staff who had worked on the development of the Integrated System Plan (**ISP**) for the National Electricity Market (**NEM**). Ms Kim Phan replied that Mr Noel Ryan, the Project Lead for the WOSP, had met with the ISP team to discuss their lessons and experiences. • Mr Porter asked what inputs ETIU had considered to prevent the Castaway scenario from occurring, given that a large-scale defection from the grid would not benefit the	

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	community. Mr Porter also questioned the Government's plans in relation to a future cost on carbon. In response, Mr Jupp noted that the Castaway and Double Bubble scenarios were two 'book end' inputs to the modelling. The WOSP outputs are intended to assist the regulator, policy makers and industry with policy formulation. Mr Jupp noted that ETIU was not including any specific carbon pricing inputs in its modelling because there is no set policy at this stage. Mr Porter considered that eventually there will be a cost for carbon and questioned why that eventuality was not incorporated into the WOSP. Mr Jupp noted that the current WOSP was intended to be the first of a series, and that carbon pricing implications could be considered in a future WOSP once the policy position was clearer. Mr Barker added that ETIU intended to consider the process for developing future WOSPs next year, towards the end of the development of the first WOSP. ETIU would consider matters such as how the WOSP would be developed and how frequently, and how the process would tie into other regulatory processes (e.g. the ERA's consideration of Western Power's access arrangements).	
7	**AEMO Procedure Change Working Group (APCWG) Update** The MAC noted the update on AEMO's Market Procedures.	
8(a)	**Overview of Rule Change Proposals** The Chair noted that the Final Rule Change Report for Rule Change Proposal: Outage Planning Phase 2 – Outage Process Refinements (RC_2013_15) was due to be published during August 2019. Ms Laidlaw noted that after further discussion with AEMO on Rule Change Proposal: Administrative Improvements to the Outage Process (RC_2014_03), RCP Support had revised the previous straw man proposal for the management of ex-ante Consequential Outages. Ms Laidlaw sought the preferences of the MAC on whether RCP Support should hold a workshop to discuss the revised straw man (and other aspects of the Rule Change Proposal) before or after the publication of a call for further submissions. There was general agreement from MAC members to hold the workshop before the publication of a call for further submissions. The Chair noted that RCP Support intended to hold a MAC workshop to discuss Rule Change Proposal: Implementation of	

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	30-Minute Balancing Gate Closure (RC_2017_02). The current target date for the workshop was 16 August 2019. Mr Richard Cheng noted that a new version of the Market Rules was due to be published on 1 August 2019. The MAC noted the overview of Rule Change Proposals.	
8(b)	**RC_2019_01: The Relevant Demand calculation** The Chair noted that the first submission period for Rule Change Proposal: The Relevant Demand calculation (RC_2019_01) was due to close on 9 August 2019. The Chair invited comments on the Rule Change Proposal from Ms Claire Richards (the submitter of RC_2019_01) and then from the MAC. The following points were discussed. • Ms Richards noted that the MAC discussed a draft of the Rule Change Proposal at its 5 February 2019 meeting. Enel X had sought to incorporate the comments provided by the MAC, and other specific comments provided by RCP Support, into the final version of the Rule Change Proposal. • Ms Richards provided an overview of RC_2019_01, including why Enel X submitted the Rule Change Proposal and why it proposed the use of a more dynamic Relevant Demand calculation. • Ms Richards noted that some fundamental concerns were raised during the 5 February 2019 MAC meeting about the role of the demand side in the RCM. Enel X had not sought to address these concerns in RC_2019_01, because it considered the Final Report for the Minister's RCP Pricing Reforms had clearly indicated the policy position that demand side management was to play an important ongoing role in the Wholesale Electricity Market, and that equivalent remuneration of the supply and demand side should be restored. • In response to a question from Mr Peter Huxtable, Mr Barker confirmed that RC_2019_01 did not overlap with ETIU's work program. • Mr Peake queried how a dynamic assignment of Relevant Demand tied in with the certification process. Ms Richards replied that the baseline calculation (whether static or dynamic) was not used in the certification process. The dynamic baseline approach was only used to verify and measure the counterfactual demand when a Demand Side Programme (**DSP**) was actually dispatched.	

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	• Mr Huxtable suggested that a dynamic baseline calculation would be better for aggregators than individual loads because the risk of a dynamic baseline for an individual load might be too high. • Mr Schubert considered that using a dynamic baseline was sensible because it would provide a more accurate estimate of the counterfactual demand of a DSP. • In response to a question from Mr Matthew Martin, Ms Richards clarified that dynamic baseline methodologies usually only considered quite recent historical data, e.g. from the previous 10 days. • Ms Laidlaw noted that the Market Rules allowed a DSP to be assigned Certified Reserve Capacity for a Capacity Year well before any Loads were associated with the DSP for that Capacity Year, i.e. well before a baseline of any type could be calculated. • Mr Sharafi considered that System Management needed to know whether a DSP's capacity was available to be dispatched and questioned how this would be done if the availability was not monitored on an on-going basis. Ms Richards replied that Enel X had suggested in RC_2019_01 that ongoing monitoring to clarify that a DSP is compliant with its capacity obligations in every Trading Interval is unnecessary, and not an approach taken in other markets. However, in other markets there is usually constant communication between the system operator and the DSP provider during periods when it is likely that the DSP will need to be dispatched. The NEM's Reliability and Reserve Trader mechanism operated in this way. Ms Laidlaw noted that RC_2019_01 proposed to remove the existing penalty that applied to a DSP when its Relevant Demand was too low to provide its certified capacity. There was some discussion about when the capacity of DSPs and Scheduled Generators should have to be available. • Mr Huxtable questioned whether a dynamic baseline methodology would require full outage scheduling for DSPs. Ms Laidlaw replied that several different options existed to manage the equivalent of Outages for DSPs. The Chair sought a recommendation from the MAC on the urgency rating for RC_2019_01. After some discussion, the MAC agreed to recommend a Medium urgency rating for the Rule Change Proposal, with several members noting that the changes were not urgently required.	

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	The MAC recommended that RCP Support hold a workshop to discuss RC_2019_01 and its development and implementation options before deciding on the next steps for the progression of the Rule Change Proposal.	
8(c)	**RC_2019_03: Method used for the assignment of Certified Reserve Capacity to Intermittent Generators** The Chair noted that the ERA had developed Pre-Rule Change Proposal: Method used for the assignment of Certified Reserve Capacity to Intermittent Generators (RC_2019_03) following discussions at the 5 February 2019 and 30 April 2019 MAC meetings. Ms Sara O'Connor noted that the Pre-Rule Change Proposal was based on the recommendations of the ERA's recent review of the Relevant Level Methodology. The ERA had consulted broadly throughout the review period and had spoken to the MAC on two occasions about what it intended to include in the Pre-Rule Change Proposal. Ms O'Connor asked members to raise any issues they had with the Pre-Rule Change Proposal so that the ERA could consider those issues before the proposal was submitted into the formal rule change process. In response to a request from Mrs Papps, Ms O'Connor advised that the ERA would be willing to provide Market Participants with the redacted information in Table 5 of Attachment 2 of the Pre-Rule Change Proposal that was relevant to their Candidate Facilities. The Chair asked if attendees had any questions or comments that they would like the ERA to address before it submitted the Rule Change Proposal. Mr Maticka indicated that he intended to discuss a few minor issues with Ms O'Connor directly. Ms Laidlaw also noted that she had some questions about the drafting that she would discuss with Ms O'Connor directly. The Chair sought the views of the MAC on the urgency rating for RC_2019_03, suggesting that it should be either High or Medium. Ms O'Connor noted that the ERA recommended a High urgency rating for two reasons: firstly, because it had concluded that the current method is flawed; and secondly, because it was aware of the current discussions under the ETS about the assignment of Capacity Credits within a constrained network environment, and wanted the proposed rule change to be included in that discussion. Mr Barker noted that ETIU intended to present more information about the proposed constrained network access certification process at the September 2019 TDOWG meeting.	

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	Mrs Papps suggested that the issues with the current methodology identified by the ERA provide a compelling case for the assignment of a High urgency rating. Mrs Papps considered that if both RC_2019_01 and RC_2019_03 were assigned a Medium urgency rating, then RC_2019_03 should be considered the more urgent of the two proposals. Mr Stevens agreed with Mrs Papps' preference for a High/Medium High rating. Mr Maticka considered that RC_2019_03 was a well thought out proposal and AEMO would not have any objections if it was assigned a High urgency rating. The MAC agreed to recommend a High urgency rating for RC_2019_03.	
9	**Issues with Reserve Capacity Testing** Mr Peake gave a presentation on several issues identified by Perth Energy around the provisions in the Market Rules for Reserve Capacity Tests. A copy of Perth Energy's presentation is available in the meeting papers. The following points were discussed. <u>Issue 1: Cost-benefit of running a test</u> • Mr Stevens considered that Perth Energy was responsible for the high cost of its Reserve Capacity Tests because it had decided to certify its Facility using diesel as its fuel. Mr Peake explained that the Facility usually ran on gas, but it was not feasible for a standalone peaking generator to have a gas contract that would satisfy the certification requirements in the Market Rules, so that it was necessary to certify and test using diesel. • There was some discussion about whether a Market Generator should be able to reduce its Capacity Credits without refunding any payments already received for the reduced capacity. Mr Maticka noted that DSPs were permitted to reduce their Capacity Credits in similar circumstances. • Mr Stevens agreed that a Market Generator who failed a Reserve Capacity Test should have the option to reduce its Capacity Credits rather than undertake a second Reserve Capacity Test. However, Mr Stevens considered that Market Generators in these situations should refund any payments have already been received for the reduced capacity. <u>Issue 2: Cost difference between self-testing and AEMO-testing</u>	

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	• Mr Maticka questioned whether a Reserve Capacity Test should cover one or two Trading Intervals and, if two Trading Intervals, whether those Trading Intervals should be consecutive. Mr Maticka considered that self-tests and directed tests should be the same length, rather than using a longer period for directed tests as a form of penalty for failing to complete a self-test. Mr Peake noted that for practical reasons Market Generators often run for at least two Trading Intervals when conducting a self-test. Ms Laidlaw asked whether it was a frequent occurrence for a Facility to achieve its target in one Trading Interval of a directed test but not both. Ms Ng suggested that a Facility may pass one Trading Interval but not another due to temperature differences. Mr Peake noted that Perth Energy had run two tests on different days and achieved the same output within 1 kW. While a subsequent meter test did not identify any problem, the meters were changed shortly after the test and Perth Energy has had no problem achieving its target output since the new meters were installed. There was some discussion about how many Trading Intervals are needed to verify the performance and reliability of a Facility. Mr Gaston considered that all Reserve Capacity Tests should cover two Trading Intervals. Mrs Papps considered that this would be a large change and questioned whether the market had experienced any problems due to Market Generators self-testing their Facilities over a single Trading Interval. In response to a question from Ms Laidlaw, Mr Peake confirmed that Perth Energy was not proposing any change to the current durations of self-tests and directed tests. <u>Issue 3: Ambiguity if a plant is on outage</u> • Mr Peake questioned whether, if a Facility fails a directed Reserve Capacity Test and is then on an outage during the prescribed period for the second test (between 14 and 28 days after the first test), AEMO should delay the second test or restart the entire test process once the Facility is available again. Mr Peake considered a rule change was needed because the Market Rules do not account for this scenario. • Mr Peake expected Perth Energy's suggestion would be to give AEMO two weeks to conduct the test once the Facility returned to service from the outage.	

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	<u>Issue 4: AEMO must reduce Capacity Credits “to reflect the maximum capabilities achieved in either Reserve Capacity Test”</u> • Mr Peake questioned how clause 4.25.4(a) of the Market Rules should be interpreted, using the scenario set out in the presentation as an example. Specifically, Mr Peake asked whether the maximum capability achieved in a directed Reserve Capacity Test was the greater of the output achieved in the first Trading Interval and the output achieved in the second Trading Interval, or the average output over the two Trading Intervals. Mr Stevens suggested that the lower of the two output values should be used, as it provided a better indication of what the Facility could reliably achieve; and that the Facility’s Capacity Credits should be set to the lowest of the four relevant Trading Interval output values. Mr Peake replied that using the lowest value would expose Facilities to the risk of losing all their Capacity Credits if they tripped during a directed Reserve Capacity Test. There was some discussion about whether investors would find this risk unacceptable. • Mr Peake questioned whether AEMO had breached clause 4.25.4(a) by not increasing the Facility’s Capacity Credits above its certified level because it had exceeded its certified level in one Trading Interval. Mr Stevens replied that the clause only required AEMO to ‘reduce’ Capacity Credits under certain conditions. • There was further discussion about how the maximum capacity of a Facility should be calculated from the two test results. Ms Ng noted that Perth Energy’s Facility regularly ran and demonstrated its availability using gas as its fuel. Mr Maticka noted that System Management can require a test at any time if it suspects that a Facility is unable to meet its Reserve Capacity Obligations. • Mr Everett noted that the real issue was that the meaning of clause 4.25.2(a) was unclear. In response to a question from the Chair, Mr Maticka advised that AEMO currently interpreted the maximum capability to be the maximum output achieved in any of the four Trading Intervals. Mr Peake noted this meant that for the scenario in the presentation there was no point to the second test, because the Facility had exceeded Capacity Credit level in one of the Trading Intervals in the first test. Mr Peake suggested that the maximum capability should the capability of the Facility	

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	over the one-hour test period, rather than over a single Trading Interval. Mr Peake advised that Perth Energy would prepare a Pre-Rule Change Proposal to address the issues raised in the presentation for consideration at a future MAC meeting.	
10	**MAC Schedule for 2020** The Chair sought feedback from MAC members regarding the proposed MAC meeting schedule for 2020 in the meeting papers. Mrs Papps noted that 28 January 2020 was the day after the Australia Day public holiday; and several members advised that they would be unable to attend meetings that conflict with school holidays. The Chair agreed to review the schedule in light of public holiday dates. **Action: RCP Support to update the proposed 2020 MAC meeting schedule for consideration by the MAC.**	**RCP Support**
11	**General Business** The Chair noted that the Panel's annual stakeholder satisfaction survey closed on 15 July 2019 and RCP Support intended to table the results at the next MAC meeting. The Chair noted that the Panel's annual activities report for 2018/19 was with the Panel for review. The Panel will submit the report to the Minister by the end of August 2019 and the Minister then has two months to table the report in Parliament.	

The meeting closed at 12:30 PM.