RCP | Rule Change Panel
Market Advisory Committee

Meeting Agenda

Meeting Title:	Market Advisory Committee
Date:	Monday 29 July 2019
Time:	9:30 AM – 12:30 PM
Location:	Training Room No. 2, Albert Facey House 469 Wellington Street, Perth

Item	Item	Responsibility	Duration
1	Welcome	Chair	5 min
2	Meeting Apologies/Attendance	Chair	5 min
3	**(a)** Minutes of Meeting 2019_04_30	Chair	5 min
	(b) Minutes of MAC Workshop 2019_05_10 (RC_2013_15)	Chair	5 min
4	Actions Items	Chair	25 min
5	MAC Market Rules Issues List	Chair	5 min
6	Update on the Energy Transformation Strategy		
	(a) Status Update (verbal update – no paper)	ETIU	10 min
	(b) Market Design and Operation Working Group (MDOWG) Update (verbal update – no paper)	ETIU	5 min
	(c) Power System Operation Working Group (PSOWG) Update (verbal update – no paper)	AEMO	5 min
	(d) Approval of the Revised Terms of Reference for the MDOWG and PSOWG	Chair	10 min
	(e) Whole of System Plan	ETIU	20 min

Item	Item	Responsibility	Duration
7	AEMO Procedure Change Working Group Update	AEMO	5 min
8	Rule Changes		
	(a) Overview of Rule Change Proposals	Chair	5 min
	(b) RC_2019_01: The Relevant Demand calculation	Chair / Enel X	15 min
	(c) RC_2019_03: Method used for the assignment of Certified Reserve Capacity to Intermittent Generators	ERA	30 min
9	Issues with Reserve Capacity Testing	Perth Energy	15 min
10	MAC Schedule for 2020	Chair	5 min
11	General Business	Chair	5 min
Next Meeting: 3 September 2019			

Please note, this meeting will be recorded.

Minutes

Meeting Title:	Market Advisory Committee (**MAC**)
Date:	11 June 2019
Time:	09:30 AM – 11:30 AM
Location:	Training Room No. 2, Albert Facey House 469 Wellington Street, Perth

Attendees	Class	Comment
Stephen Eliot	Chair	
Matthew Martin	Minister's Appointee – Small-Use Consumer Representative	
Martin Maticka	Australian Energy Market Operator (**AEMO**)	
Teresa Smit	System Management	Proxy for Dean Sharafi
Julian Fairhall	Economic Regulation Authority (**ERA**) Observer	Proxy for Sara O'Connor
Andrew Everett	Synergy	
Margaret Pyrchla	Network Operator	
Jacinda Papps	Market Generators	
Wendy Ng	Market Generators	
Daniel Kurz	Market Generators	
Andrew Stevens	Market Generators	From 10:15 AM
Patrick Peake	Market Customers	
Geoff Gaston	Market Customers	
Tim McLeod	Market Customers	
Chayan Gunendran	Market Customers	
Peter Huxtable	Contestable Customers	

Apologies	Class	Comment
Dean Sharafi	System Management	
Sara O'Connor	ERA Observer	

Also in attendance	From	Comment
Jenny Laidlaw	RCP Support	Minutes

Kate Ryan	Energy Transformation Implementation Unit (**ETIU**)	Presenter to 11:00 AM
Aden Barker	ETIU	Presenter to 10:55 AM
Matt Shahnazari	ERA	Presenter
Noel Schubert	ERA	Observer
John Lorenti	Synergy	Observer, to 10:55 AM
Dimitri Lorenzo	Bluewaters Power	Observer
Matthew Bowen	Jackson McDonald	Observer
Scott Davis	Australian Energy Council	Observer
Erin Stone	Point Economics	Observer
Kei Sukmadjaja	Western Power	Observer
Dean Frost	Western Power	Observer
Richard Cheng	RCP Support	Observer
Natalie Robins	RCP Support	Observer
Sandra Ng Wing Lit	RCP Support	Observer

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:30 AM and welcomed members and observers to the 11 June 2019 MAC meeting. The Chair welcomed new MAC members Mr Tim McLeod and Mr Chayan Gunendran. The Chair noted his intention to reverse the order of agenda items 5 (MAC Market Rules Issues List) and 6 (Update on the Energy Reform Strategy), due to the dependence of the former on the latter.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above.	
3	**Minutes from Previous Meeting** Draft minutes of the MAC meeting held on 30 April 2019 were circulated on 15 May 2019. The MAC accepted the minutes as a true and accurate record of the meeting. **Action: RCP Support to publish the minutes of the 30 April 2019 MAC meeting on the Rule Change Panel's (Panel's) website as final.**	**RCP Support**

Item	Subject	Action
4	**Action Items** There were no open action items, and the closed action items were taken as read.	
4(a)	**Action Item 4/2019 – Multiple generators on a single line forming the largest single contingency**	

Ms Teresa Smit gave a presentation on the Spinning Reserve implications of multiple generators on a single transmission line. A copy of AEMO's presentation is available on the Panel's website.

The following points were discussed:

- Mr Patrick Peake asked whether the problem was that the two new generators were 'teed in'; and if there was a break between the generators, whether there was enough line capacity for power to go the other way. Ms Smit replied that under the currently proposed configuration a line failure would cause the loss of both generators.
- Mrs Jacinda Papps noted that Alinta's modelling indicated the likelihood of NewGen Neerabup and the two new generators running to full capacity at the same time was reasonably low. Ms Smit agreed, noting that AEMO's larger concern was having a high contingency from the two new generators at times when other generators' output levels were low.
- Mrs Papps suggested that a similar situation already arose when the two Bluewaters generators were operating on a single line. Ms Smit noted that the Bluewaters scenario only occurred when lines were out of service, but the scenario under discussion would exist under system normal conditions.
- In response to a question from Mr Julian Fairhall, Ms Smit confirmed that AEMO had accounted for the load that would also be lost in the event of a network fault on the transmission line.
- Ms Smit agreed with Mrs Papps that the Spinning Reserve requirement would be highly variable given the transient nature of the wind farms' output. Ms Smit indicated that to carry the Spinning Reserve requirement for the two new generators would be feasible, but it would be very difficult to carry the Spinning Reserve requirement for the two new generators and NewGen Neerabup.
- Mr Peake noted that the market was already incurring very high ancillary service costs, and he would not want any

Item	Subject	Action
	additional Spinning Reserve costs to be automatically passed on to other customers and generators. • Mr Andrew Everett considered a more fundamental issue was that the determination of Spinning Reserve costs was incorrect and probably understating the cost of providing the service. This was because the modelling used to determine margin values (which in turn determine Spinning Reserve payments) assumed that Upwards LFAS providers were also providing Spinning Reserve. However, neither NewGen Kwinana nor Alinta had Spinning Reserve contracts, so the margin value calculations were understating the level of Spinning Reserve provided by the Balancing Portfolio. Mr Everett considered that if there was going to be a need to call for more Spinning Reserve, the priority should be to ensure that the cost of Spinning Reserve provision is calculated correctly. • Ms Jenny Laidlaw noted that the Spinning Reserve cost allocation method assumes the largest single contingency is caused by the output of a single generator, consistent with clause 3.10.2 of the Market Rules. Ms Laidlaw noted that in the past (at least until about 2011) there appeared to be general agreement that clause 3.10.2 applied in all but emergency conditions; and that the Technical Rules required Western Power to configure the network in a way that ensured that level of Spinning Reserve was sufficient. However, this no longer appeared to be the case. • Mr Everett noted AEMO's proposal that the "directly impacted parties" prepare more detailed analysis of the issue for presentation at the next MAC meeting; and questioned who these parties were. Ms Smit replied that she expected AEMO would undertake the analysis work but would need to rely on information from Rule Participants. Mr Everett requested that Spinning Reserve providers be included in any discussions. • Mr Everett reiterated his concern that during times of low system demand there may not be enough plant on-line to provide the required levels of Spinning Reserve. • Mr Geoff Gaston supported Mr Peake's views, noting that in recent months Ancillary Service costs had reached $5/MWh, compared to less than $1/MWh in the National Electricity Market. Mr Gaston also suggested that because Intermittent Generators have no obligation to the deliver to the market, the market should have no obligation to take their generation or pay them constrained off compensation. Mr Gaston considered that constraining the relevant	

Item	Subject	Action
	Generator Interim Access (**GIA**) generators without constrained off compensation would be the lowest cost option in these scenarios. • There was some discussion about the nature of the physical connections of the new GIA generators, the timing and status of the Mid West Energy Project Southern Section Stage 2 project, and public perceptions about the reasons for increasing energy prices. • The Chair recalled that prior to the announcement of the Energy Transformation Strategy (**ETS**) the Public Utilities Office (**PUO**) intended to consider the issue as part of the WEM Reform Program. The Chair questioned whether the issue was now a PUO responsibility, an Energy Transformation Implementation Unit (**ETIU**) responsibility, or something that should be dealt with through the MAC and the creation of a Rule Change Proposal. Mr Aden Barker noted that while ETIU was dealing with some of the higher order philosophical issues, such as who should be subject to constraints in what circumstances, and whether they ought to receive any compensation when constrained, ETIU's formal scope did not include this specific issue. Ms Laidlaw noted that allowing the connection of multiple large generators on a single line was a material change, which was not made by the MAC or any specific Market Participant. Ms Laidlaw questioned who was responsible for considering the obvious implications of this change, such as how Spinning Reserve procurement and cost allocation were affected. Mr Barker noted that ETIU was working on the quantities of services such as Spinning Reserve that are likely to be required going forward and how they will be procured from the market. Mr Barker expected ancillary services would be the main subject of the next two Market Design and Operation Working Group (**MDOWG**) meetings, which were planned for late June and early July 2019. Ms Kate Ryan noted that the longer-term redesign of Spinning Reserve and other essential system services was part of ETIU's remit. Mr Everett acknowledged that this longer-term work was being undertaken but noted AEMO had an existing responsibility to model the SWIS and determine the margin values. Mr Everett questioned how the scenarios under discussion were going to be incorporated into the next margin values determination.	

Item	Subject	Action
	• Mr Peake questioned how the current situation had developed and whether participants with new generators were aware that they may be suddenly run back or asked to make large contributions to Spinning Reserve costs. Mr Martin Maticka noted there were two issues: whether Synergy was correctly compensated for its provision of Spinning Reserve, and the larger issue of how the costs of dealing with the scenarios under discussion would be allocated. Mr Gaston considered the issues could not wait until 2022 and needed to be addressed before the new generators came on-line. Mr Gaston suggested that allowing System Management to constrain the generators without compensation in the relevant circumstances should form part of the solution. • Ms Wendy Ng asked how frequently the generators were likely to cause the largest contingency. Ms Smit replied that although further modelling was needed AEMO expected this would happen more often than AEMO would like. • There was some discussion about whether a MAC workshop should be held to discuss potential solutions; and about who should take responsibility for the issue going forward. Mr Matthew Martin considered that having a workshop would help to formulate the options, after which a way forward could be determined. Mr Maticka suggested that a workshop may help to narrow the list of feasible short-term options. The Chair asked whether any other options existed apart from the three listed in slide 7 of the presentation. Ms Laidlaw noted that another option would be to constrain the two GIA generators down under their Network Control Service Contracts. • Mr Maticka questioned whether the potential network reinforcement work shown in slide 9 of the presentation could be completed before 2022. Mrs Papps considered that network reinforcement should not be removed from the list of options because Western Power was considering the project. After some discussion it was agreed that network reinforcement is not a solution to the problem in the short term, but should not be rejected as a longer-term solution. • There was some discussion about the four identified options and what the scope of a MAC workshop would be. Mr Peake asked, in respect of the first option (to modify the causer pays principles for Spinning Reserve costs), whether it would be physically possible to provide the high levels of	

Item	Subject	Action
	Spinning Reserve contemplated. Ms Smit considered that System Management would be able to increase the Spinning Reserve levels in some periods but would still need to curtail generation in other periods. Mr Maticka considered that the criteria for curtailing generation in these situations would need to be specified. • Mr Gunendran asked whether the fourth option (to curtail GIA generators under their Network Control Service Contracts) would be the lowest cost option in the short term. Ms Laidlaw replied that while this would be the lowest cost option for other Market Participants, it may not be a palatable option for the relevant Market Generators, depending on the frequency of their curtailment. • Mrs Papps suggested that the next step should be for AEMO to undertake its additional modelling. Ms Smit noted that the modelling would take 1-2 months and might not provide the nuances of information required to select the best option. There was general agreement that while further modelling could provide an indication of how often the situation might occur, it was already clear that the situation will occur from time to time. • There was further discussion about what next steps should be taken. Mr Martin noted that the PUO did not currently have resources to develop a solution to the issue, given the recent transfer of resources to ETIU. Mr Barker noted that ETIU also had no available resources. Mr Maticka considered that the choice of option was a policy decision, and that AEMO could provide technical expertise but not policy direction or proposals. • The MAC agreed to wait on the results of AEMO's modelling to gain an understanding of the scale of the issue, and to discuss next steps at the next MAC meeting.	
	Action: AEMO to conduct further modelling to assess how often the connection of multiple generators on a single North Country line will increase the size of the largest contingency beyond the output of any single generator and report back to the MAC with the results.	**AEMO**
5	**Update on the Network and Market Reform Program** Ms Ryan provided an update on the ETS. A copy of the presentation is available on the Panel's website. The following points were discussed. • In response to a question from Ms Ng, Ms Ryan confirmed that ETIU intended to have the necessary Market Rule	

Item	Subject	Action
	changes for the Foundation Regulatory Frameworks workstream published in the Gazette by mid-2020. The changes would not be progressed through the Rule Change Panel. • Mr Gunendran asked whether affordability was the primary objective of the reforms. Ms Ryan replied that all the objectives were important, and security and reliability were at times maybe more important than affordability. Mr Gunendran asked whether the ERA would have a role in assessing the effects of the changes on affordability. Ms Ryan replied that this was not at present being contemplated. It was ETIU's job as a policy advisor to consider the costs and benefits of the reforms and recommend changes where the benefits outweighed the costs. Ms Ryan noted that a formal cost/benefit exercise would be undertaken for the Foundation Regulatory Frameworks changes, and the Whole of System Plan work was aimed at finding a least cost path forward for the SWIS. • In response to a question from Mr Andrew Stevens, Ms Ryan explained that Western Power had a fundamental role to play in both the development and implementation of the reforms; and had been included in the Program Implementation Coordination Group. There was some discussion about the need to balance competing network, security, reliability and market considerations in the Whole of System Plan and other ETS reforms. • Ms Ryan and Mr Barker confirmed that a constrained network access regime was scheduled to be implemented on 1 October 2022, at the same time as the new security constrained economic dispatch arrangements. • In response to a question from Ms Ng, Ms Ryan advised that ETIU intended to email stakeholders about ETS publications and events, so that stakeholders would not need to monitor the Treasury website for updates. The current administration arrangements for the MDOWG and Power System Operation Working Group (**PSOWG**) would continue. ETIU intends to use monthly newsletters, which will be published on its website and emailed to ETIU's distribution list, to provide information on the other workstreams and whole-of-program information. Stakeholders could request to be added to the distribution list, which was based on the previous PUO distribution list, by sending a request to one of the email addresses listed in the slide pack.	

Item	Subject	Action
	• Ms Ng requested an update on the adoption of constrained network access. Ms Ryan noted that the Minister and Mr Steve Edwell recently confirmed that constrained network access would be implemented. ETIU was working with the Minister and Western Power on implementation options for constrained network access. While recently there had been little public engagement on the matter, ETIU hoped to start re-engaging with stakeholders within the next two months.	
	• In response to a question from Mr Everett, Mr Barker confirmed that Sapere would still be undertaking a cost-benefit analysis of the proposed market and network access reforms. ETIU also intended to provide quantitative analysis when it brought proposals to the MDOWG and PSOWG, although this analysis will not necessarily be complete at the time due to interactions with other aspects of the market design.	
	• Mr Martin noted that work on the Reserve Capacity Mechanism (**RCM**) pricing reforms has not been transferred to ETIU because it is nearly complete. The PUO's legal advisors have prepared a final draft of the amending rules and the PUO was working with AEMO on a few issues to make sure that the rules work as intended. The PUO hoped to hold a workshop within the next couple of weeks before the amendments are finalised and sent to the Minister to be made. Mr Martin confirmed that the rule changes would not be made before 1 July 2019. Mr Maticka noted that AEMO was assuming the certification window for the 2019 Reserve Capacity Cycle would close on 1 July 2019 as scheduled. Mr Maticka recommended that Market Participants submit their certification applications as soon as possible. In response to a question from Ms Laidlaw, Mr Martin advised that the PUO was currently in discussions about when the new pricing arrangements would come into effect.	
	• The Chair noted that the Terms of Reference for the MDOWG and PSOWG required changes to reflect the ETS and the transfer of responsibilities from the PUO to ETIU. The Chair offered to draft amendments to the two documents for consideration by ETIU, before circulating the drafts to the MAC for approval out of session. Mr Barker noted that ETIU would chair the MDOWG in future while AEMO would continue to chair the PSOWG.	

Item	Subject	Action
	• Mr Barker advised that ETIU planned to attend the PUO's RCM pricing reform workshop to discuss some additional changes to the Market Rules. Mr Barker had previously flagged the PUO's difficulties in obtaining the data needed for modelling to demonstrate the benefits of reform. ETIU was therefore proposing changes to the Market Rules to allow the Coordinator of Energy to access information from AEMO. The intention at this stage was for that change to be linked specifically to the work of ETIU and the Energy Transformation Taskforce (**ETT**), including the Whole of System Planning and Distributed Energy Resources workstreams as well as the Foundation Regulatory Frameworks workstream. The powers would be limited to the duration of the ETT. ETIU also proposed to implement an additional Market Rule to reinstate the Minister's temporary rule-making powers (which expired in 2018) for the duration of the ETT. This would allow the Minister to make rule changes more efficiently than by repealing and replacing the entire Market Rules. ETIU also intends to remove the requirement for the Minister's amending rules to be published in the Gazette, to avoid some of the costs and risks associated with the current process. • Mr Barker noted that ancillary services would be the subject of the next two MDOWG meetings, which were planned for the end of June and the start of July 2019. The first meeting would consider the technical segmentation of the services, which is a function of the requirements of the system and the capability of individual generators, with an economic lens applied. The second meeting would focus on how the services would be acquired and how service costs would be allocated. • Mr Barker noted that ETIU would provide stakeholders with dates for the two MDOWG meetings by mid-week, along with dates for upcoming meetings and some of the specific topics to be covered in those meetings. ETIU planned to circulate papers to attendees five working days before each meeting; and intended that the meetings, along with any discussions that stakeholders want to have either before or after those meetings, would be ETIU's primary method of consultation on the reforms. While ETIU would be open to follow-up discussions after MDOWG and PSOWG meetings, it expected that advice	

Item	Subject	Action
	and recommendations would be taken to the ETT shortly after the MDOWG and PSOWG meetings. Following consideration by the ETT an information paper will be published explaining what has been decided and the rationale for the decision. The decisions should not be a surprise to anyone because the options will have been previously discussed at a working group meeting. • Ms Ng noted the ETT could make a decision on an issue despite Market Participants expressing a different view at a working group meeting. Mr Barker replied that it will be incumbent on ETIU to ensure it faithfully represents the views of stakeholders and explains the reasons if it recommends a different option; and that different stakeholders may at times hold contending views. • Mr Barker noted that the next PSOWG meeting would be held before the end of June 2019 and would cover a range of matters including the technical rules change management processes, the regulatory framework for power system security and reliability standards, where the various standards will be located, and related issues of change management, monitoring and governance. The meeting would also cover the governance framework for the development of constraints information. Most of these matters will be considered at an ETT meeting in July 2019, except for ancillary services. • Mr Peake asked whether the working groups would be working to the ETS objectives or the Wholesale Market Objectives. Mr Barker replied that proposals needed to be consistent with both sets of objectives, and that ETIU would also consider the six guiding design principles that were presented at the first MDOWG meeting on 12 March 2019.	
	Action: RCP Support to consult with ETIU on changes to the Terms of Reference for the MDOWG and PSOWG to reflect the ETS and the transfer of responsibilities from the PUO to ETIU, and then circulate revised drafts to the MAC for out of session review and approval.	**RCP Support**
6	**MAC Market Rules Issues List (Issues List)** The Chair noted that 10 of the issues in table 4 (Issues on Hold) of the Issues List referred to the WEM Reform Program. After some discussion, the MAC agreed to leave the 10 issues (listed below) on hold until mid-2020, when the regulatory changes for the Foundation Regulatory Frameworks workstream were expected to have been made:	

Item	Subject	Action
	• issue 7 (Improved definition of the quantity of LFAS (a) required and (b) dispatched); • issue 10 (Review of participant and facility classes); • issue 11 (Whole of system planning oversight); • issue 12 (Review of institutional responsibilities in the Market Rules); • issue 18 (Spinning Reserve procurement process); • issue 19 (margin values evaluation process); • issue 28 (Appropriate rule changes to allow for battery storage); • issue 42 (Ancillary Services approvals process); • issue 53 (problems with the provisions relating to generator models implemented by the Minister on 30 June 2017); and • issue 54 (Review of Protected Provisions in the market Rules). The MAC agreed with the Chair's suggestion that issues 27 and 54 should be merged because both relate to a review of Protected Provisions. The Chair sought the views of MAC members on what preliminary urgency rating should be assigned to issue 55 (conflict between the current and proposed Relevant Level Methodology and the early and conditional certification of new Intermittent Generators). The MAC agreed with Mr Maticka's suggestion that a Low urgency rating be assigned to the issue.	
7	**AEMO Procedure Change Working Group (APCWG) Update** Mr Maticka noted that AEMO received no submissions on the Procedure Change Proposals relating to the Power System Operation Procedure: Dispatch and the changes resulting from Rule Change Proposal RC_2014_06: Removal of Resource Plans and Dispatchable Loads. The submission periods for the Procedure Change Proposals closed on 6 June 2019. Mr Maticka also noted that AEMO intended to publish several Procedure Change Reports during June 2019. The MAC noted the update on AEMO's Market Procedures.	
8(a)	**Overview of Rule Change Proposals** The Chair noted that RCP Support held a drafting review workshop on 10 June 2019 for Rule Change Proposal RC_2013_15: Outage Planning Phase 2 – Outage Process Refinements. The Chair thanked meeting attendees for their	

Item	Subject	Action
	input and noted the second submission period for RC_2013_15 closes on 28 June 2019. Mr Martin advised that on 10 June 2019 the Minister approved the Amending Rules for Rule Change Proposal RC_2015_01: Removal of Market Operation Market Procedures. The Chair noted that RCP Support proposed to hold a workshop in late June 2019 to discuss Rule Change Proposal RC_2017_02: Implementation of 30-Minute Balancing Gate Closure. The Chair asked MAC members whether they were happy with this timing given the other workshops and meetings scheduled for late June and early July. MAC members raised no concerns about the scheduling of the proposed workshop in late June 2019. The Chair also noted that: • the Amending Rules for Rule Change Proposal RC_2017_06: Reduction of the prudential exposure in the Reserve Capacity Mechanism commenced on 1 June 2019; • the Panel had sought clarification from Enel X on its Rule Change Proposal submitted on 29 April 2019 regarding changes to the Relevant Demand calculation; and was waiting on Enel X's response before deciding whether to progress that Rule Change Proposal; and • Amending Rules for three Rule Change Proposals (RC_2014_06: Removal of Resource Plans and Dispatchable Loads, RC_2014_07: Omnibus Rule Change, and RC_2018_07: Removal of constrained off compensation for Outages of network equipment) were due to commence on 1 July 2019. The MAC noted the overview of Rule Change Proposals.	
9	**Relevant Level Method – Rule Change Proposal Presentation to the MAC** Dr Matt Shahnazari provided an update to the MAC on the ERA's work to develop a Rule Change Proposal for changes to the Relevant Level Methodology. A copy of the ERA's presentation is available in the meeting papers.	
10	**General Business** <u>Annual Stakeholder Satisfaction Survey</u> The Chair noted that the Panel will be conducting its annual stakeholder satisfaction survey between 28 June 2019 and 15 July 2019. The anonymous online survey will contain eight questions and include fields to allow stakeholders to provide	

Item	Subject	Action
	additional comments. The results of the survey will be reported in the Panel's Activities Report for the 2018/19 Financial Year. The Chair encouraged all stakeholders to participate in the survey. <u>Reserve Capacity Testing Issues</u> The Chair noted that Mr Peake had raised several issues around Reserve Capacity Testing for discussion by the MAC and potential inclusion in the Issues List. RCP Support circulated the list of issues to MAC members on 5 June 2019. Due to a lack of time the MAC agreed to defer discussion of the issues until the next MAC meeting. <u>Reserve Capacity Certification Issues</u> Ms Ng noted that certification for the 2022/23 Capacity Year (the first Capacity Year under the new constrained network access regime) was scheduled to occur in 2020. Ms Ng requested that the agenda for the next MAC meeting include a discussion of the certification process and information requirements for that Reserve Capacity Cycle. Ms Ng suggested the discussion should also consider whether the current certification requirements were still appropriate for future Reserve Capacity Cycles. As an example, Ms Ng questioned whether the current requirement for some generators to maintain fuel for 14 hours onsite was still appropriate. Mr Stevens suggested that the 2020 Reserve Capacity Cycle timeframes should be extended well in advance if there was not going to be enough information available within the default timeframes. This would reduce uncertainty and prevent last minute extensions of the certification timeframes. Mr Peake noted that extending the timeframes for certification and the assignment of Capacity Credits was hard for retailers because of the uncertainty it created regarding Reserve Capacity Prices. Mr Stevens considered that delays were difficult for all Market Participants, but worse if the timeframes were extended at the last minute. There was some discussion whether the RCM pricing reforms would apply for the 2019 Reserve Capacity Cycle. Mr Maticka recommended that Market Participants ensure their applications for certification were submitted by the 1 July 2019 deadline.	
	Action: RCP Support to include a discussion of the issues raised by Perth Energy regarding Reserve Capacity Testing on the agenda for the 30 July 2019 MAC meeting.	**RCP Support**

Item	Subject	Action
	Action: RCP Support to include a discussion about certification timeframes, requirements and processes for the 2020 Reserve Capacity Cycle on the agenda for the 30 July 2019 MAC meeting.	**RCP Support**

The meeting closed at 11:30 AM.

Rule Change Panel
Market Advisory Committee

Minutes

Meeting Title:	RC_2013_15: Outage Planning Phase 2 – Outage Process Refinements - Drafting Review Workshop
Date:	10 June 2019
Time:	9:30 AM – 12:15 PM
Location:	Training Room 2, Albert Facey House 469 Wellington Street, Perth

Attendees	Class	Comment
Jenny Laidlaw	RCP Support	
Stephen Eliot	RCP Support	
Natalie Robins	RCP Support	
Jake Flynn	Economic Regulation Authority (**ERA**)	
Brad Huppatz	Synergy	
Winston Cheng	AEMO	
Matthew Fairclough	AEMO	
Clayton James	AEMO	
Jas Bhandal	AEMO	
Jacinda Papps	Alinta Energy	
Adam Stephen	Alinta Energy	
Sam Lei	Alinta Energy	
Paul Arias	Bluewaters Power	
Dimitri Lorenzo	Bluewaters Power	
Kei Sukmadjaja	Western Power	To 11:10 AM
Dean Frost	Western Power	To 11:10 AM

Clause/Term	Comments/Suggestions
2.34.4	Mrs Jacinda Papps suggested that “the capability of a Registered Facility” in clause 2.34.4 might need to be modified to “the capacity or capability of a Registered Facility”.
3.18.1A	Ms Jenny Laidlaw sought the views of attendees on whether the proposed materiality threshold should be based on the Sent Out Capacity of the Facility instead of its nameplate capacity.

Clause/Term	Comments/Suggestions
	Mr Sam Lei noted that the Sent Out Capacity of a Non-Scheduled Generator can be materially lower than its nameplate capacity (e.g. if a hybrid Non-Scheduled Generator has 150 MW of wind capacity, 50 MW of solar capacity and a Declared Sent Out Capacity (**DSOC**) of 150 MW. Mr Lei questioned whether the Market Generator should be required to report an outage if the solar capacity was unavailable). Mr Clayton James noted that an understanding of the availability of the different components of a hybrid Facility would support more accurate forecasting of the likely output of the Facility. Ms Laidlaw agreed that more detailed information would need to be provided if central forecasting of Non-Scheduled Generator output was to be implemented in future, but noted this was not the case currently and that it appeared the Energy Transformation Implementation Unit (**ETIU**) had not yet decided on the future arrangements. Mr Adam Stephen noted that the physical capacity of Non-Scheduled Generators may decline over time so they may not remain capable of generating to their nameplate capacity levels. Ms Laidlaw suggested arranging a separate meeting with Alinta to discuss the treatment of outages for a Non-Scheduled Generator with a nameplate capacity greater than its DSOC. **Action: RCP Support to meet with Alinta to discuss the treatment of outages for a Non-Scheduled Generator with a nameplate capacity greater than its DSOC.**
3.18.1B	Mr Stephen considered that the meaning of 'capacity or capability' should be clarified. There was some discussion about outages that relate to services other than the provision of energy (e.g. the services provided by network equipment, and Ancillary Services like System Restart that are provided under Ancillary Service Contracts). There was also discussion about Facilities that provide two distinct services (e.g. energy and System Restart), including: • whether the use of '0 MW' outages was the most expedient way to report outages of the Ancillary Service capability; • whether there was any need to specify multiple Outage Facilities, one for each service provided; and • the use of 0 MW outages to report the unavailability of one fuel for dual-fuel Facilities and the Reserve Capacity Testing implications. Mr James and Mr Matthew Fairclough considered that 0 MW outages were likely to be the most expedient means of reporting outages of Ancillary Service capability and situations where a dual-fuel generator was unable to run on one of its fuels. Ms Laidlaw agreed to consider what additional prescription or clarification was needed in the drafting.
3.18.1C	Mrs Papps suggested that the term 'maintenance' be defined in the Glossary rather than in a clause. Ms Laidlaw agreed to investigate where 'maintenance' was used in the Market Rules and the implications of introducing a defined term 'Maintenance'.

Clause/Term	Comments/Suggestions
	In response to a question from Mr Stephen, Ms Laidlaw confirmed that the drafting was not intended to imply that a Commissioning Test could only be taken under a Planned Outage. Mr Jake Flynn noted that Facility upgrades may not always be "reasonably considered to be required in accordance with good electricity industry practice". Ms Laidlaw agreed that the clause may need to be restructured to ensure that discretionary Facility upgrades were not unintentionally excluded from the definition of maintenance.
3.18.2(c)	Ms Laidlaw noted that the Market Rules currently allow the registration of a Non-Scheduled Generator that is not an Intermittent Generator, and that the drafting of proposed clauses 3.18.2(c)(ii) and (iii) may require further amendment to account for such Facilities.
3.18.2(f)	Mr Flynn suggested that the clause could be simplified without loss of meaning by removing ". Outages must be scheduled".
3.18.2A(h), 3.18.9A and 3.19.2E	Ms Laidlaw noted that prohibiting the changes listed in clauses 3.18.2A(h), 3.18.9A and 3.19.2E could materially simplify the drafting of the outage rules, but would require Rule Participants wishing to amend their outages in this way to either**:** • submit an additional request/notification for the additional period or quantity of de-rating; or • withdraw the original request/notification and submit a new one. Attendees raised no concerns about amending the three clauses to prohibit changes of this type to Planned Outage requests and notifications.
3.18.3(d)	Mr Flynn suggested that the clause be modified to explicitly require System Management to publish an updated Equipment List on the Market Web Site in the specified circumstances.
3.18.4(b)	In response to a question from Mrs Papps, Ms Laidlaw noted that the Rule Change Panel had decided not to change references to System Management to references to AEMO as part of this Rule Change Proposal, following legal advice that cautioned against making such changes in a piecemeal manner. Mrs Papps questioned whether the clause reference in clause 3.18.4(b) should be to clause 3.18.15(g) (which requires System Management to schedule an Outage Plan if directed to by the ERA) rather than clause 3.18.15(f) (the clause that permits the ERA to provide such a direction).
3.18.6A	Mr Flynn suggested removing the words "be possible to" to avoid potential confusion while retaining the meaning of the clause. Mr Flynn agreed with Ms Laidlaw that another option would be to replace "that it will not be possible to" with "that it will (or would) not be able to".
3.18.9C	Mr James and Mr Fairclough noted that AEMO was still considering this clause; and had some concerns about how it would monitor compliance

Clause/Term	Comments/Suggestions
	with the clause and whether it needed to be informed once the proposed maintenance could no longer be brought forward. Ms Laidlaw noted two other options: • removing the proposed exemption and requiring the Market Participant to advise System Management when the outage became availability-challenged; or • requiring the Market Participant to include relevant details about the time-sensitive nature of the maintenance in its Outage Plan.
3.18.10A	Mr Stephen and Mrs Papps raised concerns about the inclusion of "or ought to be aware" in the clause and questioned how System Management ought to be aware of something when assessing an outage request. Ms Laidlaw reiterated that the clause placed no new obligations on System Management to undertake additional proactive monitoring of Outage Facilities, and that "ought to be aware in the circumstances" was intended to prevent wilful blindness on System Management's part, consistent with the corresponding drafting for Market Participants and Network Operators. Mr Fairclough advised that AEMO's concern was that the inclusion of "or ought to be aware in the circumstances" would force AEMO to undertake additional proactive actions and investigations to allow it to be sure it was complying with the obligation. There was some discussion about AEMO's interpretation of the obligation, whether the intent of the obligation was already covered by other provisions in the Market Rules, the existence of similar obligations on AEMO under other regulatory instruments (such as the Gas Retail Market Procedures) and the circumstances under which the ERA was likely to investigate AEMO for a breach of the clause. Ms Laidlaw reiterated that AEMO was welcome to suggest additional wording to clarify the meaning of the clause and avoid any perverse interpretation of the obligation. Ms Laidlaw suggested that early discussion with AEMO's auditors might assist with this process.
3.18.11(b)	Mr Stephen suggested that "or capability" should be included after "capacity" for consistency with other clauses.
3.19.2(b)(ii)	Mr Stephen suggested replacing the word "will" with "does".
3.19.2(b)(iii)	Mr Stephen suggested that the word "outage" in "Opportunistic Maintenance outage period" was redundant and should be removed.
3.19.2C	In response to a question from Mrs Papps, Ms Laidlaw advised that the Rule Change Panel had suggested clause 3.19.2C as a candidate for classification as a civil penalty provision because the corresponding clause for Scheduled Outages was already a civil penalty provision; and because failing to promptly withdraw an Opportunistic Maintenance request prevented the outage slot from being used by another Market Generator and reduced the accuracy of the Forecast BMO.

Clause/Term	Comments/Suggestions
	Ms Laidlaw noted that RCP Support would forward any comments about civil penalties received in submissions to the PUO for consideration. Ms Laidlaw noted that clauses had generally been identified as candidate civil penalty provisions because a failure to comply with the clause could have adverse impacts on market outcomes or other Rule Participants.
3.19.2H	Mr Fairclough noted that clause 3.19.2H(c) could be interpreted to mean that the Market Generator could start its maintenance work as soon as the request was approved. Mr Fairclough noted clause 3.21.1 stated that a Forced Outage was maintenance that was not approved by System Management and suggested that the clause may need revision to account for Planned Outages of the type contemplated in clause 3.19.2H.
3.19.4A	Several attendees suggested that the words "for the purposes of the Market Rules" were not required and should be removed from the proposed clause.
3.19.12(a)	Ms Laidlaw noted that the proposed insertion of the words "under clause 3.19.5" in clause 3.19.12(a) would restrict compensation for the late rejection of an Outage Plan to Outage Plans that have been approved (rather than just scheduled) by System Management. The Rule Change Proposal does not provide the reasons for the proposed change. Mr James considered that most Scheduled Outages would be approved or rejected before the 48-hour deadline for compensation, but agreed this might not always be the case given the proposed deadline for approval decisions on Scheduled Outages was 2:00 PM on TD-2.
3.20.1	Mr Stephen suggested including "a" before "High Risk Operating State".
7A.2.8A	Ms Laidlaw questioned whether clause 7A.2.8A(a) was redundant given that the requirement to report capacity subject to an approved Planned Outage as unavailable in Balancing Submissions was covered by other clauses. Mr Paul Arias asked how the clause affected Facilities that returned from a Planned Outage earlier than expected. Ms Laidlaw replied that the intention was for a Market Participant to update its outage end time in SMMITS before updating its Balancing Submissions, so that the Facilities were not participating in the Balancing Market while under a Planned Outage; and that there may be benefit in leaving the clause as drafted if it helps to clarify that requirement. Mrs Papps noted that civil penalty payments for breaches of the surrounding clauses (7A.2.8 and 7A.2.9) were distributed to Market Participants.
7A.2A	Mrs Papps suggested that the title of section 7A.2A (currently "Unavailable Capacity in a Balancing Submission") was potentially

Clause/Term	Comments/Suggestions
	misleading and suggested a change to something like “Accounting for Unavailable Capacity in a Balancing Submission”.
7A.2A.3 and 7A.2A.4	Ms Laidlaw noted that clauses 7A.2A.3 and 7A.2A.4 could be removed in future by the Rule Change Proposal RC_2014_03: Administrative Improvements to the Outage Process and replaced with an expanded list of criteria for a Consequential Outage.

The workshop ended at 12:15 PM.

RCP | Rule Change Panel

Market Advisory Committee

Agenda Item 4: MAC Action Items

Meeting 2019_07_29

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

Item	Action	Responsibility	Meeting Arising	Status
9/2019	RCP Support to publish the minutes of the 30 April 2019 MAC meeting on the Rule Change Panel's website as final.	RCP Support	2019_06_11	**Closed** The minutes were published on the Rule Change Panel's website on 12 June 2019.
10/2019	AEMO to conduct further modelling to assess how often the connection of multiple generators on a single North Country line will increase the size of the largest contingency beyond the output of any single generator and report back to the MAC with the results.	AEMO	2019_06_11	**Open** AEMO will present the results of its modelling at the MAC meeting on 29 July 2019.

Item	Action	Responsibility	Meeting Arising	Status
11/2019	RCP Support to consult with the Energy Transformation Implementation Unit (**ETIU**) on changes to the Terms of Reference for the Market Design and Operation Working Group (**MDOWG**) and Power System Operation Working Group (**PSOWG**) to reflect the Energy Transformation Strategy and the transfer of responsibilities from the Public Utilities Office to the ETIU, and then circulate revised drafts to the MAC for out of session review and approval.	RCP Support	2019_06_11	**Closed** RCP Support and the ETIU consulted on changes to the MDOWG and PSOWG Terms of Reference, and RCP Support sent updated drafts of the Terms of Reference to the MAC for review and comment by email on 26 June 2019 for comment by 4 July 2019. See Agenda Item 6(d).
12/2019	RCP Support to include a discussion of the issues raised by Perth Energy regarding Reserve Capacity Testing on the agenda for the 29 July 2019 MAC meeting.	RCP Support	2019_06_11	**Closed** See Agenda Item 9.
13/2019	RCP Support to include a discussion about certification timeframes, requirements and processes for the 2020 Reserve Capacity Cycle on the agenda for the 29 July 2019 MAC meeting.	RCP Support	2019_06_11	**Open** The ETIU will provide a response to this action item at the MAC meeting on 29 July 2019.

RCP Rule Change Panel
Market Advisory Committee

Agenda Item 5: MAC Market Rules Issues List Update

Meeting 2019_07_29

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;
- indicate whether there are any new issues to be raised;
- discuss the questions raised under issue 14/36; and
- discuss the questions raised under issue 52.

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

29 July 2019

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
31	Synergy November 2018	**LFAS Report** Under clauses 7A.2.9(b) and 7A.2.9(c) of the Market Rules, Synergy is obligated to compile and send the LFAS weekly report to AEMO based on the LFAS data for each Trading Interval supplied to Synergy by System Management. Given that System Management is now part of AEMO, it seems reasonable to remove this obligation on Synergy to reduce administrative burden. This rule change supports Wholesale Market Objective (a).	**Panel rating:** Low, but OK to progress using the Fast Track Rule Change Process **MAC ratings:** Low: Alinta, Bluewaters Medium: Geoff Gaston, AEMO High: Peter Huxtable **Status:** This issue has not been progressed.
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:** Waiting on the ERA to provide its position on the proposal, but this is a low priority issue for the ERA.
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	**Panel rating:** Low **MAC ratings:** Low **Status:**

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		this responsibility as it no longer maintains the broader market development and compliance functions of the IMO.	Waiting on the ERA to provide its position on the proposal, but this is a low priority issue for the ERA.
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.
53	Alinta February 2019	**TES Recalculation** Alinta is seeking a rule change to allow the recalculation of TES after the current 15 Business Day deadline.	**Panel rating:** Low **MAC ratings:** Low **Status:** This issue has not been progressed.
55	MAC April 2019	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:** This issue has not been progressed.

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

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

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 annual, independent Integrated Grid Plan to identify emerging issues and opportunities for investment at different locations in the network to support power system security and reliability. This role would support	This issue was initially flagged for consideration as part of the preliminary review of roles in the market. However, the Energy Transformation Implementation Unit has advised that the issue will be covered as part of the Energy

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		AEMO's responsibility for the maintenance of power system security and will be increasingly important as network congestion increases and the characteristics of the power system evolve in the course of transition to a predominantly non-synchronous future grid with distributed energy resources, highlighting new requirements (e.g. planning for credible contingency events, inertia, and fast frequency response). This function would support the achievement of power system security and reliability, in line with Wholesale Market Objective (a).	Transformation Strategy, so the issue has been put on hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020).
12	AEMO 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). The PUO has advised that the remaining issues will be covered as part of the Energy Transformation Strategy, so the remaining issues have been put on hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020).
14/36	Bluewaters and ERM Power	Capacity Refund Arrangements: The current capacity refund arrangement is overly punitive as Market Participants face excessive capacity refund exposure. This refund	On 9 May 2018 the MAC agreed to place this issue on hold for 12 months (until June 2019) to

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
	November 2017	exposure is well more than what is necessary to incentivise the Market Participants to meet their obligations for making capacity available. Practical impacts of such excessive refund exposure include: • 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.	allow time for historical data on dynamic refund rates to accumulate. It has been 12 months since this issue was put on hold, so the MAC is asked to consider: • whether this issue still needs to be considered; and • if so, what analysis should be conducted and in what timeline?
15/34	Bluewaters and ERM Power November 2017	An interpretation of clause 3.18.7 of the Market Rules is that System Management will not approve a Planned Outage for a generator unless it was available at the time the relevant Outage Plan was submitted. This gives rise to the following issues: • Operational inefficiency for the generators – it is not uncommon for minor problems to be discovered during a Planned Outage and addressing these problems may require the Planned Outage period	On hold pending a final decision on RC_2013_15: Outage Planning Phase 2 – Outage Process Refinements

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

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		This can result in under reporting of Forced Outages, and as a consequence, use of incorrect information used in WEM settlements. 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.	
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 to lead to a more efficient economic outcome and in turn promote the Wholesale Market Objectives.	On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020).
19	Bluewaters 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;	On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020).

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		• lack of transparency: (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 • allowing a better-informed margin values determination process, which is likely to give a more accurately priced margin values to promote an efficient economic outcome.	Also, AEMO and the ERA to consider whether any options exist to improve transparency of the current margin values process.
22	Bluewaters November 2017	Prudential arrangement design issue: clause 2.37.2 of the Market Rules enables AEMO to review and revise a Market Participant's Credit Limit at any time. It is expected that AEMO will review and increase Credit Limit of a Market Participant if AEMO considers its credit exposure has increased (for example, due to an extended plant outage event).	On hold pending AEMO's proposed review of its process for Credit Limit determination.

Table 4 – Issues on Hold			
Id	Submitter/Date	Issue	Urgency and Status
		In response to the increase in its credit exposure, clause 2.40.1 of the Market Rules and section 5.2 of the Prudential Procedure allow the Market Participant to make a voluntary prepayment to reduce its Outstanding Amount to a level below its Trading Limit (87% of the Credit Limit). 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 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	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	On hold pending the outcome of a PUO review of the current Protected Provisions in the Market Rules, with timing dependent on Energy Transformation Strategy.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
	MAC August 2018	because shifting the rule change function to the Rule Change Panel has removed some of the potential conflicts of interest that led to the original classification of some Protected Provisions.	
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 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.	On hold pending a final decision on RC_2014_03: Administrative Improvements to the Outage Process.
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:	On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020).

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		• there is no guidance in the rules on what the ERA's audit should cover, or what factors the ERA should consider in making its determination on the requirements; • 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); • 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)).	

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
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 MAC agreed to include this issue in the Issues List and place it on hold until a decision is made on RC_2018_07, and if the Rule Change Proposal is approved, the changes have been in place for 12 months.
50	MAC November 2018	Should the Minimum STEM Price (currently -$1,000/MWh) be increased to reduce the potential magnitude of constrained off compensation (e.g. by restoring the former practice of setting the Minimum STEM Price to the Maximum STEM Price multiplied by -1):	The MAC agreed to include this issue in the Issues List and place it on hold pending the outcomes of the ERA's next review of the methodology for setting the Energy Price Limits under clause 2.26.3 of the Market Rules.
51	MAC 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.
52	MAC February 2019	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?	This issue was discussed under Agenda Item 4(a) at the MAC meeting on 11 June 2019 and will be further discussed under Agenda Item 4 at the MAC meeting on 29 July 2019. The MAC is asked to consider whether this issue should remain on hold or progressed in the nearer term.
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	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**
		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.	

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.

RCP | Rule Change Panel
Market Advisory Committee

Agenda Item 6(d): Approval of the Revised Terms of Reference for the MDOWG and PSOWG

Meeting 2019_07_29

1. Background

Action Item 11/2019 from the MAC meeting on 2019_06_11 requires:

> RCP Support to consult with the Energy Transformation Implementation Unit (**ETIU**) on changes to the Terms of Reference for the Market Design and Operation Working Group (**MDOWG**) and Power System Operation Working Group (**PSOWG**) to reflect the Energy Transformation Strategy and the transfer of responsibilities from the Public Utilities Office to the ETIU, and then circulate revised drafts to the MAC for out of session review and approval.

The updated Terms of Reference were circulated to the relevant MAC contacts on Wednesday 26 June 2019 for comment.

The RCP Support received feedback from AEMO and Western Power.

AEMO

AEMO's feedback is provided in Attachment 1, where AEMO:

- requested confirmation from the ETIU of whether the 'Improving Access to the South West Interconnected System' workstream is responsible for resolving the allocation of Capacity Credits in a constrained network access framework;
- requested confirmation from the ETIU that the work on the Reserve Capacity Mechanism under constrained access is under the 'Improving Access to the South West Interconnected System' workstream rather than under the 'Delivering the Future Power System' workstream;
- corrected referencing to the two parts that make up the Foundation Regulatory Frameworks workstream; and
- proposed additions and corrections to the 'Delivering the Future Power System' work program.

Western Power

Western Power's feedback is provided in Attachment 2, where Western Power suggested that the scope of works for each working group should be more precisely defined, including:

- PSOWG to cover:
  - Power System Security and Reliability standards;
  - Operational Planning;

- Outage management; and
- Dispatch.

- MDOWG to cover:
  - Constrained Access Framework;
  - Constraint development and management; and
  - Essential System Services Framework and operation.

Alternatively, due to the common elements between MDOWG and PSOWG, whether the working groups be merged into one with an ETIU chair. If the working groups are not merged, then the ETIU should appoint the chair of the PSOWG.[1]

Additionally, Western Power suggested that a new working group should be established to address matters beyond the Wholesale Electricity Market (**WEM**), such as the Technical Rules, Access Code, Reliability Standard or alternatively that several working groups be created that reflect the different ETIU workstreams.

2. Discussion

To assist RCP Support in updating the Terms of References, guidance is sought on the following points:

- Should the MDOWG and PSOWG be merged as suggested by Western Power?
- Should the preamble and descriptions of the relevant workstreams for both the MDOWG and PSOWG be identical?
- Should the Terms of Reference specify exactly what is to be covered and what the scope of each working group should be?
- Which working group is responsible for constrained access, or are both working groups to be involved?
- What role should the MDOWG and PSOWG have, if any, regarding the matters outside the WEM such as the Technical Rules, etc as suggested by Western Power?
- Who should appoint the chair of the PSOWG?

3. Recommendation

It is recommended that the MAC review the comments and feedback on the Terms of Reference for both the MDOWG and PSOWG and provide RCP Support with guidance on updating them accordingly.

Attachments

1. AEMO feedback – MDOWG Terms of Reference (Tracked changes)
2. Western Power feedback
3. PSOWG Terms of Reference

[1] The chair of the PSOWG is currently appointed by AEMO.

RCP | Rule Change Panel

Market Design and Operation Working Group Terms of Reference

19 June 2019

1. Background

The Market Design and Operation Working Group (**MDOWG**) has been established, in accordance with clause 2.3.17 of the Market Rules and section 9 of the Constitution of the Market Advisory Committee (**MAC**). The MDOWG has been established to assist the MAC in fulfilling its obligation under clause 2.3.1(d) of the Market Rules to provide advice to the Rule Change Panel regarding matters concerning the evolution of these Market Rules.

2. Scope of Work

In May 2019, the Minister for Energy:

- announced the Energy Transformation Strategy;
- established the Energy Transformation Taskforce to deliver the Energy Transformation Strategy;[1] and
- established the Energy Transformation Implementation Unit (**ETIU**) within the Department of Treasury to support the Energy Transformation Taskforce.

The Energy Transformation Strategy consists of three workstreams, one being the Foundation Regulatory Frameworks workstream, which itself has two parts.

Improving Access to the South West Interconnected System:[2]

Improving A~~a~~ccess to the South West Interconnected Systems focuses on implementation of constrained access, primarily through the application of security constrained economic dispatch in the Wholesale Electricity Market (**WEM**). Changes to facilitate these reforms will be progressed largely through amendments to the Market Rules and *Electricity Networks Access Code 2004*.

Commented [SM1]: This capitalisation needs to be replicated in the PSOWG ToR

Commented [SM2]: Need to confirm with ETIU if this workstream is responsible for resolving the allocation of capacity credits in a constrained network access framework

[1] The Energy Transformation Taskforce's Terms of Reference are available at: https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Energy_Transformation/Energy-Transformation-Taskforce-Terms-of-Reference.pdf.

[2] Details are available at: https://www.treasury.wa.gov.au/Energy-Transformation/Improving-access-to-the-SWIS/.

Delivering the Future Power System:[3]

Delivering the F~~f~~uture P~~p~~ower S~~s~~ystem consists of two major elements:

Commented [SM3]: This capitalisation needs to be replicated in the PSOWG ToR

- **Power System Security and Reliability** – ensuring that regulatory frameworks, obligations placed on Market Participants and the tools are made available to AEMO to ensure power system security and reliability is maintained. This includes:
  - a new ~~ancillary~~ Essential System S~~s~~ervices framework;
  - generator performance standards;
  - regulatory architecture and governance; and
  - reliability standards.
- **Future Market Operations** – major improvements to the design and operation of the WEM to ensure that electricity is dispatched at the lowest sustainable cost and the operation of the market efficiently reflects and facilitates improvements to the way Western Power's network is accessed. This includes:
  - settlement and prudentials
  - registration and participation
  - security constrained economic dispatch;
  - Synergy facility bidding;
  - the Reserve Capacity Mechanism under constrained access; and
  - controls for efficient market outcomes.

Commented [SM4]: Need to confirm with ETIU – I thought this was part of the Improving Access to the SWIS workstream even though I believe it should be in the Future Market Operations

The Program Director for ETIU gave a presentation at the 11 June 2019 MAC meeting[4] detailing a redefined role for the MDOWG as a forum for stakeholder engagement for the Foundation Regulatory Frameworks.

The MDOWG's scope of work includes consideration, assessment and development of changes to the Market Rules and Market Procedures, in respect to the Foundation Regulatory Frameworks.

In assessing these areas, the MDOWG may also need to consider and advise on any interdependencies with regulatory instruments other than the Market Rules. While recommendations on potential changes to other regulatory instruments are outside of the scope of the MAC as outlined in clause 2.3.1 of the Market Rules, the ETIU may consider any relevant deliberations of the MDOWG to effect changes to other regulatory instruments, as required.

The MDOWG will work in parallel with the Power System Operation Working Group (**PSOWG**), and potentially other working groups, to provide advice to the MAC, which may be utilised by the ETIU to inform the Energy Transformation Taskforce for implementation of the Energy Transformation Strategy.

Whilst the MDOWG's advice will be provided to the MAC, the ultimate process for amending the relevant Market Rules will be determined by the ETIU in consultation with the Energy Transformation Taskforce.

[3] Details are available at: https://www.treasury.wa.gov.au/Energy-Transformation/Delivering-the-Future-Power-System/.

[4] Meeting papers and presentations for the 11 June 2019 MAC meeting are available at: https://www.erawa.com.au/rule-change-panel/market-advisory-committee/market-advisory-committee-meetings.

3. Membership

The MDOWG has a Chair appointed by the ETIU. The ETIU may replace the Chair at any time and must promptly advise the MAC of this action via the Rule Change Panel Secretariat.

To accommodate the broad range of subject matters to be covered, the MDOWG has no permanent members apart from the Chair. Instead, interested stakeholders may:

- register to receive information relating to the activities of the MDOWG, including notification of upcoming meetings, meeting papers and documents distributed out-of-session, by providing an email address for such correspondence to the MDOWG Secretariat;
- nominate up to two representatives to attend a MDOWG meeting by advising the MDOWG Secretariat in advance of that meeting; and
- with the permission of the MDOWG Chair, send additional representatives to an MDOWG meeting, noting that the attendance of additional representatives is at the discretion of the MDOWG Chair.

The Chair may allow for other attendees from the ETIU, Energy Transformation Taskforce or Public Utilities Office to provide administrative support or subject matter expertise to the MDOWG, where required.

4. Responsibilities of Meeting Attendees

A person attending an MDOWG meeting (either physically or remotely) is expected to:

- have suitable knowledge and experience to engage in and contribute to technical discussions relevant to the specific meeting;
- prepare for the meeting, including by reading any meeting papers distributed before the meeting;
- participate as a general industry representative rather than representing their company's interests; and
- carry out actions (e.g. technical analysis, impact assessment) if and as agreed.

5. Administration

The secretariat for the MDOWG will be provided by ETIU.

The ETIU will work with the Rule Change Panel Secretariat to ensure contact details for the MDOWG on the Rule Change Panel's website are maintained.

The MDOWG Chair will convene the MDOWG upon request from the ETIU, Energy Transformation Taskforce, Public Utilities Office, AEMO, or the MAC Chair.

The ETIU will prepare and distribute all meeting correspondence via email to the MDOWG. Following an initial request for subscriptions, at least once per year, the ETIU will contact MAC members and AEMO's WA Electricity Consultative Forum stakeholder group to invite interested stakeholders to subscribe for MDOWG notifications.

The ETIU will provide the following documentation by email to its MDOWG stakeholder list in respect of a MDOWG meeting, and will use best endeavours to meet the following timeframes:

- notice of meeting and agenda at least 10 business days prior to the meeting;

- relevant meeting papers between three to five business days prior to the meeting; and
- a record of meeting and actions arising no more than five business days following the meeting.

The ETIU may, following consultation with the MDOWG, vary the timeframes for document distribution if it considers that they are impeding the schedule and progress of the MDOWG.

Meeting outputs, such as concept papers and position papers, will be published on the Rule Change Panel's website for wider industry consultation once considered by the MAC and the Energy Transformation Taskforce.

Attendees will be expected to:

- advise the MDOWG Secretariat of intended attendance at an MDOWG meeting at least five business days prior to the meeting; and
- provide any feedback or endorsement to the record of meeting and actions arising no more than five business days following distribution.

The record of meeting is to detail attendance, main points of discussion, agreed recommendations and action items.

6. Reporting Arrangements

The MDOWG Chair (ETIU) must provide a report to the MAC on the activities of the MDOWG at each MAC meeting. The MDOWG Chair must also report back at other times requested by the MAC on issues referred to the MDOWG by the MAC. The MDOWG Chair, in collaboration with AEMO, will also have responsibility to provide a report to the Energy Transformation Taskforce on recommendations from MDOWG discussions.

The periodic reports must include, at a minimum:

- details of the most recent meeting, including the date of the meeting and a list of the issues or proposals considered;
- the date of the next meeting and the issues or proposals to be considered (if known); and
- an indicative forward agenda.

7. Contact Details

Market Participants and other stakeholders may contact the MDOWG Secretariat at marketdesign.wg@treasury.wa.gov.au. Documentation and information related to the MDOWG will be published on the Rule Change Panel's website at https://www.erawa.com.au/rule-change-panel-mdowg.

To: RCP Support <Support@rcpwa.com.au>
Subject: RE: MDOWG and PSOWG Terms of Reference Updates

Thank you for the opportunity to provide feedback on the MDOWG and PSOWG terms of reference. I apologise for the late response and hope that Western Power's feedback can still be considered.

Western Power acknowledges that the working groups have been good platforms to discuss the various reform streams in the past, however we identified the following issues:

- Scope of works for the working groups.
  The scope of works for the PSOWG and MDOWG are very similar and both include consideration, assessment and development of changes to the Market Rules and Market Procedures. The scope of works and deliveries for each of these groups needs better definition. The suggested scope of works for the groups are as follows:
  - For PSWOG
    - Power System Security and Reliability standards – GPG, Reliability Standard
    - Operational Planning
    - Outage management
    - Dispatch
  - For MDOWG
    - Constrain Access Framework
    - Constraint development and management
    - Essential System Services Framework and operation

  Alternatively, as these two groups have a number of common elements and interdependencies that will be hard to separate, it may be more practical and efficient to merge these two groups together, with a chair appointed by ETIU.

  Further, the scope of works for the PSOWG includes the change management framework for Technical Rules and the regulatory tidy up (Access Code and NQRS Code). These issues extend beyond the matters of concern for the WEM Rules and the Rule Change Panel.

- Representation in the working groups
  Since these two groups have limited representation from the participating organisations, appropriate SMEs are not able to be sent for the variety of discussions that take place. Furthermore, in meetings the discussions overlap the scope of the two working groups and the participants from one working group are not across matters discussed in the other. This concern was also raised in the last MDOWG meeting (3rd July) by a market participant. This fact supports Western Power's view that the working groups could be merged.

Therefore, Western Power suggests the following options:

1. A new working group is established to address matters that extend beyond the WEM, such as the Technical Rules, Access Code, Reliability Standard or several working groups be created that reflect the ETIU streams. This will ensure that conflict of interests between the various participants are responded to fairly.
2. The PSWOG and MDOWG are merged to address all considerations, assessments and development of changes to the Market Rules and Market Procedures and the ETIU chair the group. This would improve the efficiency of the meetings, avoid the interdependencies that will exist between the two groups and improve the representation at the meeting from the relevant subject matter experts; or
3. at the very least, the PSOWG has a chair appointed by the ETIU (similar to that of the MDOWG).

Please don't hesitate to contact me should you have any queries regarding the above.

Kind regards

W: westernpower.com.au

Power System Operation Working Group Terms of Reference

19 June 2019

1. Background

The Power System Operation Working Group (**PSOWG**) has been established, in accordance with clause 2.3.17 of the Market Rules and section 9 of the Constitution of the Market Advisory Committee (**MAC**). The PSOWG has been established to assist the MAC in fulfilling its obligation under clause 2.3.1(d) of the Market Rules to provide advice to the Rule Change Panel regarding matters concerning the evolution of these Market Rules.

2. Scope of Work

In May 2019, the Minister for Energy:

- announced the Energy Transformation Strategy;
- established the Energy Transformation Taskforce to deliver the Energy Transformation Strategy;[1] and
- established the Energy Transformation Implementation Unit (**ETIU**) within the Department of Treasury to support the Energy Transformation Taskforce.

The Energy Transformation Strategy consists of three workstreams, one being the Foundation Regulatory Frameworks workstream, which itself has two parts.

Improving Access to the South West Interconnected System:[2]

Improving access to the South West Interconnected Systems focuses on implementation of constrained access, primarily through the application of security constrained economic dispatch in the Wholesale Electricity Market (**WEM**). Changes to facilitate these reforms will be progressed largely through amendments to the Market Rules and *Electricity Networks Access Code 2004*.

1 The Energy Transformation Taskforce's Terms of Reference are available at: https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Energy_Transformation/Energy-Transformation-Taskforce-Terms-of-Reference.pdf.

2 Details are available at: https://www.treasury.wa.gov.au/Energy-Transformation/Improving-access-to-the-SWIS/.

Delivering the Future Power System:[3]

Delivering the future power system consists of two major elements:

- **Power System Security and Reliability** – ensuring that regulatory frameworks, obligations placed on Market Participants, and the tools are made available to AEMO to ensure power system security and reliability is maintained. This includes:
  - a new ancillary services framework;
  - generator performance standards;
  - regulatory architecture and governance; and
  - reliability standards.
- **Future Market Operations** – major improvements to the design and operation of the WEM to ensure that electricity is dispatched at the lowest sustainable cost and the operation of the market efficiently reflects and facilitates improvements to the way Western Power's network is accessed. This includes:
  - security constrained economic dispatch;
  - Synergy facility bidding;
  - the Reserve Capacity Mechanism under constrained access; and
  - controls for efficient market outcomes.

The Program Director for ETIU gave a presentation at the 11 June 2019 MAC meeting[4] detailing a redefined role for the PSOWG as a forum for stakeholder engagement for the Delivery of the Future Power System and Improving Access to the SWIS workstreams.

The PSOWG's scope of work includes consideration, assessment and development of changes to the Market Rules and Market Procedures, in respect to the operation of the power system to support the Energy Transformation Strategy.

The core topic areas to be considered by the PSOWG include (but are not limited to):

- Power System Security and Reliability standards and frameworks;
- Constraint development and management;
- Operational Planning (e.g. pre-dispatch, PASA);
- Outage Management;
- Dispatch; and
- Essential System Services.

In assessing these areas, the PSOWG may also need to consider and advise on any interdependencies with regulatory instruments other than the Market Rules. While recommendations on potential changes to other regulatory instruments are outside of the scope of the MAC as outlined in clause 2.3.1 of the Market Rules, the ETIU may consider any relevant deliberations of the PSOWG to effect changes to other regulatory instruments as required.

3 Details are available at: https://www.treasury.wa.gov.au/Energy-Transformation/Delivering-the-Future-Power-System/.

4 Meeting papers and presentations for the 11 June 2019 MAC meeting are available at: https://www.erawa.com.au/rule-change-panel/market-advisory-committee/market-advisory-committee-meetings.

The PSOWG will work in parallel with the Market Design and Operation Working Group (**MDOWG**), and potentially other working groups, to provide advice to the MAC, which may be utilised by the ETIU to inform the Energy Transformation Taskforce for implementation of the Energy Transformation Strategy.

Whilst the PSOWG's advice will be provided to the MAC, the ultimate process for amending the relevant Market Rules will be determined by the ETIU in consultation with the Energy Transformation Taskforce.

3. Membership

The PSOWG has a Chair appointed by AEMO, which is leading this area of reform activity on behalf of the ETIU. AEMO may replace the Chair at any time and must promptly advise the MAC of this action via the Rule Change Panel Secretariat.

To accommodate the broad range of subject matters to be covered, the PSOWG has no permanent members apart from the Chair. Instead, interested stakeholders may:

- register to receive information relating to the activities of the PSOWG, including notification of upcoming meetings, meeting papers and documents distributed out-of-session, by providing an email address for such correspondence to the PSOWG Secretariat;
- nominate up to two representatives to attend a PSOWG meeting by advising the PSOWG Secretariat in advance of that meeting; and
- with the permission of the PSOWG Chair, send additional representatives to a PSOWG meeting, noting that the attendance of additional representatives is at the discretion of the PSOWG Chair.

The Chair may allow for other attendees from AEMO where required to provide administrative support or subject matter expertise to the PSOWG.

4. Responsibilities of Meeting Attendees

A person attending a PSOWG meeting (either physically or remotely) is expected to:

- have suitable knowledge and experience to engage in and contribute to technical discussion relevant to the specific meeting;
- prepare for the meeting, including by reading any meeting papers distributed before the meeting;
- participate as a general industry representative rather than representing their company's interests; and
- carry out actions (e.g. technical analysis, impact assessment) as agreed.

5. Administration

The secretariat for the PSOWG will be provided by AEMO.

AEMO will work with the Rule Change Panel Secretariat to ensure contact details for the PSOWG on the Rule Change Panel's website are maintained.

The PSOWG Chair will convene the PSOWG upon request from AEMO, the ETIU, Energy Transformation Strategy or the MAC Chair.

AEMO will prepare and distribute all meeting correspondence via email to the PSOWG. Following an initial request for subscriptions, at least once per year, AEMO will contact MAC members and its WA Electricity Consultative Forum stakeholder group to invite interested stakeholders to subscribe to PSOWG notifications.

AEMO will provide the following documentation by email to its PSOWG stakeholder list in respect of a PSOWG meeting, and will use best endeavours to meet the following timeframes:

- notice of meeting and agenda at least 10 business days prior to the meeting;
- relevant meeting papers between three to five business days prior to the meeting; and
- a record of meeting and actions arising no more than five business days following the meeting.

AEMO may, following consultation with the PSOWG, vary the timeframes for document distribution if it considers that they are impeding the schedule and progress of the PSOWG.

Meeting outputs, such as concept papers and position papers, will be published on the Rule Change Panel's website for wider industry consultation once considered by the MAC and the Energy Transformation Taskforce.

Attendees will be expected to:

- advise the PSOWG Secretariat of intended attendance at an PSOWG meeting at least five business days prior to the meeting; and
- provide any feedback or endorsement to the record of meeting and actions arising no more than five business days following distribution.

The record of meeting is to record attendance, main points of discussion, agreed recommendations and action items.

6. Reporting Arrangements

The PSOWG Chair (AEMO) must provide a report to the MAC on the activities of the PSOWG at each MAC meeting. The PSOWG Chair must also report back at other times requested by the MAC on issues referred to the PSOWG by the MAC. The PSOWG Chair, in collaboration with the ETIU, will also have responsibility to provide a report to the Energy Transformation Taskforce on recommendations from PSOWG discussions.

The periodic reports must include, at a minimum:

- details of the most recent meeting, including the date of the meeting and a list of the issues or proposals considered;
- the date of the next meeting and the issues or proposals to be considered (if known); and
- an indicative forward agenda.

7. Contact Details

Market Participants and other stakeholders may contact the PSOWG Secretariat at WARPSO@aemo.com.au. Documentation and information related to the PSOWG will be published on the Rule Change Panel's website at https://www.erawa.com.au/rule-change-panel-psowg.

Energy Transformation Implementation Unit

Government of Western Australia
Department of Treasury

Agenda Item 6(e)

Whole of System Plan

Market Advisory Committee Meeting

29 July 2019

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The information, representations and statements contained in this presentation have been prepared by the Department of Treasury, Energy Transformation Implementation Unit. It is provided to assist in obtaining public comment on, and contains only a general discussion of issues relating to, the inaugural Whole of System Plan.

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PURPOSE OF THE WOSP

WOSP should demonstrate how to deliver electricity supplies at lowest sustainable cost within the reliability and security standards over a 20 year period.

Guide **policy, market and regulatory changes**

Guide **future investment** in the short-term (least regrets) and medium / long term (less certain)

Inform stakeholders (market participants, customers, future investors, regulators and Government) and help them **make informed decisions**

ROLES AND RESPONSIBILITIES

GOVERNMENT OF WESTERN AUSTRALIA
Department of Treasury

Energy Transformation Implementation Unit

Project leader/manager, provider of policy development insights

westernpower

Provider of network development insights and data

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Provider of system / market development insights

Market participants

Provide data, input and feedback

Modelling consultant

Provider of external modelling expertise

TIMEFRAMES

PHASE 1
Develop and agree scenarios
Apr – Jul 2019

PHASE 2
Deliver forecasts, technical assessments and modelling
Jul – Dec 2019

PHASE 3
Develop capability/network /system recommendations and investment plan
Jan – Jun 2020

PHASE 4
Deliver Whole of System Plan
May – Jul 2020

Review PUO GenMix work

System & network assessment

Least cost expansion model build

Least cost expansion modelling (constrained)

Constraint equations update

Market dispatch modelling

Iterate

Finalise

Document finalisation and approvals

Jun 2019 | **Oct 2019** | **Jan 2020** | **Feb 2020** | **Mar 2020** | **Mid Apr 2020** | **Jun 2020** | **Aug 2020**

Q2 2019 | **Q3 2019** | **Q4 2019** | **Q1 2020** | **Q2 2020** | **Q3 2020**

Jul 2019
- Industry forum on scenarios
- 1:1 meetings with stakeholders
- Present to MAC on scenarios
- Finalise scenarios

Sep 2019
Present to MAC on inputs and assumptions

Dec 2019
Present to MAC on technical assessment

Mar 2020
Present to MAC on preliminary generation and network plans

Jun 2020
- Present to MAC on SWIS/network investment plan
- Industry forum on preliminary findings

Aug 2020
Government approval to publish WOSP

SCENARIOS

The following scenarios have been developed in close collaboration between the Energy Transformation Implementation Unit, Western Power and Australian Energy Market Operator.

1

Cast Away

Leaving the grid with muted economic growth.

2

Groundhog Day

Renewables thrive, but reliance on the network remains high.

3

Techtopia

Technological change places downward pressure on energy costs.

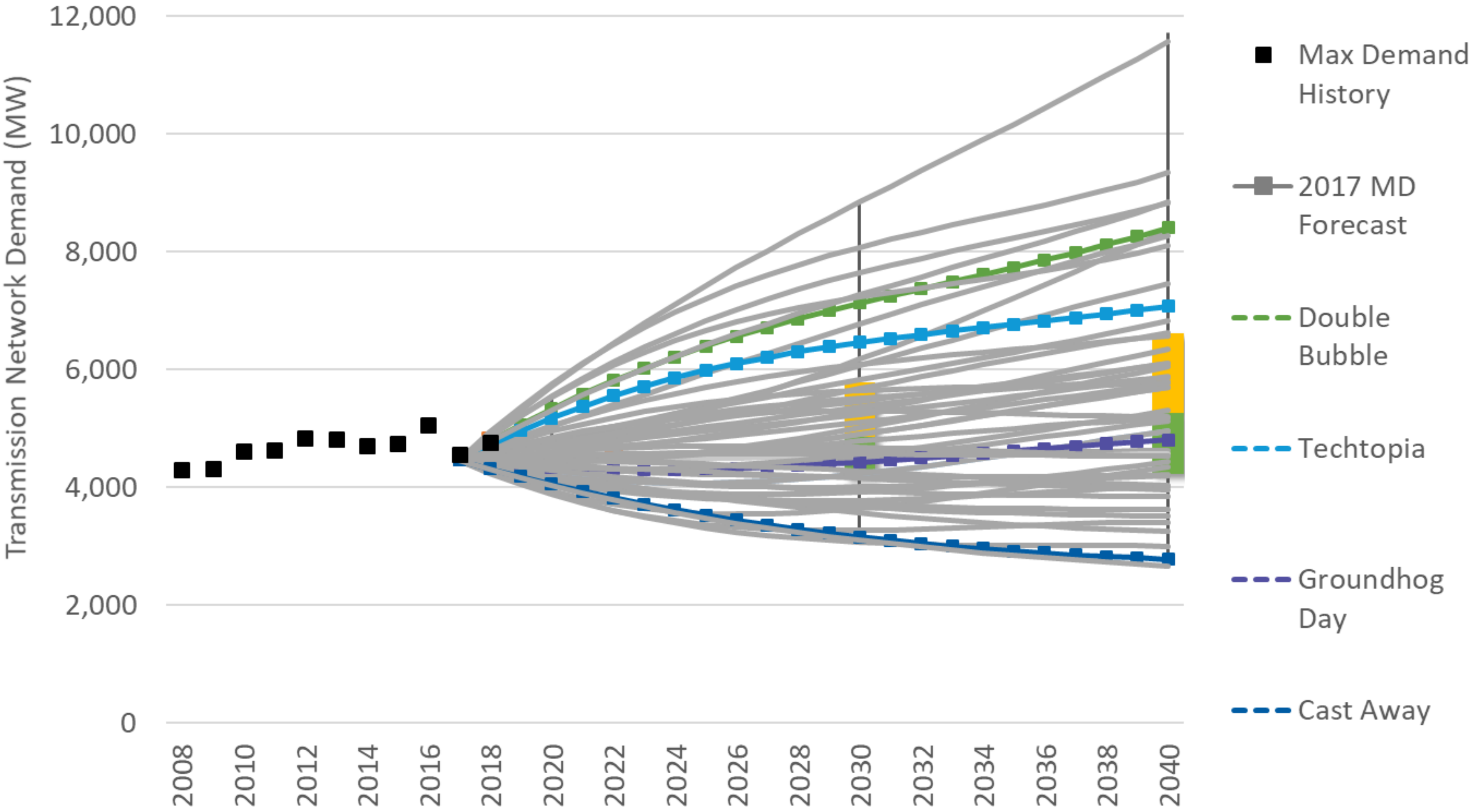
4

Double Bubble

Booming economy with limited global action on climate change.

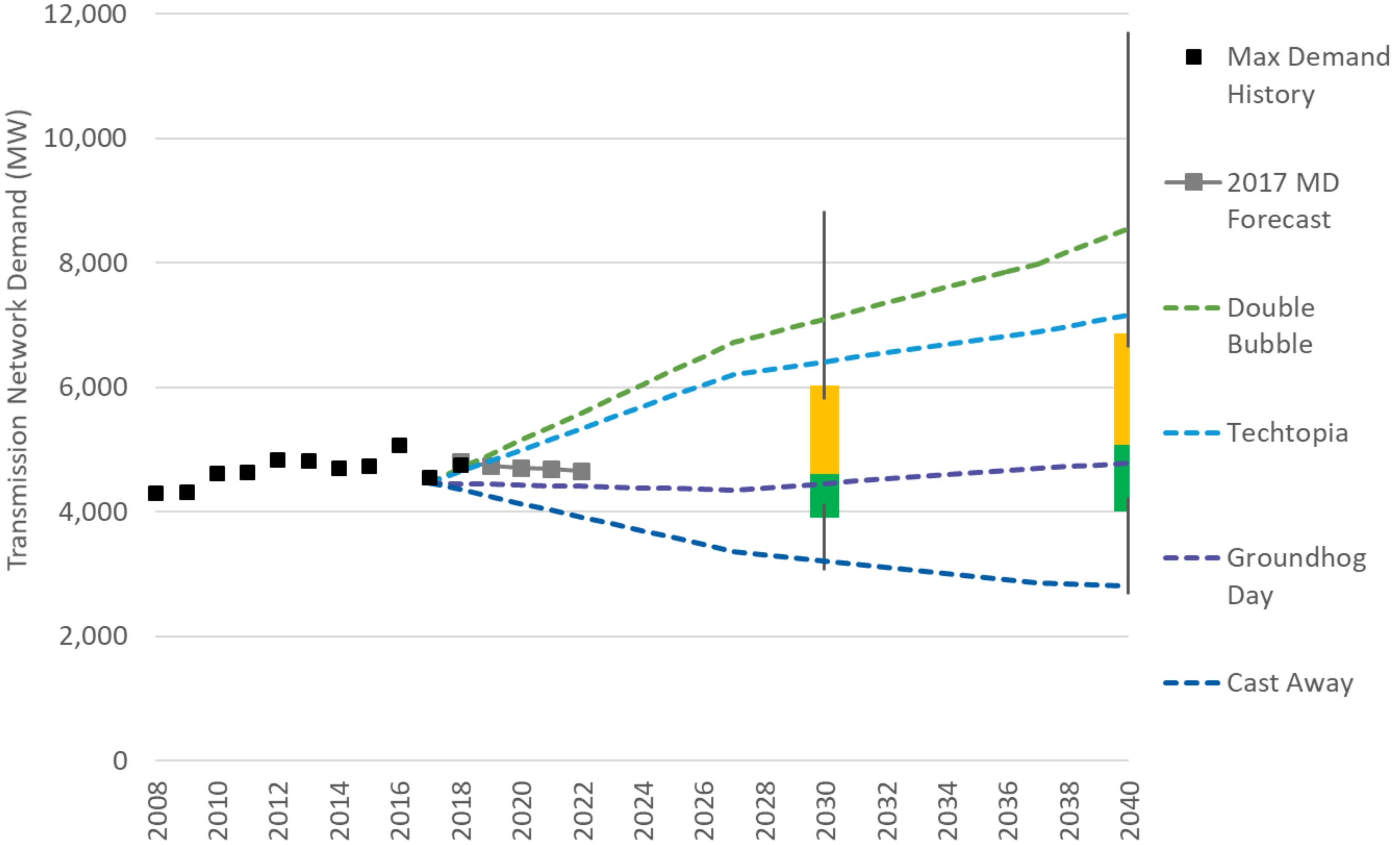
MAXIMUM DEMAND – 50 SCENARIOS

There are 50 energy forecasts generated based on the different permutations of key drivers.



Source: Western Power

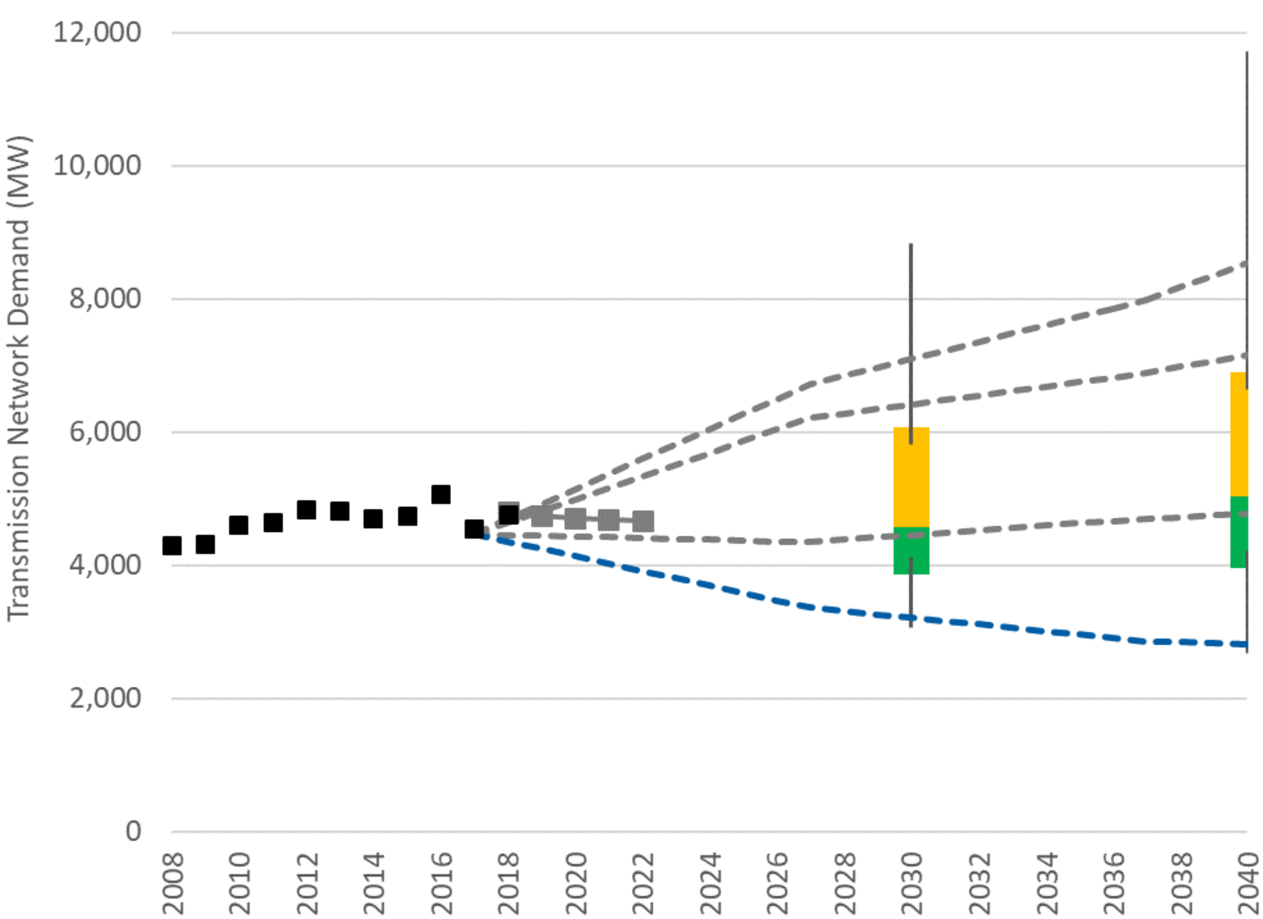
MAXIMUM DEMAND – FOUR SCENARIOS

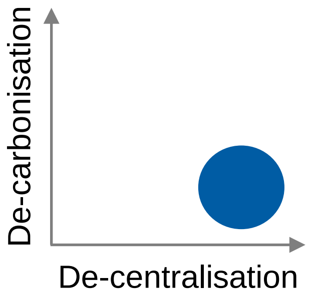


Source: Western Power

1 CAST AWAY

Leaving the grid with muted economic growth





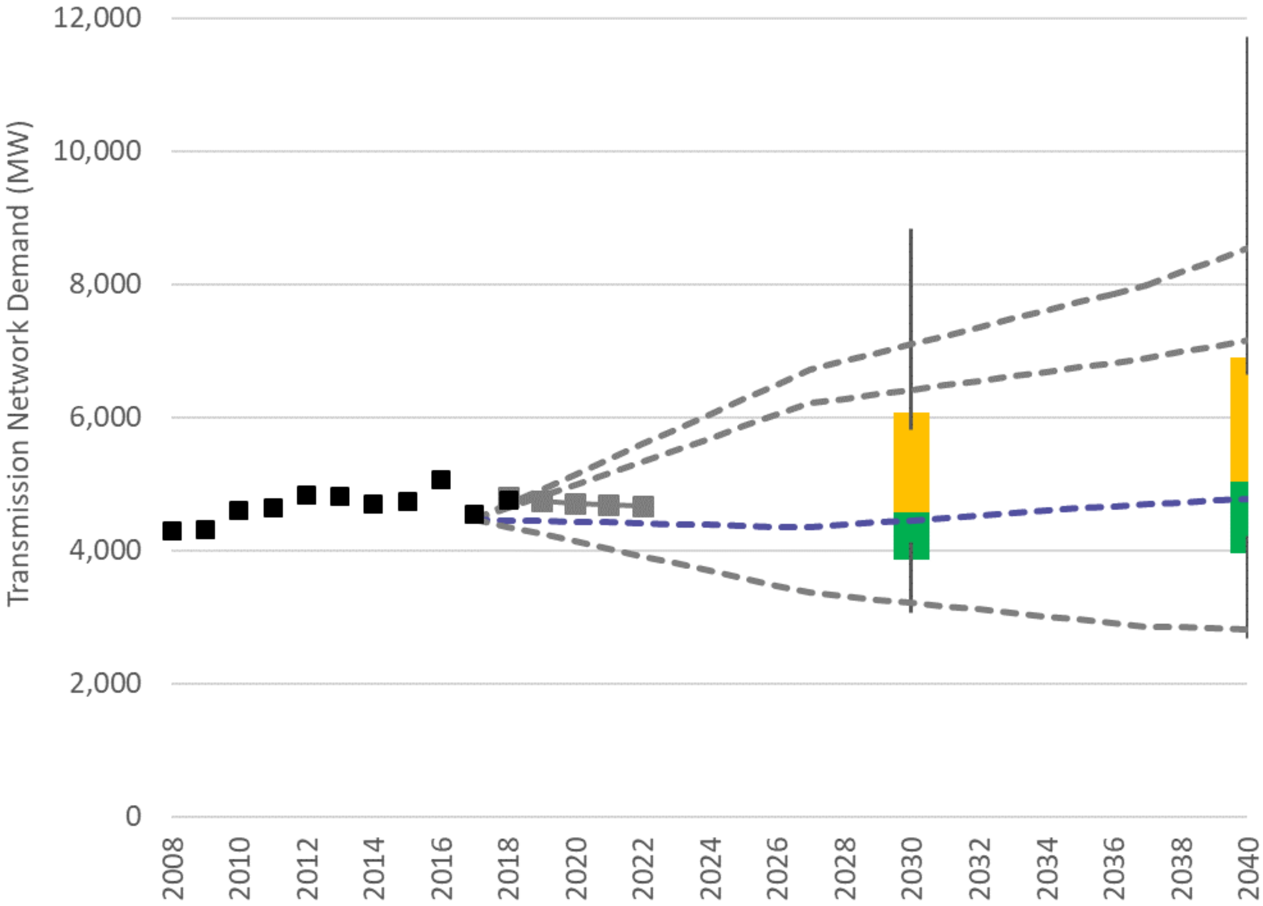
PROFILE

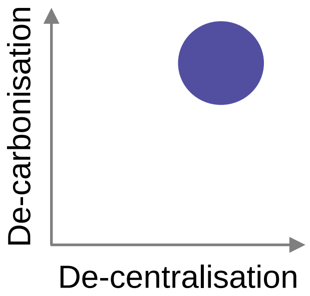
- Low economic growth
- Low de-carbonisation
- Low (on grid) DER uptake
- Low utility scale renewables

Source: Western Power

2 GROUNDHOG DAY

DER thrives, but reliance on the network remains high





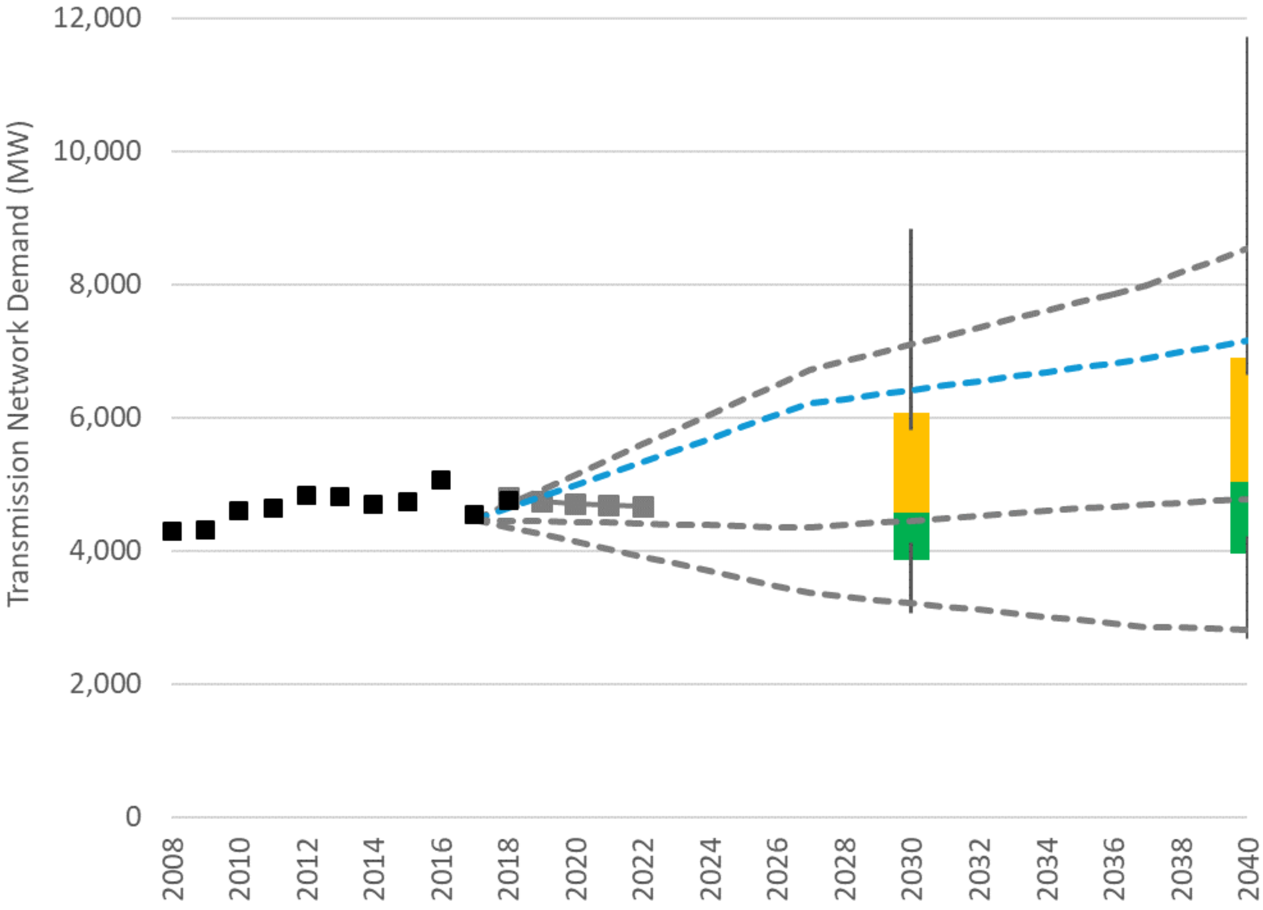
PROFILE

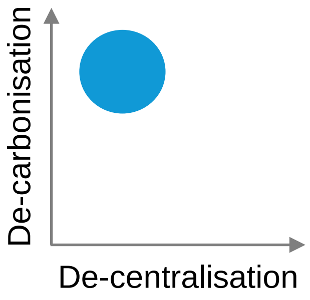
- Medium economic growth
- High de-carbonisation
- Extremely high DER uptake
- Medium utility scale renewables

Source: Western Power

3 TECHTOPIA

Technological change places downward pressure on energy costs





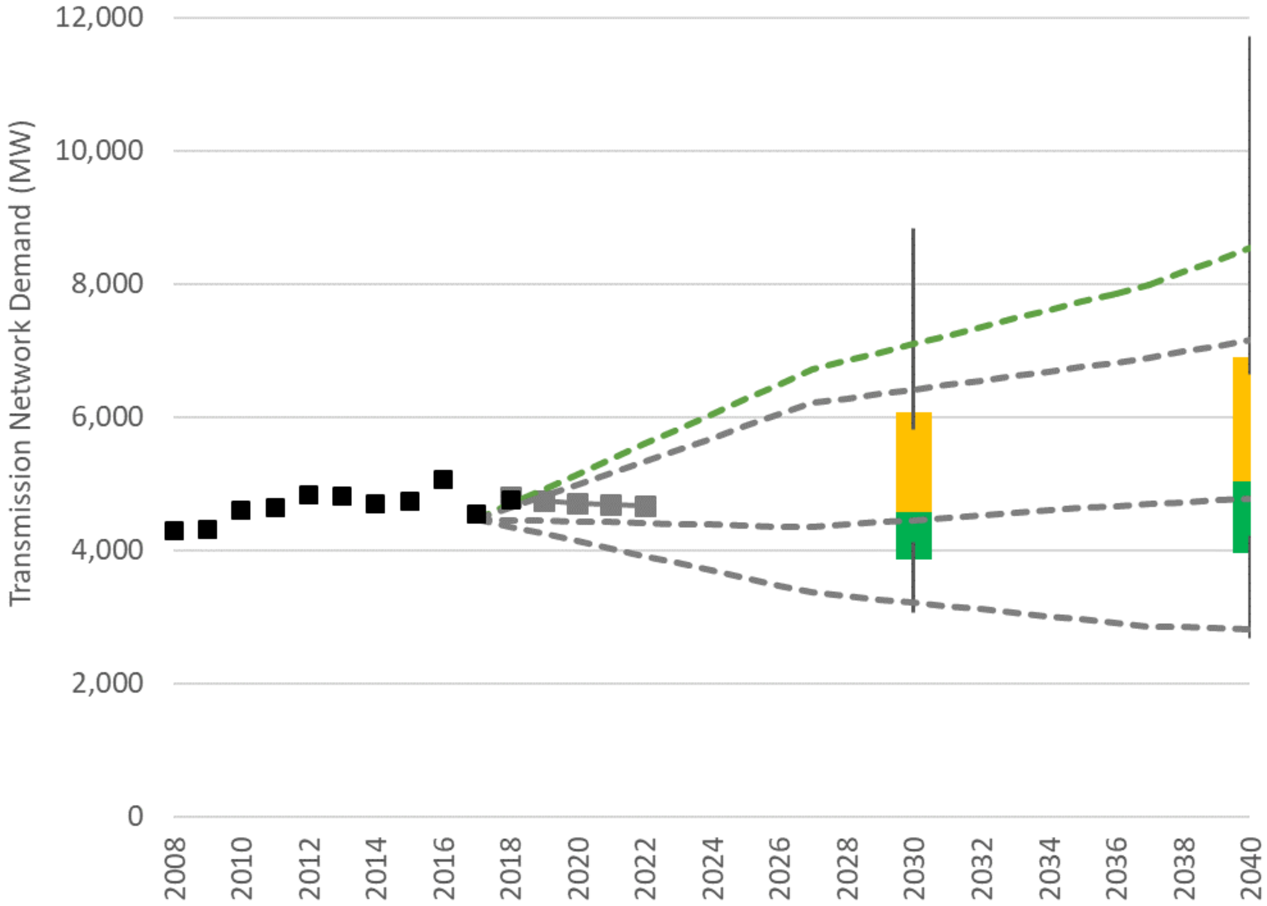
PROFILE

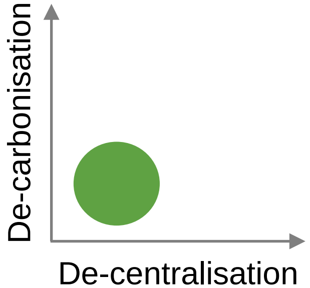
- Medium economic growth
- High de-carbonisation
- High DER uptake
- High utility scale renewables

Source: Western Power

4 DOUBLE BUBBLE

Booming economy with limited global action on climate change





PROFILE

- High economic growth
- Medium de-carbonisation
- Medium DER uptake
- High utility scale renewables

Source: Western Power

Stakeholder Engagement and Feedback

Interested parties have been invited to provide feedback on the proposed modelling scenarios by 26 July 2019.

An additional slide, regarding this feedback, will be provided on 29 July 2019.

Contact details

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http://www.treasury.wa.gov.au/Energy-Transformation/Whole-of-System-Planning/

MARKET ADVISORY COMMITTEE MEETING, 29 JULY 2019

FOR NOTING

SUBJECT: UPDATE ON AEMO'S MARKET PROCEDURES

AGENDA ITEM: 7

1. PURPOSE

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

2. AEMO PROCEDURE CHANGE WORKING GROUP (APCWG)

	Most recent meeting	**Next meeting**
Date	2 May 2019 (i.e. no meeting since last MAC)	8 Aug 2019
Market Procedures for discussion	• PSOP: Dispatch Market Procedures resulting from RC_2014_06 (Removal of Resource Plans and Dispatchable Loads) • Balancing Market Forecast • Balancing Facility Requirements • Determining Loss Factors • Determination of DSM Dispatch Payment Tranches & Adjustments • Settlement • Certification of Reserve Capacity	Procedures related to RC_2015_03 (Formalisation of the Process for Maintenance Applications): • Market Procedure: IRCR • Conversion of Consumption Deviation Application guideline into a procedure

3. AEMO PROCEDURE CHANGE PROPOSALS

The status of AEMO Procedure Change Proposals is described below, current as at 19 July 2019. Changes since the previous MAC meeting are in red text. A procedure change is removed from this report after its commencement has been reported or a decision has been taken not to proceed with a potential Procedure Change Proposal.

ID	Summary of changes	Status	Next steps	Date
AEPC_2018_03: PSOP: Communications and Control Systems	The proposed amendments will update the procedure in line with current AEMO standards and add content previously placed in the IMS Market Procedure.	Procedure Change Report published 14 Jun 2019. Procedure commenced.	-	1 Jul 2019
AEPC_2018_05: IMS Interface	The proposed amendments are consequential, arising from the amendment to the PSOP: Communications and Control Systems	Procedure Change Report published 14 Jun 2019. Procedure commenced.	-	1 Jul 2019
AEPC_2019_03: Market Procedure: Capacity Credit Allocation Market Procedure: Individual Reserve Capacity Requirements Market Procedure: Prudential Requirements	Amendments arising from Rule Change RC_2017_06 (Reduction of prudential exposure in the Reserve Capacity Mechanism) are proposed.	Procedure Change Report published 29 Apr 2019. All procedures commenced.	-	27 Jun 2019
AEPC_2019_04: PSOP: Dispatch	The proposed amendments include editorial clarifications and changes required by upcoming rule changes, audit items or operational matters.	No submissions received. Procedure Change Proposal published 21 Jun 2019. Procedure commenced.	-	1 Jul 2019

ID	Summary of changes	Status	Next steps	Date
AEPC_2019_06: Market Procedure: Balancing Market Forecast Market Procedure: Balancing Facility Requirements Market Procedure: Determining Loss Factors Market Procedure: Determination of DSM Dispatch Payment Tranches & Adjustments Market Procedure: Settlement Market Procedure: Certification of Reserve Capacity	The proposed amendments predominantly arise from Rule Change RC_2014_06 (Removal of Resource Plans and Dispatchable Loads)	No submissions received. Procedure Change Proposal published 24 Jun 2019. Procedures commenced.	-	1 Jul 2019
AEPC_2019_07: PSOP: Ancillary Services	The proposed amendments seek to revise the Procedure in line with current standards and ensure the Procedure complies with obligations.	Procedure Change Proposal published 21 Jun 2019. Procedure commenced.	-	1 Jul 2019
AEPC_2019_08: PSOP: Power System Security	The proposed amendments seek to revise the Procedure in line with current standards and ensure the Procedure complies with obligations.	Procedure Change Report published 14 Jun 2019. Procedure commenced.	-	1 Jul 2019

RCP | Rule Change Panel

Market Advisory Committee

Agenda Item 8(a): Overview of Rule Change Proposals (as at 22 July 2019)

Meeting 2019_07_29

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

Rule Change Proposals Commenced since the last MAC Meeting

Reference	Submitted	Proponent	Title	Commenced
RC_2014_06	28/01/2015	IMO	Removal of Resource Plans and Dispatchable Loads	01/07/2019
RC_2014_07	22/12/2014	IMO	Omnibus Rule Change	01/07/2019
RC_2018_07	14/12/2018	PUO	Removal of constrained off compensation for Outages of network equipment	01/07/2019

Approved Rule Change Proposals Awaiting Commencement

Reference	Submitted	Proponent	Title	Commencement
RC_2015_01	03/03/2015	IMO	Removal of Market Operation Market Procedures	01/08/2019
RC_2018_06	26/11/2018	PUO	Full Runway Allocation of Spinning Reserve Costs	01/09/2019

Rule Change Proposals Rejected since 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_2015_03	27/03/2015	IMO	Formalisation of the Process for Maintenance Applications	23/07/2019
RC_2018_05	27/09/2018	ERA	ERA access to market information and SRMC investigation process	26/07/2019

Formally Submitted Rule Change Proposals

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
Fast Track Rule Change Proposals with Consultation Period Closed						
None						
Fast Track Rule Change Proposals with Consultation Period Open						
None						
Standard Rule Change Proposals with Second Submission Period Closed						
RC_2013_15	24/12/2013	IMO	Outage Planning Phase 2 – Outage Process Refinements	Medium	Publication of Final Rule Change Report	26/08/2019
Standard Rule Change Proposals with Second Submission Period Open						
None						

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
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 call for further submissions	August-October 2019
RC_2014_05	02/12/2014	IMO	Reduced Frequency of the Review of the Energy Price Limits and the Maximum Reserve Capacity Price	Medium	Publication of Draft Rule Change Report	31/12/2019
RC_2014_09	13/03/2015	IMO	Managing Market Information	Low	Publication of Draft Rule Change Report	31/10/2019
RC_2017_02	04/04/2017	Perth Energy	Implementation of 30-Minute Balancing Gate Closure	Medium	Publication of Draft Rule Change Report[1]	31/12/2019
RC_2018_03	01/03/2018	Collgar Wind Farm	Capacity Credit Allocation Methodology for Intermittent Generators	Medium	Publication of Draft Rule Change Report	31/12/2019
Standard Rule Change Proposals with the First Submission Period Open						
RC_2019_01	21/06/2019	Enel X	The Relevant Demand calculation	TBD	Closure of the first submission period	09/08/2019

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	AEMO	Adjusting Non-STEM Settlements using latest available data	Submit Rule Change Proposal	TBD

[1] RCP Support intends to hold a MAC workshop to discuss RC_2017_02 and is currently targeting 16 August 2019. The Panel's timeline for progressing RC_2017_02 will be determined pending workshop outcomes.

RCP | Rule Change Panel
Market Advisory Committee

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

Meeting 2019_07_29

1. Background

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

The Rule Change Panel decided to progress RC_2019_01 and published the Rule Change Notice and Proposal (Attachment 1) on its website on 28 June 2019.

Broadly, Enel X's Rule Change Proposal is seeking to change the way the Relevant Demand of a Demand Side Programme is calculated.

2. Urgency Rating

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

Urgency	Description	Resourcing Implications
1	**Essential:** e.g. legal necessity, unacceptable market outcomes or a serious threat to power system security and reliability.	Do not delay – acquire additional resources, request increase to the ERA budget from Treasury if necessary
2	**High:** Compelling proposal, and either large net benefit or else necessary to avoid serious perverse market outcomes.	Do not delay – acquire additional resources if available subject to overall ERA budget limitations
3	**Medium:** Net benefit either: • may be large but needs more analysis to determine; or • material but not large enough to warrant a High rating.	May delay up to 3 months if budgeted resources unavailable
4	**Low:** Minor net benefit (e.g. reduced administration costs).	May delay up to 6 months if budgeted resources unavailable
5	**Housekeeping:** Negligible market benefit, e.g. just improves the readability of the Market/GSI Rules	May delay up to 12 months if budgeted resources unavailable

3. Drafting of Amending Rules

Since RC_2019_01 does not propose specific amendments to the Market Rules, the Rule Change Panel is seeking the MAC's advice on how to develop and consult on the necessary Amending Rules.

The initial course of action, once the first submission period has ended (9 August 2019), will be for RCP Support to hold a workshop with interested parties to develop straw man design options to guide the development of the required drafting. Timing for the workshop will depend on the urgency rating of the Rule Change Proposal and availability of RCP Support resources.

Options for the next steps after the workshop include:

1. publishing a call for further submissions on a straw man design (without drafting) which will inform the development of drafting to be included in the Draft Rule Change Report;
2. publishing a call for further submissions on a straw man design with drafting prior to consideration in the Draft Rule Change Report; or
3. publishing a Draft Rule Change Report that details the preferred design and drafting with a further round of consultation if required.

It is likely that due to the requirement to develop drafting that an extension will be required to the timeline for this Rule Change Proposal.

4. Recommendation

That the MAC:

1. recommends an urgency rating for RC_2019_01 (Enel X has recommended a high urgency in the Rule Change Proposal);
2. recommend an approach for developing the proposed Amending Rules for RC_2019_01; and
3. provide feedback and comments on the major issues that need to be addressed in analysing this Rule Change Proposal and for developing a straw man design.

Attachments

1. RC_2019_01 – Rule Change Notice and Proposal

Rule Change Notice: The Relevant Demand calculation (RC_2019_01)

This notice is given under clause 2.5.7 of the Wholesale Electricity Market Rules (**Market Rules**).

Submitter: Claire Richards – Enel X

Date submitted: 21 June 2019

The Rule Change Proposal

Enel X originally submitted RC_2019_01 to the Rule Change Panel on 29 April 2019. The Rule Change Panel sought clarification on some aspects of the Rule Change Proposal and Enel X provided the requested clarifications on Friday 21 June 2019.

Enel X is seeking to change the way the Relevant Demand of a Demand Side Programme (**DSP**) is calculated. Enel X states that:

- The Relevant Demand level is intended to be an estimate of a DSP's counterfactual demand when the DSP is dispatched. If a DSP is dispatched, it is required to deliver the quantity of capacity it is certified for as a reduction from its Relevant Demand level.
- The current Relevant Demand calculation significantly under-calculates the "curtailability" of loads.
- A DSP's Relevant Demand is currently set at the lesser of:
  - the fifth percentile of the top 200 system peak hours in the previous Capacity Year; and
  - the sum of all Individual Reserve Capacity Requirement (**IRCR**) Contributions of the DSP's associated loads.

  In most cases, the fifth percentile calculation results in a lower value than the IRCR calculation and hence sets the DSP's Relevant Demand.
- AEMO calculates a DSP's Required Level as the Facility's Relevant Demand minus the Capacity Credits assigned to it. A capacity provider's compliance with the various obligations of the Reserve Capacity Mechanism (**RCM**) is largely tied to its ability to operate at a level equivalent to its Required Level. Thus, a major consequence of the current Relevant Demand calculation is that the DSP must commit to curtailing a significant amount of load, uncredited, before it reaches its Relevant Demand level. Participation in the RCM is therefore uneconomic for many industry sectors, and impossible for others.
- Any concerns about the availability of a DSP are more appropriately addressed through the testing and compliance framework, not by restricting its participation outright through the Relevant Demand calculation.
- Under-calculating a DSP's Relevant Demand level means that a DSP will be certified for a much lower number of Capacity Credits than the capacity it is capable of providing.

The associated outcomes of this under-calculation are inconsistent with the Wholesale Market Objectives.

- The objective of the Relevant Demand calculation should be to determine the "baseline" consumption of a demand side resource with reasonable accuracy when it is dispatched.
- The Market Rules should be amended to:
  - include a clear definition of Relevant Demand, and a clear description of what the calculation is intended to achieve, so that stakeholders are clear on its purpose. Enel X's proposed definition is:

    "*An estimate of demand side programme's counterfactual demand when it is dispatched"*;
  - adopt a baseline methodology for DSPs that strikes an appropriate balance between accuracy,[1] simplicity[2] and integrity.[3]
    - 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 proposes that an "X of Y" methodology[4] is best suited for the WEM because:
      - it will provide an accurate measure of a DSP's expected baseline consumption, thus minimising errors;
      - it can accommodate natural and unexpected fluctuations in demand in any Trading Interval as dynamic baseline methodologies can take into account a Load's variability over whatever hours the DSP is actually dispatched relative to a static approach;
      - it is reasonably easy to apply and therefore not expected to involve significant costs; and
      - such methodologies are commonly used in other markets, thus making available a large amount of analysis and expertise to draw upon.

Enel X also provided responses to the issues of capacity certification, availability of demand side resources and availability monitoring in the Rule Change Proposal.

Enel X did not propose drafting for the Amending Rules. The Market Rules permit a Rule Change Proposal to be submitted without drafting, but this means that RCP Support will need to develop drafting and additional consultation may be needed on the Rule Change Proposal to allow stakeholders an opportunity to comment accordingly.

Appendix 1 contains the Rule Change Proposal and gives information about:

- relevant references to the Market Rules and the sections of the Market Rules that are likely to be affected; and
- the submitter's description of how the proposal would allow the Market Rules to better address the Wholesale Market Objectives.

---

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

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

3 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").

4 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.

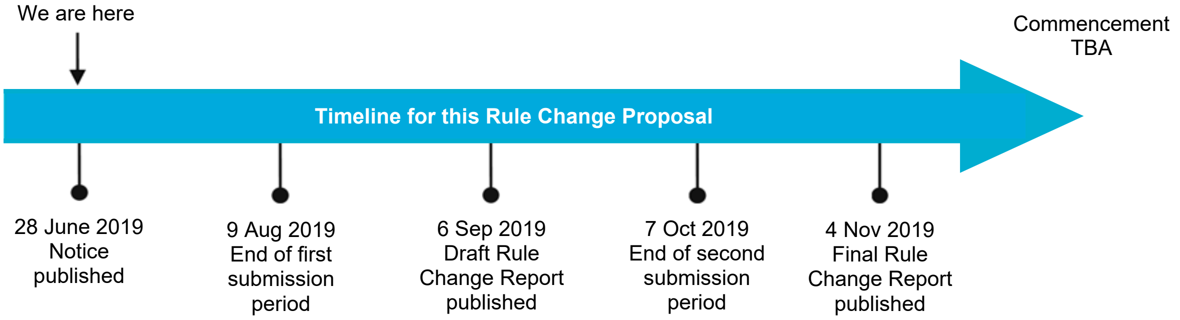
Decision to progress the Rule Change Proposal

The Rule Change Panel has decided to progress this Rule Change Proposal on the basis that stakeholders should be given an opportunity to consider the Rule Change Proposal and provide submissions through the rule change process.

Timeline

This Rule Change Proposal will be progressed using the Standard Rule Change Process, described in section 2.7 of the Market Rules.

The projected timeline for progressing this proposal is:



Call for submissions

The Rule Change Panel invites interested stakeholders to make submissions on this Rule Change Proposal. The submission period is 30 Business Days from the Rule Change Notice publication date. Submissions must be delivered to the RCP Secretariat by **5:00 PM** on **Friday, 9 August 2019**.

The Rule Change Panel prefers to receive submissions by email, using the submission form available at: https://www.erawa.com.au/rule-change-panel/make-a-rule-change-submission sent to support@rcpwa.com.au.

Submissions may also be sent to the Rule Change Panel by post, addressed to:

> **Rule Change Panel**
> Attn: Executive Officer
> C/o Economic Regulation Authority
> PO Box 8469
> PERTH BC WA 6849

RCP | Rule Change Panel

Wholesale Electricity Market Rule Change Proposal

Rule Change Proposal ID: **RC_2019_01**
Date received: **21 June 2019**

Change requested by:

Name:	Claire Richards
Phone:	0416 194 215
Email:	claire.richards@enel.com
Organisation:	Enel X
Address:	Level 18, 535 Bourke St, Melbourne, VIC 3000
Date submitted:	21 June 2019
Urgency:	High
Rule Change Proposal title:	The relevant demand calculation
Market Rule(s) affected:	Appendix 10, clause 4.11.1(j), and consequential amendments as required.

Introduction

Clause 2.5.1 of the Wholesale Electricity Market (WEM) Rules (Market Rules) provides that any person may make a Rule Change Proposal by completing a Rule Change Proposal form that must be submitted to the Rule Change Panel.

This Rule Change Proposal can be sent by:

Email to: support@rcpwa.com.au

Post to: Rule Change Panel
Attn: Executive Officer
C/o Economic Regulation Authority
PO Box 8469
PERTH BC WA 6849

The Rule Change Panel will assess the proposal and, within 5 Business Days of receiving this Rule Change Proposal form, will notify you whether the Rule Change Proposal will be further progressed.

In order for the proposal to be progressed, all fields below must be completed and the change proposal must explain how it will enable the Market Rules to better contribute to the achievement of the Wholesale Market Objectives.

The objectives of the market are:

(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;

(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;

(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;

(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and

(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

Details of the Proposed Rule Change

1. Describe the concern with the existing Market Rules that is to be addressed by the proposed rule change:

This rule change request proposes a change to the way in which the relevant demand of a demand side programme is calculated. While not explicitly defined in the WEM rules, the relevant demand level is generally intended to be an estimate of a demand side programme's counterfactual demand when it is dispatched. If a programme is dispatched, it is required to deliver the quantity of capacity it is certified for as a reduction from its relevant demand level.

1.1 Background

In 2014 Minister Nahan initiated a review of the WEM. The objective of the review was to reduce the cost of capacity at a time when the SWIS was experiencing a capacity oversupply. It was identified that the fundamental problem with the reserve capacity mechanism was a lack of price response to capacity – capacity was overvalued when there was an excess and underpriced when there was a shortage. The rules made in 2016 at the conclusion of the review adjusted the capacity price formula to progressively steepen the capacity price curve.

The review also resulted in significant amendments to the way in which the demand side participates in the reserve capacity mechanism, including:

1. **Pricing of demand side capacity.** The new rules introduced pricing arrangements that severely devalued a demand side programme’s provision of capacity compared to generation, despite the fact that changes were also made to harmonise the demand side service requirements with those applying to the supply side.
2. **Calculation of a demand side programme’s relevant demand.** The new rules changed the relevant demand calculation. Prior to the change, the relevant demand of a demand side programme was the median of the historical consumption quantities of all associated loads in the 32 trading intervals of highest demand during the hot season of the previous capacity year. A demand side programme’s relevant demand is now determined based on the lesser of:
    - the fifth percentile of the top 200 system peak hours in the previous capacity year – that is, the tenth lowest of 200 consumption values
    - the sum of all individual reserve capacity requirement (IRCR) contributions of the associated loads of the programme.[1]

[1] See clause 4.26.2CA and Appendix 10 of the WEM rules.

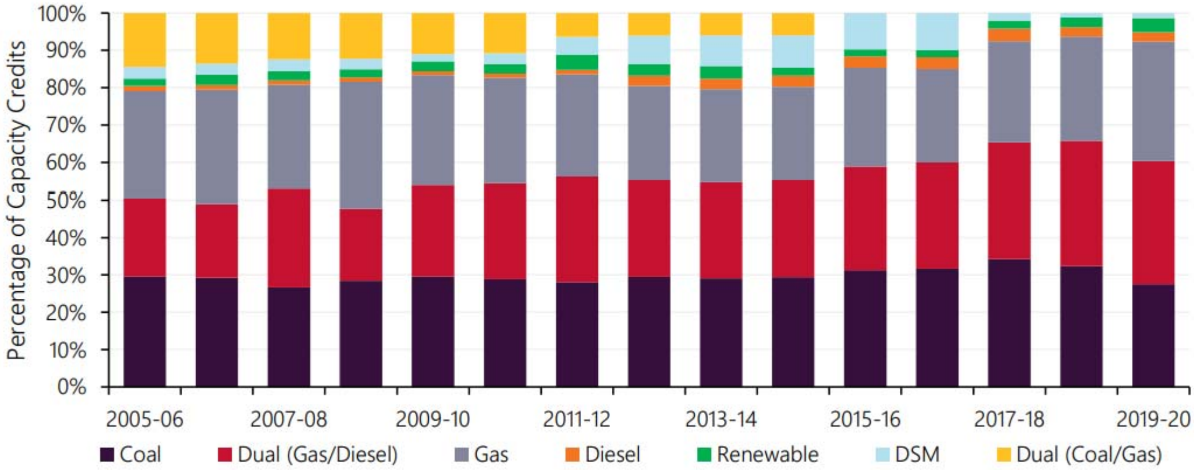
These two changes significantly undervalued and under-calculated the contribution that the demand side can bring to supporting reliability outcomes in the WEM, and resulted in about 500 MW of demand side capacity exiting the market (relative to the 2016/17 capacity year), as shown in the table below.

Table A: Reduction in demand side participation since 2016 rule changes

	2016-17	2017-18	2018-19	2019-20
Capacity credits assigned to demand side programmes (MW)[2]	560	106	57	66
Reduction from 2016/17 levels (MW)	-	-454	-503	-494

The graph below shows this reduction. It also shows that there is even less demand side capacity now than when the WEM started in 2006.

Figure A: Capacity credits by fuel type[3]



While it could be argued that the exit quickly assuaged over-capacity concerns, the changes:

- ensured that there is no meaningful level of demand side participation in the reserve capacity mechanism
- rendered the WEM an outlier amongst global capacity markets.

This first outcome is inconsistent with the WEM objectives, for the reasons set out in section 1.3 below.

The changes to the capacity price formula were intended to be transitional until a longer-term solution was put in place. This longer-term solution has now been developed and consulted on by the PUO through its work on *Improving reserve capacity pricing signals*.[4] Enel X supports the implementation of a capacity pricing formula that incentivises an efficient level of capacity to meet the reliability needs of electricity consumers in the SWIS. With such a formula in place, Enel X sees no reason why the regulatory framework should not be technology neutral, consistent with the WEM objectives.

Enel X therefore strongly supports the PUO's conclusion in its final report that equal

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[2] Data from AEMO. See: https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Assignment-of-capacity-credits
[3] AEMO, Quarterly energy dynamics, Q4 2018, p. 32.
[4] See: https://www.treasury.wa.gov.au/Public-Utilities-Office/Industry-reform/Improving-Reserve-Capacity-pricing-signals/

remuneration of demand and supply side capacity be restored. This change will go some way toward bringing demand side resources back into the reserve capacity mechanism where there are efficient signals to do so, to the benefit of WA electricity consumers. However, the calculation of relevant demand for a demand side programme was not considered in the PUO's review. Without change, this calculation will continue to present an unjustifiable and inefficient barrier to the entry of demand side resources.

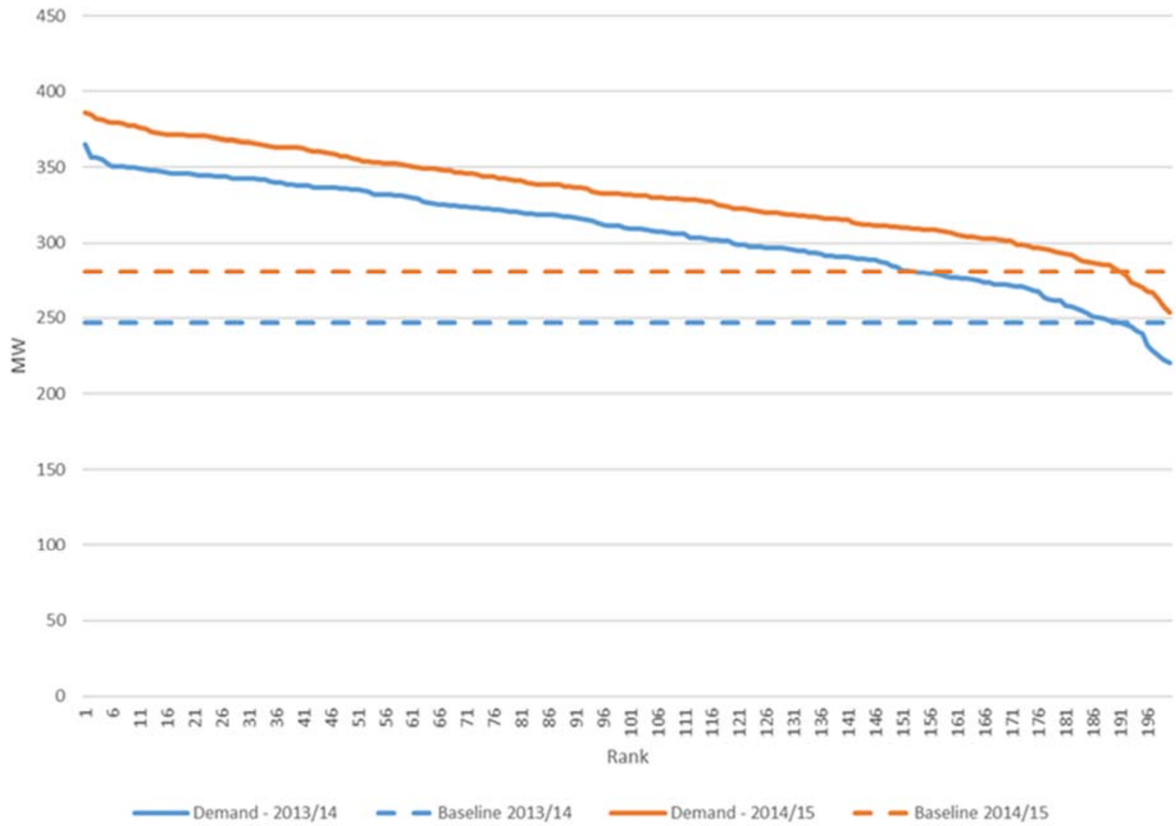
1.2 The issue

The issue with the current relevant demand calculation is that it significantly under-calculates the "curtailability" of loads.

As above, a demand side programme's relevant demand is currently set at the lesser of the fifth percentile of the top 200 system peak hours in the previous capacity year, and the sum of all IRCR contributions of the programme's associated loads. As you would expect, in most cases the fifth percentile calculation results in a lower value than the IRCR calculation, and hence sets the programme's relevant demand.

This is shown in Figure B below, which uses data from a 200 MW sample of Enel X's portfolio in the 2013/14 and 2014/15 capacity years. The solid lines show the portfolio's total demand, ranked from the highest demand (rank 1) to the lowest demand (rank 200) in the 200 system peak hours. The dotted lines show what the portfolio's relevant demand would be under the current fifth percentile calculation.

Figure B: Portfolio demand and relevant demand



The graph shows that the portfolio's demand was much higher than its relevant demand in the majority of the 200 highest system peak hours.

The "required level" of a demand side programme is calculated by AEMO using the facility's relevant demand minus the capacity credits assigned to it.[5] A capacity provider's compliance with the various obligations of the reserve capacity mechanism is largely tied to its ability to operate at a level equivalent to its required level. Thus a major consequence of the current relevant demand calculation is that the programme must commit to curtailing a significant amount of load, uncredited, before it reaches its relevant demand level. Participation in the reserve capacity mechanism is therefore uneconomic for many industry sectors, and impossible for others.

This is demonstrated in Table A below, which has been compiled using interval data from the industry sectors that made up the majority of Enel X's portfolio in the 2014/15 capacity year. It sets out the effective compensation rate for certain industry sectors under the current relevant demand calculation. By "effective compensation rate", we mean the percentage of the sector's curtailment that can actually be certified and rewarded through the reserve capacity mechanism. This is a factor of how much the sector is technically able to curtail ("average maximum curtailment") and the magnitude of the reduction below the relevant demand level ("credited MW").

The table shows this for the 25, 50 and 100 highest demand hours of the 200 system peak hours.

Table A: Effective compensation rate under the current relevant demand calculation

	Average max. curtailment (MW)[6]	Credited MW	Effective compensation rate
Agricultural sector (average demand 11.5 MW)			
Top 25 hrs	9.2	4.9	53%
Top 50 hrs	9.0	5.0	56%
Top 100 hrs	8.7	5.1	59%
Commercial property sector (average demand 29.5 MW)			
Top 25 hrs	10.7	-7.9	-
Top 50 hrs	10.5	-7.5	-
Top 100 hrs	10.2	-6.7	-
Manufacturing (average demand 68.1 MW)			
Top 25 hrs	64.6	31.4	49%
Top 50 hrs	63.6	31.6	50%
Top 100 hrs	61.0	32.3	53%
Mining (average demand 153.2 MW)			
Top 25 hrs	141.4	68.3	48%
Top 50 hrs	139.3	68.8	49%
Top 100 hrs	135.5	69.8	51%

[5] See clause 4.11.3B(c) of the WEM rules. *Required level* is defined as the level of output, in MW, required to be met by a facility as determined in clause 4.11.3B.
[6] This is based on a curtailment potential of: 70 per cent for agriculture, 30 per cent for commercial property, 80 per cent for manufacturing, 80 per cent for mining and 65 per cent for refrigerated storage.

Refrigerated storage (average demand 8.1 MW)			
Top 25 hrs	7.0	4.3	61%
Top 50 hrs	6.9	4.4	63%
Top 100 hrs	6.7	4.4	67%

The table shows that, under the current rules, most industry sectors can only get credit for about half of the load curtailment they can provide.

The table also shows that the sample loads in the commercial property sector were not able to reduce their aggregate demand enough to reach their relevant demand level at all, even though they were capable of curtailing around 10 MW. As a result, it is likely to be impossible for this sector to offer capacity in the reserve capacity mechanism under the current rules.

Interaction with the 200 hour availability requirement

The rules made in 2016 increased the yearly availability requirement for a programme from 24 hours to 200 hours, and increased the number of values in the relevant demand calculation from 32 intervals to 200 hours. Enel X understands that these changes were made to address a concern that demand side resources would not be able to deliver the capacity they are credited for when called upon. Using a high number of hours increases the range of consumption values in the relevant demand calculation, and thus delivers a low relevant demand level. This presumably gives AEMO a high degree of confidence that the small quantity of certified capacity can be delivered if and when it is called upon.

While not explicitly defined, the relevant demand level is generally intended to be an estimate of a demand side programme's counterfactual demand when it is dispatched. The current relevant demand calculation gives a reasonably accurate estimate of this in the 190th system peak hour, but not during the intervals when a demand side programme is most likely to be dispatched – i.e. during extreme system events.[7]

If the objective is to determine an accurate measure of a programme's demand in the 200 hours AEMO expects it might be dispatched, then a static relevant demand calculation is not the way to achieve this. Using a low, static calculation not only under-calculates and undervalues the potential of the demand side, but results in a very inaccurate picture of the programme's expected consumption in the majority of the 200 hours. The more biased a baseline methodology is (in either direction), the less accurate settlement will be. Reducing bias is an absolute good.

Section 1.4 sets out an alternative relevant demand methodology that can reduce errors and more accurately measure the expected consumption of a demand side programme.

In Enel X's view, any concerns about the availability of a demand side programme are more appropriately addressed through the testing and compliance framework (discussed further in section 1.4.2), not by restricting its participation outright through the relevant demand calculation.

1.3 Implications of the current rules

Under-calculating a programme's relevant demand level means that the number of capacity credits it can be certified for is much less than the capacity it is capable of providing. This has

[7] The rules prioritise the dispatch of the Synergy portfolio; AEMO will only dispatch a demand side programme if there is a system reliability or security concern. See rule 6.12 and clauses 7.6.1C-D of the WEM rules.

the following outcomes:

- Fewer resources offering capacity, resulting in higher market-wide capacity costs, which are borne by WEM consumers.
- Significant under-utilisation of demand side capacity resources that:
    - provide valuable CO_2 emission reductions
    - relieve network congestion,

  again to the detriment of WEM consumers.
- Limited participation by many demand side resources, and no participation by others (e.g. businesses in the commercial property sector). Opening up energy frameworks to demand side resources not only supports competition and cost reductions in those frameworks, but brings benefits to the providers themselves, including improved business competitiveness, which has economy-wide benefits.

These outcomes are inconsistent with the WEM objectives to:

- promote the economically efficient, safe and reliable production and supply of electricity
- encourage competition … including by facilitating efficient entry of new competitors
- avoid discrimination … 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
- minimise the long-term cost of electricity
- encourage the taking of measures to manage the amount of electricity used and when it is used.

The benefits of enabling demand side participation in electricity markets are well recognised. In its consultation paper on *Improving reserve capacity pricing signals*, the PUO noted that:

> "Demand side capacity providers must continue to be able to participate in the Reserve Capacity Mechanism arrangements. Demand side capacity is a valuable participant in most capacity markets worldwide. It has many unique characteristics that generation capacity cannot easily or cheaply replicate; being scalable, with short lead times to develop and be readily able to enter and exit the capacity market."

Capacity markets around the world have arrived at this same conclusion. However, for the reasons set out above, demand side capacity providers will not be able to participate in the reserve capacity mechanism at any meaningful level unless the relevant demand calculation is amended.

1.4 Proposed changes to address the identified issues

In Enel X's view, the objective of the relevant demand calculation should be to determine the "baseline" consumption of a demand side resource with reasonable accuracy when it is dispatched. For the reasons explained above, the current relevant demand calculation does not achieve this. This section sets out Enel X's proposed amendments to the WEM rules so that this objective can be achieved.

1.4.1 Define relevant demand

'Relevant demand' is not currently a defined term. Enel X proposes that the WEM rules be amended to include a clear definition of relevant demand, and a clear description of what the calculation is intended to achieve, in order to provide clarity to all stakeholders on its underlying purpose.

Enel X's proposed definition of relevant demand is:

> *An estimate of a demand side programme's counterfactual demand when it is dispatched*.

1.4.2 Implement a dynamic baseline methodology

In Enel X's view, any baseline methodology for a demand side programme should strike an appropriate balance between accuracy, simplicity and integrity.[8]

- **Accuracy** means that customers receive credit for no more and no less than the curtailment they actually provide.
- **Simplicity** means that the methodology makes baseline and curtailment calculations easy to calculate and easy for customers to understand.
- **Integrity** means that the methodology does not encourage irregular consumption, and irregular consumption does not influence baseline calculations. In other words, a methodology with a high level of integrity will protect against attempts to "game the system".

Enel X has always advocated for baselines that are determined on a dynamic basis – that is, in a way that takes into account a load's variability – and we will continue to do so. Enel X operates over 50 demand response programs in 12 countries, and our experience in those markets confirms that dynamic baseline calculations strike a much better balance between accuracy, simplicity and integrity than static baseline methodologies do. Almost all electricity markets around the world with any meaningful level of demand side participation have moved or are moving to the application of dynamic baseline methodologies, including:

- Asia: Japan, South Korea.
- Europe: France, Great Britain, Greece, Ireland, Poland.
- USA: California (CAISO), Mid-Atlantic (PJM), Midwest (MISO), New England (ISO-NE) New York (NYISO), Texas (ERCOT).

The most commonly used dynamic baseline methodology is an "X of Y" methodology. This approach determines a load's expected demand drawing on data from a number of previous days (the "Y"), which typically excludes holidays, previous event days, and weekends. Once a group of prior days is identified as the Y days, that group is narrowed down to a subset of days (the "X") in order to obtain a more representative sample. For example, a demand response event within a summer emergency demand response program will usually be called on a day when demand is expected to be high, driven by extreme weather conditions. Not all of the eligible Y days, however, will have been days with high demand, so a better match could be achieved by choosing the X number of days within Y with the highest load levels. Best practice when "X of Y" baseline methodologies are used is to apply day-of adjustments to more accurately reflect load conditions on the event day.

Enel X is of the view that an "X of Y" methodology is best suited for the WEM for the following reasons.

- It will provide an accurate measure of the expected baseline consumption of a demand

[8] See: EnerNOC, *The demand response baseline*, 2011, available here; and Florence School of Regulation, *Measuring the intangible: An overview of the methodologies for calculating customer baseline load in PJM*, May 2018, available here.

side programme, thus minimising errors. Dynamic approaches minimise the total error across however many hours of dispatch there turn out to be.

- It will be able to accommodate natural and unexpected fluctuations in demand in *any* interval. Dynamic baseline methodologies measure baseline consumption much more accurately than static approaches because they are capable of taking into account a load's variability over whatever hours the programme is actually dispatched. As a result, dynamic baselines do not require you to estimate the number of hours of dispatch and the extent to which they will coincide with system demand peaks.
- It is reasonably easy to apply, and is therefore not expected to involve significant costs. Dynamic methodologies do not require the market operator to conduct ongoing calculations. Calculations are only needed to estimate the programme's counterfactual demand during dispatches and tests.
- Such methodologies are commonly used in other markets, and thus there is a large amount of analysis and expertise available to draw upon.

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.

Dynamic baselines and capacity certification

One question that has been raised about the applicability of a dynamic baseline methodology in the WEM is how a demand side programme's capacity can be certified two years ahead of the relevant capacity year. Enel X's response to this is: the same way that all capacity is certified now. That is:

- AEMO determines the quantity of capacity credits that a facility is eligible for, based on its expectation of how much generation or load reduction the facility will be able to provide. If the facility does not yet exist (e.g. the generator has not yet been built or specific loads have not been identified), AEMO has the ability to check whether the provider's intentions are credible in determining the quantity of capacity credits it is eligible for. The rules give AEMO the ability to request regular updates on the progress of new facilities.
- The participant commits to make that quantity of capacity available in the relevant capacity year. A prudent demand side programme provider will contract with more load than is required to meet its capacity obligations. It will do this so it can be certain of delivering the full quantity of certified capacity in light of natural or unexpected variations in the availability of the individual loads in the programme.

This is the approach to capacity certification taken in other capacity markets, regardless of what baseline methodology they use.

Baseline methodologies are purely about *measurement*. They provide an objective means to calculate how much load is curtailed when a demand side programme is dispatched in real or test events. This calculation can then be used to determine whether the programme was compliant with its capacity delivery obligations.

While this information is likely to be helpful in the ongoing capacity certification process for existing programmes, it is not necessary (or even possible) to use a relevant demand calculation to determine how much capacity a new demand side programme could be certified for. As above, there is an existing framework by which AEMO certifies capacity for new facilities. This framework is somewhat confused by the second limb of clause 4.11.1(j) of the WEM rules, which refers to relevant demand in the context of capacity certification. Enel X recommends that this clause be clarified through this rule change process to remove any confusing link between capacity certification and the relevant demand calculation.

Ensuring the availability of demand side resources

Enel X is also aware of a concern that the amount of capacity a demand side programme has been credited for will not actually be available. Again, a framework exists and applies to all capacity providers to mitigate this risk. Specifically:

- The participant puts up a security deposit that AEMO can draw down on if the participant fails to meet certain obligations. The PUO's final report on *Improving reserve capacity pricing signals* recommended that demand side programmes be required to provide a security deposit each year of capacity certification.[9]
- AEMO conducts testing to ensure that each facility is capable of meeting its reserve capacity obligations. The PUO's final report on *Improving reserve capacity pricing signals* recommended more stringent testing of demand side programmes, including by conducting random tests.

Demand side programme providers have an incentive and a regulatory obligation to make sure that the amount of capacity they committed to provide is there in the relevant capacity year, as do generators. The security, testing and penalty regimes described above are robust enough to deter any participant from taking on a capacity obligation speculatively or failing to deliver contracted capacity. When implemented, the PUO's final recommendations with respect to security deposits and testing for demand side programmes will make this framework even more robust.

Availability monitoring

The WEM rules currently require a demand side programme to pay a refund to AEMO if it fails to comply with its reserve capacity obligations in any given trading interval. AEMO determines whether a refund is payable by calculating the difference between the programme's relevant demand and its minimum load. If this calculation results in a quantity that is less than the programme provider's reserve capacity obligation, a refund is payable in proportion to the deficit.[10]

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. The risk of using an ongoing availability monitoring approach is that it may create a false sense of security. That is, availability monitoring tells a system operator that a programme's baseline is high enough that it's theoretically possible for the programme to reduce its demand by enough to meet its capacity obligations. But it doesn't actually give the system operator any real assurance that the programme will be able to reduce demand by that amount.

Therefore, in line with the approach taken in other capacity markets, Enel X is of the view that continuous availability monitoring of demand side programmes is not required. Rather, any concerns about a demand side programme's inability to meet its reserve capacity obligations are better addressed through the security, testing and penalty frameworks described above.

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[9] Demand side resources are currently only required to provide a security deposit until they pass their first capacity test, just like any other capacity.
[10] See clause 4.26.1A(a)(ii)(6)) of the WEM rules.

1.5 Consultation

Enel X discussed an earlier version of this proposal with AEMO, the PUO and members of the MAC.[11] The feedback received from those parties is summarised below.

- The PUO suggested that Enel X:
  - consider whether the rule change would address the concern that demand side resources might not be available when called upon
  - provide some analysis showing the potential impact of implementing the proposed approach on a programme's relevant demand level.
- AEMO suggested that Enel X:
  - clearly articulate how the proposal would better meet the WEM objectives than the current arrangements
  - provide evidence of whether and how this approach has worked in other markets.
- The MAC suggested that Enel X:
  - provide further information on how international capacity markets that use dynamic baselines certify capacity ahead of time
  - make a clear argument as to why the Rule Change Panel and other relevant bodies should consider this rule change as a priority.

We have sought to address these comments in this rule change proposal.

Some members of the MAC had more fundamental questions about the role of the demand side in the reserve capacity mechanism. Specifically, they raised questions about whether demand side resources should be remunerated in the same form and at the same price as other forms of capacity, and concerns that demand side resources will "flood the market" under equal pricing and make it difficult for generators to recover costs. Enel X has not sought to address these comments in this rule change proposal because the PUO made a clear statement in its final report on *Improving reserve capacity pricing signals* that demand and supply side capacity should be remunerated equivalently. Given this, Enel X does not consider it appropriate or necessary to address the aforementioned concerns in this rule change request.

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2. Explain the reason for the degree of urgency

Enel X proposes that this rule change request be considered with high urgency. As noted above, the PUO concluded that demand and supply-side capacity should be remunerated equivalently. However, reinstating equal remuneration without a consequential change to the relevant demand methodology would result in serious perverse outcomes, as explained in section 1. Without such a change, Enel X expects that the reserve capacity mechanism will continue to see inefficiently low levels of demand side capacity, to the detriment of electricity consumers in the SWIS.

Enel X recommends that this rule change request commence consideration as soon as the

[11] Enel X presented a pre-rule change proposal to the MAC on 5 February 2019.

rules to implement the recommendations in the PUO's final report are finalised.[12] Doing so would mean that the rule could come into effect in the same capacity year as the other changes to the reserve capacity mechanism. It is likely to be more efficient for AEMO to implement, and for industry to comply with, rules that relate to similar issues which come into effect all at once (as opposed to operating under one regime for a period and then another sometime after). Making a rule that addresses the issues identified above will also ensure that the benefits of broader participation by the demand side in the reserve capacity mechanism can be realised in the 2021/22 capacity year.

3. Provide any proposed specific changes to particular Market Rules

Enel X has not provided specific rule drafting for this rule change proposal.

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

Enel X expects that the changes proposed in section 1.4 would allow the Market Rules to address all of the Wholesale Market Objectives better than the status quo, for the reasons set out under each objective below.

(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;

It is well recognised that the demand side must play an increasing role in meeting the future reliability and security needs of electricity systems around the world. WA is no exception. AEMO noted the following recently:[13]

> "Historically, the predominant method to avoid involuntary load reductions during peak periods or to address unplanned generation or system outages would be to construct new peaking generation, along with the transmission and distribution necessary to accommodate peak conditions.
>
> Now, with the increase in [distributed energy resources] and the growing capability for voluntary price-responsive demand to contribute to the reliability and security of the power system, properly designed wholesale markets can increase competition and support more economically efficient system-wide asset utilisation. The net outcome of a well-designed two-way market can create significant consumer benefits – a more efficient, reliable and secure system at a lower total cost at the meter."

By accurately measuring the curtailment of a demand side programme during dispatches, the proposed rule will help to ensure that any existing or future demand side participation in the reserve capacity mechanism can contribute effectively to reliability outcomes in the WEM. It may be the case that the capacity price signals that there is no need for new capacity, or it may signal a need for new capacity. Whichever it is, Enel X's proposed rule will be robust to the changing capacity needs of the system,

[12] Enel X understands that these rules were due to be finalised by the end of April 2019 so that they are in place for the 2019 reserve capacity cycle. At the time of writing, the rules were not yet finalised.
[13] AEMO, Wholesale demand response mechanisms: Submission to AEMC consultation paper, December 2018, p. 3.

and will ensure that there are incentives for the demand side to offer capacity when it is economically efficient to do so.

The change will also give AEMO a much more accurate picture of the ability of the demand side to help meet peak demand, and thus will support the achievement of a reliable system at efficient cost. Where dynamic baselines are used, the market/system operator has a much clearer picture of how many MW will be curtailed in the event a demand side programme is dispatched. AEMO does not have this visibility under the current relevant demand calculation.

(b) *to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;*

The proposed rule will remove barriers to the efficient entry and participation of the demand side in the reserve capacity mechanism. Enabling the demand side to offer capacity alongside generation is likely to drive capacity price reductions, and thereby reduce the total cost of all capacity credits that is borne by consumers.

(c) *to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;*

Efficient markets consider all resources, regardless of technology, to achieve cost-effective supply-demand balance and reliability outcomes. In effect, the objective of markets is to minimise the cost (and maximise the surplus) of serving load and maintaining reliability. Resources in wholesale markets should therefore have comparable requirements. This will help foster competition, leading to better service and lower costs. Comparable does not necessarily mean identical, since different resources have different characteristics.[14]

As noted above, the rule changes implemented in 2016 had the effect of discriminating against the use of curtailable loads in the reserve capacity mechanism. Enel X's proposed rule, along with the restoration of equal pricing between the supply and demand sides, will ensure that demand side capacity is valued correctly and can contribute to efficient reliability outcomes in the WEM. This will remove the discrimination against the demand side that currently exists.

(d) *to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and*

As noted above, the demand side will play an increasing role in meeting the needs of the electricity systems of the future. There is significant latent demand response capability in the WEM that can be accessed at relatively low cost to help meet the reserve capacity requirement. Accessing the full potential of this capability is likely to be much more efficient than building new generation.

Greater participation by the demand side can also result in more efficient use of the grid. Flexible load curtailment during high demand periods makes capacity available when and where it is needed and reduces the need to invest in new generation or network capacity. The flow on impact of this is a minimisation of the long-term costs consumers pay for the electricity system.

[14] PJM, Demand response strategy, 28 June 2017, p. 10.

(e) *to encourage the taking of measures to manage the amount of electricity used and when it is used.*

Technological advancements and rising electricity costs have prompted many electricity users to explore ways to manage their electricity use. Exposing the demand side to prices that signal the cost of electricity consumption at different times is an effective means to incentivise more efficient electricity consumption behaviours.

However, a framework that continues to underestimate curtailment by a demand side programme goes against objective of enabling participation by technologies that are capable of doing this. Properly measuring the performance of the demand side will encourage more loads to participate in the reserve capacity mechanism, and will more explicitly expose them to price signals to reduce or shift demand to help support system reliability.

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5. Provide any identifiable costs and benefits of the change

Enel X's views on the costs and benefits of the proposed rule are set out below, as well as in the description of the proposal in section 1.4.

- Dynamic baseline methodologies more accurately calculate and value the curtailment of loads in a demand side programme. If adopted, this will incentivise greater participation by the demand side in the reserve capacity mechanism when there are efficient price signals to do so.
- Enabling the demand side to participate in the reserve capacity mechanism will give AEMO a much more accurate picture of how much demand response capability there is in the WEM, which can help with their system planning. In the delivery year, certified demand side programmes are available as a dispatchable resource, not only to deal with periods of extremely high demand, but other problems as well, such as gas supply interruptions.

  This is in contrast to customers who manage their consumption to avoid IRCR charges. Such actions tend to reduce peak demand, but AEMO cannot rely on this for planning purposes because it is unknown whether a customer will reduce its consumption during IRCR intervals just because it did so last year. Further, customers' actions to reduce IRCR charges cannot address supply or network problems unless those problems happen to coincide with likely peak demand intervals.

  Active participation by the demand side in the reserve capacity mechanism gives AEMO a predictable, dispatchable resource. However, IRCR avoidance actions will continue to be preferable for customers if the relevant demand calculation continues to value only a fraction of the curtailment they are capable of.
- Dynamic baseline methodologies strike a balance between the diverse incentives that relevant stakeholders have regarding the participation of the demand side in the WEM, which are:
  - Market Customers want the highest possible relevant demand so they can be certified for, and sell, capacity credits in relation to the flexible capacity under their control.
  - Individual curtailable loads want revenue for selling capacity credits, but also want to reduce their IRCR.
  - AEMO wants accurate, realistic relevant demand levels so it knows how much

capacity is available.

- Consumers want the most accurate, realistic relevant demand levels so that they aren't paying for capacity that isn't there.

- A dynamic baseline methodology will deliver a reliable relevant demand calculation. That is, it will more accurately represent the demand of a demand side programme during intervals in which it is dispatched.
- If the PUO's recommendation to restore equal pricing between the demand and supply sides is taken up, this rule change will bring the reserve capacity mechanism even closer to truly equal treatment and valuation of all capacity providers.
- Dynamic methodologies are not costly or complex to design or administer. There is plenty of knowledge and analysis from other markets that can be drawn upon to help make sure this is the case.

RCP | Rule Change Panel

Market Advisory Committee

Agenda Item 8(c): RC_2019_03: Method used for the assignment of Certified Reserve Capacity to Intermittent Generators

Meeting 2019_07_29

1. Background

On 31 March 2019, the Economic Regulation Authority (**ERA**) published its review of the method used for the assignment of certified reserve capacity to intermittent generators (Relevant Level Methodology). The ERA's report contained a recommendation to change the Relevant Level Methodology.

At the 30 April 2019 MAC meeting, the ERA presented and discussed its review of the Relevant Level Methodology and consulted with the MAC about its intention to develop a Rule Change Proposal to change the Relevant Level Methodology.[1]

The ERA made a further presentation regarding the changes to the Relevant Level Method to the MAC on 11 June 2019 to update the MAC on development of the Rule Change Proposal.

The ERA submitted Pre-Rule Change Proposal RC_2019_03 to the Rule Change Panel on 18 July 2019. RC_2019_03 is attached for the MAC's review and feedback to the ERA.

2. Urgency Rating

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

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

1 This satisfies the ERA's requirement under clause 2.5.1B.

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

3. Recommendation

That the MAC:

1. recommends an urgency rating for RC_2019_03 (the ERA has recommended a high urgency in the Pre-Rule Change Proposal);
2. provides feedback to the ERA regarding Pre-Rule Change Proposal RC_2019_03.

Attachments

1. RC_2019_03 – Pre-Rule Change Proposal
2. RC_2019_03 – Pre-Rule Change Proposal – Attachment 1 (track changes)
3. RC_2019_03 – Pre-Rule Change Proposal – Attachment 1 (clean copy)
4. RC_2019_03 – Pre-Rule Change Proposal – Attachment 2 (redacted)

Wholesale Electricity Market Rule Change Proposal

Rule Change Proposal ID: RC_2019_03
Date received: 18 July 2019

Change requested by:

Name:	Sara O'Connor
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Date submitted:	18 July 2018
Urgency:	*high*
Rule Change Proposal title:	Method used for the assignment of certified reserve capacity to intermittent generators
Market Rule(s) affected:	Appendix 9, clause 1.17.5, 4.9.5, 4.10.3A(a), 4.10.3B, 4.11.2, 4.11.3A, 4.11.3C, 4.11.3E, 4.28C.7, 10.5.1(f)x, and Chapter 11.

Introduction

Clause 2.5.1 of the Wholesale Electricity Market (WEM) Rules (Market Rules) provides that any person may make a Rule Change Proposal by completing a Rule Change Proposal form that must be submitted to the Rule Change Panel.

This Rule Change Proposal can be sent by:

Email to: support@rcpwa.com.au

Post to: Rule Change Panel
Attn: Executive Officer
C/o Economic Regulation Authority
PO Box 8469
PERTH BC WA 6849

The Rule Change Panel will assess the proposal and, within 5 Business Days of receiving this Rule Change Proposal form, will notify you whether the Rule Change Proposal will be further progressed.

In order for the proposal to be progressed, all fields below must be completed and the change proposal must explain how it will enable the Market Rules to better contribute to the achievement of the Wholesale Market Objectives.

The objectives of the market are:

(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;

(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;

(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;

(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and

(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

Details of the Proposed Rule Change

1. Describe the concern with the existing Market Rules that is to be addressed by the proposed rule change:

Background

To provide a reliable supply of electricity for consumers, the Wholesale Electricity Market (WEM) was designed to have sufficient capacity available to satisfy electricity demand at all times, including during supply emergencies. The reliability planning criterion of the Wholesale Electricity Market rules specifies the required amount of capacity in the South West Interconnected System (SWIS) to maintain the reliability of the system.

The Australian Energy Market Operator (AEMO) procures the required capacity two years in advance by assigning capacity credits to capacity suppliers including generator and demand side program facilities. This ensures that sufficient capacity will be available on time to meet the reliability criterion of the SWIS.

Electricity retailers fund the procurement of capacity credits based on their contribution to peak demand in the WEM. Retailers pass the cost of procuring capacity to electricity consumers through retail tariffs. If more capacity is procured than required, the SWIS will be more reliable but consumers may pay for generation capacity they do not need.

AEMO uses methods specified in the market rules to forecast the contribution of facilities to meeting the reliability planning criterion to assign capacity credits to facilities. Intermittent generators by their nature have variable, weather-dependent output. This variability must be taken into account when determining to what extent intermittent generators can be relied upon to contribute to the reliability of the system. AEMO uses the relevant level method in the market rules to determine the quantity of capacity credits allocated to intermittent generators.

As the number of intermittent generators in the SWIS continues to grow in the relatively small and isolated SWIS, the relevant level method becomes increasingly important to ensure intermittent generators receive capacity credits that reflect their contribution to reliability.

The ERA review of the relevant level method

Under the market rules, every three years the ERA reviews the relevant level method and examines if it meets the objectives of the WEM. These objectives include lowering long-term costs for electricity consumers, promoting the reliable supply of electricity, and avoiding discrimination against energy technologies, including renewable resources.

The ERA reviewed the current relevant level method and published its final report on 31 March 2019.[1] The ERA found that the current method has several shortcomings and does not provide a reasonable forecast of the capacity contribution of intermittent generators to reliability in the SWIS, and thus is not effective to meet the market objective. Increased penetration of intermittent generators in the system will likely exacerbate this problem.

Under the market rules, the ERA is also responsible for determining the value of two constant parameters that are used in the current relevant level method (parameters K and U). The ERA found that the application of these constant parameters is not conceptually correct and therefore finding values for these parameters was not reasonable. A detailed explanation of the shortcomings of the current method was presented in the ERA's final report.[2]

The ERA proposed a method for the calculation of the capacity contribution of intermittent resources based on international best practice. The proposed method is the subject of this Rule Change Proposal and the ERA is seeking to implement it as a replacement for the current relevant level method in Appendix 9 of the market rules.

2. Explain the reason for the degree of urgency:

The ERA recommends this rule change proposal be assessed with high urgency rating because:

- The current relevant level method can result in unreasonable over or under estimation of the capacity contribution of intermittent generators. An overestimation of the capacity contribution of intermittent generators can undermine the reliability of the system because sufficient capacity may not be available to meet system demand reliably. Underestimation of the capacity contribution of intermittent generators can result in procuring capacity in excess of what the system requires to meet the reliability criterion and can increase the cost of electricity supply to consumers.

- The current relevant level method does not suitably allocate capacity credits to intermittent generation facilities based on their expected capacity contribution to the reliability of the SWIS. Some facilities receive capacity credits above their expected contribution and others below their expected contribution, when compared to the results of the proposed method.

- The proposed method will increase the transparency of the calculation of the capacity contribution of intermittent resources. Stakeholders can use the proposed method to replicate AEMO's calculation of capacity credits. Unlike the current method, the proposed method does not rely on constant parameters whose purpose and calculation are not defined in the market rules.

- There are other changes to the reserve capacity mechanism under consideration at the current time as part of the market reform program. Those changes and this rule change

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1 ERA, 2019, *Relevant level method review 2018, Capacity valuation for intermittent generators*, Final report, (online).

2 Ibid.

proposal should be considered together to ensure an optimal and transparent outcome for market participants.

3. Provide any proposed specific changes to particular Market Rules: *(for clarity, please use the current wording of the rules and place a ~~strikethrough~~ where words are deleted and underline words added)*

Refer to attachment 1.

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

(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system.

The proposed changes to the relevant level method will increase the economic efficiency and reliability of the SWIS. The proposed changes will provide a more reliable forecast of the capacity contribution of intermittent generators in the SWIS than the current method and this will avoid over or under procurement of capacity due to the use of the current relevant level method. An over procurement of capacity above what is required can increase the cost of electricity supply to electricity consumers and lower the economic efficiency of the SWIS and the economy in Western Australia. Electricity consumers may pay for the procurement of capacity that they do not require. The capital expenditure in excess capacity could be spent elsewhere in the economy to meet consumers' need.

(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors.

The proposed relevant level method is transparent and technology neutral. Market participants and new entrants to the system can replicate the method and assess the contribution of their capacity to the reliability of the SWIS and forecast the number of Certified Reserve Capacity they can receive.

In comparison, the current relevant level method is not transparent; it uses constant parameters in the calculation, the purpose and calculation of which is not defined under the market rules. Market participants and new entrants to the SWIS cannot determine the value of these parameters.

(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions.

The proposed method is technology neutral and does not discriminate against any supply technology. The basis of calculation is measuring contribution to meet the dominant reliability planning criterion in the market rules. The method can suitably be used to determine the capacity contribution of existing technologies such as biogas, solar, and wind generators, and emerging technologies such as storage.

The current relevant level method is not technology neutral. For instance, it does not account for the capacity contribution of facilities that shift the periods with high reliability risk from peak demand periods to other periods when the surplus of capacity in the system is lowest. The current relevant level method cannot also be used to assess the capacity contribution of storage and scheduled generator facilities.

(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system.

The proposed method will provide a more reliable forecast of the capacity contribution of intermittent resources than the current relevant level method. A more reliable forecast of the capacity contribution of intermittent resources will lower the long-term cost of electricity supply to customers. An overestimation of the capacity contribution of resources may result in under procuring capacity required to meet the reliability target of the SWIS. Insufficient capacity procured can result in frequent use of high cost emergency reserves in the system or disconnection of customers, which both increase the long-term cost of electricity supply to consumers.

(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

The proposed method will not affect this market objective.

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

The ERA sought AEMO's advice on its expected cost of implementing the proposed method. AEMO stated that its expected cost of implementing changes to the current relevant level method for incorporating Collgar Wind Farm's rule change proposal (RC_2018_03)[3] was approximately $170,000.

In its rule change proposal, Collgar proposed basing the calculation of Relevant Level for intermittent generators on sent out generation of facilities during peak demand periods, rather than the periods when load net of the sent out generation of intermittent generators was the largest. In comparison to the changes proposed by the ERA, Collgar's proposal required slight changes to the current relevant level method and did not contain any fundamental changes.

The proposed changes to the relevant level method in this proposal, however, are extensive. AEMO will need to review the proposed changes to the market rules and automate the calculation. The proposed relevant level method cannot be run manually and needs an automated calculation program. The program should also be connected to AEMO's Information Technology systems to ensure input data can be suitably processed.

These changes suggest that the cost of implementing the proposed relevant level method can be higher than that estimated by AEMO for implementing Collgar's proposed changes.

In its submission to the ERA's draft decision for AEMO Allowable Revenue and Forecast Capital Expenditure 2019/20 to 2021/22, AEMO provided an internal project sizing method for the development and implementation of business-as-usual rule changes.[4] AEMO categorised these projects into four levels and estimated upper bounds for the cost of each category. The ERA expects the implementation of the proposed relevant level method falls into either a medium or large project category:

- Medium projects have typical cost below $500,000, with some impact, complexity or risk, and may involve three or more divisions within AEMO.

[3] Rule Change Panel, 2018, *Capacity Credit Allocation Methodology for Intermittent Generators*, (online).

[4] AEMO's submission to *Australian Energy Market Operator Allowable Revenue and Forecast Capital Expenditure 2019/20 to 2021/2022, Draft decision*, May 2019, p. 19, (online).

- Large projects have typical cost above $500,000 (but less than $2.5 million), that may have impact on market(s) or participants, and/or on AEMO's reputation. These projects involve multiple stakeholder groups and are complex and contain significant risks.

AEMO included a forecast capital expenditure of $1.42 million to accommodate known business-as-usual rule changes that may need to be delivered during the fifth allowable revenue period but were undefined at the time of submitting its allowable revenue to the ERA for review in May 2019.

The ERA has provided a pseudocode to create the reliability model used in the proposed method (refer to attachment 1). This is to avoid some of the model development costs for AEMO and to facilitate the interpretation of proposed changes and the assessment of the proposed changes. Market participants can also use the pseudocode to replicate the reliability model used.

To assist stakeholders in assessing the proposed changes the ERA also provides the results of the model in the form of sensitivity analyses in attachment 2.

Attachment 1: proposed specific changes to particular Market Rules

Appendix 9: Relevant Level Determination

This Appendix presents the ~~methodology~~method for determining the Relevant Levels for Facilities that have applied for certification of Reserve Capacity under clause 4.11.2(b) for a given Reserve Capacity Cycle (“Candidate Facility”).

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

- the full operation date of a Candidate Facility for the Reserve Capacity Cycle (“Full Operation Date”) is:
  - the date provided under clause 4.10.1(c)(iii)(7) or revised in accordance with clause 4.27.11A, where at the time the application for certification of Reserve Capacity is made the Facility, or part of the Facility (as applicable) is yet to enter service; or
  - the date most recently provided for a Reserve Capacity Cycle under clause 4.10.1(k) otherwise; and
- a Candidate Facility will be considered to be:
  - a new ~~candidate~~Candidate Facility, if the ~~five year~~ period identified in ~~step 1(a)~~Step 1(a)Step 1(a) of this Appendix commenced before 8:00 AM on the Full Operation Date for the Facility (“New Candidate Facility”); or
  - an existing Candidate Facility (“Existing Candidate Facility”), otherwise.
- each Candidate Facility will be assigned to one of the “Biogas Technology Class”, “Solar Technology Class” or “Wind Technology Class”, based on the generation technology of that Candidate Facility, as determined by AEMO based on the information received under clause 4.10.1(dA) or clause 2.33.3.
- AEMO may decide to identify a new Technology Class (other than Biogas Technology Class, Solar Technology Class and Wind Technology Class) and assign any Candidate Facility to that new Technology Class, if AEMO has cause to believe that the assignment of a Candidate Facility to any other Technology Class than the new Technology Class can contribute to a material underestimation or overestimation of the Relevant Level for that Candidate Facility or other Candidate Facilities that have applied for the certification of Reserve Capacity under clause 4.11.2(b).

- The available capacity of a Candidate Facility for a Trading Interval is the amount of capacity available to be sent out (in MW) and is not subject to a Planned Outage or Forced Outage ("Available Sent Out Capacity").

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

Determining ~~Existing Facility~~System Load and Load for Scheduled Generation

Explanation

The proposed method uses a sample of seven years for the calculation. It is also possible to use a larger sample of 10 years to dampen the variability of results between years. Using a larger sample, however, may increase the cost of producing estimated data for the Available Sent Out Capacity of new or upgraded facilities.

Step 1. ~~Step 1:~~ Identify~~:~~,

(a) ~~(a)~~ the ~~five~~seven year period ending at 8:00 AM on 1 April of Capacity Year 1 of the relevant Reserve Capacity Cycle; and

(b) ~~(b)~~ any 12 month period, from 1 April to 31 March, occurring during the ~~five~~seven year period identified in ~~step 1(a), where the 12 Trading Intervals with the highest Existing Facility Load for Scheduled Generation in that 12 month period have not previously been determined under this Appendix 9; and~~Step 1(a)Step 1(a).

~~(c) any 12 month period, from 1 April to 31 March, occurring during the five year period identified in step 1(a), where the 12 Trading Intervals with the highest Existing Facility Load for Scheduled Generation in that 12 month period have previously been determined under this Appendix 9.~~

Step 2. ~~Step 2:~~ Determine:

(a) the quantity of electricity (in MWh) sent out by ~~each~~the Candidate Facility using Meter Data Submissions for each Candidate Facility and for each of the Trading Intervals in the period identified in ~~step~~ Step 1(b)Step 1(b) ("Sent Out Generation"); and

for each New Candidate Facility, for each Trading Interval in the period identified in Step 1(b)Step 1(b) that falls before 8:00 AM on the Full Operation Date for the Facility, an estimate of the quantity of Available Sent Out Capacity (in MW), that would have been available by the Facility in the Trading Interval, if it had been in operation with the configuration proposed under clause 4.10.1(~~b).~~

(b) ~~Step~~ dA) in the relevant application for certification of Reserve Capacity. The estimates must reflect the estimates in the expert report provided for the Facility under clause 4.10.3~~:~~, unless AEMO reasonably considers the estimates in the expert report to be inaccurate.

~~Step 2.~~Step 3. For each Candidate Facility, identify any Trading Intervals in the period identified in ~~step 1(b)~~Step 1(b)Step 1(b) where:

(a) ~~(a)~~ the Facility, other than a Facility in the Balancing Portfolio, was directed to restrict its output under a Dispatch Instruction as provided in a schedule under clause 7.13.1(c); or

(b) ~~(b)~~ the Facility, if in the Balancing Portfolio, was instructed by System Management to deviate from its Dispatch Plan or change its commitment or output as provided in a schedule under clause 7.13.1C(d); or

(c) ~~(c)~~ the Facility was affected by a Consequential Outage as notified by System Management to AEMO under clause 7.13.1A.

~~Step 3.~~Step 4. ~~Step 4:~~For each Candidate Facility and Trading Interval identified in ~~step 3(a):~~Step 3(a)Step 3(a):

(a) ~~(a) identify~~ the ~~actual~~Sent Out Generation is equal to the Sent Out Generation quantity ~~as~~ determined in ~~step 2~~Step 2(a)Step 2(a) if:

i ~~i.~~ System Management has made a revised estimate of the maximum quantity in accordance with clause 7.7.5A(c) and the Power System Operation Procedure; and

ii ~~ii.~~ the revised estimate of the maximum quantity is lower than the ~~actual~~Actual Sent Out Generation quantity as determined in ~~step 2;~~Step 2(a)Step 2(a);

(b) ~~(b) identify~~ the ~~actual~~Sent Out Generation is equal to the Sent Out Generation quantity ~~as~~ determined in ~~step 2~~Step 2(a)Step 2(a) if:

~~i.~~ ~~step 4(a)~~i. Step 4(a)Step 4(a) does not apply; and

ii. the estimated maximum quantity determined by System Management under clause 7.13.1(eF) is lower than the ~~actual~~Sent Out Generation quantity (as specified in a Meter Data Submission covering the Facility and the Trading Interval);~~ and~~

~~(c) if steps 4(a) and (b) do not apply:~~

(c) if Step 4Step 4Step 4(a)Step 4(a) and Step 4(b)Step 4(b) do not apply, the Sent Out Generation is:

i. ~~identify~~ the revised estimate of the maximum quantity determined by System Management in accordance with the Power System Operation Procedure specified in clause 7.7.5A; or

ii. ~~if there is no revised estimate, identify~~ the estimate determined by System Management under clause 7.13.1(eF~~).~~), if there is no revised estimate.

~~Step 4.~~Step 5. ~~Step 5:~~For each Candidate Facility and Trading Interval identified in ~~step 3(b)~~Step 3(b)Step 3(b) use:

(a) ~~(a)~~ the estimate recorded by System Management under clause 7.13.1C(e); and

(b) ~~(b)~~ the quantity determined for the Facility and Trading Interval in ~~step 2,~~Step 2(a)Step 2(a),

to estimate the quantity of energy (in MWh) that would have been sent out by the Facility had it not complied with System Management's instruction to change its commitment or output during the Trading Interval. Identify this estimated quantity as the Sent Out Generation of the Candidate Facility for the Trading Interval.

~~Step 5.~~Step 6. ~~Step 6:~~ For each Candidate Facility and Trading Interval identified in ~~step 3(c)~~Step 3(c)Step 3(c) use:

(a) ~~(a)~~ the schedule of Consequential Outages determined by System Management under clause 7.13.1A;

(b) ~~(b)~~ the quantity determined for the Facility and Trading Interval in ~~step 2;~~Step 2(a)Step 2(a); and

(c) ~~(c)~~ the information recorded by System Management under clause 7.13.1C(a),

to estimate the quantity of energy (in MWh) that would have been sent out by the Facility had it not been affected by the notified Consequential Outage during the Trading Interval. Identify this estimated quantity as the Sent Out Generation of the Candidate Facility for the Trading Interval.

Step 7. For any Trading Interval in the period identified in Step 1(b)Step 1(b) that falls after and including 8:00 AM on the Full Operation Date of a Candidate Facility AEMO must use a half of the Available Sent Out Capacity of the Facility, provided in the expert report for the Facility under clause 4.10.3A where available, as the Sent Out Generation of the Facility, if:

(a) AEMO reasonably believes that the quantity of electricity sent out determined by Meter Data Submissions in Step 2(a), or estimated in Step 4Step 4, Step 5Step 5 or Step 6Step 6 as applicable, when multiplied by two to convert to units of MW, does not reasonably reflect Available Sent Out Capacity of ~~Step 7: Determine for~~the ~~each~~ Facility for that Trading Interval~~Trading Interval in each 12 month period identified in step 1(b)~~ ; and

(b) the ~~Existing~~ Facility ~~Load for Scheduled~~had a greater estimated Available Sent Out Capacity than twice the Sent Out Generation ~~(~~of the Facility determined in ~~MWh)~~Step 2(a)Step 2(a) or estimated in Step 4Step 4, Step 5Step 5 or Step 6Step 6 as~~:~~ applicable, for that Trading Interval, unless AEMO reasonably considers the estimates in the expert report provided for the Facility under clause 4.10.3, to be inaccurate.

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

Step 8. Determine for each Trading Interval in the period identified in Step 1(a)Step 1(a):

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

$$(Total\_Generation + DSP\_Reduction + Interruptible\_Reduction + Involuntary\_Reduction) \times 2$$

where

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

DSP_Reduction is the total quantity (in MWh) by which all Demand Side Programmes reduced their consumption in response to a Dispatch Instruction, as determined under clause 6.17.6(c)(i);

Interruptible_Reduction is the total quantity (in MWh) by which all Interruptible Loads reduced their consumption in accordance with the terms of an Ancillary Service Contract, as recorded by System Management under clause 7.13.1C(c);

Involuntary_Reduction is the total quantity of energy (in MWh) not served due to involuntary load shedding (manual and automatic), as recorded by System Management under clause 7.13.1C(b~~); and~~).

(b) for each Technology Class c, the CF_Generation ~~is the total sent out generation of all~~ (c) as,

$$\sum_{f \in c} (Actual\_CF\_Generation(f) + Estimated\_CF\_Generation(f))$$

where, the operator $\sum_{f \in c}()$ represents a summation across all facilities f in the Technology Class c.

For Existing Candidate Facilities~~, as determined in step 2 or estimated in steps 4, 5 or 6 as applicable.~~:

~~Step 8: Determine for each 12 month period identified in step 1(b) the 12 Trading Intervals, occurring on separate Trading Days, with the highest Existing Facility Load for Scheduled Generation.~~

~~Step 9: Identify, for each 12 month period identified in step 1(c), the following:~~

~~(a) the Existing Facility Load for Scheduled Generation previously determined under this Appendix 9 for each Trading Interval in the 12 month period;~~

~~(b) subject to step 9A, the sent out generation (in MWh) for each Candidate Facility and for each Trading Interval in that 12 month period, where that~~

~~sent out generation was used to determine the CF_Generation (which is one of the variables used to determine the Existing Facility Load for Scheduled Generation in step 7) for that Trading Interval; and~~

~~(c) the 12 Trading Intervals occurring on separate Trading Days that were previously determined to have the highest Existing Facility Load for Scheduled Generation in the 12 month period.~~

~~Step 9A: For the purposes of step 9(b), if:~~

~~(a) System Management has determined a revised estimate of the maximum quantity in accordance with the Power System Operation Procedure specified in clause 7.7.5A;~~

~~(b) the revised estimate relates to a Candidate Facility and a Trading Interval in a 12 month period identified in step 1(c); and~~

~~(c) AEMO determined the sent out generation for that Candidate Facility and for that Trading Interval in accordance with step 4 before it revised the estimate,~~

~~then AEMO must redetermine the sent out generation for that Candidate Facility and that Trading Interval in accordance with step 4.~~

~~***Determining New Facility Load for Scheduled Generation***~~

~~Step 10: For each New Candidate Facility determine, for each Trading Interval in the period identified in step 1(a) that falls before 8:00AM on the Full Operation Date for the Facility, an estimate of the quantity of energy (in MWh) that would have been sent out by the Facility in the Trading Interval, if it had been in operation with the configuration proposed under clause 4.10.1(dA) in the relevant application for certification of Reserve Capacity. The estimates must reflect the estimates in the expert report provided for the Facility under clause 4.10.3, unless AEMO reasonably considers the estimates in the expert report to be inaccurate.~~

~~Step11: For each New Candidate Facility determine, for each Trading Interval in the period identified in step 1(a), the New Facility Load for Scheduled Generation (in MWh) as:~~

~~(a) if the Trading Interval falls before 8:00 AM on the Full Operation Date for the Facility:~~

- ~~EFLSG + Actual_CF_Generation –~~ the Actual_CF_Generation(f) for the Trading Interval is the Sent Out Generation determined in Step 2(a)Step 2(a) or estimated in Step 4Step 4, Step 5Step 5, Step 6Step 6, or Step 7Step 7 as applicable, and

- the Estimated_CF_Generation is zero, and

~~where~~

~~EFLSG is the Existing Facility Load for Scheduled Generation for the Trading Interval, determined in step 7 or identified in step 9(a) as applicable;~~

for New Candidate Facilities:

- the Actual_CF_Generation ~~is~~ , for the Trading Intervals falling after and including 8:00 AM on the ~~sent out generation of the New Candidate Facility for the Trading Interval, as identified in step 9(b),~~ Full Operation Date for the Facility, is the Sent Out Generation determined in step 2(a) or estimated in ~~steps 4, 5 or 6 as applicable; and~~Step 4Step 4, Step 5Step 5, Step 6Step 6, or Step 7Step 7 as applicable, and zero otherwise; and
- the Estimated_CF_Generation ~~is~~, for the Trading Intervals falling before 8:00 AM on the Full Operation Date for the Facility, is half of the quantity determined for the New Candidate Facility and the Trading Interval in ~~step 10;~~ 0Step 2(b), and zero otherwise.

~~or~~

~~(d)~~(c) ~~(b)~~ the ~~Existing Facility~~ Load for Scheduled Generation ~~for the Trading Interval, otherwise.~~(in MW) as:

~~Step 12: For each New Candidate Facility determine,~~$System\ Demand - \sum_c CF\_Generation(c) \times 2$

where the expression $\sum_c CF\_Generation(c) \times 2$ represents the sum of CF_Generation(c) calculated in step 7(b) across all Technology Classes c, multiplied by 2 to convert to units of MW.

~~Step 6.~~Step 9. Determine, for each 12 month period identified in ~~step 1(a),~~Step 1(b)Step 1(b), the 12 Trading Intervals~~,~~ occurring on separate Trading Days~~, with the highest New Facility Load for Scheduled Generation.~~ with:

(a) ~~***Determining the Facility Average Performance***~~the highest Load for Scheduled Generation;

(b) the highest System Demand.

Calculation of Relevant Level scenarios

~~Step 13: For each Existing Candidate Facility, determine the 60 quantities comprising:~~

~~(a) the MWh quantities determined in step 2 or estimated in steps 4, 5 or 6 as applicable for each of the Trading Intervals determined in step 8, multiplied by 2 to convert to units of MW; and~~

~~(b) the MWh quantities determined in step 9(b) for each of the Trading Intervals identified in step 9(c), multiplied by 2 to convert to units of MW.~~

~~Step 14: For each New Candidate Facility, determine the 60 quantities comprising:~~

~~(a) the MWh quantities identified in step 9(b), determined in step 2 or estimated in steps 4, 5 or 6 as applicable for each of the Trading Intervals identified in step 12 that fall after 8:00 AM on the Full Operation Date for the Facility, multiplied by 2 to convert to units of MW; and~~

~~(b) the MWh quantities determined in step 10 for each of the Trading Intervals identified in step 12 that fall before 8:00 AM on the Full Operation Date of the Facility, multiplied by 2 to convert to units of MW.~~

~~Step 15: Determine the average performance level (in MW) for each Candidate Facility f ("Facility Average Performance Level") as the mean of the 60 quantities determined for Facility f in step 13 or step 14 as applicable.~~

~~***Determine the Facility Adjustment Factor***~~

~~Step 16: Determine the variance (in MW) for each Candidate Facility f ("Facility Variance") as the variance of the MW quantities determined for Facility f in step 13 or step 14 as applicable.~~

~~Step 17: Determine the facility adjustment factor (in MW) for each Candidate Facility f ("Facility Adjustment Factor") in accordance with the following formula:~~

~~Facility Adjustment Factor = min(G x Facility Variance (f), Facility Average Performance Level (f) / 3 + K x Facility Variance (f))~~

~~Where~~

~~G = K + U / Facility Average Performance Level (f)~~

~~K is determined in accordance with the following table:~~

Step 10. Determine:

(a) for each 12 month period identified in Step 1(b)Step 1(b) as the Relevant_Period, the Annual_Relevant_Level_Candidate_Facilities_Fleet (in MW) using the calculation in Step 8Step 18, and the corresponding Net_Demand data defined in Table 1; and

(b) for the period identified in Step 1(a)Step 1(a), as the Relevant_Period, the Full_Period_Relevant_Level_Candidate_Facilities_Fleet (in MW) using the calculation in Step 8Step 18, and the corresponding Net_Demand data defined in Table 1.

Step 11. Select:

(a) the Relevant_Level_Candidate_Facilities_Fleet as the smaller of

- the Full_Period_Relevant_Level_Candidate_Facilities_Fleet estimated in Step 9(b)Step 10(b)Step 10(b), and

- the median of the Annual_Relevant_Level_Candidate_Facilities_Fleet determined in Step 10(a)Step 10(a), and

record the Relevant_Period corresponding to the Relevant Level scenario selected in this step as Selected_Period, and

(b) determine for each Technology Class c the Technology_Class_Relevant_Level(c), using the calculation in Step 8Step 18 and corresponding Net_Demand data and Relevant_Period defined in Table 1.

Table 1. Relevant Level scenario and corresponding variables

~~**Reserve Capacity Cycle**~~	~~**Capacity Year**~~		~~**K value**~~
~~2012~~	~~2014/15~~		~~0.001~~
~~2013~~	~~2015/16~~		~~0.002~~
~~2014~~Relevant Level scenario	Facility_Group	~~2016/17~~Net_Demand data, used in step 17(b)	~~0.003~~Relevant_Period
Annual_Relevant_Level_Candidate_Facilities_Fleet	all Candidate Facilities	Load for Scheduled Generators rounded to the nearest integer	each 12 month period identified in 0Step 1(b)Step 1(b).
Full_Period_Relevant_Level_Candidate_Facilities_Fleet	all Candidate Facilities	Load for Scheduled Generators rounded to the nearest integer	entire period identified in Step 1(a)Step 1(a)
~~2015 onwards~~Technology_Class_Relevant_Level (c)	~~From 2017/18 onwards~~all Facilities in the Technology Class c	System Demand – 2 × $CF\_Generation(c)$ rounded to the nearest integer	~~To be~~Selected_Period as determined ~~by the Economic Regulation Authority~~ in ~~accordance with clause 4.11.3C.~~Step 11(a)Step 11(a)

(a) determine the Solar_Wind_Interaction_Effect as:

$$Relevant\_Level\_Candidate\_Facilities\_Fleet - \sum_c Technology\_Class\_Relevant\_Level(c)$$

where the expression $\sum_c Technology\_Class\_Relevant\_Level(c)$ represents the sum of all Technology_Class_Relevant_Level(c) for all Technology Classes estimated in Step 10(b)Step 11(b)Step 11(b);

(b) determine the $Adjusted\_Technology\_Class\_Relevant\_Level(c)$ for each Technology Class c, comprising the Solar Technology Class and Wind Technology Class as:

$$Technology\_Class\_Relevant\_Level(c) + \frac{Technology\_Class\_Relevant\_Level(c)}{\sum_c Technology\_Class\_Relevant\_Level(c)} \times Solar\_Wind\_Interaction\_Effect$$

where the Technology_Class_Relevant_Level(c) is determined in Step 10(b)Step 10(b).

The Adjusted_Technology_Class_Relevant_Level(c) for the Biogas Technology Class and any New Technology Class determined by AEMO, is respectively equal to the Technology_Class_Relevant_Level (Biogas Technology Class) and Technology_Class_Relevant_Level (New Technology Class) determined in Step 11(b)Step 11(b).

Allocation of Technology Class Relevant Level to individual Candidate Facilities

Step 2. For each Candidate Facility f within a Technology Class c:

(a) determine the quantities of

$$Actual\_CF\_Generation(f) + Estimated\_CF\_Generation(f)$$

as calculated in Step 8(b)Step 8(b), during the Trading Intervals identified in Step 9(a)Step 9(a) and Step 9(b)Step 9(b), multiplied by 2 to convert to units of MW, and

(b) determine the Facility_Average_Performance_Level(f) as the mean of the quantities determined for Facility f in Step 2(a)Step 12(a).

Step 3. For each Technology Class c determine the Scaling_Factor(c) as:

$$\frac{Adjusted\_Technology\_Class\_Relevant\_Level(c)}{\sum_{f\in c} Facility\_Average\_Performance\_Level(f)}$$

where the denominator represents the sum of Facility_Average_Performance_Level for all Facilities f in the Technology Class c.

Step 4. Determine for each Facility f in the Technology Class c the Relevant Level (in MW) as:

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

Calculation of Capacity Outage Probability Table

Step 5. Identify:

(a) all Scheduled Generators and Demand Side Programme Facilities that will receive Certified Reserve Capacity for the Capacity Year 3 of the relevant Reserve Capacity Cycle, using the method in clause 4.11;

(b) the quantity of Certified Reserve Capacity to be assigned to Scheduled Generators and Demand Side Programme Facilities identified in Step 5(a)Step 15(a) for the Capacity Year 3 of the relevant Reserve Capacity Cycle;

(c) the Forced Outage Rate, estimated using Power System Operation Procedure: Facility Outages (for the purpose of clause 4.11.1(h)), for each Scheduled Generator Facility identified in Step 5(a)Step 15(a), for the Relevant Reserve Capacity Cycle and the two preceding Reserve Capacity Cycles to the Relevant Reserve Capacity Cycle. For each Facility identified in Step 5(a)Step 15(a) set the parameter U as the average of the three Forced Outage Rates for the three Reserve Capacity Cycles identified in this clause for the Facility; and

~~(a)~~(d) the Forced Outage Rate for Demand Side Programme Facilities, identified in Step 5(a)Step 15(a), as zero.

Explanation

Step 16 explains how a capacity outage probability table must be calculated. The capacity outage probability table is a table of possible outage amounts for the fleet of Scheduled Generators and Demand Side Programme Facilities.

The table has two columns: the first column lists possible outage amounts X from zero MW to total installed capacity of fleet of Scheduled Generators and Demand Side Programme Facilities, with an increment of one MW. The second column lists the probability of having an outage greater than or equal to the amount X in respective rows (cumulative probability of an outage amount X, or P(X)).

Each outage amount X can result from numerous combinations of plants on outage and the calculation in Step 16 provides a method for calculation of the cumulative probability of an outage X. Although simple in concept, the method uses loops to determine the table, which can be difficult to understand without examples to show its application.

There are two options for defining this step:

- Option 1: define the calculation of the table in Step 16, as written in this rule change proposal.
- Option 2: simplify Step 16 as below:

  Step 16: Using Forced Outage Rates and Certified Reserve Capacities identified in Step 15(b) to Step 15(d), AEMO must determine a table of capacity outage amounts X (in MW) and respective cumulative probability of that outage amount, P(X), for any outage amount from zero MW to the sum of Certified Reserve Capacity amounts assigned to Scheduled Generator and Demand Side Programme Facilities identified in Step 15(a) ("Capacity Outage Probability Table").

If option 2 is preferred, the ERA can publish a guideline including the pseudocode for the calculation of capacity outage probability table, to increase the transparency of the proposed relevant level method.

Step 6. Determine a table of capacity outage amounts X (in MW) and respective cumulative probability of that outage amount by incrementally adding the capacity of all Scheduled Generator and Demand Side Programme Facilities identified in Step 4Step 5Step 15 to that table as explained below:

(a) For each Scheduled Generator and Demand Side Programme Facility G with the Certified Reserve Capacity C, rounded to the nearest integer, and Forced Outage Rate U identified in Step 5Step 15,

while P(X) is greater than zero, for each outage amount X (in MW) from zero with increment of 1 MW, determine P(X) as:

$$P(X) = (1 - U) \times P'(X) + U \times P'(X - C)$$

where,

P(X) is the cumulative probability of the capacity outage of X MW after adding the Facility G to the table.

P'(X) is the cumulative probability of the capacity outage of X MW before adding the Facility G. P'(X)=1.0 if X is less than or equal to zero. For the first Facility G added to the table, P'(X)=0 if X is greater than zero.

(b) Identify the capacity outage probability table as a table listing all outage amounts X from zero to the total Certified Reserve Capacity of Scheduled Generator and Demand Side Programme Facilities identified in Step 5(a)Step 15(a), and corresponding P(X) after adding the last Facility in Step 6(a)Step 16(a) ("Capacity Outage Probability Table").

Calculation of Loss of Load Probability and Loss of Load Expectation

Step 7. Determine:

(a) the loss of load probability for a Trading Interval with a system load of D MW as ("Loss of Load Probability"):

$$P(CC - D)$$

where

CC is the total Certified Reserve Capacities assigned to Scheduled Generators and Demand Side Programme Facilities identified in Step 5(b)Step 15(b);

P(CC – D) is the cumulative probability of an outage of X=CC – D MW that is derived from the Capacity Outage Probability Table calculated in Step 6Step 16; and

(b) the loss of load expectation during a Relevant_Period as the sum of the Loss of Load Probability, as determined in Step 7(a)Step 17(a), for each Trading Interval in that Relevant_Period ("Loss of Load Expectation").

Calculation of the Relevant Level

Step 8. Determine the Relevant Level of a Facility_Group during a Relevant_Period using the steps below:

(a) Calculate the Loss of Load Expectation in the SWIS using the calculation in Step 7(b)Step 17(b) and the System Demand determined in Step 8(a)Step 8(a), rounded to the nearest integer, as system load during the Relevant_Period.

(b) Calculate the Loss of Load Expectation in the SWIS using the calculation in Step 7(b)Step 17(b) and the Net_Load data identified in Table 1 corresponding to the Facility_Group, as system load during the Relevant_Period.

(c) Increase the Net_Load data in Step 8(b)Step 18(b), with increments of whole MW and fixed across all Trading Intervals in the Relevant_Period, and repeat the calculation in Step 8(b)Step 18(b) with the increased Net_Load data.

(d) Repeat Step 8(c)Step 18(c) until the Loss of Load Expectation calculated in Step 8(c)Step 18(c) is equal or closest to that in Step 8(a)Step 18(a).

The Relevant Level of the Facility_Group during the Relevant_Period is the total increase in Net_Load (in MW) identified in Step 8(c)Step 18(c) that makes the Loss of Load Expectation calculated in Step 8(c)Step 18(c) equal or closest to that calculated in Step 8(a)Step 18(a).

Publication of information

~~Step 19:~~ Publish on the Market Web Site by 1 June of Year 1 of the relevant Reserve Capacity Cycle ~~on~~ a provisional ~~basis:~~

~~Step 2.~~Step 9. ~~(a) a~~ forecast of the Trading Intervals that may be identified in ~~step 8; and~~Step 9Step 9.

~~(b) a forecast of the Existing Facility Load for Scheduled Generation quantities that may be determined in step 7.~~

~~Step 3.~~Step 10. ~~Step 20:~~ Publish on the Market Web Site within three Business Days after the date specified in clause 4.1.11 (as modified or extended) for the relevant Reserve Capacity Cycle:

~~(a) the Trading Intervals identified in step 8; and~~

(a) ~~(b) the Existing Facility~~the System Demand calculated in Step 8(c)Step 8(a)Step 8(a) determined for each Trading Interval in the period identified in Step 1(a)Step 1(a);

~~(a)~~(b) the Load for Scheduled Generation ~~quantities determined in step 7.~~calculated in Step 8(c)Step 8(c) determined for each Trading Interval in the period identified in Step 1(a)Step 1(a);

(c) the Capacity Outage Probability Table calculated in Step 6Step 16.

(d) the Annual_Relevant_Level_Candidate_Facilities_Fleet determined in Step 10(a)Step 10(a);

(e) the Full_Period_Relevant_Level_Candidate_Facilities_Fleet estimated in Step 10(b)Step 10(b);

(f) for each Technology Class c the Technology_Class_Relevant_Level(c) calculated in Step 10(b)Step 11(b)Step 11(b); and

(g) the amount of CF_Generation(c) in Step 8(b) for Biogas Technology Class, Solar Technology Class, Wind Technology Class and any New Technology Class identified by AMEO under the Relevant Level Method.

Changes to Chapter 11 (Glossary)

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

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

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

Load for Scheduled Generation: is an estimate of System Demand to be met by Scheduled Generators expressed in MW, as determined for a Trading Interval under Step 8(c) of the Relevant Level Method.

System Demand: is an estimate of the total amount of electricity demand in the SWIS in MW over a Trading Interval that should have been supplied through the transmission grid if no load was reduced or disconnected by AEMO, as calculated in Step 8(a) of the relevant level method.

Changes to other market rules

Replace all references to the Relevant Level Methodology with Relevant Level Method.

Clause 1.17.5 is no longer required and can be removed.

Changes to clause 4.11.2

The market rules allows an applicant to nominate under clause 4.10.1(i) to have AEMO use the relevant level method to apply to a Scheduled Generator or Non-Scheduled Generator.

The current relevant level method is not suitable for calculating the capacity contribution of Scheduled Generators, because it uses the observed sent out generation of Facilities to determine their capacity contribution. The observed sent out generation of Scheduled Generators is not a suitable proxy for their available capacity.

The proposed changes to the relevant level method accounts for the available sent out capacity of resources and can provide a reasonable estimate for the capacity contribution of Scheduled Generators or any other capacity resource. However, the proposed relevant level method when applied to a Scheduled Generator will provide fairly similar results to the method specified in clause 4.11.1 of the market rules.

Clause 4.11.1 of the market rules already provides a simple method for the calculation of the capacity contribution of Scheduled Generators. The calculation of the capacity contribution of a Scheduled Generator using the relevant level method may increase the computation burden for AEMO and increase AEMO's administration costs. Changes to clause 4.11.2 allow AEMO to reject a Scheduled Generators' nomination for using the relevant level method, if AEMO reasonably believes that clause 4.11.1 can provide a reasonable capacity value for that Scheduled Generator.

Arrangements for dampening variation in results

Changes to this clause also specify that AEMO must assign a Relevant Level to facilities based on a three-year moving average. This will dampen possible variations between the results of the proposed relevant level method and provide a glide path for changes to the relevant level method.

As discussed in the ERA's relevant level method review report, the capacity value of intermittent generators varies substantially from year to year. This variation creates a high level of uncertainty for the forecasts generated by the relevant level method. The ERA used several measures to suitably address the uncertainty and dampen the variation in results:

- The proposed changes use a larger sample of seven years for the calculation (in compare to five-year sample in the current method).
- The proposed changes also use the median of capacity value results determined for each year in the seven year period. Use of median ensures that results will not be biased towards extremely large or small values in the seven-year sample. The median is also capped by the capacity value of the fleet of intermittent generators based on the full seven-year period sample result.
- The use of three-year moving average, specified in clause 4.11.2(c) also ensures that results will not vary drastically between years and in the medium to long term trend towards the capacity value of intermittent generation fleet estimated using the reliability model implemented in the proposed changes.
- The development of the reliability model used in the proposed method, i.e. the Capacity Outage Probability Table, uses an average of forced outage rates for Scheduled Generators in the previous three years.

4.11.2. Where an applicant submits an application for Certified Reserve Capacity, in accordance with clause 4.10, and nominates under clause 4.10.1(i) to have AEMO use the method~~ology~~ described in clause 4.11.2(b) to apply to a Scheduled Generator or a Non-Scheduled Generator, AEMO:

(a) may reject the nomination to use the method described in clause 4.11.2(b) to apply to a Scheduled Generator if AEMO reasonably believes that:

i. ~~- AEMO reasonably believes that~~ the capacity of the Facility has permanently declined, or is anticipated to permanently decline prior to or during the Reserve Capacity Cycle to which the Certified Reserve Capacity relates; or

ii. the method described in clause 4.11.1(a) provides a reasonable value for the Certified Reserve Capacity or Conditional Certified Reserve Capacity to be assigned to the Facility.

(aA) if ~~it~~ AEMO rejects a nomination under clause 4.11.2(a), must process the application as if the application had nominated to use the method~~ology~~ described in clause 4.11.1(a) rather than the method~~ology~~ described in clause 4.11.2(b); and

(b) subject to clause 4.11.12, if it has not rejected the nomination under clause 4.11.2(a), must assign a quantity of Certified Reserve Capacity to the relevant Facility for the Reserve Capacity Cycle equal to the Relevant Level as determined in accordance with the Relevant Level Method~~ology~~, but subject to clauses 4.11.1(b), 4.11.1(bA), 4.11.1(bB), 4.11.1(c), 4.11.1(f), 4.11.1(g), 4.11.1(h), ~~and~~ 4.11.1(i) and 4.11.2(c).

Explanation

The purpose of clause 4.11.2(c) is to dampen possible variations in capacity value results between years and provide a glide path for the transition to the proposed Relevant Level Method.

The possible effect of this clause on the assigned Certified Reserve Capacities is presented in attachment 2, section 1.3.

This clause specifies that AEMO must assign Certified Reserve Capacities to a Facility based on a moving average of four values: the result of the Relevant Level Method in Appendix 9 and any available Certified Reserve Capacity quantity assigned to the Facility in the three preceding Reserve Capacity Cycles. This calculation excludes any Facility that has been recently upgraded or under significant maintenance.

(c) AEMO must assign a quantity of Certified Reserve Capacity to the relevant Facility for that Reserve Capacity Cycle equal to the average of the Relevant Level assigned to the Facility according to paragraph b and any available Certified Reserve Capacity assigned to the relevant Facility in the three preceding Reserve Capacity Cycles. This paragraph does not apply to a Facility that is yet to re-enter service after significant maintenance or is to re-enter service after having been upgraded since the date and time specified in clause 4.1.12(b), or otherwise modified or extended under clause 4.1.32, for the preceding Reserve Capacity Cycle to the relevant Reserve Capacity Cycle.

Changes to clauses 4.10.3A(a) and addition of new clause 4.10.3B

The proposed changes to Appendix 9 (in Step 2(b)) require an estimate of the expected sent out capacity (in MW), not subject to Planned Outage or Forced Outage, that would have been available to be sent out by the Facility. These changes need to be reflected in clause 4.10.3A of the market rules.

This change is important to ensure the proposed method remains robust and suitable for the calculation of the capacity value of generators with constrained access network rights or generators with sent out capacity available that may differ from their observed sent out generation. For example, the observed sent out generation of scheduled generators is often not a suitable proxy for the calculation of their available capacity to be sent out.

4.10.3A. A report provided under clause 4.10.3, or clause 4.10.3B as applicable, must include:

(a) ~~(a)~~ for each Trading Interval during the period identified in ~~step~~ step 1(a) of the Relevant Level Method~~ology,~~ a reasonable estimate of the expected capacity (in MW) ~~energy~~ that would have been available to be sent out by the Facility had it been in operation with the configuration proposed under clause 4.10.1(dA) in the relevant application for certification of Reserve Capacity. This estimate must factor in the effect of Planned Outages or Forced Outages, and ignore the effect of Consequential Outages, on the capacity available to be sent out;

4.10.3B. If clause 4.10.3 does not apply to a Facility and an applicant, who includes a nomination to use the method described in clause 4.11.2(b) for a Facility, reasonably considers that:

(a) in the Relevant Level Method the quantity of electricity sent out determined by Meter Data Submissions in step 2(a), or estimated in steps 4, 5 or 6 as applicable, when multiplied by two to convert to units of MW, does not reasonably reflect the Available Sent Out Capacity for any Trading Interval in the period identified in step 1(a) that falls after and including 8:00 AM on the Full Operation Date of the Facility,

(b) the applicant can include a report prepared by an expert accredited by AEMO in accordance with clause 4.11.6. AEMO will use the report to assign Certified Reserve Capacity for the Facility and to determine the Required Level for that Facility.

Changes to clause 4.9.5. Conditional Certification of Reserve Capacity

The ERA explained in its review that the capacity contribution of some intermittent generators, such as wind and solar farms, depends on the capacity contribution of other resources available in the system (refer to sections 4 and 6.7.3 in the ERA's review report). Consequently, it is not suitable to estimate the capacity contribution of those resources without considering the contribution of other resources in the system. These resources typically have available capacity that is correlated with the available capacity of other generators and/or system demand.

The Conditional Certification of Reserve Capacity for a future Reserve Capacity Cycle can increase the long-term cost of supply to consumers and/or decrease the reliability of the SWIS, if AEMO's estimate of the Conditional Certified Reserve Capacity assigned to a Facility is not reliable. This is possible because at the time AEMO assigns Conditional Certified Reserve Capacity, it may not have sufficient and reliable information to calculate the capacity contribution of the Facility.

4.9.5. If AEMO assigns Certified Reserve Capacity to a Facility for a future Reserve Capacity Cycle under clause 4.11 ("**Conditional Certified Reserve Capacity**"):

(a) the Conditional Certified Reserve Capacity is conditional upon:

i. the information included in the application for Certified Reserve Capacity remaining correct as at the date and time specified in clause 4.1.11 for that future Reserve Capacity Cycle; and

ii. AEMO's assessment of the Certified Reserve Capacity for the Facility for the Reserve Capacity Cycle, until the time specified in clause 4.1.15 for that future Reserve Capacity Cycle, remains reasonably equal to the Conditional Certified Reserve Capacity assigned to the capacity.

(b) the Market Participant holding the Conditional Certified Reserve Capacity must, in accordance with clauses 4.9.1 and 4.9.3, re-lodge an application for Certified Reserve Capacity with AEMO between the date and time specified in clause 4.1.7 and the time specified in clause 4.1.11 for that future Reserve Capacity Cycle;

(c) if AEMO is satisfied that the application re-lodged in accordance with paragraph (b) is consistent with the information upon which the Conditional Certified Reserve Capacity was assigned and is correct, and AEMO's assessment of the Certified Reserve Capacity for the Facility remains equal to the Conditional Certified Reserve Capacity previously assigned to the Facility, then AEMO must confirm:

i. the Certified Reserve Capacity;

ii. the Reserve Capacity Obligations Quantity; and

iii. the Reserve Capacity Security levels, that were previously conditionally assigned, set or determined by AEMO, subject to the Certified Reserve Capacity for an Intermittent Generator being assigned in accordance with clause 4.11.2(b); and

(d) if the application re-lodged in accordance with paragraph (b) is found by AEMO to be inaccurate or is not consistent with the information upon which the Conditional Certified Reserve Capacity was assigned, or AEMO's assessment of the Certified Reserve Capacity for the Facility differs from the Conditional Certified Reserve Capacity previously assigned to the Facility then AEMO must process the application without regard for the Conditional Certified Reserve Capacity.

Changes to clause 4.28C. Early Certification of Reserve Capacity

Similar to that explained for the Conditional Certified Reserve Capacity, the early certification of capacity (at any time before 1 January of Year 1 of the Reserve Capacity Cycle as specified in clause 4.28C.2) can increase the long-term cost of supply to consumers and/or decrease the reliability of the SWIS, if AEMO cannot reasonably estimate the capacity contribution of the Facility applying for early certification of reserve capacity.

4.28C.7. AEMO must, within ~~90~~ 10 days of receiving the application, determine if it can reliably set Early Certified Reserve Capacity for the Facility ~~to that amount~~as it would normally grant the Facility if processing an application for Certified Reserve Capacity in accordance with clause 4.11 lodged with AEMO between the date and time specified in clause 4.1.7 and the time specified in clause 4.1.11 for that future Reserve Capacity Cycle. AEMO:

(a) must reject the application if it has cause to believe that it cannot reliably set the Early Certified Reserve Capacity and communicate the rejection to the Market Participant; otherwise

(b) must, within 90 days of receiving the application, set Early Certified Reserve Capacity for the Facility to that amount it would normally grant the Facility if processing an application for Certified Reserve Capacity in accordance with clause 4.11.

To be considered by the Rule Change Panel: possible changes to allow AEMO run the relevant level method a second time before/after receiving Reserve Capacity Securities

Clause 4.1 of the market rules specifies the timeline by which the main events in a Reserve Capacity Cycle occur. The process for the early certification of capacity (Clause 4.28B) and certification of new small generators (4.28C) are not required to comply with the timetable in clause 4.1.

Clause 4.1.32 allows AEMO to modify or extend a date or time specified under clause 4.1.

Some of the main events for the certification and assignment of Reserve Capacity are listed below:

- AEMO receives applications for the certification of Reserve Capacity between 1 May and 1 July in Year 1 of the reserve capacity cycle.
- AEMO notifies each applicant for certification of Reserve Capacity of the Certified Reserve Capacity to be assigned by 19 August of Year 1. This implies that AEMO runs the methods for the calculation of Certified Reserve Capacity, including the relevant level method, based on applications received by 1 July of Year 1.
- AEMO receives Reserve Capacity Securities from Market Participants by 2 September of Year 1.
- Also by 2 September of Year 1 (or 14 September of Year 1), each Market Participant holding Certified Reserve Capacity for the Reserve Capacity Cycle provides to AEMO notification as to how its Certified Reserve Capacity will be dealt with including the total amount of Reserve Capacity the Market Participant intends to trade bilaterally and the amount it has decided not to be made available to the market.
- On the first business day following the notification deadline in the previous bullet point (2 September), AEMO confirms to each Market Participant the amount of Certified Reserve Capacity that can be traded from its Facilities.
- AEMO publishes the Certified Reserve Capacity for each Facility after the dead line in the previous bullet point.

It is possible that the capacity contribution of Facilities change after AEMO calculates them by 19 August of Year 1. This is because the capacity value of some intermittent generators such as wind and solar farms is dependent on the contribution of other intermittent generators in the system. If a large amount of capacity from solar and wind farms is withdrawn or not assigned capacity credits before or after the provision of Reserve Capacity Security to AEMO, the capacity contribution for the remaining solar and wind farms changes.

Under the current market rules, it is possible that some applicants withdraw their application for Certified Reserve Capacity before providing Reserve Capacity Security to AEMO.

The Public Utilities Office proposed improvements to the Reserve Capacity pricing in the market rules. Under the proposed changes, AEMO is to award capacity credits to new floating price capacity and existing capacity providers first and, if an adequate level of capacity is not achieved, then award all capacity resources that opted for a price lock-in. So it is possible that some of the intermittent generation Facilities, that were to be assigned Certified Reserve Capacity based on the results of the relevant level method, do not receive Certified Reserve Capacity.

The market rules can be amended to allow AEMO to run the relevant level method a second time after receiving Reserve Capacity Securities, declaration of bilateral trades, and the determination of any capacity not receiving capacity credits. This change should allow adjustment to Reserve Capacity Security and bilateral trade amounts to be declared after the recalculation of Certified Reserve Capacities.

Sensitivity analysis results in attachment 2 show that interaction between the capacity value of intermittent generators can be large if the entry or exit of intermittent generators is large. The absolute interaction amount between the capacity value of solar and wind farms could reach to 55 MW. This represents the effect of the capacity value of solar and wind farms on each other.

Changes to clause 4.11.3C and 4.11.3E

The proposed changes to the relevant level method no longer use constant parameters K and U.

The ERA is also required to review the relevant level method again by 1 April 2021. The approval and implementation of the proposed relevant level method is expected to happen in 2020. There will not be sufficient time before 1 April 2021 to assess the application of the proposed method in practice. The next review of relevant level method can be postponed to 1 April 2022.

4.11.3C. For each three year period, beginning with the period commencing on 1 January ~~2015~~2022, the Economic Regulation Authority must, by 1 April of the first year of that period, conduct a review of the Relevant Level Methodology. In conducting the review, the Economic Regulation Authority ~~must~~:

(a) must examine the effectiveness of the Relevant Level Method~~ology~~ in meeting the Wholesale Market Objectives; and

(b) ~~determine the values of the parameters K and U in step 17 of the Relevant Level Methodology to be applied for each of the three Reserve Capacity Cycles commencing in the period,~~

~~and the Economic Regulation Authority~~ may examine any other matters that the Economic Regulation Authority considers to be relevant.

4.11.3E. At the conclusion of a review under clause 4.11.3C, the Economic Regulation Authority must publish a final report containing:

(a) details of the Economic Regulation Authority's review of the Relevant Level Method~~ology~~;

(b) a summary of the submissions received during the consultation period;

(c) the Economic Regulation Authority's response to any issues raised in those submissions;

~~(d) the values of the parameters K and U determined under clause 4.11.3C; and~~

(d~~e~~) any recommended amendments to the Relevant Level Method~~ology~~ which the Economic Regulation Authority intends to progress as a Rule Change Proposal.

Information to be Released via the Market Web Site

10.5.1(f)x the following information identified for a Reserve Capacity Cycle under the Relevant Level Method~~ology~~:

1. the System Demand calculated in Step 8(c)Step 8(a)Step 8(a) determined for each Trading Interval in the period identified in Step 1(a)Step 1(a).

2. the Load for Scheduled Generation calculated in Step 8(c)Step 8(c) determined for each Trading Interval in the period identified in Step 1(a)Step 1(a).

3. the Capacity Outage Probability Table calculated in Step 6Step 16.

4. the Annual_Relevant_Level_Candidate_Facilities_Fleet determined in Step 10(a)Step 10(a).

5. the Full_Period_Relevant_Level_Candidate_Facilities_Fleet estimated in Step 10(b)Step 10(b).

6. for each Technology Class c the Technology_Class_Relevant_Level(c) calculated in Step 10(b)Step 11(b)Step 11(b).

7. the amount of CF_Generation(c) in Step 8(b) for Biogas Technology Class, Solar Technology Class, Wind Technology Class and any New Technology Class identified by AMEO under the Relevant Level Method, determined for each Trading Interval in the period identified in Step 1(a)Step 1(a).

~~the Existing Facility Load for Scheduled Generation for each Trading Interval in the five year period determined under Step 1(a) of Appendix 9; and~~

~~2. the 12 Trading Intervals occurring on separate Trading Days with the highest Existing Facility Load for Scheduled Generation for each 12 month period in the five year period; and~~

Pseudocode for the calculation of Capacity Outage Probability Table in Step 16

The pseudocode provided below can facilitate the interpretation of the calculation of capacity outage probability table in Step 16 of Appendix 9. This can also assist AEMO in implementing the proposed relevant level method.

algorithm COPT-Calculation **is:**

input: table array $G_{SG,DSM}(C,U)$ comprising the variables *C* for Certified Reserve Capacities and *U* for Forced Outage Rates for the Scheduled Generator and Demand Side Programme Facilities identified in Step 15,

outage step *s=1*

output: table array *COPT(Outage*, P'_X, P'_{X-C},*P(X))* comprising variables *Outage* for outage quantity expressed in MW and corresponding P'_X, P'_{X-C} and *P(X)*.

(initialise *COPT* by creating a table array comprising variables Outage, P'_X, P'_{X-C},*P(X)* and number of rows equal to the sum of quantities for variable *C* in table array $G_{SG,DSM}$ plus two. Fill *COPT* with zero)

for each *(C,U)* **in** table array $G_{SG,DSM}$ **do**

set *c_prob* **to**1

set *X* **to** 0

while *c_prob* **is greater than** 0

set for row index *X* **in** *COPT* the amount of variable *Outage* **to** *X*

if *X* equals 0 **then**

set for row index *X* **in** *COPT* the amount of variable P'_X ***to 1***

else

set for row index *X* **in** *COPT* the amount of variable P'_X **to** the amount of *P(X)* in row index *X* of *COPT*

end if

if (*X*-*C*) **is less than or equal to** 0 **then**

set for row index *X* **in** *COPT* the amount of variable P'_{X-C} to 1

else

set *idx* **to** the index of the row in *COPT* where the amount of variable *Outage* equals *X-C*

set for the row *X* in *COPT* the amount of variable P'_{X-C} to the amount of variable P'_X in row *idx*

end if

set for the row index *X* **in** *COPT* the amount of variable *P(X)* **to**

$$P'_X \times (1 - U) + U \times P'_{X-C}$$

set *c_prob* **to** the amount of variable *P(X)* in row *X* of *COPT*

set *X* **to** *X+s*

end while

end for

return *COPT*

(the calculation in Step 16 uses only the variables *Outage* and *P(X)* in the *COPT* calculated in the above algorithm).

Attachment 1: proposed specific changes to particular Market Rules (clean version)

Appendix 9: Relevant Level Determination

This Appendix presents the method for determining the Relevant Levels for Facilities that have applied for certification of Reserve Capacity under clause 4.11.2(b) for a given Reserve Capacity Cycle (“Candidate Facility”).

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

- the full operation date of a Candidate Facility for the Reserve Capacity Cycle (“Full Operation Date”) is:
  - the date provided under clause 4.10.1(c)(iii)(7) or revised in accordance with clause 4.27.11A, where at the time the application for certification of Reserve Capacity is made the Facility, or part of the Facility (as applicable) is yet to enter service; or
  - the date most recently provided for a Reserve Capacity Cycle under clause 4.10.1(k) otherwise; and
- a Candidate Facility will be considered to be:
  - a new Candidate Facility, if the period identified in Step 1(a) of this Appendix commenced before 8:00 AM on the Full Operation Date for the Facility (“New Candidate Facility”); or
  - an existing Candidate Facility (“Existing Candidate Facility”), otherwise.
- each Candidate Facility will be assigned to one of the “Biogas Technology Class”, “Solar Technology Class” or “Wind Technology Class”, based on the generation technology of that Candidate Facility, as determined by AEMO based on the information received under clause 4.10.1(dA) or clause 2.33.3.
- AEMO may decide to identify a new Technology Class (other than Biogas Technology Class, Solar Technology Class and Wind Technology Class) and assign any Candidate Facility to that new Technology Class, if AEMO has cause to believe that the assignment of a Candidate Facility to any other Technology Class than the new Technology Class can contribute to a material underestimation or overestimation of the Relevant Level for that Candidate Facility or other Candidate Facilities that have applied for the certification of Reserve Capacity under clause 4.11.2(b).
- The available capacity of a Candidate Facility for a Trading Interval is the amount of capacity available to be sent out (in MW) and is not subject to a Planned Outage or Forced Outage (“Available Sent Out Capacity”).

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

Determining System Load and Load for Scheduled Generation

Explanation

The proposed method uses a sample of seven years for the calculation. It is also possible to use a larger sample of 10 years to dampen the variability of results between years. Using a larger sample, however, may increase the cost of producing estimated data for the Available Sent Out Capacity of new or upgraded facilities.

Step 1. Identify,

(a) the seven year period ending at 8:00 AM on 1 April of Capacity Year 1 of the relevant Reserve Capacity Cycle; and

(b) any 12 month period, from 1 April to 31 March, occurring during the seven year period identified in Step 1(a).

Step 2. Determine:

(a) the quantity of electricity (in MWh) sent out by the Candidate Facility using Meter Data Submissions for each Candidate Facility and for each of the Trading Intervals in the period identified in Step 1(b) ("Sent Out Generation"); and

(b) for each New Candidate Facility, for each Trading Interval in the period identified in Step 1(b) that falls before 8:00 AM on the Full Operation Date for the Facility, an estimate of the quantity of Available Sent Out Capacity (in MW), that would have been available by the Facility in the Trading Interval, if it had been in operation with the configuration proposed under clause 4.10.1(dA) in the relevant application for certification of Reserve Capacity. The estimates must reflect the estimates in the expert report provided for the Facility under clause 4.10.3, unless AEMO reasonably considers the estimates in the expert report to be inaccurate.

Step 3. For each Candidate Facility, identify any Trading Intervals in the period identified in Step 1(b) where:

(a) the Facility, other than a Facility in the Balancing Portfolio, was directed to restrict its output under a Dispatch Instruction as provided in a schedule under clause 7.13.1(c); or

(b) the Facility, if in the Balancing Portfolio, was instructed by System Management to deviate from its Dispatch Plan or change its commitment or output as provided in a schedule under clause 7.13.1C(d); or

(c) the Facility was affected by a Consequential Outage as notified by System Management to AEMO under clause 7.13.1A.

Step 4. For each Candidate Facility and Trading Interval identified in Step 3(a):

(a) the Sent Out Generation is equal to the Sent Out Generation quantity determined in Step 2(a) if:

i System Management has made a revised estimate of the maximum quantity in accordance with clause 7.7.5A(c) and the Power System Operation Procedure; and

ii the revised estimate of the maximum quantity is lower than the Actual Sent Out Generation quantity as determined in Step 2(a);

(b) the Sent Out Generation is equal to the Sent Out Generation quantity determined in Step 2(a) if:

i. Step 4(a) does not apply; and

ii. the estimated maximum quantity determined by System Management under clause 7.13.1(eF) is lower than the Sent Out Generation quantity (as specified in a Meter Data Submission covering the Facility and the Trading Interval);

(c) if Step 4Step 4 and Step 4(b) do not apply, the Sent Out Generation is:

i. the revised estimate of the maximum quantity determined by System Management in accordance with the Power System Operation Procedure specified in clause 7.7.5A; or

ii. the estimate determined by System Management under clause 7.13.1(eF), if there is no revised estimate.

Step 5. For each Candidate Facility and Trading Interval identified in Step 3(b) use:

(a) the estimate recorded by System Management under clause 7.13.1C(e); and

(b) the quantity determined for the Facility and Trading Interval in Step 2(a),

to estimate the quantity of energy (in MWh) that would have been sent out by the Facility had it not complied with System Management's instruction to change its commitment or output during the Trading Interval. Identify this estimated quantity as the Sent Out Generation of the Candidate Facility for the Trading Interval.

Step 6. For each Candidate Facility and Trading Interval identified in Step 3(c) use:

(a) the schedule of Consequential Outages determined by System Management under clause 7.13.1A;

(b) the quantity determined for the Facility and Trading Interval in Step 2(a); and

(c) the information recorded by System Management under clause 7.13.1C(a),

to estimate the quantity of energy (in MWh) that would have been sent out by the Facility had it not been affected by the notified Consequential Outage during the Trading Interval. Identify this estimated quantity as the Sent Out Generation of the Candidate Facility for the Trading Interval.

Step 7. For any Trading Interval in the period identified in Step 1(b) that falls after and including 8:00 AM on the Full Operation Date of a Candidate Facility AEMO must use a half of the Available Sent Out Capacity of the Facility, provided in the expert report for the Facility under clause 4.10.3A where available, as the Sent Out Generation of the Facility, if:

(a) AEMO reasonably believes that the quantity of electricity sent out determined by Meter Data Submissions in Step 2(a), or estimated in Step 4, Step 5 or Step 6 as applicable, when multiplied by two to convert to units of MW, does not reasonably reflect Available Sent Out Capacity of the Facility for that Trading Interval; and

(b) the Facility had a greater estimated Available Sent Out Capacity than twice the Sent Out Generation of the Facility determined in Step 2(a) or estimated in Step 4, Step 5 or Step 6 as applicable, for that Trading Interval,

unless AEMO reasonably considers the estimates in the expert report provided for the Facility under clause 4.10.3, to be inaccurate.

Step 8. Determine for each Trading Interval in the period identified in Step 1(a):

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

$$(Total\_Generation + DSP\_Reduction + Interruptible\_Reduction + Involuntary\_Reduction) \times 2$$

where

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

DSP_Reduction is the total quantity (in MWh) by which all Demand Side Programmes reduced their consumption in response to a Dispatch Instruction, as determined under clause 6.17.6(c)(i);

Interruptible_Reduction is the total quantity (in MWh) by which all Interruptible Loads reduced their consumption in accordance with the terms of an Ancillary Service Contract, as recorded by System Management under clause 7.13.1C(c);

Involuntary_Reduction is the total quantity of energy (in MWh) not served due to involuntary load shedding (manual and automatic), as recorded by System Management under clause 7.13.1C(b).

(b) for each Technology Class c, the CF_Generation(c) as,

$$\sum_{f \in c} (Actual\_CF\_Generation(f) \; + \; Estimated\_CF\_Generation(f))$$

where, the operator $\sum_{f \in c}()$ represents a summation across all facilities f in the Technology Class c.

For Existing Candidate Facilities:

- the Actual_CF_Generation(f) for the Trading Interval is the Sent Out Generation determined in Step 2(a) or estimated in Step 4, Step 5, Step 6, or Step 7 as applicable, and
- the Estimated_CF_Generation is zero, and

for New Candidate Facilities:

- the Actual_CF_Generation, for the Trading Intervals falling after and including 8:00 AM on the Full Operation Date for the Facility, is the Sent Out Generation determined in step 2(a) or estimated in Step 4, Step 5, Step 6, or Step 7 as applicable, and zero otherwise; and
- the Estimated_CF_Generation, for the Trading Intervals falling before 8:00 AM on the Full Operation Date for the Facility, is half of the quantity determined for the New Candidate Facility and the Trading Interval in Step 2(b), and zero otherwise.

(c) the Load for Scheduled Generation (in MW) as:

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

where the expression $\sum_c CF\_Generation(c) \times 2$ represents the sum of CF_Generation(c) calculated in step 7(b) across all Technology Classes c, multiplied by 2 to convert to units of MW.

Step 9. Determine, for each 12 month period identified in Step 1(b), the 12 Trading Intervals occurring on separate Trading Days with:

(a) the highest Load for Scheduled Generation;

(b) the highest System Demand.

Calculation of Relevant Level scenarios

Step 10. Determine:

(a) for each 12 month period identified in Step 1(b) as the Relevant_Period, the Annual_Relevant_Level_Candidate_Facilities_Fleet (in MW) using the calculation in Step 8, and the corresponding Net_Demand data defined in Table 1; and

(b) for the period identified in Step 1(a), as the Relevant_Period, the Full_Period_Relevant_Level_Candidate_Facilities_Fleet (in MW) using the calculation in Step 8, and the corresponding Net_Demand data defined in Table 1.

Step 11. Select:

(a) the Relevant_Level_Candidate_Facilities_Fleet as the smaller of

- the Full_Period_Relevant_Level_Candidate_Facilities_Fleet estimated in Step 9(b), and

- the median of the Annual_Relevant_Level_Candidate_Facilities_Fleet determined in Step 10(a), and

record the Relevant_Period corresponding to the Relevant Level scenario selected in this step as Selected_Period, and

(b) determine for each Technology Class c the Technology_Class_Relevant_Level(c), using the calculation in Step 8 and corresponding Net_Demand data and Relevant_Period defined in Table 1.

Table 1. Relevant Level scenario and corresponding variables

Relevant Level scenario	Facility_Group	Net_Demand data, used in step 17(b)	Relevant_Period
Annual_Relevant_Level_Candidate_Facilities_Fleet	all Candidate Facilities	Load for Scheduled Generators rounded to the nearest integer	each 12 month period identified in Step 2(b).
Full_Period_Relevant_Level_Candidate_Facilities_Fleet	all Candidate Facilities	Load for Scheduled Generators rounded to the nearest integer	entire period identified in Step 1(a)
Technology_Class_Relevant_Level (c)	all Facilities in the Technology Class c	System Demand – 2 × $CF\_Generation(c)$ rounded to the nearest integer	Selected_Period as determined in Step 11(a)

(a) determine the Solar_Wind_Interaction_Effect as:

$$Relevant\_Level\_Candidate\_Facilities\_Fleet - \sum_c Technology\_Class\_Relevant\_Level(c)$$

where the expression $\sum_c Technology\_Class\_Relevant\_Level(c)$ represents the sum of all Technology_Class_Relevant_Level(c) for all Technology Classes estimated in Step 10(b);

(b) determine the $Adjusted\_Technology\_Class\_Relevant\_Level(c)$ for each Technology Class c, comprising the Solar Technology Class and Wind Technology Class as:

$$Technology\_Class\_Relevant\_Level(c) + \frac{Technology\_Class\_Relevant\_Level(c)}{\sum_c Technology\_Class\_Relevant\_Level(c)} \times Solar\_Wind\_Interaction\_Effect$$

where the Technology_Class_Relevant_Level(c) is determined in Step 10(b).

The Adjusted_Technology_Class_Relevant_Level(c) for the Biogas Technology Class and any New Technology Class determined by AEMO, is respectively equal to the Technology_Class_Relevant_Level (Biogas Technology Class) and Technology_Class_Relevant_Level (New Technology Class) determined in Step 11(b).

Allocation of Technology Class Relevant Level to individual Candidate Facilities

Step 2. For each Candidate Facility f within a Technology Class c:

(a) determine the quantities of

$$Actual\_CF\_Generation(f) + Estimated\_CF\_Generation(f)$$

as calculated in Step 8(b), during the Trading Intervals identified in Step 9(a) and Step 9(b), multiplied by 2 to convert to units of MW, and

(b) determine the Facility_Average_Performance_Level(f) as the mean of the quantities determined for Facility f in Step 2(a).

Step 3. For each Technology Class c determine the Scaling_Factor(c) as:

$$\frac{Adjusted\_Technology\_Class\_Relevant\_Level(c)}{\sum_{f \in c} Facility\_Average\_Performance\_Level(f)}$$

where the denominator represents the sum of Facility_Average_Performance_Level for all Facilities f in the Technology Class c.

Step 4. Determine for each Facility f in the Technology Class c the Relevant Level (in MW) as:

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

Step 5. ***Calculation of Capacity Outage Probability Table***Identify:

(a) all Scheduled Generators and Demand Side Programme Facilities that will receive Certified Reserve Capacity for the Capacity Year 3 of the relevant Reserve Capacity Cycle, using the method in clause 4.11;

(b) the quantity of Certified Reserve Capacity to be assigned to Scheduled Generators and Demand Side Programme Facilities identified in Step 5(a) for the Capacity Year 3 of the relevant Reserve Capacity Cycle;

(c) the Forced Outage Rate, estimated using Power System Operation Procedure: Facility Outages (for the purpose of clause 4.11.1(h)), for each Scheduled Generator Facility identified in Step 5(a), for the Relevant Reserve Capacity Cycle and the two preceding Reserve Capacity Cycles to the Relevant Reserve Capacity Cycle. For each Facility identified in Step 5(a) set the parameter U as the average of the three Forced Outage Rates for the three Reserve Capacity Cycles identified in this clause for the Facility; and

(d) the Forced Outage Rate for Demand Side Programme Facilities, identified in Step 5(a), as zero.

Explanation

Step 16 explains how a capacity outage probability table must be calculated. The capacity outage probability table is a table of possible outage amounts for the fleet of Scheduled Generators and Demand Side Programme Facilities.

The table has two columns: the first column lists possible outage amounts X from zero MW to total installed capacity of fleet of Scheduled Generators and Demand Side Programme Facilities, with an increment of one MW. The second column lists the probability of having an outage greater than or equal to the amount X in respective rows (cumulative probability of an outage amount X, or P(X)).

Each outage amount X can result from numerous combinations of plants on outage and the calculation in Step 16 provides a method for calculation of the cumulative probability of an outage X. Although simple in concept, the method uses loops to determine the table, which can be difficult to understand without examples to show its application.

There are two options for defining this step:

- Option 1: define the calculation of the table in Step 16, as written in this rule change proposal.
- Option 2: simplify Step 16 as below:

  Step 16: Using Forced Outage Rates and Certified Reserve Capacities identified in Step 15(b) to Step 15(d), AEMO must determine a table of capacity outage amounts X (in MW) and respective cumulative probability of that outage amount, P(X), for any outage amount from zero MW to the sum of Certified Reserve Capacity amounts assigned to Scheduled Generator and Demand Side Programme Facilities identified in Step 15(a) ("Capacity Outage Probability Table").

If option 2 is preferred, the ERA can publish a guideline including the pseudocode for the calculation of capacity outage probability table, to increase the transparency of the proposed relevant level method.

Step 6. Determine a table of capacity outage amounts X (in MW) and respective cumulative probability of that outage amount by incrementally adding the capacity of all Scheduled Generator and Demand Side Programme Facilities identified in Step 4 to that table as explained below:

(a) For each Scheduled Generator and Demand Side Programme Facility G with the Certified Reserve Capacity C, rounded to the nearest integer, and Forced Outage Rate U identified in Step 5,

while P(X) is greater than zero, for each outage amount X (in MW) from zero with increment of 1 MW, determine P(X) as:

$$P(X) = (1 - U) \times P'(X) + U \times P'(X - C)$$

where,

P(X) is the cumulative probability of the capacity outage of X MW after adding the Facility G to the table.

P'(X) is the cumulative probability of the capacity outage of X MW before adding the Facility G. P'(X)=1.0 if X is less than or equal to zero. For the first Facility G added to the table, P'(X)=0 if X is greater than zero.

(b) Identify the capacity outage probability table as a table listing all outage amounts X from zero to the total Certified Reserve Capacity of Scheduled Generator and Demand Side Programme Facilities identified in Step 5(a), and corresponding P(X) after adding the last Facility in Step 6(a) ("Capacity Outage Probability Table").

Calculation of Loss of Load Probability and Loss of Load Expectation

Step 7. Determine:

(a) the loss of load probability for a Trading Interval with a system load of D MW as ("Loss of Load Probability"):

$$P(CC - D)$$

where

CC is the total Certified Reserve Capacities assigned to Scheduled Generators and Demand Side Programme Facilities identified in Step 5(b);

P(CC – D) is the cumulative probability of an outage of X=CC – D MW that is derived from the Capacity Outage Probability Table calculated in Step 6; and

(b) the loss of load expectation during a Relevant_Period as the sum of the Loss of Load Probability, as determined in Step 7(a), for each Trading Interval in that Relevant_Period ("Loss of Load Expectation").

Calculation of the Relevant Level

Step 8. Determine the Relevant Level of a Facility_Group during a Relevant_Period using the steps below:

(a) Calculate the Loss of Load Expectation in the SWIS using the calculation in Step 7(b) and the System Demand determined in Step 8(a), rounded to the nearest integer, as system load during the Relevant_Period.

(b) Calculate the Loss of Load Expectation in the SWIS using the calculation in Step 7(b) and the Net_Load data identified in Table 1 corresponding to the Facility_Group, as system load during the Relevant_Period.

(c) Increase the Net_Load data in Step 8(b), with increments of whole MW and fixed across all Trading Intervals in the Relevant_Period, and repeat the calculation in Step 8(b) with the increased Net_Load data.

(d) Repeat Step 8(c) until the Loss of Load Expectation calculated in Step 8(c) is equal or closest to that in Step 8(a).

The Relevant Level of the Facility_Group during the Relevant_Period is the total increase in Net_Load (in MW) identified in Step 8(c) that makes the Loss of Load Expectation calculated in Step 8(c) equal or closest to that calculated in Step 8(a).

Publication of information

Step 9. Publish on the Market Web Site by 1 June of Year 1 of the relevant Reserve Capacity Cycle a provisional forecast of the Trading Intervals that may be identified in Step 9.

Step 10. Publish on the Market Web Site within three Business Days after the date specified in clause 4.1.11 (as modified or extended) for the relevant Reserve Capacity Cycle:

(a) the System Demand calculated in Step 8(c) determined for each Trading Interval in the period identified in Step 1(a);

(b) the Load for Scheduled Generation calculated in Step 8(c) determined for each Trading Interval in the period identified in Step 1(a);

(c) the Capacity Outage Probability Table calculated in Step 6.

(d) the Annual_Relevant_Level_Candidate_Facilities_Fleet determined in Step 10(a);

(e) the Full_Period_Relevant_Level_Candidate_Facilities_Fleet estimated in Step 10(b);

(f) for each Technology Class c the Technology_Class_Relevant_Level(c) calculated in Step 10(b); and

(g) the amount of CF_Generation(c) in Step 8(b) for Biogas Technology Class, Solar Technology Class, Wind Technology Class and any New Technology Class identified by AMEO under the Relevant Level Method.

Changes to Chapter 11 (Glossary)

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

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

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

Load for Scheduled Generation: is an estimate of System Demand to be met by Scheduled Generators expressed in MW, as determined for a Trading Interval under Step 8(c) of the Relevant Level Method.

System Demand: is an estimate of the total amount of electricity demand in the SWIS in MW over a Trading Interval that should have been supplied through the transmission grid if no load was reduced or disconnected by AEMO, as calculated in Step 8(a) of the relevant level method.

Changes to other market rules

Replace all references to the Relevant Level Methodology with Relevant Level Method.

Clause 1.17.5 is no longer required and can be removed.

Changes to clause 4.11.2

The market rules allows an applicant to nominate under clause 4.10.1(i) to have AEMO use the relevant level method to apply to a Scheduled Generator or Non-Scheduled Generator.

The current relevant level method is not suitable for calculating the capacity contribution of Scheduled Generators, because it uses the observed sent out generation of Facilities to determine their capacity contribution. The observed sent out generation of Scheduled Generators is not a suitable proxy for their available capacity.

The proposed changes to the relevant level method accounts for the available sent out capacity of resources and can provide a reasonable estimate for the capacity contribution of Scheduled Generators or any other capacity resource. However, the proposed relevant level method when applied to a Scheduled Generator will provide fairly similar results to the method specified in clause 4.11.1 of the market rules.

Clause 4.11.1 of the market rules already provides a simple method for the calculation of the capacity contribution of Scheduled Generators. The calculation of the capacity contribution of a Scheduled Generator using the relevant level method may increase the computation burden for AEMO and increase AEMO's administration costs. Changes to clause 4.11.2 allow AEMO to reject a Scheduled Generators' nomination for using the relevant level method, if AEMO reasonably believes that clause 4.11.1 can provide a reasonable capacity value for that Scheduled Generator.

Arrangements for dampening variation in results

Changes to this clause also specify that AEMO must assign a Relevant Level to facilities based on a three-year moving average. This will dampen possible variations between the results of the proposed relevant level method and provide a glide path for changes to the relevant level method.

As discussed in the ERA's relevant level method review report, the capacity value of intermittent generators varies substantially from year to year. This variation creates a high level of uncertainty for the forecasts generated by the relevant level method. The ERA used several measures to suitably address the uncertainty and dampen the variation in results:

- The proposed changes use a larger sample of seven years for the calculation (in compare to five-year sample in the current method).
- The proposed changes also use the median of capacity value results determined for each year in the seven year period. Use of median ensures that results will not be biased towards extremely large or small values in the seven-year sample. The median is also capped by the capacity value of the fleet of intermittent generators based on the full seven-year period sample result.
- The use of three-year moving average, specified in clause 4.11.2(c) also ensures that results will not vary drastically between years and in the medium to long term trend towards the capacity value of intermittent generation fleet estimated using the reliability model implemented in the proposed changes.
- The development of the reliability model used in the proposed method, i.e. the Capacity Outage Probability Table, uses an average of forced outage rates for Scheduled Generators in the previous three years.

4.11.2. Where an applicant submits an application for Certified Reserve Capacity, in accordance with clause 4.10, and nominates under clause 4.10.1(i) to have AEMO use the method described in clause 4.11.2(b) to apply to a Scheduled Generator or a Non-Scheduled Generator, AEMO:

(a) may reject the nomination to use the method described in clause 4.11.2(b) to apply to a Scheduled Generator if AEMO reasonably believes that:

i. the capacity of the Facility has permanently declined, or is anticipated to permanently decline prior to or during the Reserve Capacity Cycle to which the Certified Reserve Capacity relates; or

ii. the method described in clause 4.11.1(a) provides a reasonable value for the Certified Reserve Capacity or Conditional Certified Reserve Capacity to be assigned to the Facility.

(aA) if AEMO rejects a nomination under clause 4.11.2(a), must process the application as if the application had nominated to use the method described in clause 4.11.1(a) rather than the method described in clause 4.11.2(b); and

(b) subject to clause 4.11.12, if it has not rejected the nomination under clause 4.11.2(a), must assign a quantity of Certified Reserve Capacity to the relevant Facility for the Reserve Capacity Cycle equal to the Relevant Level as determined in accordance with the Relevant Level Method, but subject to clauses 4.11.1(b), 4.11.1(bA), 4.11.1(bB), 4.11.1(c), 4.11.1(f), 4.11.1(g), 4.11.1(h), 4.11.1(i) and 4.11.2(c).

Explanation

The purpose of clause 4.11.2(c) is to dampen possible variations in capacity value results between years and provide a glide path for the transition to the proposed Relevant Level Method.

The possible effect of this clause on the assigned Certified Reserve Capacities is presented in attachment 2, section 1.3.

This clause specifies that AEMO must assign Certified Reserve Capacities to a Facility based on a moving average of four values: the result of the Relevant Level Method in Appendix 9 and any available Certified Reserve Capacity quantity assigned to the Facility in the three preceding Reserve Capacity Cycles. This calculation excludes any Facility that has been recently upgraded or under significant maintenance.

(c) AEMO must assign a quantity of Certified Reserve Capacity to the relevant Facility for that Reserve Capacity Cycle equal to the average of the Relevant Level assigned to the Facility according to paragraph b and any available Certified Reserve Capacity assigned to the relevant Facility in the three preceding Reserve Capacity Cycles. This paragraph does not apply to a Facility that is yet to re-enter service after significant maintenance or is to re-enter service after having been upgraded since the date and time specified in clause 4.1.12(b), or otherwise modified or extended under clause 4.1.32, for the preceding Reserve Capacity Cycle to the relevant Reserve Capacity Cycle.

Changes to clauses 4.10.3A(a) and addition of new clause 4.10.3B

The proposed changes to Appendix 9 (in Step 2(b)) require an estimate of the expected sent out capacity (in MW), not subject to Planned Outage or Forced Outage, that would have been available to be sent out by the Facility. These changes need to be reflected in clause 4.10.3A of the market rules.

This change is important to ensure the proposed method remains robust and suitable for the calculation of the capacity value of generators with constrained access network rights or generators with sent out capacity available that may differ from their observed sent out generation. For example, the observed sent out generation of scheduled generators is often not a suitable proxy for the calculation of their available capacity to be sent out.

4.10.3A. A report provided under clause 4.10.3, or clause 4.10.3B as applicable, must include:

(a) for each Trading Interval during the period identified in step 1(a) of the Relevant Level Method a reasonable estimate of the expected capacity (in MW) that would have been available to be sent out by the Facility had it been in operation with the configuration proposed under clause 4.10.1(dA) in the relevant application for certification of Reserve Capacity. This estimate must factor in the effect of Planned Outages or Forced Outages, and ignore the effect of Consequential Outages, on the capacity available to be sent out;

4.10.3B. If clause 4.10.3 does not apply to a Facility and an applicant, who includes a nomination to use the method described in clause 4.11.2(b) for a Facility, reasonably considers that:

(a) in the Relevant Level Method the quantity of electricity sent out determined by Meter Data Submissions in step 2(a), or estimated in steps 4, 5 or 6 as applicable, when multiplied by two to convert to units of MW, does not reasonably reflect the Available Sent Out Capacity for any Trading Interval in the period identified in step 1(a) that falls after and including 8:00 AM on the Full Operation Date of the Facility,

(b) the applicant can include a report prepared by an expert accredited by AEMO in accordance with clause 4.11.6. AEMO will use the report to assign Certified Reserve Capacity for the Facility and to determine the Required Level for that Facility.

Changes to clause 4.9.5. Conditional Certification of Reserve Capacity

The ERA explained in its review that the capacity contribution of some intermittent generators, such as wind and solar farms, depends on the capacity contribution of other resources available in the system (refer to sections 4 and 6.7.3 in the ERA's review report). Consequently, it is not suitable to estimate the capacity contribution of those resources without considering the contribution of other resources in the system. These resources typically have available capacity that is correlated with the available capacity of other generators and/or system demand.

The Conditional Certification of Reserve Capacity for a future Reserve Capacity Cycle can increase the long-term cost of supply to consumers and/or decrease the reliability of the SWIS, if AEMO's estimate of the Conditional Certified Reserve Capacity assigned to a Facility is not reliable. This is possible because at the time AEMO assigns Conditional Certified Reserve Capacity, it may not have sufficient and reliable information to calculate the capacity contribution of the Facility.

4.9.5. If AEMO assigns Certified Reserve Capacity to a Facility for a future Reserve Capacity Cycle under clause 4.11 ("**Conditional Certified Reserve Capacity**"):

(a) the Conditional Certified Reserve Capacity is conditional upon:

i. the information included in the application for Certified Reserve Capacity remaining correct as at the date and time specified in clause 4.1.11 for that future Reserve Capacity Cycle; and

ii. AEMO's assessment of the Certified Reserve Capacity for the Facility for the Reserve Capacity Cycle, until the time specified in clause 4.1.15 for that future Reserve Capacity Cycle, remains reasonably equal to the Conditional Certified Reserve Capacity assigned to the capacity.

(b) the Market Participant holding the Conditional Certified Reserve Capacity must, in accordance with clauses 4.9.1 and 4.9.3, re-lodge an application for Certified Reserve Capacity with AEMO between the date and time specified in clause 4.1.7 and the time specified in clause 4.1.11 for that future Reserve Capacity Cycle;

(c) if AEMO is satisfied that the application re-lodged in accordance with paragraph (b) is consistent with the information upon which the Conditional Certified Reserve Capacity was assigned and is correct, and AEMO's assessment of the Certified Reserve Capacity for the Facility remains equal to the Conditional Certified Reserve Capacity previously assigned to the Facility, then AEMO must confirm:

i. the Certified Reserve Capacity;

ii. the Reserve Capacity Obligations Quantity; and

iii. the Reserve Capacity Security levels, that were previously conditionally assigned, set or determined by AEMO, subject to the Certified Reserve Capacity for an Intermittent Generator being assigned in accordance with clause 4.11.2(b); and

(d) if the application re-lodged in accordance with paragraph (b) is found by AEMO to be inaccurate or is not consistent with the information upon which the Conditional Certified Reserve Capacity was assigned, or AEMO's assessment of the Certified Reserve Capacity for the Facility differs from the Conditional Certified Reserve Capacity previously assigned to the Facility then AEMO must process the application without regard for the Conditional Certified Reserve Capacity.

Changes to clause 4.28C. Early Certification of Reserve Capacity

Similar to that explained for the Conditional Certified Reserve Capacity, the early certification of capacity (at any time before 1 January of Year 1 of the Reserve Capacity Cycle as specified in clause 4.28C.2) can increase the long-term cost of supply to consumers and/or decrease the reliability of the SWIS, if AEMO cannot reasonably estimate the capacity contribution of the Facility applying for early certification of reserve capacity.

4.28C.7. AEMO must, within 10 days of receiving the application, determine if it can reliably set Early Certified Reserve Capacity for the Facility as it would normally grant the Facility if processing an application for Certified Reserve Capacity in accordance with clause 4.11 lodged with AEMO between the date and time specified in clause 4.1.7 and the time specified in clause 4.1.11 for that future Reserve Capacity Cycle. AEMO:

(a) must reject the application if it has cause to believe that it cannot reliably set the Early Certified Reserve Capacity and communicate the rejection to the Market Participant; otherwise

(b) must, within 90 days of receiving the application, set Early Certified Reserve Capacity for the Facility to that amount it would normally grant the Facility if processing an application for Certified Reserve Capacity in accordance with clause 4.11.

To be considered by the Rule Change Panel: possible changes to allow AEMO run the relevant level method a second time before/after receiving Reserve Capacity Securities

Clause 4.1 of the market rules specifies the timeline by which the main events in a Reserve Capacity Cycle occur. The process for the early certification of capacity (Clause 4.28B) and certification of new small generators (4.28C) are not required to comply with the timetable in clause 4.1.

Clause 4.1.32 allows AEMO to modify or extend a date or time specified under clause 4.1.

Some of the main events for the certification and assignment of Reserve Capacity are listed below:

- AEMO receives applications for the certification of Reserve Capacity between 1 May and 1 July in Year 1 of the reserve capacity cycle.
- AEMO notifies each applicant for certification of Reserve Capacity of the Certified Reserve Capacity to be assigned by 19 August of Year 1. This implies that AEMO runs the methods for the calculation of Certified Reserve Capacity, including the relevant level method, based on applications received by 1 July of Year 1.
- AEMO receives Reserve Capacity Securities from Market Participants by 2 September of Year 1.
- Also by 2 September of Year 1 (or 14 September of Year 1), each Market Participant holding Certified Reserve Capacity for the Reserve Capacity Cycle provides to AEMO notification as to how its Certified Reserve Capacity will be dealt with including the total amount of Reserve Capacity the Market Participant intends to trade bilaterally and the amount it has decided not to be made available to the market.
- On the first business day following the notification deadline in the previous bullet point (2 September), AEMO confirms to each Market Participant the amount of Certified Reserve Capacity that can be traded from its Facilities.
- AEMO publishes the Certified Reserve Capacity for each Facility after the dead line in the previous bullet point.

It is possible that the capacity contribution of Facilities change after AEMO calculates them by 19 August of Year 1. This is because the capacity value of some intermittent generators such as wind and solar farms is dependent on the contribution of other intermittent generators in the system. If a large amount of capacity from solar and wind farms is withdrawn or not assigned capacity credits before or after the provision of Reserve Capacity Security to AEMO, the capacity contribution for the remaining solar and wind farms changes.

Under the current market rules, it is possible that some applicants withdraw their application for Certified Reserve Capacity before providing Reserve Capacity Security to AEMO.

The Public Utilities Office proposed improvements to the Reserve Capacity pricing in the market rules. Under the proposed changes, AEMO is to award capacity credits to new floating price capacity and existing capacity providers first and, if an adequate level of capacity is not achieved, then award all capacity resources that opted for a price lock-in. So it is possible that some of the intermittent generation Facilities, that were to be assigned Certified Reserve Capacity based on the results of the relevant level method, do not receive Certified Reserve Capacity.

The market rules can be amended to allow AEMO to run the relevant level method a second time after receiving Reserve Capacity Securities, declaration of bilateral trades, and the determination of any capacity not receiving capacity credits. This change should allow adjustment to Reserve Capacity Security and bilateral trade amounts to be declared after the recalculation of Certified Reserve Capacities.

Sensitivity analysis results in attachment 2 show that interaction between the capacity value of intermittent generators can be large if the entry or exit of intermittent generators is large. The absolute interaction amount between the capacity value of solar and wind farms could reach to 55 MW. This represents the effect of the capacity value of solar and wind farms on each other.

Changes to clause 4.11.3C and 4.11.3E

The proposed changes to the relevant level method no longer use constant parameters K and U.

The ERA is also required to review the relevant level method again by 1 April 2021. The approval and implementation of the proposed relevant level method is expected to happen in 2020. There will not be sufficient time before 1 April 2021 to assess the application of the proposed method in practice. The next review of relevant level method can be postponed to 1 April 2022.

4.11.3C. For each three year period, beginning with the period commencing on 1 January 2022, the Economic Regulation Authority must, by 1 April of the first year of that period, conduct a review of the Relevant Level Methodology. In conducting the review, the Economic Regulation Authority:

(a) must examine the effectiveness of the Relevant Level Method in meeting the Wholesale Market Objectives; and

(b) may examine any other matters that the Economic Regulation Authority considers to be relevant.

4.11.3E. At the conclusion of a review under clause 4.11.3C, the Economic Regulation Authority must publish a final report containing:

(a) details of the Economic Regulation Authority's review of the Relevant Level Method;

(b) a summary of the submissions received during the consultation period;

(c) the Economic Regulation Authority's response to any issues raised in those submissions;

(d) any recommended amendments to the Relevant Level Method which the Economic Regulation Authority intends to progress as a Rule Change Proposal.

Information to be Released via the Market Web Site

10.5.1(f)x the following information identified for a Reserve Capacity Cycle under the Relevant Level Method:

1. the System Demand calculated in Step 8(c) determined for each Trading Interval in the period identified in Step 1(a).

2. the Load for Scheduled Generation calculated in Step 8(c) determined for each Trading Interval in the period identified in Step 1(a).

3. the Capacity Outage Probability Table calculated in Step 6.

4. the Annual_Relevant_Level_Candidate_Facilities_Fleet determined in Step 10(a).

5. the Full_Period_Relevant_Level_Candidate_Facilities_Fleet estimated in Step 10(b).

6. for each Technology Class c the Technology_Class_Relevant_Level(c) calculated in Step 10(b).

7. the amount of CF_Generation(c) in Step 8(b) for Biogas Technology Class, Solar Technology Class, Wind Technology Class and any New Technology Class identified by AMEO under the Relevant Level Method, determined for each Trading Interval in the period identified in Step 1(a).

Pseudocode for the calculation of Capacity Outage Probability Table in Step 16

The pseudocode provided below can facilitate the interpretation of the calculation of capacity outage probability table in Step 16 of Appendix 9. This can also assist AEMO in implementing the proposed relevant level method.

algorithm COPT-Calculation **is:**

input: table array $G_{SG,DSM}(C,U)$ comprising the variables *C* for Certified Reserve Capacities and *U* for Forced Outage Rates for the Scheduled Generator and Demand Side Programme Facilities identified in Step 15,

outage step *s=1*

output: table array *COPT(Outage,* P'_X, P'_{X-C},*P(X))* comprising variables *Outage* for outage quantity expressed in MW and corresponding P'_X, P'_{X-C} and *P(X)*.

(initialise *COPT* by creating a table array comprising variables Outage, P'_X, P'_{X-C},*P(X)* and number of rows equal to the sum of quantities for variable *C* in table array $G_{SG,DSM}$ plus two. Fill *COPT* with zero)

for each *(C,U)* **in** table array $G_{SG,DSM}$ **do**

set *c_prob* **to**1

set *X* **to** 0

while *c_prob* **is greater than** 0

set for row index *X* **in** *COPT* the amount of variable *Outage* **to** *X*

if *X* equals 0 **then**

set for row index *X* **in** *COPT* the amount of variable P'_X ***to** 1*

else

set for row index *X* **in** *COPT* the amount of variable P'_X **to** the amount of *P(X)* in row index *X* of *COPT*

end if

if (*X*-*C*) **is less than or equal to** 0 **then**

set for row index *X* **in** *COPT* the amount of variable P'_{X-C} to 1

else

set *idx* **to** the index of the row in *COPT* where the amount of variable *Outage* equals *X-C*

set for the row *X* in *COPT* the amount of variable P'_{X-C} to the amount of variable P'_X in row *idx*

end if

set for the row index *X* **in** *COPT* the amount of variable *P(X)* **to**

$$P'_X \times (1-U) + U \times P'_{X-C}$$

set *c_prob* **to** the amount of variable *P(X)* in row *X* of *COPT*

set *X* **to** *X+s*

end while

end for

return *COPT*

(the calculation in Step 16 uses only the variables *Outage* and *P(X)* in the *COPT* calculated in the above algorithm).

Attachment 2: Sensitivity analyses and example calculation

The ERA conducted several sensitivity analysis scenarios to explore the effect of different factors on the outcomes of the proposed method. Additionally, the ERA analysed possible variation in capacity value results from year to year for both the intermittent generation fleet capacity value and individual facility capacity values.

Sensitivity analyses are based on the sample model the ERA developed in its review of the relevant level method. Further details about the sample model can be found in the ERA's final report on the review of the relevant level method.[1]

The ERA improved the sample model as explained in section 1.1. The calculation of the sample model is explained in detail and in conjunction with the calculation steps in the proposed relevant level method. This provides a detailed example calculation to facilitate the interpretation of the changes proposed and the assessment of the rule change proposal.

Although the proposed calculation in Appendix 9 uses a seven-year sample period (Step 1(a)), the analysis provided in this report is based on a sample period of five years. This is because the available estimated output of New Candidate Facilities currently covers a maximum of five years only. The proposed changes to the Relevant Level Method are based on a sample period of seven years to reduce the variability of results between years.

1.1 2017 reserve capacity cycle

In its review of the relevant level method, the ERA developed a sample model to illustrate the application of the proposed relevant level method. The model calculated the Relevant Level of Candidate Facilities for the 2017 Reserve Capacity Cycle (the 2019/20 Capacity Year) using their observed (or estimated) output from 1 April 2012 to 1 April 2017. AEMO used the current relevant level method to estimate Relevant Levels for the same capacity year.

The sample model calculated several estimates of Relevant Level for the fleet of Candidate Facilites, including:

- Relevant Level based on system demand and generation data for each year in the five-year period between 2012 and 2017. This provided a sample of five Annual_Relevant_Level_Candidate_Faciliitlies (Step 10(a)). Results showed that the Relevant Level of the fleet of intermittent generators varied from year to year.
- A longer-term estimate of the Relevant Level of the fleet of Candidate Facilites based on the time series of demand and output of intermittent generators for the whole five-year period between 2012 and 2017 (Full_Period_Relevant_Level_Candidate_Facilities_Fleet as in Step 10(b)).

The ERA improved the sample model and remedied one error in the input data to the model.[2] Results of the enhanced sample model are presented in Table 1. The improvements to the

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

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

sample model provided results that are generally consistent with that presented in the ERA's review report.

For comparison, AEMO's estimate of the total capacity value of intermittent generators in the SWIS for the capacity year 2019/20 was approximately 183 MW.

Table 1. Relevant Level of the fleet of Candiate Facilities (2017 Reserve Capacity Cycle)

Relevant_Period	Relevant Level (MW) (published in the ERA's review report)	Relevant Level (MW), enhanced sample model
2012/13	200	214
2013/14	377	403
2014/15	190	196
2015/16	253	266
2016/17	180	193
2012–17 (full period)	250	264

The proposed method sets the relevant level for the fleet of candidate facilities as the smaller of the median of the annual relevant levels and the full period relevant level (Step 11(a)):

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

The fleet Relevant Level in this sample model is set by the observed (or estimated) output of Candidate Facilities in the 2012/13 period. Step 11(a) specifies that the Selected_Period is 2012/13, because the fleet Relevant Level is set by the annual Relevant Level in the 2012/13 period. This Selected_Period is used in the calculation specified in Step 11(b).

Table 2 shows the Relevant Level of facilities in each Technology Class as a group calculated based on Step 11(b). Using the results in Table 2 and the calculation Steps 11(c), the amount of interaction between solar and wind technology classes is:

$$\begin{aligned} Solar\_Wind\_Interaction\_Effect &= 214 - (14.7 + 39 + 159) \\ &= 1.3\ MW \end{aligned}$$

In the sample model presented in the ERA's review of the relevant level method, the amount of interaction between solar and wind generators was evenly allocated to each of the solar and wind technology classes. Sensitivity analysis results showed that the amount of interaction between solar and wind generators can be large and is variable. To dampen the variability of results between years, the proposed method allocates the interaction effect in proportion to technology class relevant levels (Step 11(d)).

Based on the calculation in Step 11(d), the adjusted technology class capacity values are presented in Table 3. The table also includes additional data to indicate the Relevant Level as a percentage of installed capacity of each technology class. This data is shaded grey to indicate that it is not part of the calculation in the proposed method. For the rest of this appendix, all shaded columns in tables represent information that is not used in the proposed calculation of relevant level.

Table 2. Technology Class relevant level for the selected period 2012/13 (2017 Reserve Capacity Cycle)

Technology_Class_Relevant_Level	Net_Demand data	Relevant_Period	Relevant Level (MW)
Technology_Class_Relevant_Level (Biogas Technology Class)	System Demand-CF_Generation(Biogas Technology Class)x2	2012/13 (Selected_Period)	14.7*
Technology_Class_Relevant_Level (Solar Technology Class)	System Demand-CF_Generation(Solar Technology Class)x2	2012/13 (Selected_Period)	39
Technology_Class_Relevant_Level (Wind Technology Class)	System Demand-CF_Generation(Wind Technology Class)x2	2012/13 (Selected_Period)	159

**Note: the amount of Relevant Level for the Biogas Technology Class was determined used a linear interpolation. For instance, with a Net_Demand offset of 15 MW, LOLE calculated for Step 18(c) was 0.00026825, whereas at a Net_Demand offset of 14 MW, LOLE was 0.00026449. The target LOLE (estimated in Step 18(a)) was 0.000267. A linear interpolation between 14 and 15 MW point estimates, yielded a Relevant Level of 14.7 MW at the target LOLE of 0.00026825.*

Table 3. Technology class relevant levels (2017 Reserve Capacity Cycle)

Adjusted_Technology_Class_Relevant_Level	Relevant Level (MW)	Total installed capacity of technology class (MW)	Relevant Level of technology class as % of total installed capacity
Adjusted_Technology_Class_Relevant_Level(Biogas)	14.7	21.598	68
Adjusted_Technology_Class_Relevant_Level(Solar)	39.25	120	33
Adjusted_Technology_Class_Relevant_Level(Wind)	160.04	606.57	26
Total (all Candidate Facilities)	214	748.168	29

Although not required by the proposed method, this analysis repeated the calculation in Step 11(b) using data from 2013/14, 2014/15, 2015/16, 2016/17 and 2012 to 2017 as the Relevant_Period. The results of this analysis provided insights about the variation in technology class Relevant Levels from year to year, as presented in Table 4.

Table 4. Technology class relevant level for different Relevant_Period used in Step 11(b) and Solar_Wind_Interaction_Effect (Step 11(c)) (2017 Reserve Capacity Cycle)

Technology_Class_Relevant_Level	Relevant_Period used in Step 11(b), MW				
	2013/14	2014/15	2015/16	2016/17	2012 to 2017
Technology_Class_Relevant_Level (Biogas Technology Class)	16	14	15	15	15
Technology_Class_Relevant_Level (Solar Technology Class)	44	69	44	57	45
Technology_Class_Relevant_Level (Wind Technology Class)	326	97	207	130	203
Solar_Wind_Interaction_Effect	17	16	0	-9	1

Table 4 shows that most of the variation in the intermittent generation fleet capacity value is due to the variation of the capacity value of wind technology class followed by solar technology class. The biogas technology class has relatively stable capacity contribution to the reliability of the SWIS.

The solar and wind interaction effect is an indicator of the effect of capacity value of generators on each other. For example, the interaction effect in 2013/14 period is 17 MW. This, for example, shows if all solar facilities had withdrawn their application for Certified Reserve Capacity, wind generators would have had 17 MW less capacity value than the 326 MW estimated. Or for the 2016/17 period, if all solar facilities had withdrawn their application, wind facilities would have had 9 MW more capacity value than the 130 MW estimated.

Table 5 presents the results of the allocation method specified in Steps 12 and 13. Many Candidate Facilities for the 2017 Reserve Capacity Cycle could have earned more Certified Reserve Capacity if AEMO used the proposed Relevant Level Method instead of the current Relevant Level Method for that Reserve Capacity Cycle.

All biogas facilities received a lower Relevant Level than that estimated by the current Relevant Level Method. When compared to the results of the current method, the largest increase in Relevant Level was for Collgar Wind Farm (+12.2 MW) followed by Badgingarra Wind Farm (10.94 MW). The largest decrease in Relevant Level was for Emu Downs Wind Farm (-4.3 MW).

Table 5. Allocated Relevant Level to Candidate Facilities (2017 Reserve Capacity Cycle)

Facility	Maximum Capacity (MW)	Facility_Average_Performance_Level in Step 12(b) (MW)	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Capacity Credits assigned based on the current Relevant Level Method (MW)	Difference between proposed and current methods (MW)
ALBANY_WF1	21.6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ALINTA_WWF	89.1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BADGINGARRA_WF1	130	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BIOGAS01	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BLAIRFOX_KARAKIN_WF1	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BREMER_BAY_WF1	0.6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DCWL_DENMARK_WF1	1.44	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EDWFMAN_WF1	80	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GRASMERE_WF1	13.8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GREENOUGH_RIVER_PV1	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
HENDERSON_RENEWABLE_IG1	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
INVESTEC_COLLGAR_WF1	206	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
KALBARRI_WF1	1.6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MERSOLAR_PV1	100	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MWF_MUMBIDA_WF1	55	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NORTHAM_SF_PV1	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
RED_HILL	3.64	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ROCKINGHAM	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SKYFRM_MTBARKER_WF1	2.43	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SOUTH_CARDUP	4.158	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TAMALA_PARK	4.8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

**Note: The quantity of Scaling_Factor calculated for each Technology Class was: Scaling_Factor(Biogas)=0.9263, Scaling_Factor(Solar)=0.7579, Scaling_Factor(Wind)=0.8044.*

1.2 2018 Reserve capacity cycle

The sample model was also run for the 2018 Reserve Capacity Cycle. The capacity value results for the fleet of Candidate Facilities in 2018 are presented in Table 6. For comparison, AEMO's estimate of the total capacity value of intermittent generators in the SWIS for the same capacity year 2020/21 was approximately 258 MW.

Table 6. Relevant Level of the fleet of Candidate Facilities (2018 Reserve Capacity Cycle)

Relevant_Period	Relevant Level (MW)
2013/14	587
2014/15	310
2015/16	352
2016/17	336
2017/18	292
2013–18 (full period)	352

The proposed method sets the relevant level for the fleet of candidate facilities as the smaller of the median of the annual relevant levels and the full period relevant level (Step 11(a)):

$$Relevant\_Level\_Candidate\_Facilities\_Fleet = 336$$

The fleet Relevant Level in this sample model is set by the observed (or estimated) output of Candidate Facilities in the 2016/17 period.

Table 7 shows the Relevant Level of facilities in each Technology Class as a group calculated based on Step 11(b). Using the results in Table 7 and the calculation Steps 11(c), the amount of interaction between solar and wind technology classes is negative 33.7 MW.

Based on the calculation in Step 11(d), the adjusted technology class capacity values are presented in Table 8. The table also includes additional data to indicate the Relevant Level as a percentage of installed capacity of each technology class.

Similar to that presented for the 2017 Reserve Capacity Cycle, the analysis repeated the calculation in Step 11(b) using data from 2013/14, 2014/15, 2015/16, 2017/18 and 2013 to 2018 as the Relevant_Period. The results of this analysis provided insights about the variation in technology class Relevant Levels from year to year, as presented in Table 9. Similar to that observed in the 2017 Reserve Capacity results, most of the variation in the intermittent generation fleet capacity value is due to the variation of the capacity value of wind technology class followed by solar technology class. The biogas technology class has relatively stable capacity contribution to the reliability of the SWIS.

However, with increased installation of solar and wind generators the magnitude of variation in technology class capacity values has increased. The interaction between solar and wind technology class capacity values has also increased.

For example, the interaction effect in 2013/14 period is 55.4 MW. This, for example, shows if all solar facilities had withdrawn their application for Certified Reserve Capacity, wind generators would have had 55.4 MW less capacity value than the 461 MW estimated. Or for the 2015/16 period, if all solar facilities had withdrawn their application, wind facilities would have had 35.5 MW more capacity value than the 308 MW estimated.

Table 7. Technology Class relevant level for the selected period 2016/17 (2018 Reserve Capacity Cycle)

Technology_Class_Relevant_Level	Net_Demand data	Relevant_Period	Relevant Level (MW)
Technology_Class_Relevant_Level (Biogas Technology Class)	System Demand-CF_Generation(Biogas Technology Class)x2	2016/17 (Selected_Period)	15.7
Technology_Class_Relevant_Level (Solar Technology Class)	System Demand-CF_Generation(Solar Technology Class)x2	2016/17 (Selected_Period)	70
Technology_Class_Relevant_Level (Wind Technology Class)	System Demand-CF_Generation(Wind Technology Class)x2	2016/17 (Selected_Period)	284

Table 8. Technology class relevant levels (2018 Reserve Capacity Cycle)

Adjusted_Technology_Class_Relevant_Level	Relevant Level (MW)	Total installed capacity of technology class (MW)	Relevant Level of technology class as % of total installed capacity
Adjusted_Technology_Class_Relevant_Level(Biogas)	15.7	21.598	73
Adjusted_Technology_Class_Relevant_Level(Solar)	63.3	150.96	42
Adjusted_Technology_Class_Relevant_Level(Wind)	257.0	1021.87	25
Total (all Candidate Facilities)	336	1194.428	28

Table 10 presents the results of the allocation method specified in Steps 12 and 13. Many Candidate Facilities for the 2018 Reserve Capacity Cycle could have earned more Certified Reserve Capacity if AEMO used the proposed Relevant Level Method instead of the current Relevant Level Method.

Table 9. Technology class relevant level for different Relevant_Period used in Step 11(b) and Solar_Wind_Interaction_Effect (Step 11(c)) (2018 Reserve Capacity Cycle)

Technology_Class_Relevant_Level	Relevant_Period used in Step 11(b), MW				
	2013/14	2014/15	2015/16	2017/18	2013 to 2018
Technology_Class_Relevant_Level (Biogas Technology Class)	16.6	14.5	15.5	16.6	15.5
Technology_Class_Relevant_Level (Solar Technology Class)	54	83	64	33	64
Technology_Class_Relevant_Level (Wind Technology Class)	461	220	308	242	307
Solar_Wind_Interaction_Effect	55.4	-7.5	-35.5	0.4	-34.5

Table 10. Allocated Relevant Level to Candidate Facilities (2018 Reserve Capacity Cycle)

Facility	Maximum Capacity (MW)	Facility_Average_Performance_Level in Step 12(b)	Relevant Level in Step 14 (MW)	Relevant_Level (% of maximum capacity)	Capacity Credits assigned based on the current Relevant Level Method (MW)	Difference between proposed and current methods (MW)
ALBANY_WF1	21.6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ALINTA_WWF	89.1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
AMBRISOLAR_PV1	0.96	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BADGINGARRA_WF1	130	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BADGINGARRA_WF1_UPG_1	17.5	[redacted]	[redacted]	[redacted]		
BIOGAS01	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BLAIRFOX_KARAKIN_WF1	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BREMER_BAY_WF1	0.6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DCWL_DENMARK_WF1	1.44	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EDWFMAN_WF1	80	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GRASMERE_WF1	13.8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GREENOUGH_RIVER_PV1	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GREENOUGH_RIVER_PV1_UPG_1	30	[redacted]	[redacted]	[redacted]		
HENDERSON_RENEWABLE_IG1	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
INVESTEC_COLLGAR_WF1	206	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
KALBARRI_WF1	1.6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MERSOLAR_PV1	100	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MWF_MUMBIDA_WF1	55	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NORTHAM_SF_PV1	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
RED_HILL	3.64	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ROCKINGHAM	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SKYFRM_MTBARKER_WF1	2.43	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SOUTH_CARDUP	4.158	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TAMALA_PARK	4.8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
WARRADARGE_WF1	183.6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
YANIDN_WF1	214.2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

**Note: The quantity of Scaling_Factor calculated for each Technology Class was: Scaling_Factor(Biogas)=0.9682, Scaling_Factor(Solar)=1.2384, Scaling_Factor(Wind)=0.8104.*

1.3 Assignment of Certified Reserve Capacities based on the proposed clause 4.11.2(c)

The proposed changes to the market rules include an additional clause 4.11.2(c). The purpose of this clause is to dampen possible variations in capacity value results between years and provide a glide path for the transition to the proposed Relevant Level Method. Clause 4.11.2(c) specifies that AEMO must assign a quantity of Certified Reserve Capacity to the relevant Facility for that Reserve Capacity Cycle equal to the average of the Relevant Level assigned to the Facility using the relevant level method in Appendix 9 and any available Certified Reserve Capacity assigned to the relevant Facility in the three preceding Reserve Capacity Cycles.

This clause does not apply to a Facility that is yet to re-enter service after significant maintenance or is to re-enter service after having been upgraded since the date and time specified in clause 4.1.12(b), or otherwise modified or extended under clause 4.1.32, for the preceding Reserve Capacity Cycle to the relevant Reserve Capacity Cycle.

Results in sections 1.1 and 1.2 are used to assess the effect of clause 4.11.2(c) on the amount of Certified Reserve Capacity that would have been assigned to Facilities, if AEMO had used the proposed Relevant Level Method in the 2017 and 2018 Reserve Capacity Cycles. Results are presented in Table 11.

Table 11. Assignment of Certified Reserve Capacity based on the proposed clause 4.11.2(c)

Candidate_Facility	2016/17	2017/18	2018/19	Appendix 9 results (2019/20)	Appendix 9 results (2020/21)	2019/20 Certified Reserve Capacity assigned based on proposed clause 4.11.2(c)	2020/21 Certified Reserve Capacity Assigned based on proposed clause 4.11.2(c)
ALBANY_WF1	8.223	7.809	7.757	8.330	8.052	[redacted]	[redacted]
ALINTA_WWF	21.699	23.203	26.096	27.925	23.191	[redacted]	[redacted]
AMBRISOLAR_PV1			-		0.352		[redacted]
BADGINGARRA_WF1				46.682	39.093	[redacted]	[redacted]
BADGINGARRA_WF1_UPG_1					5.555		[redacted]
BIOGAS01	0.93	1.795	1.654	1.532	1.517	[redacted]	[redacted]
BLAIRFOX_KARAKIN_WF1	0.97	0.838	0.824	0.849	0.649	[redacted]	[redacted]
BREMER_BAY_WF1	0.078	0.112	0.151	0.234	0.230	[redacted]	[redacted]
DCWL_DENMARK_WF1	1.118	0.845	0.695	0.634	0.563	[redacted]	[redacted]
EDWFMAN_WF1	17.734	17.8	28.037	25.830	19.467	[redacted]	[redacted]
GRASMERE_WF1	5.23	4.957	5.074	5.808	5.402	[redacted]	[redacted]
GREENOUGH_RIVER_PV1	3.833	3.086	2.528	1.949	2.089	[redacted]	[redacted]
GREENOUGH_RIVER_PV1_UPG_1					13.376		[redacted]
HENDERSON_RENEWABLE_IG1	2.272	2.104	1.938	1.781	1.775	[redacted]	[redacted]
INVESTEC_COLLGAR_WF1	15.048	20.105	20.567	31.135	33.826	[redacted]	[redacted]
KALBARRI_WF1	0.272	0.283	0.323	0.382	0.302	[redacted]	[redacted]
MERSOLAR_PV1				34.344	43.950	[redacted]	[redacted]
MWF_MUMBIDA_WF1	14.9	13.828	10.631	11.452	9.513	[redacted]	[redacted]
NORTHAM_SF_PV1			4.101	2.963	3.569	[redacted]	[redacted]
RED_HILL	2.93	2.876	2.776	2.648	2.885	[redacted]	[redacted]
ROCKINGHAM	2.682	2.576	2.022	2.053	2.311	[redacted]	[redacted]
SKYFRM_MTBARKER_WF1	0.935	0.806	0.766	0.784	0.741	[redacted]	[redacted]
SOUTH_CARDUP	2.446	2.486	2.954	2.803	3.040	[redacted]	[redacted]
TAMALA_PARK	3.933	3.962	4.213	3.883	4.173	[redacted]	[redacted]
WARRADARGE_WF1					51.316		[redacted]
YANDIN_WF1					59.062		[redacted]

RCP Rule Change Panel
Market Advisory Committee

Agenda Item 9: Issues with Reserve Capacity Testing

Meeting 2019_07_29

1. Background

Action Item 12/2019 from the MAC meeting on 2019_06_11 requires:

> RCP Support to include a discussion of the issues raised by Perth Energy regarding Reserve Capacity Testing on the agenda for the 29 July 2019 MAC meeting.

The issues regarding Reserve Capacity Testing were raised in an email from Perth Energy, provided in Attachment 1, that was circulated to the MAC on 5 June 2019 for discussion at the MAC meeting on 11 June 2019 under Agenda Item 10 (General Business). Discussion of the issues was deferred to the July MAC meeting due to insufficient time.

Perth Energy has provided a series of slides to help guide the discussion at the July MAC meeting and to explain its position (Attachment 2).

2. Recommendation

It is recommended that the MAC review the issues presented in the email from Perth Energy, and presented in the slides relating to Reserve Capacity Testing, and:

- discuss the issues;
- discuss options for addressing these issues;
- decide whether to add anything relating to Reserve Capacity Testing to the issues list; and
- determine any other actions, as appropriate.

Attachments

1. Email from Perth Energy regarding issues with Reserve Capacity Testing
2. Perth Energy's slides explaining its position.

Stephen Eliot

From: Patrick Peake <p.peake@perthenergy.com.au>
Sent: Wednesday, 5 June 2019 1:48 PM
To: Stephen Eliot
Subject: Potential Rule Change proposal

Hi Stephen, Jenny

Perth Energy would like to add a review of reserve capacity testing rules to the list of Potential Rule Change Proposals. As you may be aware, Kwinana Swift power station had some issues in being able to demonstrate that it could comply with its reserve capacity obligations earlier this year. During the various efforts to comply with the testing obligations a number of issues arose where we consider that changes to the rules could be justified. The reason for suggesting changes is that Kwinana Swift uses diesel as its primary fuel so a reserve capacity test costs in the order of $100,000 to conduct so any unnecessary testing is clearly in conflict with the market objective of minimising costs.

Issue 1
The level of capacity is tested every six months and this can be done by observing the output during normal operation or during a reserve capacity test. If the output identified by either of these approaches is very close to, but not quite equal to, the certified capacity it would be more economical for the generator to be able to re-nominate this figure as the certified capacity. For example, with a reserve capacity price of around $100,000 per MW per year, the reduction in revenue from a reduction in certified capacity of, say, 5 kW is far less than the cost of re-running a reserve capacity test.

Issue 2
If a generator uses the self-observation method it only has to meet its obligation over one trading interval whereas a capacity test requires this performance over two, nominated, successive intervals. The test is therefore a significantly higher obligation to achieve.

Issue 3
If a generator fails the first reserve capacity test, Market Rule 4.25.4 requires System Management to conduct a second test within 14-28 days. However, MR 4.25.3A prevents this test taking place if the plant is on scheduled outage. There is no rule to cover the situation where a plant is on outage for the 14-28 day period and System Management cannot comply with MR 4.25.4. This occurred at Kwinana Swift and System Management restarted the cycle by calling for two further tests whereas we considered that the first test had taken place already. The situation needs to be clarified.

Issue 4
If a generator fails two reserve capacity tests then System Management must "*reduce the number of Capacity Credits held by the relevant Market Participant for that Facility to reflect the maximum capabilities achieved in either Reserve Capacity Test performed (after adjusting these results to the equivalent values at a temperature of 41°C and allowing for the capability provided by operation on different types of fuels*)". Kwinana Swift achieved its certified reserve capacity level in one trading interval in the first test but failed to achieve this in the second trading interval. This is deemed to be a failed test. However, if the station were to subsequently fail a second test, System Management would have set its capacity credits at the maximum capability achieved which, given the output achieved in one trading interval of the first test, would be the certified reserve capacity obligation level.

Western Energy therefore made the point to AEMO that a second test should not be undertaken because, even if the station achieved zero MW output, the result of the first test would have stood. (In fact, the station should have been assigned a certified level ***above*** its certified reserve capacity obligation because this was the level actually achieved). AEMO insisted that the Rules required a second test to be made resulting in substantial costs to Western Energy.

Kind regards

Patrick

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Agenda Item 9

Some issues with Reserve Capacity Testing

Issue 1 – Cost-benefit of running a test

- For Kwinana Swift the cost of a Reserve Capacity test on diesel is around $80,000
- Reserve capacity payment is around $100,000 per MW per year
- So if the shortfall is less than 0.8 MW it would be more economic to accept the shortfall and not run another test

Issue 2 – Cost difference between self-testing and AEMO-testing

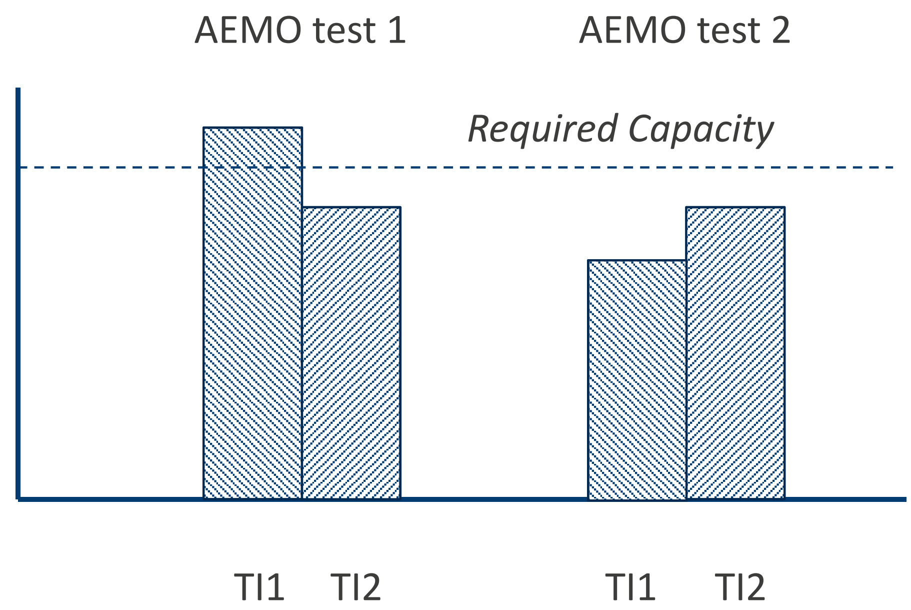
- Self-testing requires operation over only one trading interval – MR4.25.2(a)i
- AEMO-test requires operation at full power of at least two intervals – MR4.25.2(a)ii
- AEMO-test is substantially more expensive

Issue 3 – Ambiguity if plant is on outage

If a plant fails a capacity test:

- AEMO must call a second test not earlier than 14 days and not later than 28 days – MR 4.25.4
- AEMO may not call for a test if the facility is undergoing an outage – MR 4.25.3A(a) & (b)
- Rules do not cover the case where the outage extends across the period of Day 14 to day 28

Issue 4 – AEMO must reduce Capacity Credits “to reflect the maximum capabilities achieved in either Reserve Capacity Test”



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Agenda Item 10: MAC Schedule for 2020

Meeting 2019_07_29

The Rule Change Panel (**Panel**) has:

- considered and accepted a proposed schedule for Panel meetings for 2020; and
- noted proposed meeting dates for 2020 for the Market Advisory Committee (**MAC**) and the Gas Advisory Board (**GAB**).

The MAC is asked to consider and approve the proposed schedule for MAC meetings for 2020, as indicated in the table below. MAC meetings are proposed to occur every six weeks, on Tuesday mornings, starting at 9:30 AM.

The schedule for Panel meetings and the proposed schedule for GAB meetings are provided for information purposes.

Month	Proposed MAC Meetings	Proposed GAB Meetings	Panel Meetings
January 2020	28 January 2020		
February 2020			5 February 2020
March 2020	10 March 2020	26 March 2020	19 March 2020
April 2020	21 April 2020		30 April 2020
May 2020			
June 2020	2 June 2020		11 June 2020
July 2020	14 July 2020		23 July 2020
August 2020	25 August 2020		
September 2020		17 September 2020	3 September 2020
October 2020	6 October 2020		15 October 2020
November 2020	17 November 2020		26 November 2020
December 2020			