RCP | Rule Change Panel
Market Advisory Committee

Meeting Agenda

Meeting Title:	Market Advisory Committee
Date:	Tuesday 5 February 2019
Time:	9:30 AM – 12:00 PM
Location:	Training Room No. 1, Albert Facey House 469 Wellington Street, Perth

Item	Item	Responsibility	Duration
1	Welcome	Chair	5 min
2	Meeting Apologies/Attendance	Chair	5 min
3	Minutes of Meeting 2018_11_20	Chair	5 min
4	Actions Items	Chair	5 min
5	MAC Market Rules Issues List	Chair	10 min
6	Update on the Network and Market Reform Program		
	(a) Status Update (verbal update – no paper)	PUO	5 min
	(b) Market Design and Operation Working Group (MDOWG) Update (verbal update – no paper)	PUO	5 min
	(c) Power System Operation Working Group (PSOWG) Update (verbal update – no paper)	AEMO	5 min
7	AEMO Procedure Change Working Group Update	AEMO	5 min
8	Rule Changes		
	(a) Overview of Rule Change Proposals	Chair	10 min
	(b) Calculation of Relevant Demand for Demand Side Programs	EnelX	20 min

Item	Item	Responsibility	Duration
	(c) Behind-the-meter generation affecting a facility's NTDL status	Energy Made Clean	20 min
9	Wholesale Electricity Market Review 2017/18 Discussion Paper (presentation – no paper)	ERA	20 min
10	Review of the Method for Capacity Valuation of Variable Generation	ERA	20 min
11	MAC Schedule	Chair	5 min
12	General Business	Chair	5 min
Next Meeting: 12 March 2019			

Please note, this meeting will be recorded.

RCP | Rule Change Panel
Market Advisory Committee

Minutes

Meeting Title:	Market Advisory Committee (**MAC**)
Date:	20 November 2018
Time:	09:30 PM – 12:05 PM
Location:	Training Room No. 1, Albert Facey House 469 Wellington Street, Perth

Attendees	Class	Comment
Stephen Eliot	Chair	
Matthew Martin	Minister's Appointee – Small-Use Consumer Representative	
Martin Maticka	Australian Energy Market Operator (**AEMO**)	
Dean Sharafi	System Management	
Will Bargmann	Synergy	
Kei Sukmadjaja	Network Operator	Proxy for Margaret Pyrchla
Jacinda Papps	Market Generators	
Shane Cremin	Market Generators	
Wendy Ng	Market Generators	
Patrick Peake	Market Customers	
Geoff Gaston	Market Customers	
Steve Gould	Market Customers	
Geoff Down	Contestable Customers	Proxy for Peter Huxtable

Apologies	Class	Comment
Andrew Stevens	Market Generators	
Margaret Pyrchla	Network Operator	
Sara O'Connor	Economic Regulation Authority (**ERA**) Observer	
Peter Huxtable	Contestable Customers	

Also in attendance	From	Comment
Jenny Laidlaw	RCP Support	Minutes
Richard Cheng	RCP Support	Presenter

Erin Stone	Public Utilities Office (**PUO**)	Presenter
Mike Hales	AEMO	Presenter
Aditi Varma	PUO	Presenter 9:35 to 9:55 AM
Natalie Robins	ERA	Presenter
Duncan MacKinnon	Australian Energy Council	Observer
Scott Davi~~e~~s	Australian Energy Council	Observer
Oscar Carlberg	Synergy	Observer
Noel Schubert		Observer
Daniel Kurz	Bluewaters Power	Observer
Laura Koziol	RCP Support	Observer
Greta Khan	RCP Support	Observer

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:30 AM and welcomed members and observers to the 20 November 2018 MAC meeting.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above.	
3(a)	**Minutes from Previous Meeting** Draft minutes of the MAC meeting held on 12 September 2018 were circulated on 8 October 2018. The Chair noted that Mr Dean Sharafi had suggested the following change: ***Page 5, Section 5, third last paragraph:*** …Mr Sharafi considered that ~~the ESB was established because the Federal Government did not approve the last recommendation of the Finkel Review, and~~ the WEM was in a better position compared with the NEM in that there was only one government and one network operator involved. … Subject to this change, the MAC accepted the minutes as a true and accurate record of the meeting. **Action: RCP Support to amend the minutes of the 12 September 2018 meeting to reflect the agreed changes and publish on the Rule Change Panel's (Panel's) website as final.**	**RCP Support**

Item	Subject	Action
3(b)	**Minutes from MAC Workshop on Constrained Off Payments** Draft minutes of the MAC workshop held on 24 October 2018 to discuss constrained off payments were circulated to attendees on 7 November 2018. The Chair noted that a revised draft, showing tracked changes suggested by Alinta Energy and AEMO, was distributed in the meeting papers. Subject to these changes, the MAC accepted the minutes as a true record of the workshop.	
	Action: RCP Support to amend the minutes of the 24 October 2018 MAC workshop on constrained off payments to reflect the agreed changes and publish on the Panel's website as final.	**RCP Support**
4	**Action Items** The closed action items were taken as read. **Action 19/2017:** Open – to be progressed as part of the Wholesale Electricity Market (**WEM**) Reform Program. **Action 33/2017:** On hold until early 2019. **Actions 23/2018 and 24/2018:** Mr Mike Hales gave a presentation to the MAC about what information AEMO is able to publish regarding constrained on and constrained off payment amounts under the Market Rules; and what information could be provided to Market Participants early to allow them to predict the size of their constraint payment obligations, which would allow them to budget for these payments. A copy of the presentation is available on the Panel's website. The following points were discussed. • In response to a question from Ms Jenny Laidlaw, Mr Hales advised that actual constraint payment quantities for individual Market Participants were settlement data and therefore confidential, but that aggregated quantities were probably not confidential. • Dr Steve Gould asked whether there was a simple way that AEMO could publish an indicative $/MWh cost estimate, rather than require individual Market Customers to develop their own calculations. Mr Hales replied that this would require AEMO to re-develop the constraint payment calculations, as it did not own the code for the current settlement calculations. AEMO did not intend to undertake this work until 2019 due to competing priorities. • Mr Daniel Kurz noted that a Market Customer cannot determine its actual constrained off payment costs from its Non-STEM Settlement Statements, because the costs are reported as part	

Item	Subject	Action
	of an aggregated amount that includes other costs. Bluewaters had been in recent discussions with AEMO about how to ascertain these costs. Mr Hales agreed that the information could not be determined from a Market Customer's Non-STEM Settlement Statement. • The Chair sought the views of the MAC on how much benefit Market Participants would get from AEMO publishing Theoretical Energy Schedule (**TES**) values, as proposed by AEMO. Mr Shane Cremin noted that the reason for the proposed publication was the current high levels of constrained off payments, and questioned whether the TES values could be published before the likely implementation date of a rule change to reduce the magnitude of these payments. Ms Laidlaw asked whether Market Participants were likely to develop their own processes to estimate their constraint payment costs if these costs were expected to materially reduce in the near future. Mr Cremin thought that it might still be helpful for Market Participants to be able to predict their constraint payment costs, even if they are much smaller in future. Mr Kurz noted that access to actual cost information was more important for Bluewaters. • In response to a question from Mr Cremin, Mr Hales confirmed that the publication of TES values would require a minor system change but no rule changes. Mr Kurz asked whether AEMO intended to publish historical TES values as well as new values going forward. Mr Hales replied that AEMO could look into the provision of historical values if this would be useful for Market Participants. Mr Kurz indicated that publication of TES values for the periods of high constraint payments in March and April 2018 would be very beneficial. • The MAC supported the publication of TES values to assist Market Participants to estimate their upcoming constraint payment costs.	
5	**MAC Market Rules Issues List** The MAC noted the recent updates to the MAC Market Rules Issues List (**Issues List**). The Chair noted that the PUO had advised that it will consider Issue 11 (whole-of-system planning oversight) as part of the WEM Reform Program. The Chair sought the views of the MAC on whether Issue 11 should therefore be closed or placed on hold pending the outcomes of the WEM Reform Program. The MAC agreed with the suggestion made by Ms Wendy Ng and Mr Matthew Martin to place the issue on hold pending the outcomes of the WEM Reform Program.	

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	The MAC also agreed to put Issue 12 on hold pending outcomes of the WEM Reform Program. The Chair noted that Issues 20/38, 44 and 48 will be closed because Pre-Rule Change Proposals addressing the issues (RC_2018_06: Full Allocation of Spinning Reserve Costs, and RC_2018_07: Removal of constrained off compensation for Network Outages) have been presented to the MAC. The Chair sought the views of the MAC on three potential issues that were raised during the 24 October 2018 MAC workshop on constrained off payments but not included in RC_2018_07. • Whether the method used to calculate constrained off compensation should be amended to better reflect the actual costs incurred by Market Generators: after some discussion, the MAC agreed to include this issue in the Issues List and place it on hold until a decision on RC_2018_07 is made, and if the Rule Change Proposal is approved, the changes have been in place for 12 months. • Whether the Minimum STEM Price (currently -$1,000/MWh) should 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. Mr Cremin asked when the ERA's next review was due to be completed. Dr Natalie Robins noted that Ms Sara O'Connor discussed the proposed date with the MAC earlier in 2018, but agreed to report back to the MAC with an updated delivery date. • How to manage potential future scenarios in which multiple generating units that are connected to the same line constitute the largest credible contingency, without imposing excessive constraint payment costs on Market Customers: Ms Laidlaw recollected that the PUO was considering this issue as part of the WEM Reform Program. Mr Patrick Peake asked whether the issue should be considered by the PUO or the ERA, given his concern that the problem was due to Western Power allowing some Market Generators to have low-cost access to the network at the expense of other Market Generators. Mr Martin was uncertain whether the issue was included in the schedule for the WEM Reform Program. There was some discussion about the causes of the issue, who should be responsible for resolving the issue, and whether there	

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	was a need for a central planning function for the South West interconnected system. Dr Robins noted that the discussion paper for the ERA's annual report to the Minister was soon to be published and suggested that stakeholders could raise the issue when providing feedback on the discussion paper.	
	The Chair agreed to discuss the issue with the Chair of the WEM Reform Program's Strategic Consultative Group and report back on the outcomes of that discussion to the MAC.	
	The MAC agreed to include an issue about the need to provide Market Customers with timely advance notice of their upcoming constraint payment liabilities in the Issues List, and to place it on hold pending the implementation of AEMO's proposed changes to the Outstanding Amount calculation in 2019.	
	Action: The ERA to provide an update to the MAC on the expected completion date for the ERA's next review of the methodology for setting the Energy Price Limits under clause 2.26.3 of the Market Rules.	**ERA**
	Action: The MAC Chair to raise the issue of how to manage potential future scenarios in which multiple generating units that are connected to the same line constitute the largest credible contingency with the Chair of the WEM Reform Program's Strategic Consultative Group; and to report back on the outcomes of that discussion to the MAC.	**MAC Chair**
6	**Update on the Network and Market Reform Program**	
	Mr Martin provided the following updates on the WEM Reform Program.	
	• The PUO intends to publish a consultation paper for the WEM Reform Program in early December 2018. The paper is expected to cover the main features of the proposed new market design, a discussion of issues with and options for changes to the Wholesale Market Objectives, and the proposed approach to the cost-benefit analysis for the WEM Reform Program changes. Mr Martin expected the consultation period would be open for six to eight weeks.	
	• Mr Martin noted that the PUO had previously worked with its Reserve Capacity Mechanism (**RCM**) Working Group on the approach for changes to the certification process to account for constrained network access. The PUO intends to go back to the working group in the near future to re-test that approach before publishing a paper with further details for comment.	
	• The PUO's ancillary services work was continuing and it expects to publish a paper in February 2019 outlining the types of	

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services that will be needed for the market going forward, and then start work on the procurement methods for those services. Mr Martin emphasised that the PUO intends to seek feedback on the relevant issues from the Market Design and Operation Working Group (**MDOWG**) and Power System Operation Working Group (**PSOWG**) on these types of papers before finalising a consultation paper.

- The PUO is working on energy storage and intends to publish a consultation paper in February 2019.
- In addition to the work being undertaken through the PSOWG on individual features of the power system security arrangements, the PUO is looking at the architecture and governance of those arrangements, such as what aspects should be covered in the Market Rules, the Technical Rules and the Network Quality and Reliability of Supply Code. A paper on this subject is expected to be published in early 2019.
- The PUO has sent the final report for the proposed RCM pricing changes to the Minister for endorsement, and has started work on drafting the Amending Rules to implement those changes. The PUO plans to have the new rules in place to take effect from the 2019 Reserve Capacity Cycle.
- The network access team is working on a Cabinet submission for approval to draft legislation to be introduced into Parliament in 2019.

Ms Ng asked about the outcomes of the submissions provided by stakeholders on the proposed constrained network access changes. Mr Martin replied that the PUO was working through the submissions and using them as input into the drafting process. In response to a question from Dr Gould, Mr Martin advised that the PUO was seeking approval to publish the submissions.

In response to a question from Mr Peake, Mr Martin clarified that there was no specific working group for market power mitigation. The PUO was working on the ERA's recommendations in relation to the Electricity Generation and Retail Corporation regulatory scheme, and drafting a paper to outline its future approach. A separate, second phase of reform would look at the new market design and consider what consequential changes were necessary to the market power mitigation arrangements.

Mr Martin noted that the MDOWG was not expected to meet until early 2019.

Mr Sharafi noted that the PSOWG had now met three times and gave an overview of the topics covered to date. Mr Sharafi advised that future meetings would cover further work on the constraint framework and the development of reliability standards.

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	Mr Cremin questioned the basis for deciding what WEM Reform Program work was to be undertaken by AEMO and charged to Market Participants, vs what was to be undertaken by the PUO and paid by Government. Mr Martin replied that the working assumption was that the PUO would work on policy design matters while AEMO would look at operationalising the policy design. The PUO intended to take responsibility for all rule drafting. There was some discussion about the rationale for AEMO's early involvement in the market design process and how the program will be funded. Mr Cremin considered that the program costs are likely to be significant and the basis for allocating those costs was not logical.	
7	**AEMO Procedure Change Working Group (APCWG) Update** Mr Sharafi noted that AEMO's internal review of the new Monitoring and Reporting Protocol had taken longer than anticipated. Following discussions with the ERA, AEMO intended to conduct a further round of consultation in early 2019 because of the length of time that had passed since the formal consultation period. The MAC noted the update on AEMO's Market Procedures.	
8(a)	**Overview of Rule Change Proposals** The MAC noted the overview of Rule Change Proposals.	
8(b)	**Indicative Rule Change Proposal Work Program** The MAC noted the indicative Rule Change Proposal work program.	
8(c)	**PRC RC_2018_06 – Full Runway Allocation of Spinning Reserve Costs** Mr Martin noted that the PUO was seeking comments on its Pre-Rule Change Proposal: Full Runway Allocation of Spinning Reserve Costs (RC_2018_06) before its formal submission into the rule change process; and that the issue addressed by the proposal had been discussed by the MAC on several occasions. Ms Aditi Varma provided an overview of the Pre-Rule Change Proposal. The following points were discussed. • Mr Kurz noted that Bluewaters had raised concerns with the block method for Spinning Reserve cost allocation for several years, and thanked the PUO for developing the Pre-Rule Change Proposal. Mr Kurz considered that the full runway method is a more appropriate cost allocation method and would remove inefficiencies that affect the Bluewaters Facilities. Mr Kurz had no issues with the drafting of the proposal.	

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	• Ms Varma noted that the drafting was reviewed by AEMO and RCP Support and updated to reflect their comments, but welcomed any further comments from members and observers. • Ms Varma advised that AEMO's preliminary cost estimate was around $250,000, but requested that AEMO review this figure and provide any new update. Mr Martin Maticka responded that based on its re-estimates, AEMO intended to include a range between $220,000 and $290,000 for the proposal in its Allowable Revenue submission for the July 2019-June 2022 Review Period. • Mrs Jacinda Papps asked whether the magnitude of the proposal's benefits had been assessed. Ms Varma replied that the PUO undertook some static analysis using 2017 historical data, which indicated, for example, that smaller generators were able to receive benefits of up to $1 million across generators. Mr Cremin considered that the issue with the current block methodology was that it deterred Market Generators from offering inexpensive capacity into the Balancing Market and reducing the Balancing Price. Mr Cremin asked whether any analysis had been done on effects of removing this disincentive on energy costs. Ms Varma replied that the PUO had not undertaken this analysis but agreed it might be worth undertaking. In response to a question from Mr Cremin, Mr Kurz advised that while Bluewaters had only assessed the effect on its own dispatch levels, the removal of the effective 200 MW cap imposed by the block method would encourage it to offer additional low-cost capacity into the Balancing Market. Ms Varma agreed to take the question on notice and report back to the MAC. Mr Cremin expected that the analysis would show potential savings of millions of dollars per year, and considered the change should have been made when it was first suggested in 2014. • The Chair noted that the MAC and the Panel previously assigned a Medium urgency rating to the issue. There was some discussion about the relative urgency of the Pre-Rule Change Proposal compared with other proposals that were either open or likely to be submitted in the near future, such as the Pre-Rule Change Proposal: Removal of constrained off compensation for network outages (RC_2018_07). The MAC agreed that RC_2018_06 should retain its Medium urgency rating. • Mrs Papps considered that the issue of new generator connections on a single line increasing the Spinning Reserve	

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	requirement was a higher priority issue than the one being addressed by RC_2018_06. • Most MAC members and observers were supportive of the proposal and its submission into the formal rule change process. However, Mr Will Bargmann advised that Synergy was not yet able to provide comments on the proposal, and intended to do so as part of the formal consultation process. • Mrs Papps asked how AEMO intended to rank two Facilities with the same output level in a Trading Interval. There was general agreement that the choice of method would have no effect on the cost allocation outcomes.	
	Action: The PUO to consider undertaking further analysis to assess the likely effect on energy market prices of moving to a full runway approach for Spinning Reserve cost allocation.	**PUO**
8(d)	**PRC RC_2018_07 – Removal of constrained off compensation for Network Outages** Mr Martin noted that the issue addressed by the Pre-Rule Change Proposal: Removal of constrained off compensation for Network Outages (RC_2018_07) was identified as a high priority issue at the 12 September 2018 MAC meeting. The MAC workshop held to consider the issue on 24 October 2018 focussed on constrained off payments due to network outages and different options to remove those payments. Workshop attendees agreed that option 3 (requiring AEMO to issue an Operating Instruction where a Facility is constrained off due to a network outage) was the most preferable, and the PUO committed to draft a Rule Change Proposal to take the matter forward. Mr Martin noted that the PUO engaged Ms Erin Stone to assist it with the development of the Rule Change Proposal. The PUO hoped that, with high-level support from the MAC, the proposal could be implemented by around April 2019, to address any issues that may arise if there is a seasonal aspect to the network outages that caused the high constraint payments in 2018. Ms Stone provided the MAC with an overview of the Pre-Rule Change Proposal. Ms Stone noted that the proposal would need to be progressed using the Standard Rule Change Process and reiterated Mr Martin's suggestion that it be progressed as quickly as possible under that process. The following points were discussed. • Ms Ng asked whether Operating Instructions were to be issued for all or only some network outages. Ms Laidlaw noted that the intention discussed at the workshop was that if System Management dispatched a Scheduled Generator or Non-Scheduled Generator down out of merit because of a	

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	network outage, then afterwards it would issue an Operating Instruction for the period to the Market Generator, which would switch off any constraint payments.	
	• Mrs Papps asked whether a Market Generator might receive an Operating Instruction that dealt with some past intervals and some future intervals. Ms Laidlaw questioned the need to issue Operating Instructions in advance because the current Dispatch Advisory and Dispatch Instruction mechanisms were sufficient to meet the operational requirements. Ms Laidlaw agreed with Mrs Papps that the use of Operating Instructions was intended to be a retrospective settlement solution rather than an operational tool.	
	There was some discussion about where the retrospective nature of these Operating Instructions should be clarified (e.g. in the text of the Rule Change Proposal, the Power System Operation Procedure: Dispatch, or the Market Rules themselves).	
	• Mrs Papps questioned whether the proposed amendments would have an adverse effect on the certification of a Non-Scheduled Generator. There was general agreement that the output of a Non-Scheduled Generator should be estimated for the relevant certification Trading Intervals in the same way as if it had an approved Consequential Outage.	
	• Ms Laidlaw questioned whether Operating Instructions were issued to the Balancing Portfolio; and whether Synergy should be made ineligible for constraint payments because the output of one of its generators was reduced, since in most cases the output of another Synergy generator would be increased by a corresponding quantity. Mr Sharafi agreed to confirm how and whether Operating Instructions were used for the Balancing Portfolio and report back to the PUO and the MAC.	
	• Ms Ng asked whether consideration had been given to the implications of the proposal on a contracted Scheduled Generator that was constrained down because of a network outage and then obliged to buy energy from the Balancing Market to meet its contracted position. Ms Laidlaw noted that the proposed outcome is similar to the outcome for a Scheduled Generator that is disconnected by a network outage, in that the Market Generator does not have to pay Capacity Cost Refunds but is not eligible for any compensation.	
	Mr Peake suggested that Western Power should be required to pay compensation in these circumstances as an incentive to optimise its maintenance. Ms Kei Sukmadjaja noted that Western Power tries to minimise the impact of its outages as	

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	much as possible, but there are sometimes inevitable situations where network outages have to happen. • In response to a question from Mr Cremin, Ms Stone and Mr Maticka confirmed that AEMO considered the implementation costs would be low. • Mr Kurz noted that Market Generators had specific obligations to respond to Operating Instructions and questioned whether the same obligations should apply to the proposed retrospective Operating Instructions. Ms Laidlaw replied that RCP Support was aware of the issue but considered it should be relatively easy to specify different response obligations for the retrospective Operating Instructions. The MAC supported the submission of RC_2018_07 into the formal rule change process once the PUO had considered the issues raised during the MAC discussion. The MAC confirmed the High urgency rating it previously assigned to the proposal.	
	Action: AEMO to provide advice to the PUO and the MAC about how and whether Operating Instructions are used for the Balancing Portfolio.	**AEMO**
8(e)	**Pre-PRC – Adjusting Non-STEM Settlements Using Latest Available Data** Mr Hales gave a presentation to the MAC about two issues in the non-STEM settlement adjustment process that AEMO considers should be addressed by a change to the Market Rules. Mr Hales noted that AEMO wished to consult with the MAC, as required under clause 2.5.1A of the Market Rules, before commencing the development of a Rule Change Proposal to address the issues. A copy of the presentation is available in the meeting papers. Mrs Papps noted that she developed a Pre-Rule Change Proposal in 2012 to allow Minimum and Maximum TES values to be recalculated. Mrs Papps agreed it made sense to not recalculate prices, but did not understand why the recalculation of TES values, which are quantities rather than prices, was not allowed. Ms Laidlaw suggested that the restriction was mainly to avoid IT costs. Mr Hales advised that AEMO would consider whether the recalculation of TES values should be allowed as part of its development of the Rule Change Proposal. The MAC agreed that AEMO should develop a Pre-Rule Change Proposal to address the two issues raised in the presentation.	
9	**Treatment of Storage Technologies in other Jurisdictions** Dr Robins gave a presentation to the MAC on the treatment of storage technologies in other jurisdictions. A copy of the presentation	

Item	Subject	Action
	is available in the meeting papers. The following points were discussed. • In response to a question from Mr Cremin, Dr Robins confirmed that previously in the Great Britain market any type of storage was assigned a capacity value equivalent to 96.11% of its rated capacity. However, the de-rating factor for 30-minute duration batteries was recently reduced from 96.11% to 17.89%. Mr Cremin considered the changes mirrored the WEM's experience with Demand Side Programmes. • Dr Robins noted a proposal in the Great Britain market to prohibit network operators from operating storage assets, due to the potential impacts on competition in the market. Mr Peake observed that Western Power was involved in various battery trials and micro-grid developments, but did not have a retail licence and was not required to comply with the obligations of a retail licence holder. Mr Cremin noted that network operators in the National Electricity Market were restricted from buying and selling electricity via storage assets except through a ring-fenced entity. • Mr Martin advised that the PUO was working with AEMO on how to facilitate energy storage in the WEM. The PUO considered the best option was for large scale storage to initially provide ancillary services via contract-based arrangements, with a view to having these facilities fully participate in the future ancillary service markets. The PUO was also working with Tesla, AEMO and Western Power on options for storage; and intended to talk with the ERA about the findings of its investigations. The PUO's first focus was on the ancillary services that will be needed going forward, as it considered energy storage has a large role to play in the provision of those services. Mr Martin noted that various small-scale storage trials were also underway, along with work on a virtual power plant proposal for the Goldfields. • Mr Noel Schubert considered that in some situations the quickest, easiest and most cost-effective solution was for a network company to install a battery or micro-grid; and that regulatory barriers should not inhibit sensible solutions. Mr Martin noted that the PUO intended to publish a paper in the near future on standalone power systems, and would be seeking consultation before looking at the different approaches that can be followed for standalone power systems. • Mr Cremin suggested that changes to the Individual Reserve Capacity Requirement rules could be used to incentivise the	

Item	Subject	Action
	efficient use of small-scale storage; and that changes to the Technical Rules were also needed to remove unnecessary barriers to the participation of storage in the market. • In response to a question from Mr Peake, Mr Martin advised that he was unaware of any current policy initiatives to subsidise batteries.	
10	**Review of the MAC Constitution and MAC Appointment Guidelines and the 2019 MAC Composition Review** The Chair noted that on 13 November 2018 the Panel published an invitation for submissions on proposed amendments to the MAC Constitution and MAC Appointment Guidelines. The proposed amendments include, among other things, changes to more evenly distribute the terms for discretionary MAC members, so that an approximately even number of positions expire each year. This will address the current imbalance that has caused seven discretionary positions to expire in February 2019 but only two discretionary positions to expire in February 2020. The Chair advised that the submission period would close on 10 December 2018. In addition, a call for nominations for the seven positions that are due to expire in February 2019 was due to be published at the end of November 2018. In response to a question from Mr Maticka, the Chair advised that the Panel had not yet decided how it would determine which nominees to appoint for only one year. Mr Maticka asked whether the composition review had considered situations where a member, whose tenure only covered another one or two meetings, left the MAC. The Chair replied that there was some discussion of this matter in the invitation for submissions. Mr Maticka suggested that the Panel make its selection criteria less onerous to streamline the assessment process.	
11	**MAC Schedule** The MAC noted the MAC meeting schedule for the remainder of 2018/19.	
12	**General Business** The Chair noted that the ERA recently experienced a problem with its back-end systems, which delayed the publication of submissions received for the recent calls for further submissions on Rule Change Proposals: Omnibus Rule Change (RC_2014_07) and Removal of Market Operation Market Procedures (RC_2015_01). The problem has been corrected and the submissions are now available on the Panel's website.	

The meeting closed at 12:05 PM.

RCP | Rule Change Panel
Market Advisory Committee

Agenda Item 4: MAC Action Items

Meeting 2019_02_05

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
19/2017	The PUO to consult with AEMO and RCP Support on how to address the concerns raised by MAC members about the 2017/03 Amending Rules and develop a proposal for consideration at the next MAC meeting.	PUO/ AEMO/ RCP Support	2017_08_16	**Open** To be progressed as part of the WEM Reform Program.
33/2017	The PUO to review the current list of Protected Provisions in the Market Rules to determine if any of the provisions no longer need to be Protected Provisions.	PUO	2017_08_16	**Open** Held over to early 2019.
23/2018	AEMO to provide clarification to the MAC on what information AEMO is permitted to publish regarding constrained on and constrained off payment amounts under the Market Rules.	AEMO	2018_09_12	**Closed** AEMO made a presentation to the MAC on 20 November 2018 to address action item 23/2018 (see Agenda Item 4).

Item	Action	Responsibility	Meeting Arising	Status
24/2018	AEMO to investigate and report back to the MAC on what information could be provided to Market Participants early to allow them to predict the size of, and budget for, their constraint payment obligations.	AEMO	2018_09_12	**Closed** AEMO made a presentation to the MAC on 20 November 2018 to address action item 24/2018 (see Agenda Item 4).
28/2018	RCP Support to amend the minutes of the 12 September 2018 meeting to reflect the agreed changes and publish on the Rule Change Panel's (**Panel's**) website as final.	RCP Support	2018_11_20	**Closed** The updated minutes were published on the Panel's website on 7 December 2018.
29/2018	RCP Support to amend the minutes of the 24 October 2018 MAC workshop on constrained off payments to reflect the agreed changes and publish on the Panel's website as final.	RCP Support	2018_11_20	**Closed** The updated minutes were published on the Panel's website on 7 January 2019.
30/2018	The ERA to provide an update to the MAC on the expected completion date for the ERA's next review of the methodology for setting the Energy Price Limits under clause 2.26.3 of the Market Rules.	ERA	2018_11_20	**Closed** The ERA has advised that it is to review the Energy Price Limits and the Benchmark Reserve Capacity Price methodologies together. The review is expected to take about 12 months, starting in Q2 2019.

Item	Action	Responsibility	Meeting Arising	Status
31/2018	The MAC Chair to raise the issue of how to manage potential future scenarios in which multiple generating units that are connected to the same line constitute the largest credible contingency with the Chair of the WEM Reform Program's Strategic Consultative Group; and to report back on the outcomes of that discussion to the MAC.	MAC Chair	2018_11_20	**Closed** The PUO has indicated that the PUO and AEMO will consider this issue as part of the Power System Security and Reliability work in the WEM Reform Program. Further information will be made available in due course.
32/2018	The PUO to consider undertaking further analysis to assess the likely effect on energy market prices of moving to a full runway approach for Spinning Reserve cost allocation.	PUO	2018_11_20	**Closed** The PUO has submitted RC_2018_06 to the Rule Change Panel. RCP Support will analyse the impact of this proposal to inform the Panel's decision on the proposal, and this analysis will be reported in the Draft Rule Change Report for the proposal.
33/2018	AEMO to provide advice to the PUO and the MAC about how and whether Operating Instructions are used for the Balancing Portfolio.	AEMO	2018_11_20	**Open**

Rule Change Panel
Market Advisory Committee

Agenda Item 5: MAC Market Rules Issues List Update

5 February 2019

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 as a means 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; and
- indicate whether there are any new issues to be raised;

In addition, as noted under Action item 31/2018 (see Agenda Item 4), the Public Utilities Office (**PUO**) has indicated that it will consider as part of the WEM Reform Program how to manage potential future scenarios in which multiple generating units that are connected to the same line constitute the largest credible contingency, without imposing excessive constraint payment costs on Market Customers. RCP Support recommends that the MAC consider whether this matter should be listed in Table 4under (Issue on Hold), pending outcomes of the WEM Reform Program.

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

5 February 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.

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 day time 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.
39	Alinta Energy November 2017	**Commissioning Test Process** The commissioning process within the Market Rules and PSOP works well for known events (i.e. the advance timings of tests). However the Market Rules and PSOP do not work for close to real time events. There is limited flexibility in the Market Rules and PSOP to deal with the practical and operational realities of commissioning facilities. The Market Rules and PSOP require System Management to approve a Commissioning Test Plan or a revised Commissioning Test Plan by 8:00 AM on the Scheduling Day on which the Commissioning Test Plan would apply.	To be considered in the preliminary review of the Commissioning Tests.

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

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

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

Notes:

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

Table 3 – Preliminary Reviews	
Review	**Status**
(1) Review of roles in the market	**Issues:** 11 and 12. **Status:** Review deferred until Issues 11 and 12 are reopened following completion of the WEM reform program.
(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**
5	Community Electricity November 2017	Improved definition of SRMC.	On hold pending development of ERA Balancing Market Bidding Guidelines.
6	Community Electricity November 2017	Improved definition of Market Power.	On hold pending development of ERA Balancing Market Bidding Guidelines.
7	Community Electricity November 2017	Improved definition of the quantity of LFAS (a) required and (b) dispatched.	On hold pending the outcome of the WEM reform program, 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.	On hold pending the outcome of the Minister's WEM Reform program. Treatment of storage facilities was considered under the preliminary review of the treatment of storage facilities in the market.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		Would support new entry, competition and market efficiency; particularly supporting the achievement of Wholesale Market Objectives (a) and (b).	
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 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).	This issue was initially flagged for consideration as part of the preliminary review of roles in the market. However, the PUO has since advised that the issue will be covered as part of the WEM reform program, so the issue has been put on hold pending completion of the WEM reform program.
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	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).

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		promote efficiency in market administration, supporting Wholesale Market Objectives (a) and (d).	The PUO has advised that the remaining issues will be covered as part of the WEM reform program, so the remaining issues have been put on hold pending completion of the WEM reform program.
14/36	Bluewaters and ERM Power November 2017	Capacity Refund Arrangements: The current capacity refund arrangement is overly punitive as Market Participants face excessive capacity refund exposure. This refund exposure is well more than what is necessary to incentivise the Market Participants to meet their obligations for making capacity available. Practical impacts of such excessive refund exposure include: • compromising the business viability of some capacity providers - the resulting business interruption can compromise reliability and security of the power system in the SWIS; and • excessive insurance premiums and cost for meeting prudential support requirements. Bluewaters recommended imposing seasonal, monthly and/or daily caps on the capacity refund. Bluewaters considered that reviewing capacity refund arrangements and reducing the excessive refund exposure is likely to promote the Wholesale Market Objectives by minimising: • unnecessary business interruption to capacity providers and in turn minimising disruption to supply availability; which is expected to promote power system reliability and security; and	On 9 May 2018 the MAC agreed to place this issue on hold for 12 months (until June 2019) to allow time for historical data on dynamic refund rates to accumulate.

Table 4 – Issues on Hold			
Id	Submitter/Date	Issue	Urgency and Status
		• unnecessary excessive insurance premium and prudential support costs, the saving of which can be passed on to consumers.	
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 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	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**
		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. This can result in under reporting of Forced Outages, and as a consequence, use of incorrect information used in WEM settlements. Bluewaters recommend a rule change to enable Market Participants to retrospectively log a Forced Outage after the 15 day deadline. If a Market Participant is found to be in breach of the Market Rules by not logging the Forced Outage by the deadline, it should be required to log the outage. Accurately reporting outages will enable the WEM to function as intended and will help meet the Wholesale Market Objectives.	On hold pending a final decision on RC_2014_03: Administrative Improvements to the Outage Process.
18	Bluewaters November 2017	The Spinning Reserve procurement process does not allow Market Participants to respond to the draft margin values determination by altering its Spinning Reserve offer. Bluewaters recommended amending the Market Rules to allow Market Participants to respond to the draft margin values determination by altering its Spinning Reserve offer.	On hold pending the outcomes of the ancillary services review being undertaken as part of the WEM reform program.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		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.	
19	Bluewaters November 2017	The Spinning Reserve margin values evaluation process is deficient for the following reasons: • shortcomings in the process for reviewing assumptions; • inability to shape load profile; • lack of transparency: (a) modelling was a "black box"; (b) confidential information limits stakeholders' ability to query the results; and • lack to retrospective evaluation of spinning reserve margin values. As a result, the margin values have been volatile, potentially inaccurate and not verifiable. Recommendation: conduct a review on the margin values evaluation process and propose rule changes to address any identified deficiencies. Addressing the deficiencies in the margin values evaluation process can promote the Wholesale Market Objectives by enhancing economic efficiency in the WEM. This can be achieved through:	On hold pending the outcome of the WEM reform program. Also, AEMO and the ERA to consider whether any options exist to improve transparency of the current margin values process.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		• 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.	
22	Bluewaters November 2017	Prudential arrangement design issue: clause 2.37.2 of the Market Rules enables AEMO to review and revise a Market Participant's Credit Limit at any time. It is expected that AEMO will review and increase Credit Limit of a Market Participant if AEMO considers its credit exposure has increased (for example, due to an extended plant outage event). In response to the increase in its credit exposure, clause 2.40.1 of the Market Rules and section 5.2 of the Prudential Procedure allow the Market Participant to make a voluntary prepayment to reduce its Outstanding Amount to a level below its Trading Limit (87% of the Credit Limit). Under the current Market Rules and Prudential Procedure, AEMO can increase the Market Participant's Credit Limit (hence increasing its prudential support requirement) despite that a prepayment has already been paid (it is understood that this is AEMO's current practice). The prepayment would have already served as an effective means to reduce the Market Participant's credit exposure to an acceptable level. Increasing the Credit Limit in addition to this prepayment would be an unnecessary duplication of prudential requirement in the WEM.	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**
		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	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.	On hold pending the outcome of a PUO review of the current Protected Provisions in the Market Rules.
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 pending the outcomes of the WEM reform program.
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	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**
		of what capacity is really available to the system. This should also assist System Management in generation planning for the system.	
41	IMO November 2017	On 1 September 2017, the Electricity Review Board (**Board**) published its decision and its reasons for decision regarding the IMO's Application No. 1 of 2016 against Vinalco Energy Pty Ltd (**Vinalco**) (http://www.edawa.com.au/reviews/12016). Even though the Board found that Vinalco breached clause 7A.2.17 of the Market Rules during the relevant periods and ordered Vinalco to pay two nominal penalties, the Board was sympathetic to the argument that 'constrained-on' dispatch through the Balancing Market was not the most appropriate mechanism in Vinalco's circumstances. The IMO considers that further work is required to consider what changes are required to the Market Rules to mitigate the risk of a similar situation arising again, and what the next steps may be to progress those changes.	On hold pending development of ERA Balancing Market Offer Guidelines
42	ERA November 2017	**Ancillary Services approvals process** Clause 3.11.6 of the Market Rules requires System Management to submit the Ancillary Services Requirements in a report to the ERA for audit and approval by 1 June each year, and System Management must publish the report by 1 July each year. The ERA conducted this process for the first time in 2016/17. In carrying out the process it became apparent that: • there is no guidance in the rules on what the ERA's audit should cover, or what factors the ERA should consider in making its determination on the requirements;	On hold pending the outcome of the WEM reform program.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		• 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)).	
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.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
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.

Notes:

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

MARKET ADVISORY COMMITTEE MEETING, 5 FEBRUARY 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	16 Jan 2019	21 Feb 2019
Market Procedures for discussion	• PSOP: Medium Term PASA • PSOP: Short Term PASA • PSOP: Commissioning Tests	• Market Procedure: Capacity Credit Allocation • Market Procedure: Individual Reserve Capacity Requirements • Market Procedure: Prudential Requirements

3. AEMO PROCEDURE CHANGE PROPOSALS

The status of AEMO Procedure Change Proposals is described below, current as at 13 November 2018. 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_01: Monitoring and Reporting Protocol	The new Monitoring and Reporting Protocol details how AEMO implements its obligations to support the ERA's monitoring of compliance with the Market Rules.	Updated consultation closed 10 Jan 2019. Two further submissions received	Prepare Procedure Change Report for ERA consideration	Mar 2019

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.	Submissions closed 21 May 2018. One submission received.	Publish further proposed amendments for consultation	Mar 2019
AEPC_2018_04: PSOP: Outages	The proposed amendments seek to revise the Procedure in line with current standards and ensure the Procedure complies with obligations.	Revised procedure has commenced	-	7 Jan 2019
AEPC_2018_05: IMS Interface	The proposed amendments are consequential, arising from the amendment to the PSOP: Communications and Control Systems	Submissions closed 21 May 2018. One submission received.	Prepare Procedure Change Report	Mar 2019
AEPC_2018_06: PSOP: Commissioning Tests	The proposed amendments seek to revise the Procedure in line with current standards and ensure the Procedure complies with obligations.	Considered by APCWG 16 Jan 2019	Publish Procedure Change Proposal	Feb 2019
AEPC_2019_01: PSOP: Short Term PASA	The proposed amendments seek to revise the Procedure in line with current standards and ensure the Procedure complies with obligations.	Considered by APCWG 16 Jan 2019	Publish Procedure Change Proposal	Feb 2019
AEPC_2019_02: PSOP: Medium Term PASA	The proposed amendments seek to revise the Procedure in line with current standards and ensure the Procedure complies with obligations.	Considered by APCWG 16 Jan 2019	Publish Procedure Change Proposal	Feb 2019
Market Procedure: Capacity Credit Allocation (Procedure Change Proposal number yet to be assigned)	Amendments arising from Rule Change RC_2017_06 (Reduction of prudential exposure in the Reserve Capacity Mechanism) will be proposed	Preparing draft amendments	Consideration by APCWG 21 Feb 2019	21 Feb 2019
Market Procedure: Individual Reserve Capacity Requirements (Procedure Change Proposal number yet to be assigned)	Amendments arising from Rule Change RC_2017_06 (Reduction of prudential exposure in the Reserve Capacity Mechanism) will be proposed	Preparing draft amendments	Consideration by APCWG 21 Feb 2019	21 Feb 2019

ID	Summary of changes	Status	Next steps	Date
Market Procedure: Prudential Requirements (Procedure Change Proposal number yet to be assigned)	Amendments arising from Rule Change RC_2017_06 (Reduction of prudential exposure in the Reserve Capacity Mechanism) will be proposed	Preparing draft amendments	Consideration by APCWG 21 Feb 2019	21 Feb 2019

RCP Rule Change Panel
Market Advisory Committee

Agenda Item 8(a): Overview of Rule Change Proposals (as at 29 January 2019)

Meeting 2019_02_05

- 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_07	22/12/2014	IMO	Omnibus Rule Change	11/01/2019[1]

Approved Rule Change Proposals Awaiting Commencement

Reference	Submitted	Proponent	Title	Commencement
RC_2017_06	17/07/2017	AEMO	Reduction of the prudential exposure in the Reserve Capacity Mechanism	01/06/2019
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

[1] All Amending Rules for RC_2014_07 commenced on 11/01/2019, except the changes to clause 2.34.14, which will commence on 01/07/2019 immediately after commencement of RC_2014_06.

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
None				

Formally Submitted Rule Change Proposals

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
Fast Track Rule Change Proposals with Consultation Period Closed						
None						
Fast Track Rule Change Proposals with Consultation Period Open						
None						
Standard Rule Change Proposals with Second Submission Period Closed						
None						
Standard Rule Change Proposals with Second Submission Period Open						
None						
Standard Rule Change Proposals with First Submission Period Closed						
RC_2013_15	24/12/2013	IMO	Outage Planning Phase 2 – Outage Process Refinements	Medium	Publication of Draft Rule Change Report	1/04/2019

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
RC_2014_03	27/01/2014	IMO	Administrative Improvements to the Outage Process	High	Publication of Draft Rule Change Report	TBD
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	TBD
RC_2014_09	13/03/2015	IMO	Managing Market Information	Low	Closure of call for further submissions	15/02/2019
RC_2015_01	03/03/2015	IMO	Removal of Market Operation Market Procedures	Low	Publication of Draft Rule Change Report	1/04/2019
RC_2015_03	27/03/2015	IMO	Formalisation of the Process for Maintenance Applications	Low	Publication of Draft Rule Change Report	1/04/2019
RC_2017_02	04/04/2017	Perth Energy	Implementation of 30-Minute Balancing Gate Closure	Medium	Publication of Draft Rule Change Report	TBD
RC_2018_03	01/03/2018	Collgar Wind Farm	Capacity Credit Allocation Methodology for Intermittent Generators	Medium	Publication of Draft Rule Change Report	TBD
RC_2018_05	27/09/2018	ERA	ERA access to market information and SRMC investigation process	Medium	Publication of Draft Rule Change Report	1/04/2019
Standard Rule Change Proposals with the First Submission Period Open						
RC_2018_06	26/11/2018	PUO	Full Runway Allocation of Spinning Reserve Costs	Medium	Closure of first submission period	30/01/2019
RC_2018_07	14/12/2018	PUO	Removal of constrained off compensation for Outages of network equipment	High	Closure of first submission period	08/02/2019

Pre-Rule Change Proposals

Reference	Proponent	Description	Next Step	Submitted
TBD	AEMO	Adjusting Non-STEM Settlements using latest available data	Submit Rule Change Proposal	TBD

Rule Change Panel

Wholesale Electricity Market Rule Change Proposal

Rule Change Proposal ID: *[to be filled in by the RCP]*
Date received: *[to be filled in by the RCP]*

Change requested by:

Name:	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:	
Urgency:	High
Rule Change Proposal title:	
Market Rule(s) affected:	

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. The relevant demand level is intended to be a measure of the “curtailability” of loads participating in the reserve capacity mechanism, and thus sets how many capacity credits a demand side programme can be certified for.

<u>The issue</u>

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 – excess capacity was significantly overvalued and, when there was a looming shortage, capacity was underpriced. The rules made in 2016 at the conclusion of the review made adjustments to 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 significantly 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 existing relevant demand level calculation.[1] 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.[2]

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 500MW of demand side capacity exiting the market (relative to the 2016/17 capacity year), as

[1] 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.

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

shown in the table below.

Capacity credits (MW)[3]	2016-17	2017-18	2018-19	2019-20
Demand side program	560	106	57	66
Reduction in demand side participation from 2016/17	-	-454	-503	-494

While it could be argued that the exit quickly assuaged over-capacity concerns, the changes reduced competition in the reserve capacity mechanism by ensuring that there is no meaningful level of demand side participation and rendered the WEM an outlier amongst global capacity markets.

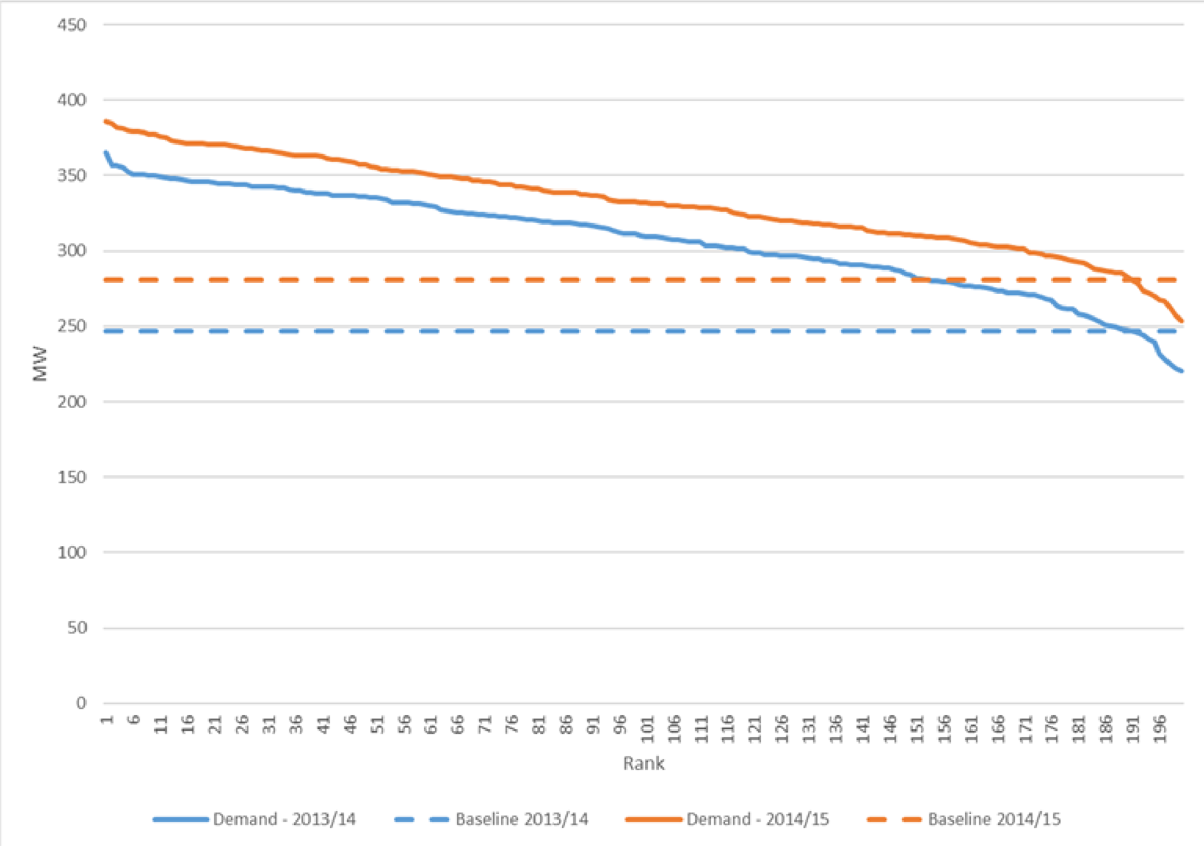
The changes to the capacity price formula were intended to be transitional only until a longer term solution was developed. This longer term solution is now being considered and consulted on by the PUO through its work on *Improving reserve capacity pricing signals*.[4] Enel X supports the development and 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 recommendation in the PUO's draft report to restore equal pricing between generation and demand side resources. If implemented, this recommendation 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, the current relevant demand calculation will continue to present an inefficient barrier to the entry of demand side resources.

The issue with the current relevant demand calculation is that it significantly under-represents the "curtailability" of loads. As above, a demand side programme's relevant demand is currently 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 at a level that is much lower than what the load is capable of curtailing during peak demand periods.

This is shown in the graph below, which uses data from a 200MW sample of Enel X's portfolio in the 2013/14 and 2014/15 capacity years. The solid lines show the portfolio's total demand and the dotted lines show what the portfolio's relevant demand would be under the current fifth percentile calculation, for each capacity year, during the 200 system peak hours. The graph shows that the portfolio is capable of curtailing much more than what its relevant demand dictates, and thus that in most intervals it must curtail a significant amount of load before it is credited for that curtailment.

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



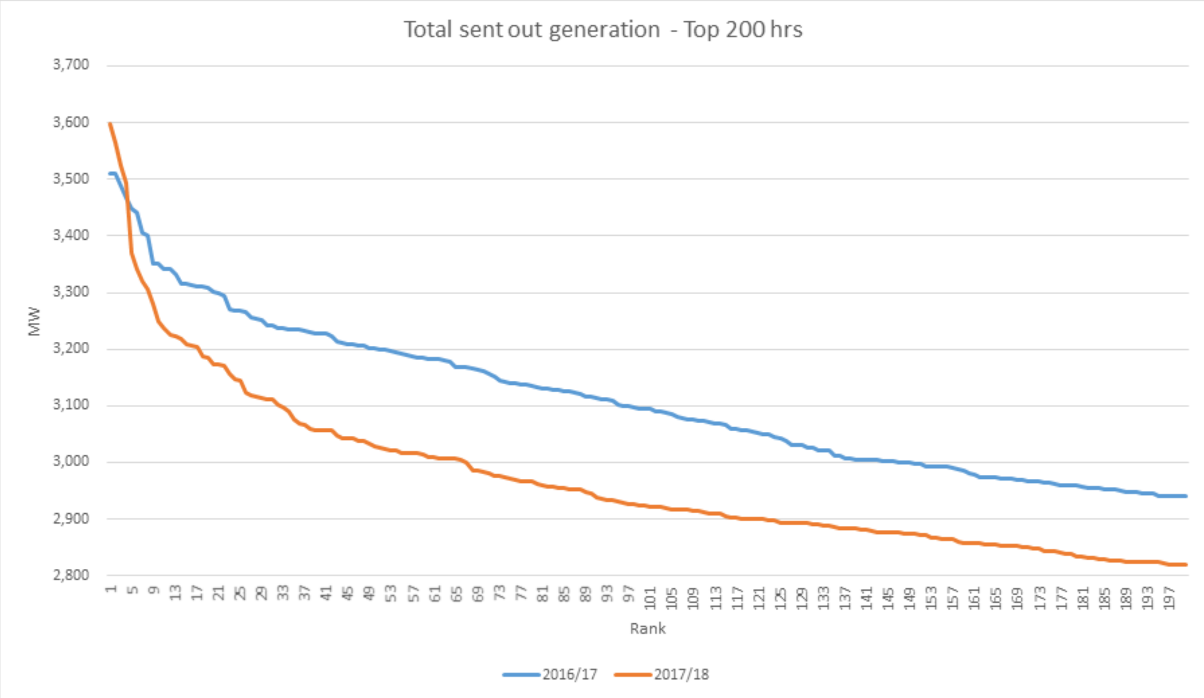
Attachment A shows the impact of the current relevant demand calculation on specific customer segments, using data from customers in our previous demand side programme.

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 gives AEMO a high degree of confidence that the quantity of certified capacity can be delivered if and when it is called upon.

While not explicitly defined, relevant demand is generally acknowledged to be a calculation that reflects a programme's expected consumption during intervals when *most likely to be dispatched*. However, the likelihood of a demand side programme being dispatched for 200 hours a year under the current market design is very slim. This is because 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.[5] The WEM has historically been a reliable and secure system. The current relevant demand calculation does not reflect the "curtailability" of a demand side programme when it is most likely to be dispatched – that is, during extreme system events.

The graph below shows that the top 200 system peak hours covered between 550-800MW of peak demand in 2016/17 and 2017/18. In the 200th hour, sent out generation was roughly 2,900MW. Enel X questions the likelihood of a system security or reliability concern existing when total sent out generation (i.e. grid demand) is at levels around 2,900MW.

[5] See rule 6.12 and clauses 7.6.1C-D of the WEM rules.



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

<u>Implications of the current rules</u>

Under-representing the amount of load a demand side programme can curtail means that the number of capacity credits it eligible for is much less than the capacity it is capable of providing. This has the following outcomes:

- under-utilisation of resources that can potentially provide capacity at lower cost and higher reliability than supply-side resources
- limited participation by the demand side, and thus reduced competition in the reserve capacity mechanism
- higher market-wide capacity costs, as a result of the displacement of lower cost demand side resources, that are borne by WA consumers.

The benefits of enabling demand side participation in energy 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.

<u>Rationale for this rule change proposal</u>

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

Enel X (as EnerNOC) has always advocated for demand side programme 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 the most efficient balance between accuracy, simplicity and integrity when compared to static baseline methodologies. 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, and in fact many offer providers a choice between various methodologies.

However, conversations we have had with AEMO, the PUO and some industry participants over the years indicate a concern about the costs and complexity associated with designing and implementing a dynamic baseline approach. The PUO's final report on *Reforms to the reserve capacity mechanism* in 2016 accepted that "there may be value that could be provided from lower availability resources, through adoption of a more flexible 'profile' baseline approach", but concluded that "the complexity and time required to implement separate procurement measures for these resources is not warranted at this point".[6]

This pre-rule change proposal seeks to find a middle ground on the issue by retaining a static approach but using one that more accurately reflects the "curtailability", and therefore the value, of a demand side programme. While not our preferred solution, Enel X is of the view that such an approach will better meet the WEM objectives than the status quo, for the reasons set out in section 4.

<u>The IRCR method</u>

One option we have been exploring as a potential middle ground on the issue is setting a demand side programme's relevant demand based on its IRCR. That is:

1. Select the four days with the highest daily system load from the previous hot season.
2. Select the three highest demand trading intervals from each of those days.
3. Sum the metered consumption of all individual loads in the demand side program in those 12 trading intervals.
4. List the total metered consumption from those 12 intervals in size order.
5. Take the median value.
6. Find the average MW quantity by doubling the median value.
7. Recalculate monthly to reflect any changes in participation in the programme.

The steps above reflect those involved in the calculation of a load's IRCR under the current arrangements.

A relevant demand calculation based on IRCR intervals was the methodology recommended to the MAC by the IMO in 2010 following a review of the relevant demand calculation methodology. This recommendation was based on analysis undertaken by Data Analysis Australia for the IMO, which concluded that the IRCR method would produce a reliable result that reflects a demand side programme's normal operating level during intervals when it is most likely to be dispatched.[7]

At its meeting in August 2010, the MAC supported the IMO's recommendation that the IRCR methodology be adopted, and asked the IMO to develop a rule change proposal on the matter. Stakeholder feedback on this aspect of the resulting rule change proposal (RC_2010_29) was

[6] PUO, Final report: Reforms to the reserve capacity mechanism, 7 April 2016, p. 13.
[7] This report is not publically available, but is provided in Attachment B.

that the IMO should further explore dynamic/static baseline methodologies before making any changes to the relevant demand level calculation. Thus the final rule retained the existing relevant level calculation methodology (median of the 32 trading intervals of highest demand during the preceding hot season) on the expectation that the IMO would conduct a broader review of baselining methodologies for demand side programmes. To Enel X's knowledge, such a review has never been conducted.

In the absence of a broader review of static and dynamic baselining methodologies, Enel X proposes that the IRCR methodology be assessed and consulted on through a rule change process. Enel X is also open to discussing alternatives to the IRCR method that deliver the same objective – that is, a more accurate valuation of the "curtailability" of a demand side resource.

Similar methods are used in other capacity markets, for example PJM. Enel X would be happy to provide further information on these, and their interaction with the IRCR-equivalent.

<u>Interaction with the IRCR framework</u>

As the current rules cap a demand side programme's relevant demand at its total IRCR, activities that reduce the IRCR will limit the amount of capacity credits a programme manager could be certified for. This addresses a concern that a curtailable load could be rewarded twice if it reduces its demand during peak demand periods (i.e. through a reduced IRCR and the awarding of capacity credits in relation to that reduction). We propose that such an arrangement be retained under any new rule so there is no concern about a demand side programme being rewarded twice for a single curtailment.

As a result, measures to reduce a curtailable load's IRCR would cannibalise the relevant demand level calculation, and thus reduce the quantity of capacity credits it is eligible for. The likely outcome of making Enel X's proposed rule is that curtailable loads will choose to do one or the other – that is, to reduce their IRCR or to receive credits for the amount they are able to curtail by participating in a demand side programme through the reserve capacity mechanism.

<u>Consultation</u>

Enel X has discussed this proposal with AEMO and the PUO. 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 agreed that, from its perspective, the proposed approach would be easier to it to implement and administer than a dynamic approach. It suggested that we:
    - 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.

We have sought to address these comments in this pre-rule change proposal. We aim to fully address them for the rule change proposal itself.

Following the MAC meeting, Enel X intends to raise this proposed rule change with broader industry stakeholders, including other demand side programme providers in the WEM.

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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. While the outcome of the change itself is not strictly urgent, it is likely to be more efficient (for both the Rule Change Panel and other stakeholders) if this relatively minor change is considered alongside the other rule changes needed to implement the final recommendations of the PUO's *Improving reserve capacity pricing signals* review.

Considering this rule change alongside those broader changes would also mean that the rule (if made) could commence at the same time 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 the same issue to 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.

However, Enel X understands that consultation on the PUO's draft rules to implement its reforms to reserve capacity pricing will follow a different process to that which the Rule Change Panel undertakes. Enel X is keen to discuss the potential timing of the consideration and implementation of this rule change with the MAC, if it is not considered alongside the PUO reforms. Specifically, we are interested to know whether a rule (if made) could be implemented alongside the other reserve capacity mechanism changes for the 2021/22 capacity year, even if the rule is made after the commencement of the 2019 capacity cycle.

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

Enel X has not provided specific rule drafting for this pre-rule change proposal. We intend to include rule drafting for the rule change proposal itself, so as to reflect feedback from the MAC and others on potential solutions to the issue identified above.

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

Enel X expects that the proposed rule change would allow the Market Rules to better address all of the Wholesale Market Objectives, 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 will 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:[8]

> "Historically, the predominant method to avoid involuntary load reductions during peak periods or to address unplanned generation or system outages

[8] AEMO, Wholesale demand response mechanisms: Submission to AEMC consultation paper, December 2018, p. 3.

would be to construct new peaking generation, along with the transmission and distribution necessary to accommodate peak conditions.

Now, with the increase in DER 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 "curtailability" of a demand side programme during peak demand periods, 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, 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 better 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.

(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. Where the reserve capacity price signals it, generation and demand side resources would compete to provide the lowest cost means of meeting the WEM reliability requirement.

The ERA's latest report on the effectiveness of the WEM notes that Synergy, with half the accredited capacity in the wholesale market, has "significant market power in a highly concentrated wholesale electricity market" and the potential to drive up wholesale electricity prices.[9] Greater competition in the reserve capacity mechanism is likely to lead to a lower overall cost of meeting the reserve capacity requirement.

(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 characteristics, 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.[10]

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

[9] Economic Regulation Authority, *Report to the Minister for Energy on the effectiveness of the wholesale electricity market 2017/18*, discussion paper, 21 December 2018.
[10] PJM, Demand response strategy, 28 June 2017, p. 10.

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.

Reduced electricity demand, as a result of curtailment under the reserve capacity mechanism, can also mean lower GHG emissions.

(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.

(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 the “curtailability” of a demand side programme goes against objective of enabling participation by technologies that are capable of doing this. Properly valuing the “curtailability” 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.

---

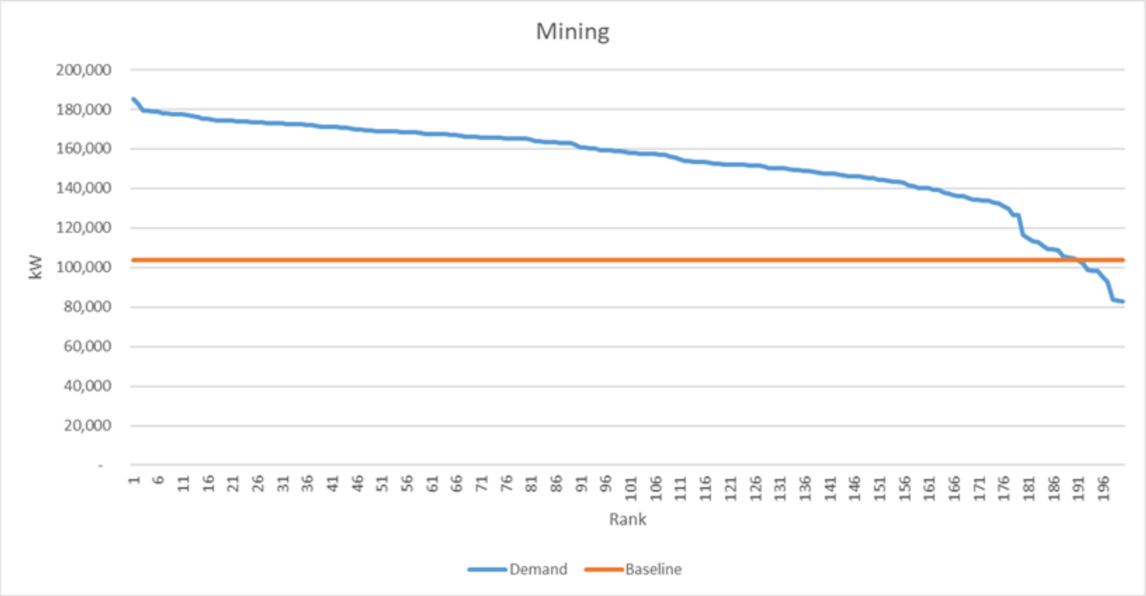
5. Provide any identifiable costs and benefits of the change:

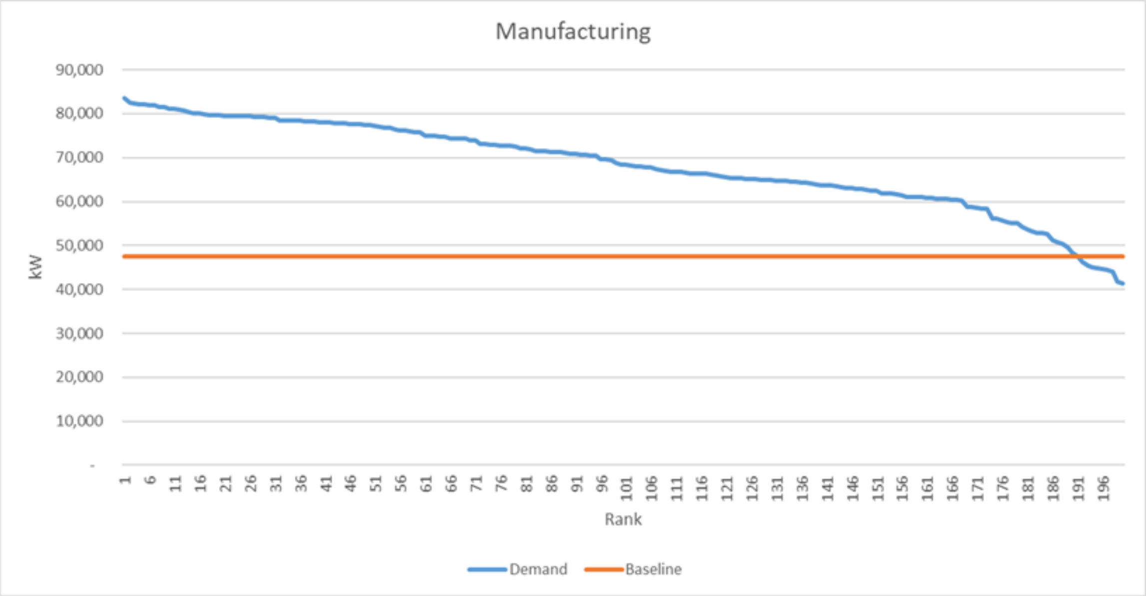
Enel X’s views on the costs and benefits of the proposed rule are set out below. While these arguments are based on the IRCR method, Enel X expects that they would apply equally to other static baseline approaches that more accurately calculate the potential contribution of demand side resources.

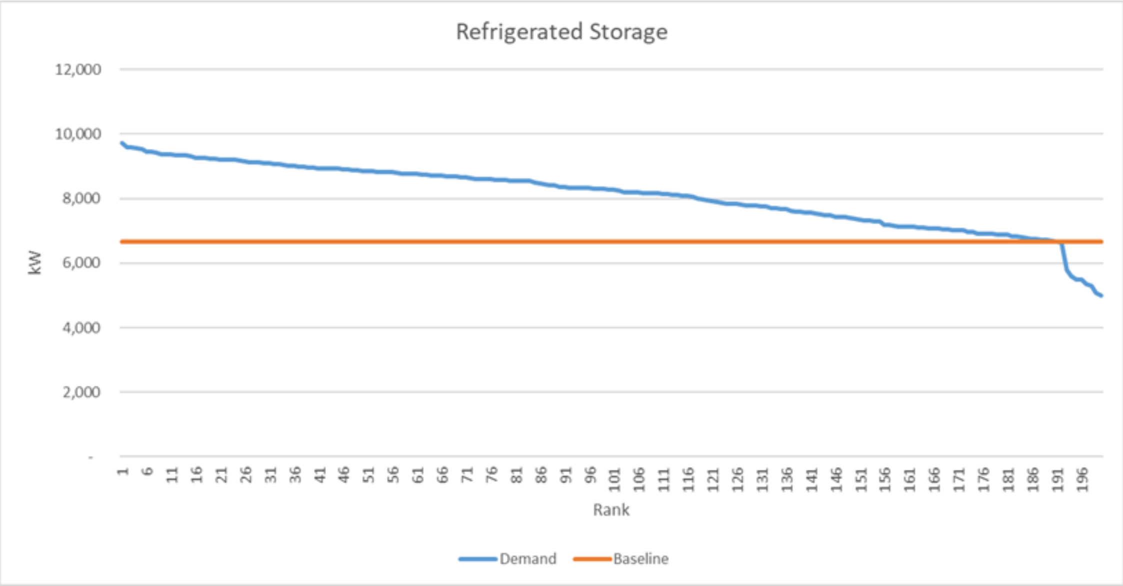
- The approach will more accurately value the “curtailability” of loads in a demand side programme, and will thus incentivise greater participation by the demand side in the reserve capacity mechanism where there are efficient price signals to do so.
- Technological advancements have enabled the demand side to become much more responsive to price signals. Encouraging the demand side to participate in the reserve capacity mechanism explicitly will mean that AEMO will have much greater visibility of how and when the demand side changes its consumption in response to prices. Explicit participation by the demand side in the reserve capacity mechanism should therefore help to support reliability and security outcomes in the interests of all electricity consumers.

- The proposed rule strikes 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 most accurate, realistic relevant demand levels so it knows how much capacity will likely be available during peak demand periods.
  - Consumers want the most accurate, realistic relevant demand levels so that they aren't paying for capacity that isn't available.
- It will deliver a reliable and stable relevant demand calculation. That is, it will more accurately represent the actual capacity that a programme would be able to provide at peak demand times, and will deliver a similar relevant demand level each year. The analysis conducted by Data Analysis Australia supports this conclusion. Specifically, it found that while using more intervals to calculate a programme's relevant demand will increase the stability of the calculation between years, the calculation becomes less representative of load levels during times of peak demand.
- If the PUO's recommendation to restore equal pricing between the demand and supply sides is taken up, our rule change will bring the reserve capacity mechanism even closer to truly equal treatment and valuation of all capacity providers.
- The IRCR approach is easy for AEMO, curtailable loads and industry more broadly to understand. The calculation of IRCR is an integral and well understood part of the reserve capacity mechanism.
- It should be easy and low cost to implement. Extending the calculation of IRCR to the calculation of a demand side programme's relevant demand aligns with and uses processes that AEMO already has in place. Enel X expects that the system and process changes required to implement this approach would be minimal. Initial feedback from AEMO indicates that they agree with this conclusion. Similarly, the cost impact on demand side programme providers is expected to be minimal.

Attachment A: Impact of current relevant demand calculation on specific customer segments






Refrigerated Storage
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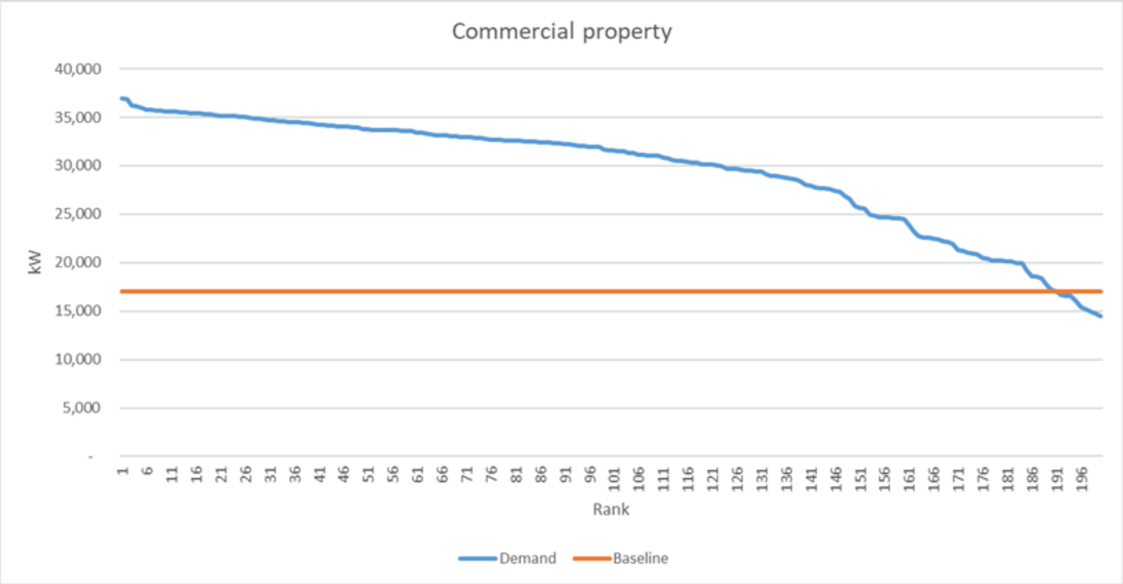
10,000
8,000
6,000
4,000
2,000
-
kW
Rank
Demand
Baseline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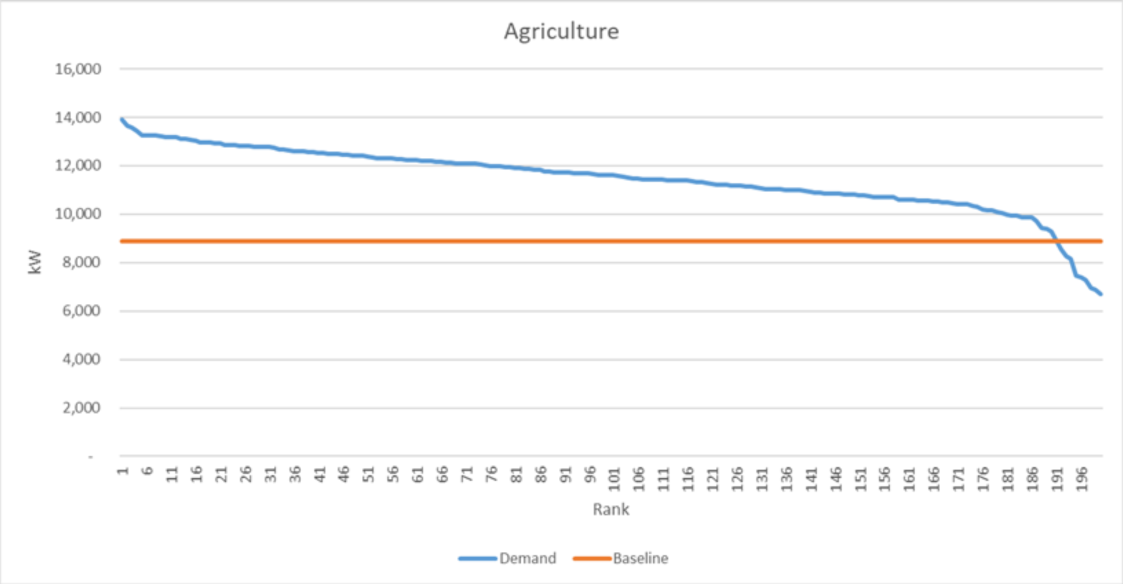
20,000
15,000
10,000
5,000
-
kW
Rank
Demand
Baseline


Agriculture
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
-
kW
Rank
Demand
Baseline

DATA

STATISTICS

ANALYSIS

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AUSTRALIA

INFORMATION

Comparison of Alternative Relevant Demand Calculation Methodologies

Draft

July 2010

Project: IMO/3

STRATEGIC INFORMATION CONSULTANTS

Comparison of Alternative Relevant Demand Calculation Methodologies

July 2010

Client: Independent Market Operator

Project: IMO/3

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Executive Summary

The Independent Market Operator (IMO) currently has certain Market Customers who receive Capacity Credits for each MW of Curtailable Load they have certified as Reserve Capacity. The Relevant Demand is a metric assigned to the Customer to assess the maximum level of Certified Reserve Capacity that can be allocated to a given Customer's Curtailable Load.

Currently, the IMO sets the Relevant Demand (in MW) for each Market Customer with a Curtailable Load, in accordance with clause 4.26.2C, parts (a), (b) and (c) of the Market Rules. That is, by taking the median of the Market Customer's metered consumption during 32 Peak Trading Intervals (PTIs), selected by the IMO from the previous Hot Season using clause 4.26.2C (a). Occasionally, a Market Customer will provide evidence that the Curtailable Load was operating at below capacity during one or more of these 32 intervals (under clause 4.26.2C (d) of the Market Rules), as the inclusion of these low intervals will result in a lower Relevant Demand value that is perhaps not representative of the Customer's business-as-usual load. This clause however, can provide an opportunity for Customers to be rewarded for periods where they may have already planned to curtail their load.

The Independent Market Operator (IMO) has suggested that the current calculation method may result in potentially volatile estimates of Relevant Demand. This is due to the small number of intervals used to feed into the calculation and the potential for Customers to influence their Relevant Demand by taking advantage of the excluded intervals clause of the Market Rules. As such the IMO has proposed to the Market that a change may be required to the method of calculating the Relevant Demand, with the aim being to devise a Relevant Demand methodology that is both **stable** and **reliable**. The Relevant Demand should be stable in that the same facilities will receive similar Relevant Demands year on year and reliable in that the Relevant Demand will represent the actual available capacity a facility will be able to curtail at the time of peak demand.

Data Analysis Australia has investigated a number of alternative Relevant Demand methodologies for ten Demand Side Management (DSM) programmes. These DSM programmes were based upon the actual meter reading data for sixty National Metering Identifiers (NMIs), which were scaled in order to maintain confidentiality. Some of the DSMs were based upon actual DSM groupings, others were randomly sampled to form DSM groups of varying sizes and four DSM scenarios were created to explore extreme DSM profiles.

The primary difference between the methodologies investigated was the number of trading intervals incorporated in the calculation of the Relevant Demand. Unsurprisingly, the analyses revealed that the inclusion of additional trading intervals in the Relevant Demand calculation increased the stability of the value over time. However, this is offset by the requirement for a realistic and reliable

Relevant Demand. As increasingly more intervals are included in the Relevant Demand calculation the result becomes less representative of times of peak demand, resulting in an under-estimate of the amount that could be curtailed at these times of peak demand. In contrast, the inclusion of too few intervals increases the volatility of the Relevant Demand in representing the following Hot Season.

From the six methods proposed by the IMO, Data Analysis Australia identified two broad types of methodology to calculate Relevant Demand. The choice of the most appropriate methodology depends on whether the IMO would like to retain control over the customers who might potentially be doubly rewarded for periods of downtime (sometimes referred to as "double-dipping"). If the IMO would like control over these customers, then a methodology that utilises a smaller number of intervals and includes a manual case-by-case assessment of customers with unusually low Relevant Demands would be more appropriate. If the IMO prefers this type of methodology, Data Analysis Australia would recommend the IRCR method, as this method focuses on the top four days of the Hot Season (December - March) and is therefore more representative of Curtailable Load at peak times. In addition, the IRCR method is more consistently reliable than the current method at representing the Relevant Demand for the following Hot Season. However, Data Analysis Australia would also recommend that the IRCR method be adapted to incorporate more PTIs, as currently only the top three consecutive intervals on the top four days are used, resulting in only 12 intervals in total. One approach could be to select the top eight consecutive intervals as in the current 32 PTI method. Adopting slightly more intervals in this way would help to improve the stability and reliability of using this methodology to inform the certification of the Reserve Capacity.

On the other hand, should the IMO require a more automated and consistent methodology and perceive any other benefit to the customer by curtailing their load as a coincidental benefit, then using yet more intervals would be more appropriate. If the IMO prefers this type of methodology, Data Analysis Australia would recommend an approach that utilises the top 250 trading intervals during the Hot Season. Whilst assigning this level is somewhat arbitrary, the analysis showed the inclusion of additional intervals over 250 did not considerably improve the stability of the Relevant Demand but did in fact reduce the reliability both within and across Hot Seasons.

The analysis of the DSM Scenarios used to represent extreme DSM profiles, confirmed that unusual DSM profiles will remain hardest to predict reliably within and between the Hot Seasons, however incorporating more intervals should provide some stability over time so that on average under- and over-estimations even out.

Data Analysis Australia also investigated the effect of two approaches of aggregating the data into DSM programmes. The first approach summed Relevant Demands for individual customers and the second approach aggregated the metered loads prior to calculating the Relevant Demand. Whilst aggregating customers into

DSM programmes does reduce the volatility in the Relevant Demand, this analysis demonstrated that the order by which the aggregation occurs has little effect on the stability and reliability of the relevant demand, and certainly has a much smaller effect than the choice of methodology used to calculate the Relevant Demand.

Data Analysis Australia understands the requirement to adopt a simple Relevant Demand methodology that is transparent and easily calculated by Market Customers, like those explored in this report. However, Data Analysis Australia believes that to fully explore the inter-relationships between customer characteristics and different Relevant Demand methodologies would require an in-depth analysis that incorporates a conceptual model of customer behaviour. Such an analysis would be invaluable to the IMO if only to confirm or deny that these simplistic approaches are a good approximation for a more complex model.

Table of Contents

1. Introduction

The Independent Market Operator (IMO) currently has certain Market Customers who receive Capacity Credits, in the order of $144k for each MW of Curtailable Load they have certified as Reserve Capacity. The maximum Certified Reserve Capacity that can be assigned to a given Market Customer's Curtailable Load is set using that Customer's Relevant Demand. It is therefore in each such Market Customer's best interests to have assigned to them the highest possible Relevant Demand. On the other hand, it is in the IMO's best interests to have each Relevant Demand set at the most realistic level, to ensure they are not paying for Capacity Credits that are not actually available.

Currently, the IMO sets the Relevant Demand (in MW) for each Market Customer with a Curtailable Load, in accordance with clause 4.26.2C, parts (a), (b) and (c) of the Market Rules. That is, by taking the median of the Market Customer's metered consumption during 32 Peak Trading Intervals (PTIs), selected by the IMO from the previous Hot Season using clause 4.26.2C (a). Occasionally, a Market Customer will provide evidence that the Curtailable Load was operating at below capacity during one or more of these 32 intervals.

It has been suggested by the IMO that the current method of calculating the Relevant Demand may result in potentially volatile estimates due to the small sample size of data used to feed into the calculation and the potential for Customers to influence their Relevant Demand by taking advantage of the excluded intervals clause of the Market Rules clause 4.26.2C (d). Data Analysis Australia has previously provided methodological advice on how to treat those customers who get approval from the IMO to have certain intervals from the 32 PTIs be excluded due to maintenance work, however IMO is now proposing further, more substantial changes to the overall methodology.

As such the IMO has proposed to the Market that a change may be required to the method of calculating the Relevant Demand, with the aim being to devise a Relevant Demand methodology that is both **stable** and **reliable**. The Relevant Demand should be stable in that the same facilities will receive similar Relevant Demands year-on-year and also reliable in that the Relevant Demand will represent the actual available capacity a facility will be able to curtail at the time of peak demand.

Data Analysis Australia has investigated a number of alternative methodologies to calculate the Relevant Demand for Demand Side Management (DSM) programmes, which are discussed in this report.

2. Data Sources

The IMO provided Data Analysis Australia with the following data:

- System load;

- Individual Reserve Capacity Requirement (IRCR) intervals (found on the IMO website);
- Meter readings for sixty individual National Metering Identifiers (NMIs); and
- The DSM programme for the above NMIs for the purposes of grouping.

The system load data was provided for the period of 8am on the 12th of February 2006 through to 7:30am on the 1st of April 2010 in half-hour intervals. This data was used to obtain the Peak Trading Intervals (PTI) for the current method of calculating Relevant Demand, the Individual Reserve Capacity Requirement (IRCR) method and the Top Peak Market Intervals method. Where possible, other sources, such as the IMO website, were used to check that the intervals had been calculated correctly. A detailed discussion of these methodologies is presented in Section 3.

The meter reading data contained information of the electricity usage of sixty NMIs over the period from 8am on the 21st of September 2006 through to 11:30pm on the 19th of May 2010 in half-hour intervals. The Relevant Demand values for the individual NMIs and Demand Side Management (DSM) groups were based upon this data. Data Analysis Australia was also provided with information relating to the DSM programmes to which all the NMIs in the load data were classified.

Some NMIs had missing and zero values in the meter reading data, which were excluded upon the aggregation of NMIs into DSM groups (discussed in Section 3), and removed in the process of the Relevant Demand calculation.

In the interests of confidentiality, Data Analysis Australia has taken several steps to anonymise the data whilst ensuring that the data remains representative of the actual data provided. These are discussed further in Section 3.

3. Methodology

3.1 Anonymising and Expanding the Data

In order to maintain confidentiality, Data Analysis Australia performed several steps to anonymise the NMI and DSM data provided by the IMO. Firstly, Data Analysis Australia scaled the meter reading data of each NMI within a DSM programme by the same factor, to ensure that the shape of the consumption was retained whilst the DSM group would become unidentifiable by the level of consumption. Each DSM programme was scaled using different factors, both upwards and downwards.

Data Analysis Australia then used the information on current NMI to DSM groupings to create a number of DSM groups of varying sizes. Six DSM programmes containing 1, 2, 5, 10, 20 and 30 NMIs each were created. Some of the DSMs groupings were based upon actual DSM programmes whereas others were generated by randomly sampling from the sixty scaled NMIs.

In addition to these six DSMs, Data Analysis Australia constructed four DSM scenarios. These scenarios were designed to represent extreme DSM profiles to provide some insight into the effect that these would have on the Relevant Demand calculations. Each of the four scenarios consisted of five NMIs, to be comparable to each other and the other DSM that contains five NMIs, described above. Five NMIs was considered to be a small enough number of NMIs so that any effect would not be hidden by the sheer number of NMIs and a big enough number so that interactions between groups of NMIs could be explored. The four scenarios are described below:

Scenario 1: This scenario comprised of five NMIs with small standard deviations.

Scenario 2: This scenario comprised of five NMIs with large standard deviations.

Scenario 3: This scenario comprised of one NMI with high electricity consumption and four NMIs with low consumption. All the NMIs had small standard deviations. The NMI with high consumption showed periods of low consumption at times of peak demand.

Scenario 4: This scenario comprised of one NMI with high electricity consumption and four NMIs with low consumption. All of the NMIs had large standard deviations.

Each of the scaled NMIs were classified as “low”, “medium” or “high” consumption using the median load of all of the Hot Seasons. NMIs with median loads in the lower quartile were classified as “low” consumption, NMIs with median loads in the upper quartile were classified as “high” consumption, the rest were classified as “medium” consumption. Also each of the scaled NMIs were classified as having “small” or “large” standard deviations by calculating the standard deviation of each NMI. NMIs with standard deviations less than the median standard deviation of all NMIs were classified as having “small” standard deviations and NMIs with standard deviations higher than the median standard deviation were classified as having “large” standard deviations. The appropriate numbers of NMIs were then randomly sampled from within the classification groups to form the DSM scenarios.

3.2 Relevant Demand Methodologies

The Relevant Demand for a DSM programme is currently estimated by summing the Relevant Demands for individual National Metering Identifiers (NMIs). An alternative approach is to first sum the consumption and then calculate the Relevant Demand.

Data Analysis Australia compared the Relevant Demand values for each DSM programme, calculated by summing the Relevant Demands for individual NMIs as described above (referred to as Approach A) and also by aggregating the NMIs **then** calculating the Relevant Demand (referred to as Approach B). Furthermore, four different methodologies were used to calculate the Relevant Demand, as outlined below:

1. The current method (Method 1) – this method takes the median of 32 Peak Trading Intervals (PTIs). Eight intervals are taken from the day with the highest system load in each month of the Hot Season (December through March). The intervals selected are the eight consecutive intervals summing to the largest Curtailable Load on a given trading day.
2. Individual Reserve Capacity Requirement (Method 2) – this method takes the median of 12 PTIs for each Hot Season. The three consecutive intervals with the highest load are selected from the four days with the highest daily System load during the Hot Season.
3. Trading Intervals during Business hours over the Hot Season (Method 3) – this method calculates the Relevant Demand as the median of all intervals between 8am and 10pm, Monday to Friday (excluding public holidays). There are approximately 2,200 half-hour intervals that occur between 8am and 10pm, Monday to Friday (excluding public holidays) each Hot Season. This number varies due to the shift of the Easter public holidays from year to year, in and out of the Hot Season.
4. Top Peak Market Intervals (Method 4_250, Method 4_500 and Method 4_750) – this method calculates the Relevant Demand as the median of the top 250, 500 and 750 PTIs in the Hot Season from the System load.

Data Analysis Australia examined the changes in the Relevant Demand value over four Hot Seasons (2006/07, 2007/08, 2008/09, 2009/10) in order to assess the stability and reliability of the Relevant Demand methodologies. In order to assess the reliability of the Relevant Demand for a particular Capacity Year, the Relevant Demands for each of the calculation methodologies from the previous Hot Season should be compared to the "actual" Relevant Demand for the Capacity Year.

This concept of the "actual" Relevant Demand is not simple, as DSM groups may have been asked to curtail their load based upon the Relevant Demand of the previous Hot Season and hence even the "actual" Relevant Demands need to be estimated. As such Data Analysis Australia compared the Relevant Demands for each of the calculation methods from the previous Hot Season to a set of potential Relevant Demands for the Capacity Year. This set of Relevant Demands should provide a range of Relevant Demands that the "actual" Relevant Demand is likely to lie within. Again this poses a conundrum, as the method used to calculate this set of Relevant Demands should be based upon the optimal method that we are trying to identify within this project. For this analysis Data Analysis Australia has adopted another calculation methodology to obtain a set of reasonable "actual" Relevant Demands for the Capacity Year to be used as a basis of a comparison.

The methodology adopted for calculating the set of "actual" Relevant Demands for the Capacity Year was to, for each DSM, sum 8 consecutive intervals (as 4 hours is the length of time a DSM is contracted to curtail) for every day over the Hot Season and pick out the intervals with the highest sums of 8 intervals. Data Analysis Australia selected the top 20 of the eight consecutive intervals for each DSM to provide a set of 20 Relevant Demands to give a range of likely Relevant Demand values for the Capacity Year. This methodology will result in (some of) the Relevant Demands being calculated on similar overlapping intervals which may not ensure a good range of Relevant Demand values. The differences between the "actual" set of Relevant Demands and the "estimated" Relevant Demands using the different methodologies from the previous Hot Season were examined using a number of summary statistics, such as absolute differences, average differences, and relative differences.

Initial findings showed that there was little difference between the Relevant Demands when changing the order of aggregation (Approach A and B). Therefore the comparisons of Relevant Demands from one Hot Season to a set of Relevant Demands from the next Hot Season was only conducted on data that had already been aggregated into DSMs (Approach B).

4. Exploratory Analysis

Exploratory data analysis was conducted on the individual NMIs within each DSM programme. Table 1 shows the number of NMIs within each DSM programme and defines the DSM group names, for reference.

DSM Programme Name	Number of NMIs
DSM1	1
DSM2	2
DSM5	5
DSM10	10
DSM20	20
DSM30	30
DSM Scenario 1	5
DSM Scenario 2	5
DSM Scenario 3	5
DSM Scenario 4	5

Table 1. Number of NMIs within each DSM programme.

As there is only one NMI within DSM1 there will be no difference between aggregating the NMIs before or after calculating the Relevant Demand. Therefore, for this DSM programme comparisons can only be made across the different Relevant Demand calculation methodologies.

The exploratory analysis revealed that a handful of NMIs had large sections of consecutive missing data and/or zero values, possibly indicating new (or old) customers or a period of downtime. For the purposes of this analysis, these missing and zero values were omitted when aggregating the NMIs into DSM programmes and also when calculating the Relevant Demands. Whilst the NMIs with the most missing and zero values appear to come from NMIs with relatively small loads, the fact that these values have been excluded will reduce the aggregated DSM load, which may bias the Relevant Demands downwards. This should be noted as a caveat when interpreting the results.

Summary statistics of the Curtailable Load during the Hot Season for each NMI were produced. These revealed that the size of the load and the standard deviation for each NMI can vary substantially within each DSM programme (in particular reference to DSM20 and DSM30 DSM programmes, which have considerably more NMIs than DSM1 and DSM2). NMIs with high loads or large standard deviations will "swamp" the effect of NMIs with small loads and standard deviations. The effect of NMIs with small loads and standard deviations could be negligible. A relative standard deviation metric was devised in order to capture the combined effect of load size and standard deviation. This showed that there were a small number of NMIs that could be skewing the Relevant Demand calculations in some DSMs.

DSM30 contained one NMI that looked to contain some unusually high Curtailable Load readings. There was no need to exclude these points from the analysis however, as the Relevant Demands are calculated using a median, which is a robust measure resistant to extreme values. One of the original NMIs provided to Data Analysis Australia had no non-zero readings during the Hot Seasons. This NMI was not included in the analysis.

Data Analysis Australia classified each of the scaled NMIs into “low”, “medium” and “high” consumption and “large” and “small” standard deviation. Table 2 shows the number of NMIs in each of the classified groups.

	Standard Deviation	
Consumption	**Large**	**Small**
High	14	1
Medium	12	17
Low	3	12

Table 2. Number of NMIs with Low, Medium or High consumption and Large or Small standard deviations.

5. Peak Trading Intervals for Each Method

The Peak Trading Intervals for each method were calculated using the System data provided by the IMO. Where available, these were checked against published PTIs by the IMO. The PTIs used for each methodology are outlined in this Section.

5.1 Method 1: Current Method (32 PTIs)

The PTIs used to calculate the Relevant Demand for the current method (Method 1) are shown in Table 3.

Method 1							
Hot Season 2006/07		Hot Season 2007/08		Hot Season 2008/09		Hot Season 2009/10	
Date	Time	Date	Time	Date	Time	Date	Time
27/12/2006	1230	27/12/2007	1100	30/12/2008	1400	21/12/2009	1330
27/12/2006	1300	27/12/2007	1130	30/12/2008	1430	21/12/2009	1400
27/12/2006	1330	27/12/2007	1200	30/12/2008	1500	21/12/2009	1430
27/12/2006	1400	27/12/2007	1230	30/12/2008	1530	21/12/2009	1500
27/12/2006	1430	27/12/2007	1300	30/12/2008	1600	21/12/2009	1530
27/12/2006	1500	27/12/2007	1330	30/12/2008	1630	21/12/2009	1600
27/12/2006	1530	27/12/2007	1400	30/12/2008	1700	21/12/2009	1630
27/12/2006	1600	27/12/2007	1430	30/12/2008	1730	21/12/2009	1700
29/01/2007	1130	17/01/2008	1300	16/01/2009	1200	18/01/2010	1330
29/01/2007	1200	17/01/2008	1330	16/01/2009	1230	18/01/2010	1400
29/01/2007	1230	17/01/2008	1400	16/01/2009	1300	18/01/2010	1430
29/01/2007	1300	17/01/2008	1430	16/01/2009	1330	18/01/2010	1500
29/01/2007	1330	17/01/2008	1500	16/01/2009	1400	18/01/2010	1530
29/01/2007	1400	17/01/2008	1530	16/01/2009	1430	18/01/2010	1600
29/01/2007	1430	17/01/2008	1600	16/01/2009	1500	18/01/2010	1630
29/01/2007	1500	17/01/2008	1630	16/01/2009	1530	18/01/2010	1700
2/02/2007	1300	28/02/2008	1300	2/02/2009	1230	25/02/2010	1400
2/02/2007	1330	28/02/2008	1330	2/02/2009	1300	25/02/2010	1430
2/02/2007	1400	28/02/2008	1400	2/02/2009	1330	25/02/2010	1500
2/02/2007	1430	28/02/2008	1430	2/02/2009	1400	25/02/2010	1530
2/02/2007	1500	28/02/2008	1500	2/02/2009	1430	25/02/2010	1600
2/02/2007	1530	28/02/2008	1530	2/02/2009	1500	25/02/2010	1630
2/02/2007	1600	28/02/2008	1600	2/02/2009	1530	25/02/2010	1700
2/02/2007	1630	28/02/2008	1630	2/02/2009	1600	25/02/2010	1730
7/03/2007	1400	11/03/2008	1300	10/03/2009	1300	12/03/2010	1330
7/03/2007	1430	11/03/2008	1330	10/03/2009	1330	12/03/2010	1400
7/03/2007	1500	11/03/2008	1400	10/03/2009	1400	12/03/2010	1430
7/03/2007	1530	11/03/2008	1430	10/03/2009	1430	12/03/2010	1500
7/03/2007	1600	11/03/2008	1500	10/03/2009	1500	12/03/2010	1530
7/03/2007	1630	11/03/2008	1530	10/03/2009	1530	12/03/2010	1600
7/03/2007	1700	11/03/2008	1600	10/03/2009	1600	12/03/2010	1630
7/03/2007	1730	11/03/2008	1630	10/03/2009	1630	12/03/2010	1700

Table 3. Peak Trading Intervals for Method 1: the current method.

5.2 Method 2: IRCR (12 PTIs)

Data Analysis Australia used System data to calculate the IRCR PTIs for each Hot Season. These were then compared to the IRCR PTIs published on the IMO website. Data Analysis Australia did not use the published IRCR PTIs for the 2007/08 Capacity Year as these utilised data from the 2005/06 Hot Season to calculate Relevant Demand[1]. Instead data from the 2006/07 Hot Season was used to calculate the Relevant Demand values that applied to the 2007/08 Capacity Year. Table 4 shows the IRCR PTIs used to calculate the Relevant Demand.

Method 2							
Hot Season 2006/07		Hot Season 2007/08		Hot Season 2008/09		Hot Season 2009/10	
Date	Time	Date	Time	Date	Time	Date	Time
29/01/2007	1200	17/01/2008	1430	15/01/2009	1530	18/01/2010	1530
29/01/2007	1230	17/01/2008	1500	15/01/2009	1600	18/01/2010	1600
29/01/2007	1330	17/01/2008	1530	15/01/2009	1630	18/01/2010	1630
6/03/2007	1430	4/02/2008	1500	16/01/2009	1400	19/01/2010	1500
6/03/2007	1500	4/02/2008	1530	16/01/2009	1430	19/01/2010	1530
6/03/2007	1530	4/02/2008	1600	16/01/2009	1500	19/01/2010	1600
7/03/2007	1500	11/02/2008	1500	2/02/2009	1430	25/02/2010	1530
7/03/2007	1530	11/02/2008	1530	2/02/2009	1500	25/02/2010	1600
7/03/2007	1600	11/02/2008	1600	2/02/2009	1530	25/02/2010	1630
8/03/2007	1430	28/02/2008	1430	11/02/2009	1500	26/02/2010	1530
8/03/2007	1500	28/02/2008	1500	11/02/2009	1530	26/02/2010	1600
8/03/2007	1530	28/02/2008	1530	11/02/2009	1600	26/02/2010	1630

Table 4. Peak Trading Intervals for Method 2: the IRCR method.

[1] The IMO used the same IRCR intervals for two Capacity Years at the start of the Market. The IRCR intervals used by the IMO for the 2006/07 and 2007/08 Capacity Years relate to the 2005/06 Hot Season.

5.3 Method 3: Business Hours (variable PTIs per Hot Season)

This method selects all the trading intervals that occur between 8am and 10pm, Monday to Friday (excluding public holidays), essentially making all the trading intervals 'Peak Trading Intervals'. The number of PTIs used to calculate the Relevant Demand for this method varies from year to year, due to the Easter public holidays moving in and out of the Hot Season. Table 5 shows the number of PTIs used to calculate the Relevant Demand for each Hot Season.

	Method 3			
	Hot Season 2006/07	Hot Season 2007/08	Hot Season 2008/09	Hot Season 2009/10
Number of PTIs	2,268	2,212	2,296	2,296

Table 5. Number of PTIs used to calculate the Relevant Demand for Method 3: Business hours.

5.4 Method 4: Top Peak Market Intervals Method (250, 500 & 750 PTIs)

For this method, Relevant Demands are calculated based upon the top 250, 500 and 750 PTIs. The PTIs were not restricted to Business hours and Business days, however, the majority of the intervals do occur during these times. Table 6 shows the number of intervals selected by the top peak market intervals (TPMIs) method that occur outside of business hours, that is not between Mondays to Fridays (unless they are public holidays) and the hours of 8am to 10pm.

Hot Season	TPMIs	TPMIs not in Business hours	Proportion of TPMIs not in business hours	No. of unique days represented by the intervals	No. of days that are not business days	Proportion of days that are not business days
2006/07	250	56	0.22	20	5	0.25
2007/08	250	0	0.00	24	0	0.00
2008/09	250	25	0.10	24	3	0.13
2009/10	250	29	0.12	18	3	0.17
2006/07	500	116	0.23	39	12	0.31
2007/08	500	33	0.07	36	4	0.11
2008/09	500	74	0.15	36	8	0.22
2009/10	500	59	0.12	36	6	0.17
2006/07	750	117	0.16	51	17	0.33
2007/08	750	83	0.11	45	8	0.18
2008/09	750	135	0.18	52	15	0.29
2009/10	750	123	0.16	50	11	0.22

Table 6. Number of Intervals and Days included in Method 4 that occur outside of Business hours.

6. Relevant Demand Calculation Methods and Stability

This section contains the Relevant Demand values calculated using each Relevant Demand methodology. As mentioned previously, the Relevant Demand values were calculated using individual NMI loads which were then summed into a single Relevant Demand for each DSM programme (Approach A) and the were alternatively calculated by using an aggregated load for each DSM Group (Approach B). The resulting Relevant Demand values for both approaches are presented in the tables in the following sections.

6.1 Method 1: Current Method (32 PTIs)

The Relevant Demand values for both approaches of aggregating the Relevant Demands have been presented for each of the DSM programmes. DSM1 to DSM30 are presented in Table 7 and Figure 1 and the DSM scenarios are presented in Table 8 and Figure 2 using the current method, with 32 PTIs.

Method 1						
	DSM 1		DSM 2		DSM 5	
	Approach		Approach		Approach	
Hot Season	A	B	A	B	A	B
2006/07	31.043	31.043	27.142	26.551	6.858	7.315
2007/08	31.204	31.204	26.065	26.163	9.800	9.663
2008/09	30.596	30.596	16.171	16.370	6.114	6.603
2009/10	30.798	30.798	21.140	21.150	3.047	3.293
	DSM 10		DSM 20		DSM 30	
	Approach		Approach		Approach	
Hot Season	A	B	A	B	A	B
2006/07	14.508	13.854	19.941	19.446	33.307	30.111
2007/08	13.376	10.962	18.835	20.003	26.980	24.183
2008/09	13.482	13.149	20.606	20.842	26.307	27.176
2009/10	12.776	11.537	20.274	20.735	23.925	22.705

Table 7. Approach A & B DSM Group Relevant Demand values Method 1: the current method (32 PTIs).

	Method 1							
	DSM Scenario 1 Approach		DSM Scenario 2 Approach		DSM Scenario 3 Approach		DSM Scenario 4 Approach	
Hot Season	A	B	A	B	A	B	A	B
2006/07	12.942	12.753	16.232	15.721	7.320	6.624	21.464	20.671
2007/08	11.897	12.083	17.001	16.927	7.522	7.424	17.224	17.538
2008/09	12.724	12.281	25.591	24.256	5.872	6.111	15.533	15.787
2009/10	12.454	11.779	18.251	18.123	6.211	6.051	18.576	19.211

Table 8. Approach A & B DSM Scenario Relevant Demand values for Method 1: the current method (32 PTIs).

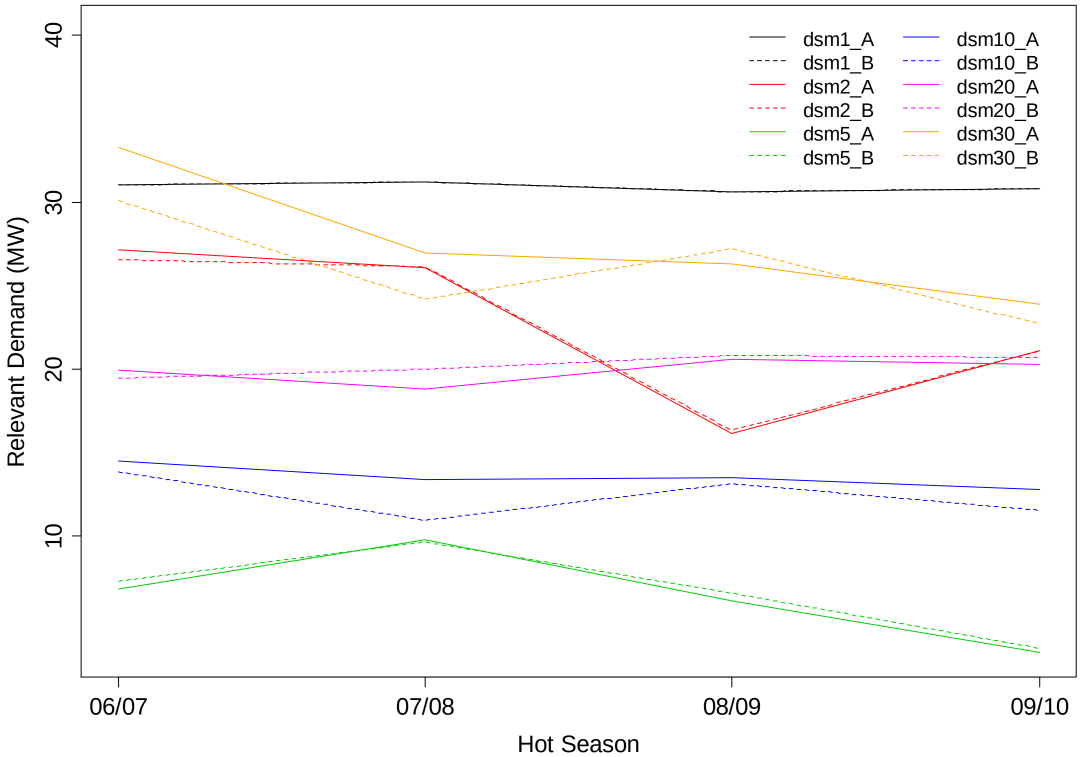

Figure 1. Relevant Demands for Method 1: the Current Method.

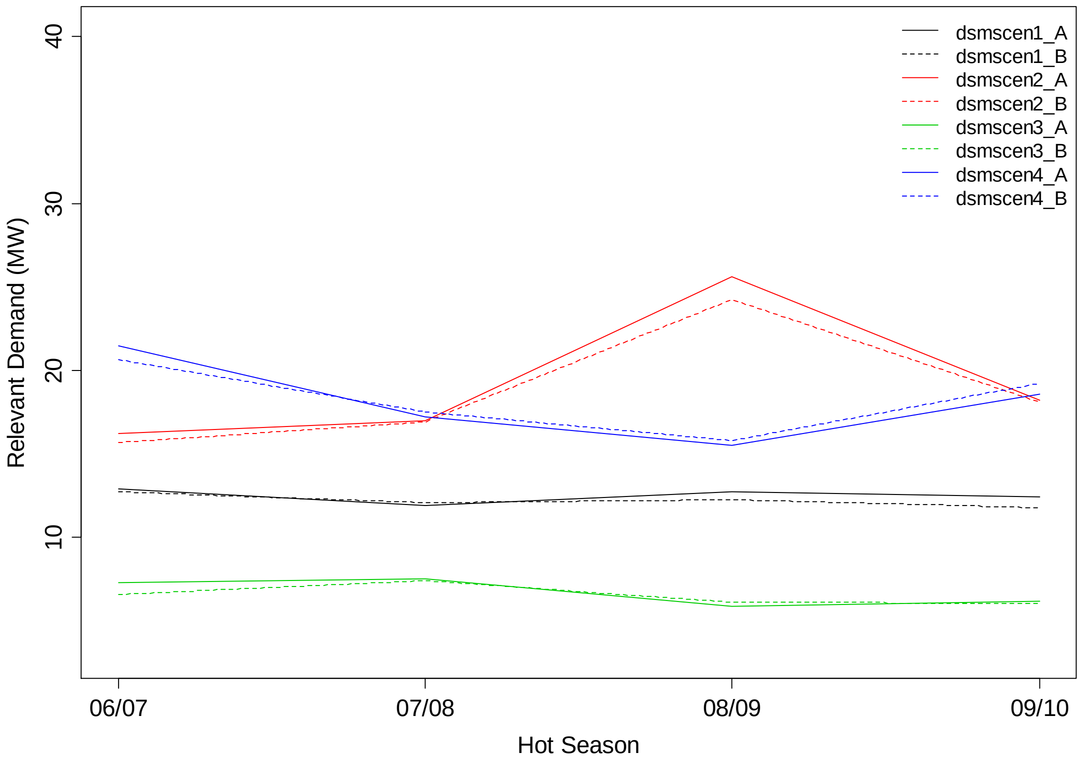

Figure 2. Relevant Demands for Method 1 – DSM Scenarios: the Current Method.

As the loads for all of the DSMs have been scaled to maintain confidentiality, comparisons in the size of the loads between DSMs have not been discussed. However, the changes in Relevant Demands over time remain relevant and show that the Relevant Demands for DSM1, DSM10 and DSM20 are relatively stable over time. DSM2 however, shows a large (almost 10MW) decrease in the 2008/09 Hot Season. DSM30 shows a decreasing Relevant Demand over the Hot Seasons and DSM5 show an increase in Relevant Demand in 2007/08 before decreasing in the following years.

The Relevant Demands for DSM Scenario 1 and DSM Scenario 3 are relatively stable over time. This is unsurprising as these are the DSM scenarios with small standard deviations. The DSM scenarios with larger standard deviations, DSM Scenario 2 and 3, show larger fluctuations. There are very little differences noted between the Relevant Demands calculated using Approach A and Approach B for any of the DSM Groups.

6.2 Method 2: IRCR (12 PTIs)

The Relevant Demands calculated using the IRCR method are shown in Table 9, Table 10, Figure 3 and Figure 5. Both approaches of aggregating the Relevant Demands have been presented.

Method 2						
	DSM 1		DSM 2		DSM 5	
	Approach		Approach		Approach	
Hot Season	A	B	A	B	A	B
2006/07	30.909	30.909	25.576	26.019	11.190	9.031
2007/08	31.151	31.151	27.319	26.873	9.875	9.963
2008/09	30.573	30.573	16.320	16.261	6.471	6.585
2009/10	30.794	30.794	24.918	24.759	2.105	2.333
	DSM 10		DSM 20		DSM 30	
	Approach		Approach		Approach	
Hot Season	A	B	A	B	A	B
2006/07	15.781	14.632	21.814	20.102	33.911	30.792
2007/08	15.769	15.002	21.822	21.444	30.183	28.972
2008/09	14.114	14.008	19.843	19.396	27.691	27.649
2009/10	7.988	7.523	20.758	19.801	11.413	12.179

Table 9. Approach A & B DSM Group Relevant Demand values for Method 2: the IRCR Method (12 PTIs).

Method 2								
	DSM Scenario 1		DSM Scenario 2		DSM Scenario 3		DSM Scenario 4	
	Approach		Approach		Approach		Approach	
Hot Season	A	B	A	B	A	B	A	B
2006/07	13.154	12.997	20.401	18.166	7.439	6.448	24.353	25.125
2007/08	13.409	12.724	18.132	18.208	7.543	7.496	21.773	21.520
2008/09	12.859	12.123	26.603	25.500	7.271	7.223	18.257	18.403
2009/10	11.079	11.376	16.333	16.917	6.246	6.094	17.534	17.020

Table 10. Approach A & B DSM Scenario Relevant Demand values for Method 2: the IRCR Method (12 PTIs).

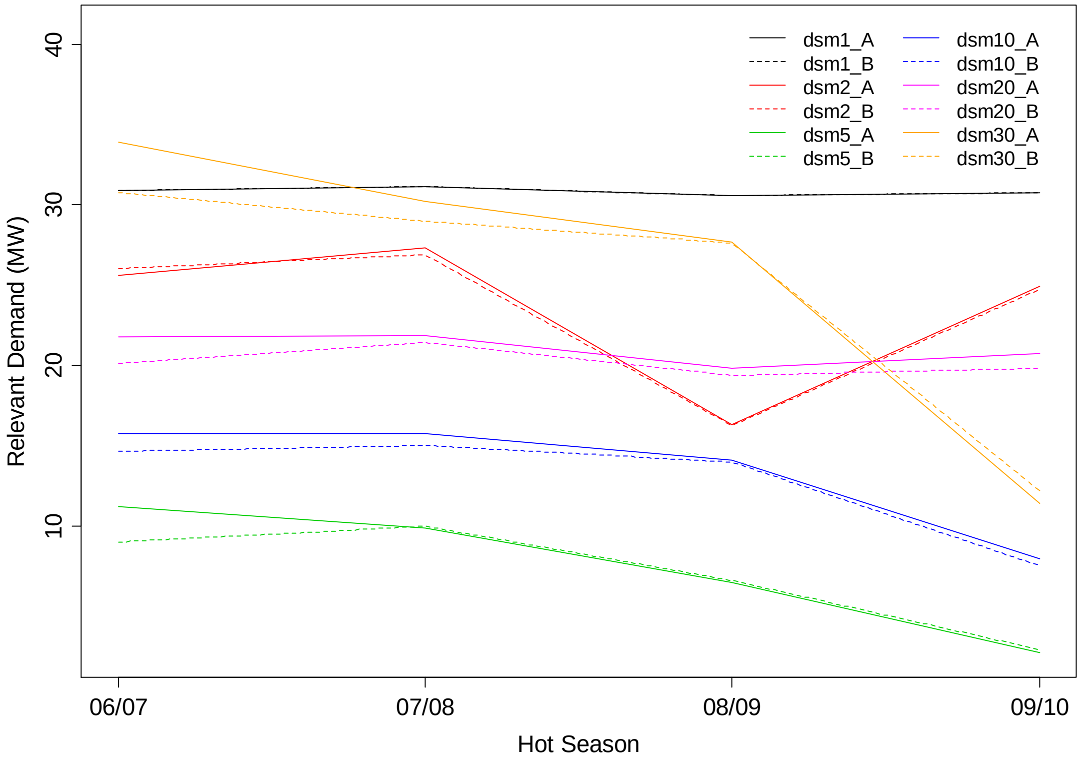

Figure 3. Relevant Demands for Method 2: the IRCR Method.

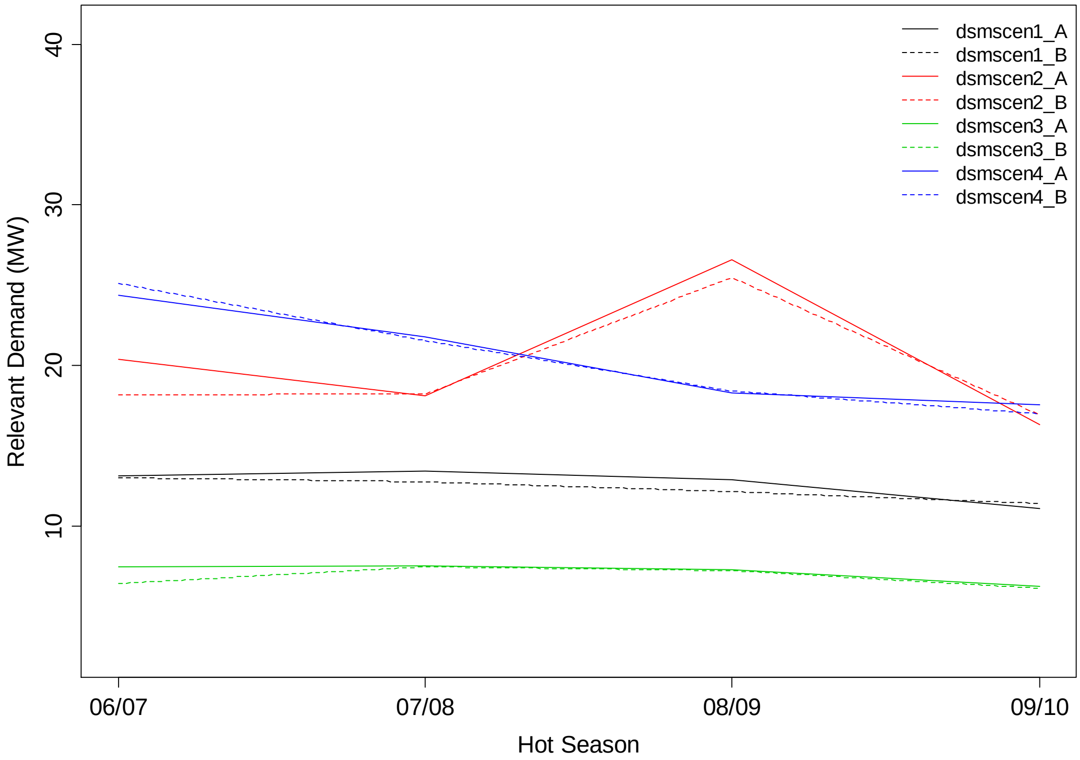

Figure 4. Relevant Demands for Method 2 – DSM Scenarios: the IRCR Method.

The Relevant Demands for DSM1 and DSM20 remain relatively stable over time but DSM5, DSM10 and DSM30 all show decreases in Relevant Demand in the 2009/10 Hot Season. The fluctuations seen in DSM2 and DSM30 were largest, where drops greater than 16MW for 2009/10 Hot Season were observed respectively. DSM5 had 4MW decrease in 2009/10, which is relatively small change in comparison to the previous two examples, but this is still a decrease of over 60% from the previous Hot Season's Relevant Demand. A large increase, by nearly 8MW, in the Relevant Demand value was observed for DSM Scenario 2 in 2008/09, but it dropped by comparable amount in the following Hot Season. The DSM scenarios with low standard deviations (DSM Scenario 1 and 3) remain relative stable with more fluctuations seen in the DSM scenarios with larger standard deviations.

Again, no notable differences between Approach A and Approach B were recorded in the IRCR method. Overall, the IRCR method seems to yield Relevant Demand values that are slightly more volatile than the current method.

6.3 Method 3: Business Hours (variable PTIs per Hot Season)

The Relevant Demands calculated using the Business hours method are shown in Table 11, Table 12, Figure 5 and Figure 7. Both approaches of aggregating the Relevant Demands have been presented.

Method 3						
	DSM 1		DSM 2		DSM 5	
	Approach		Approach		Approach	
Hot Season	A	B	A	B	A	B
2006/07	31.009	31.009	22.869	23.115	8.673	7.897
2007/08	31.067	31.067	24.002	23.595	11.222	9.560
2008/09	30.569	30.569	21.170	20.429	6.807	6.720
2009/10	31.093	31.093	22.288	22.887	8.988	8.362
	DSM 10		DSM 20		DSM 30	
	Approach		Approach		Approach	
Hot Season	A	B	A	B	A	B
2006/07	14.359	13.884	20.352	20.092	32.247	30.777
2007/08	14.443	12.521	19.303	19.158	30.965	26.812
2008/09	10.467	11.181	18.894	19.191	25.850	25.134
2009/10	13.179	12.872	18.924	19.231	26.362	25.826

Table 11. Approach A & B and DSM Group Relevant Demand values for Method 3: Business Hours.

Method 3								
	DSM Scenario 1 Approach		DSM Scenario 2 Approach		DSM Scenario 3 Approach		DSM Scenario 4 Approach	
Hot Season	A	B	A	B	A	B	A	B
2006/07	12.610	11.997	17.021	16.192	8.304	8.110	19.597	19.919
2007/08	11.411	11.565	19.808	15.384	8.610	8.485	19.106	18.470
2008/09	11.227	11.249	17.844	19.050	8.088	7.893	11.994	14.044
2009/10	10.314	10.705	17.250	16.398	7.483	7.228	13.021	14.200

Table 12. Approach A & B and DSM Scenario Relevant Demand values for Method 3: Business Hours.

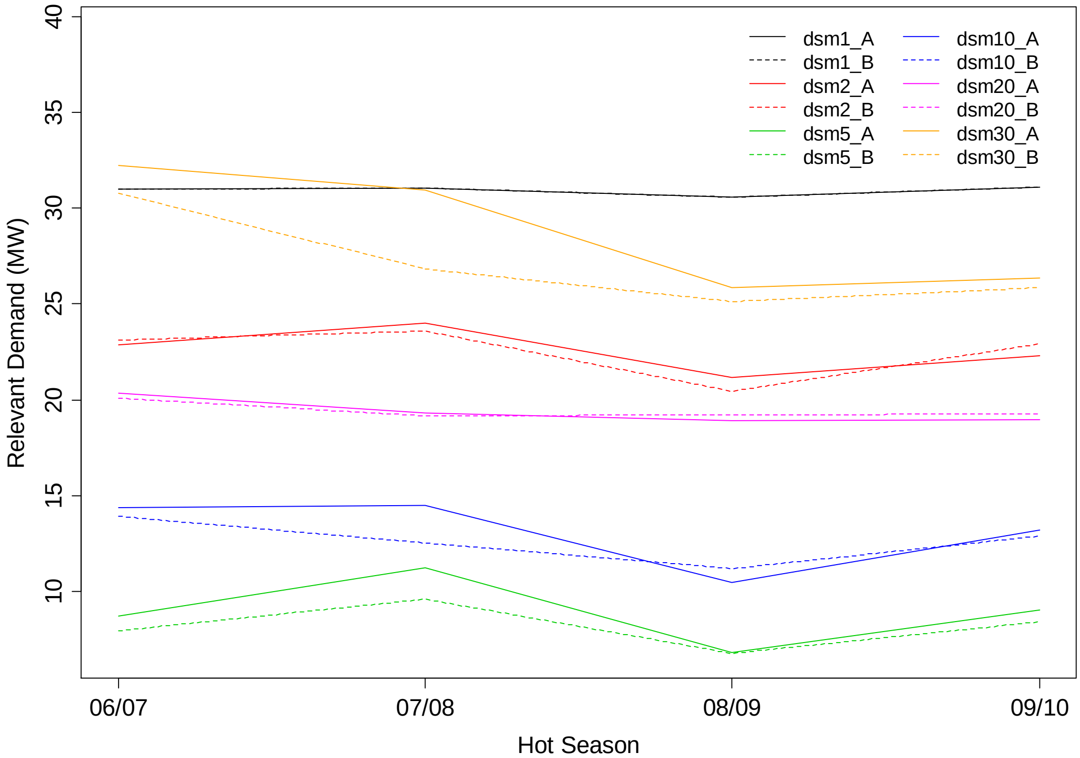

Figure 5. Relevant Demands for Method 3: Business hours.

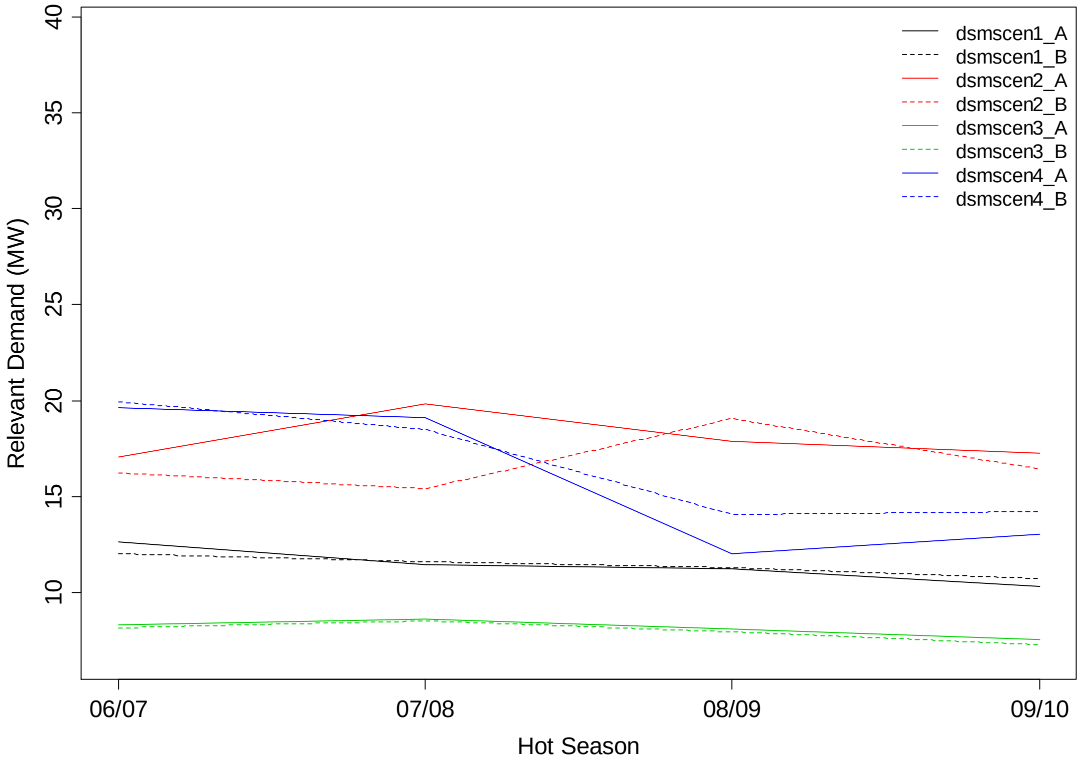

Figure 6. Relevant Demands for Method 3 – DSM Scenarios: Business hours.

The Relevant Demand values for the Business hours method are much more stable than those of the previous two methods. Some of the notable differences in the Relevant Demands are a relatively large difference between earlier Hot Seasons and late Hot Seasons for DSM30, which may not be surprising given the decreasing Relevant Demand of this DSM displayed in the previous two methods. DSM Scenario 4 exhibited a similar drop in Relevant Demand for the last two Hot Seasons as in DSM30, where a drop greater than 7MW was observed in 2008/09 Hot Season.

Again the DSM Scenarios with small standard deviations (DSM Scenarios 1 and 3) were very stable over time. A relatively large difference between Approach A and B was observed for DSM Scenario 2 in the 2007/08 Hot Season.

6.4 Method 4: Top Peak Market Intervals (250, 500 & 750 PTIs)

The Relevant Demands calculated using the top peak market intervals (TPMI) method for the top 250, 500 and 750 intervals are shown in Table 13 to Table 18, and the plots are given in Figure 7 to Figure 12. Both approaches of aggregating the Relevant Demands have been presented.

Method 4 – 250 PTIs						
	DSM 1		DSM 2		DSM 5	
	Approach		Approach		Approach	
Hot Season	A	B	A	B	A	B
2006/07	31.006	31.006	25.571	25.529	6.794	7.053
2007/08	31.167	31.167	27.207	26.670	10.231	10.155
2008/09	30.573	30.573	22.885	21.871	6.315	6.511
2009/10	31.184	31.184	25.567	24.184	3.367	3.601
	DSM 10		DSM 20		DSM 30	
	Approach		Approach		Approach	
Hot Season	A	B	A	B	A	B
2006/07	14.739	14.279	20.040	18.247	32.334	30.700
2007/08	14.930	13.190	20.545	20.763	28.793	26.215
2008/09	12.572	13.252	19.595	19.729	27.000	27.977
2009/10	12.853	13.369	19.770	19.842	24.065	26.134

Table 13. Approach A & B and DSM Group Relevant Demand values for Method 4: the Top Peak Market Intervals Method (250 PTIs).

Method 4 – 250 PTIs								
	DSM Scenario 1		DSM Scenario 2		DSM Scenario 3		DSM Scenario 4	
	Approach		Approach		Approach		Approach	
Hot Season	A	B	A	B	A	B	A	B
2006/07	12.913	12.513	17.402	14.221	8.609	8.001	20.982	18.086
2007/08	11.947	12.070	18.117	16.132	8.917	8.734	20.636	20.409
2008/09	12.723	12.257	22.302	23.269	8.316	8.218	15.144	14.788
2009/10	12.124	11.754	17.345	16.871	7.646	7.170	14.923	13.753

Table 14. Approach A & B and DSM Scenario Relevant Demand values for Method 4: the Top Peak Market Intervals Method (250 PTIs).

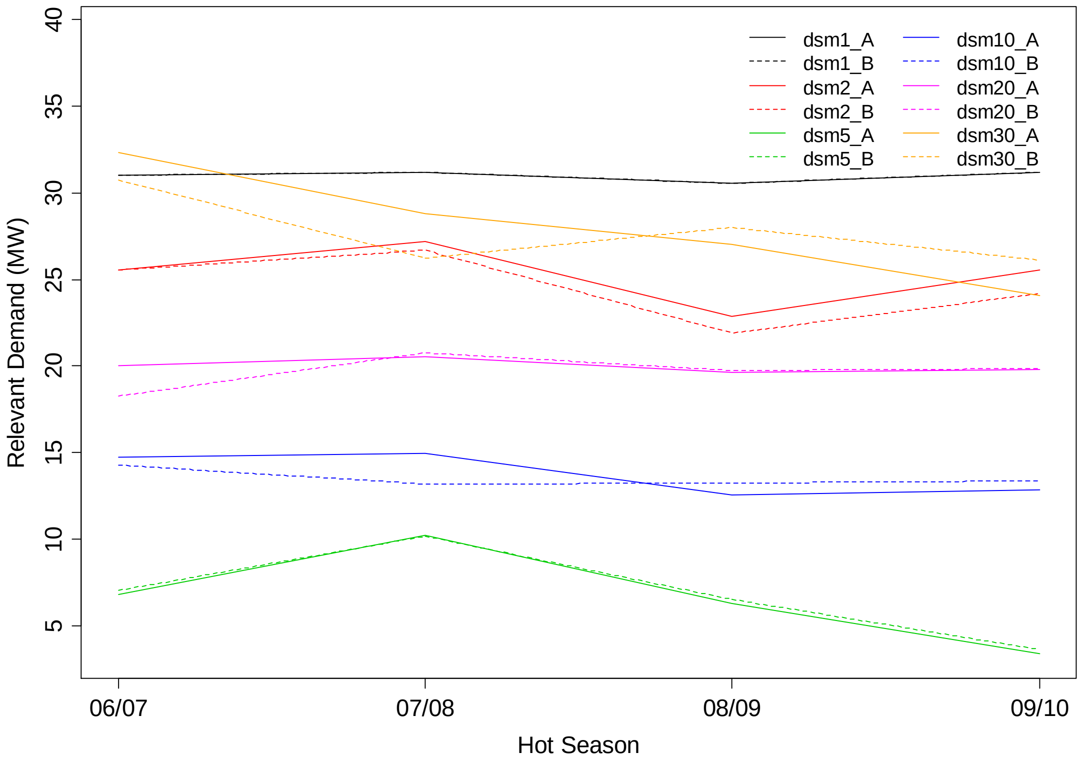

Figure 7. Relevant Demands for Method 4 using the top 250 intervals.

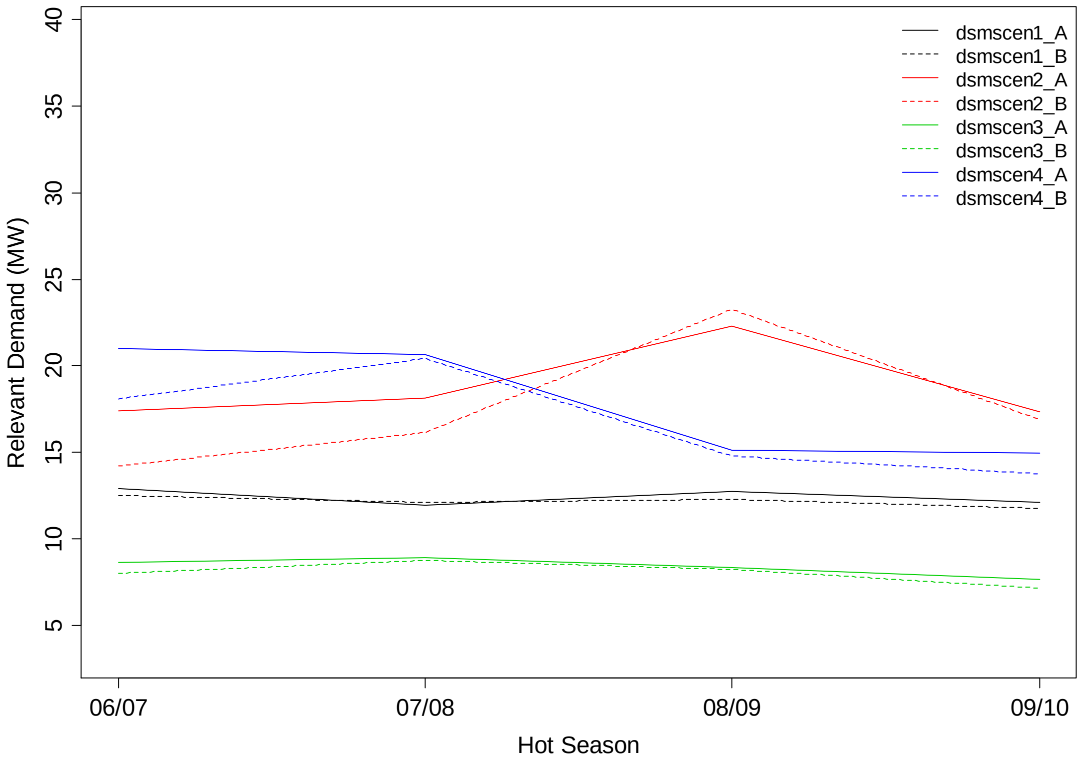

Figure 8. Relevant Demands for Method 4 – DSM Scenarios: Top 250 Peak Market Intervals.

Method 4 – 500 PTIs						
	DSM 1		DSM 2		DSM 5	
	Approach		Approach		Approach	
Hot Season	A	B	A	B	A	B
2006/07	31.006	31.006	24.930	25.048	6.848	7.088
2007/08	31.144	31.144	26.183	25.401	10.404	10.303
2008/09	30.569	30.569	21.909	21.823	6.286	6.458
2009/10	31.161	31.161	24.605	23.699	8.363	7.341
	DSM 10		DSM 20		DSM 30	
	Approach		Approach		Approach	
Hot Season	A	B	A	B	A	B
2006/07	14.775	14.210	20.451	19.328	31.499	30.463
2007/08	14.782	13.300	19.946	20.257	29.414	27.287
2008/09	12.174	13.161	18.758	19.374	27.057	27.957
2009/10	13.863	13.476	19.992	19.849	27.405	26.422

Table 15. Approach A & B and DSM Group Relevant Demand values for Method 4: the Top Peak Market Intervals Method (500 PTIs).

Method 4 – 500 PTIs								
	DSM Scenario 1		DSM Scenario 2		DSM Scenario 3		DSM Scenario 4	
	Approach		Approach		Approach		Approach	
Hot Season	A	B	A	B	A	B	A	B
2006/07	12.961	12.425	17.487	15.201	8.531	8.085	21.095	19.713
2007/08	11.845	11.993	17.878	16.090	8.872	8.676	19.805	20.362
2008/09	12.661	12.147	21.603	23.082	8.207	8.070	11.828	13.490
2009/10	11.893	11.684	17.398	17.243	7.613	7.272	14.965	14.216

Table 16. Approach A & B and DSM Scenario Relevant Demand values for Method 4: the Top Peak Market Intervals Method (500 PTIs).

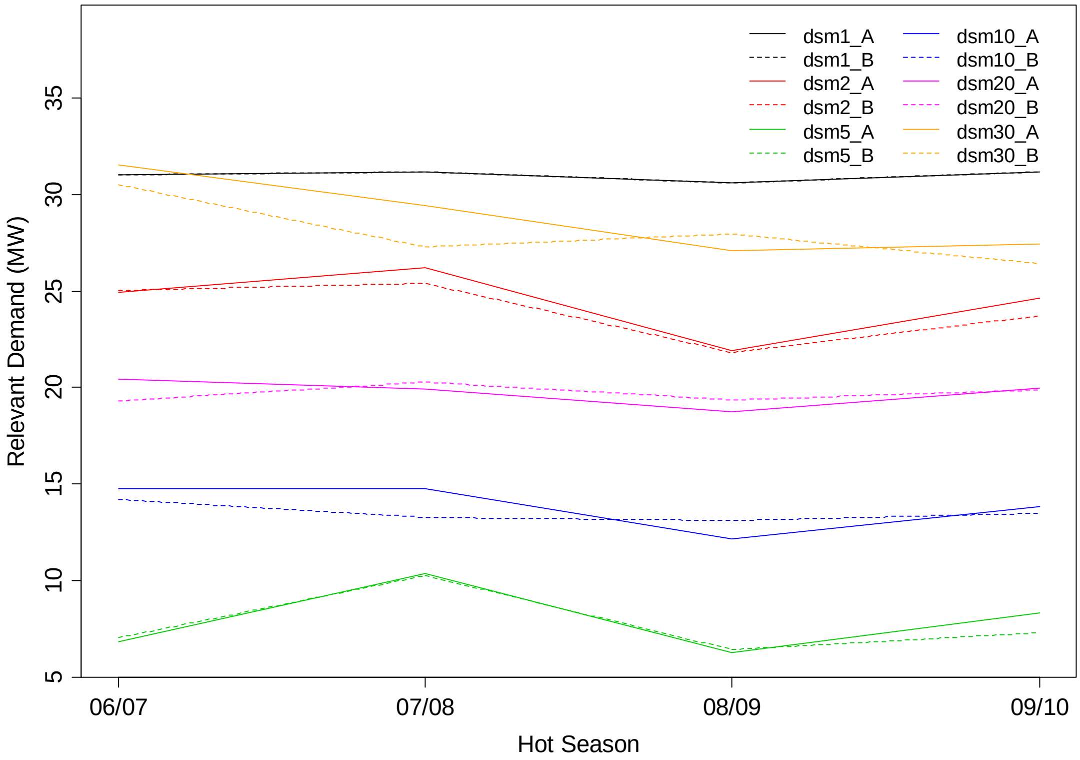

Figure 9. Relevant Demands for Method 4 using the top 500 intervals.

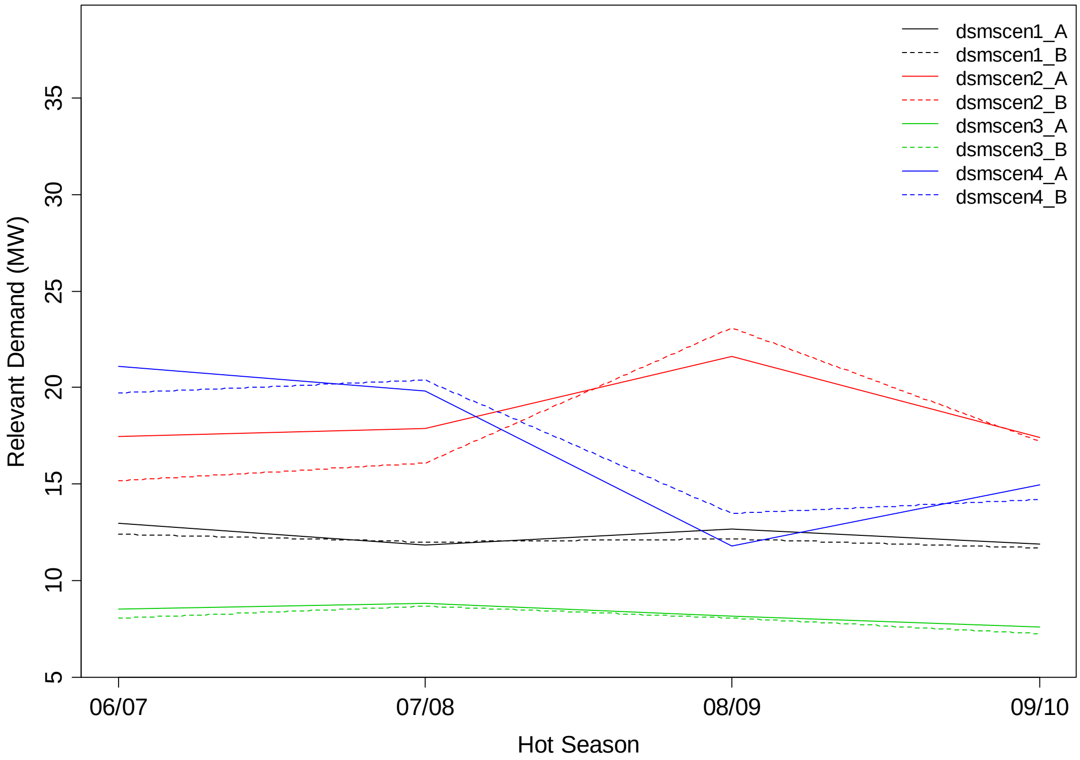

Figure 10. Relevant Demands for Method 4 – DSM Scenarios: Top 500 Peak Market Intervals.

Method 4 – 750 PTIs						
	DSM 1		DSM 2		DSM 5	
	Approach		Approach		Approach	
Hot Season	A	B	A	B	A	B
2006/07	31.009	31.009	24.765	24.786	6.819	7.141
2007/08	31.120	31.120	25.371	24.585	10.382	10.360
2008/09	30.576	30.576	22.096	21.580	6.230	6.419
2009/10	31.117	31.117	23.557	23.395	8.403	8.016
	DSM 10		DSM 20		DSM 30	
	Approach		Approach		Approach	
Hot Season	A	B	A	B	A	B
2006/07	14.812	14.273	20.473	19.704	31.586	30.914
2007/08	14.723	13.261	19.662	20.045	29.487	27.461
2008/09	12.133	13.015	18.699	19.328	26.921	27.819
2009/10	13.582	13.485	19.876	19.592	26.989	26.484

Table 17. Approach A & B and DSM group Relevant Demand values for Method 4: the Top Peak Market Intervals Method (750 PTIs).

Method 4 – 750 PTIs								
	DSM Scenario 1		DSM Scenario 2		DSM Scenario 3		DSM Scenario 4	
	Approach		Approach		Approach		Approach	
Hot Season	A	B	A	B	A	B	A	B
2006/07	12.907	12.327	17.429	15.434	8.468	8.085	21.166	19.913
2007/08	11.734	11.919	17.741	16.090	8.815	8.627	19.503	19.944
2008/09	12.607	12.044	21.435	22.376	8.155	7.986	11.478	13.450
2009/10	11.835	11.548	17.402	17.211	7.563	7.245	14.940	14.123

Table 18. Approach A & B and DSM Scenario Relevant Demand values for Method 4: the Top Peak Market Intervals Method (750 PTIs).

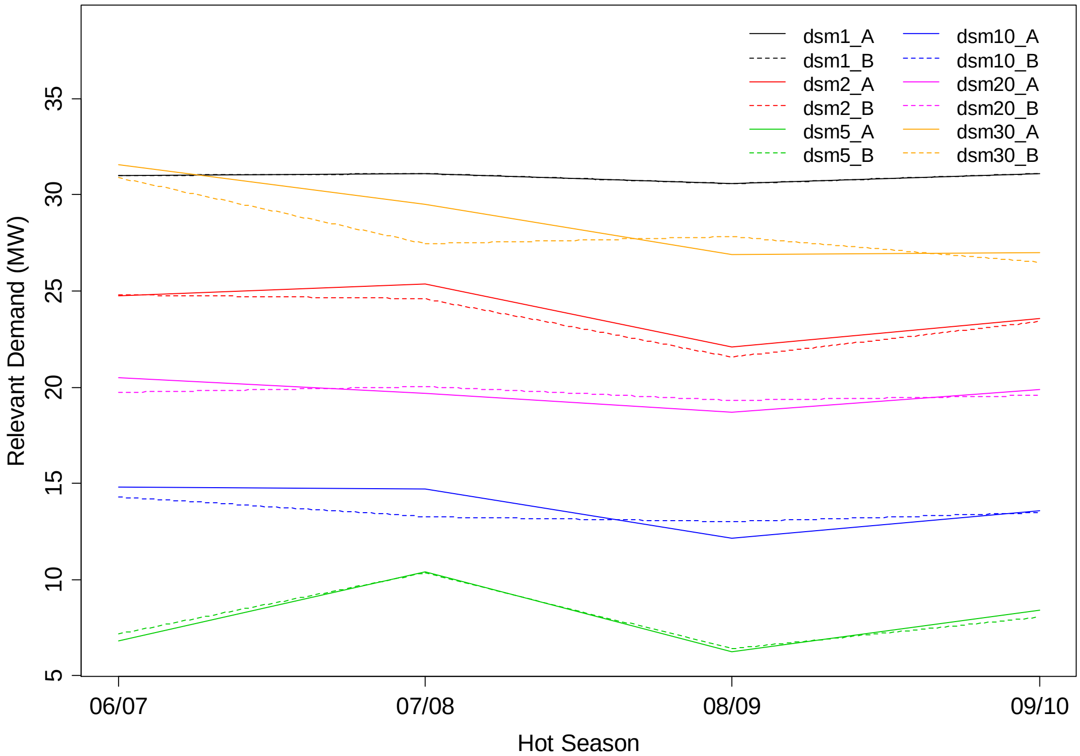

Figure 11. Relevant Demands for Method 4 using the top 750 intervals.

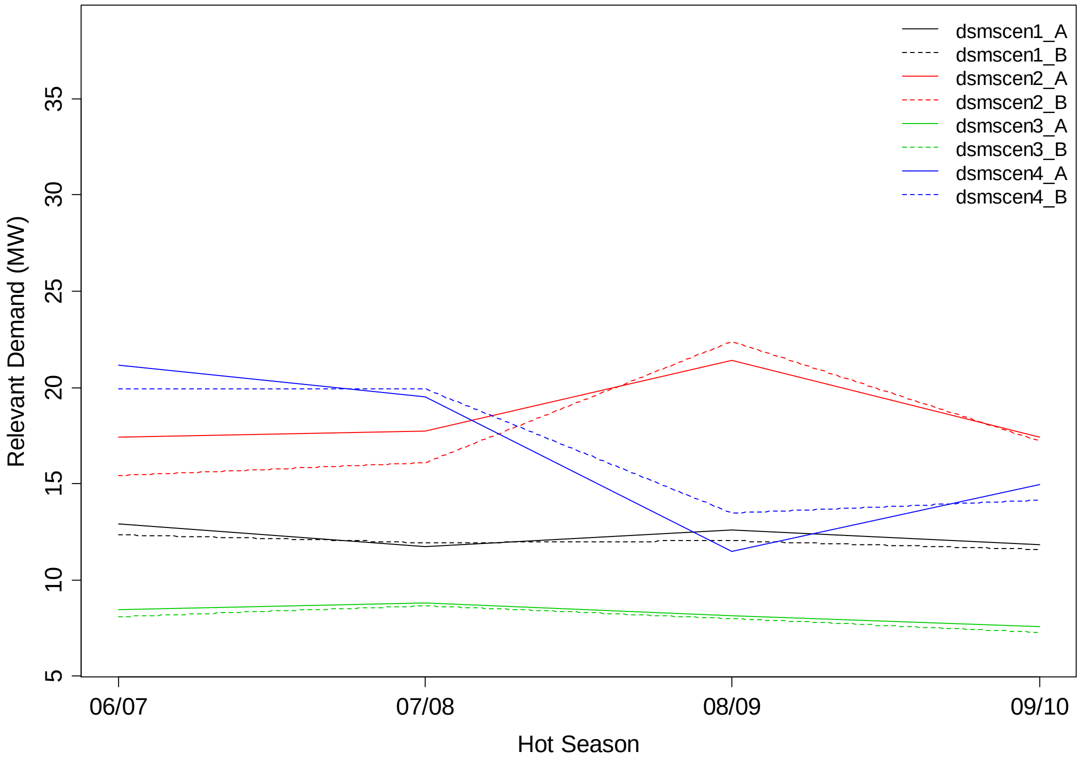

Figure 12. Relevant Demands for Method 4 – DSM Scenarios: Top 750 Peak Market Intervals.

Examination of the plotted Relevant Demand values suggest that there are no notable differences between using the top 250, 500 or 750 intervals. Due to the way in which the PTIs for each class (top 250, 500 and 750) of this method were defined, all the PTIs in the top 250 were included in top 500 PTIs and similarly, the top 500 PTIs were included in the top 750 PTIs. The Relevant Demand values for the top 250 PTIs show reasonable stability across the Hot Seasons. Although relatively minor in comparison to fluctuations observed in previous methods, a fairly large increase was observed for DSM5 in 2007/08 followed by a sharp drop in 2008/09. This pattern was apparent in the top 250, 500 and 750 PTIs. Despite the inclusion of more intervals the DSM scenarios with large standard deviation still displayed obvious fluctuations in the Relevant Demand.

The summary of the counts and proportions of PTIs that fall outside of Business hours in each class is provided in Section 5.3, and shows that the proportion of non-business day intervals increases with the total number of PTIs.

7. Measuring the Reliability of the Relevant Demand Calculations

The IMO uses the Relevant Demand to determine the Reserve Capacity for a DSM for the next Capacity Year. In order to measure the reliability of the Relevant Demands calculated using different methodologies in representing the actual Curtailable Load for the Capacity Year, one must compare the Relevant Demand from the previous Hot Season (the "estimated" Relevant Demand) to the "actual" Relevant Demand for the Capacity Year. Whilst this may sound a simple comparison, determining the "actual" Relevant Demand is not so, as customers may have been asked to curtail their load based upon the Relevant Demand from the previous Hot Season or had an unusual period of low consumption for some reason or another.

Data Analysis Australia devised a methodology that utilised a set of 20 Relevant Demands used to represent a DSM's Curtailable Load at times of their peak demand rather than System demand (described fully in Section 3.2). This method assumes that a DSM would normally have their peak usage at times of System demand except where the DSM has been asked to curtail their load or has had a period of downtime. Thus by using a set of Relevant Demands based upon the DSM's peak usage, an indication of the range that the true Relevant Demand lies can be determined.

As the methodology adopted to select the set of 20 Relevant Demands results in the use of many overlapping intervals, Data Analysis Australia first examined the number of unique days contained within each set of Relevant Demands for each DSM programme to ensure that a good range of Relevant Demand values were selected. Table 1 shows that the set of "actual" Relevant Demands for all DSMs are based upon more than one day. In fact most DSMs "actual" Relevant Demands are based upon three days or more. DSM1, DSM30 and DSM Scenario 3 have Relevant Demands based upon just two days in 2008/09. Based upon this analysis, Data Analysis Australia did not deem it necessary to increase the number of Relevant Demands in the set to ensure the inclusion of more unique days, as there were enough DSMs that utilised a fair number of unique days to determine the Relevant Demands and the Hot Seasons that used just a couple of unique days in 2008/09 may provide insights of their own.

Hot Season	DSM 1	DSM 2	DSM 5	DSM 10	DSM 20	DSM 30	DSM Scen1	DSM Scen2	DSM Scen3	DSM Scen4
2006/07	5	5	5	9	3	8	5	5	5	5
2007/08	6	4	4	8	3	6	6	3	6	4
2008/09	2	4	4	5	3	2	5	2	4	7
2009/10	9	5	3	9	4	6	5	3	4	5

Table 19. Number of unique days in the set of intervals used to represent the "actual" Relevant Demand.

To assess the reasonableness of our methodology to estimate "actual" Relevant Demands, Data Analysis Australia initially compared the Relevant Demands using the different methodologies to the "actual" Relevant Demands from the **same** Hot Season. Once assessed as reasonable, Data Analysis Australia compared the "estimated" Relevant Demand from one Hot Season to the "actual" Relevant Demand of the next Hot Season, as this is the actual problem. The results of both comparisons are shown in Figure 13.

The plot on the top-left of Figure 13 shows the Relevant Demands calculated using Method 2 - the IRCR method for DSM5 (the line on the graph) compared with the range of "actual" Relevant Demands for DSM5 (the boxplots on the graph). The plot on the bottom-left of Figure 13 show the Relevant Demands calculated using Method 4 – the top 250 intervals for DSM Scenario 3 (the line on the graph) compared with the range of "actual" Relevant Demands for DSM Scenario 2 (the boxplots on the graph).

These comparisons showed that the range of "actual" Relevant Demands were consistently higher for each Hot Season than the Relevant Demands calculated using the different methods. This is to be expected as the "actual" Relevant Demands are based upon the peak intervals for the DSM, whereas the Relevant Demands calculated using the different methodologies utilise System peak intervals which do not necessarily correspond to the DSM's peaks (e.g. the DSM may have been asked to being asked to curtail their load or have experienced a period of downtime). Although the "actual" Relevant Demands are consistently higher than the calculated Relevant Demands both tend to follow the same pattern from year to year when comparing data from the same Hot Seasons. This indicates that the Relevant Demand calculations do appear to be indicative of that particular Hot Season.

The set of "actual" Relevant Demands for DSM Scenario 2 in the 2008/09 Hot Season appear unusually high (Figure 13 bottom-left plot). This is because the intervals used to calculate these Relevant Demands were only based upon two unique days. This pattern was also observed in the other DSMs that only incorporated intervals over two unique days in the 2008/09 Hot Season (DSM1 and DSM30). DSMs that utilised three unique days in a Hot Season did not show any obvious differences in Relevant Demands from other Hot Seasons. This provides evidence that in order to get reliable Relevant Demand estimates, intervals that cover more than two unique days should be incorporated.

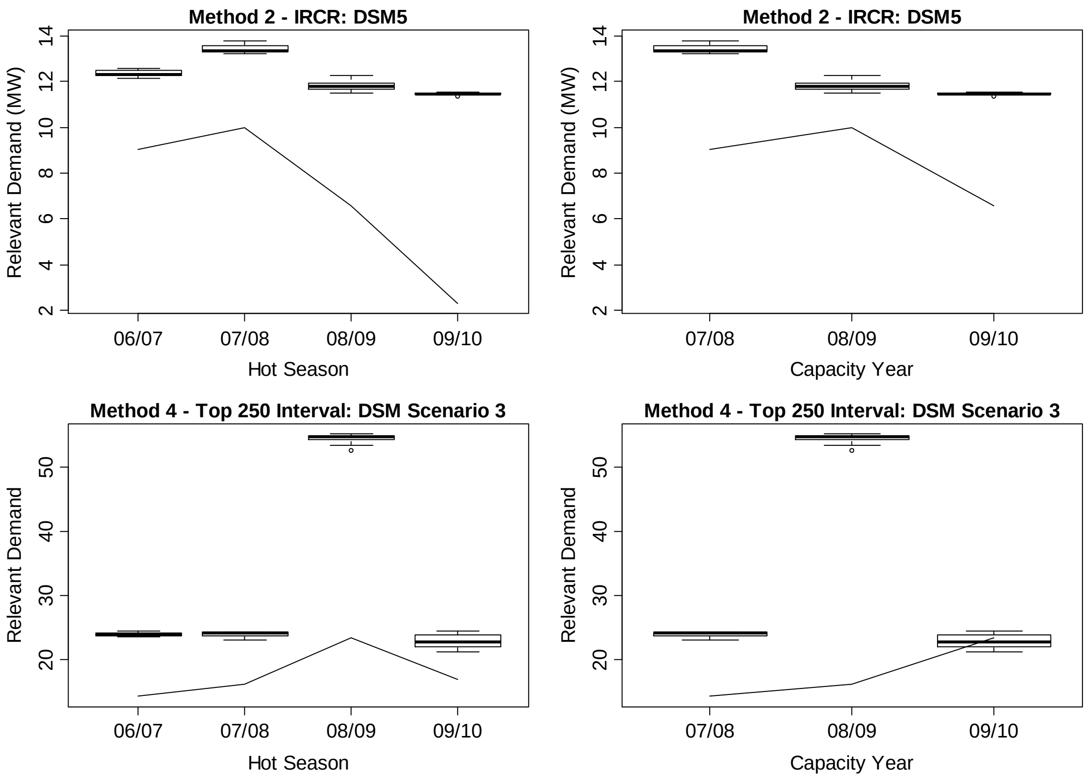

Figure 13. Plots to show the "actual" Relevant Demands alongside the "estimated" Relevant Demands from the previous Hot Season used to determine Reserve Capacity. The box plots represent the set of 20 intervals used to represent "actual" Relevant Demand and the lines represent the Relevant Demands calculated using different methodologies. The plots on the left hand side compare like Hot Seasons, whereas the plots on the right compare "actual" Relevant Demands for the Capacity Year with "estimated" Relevant Demands from the previous Hot Season.

Whilst comparing Relevant Demands from the same Hot Seasons is useful to gain some understanding of the differences between the methods used to calculate the "actual" and "estimated" Relevant Demands, one of the primary aims of this analysis was to see how reliable using the Relevant Demands from the previous Hot Season are at determining the Relevant Demand for the Capacity Year in question. As such Data Analysis Australia also compared the "actual" Relevant Demands for each Capacity Year with the "estimated" Relevant Demand calculated using the differing methodologies from the previous Hot Season.

The plot on the top-right of Figure 13 shows the range of "actual" Relevant Demands for each Capacity Year for DSM5 (the boxplots on the graph) alongside the Relevant Demand for DSM5 calculated using Method 2 – the IRCR method – from the **previous** Hot Season (the line on the graph). The plot on the bottom-right of Figure 13 shows the range of "actual" Relevant Demands for each Capacity Year for DSM Scenario 3 (the boxplots) alongside the Relevant Demands for DSM Scenario 3 calculated using Method 4 – the top 250 intervals for the **previous** Hot Season (the line on the graph).

The consistent difference noted when comparing between "actual" and "estimated" Relevant Demands from the **same** Hot Season can be described as a bias between the two methods of calculating the Relevant Demands. This bias means that **on average** we would expect the "actual" Relevant Demands to be higher than the Relevant Demand using the different methodologies across the Hot Seasons as well as in the same Hot Season. Whilst we would expect the "actual" Relevant Demands to be higher on average than the "estimated" from one Hot Season to the next, this will not always be the case, as demonstrated by some of the DSM scenarios (see the bottom-right plot in Figure 13 for the 2009/10 Capacity Year).

This bias between the "actual" and "estimated" Relevant Demands should be considered when interpreting the accuracy of using the Relevant Demand from the previous Hot Season to represent the Relevant Demand of the Capacity Year, as a positive difference still might mean that the estimated Relevant Demand is accurate and no difference or a negative difference would indicate an overestimate of the Relevant Demand. Only DSM Scenario 2 and 3 had Relevant Demands that were not consistently below the range of "actual" Relevant Demands when making comparisons to the previous Hot Season. Therefore, for the most part, the method that yields the smallest difference between the "actual" and "estimated" Relevant Demands will represent the method most reliable at achieving a Relevant Demand representative of the Capacity Year.

Examination of the differences between "actual" and "estimated" Relevant Demands revealed that for some Capacity Years the differences were smaller (i.e. more accurate) than for other years. In order to determine if one calculation method consistently produced large or small differences between "actual" and "estimated" Relevant Demand, Data Analysis Australia performed an analysis whereby each method was ranked in order of smallest to largest maximum relative difference for each of the DSM programmes.

DSM1	Method 1	Method 2	Method 3	Method4_250	Method4_500	Method4_750
2007/08	1	6	2	4	5	3
2008/09	1	3	6	2	4	5
2009/10	1	3	6	4	5	2
Ave. Rank	1	4	5	4	5	4

DSM2	Method 1	Method 2	Method 3	Method4_250	Method4_500	Method4_750
2007/08	1	2	6	3	4	5
2008/09	4	1	6	2	3	5
2009/10	6	5	4	1	3	2
Ave. Rank	4	3	6	2	4	4

DSM5	Method 1	Method 2	Method 3	Method4_250	Method4_500	Method4_750
2007/08	3	1	2	6	4	5
2008/09	6	5	1	4	2	3
2009/10	6	2	1	3	4	5
Ave. Rank	5	3	2	5	4	5

DSM10	Method 1	Method 2	Method 3	Method4_250	Method4_500	Method4_750
2007/08	5	1	6	4	3	2
2008/09	6	1	5	2	3	4
2009/10	2	1	6	3	4	5
Ave. Rank	5	1	6	3	4	4

DSM20	Method 1	Method 2	Method 3	Method4_250	Method4_500	Method4_750
2007/08	6	1	4	5	3	2
2008/09	6	1	5	2	3	4
2009/10	1	2	4	3	5	6
Ave. Rank	5	2	5	4	4	4

DSM30	Method 1	Method 2	Method 3	Method4_250	Method4_500	Method4_750
2007/08	2	1	4	3	6	5
2008/09	6	2	1	5	4	3
2009/10	5	1	6	3	2	4
Ave. Rank	5	2	4	4	4	4

DSMScen1	Method 1	Method 2	Method 3	Method4_250	Method4_500	Method4_750
2007/08	3	1	6	4	2	5
2008/09	3	1	6	2	4	5
2009/10	2	1	6	3	4	5
Ave. Rank	3	1	6	3	4	5

DSMScen2	Method 1	Method 2	Method 3	Method4_250	Method4_500	Method4_750
2007/08	6	1	5	4	2	3
2008/09	6	2	1	3	4	5
2009/10	4	5	6	1	2	3
Ave. Rank	6	3	4	3	3	4
DSMScen3	**Method 1**	**Method 2**	**Method 3**	**Method4_250**	**Method4_500**	**Method4_750**
2007/08	6	5	4	1	2	3
2008/09	6	5	1	4	3	2
2009/10	6	5	1	4	3	2
Ave. Rank	6	5	2	3	3	3
DSMScen4	**Method 1**	**Method 2**	**Method 3**	**Method4_250**	**Method4_500**	**Method4_750**
2007/08	2	1	6	5	4	3
2008/09	6	1	5	2	3	4
2009/10	2	1	4	3	5	6
Ave. Rank	4	1	5	4	4	5

Table 20. For each DSM Group each method is ranked in order of the "estimated" Relevant Demand's reliability in representing the "actual" Relevant Demand of the Capacity Year. Blue shading indicates the most reliable method for the DSM.

Table 20 shades in blue the most reliable method for determining the Relevant Demand for the Capacity Year for each DSM programme based upon maximum relative difference and demonstrates that there is no single best method to improve the reliability of the Relevant Demand value. For some DSMs a method that utilises few intervals is more reliable (such as Method 2) and for other DSMs a method that utilises more intervals is more reliable (such as Method 3). This is logical as for some DSMs the PTIs will be representative of their usage at peak times and for others, such as DSMs who have curtailed their load for whatever reason, these PTIs will not accurately represent their load at peak times. This is also demonstrated in Figure 14 which shows that Method 1 is the best method for DSM1 (left plot) but is actually the worst method for DSM Scenario 3 which had low consumption during peak times (right plot).

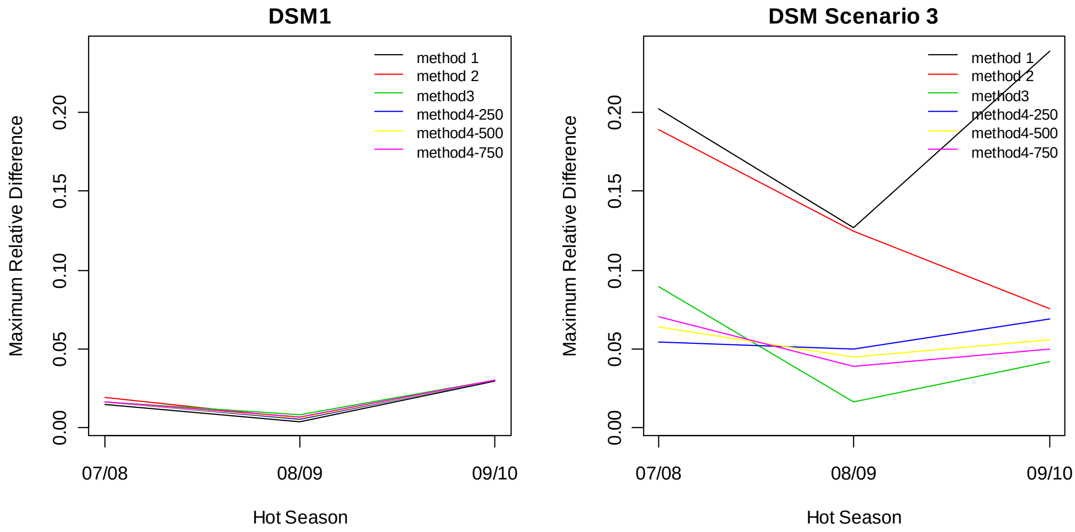

Figure 14. The maximum relative difference between "actual" and "estimated" Relevant Demand for DSM1 and DSM Scenario 3.

The left plot in Figure 14 shows that although Method 1 is method most accurate at representing the following Hot Season, there is very little difference between the methods. However, the right plot in Figure 14 shows that for DSMs with low consumption at Peak Trading Intervals (e.g. customers who have reduced their load at the request of System Management), methods that utilise few intervals such as Methods 1 and 2 result in much larger differences than methods that incorporate more intervals (a maximum relative difference in the region of 0.15 rather than 0.05). This strengthens the argument for adopting a methodology that incorporates more intervals than the current method. This variation seen in the reliability of the methods means that determining the most reliable method is not straightforward as the methods are not consistently good or bad due to the variability in customer's consumption profiles.

To determine the best overall method for all DSM programmes at representing the Relevant Demand of the Capacity Year using data from the previous Hot Season, Data Analysis Australia calculated the average rank and standard deviation of the rank for each method across all DSM programmes examined. The overall average rank demonstrates **on average** how successful the method is at representing the Relevant Demand of the Capacity Year using data from the previous Hot Season and the overall standard deviation of the ranks demonstrates how consistent each method is at representing the Relevant Demand. The ideal Relevant Demand methodology would have a high rank (indicated by a low rank number) and a small standard deviation (i.e. a methodology that will consistently and accurately predict the Relevant Demand for the following Hot Season). Methods with a low rank (indicated by a high rank number) and low standard deviation should be avoided, as they are consistently inaccurate.

	Method 1	Method 2	Method 3	Method4_250	Method4_500	Method4_750
Average Rank (1=best)	4.0	2.3	4.2	3.2	3.5	3.9
Standard Deviation	2.1	1.7	2.0	1.3	1.1	1.3

Table 21. Average ranks over all DSM groups and standard deviation of ranks for each method.

The results of this analysis are provided in Table 21 and show that some methods can be logically excluded. For example, Method 1 (the current method) is definitely not an ideal methodology as it has the second worst average rank and the largest standard deviation. In layman's terms, Method 1 does not, on average, reliably represent the Relevant Demand of the Capacity Year and in addition is highly unpredictable. Method 3 and Method4_750 can also be excluded, as they also have low rankings and large standard deviations. The choice among Method 2, Method 4_250 and Method4_500 becomes a trade-off between the reliability of the method at representing the following Hot Season (rank) and consistency in the reliability (standard deviation).

From the methodologies that use few intervals, Method 2 is preferred over Method 1 as it has better ranking and a smaller standard deviation, meaning not only is it better than Method 1 on average, it is also more consistent.

From the methodologies that incorporate more intervals, Method 3 and Method4_750 have been ruled out as reliable methods of predicting the Relevant Demand for the Capacity Year, leaving two options of the methods examined: Method4_250 and Method4_500. There is a trade-off in these two options between slightly better reliability at predicting the Relevant Demand for the following Hot Season and the consistency of this reliability.

8. Comparison of the Relevant Demand Methodologies

A comparison of the different Relevant Demand methodologies for each DSM programme was made to assess the stability and reliability of the Relevant Demands over time. This analysis revealed that method used to calculate the Relevant Demand has a considerable effect on the stability and reliability of the Relevant Demand. Furthermore, the more intervals that are included in the calculation, the more stable the Relevant Demand is over time. However, the reliability of the Relevant Demand estimates are affected as more intervals are included in the calculation due to incorporating more intervals that are not peak, thereby generating a downwards bias.

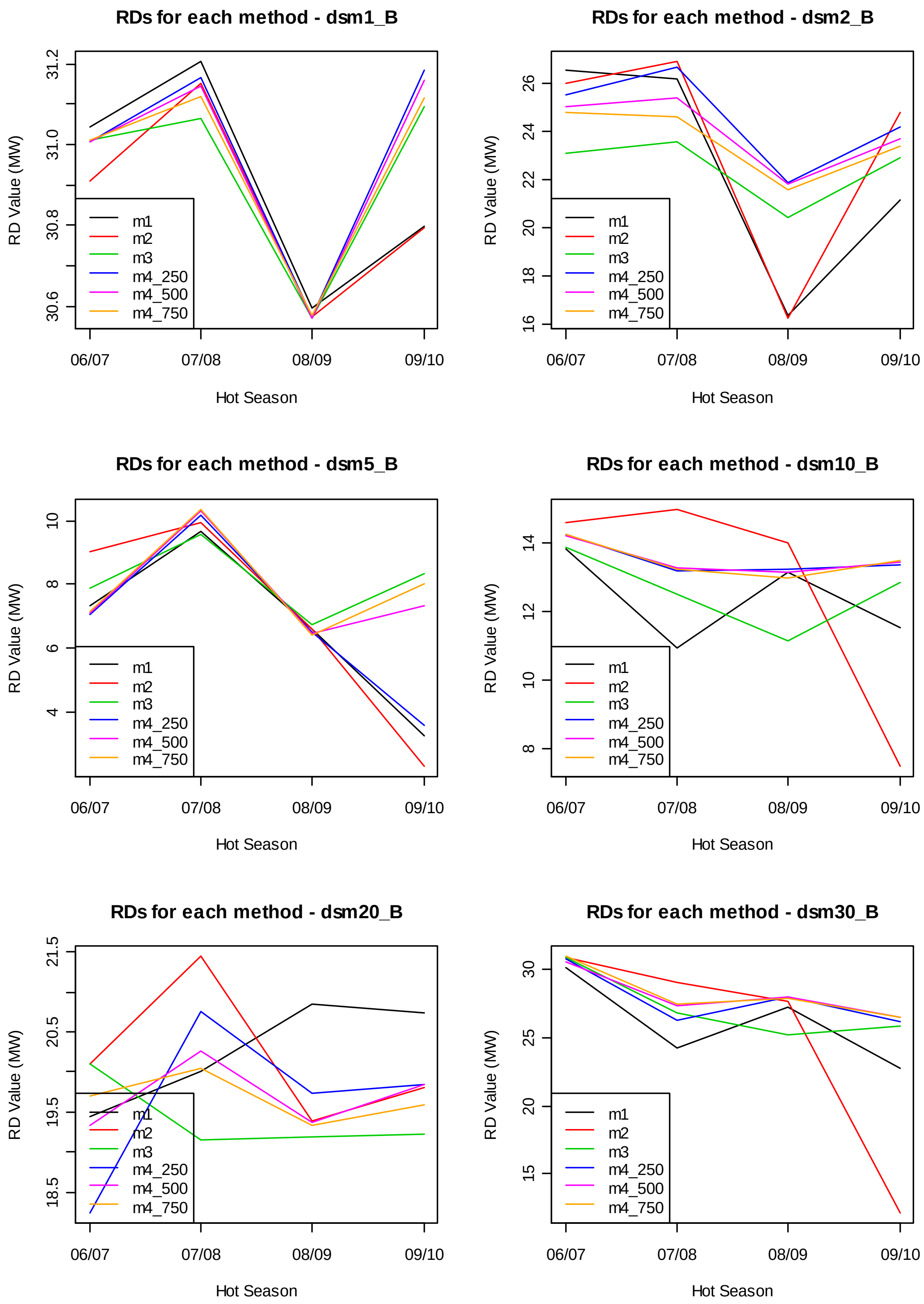

Figure 15. Comparison of Relevant Demand Methodologies for Approach B by DSM groups.

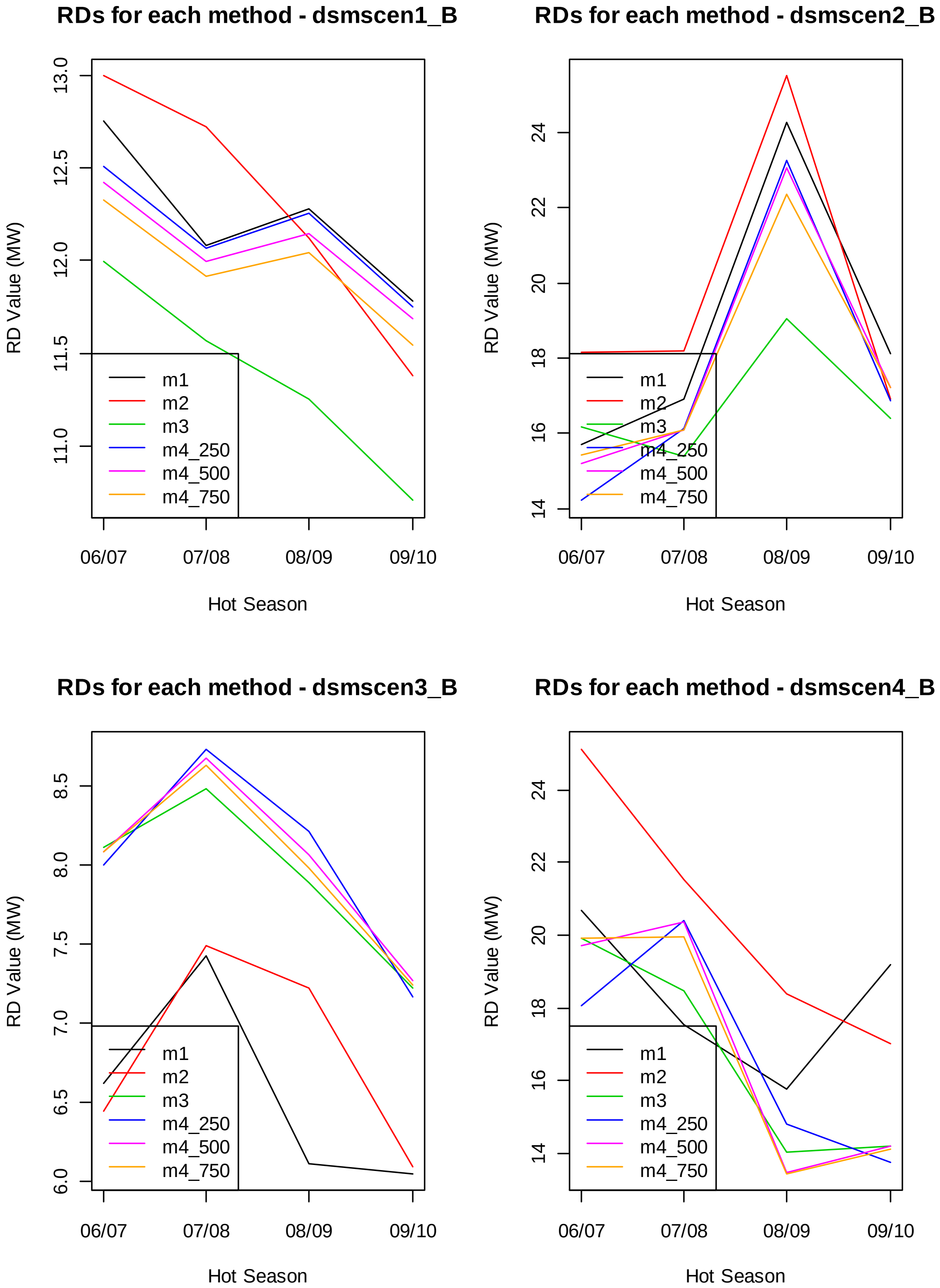

Figure 16. Comparison of Relevant Demand Methodologies for Approach B by DSM Scenarios.

Figure 15 plots the Relevant Demand methodologies using the aggregated loads (Approach B) for each DSM programme. The plots illustrate that Method 3 (business hours during the Hot Season), which uses the most PTIs in the calculation of the Relevant Demand, shows the least fluctuations in Relevant Demand from year to year. Method 2 (IRCR) on the other hand, which uses the least PTIs to calculate the Relevant Demand, shows the most fluctuations across all DSMs.

Figure 16 plots the Relevant Demand methodologies for the DSM Scenarios using Approach B. These plots also demonstrate that methods that incorporate more intervals (Method 3 and Method 4) tend to be more stable over time than the methods that use few intervals (Method 1 and Method 2). The plots also demonstrate that the inclusion of additional PTIs result in lower Relevant Demands. The Relevant Demands for Method 3 (which uses the most PTIs) are consistently lower than the Relevant Demands observed for the other methods incorporating fewer intervals. This downward bias can be attributed to the inclusion of PTIs that are not representative of peak times, which is unavoidable when including extra intervals. The exception to this occurs in DSM Scenario 3 which has periods of low consumption during PTIs. In this case including more intervals, such as in Methods 3 and 4, has resulted in larger Relevant Demands than Methods 1 and 2 which use few intervals. If the periods of low consumption at PTIs have been at the request of System Management then the Relevant Demands calculated using Methods 3 and 4 would be more accurate. The downwards bias caused by including more intervals is still evident when comparing between Methods 3 and 4, as Method 3 which incorporates the most intervals has lower Relevant Demands than Method 4 – 250 intervals.

The 2008/09 Hot Season appears to show lower Relevant Demands across a number of DSM programmes and across a number of methods. This observation could be explained by a customer with a high impact on the Relevant Demand that has already been asked to curtail their load or who curtails their load for some other unknown reason (e.g. maintenance, shutdown). This is particularly apparent in DSMs that have smaller numbers of NMIs within the DSM programme[2] (DSM2 and DSM4 contain two and one NMI respectively) and Methods 1 and 2 (the current and IRCR methods respectively) which use the least number of intervals in the calculation.

DSM Scenario 2 shows an unusually high Relevant Demand in the 2008/09 Hot Season. This can be explained by one NMI that had unusually high loads at PTIs in that year. This DSM scenario demonstrates that whilst using few intervals may provide an accurate Relevant Demand for an individual Hot Season, adopting a methodology that incorporates more intervals limits the effect of unusual peaks (and troughs) in particular Hot Seasons and makes the Relevant Demand more representative of the Relevant Demand of other Hot Seasons.

Grouping NMIs into DSM programmes has the effect of reducing some of the volatility seen in the Relevant Demand because in order to influence the Relevant

[2] Although the effect of smaller DSMs demonstrating more volatility is exaggerated by the scale of the graphs.

Demand most of the NMIs within the DSM would have to be acting similarly. In addition, the inclusion of additional intervals in the Relevant Demand calculation also reduces the volatility in the Relevant Demand. However, increasing the number of intervals used in the calculation also has the effect of reducing the reliability of the Relevant Demand value by introducing a downward bias.

Examination of Figure 15 reveals that the methods investigated can essentially be divided into two groups – methods that utilise just a handful of PTIs (Methods 1 and 2 use 32 and 12 intervals respectively) and methods that use relatively large numbers of PTIs (all the other methods use 250 intervals and upwards). The first group of methods that use less PTIs are certainly less stable than the other methods and provide more opportunity for customers to influence their Relevant Demand value by requesting that certain intervals be excluded from the Relevant Demand calculation. Whilst the current Market Rules allow for customers to request that periods of downtime are excluded from the Relevant Demand calculation, there currently is no provision for the IMO to exclude unusually high loads at peak periods that are not representative of demand over time. DSM Scenario 2 has highlighted that there may be DSMs with unusually high loads at PTIs compared to other years, thus adopting a method that uses few intervals does not take into consideration that these loads may not be representative of other Hot Seasons.

Methods utilising more PTIs are certainly more stable but are less reliable due to the downward bias caused when using less relevant intervals. The analysis of the DSM Scenarios has shown that DSMs with unusual consumption patterns are always going to be troublesome to predict reliably within and between the Hot Seasons, however incorporating more intervals should provide some stability over time so that on average under- and over-estimations even out. Both types of methodologies have benefits and drawbacks but the decision on the most appropriate methodology depends upon the aims of the IMO in relation to how they wish to deal with customers who had a significantly curtailed load, for *whatever* reason, during the actual times of system peak. This notion is discussed further in the conclusions.

The fact that the shape of the Relevant Demands curves for all the Method 4 Relevant Demands (Methods 4_250, 4_500 and 4_750) are so similar indicates that it is unnecessary to include the extra intervals as they have little effect on the stability of the Relevant Demand over time. The inclusion of yet more intervals simply introduces a downward bias on the scale of the Relevant Demand figure. This logic also applies to Method 3 which uses the most intervals in the calculation – this has made the Relevant Demand more stable but at the cost of the reliability of the value. It is not representative of peak times and as such is much lower than the other Relevant Demands.

9. Comparison between using Individual Relevant Demands and aggregated Relevant Demands

Whilst the difference in the Relevant Demands was obvious between the calculation methods, plots comparing the two approaches of using individual Relevant Demands (Approach A) and a Relevant Demand based upon on aggregated data (Approach B) showed little difference.

As DSM 1 contained only one NMI, both approaches resulted in the same Relevant Demands and as such were not comparable and are not discussed in this Section. DSM 2 only contained two NMIs so understandably there is again very little difference between the two approaches. Even where there are a number of NMIs in a DSM programme, the difference between the two approaches of summing the Relevant Demand into DSM groups is subtle. In addition, there does not appear to be an obvious bias between the approaches whereby one approach yields consistently higher Relevant Demands over the other. Figure 17 shows plots for the Relevant Demands for DSM10 using each method of calculating Relevant Demand. Each plot shows both individually calculated Relevant Demands and also the aggregated Relevant Demand (Approaches A and B).

Again DSM Scenario 2 provides the exception, in this DSM Scenario it was observed that the Relevant Demands using Approach A were consistently higher than Approach B for Methods 2, 3, and 4 (Figure 18). This can be explained by one large NMI that had periods of low consumption at PTIs, in Approach A where Relevant Demands are calculated individually before summing, only one Relevant Demand would be affected by the downtime and the others would remain relatively high. In Approach B all the NMIs would be aggregated first affecting the overall Relevant Demand more.

The plots comparing the two approaches for the other DSM programmes and scenarios are shown in the Appendix.

Data Analysis Australia considers the effect of aggregating data to be secondary to the effect on Relevant Demands caused by the different Relevant Demand methodologies. As such, no further exploration has currently been conducted to investigate the relationship causing the differences between the two approaches.

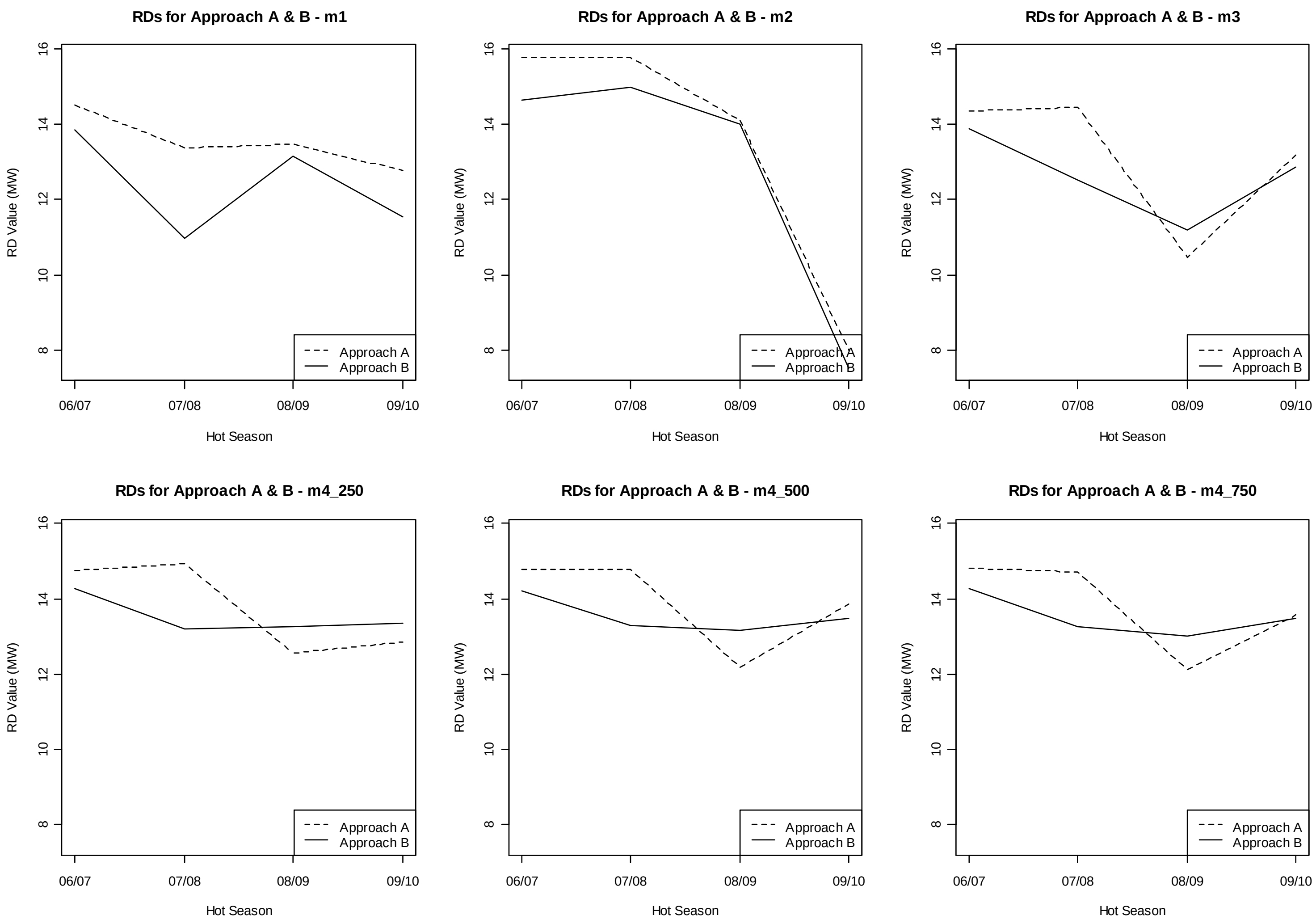

Figure 17. Comparison between Approach A and Approach B for each Method (for DSM 10 only).

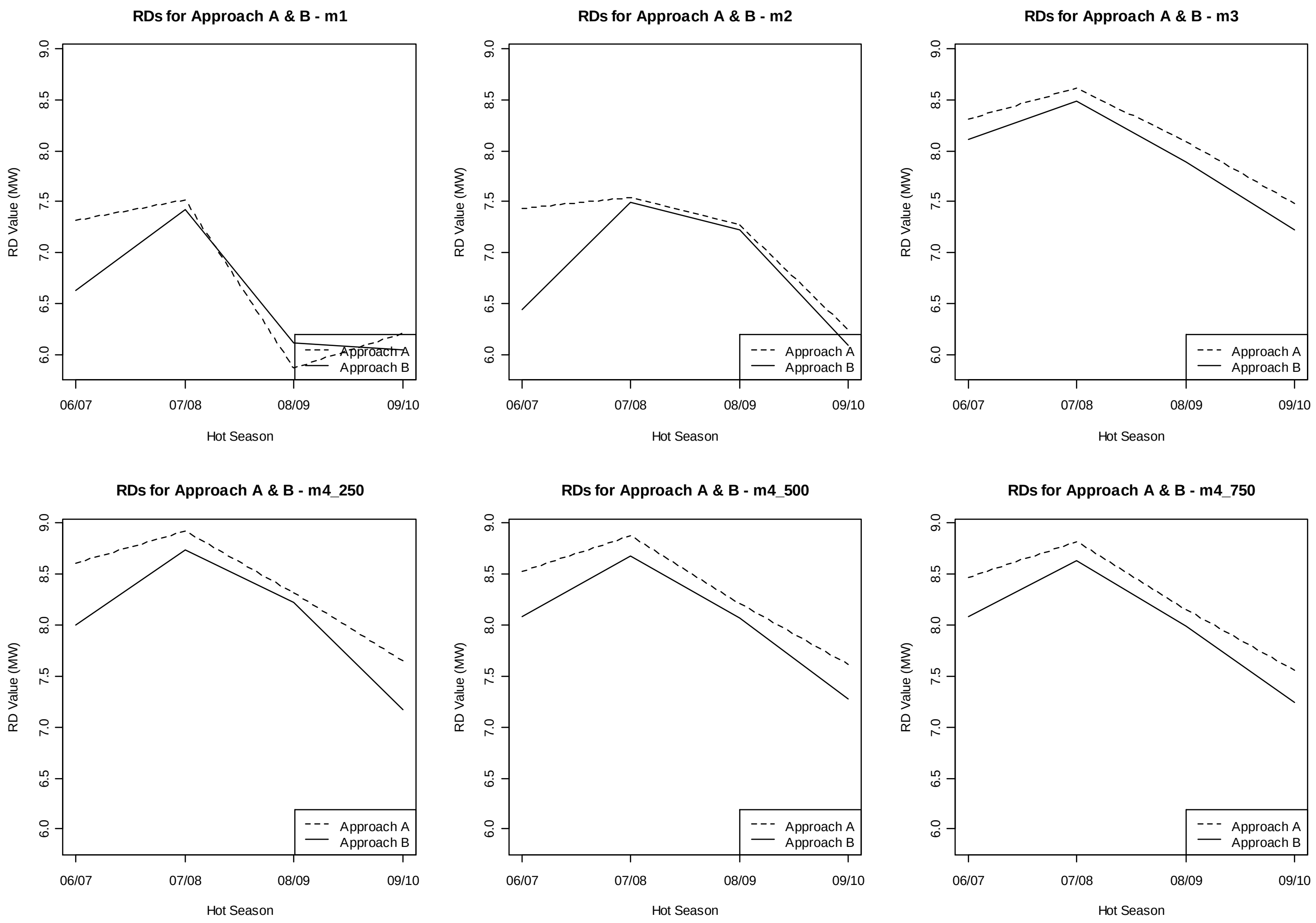

Figure 18. Comparison between Approach A and Approach B for each Method (for DSM Scenario 3 only).

10. Caveats

There are a number of caveats to the considered when interpreting the results of this analysis:

- Whilst efforts have been made to examine a range of different DSM profiles, by generating sample data to create DSM Scenarios, only a small sample of data was used to create these scenarios. Therefore Data Analysis Australia cannot comment on how this analysis may apply more generally to all DSM programmes.
- The analysis excluded missing and zero values when aggregating the NMI loads and also when calculating the Relevant Demands. The overall effect of this is believed to be relatively small, although omitting these values when aggregating the NMI loads could potentially introduce a slight downward bias. This is not so much an issue if only interested in each DSM group as a whole. Furthermore, as medians are a particularly robust measure, the effect of omitting these values will also be small when calculating the Relevant Demand.
- The analysis was conducted in a very short timescale. This means that the analysis was by no means exhaustive and exogenous factors were not investigated.

11. Conclusions

The analysis showed that it is the methodology used to calculate the Relevant Demand that is the main driver of the stability and reliability of the Relevant Demand rather than the order by which the aggregation of the Relevant Demand is conducted into DSM groups.

The primary difference between the methodologies investigated was the number of trading intervals used in the calculation of the Relevant Demand and it was not surprising to find that the inclusion of more data points (or intervals) resulted in more stable Relevant Demands over time. Furthermore, the inclusion of few intervals potentially rewards the customer by providing an opportunity to gain Capacity Credits for time intervals where they would have curtailed load anyway, sometimes referred to as “double-dipping”.

Whilst it is important to achieve stable Relevant Demands from year to year, perhaps leaning towards adopting an approach that incorporates more trading intervals, this is offset by the need for a realistic estimate of Relevant Demand for times of peak demand. As increasingly more intervals are included in the Relevant Demand calculation the result becomes less representative of times of peak demand, thus resulting in an under estimate of the amount that could be curtailed at these times of peak demand. Whilst a higher estimate of the Relevant Demand is in the interests of the customer due to the financial incentives involved in curtailing load, an underestimate of the Relevant Demand is not in the interests of the IMO as the aim of setting Reserve Capacity is to reduce system peaks.

The analysis has revealed that there are effectively two types of Relevant Demand methodology. The first type uses a relatively small number of trading intervals and is appropriate if the IMO wants control over customers who may be "double-dipping". The true reasons for periods of downtime are not evident from the data and, currently it is up to the customer to provide evidence that their load was operating below capacity for a reason acceptable to the IMO. This potentially creates an opportunity for customers to "double-dip". However, whilst this opportunity exists, using but a few intervals will highlight to the IMO customers with periods of abnormally low usage at times of system peak. This allows the IMO control over accepting requests for low operating periods – if the IMO believes that the load was curtailed for a reason that is not acceptable then the IMO can reject the request to inflate the Relevant Demand value.

In addition, if only a small number of intervals are used to estimate Relevant Demand, the result is likely to be an accurate measure of their peak usage for that particular Hot Season. This is somewhat volatile as it is not necessarily representative of their peak usage in other Hot Seasons. An unusually low Relevant Demand in one year may adversely affect a customer's Capacity Credits the in the next year, removing the incentive for that customer to curtail their load in that capacity year. This in turn may result in a high Relevant Demand in the following year. This pattern is not conducive to reducing system peaks. As such, this method may disadvantage customers who have had genuine periods of downtime during these few intervals, unless an estimate of the Curtailable Loads at these intervals is derived.

The second type of methodology involves using more intervals to estimate the Relevant Demand. This type of methodology has the benefit of providing more stability in the Relevant Demand from year to year, and also within the Hot Season, as periods of downtime have less influence on the overall estimate. The inclusion of too many intervals however, will reduce the reliability, as the result is likely to contain intervals not considered to be contributing to system peaks. This method does not rely so heavily on individual intervals, eliminating the need to evaluate customer requests for the exclusion of certain intervals and the need to substitute missing or unusually low values. This reduces customers' ability to artificially inflate their Relevant Demands and is more representative of their business-as-usual load. This methodology is also easier to implement and more consistent, as a manual case-by-case assessment of customers with unusually low periods of usage is not required.

The analysis into the reliability of the Relevant Demand methodologies at representing peak usage for the following Hot Season, showed that of the methods that utilised few intervals, Method 2 (the IRCR method) was preferable to Method 1 (the current method), as it was on average consistently more reliable. From the methodologies that incorporate more intervals, Method 3 and Method4_750 were excluded as reliable methods of predicting the Relevant Demand for the Capacity Year, leaving two options from the methods examined: Method4_250 and Method4_500. There is a trade-off in these two options between slightly better reliability at predicting the Relevant Demand for the following Hot Season and the consistency of this reliability. Of the two methods, Data Analysis Australia would recommend an approach that incorporates 250 intervals, as little difference was observed in the stability between these two methods however, the inclusion of more intervals was deemed to introduce a downwards bias thus affecting the reliability of the Relevant Demand.

The analysis of the DSM Scenarios showed unsurprisingly, that DSMs with highly volatile consumption patterns will be the hardest customers to accurately assign a Relevant Demand. However, the best way to counteract this volatility is to increase the number intervals used to calculate the Relevant Demand to provide some stability of the value used over time. In this way on average any over- and under-estimations will even out over time.

The choice of the most appropriate methodology depends on whether the IMO wants control over customers who might potentially be doubly rewarded for periods of downtime. If the IMO wants control over these customers, then a methodology that utilises a smaller number of intervals and includes a manual case-by-case assessment of customers with unusually low Relevant Demands might be more appropriate. However, should the IMO require a more automated and consistent methodology and perceives any other benefit to the customer by curtailing their load as a coincidental benefit, then using more intervals would be more appropriate. That said the best methodology to ensure a reliable Relevant Demand value varies depending upon the individual characteristics of the DSM programme. The optimal number of intervals should neither be too high or too low, as in general, the more intervals included the less representative the Relevant Demand becomes of peak times and if there are too few intervals there is less chance that the Relevant Demand will be representative of the following Hot Season.

Grouping NMIs into DSM programmes reduces the volatility of the Relevant Demand. However, the analysis revealed that performing the aggregation into DSM programmes either before or after the Relevant Demand calculation appears to have little affect on the stability and reliability of the Relevant Demand. Although if each DSM programme is to be considered as a group, conceptually it is more logical to aggregate prior to calculating the Relevant Demand (Approach B).

12. Recommendations

From the six methods proposed by the IMO, Data Analysis Australia has identified two broad types of methodology to calculate the Relevant Demand. The first methodology utilises a small number intervals to form the calculation and is most appropriate if the IMO wants control over customers who potentially “double-dip” and to have a value that accurately represents their peak usage for that particular

Hot Season. However, this is somewhat volatile as it is not necessarily representative of their peak usage in other Hot Seasons.

The second methodology utilises many more intervals and is more appropriate if the IMO wishes to focus on the stability of the Relevant Demand estimate and hence, the reliability of one Hot Seasons value representing their business-as-usual load, as periods of downtime have less influence on the overall estimate. Furthermore, if the IMO perceives any other benefit to the customer by curtailing their load, as just a coincidental benefit, then using more intervals would be more appropriate. This method does not rely so heavily on individual intervals, eliminating the need to substitute missing or unusually low values. Thus making this methodology more automated and consistent by removing the occasional requirement of a case-by-case assessment of customers. This reduces customers' ability to artificially inflate their Relevant Demands by submitting requests for the exclusion of intervals and is more representative of their business-as-usual load.

If the IMO prefers the first type of methodology, then Data Analysis Australia would recommend the IRCR method, as this method focuses on the top four days of the Hot Season and is therefore perhaps more representative of Curtailable Load at peak times. In addition, the IRCR method is consistently more reliable than the current method at representing the Relevant Demand for the following Hot Season. However, as only three intervals are selected from each day this method is highly volatile. So we would recommend more intervals be included, for example eight intervals per day like in the current 32 PTI method. This would provide slightly more stability in the Relevant Demands and potentially more reliability of the Relevant Demands from one Hot Season to the next.

If the IMO prefers the second type of methodology, then Data Analysis Australia would recommend an approach that utilises the top 250 intervals during the Hot Season be adopted. Whilst assigning this level is somewhat arbitrary, the analyses showed that the inclusion of extra intervals over 250 did not considerably improve the stability of the Relevant Demand but did in fact reduce the reliability. Furthermore, methods that incorporated 750 intervals or more were shown to be not reliable at representing the Relevant Demand of the following Hot Season.

As it was found that the order by which the data was aggregated (Approach A and B) had little effect on the final Relevant Demands, Data Analysis Australia did not conduct any further analysis to investigate the difference between the two approaches. Should further investigation be required, Data Analysis Australia envisages that NMIs with a large impact on the Relevant Demand for each DSM programme could be removed and the resulting effect on the Relevant Demands analysed.

In this report Data Analysis Australia has evaluated a number of Relevant Demand methodologies provided by the IMO. Whilst we understand the requirement to adopt a simple Relevant Demand methodology so that it is transparent and easily calculated by Market Customers, Data Analysis Australia feels that to fully explore the inter-relationships between customer characteristics and different Relevant Demand methodologies would require an in-depth analysis that incorporates a conceptual model of customer behaviour. Such an analysis would be invaluable if only to confirm or deny that these simplistic approaches are a good approximation for a more complex model.

Appendix

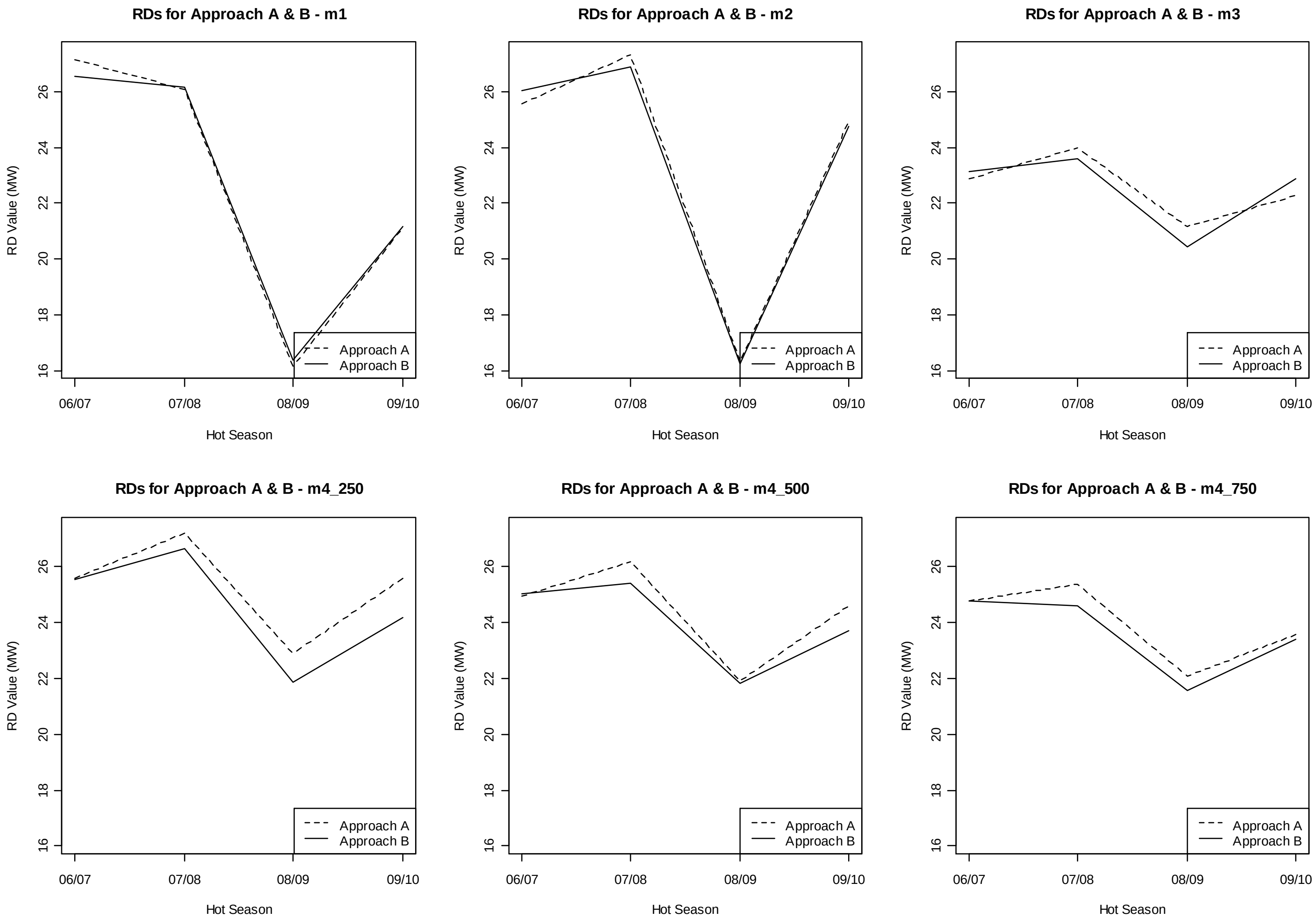

Figure 19. Comparison between Approach A and Approach B for each Method (for DSM 2 only).

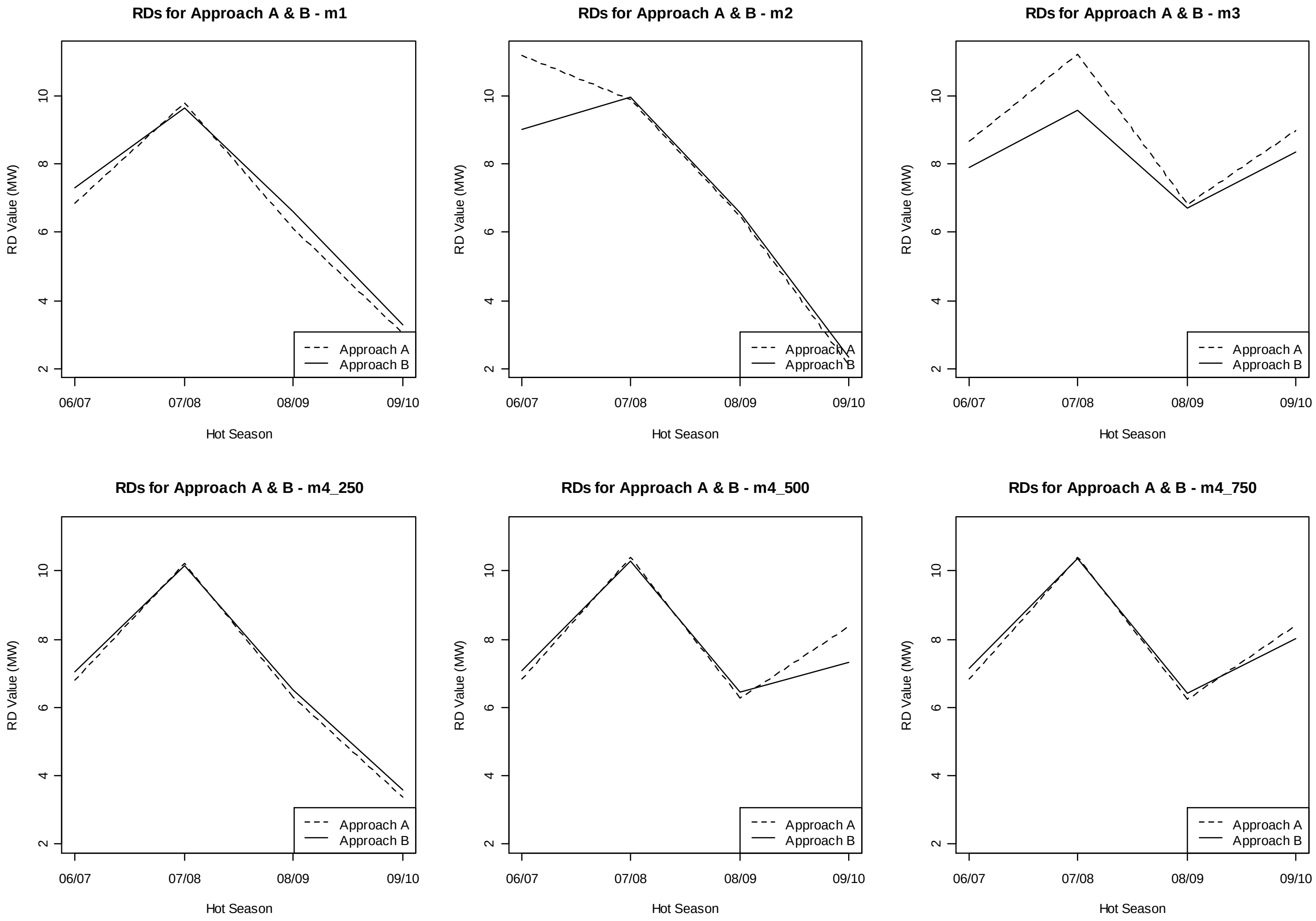

Figure 20. Comparison between Approach A and Approach B for each Method (for DSM 5 only).

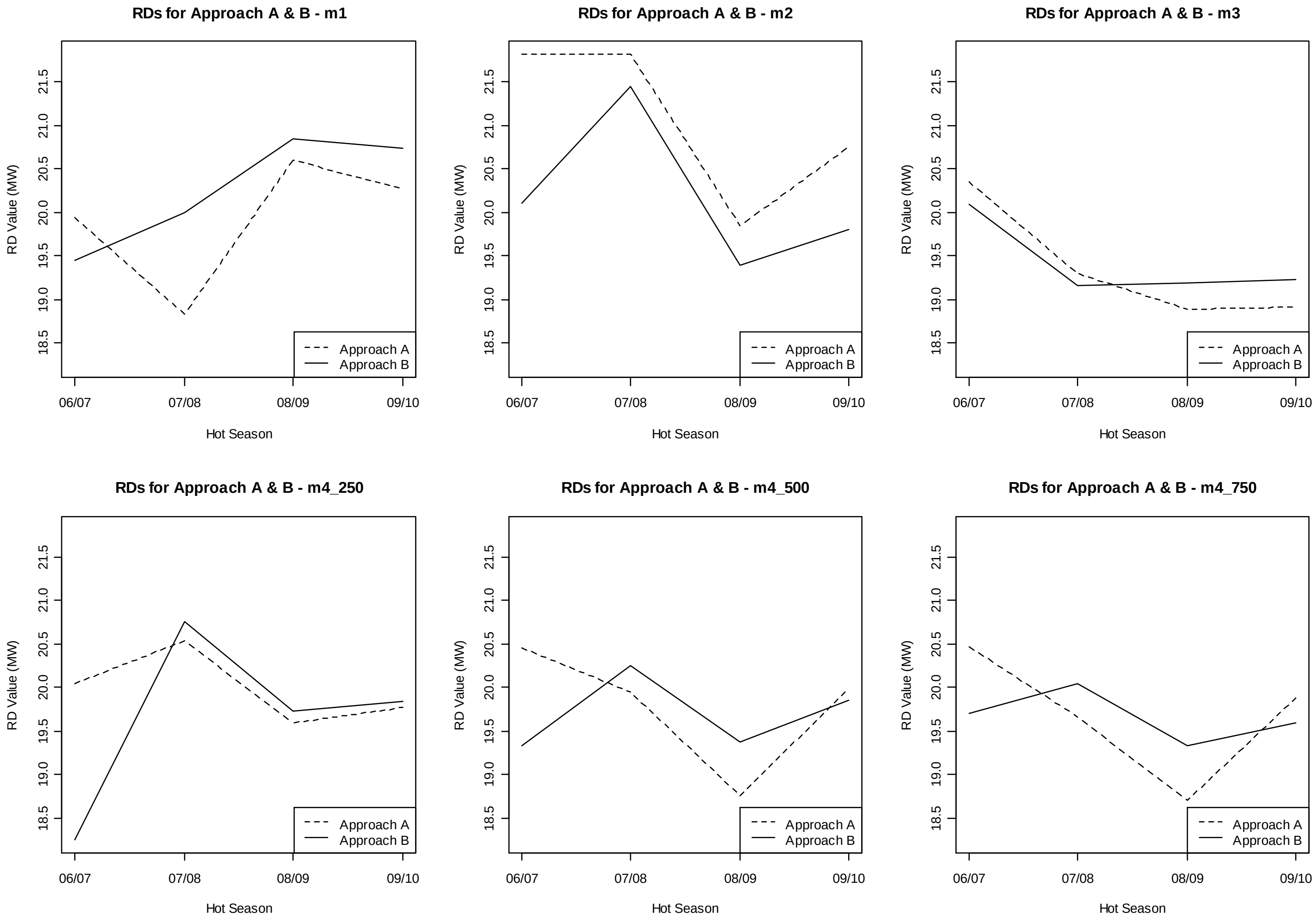

Figure 21. Comparison between Approach A and Approach B for each Method (for DSM 20 only).

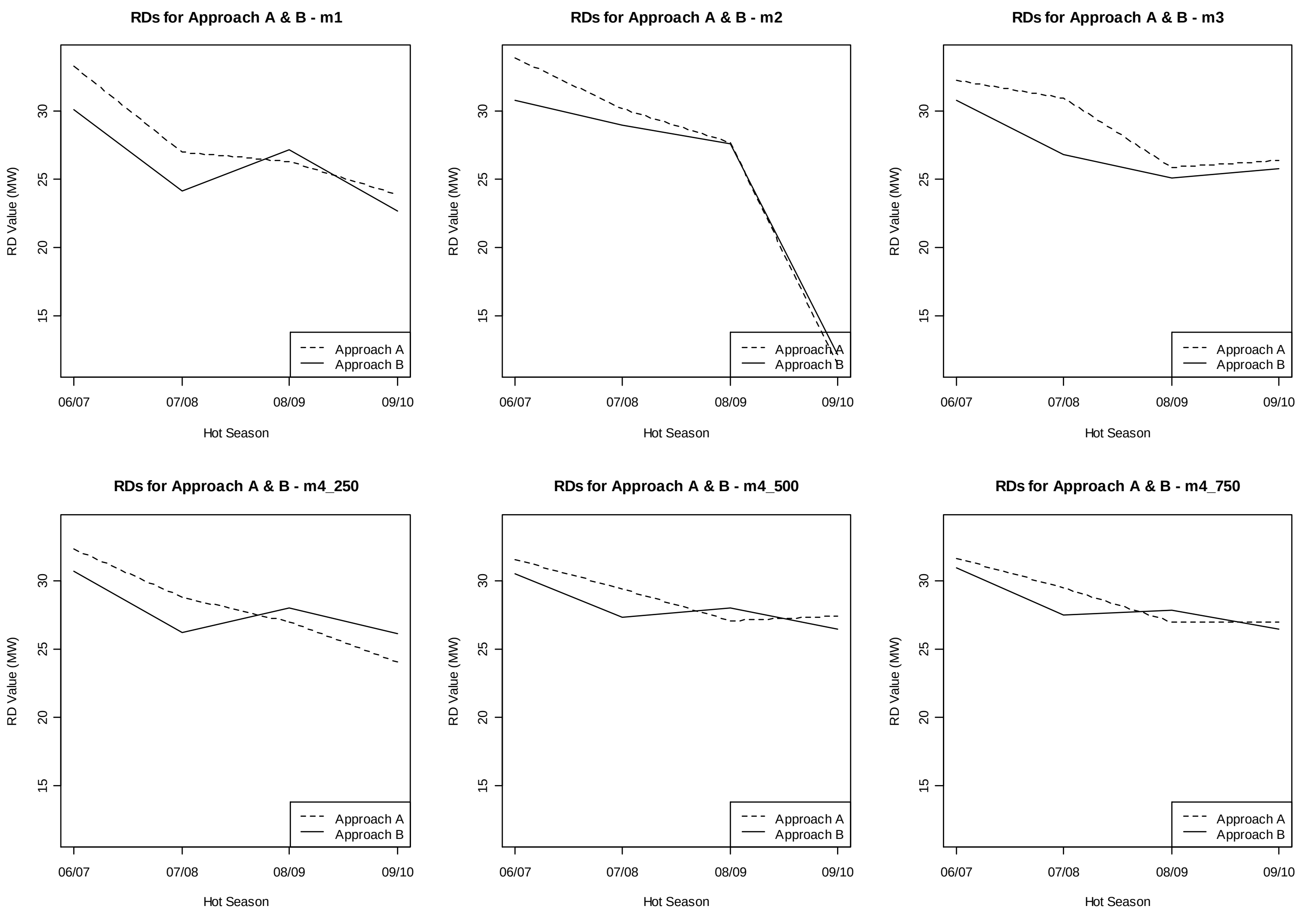

Figure 22. Comparison between Approach A and Approach B for each Method (for DSM 30 only).

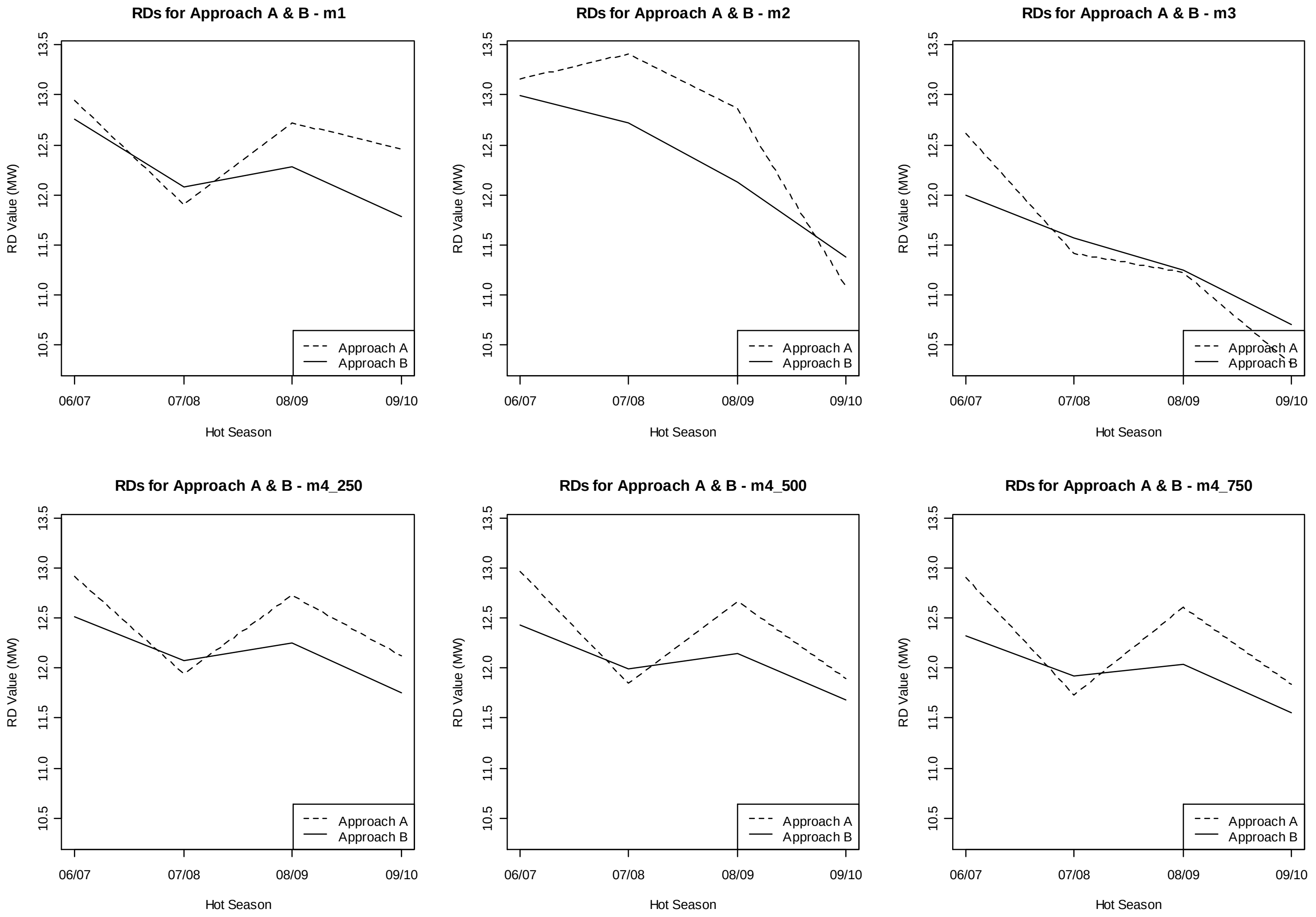

Figure 23. Comparison between Approach A and Approach B for each Method (for DSM Scenario 1 only).

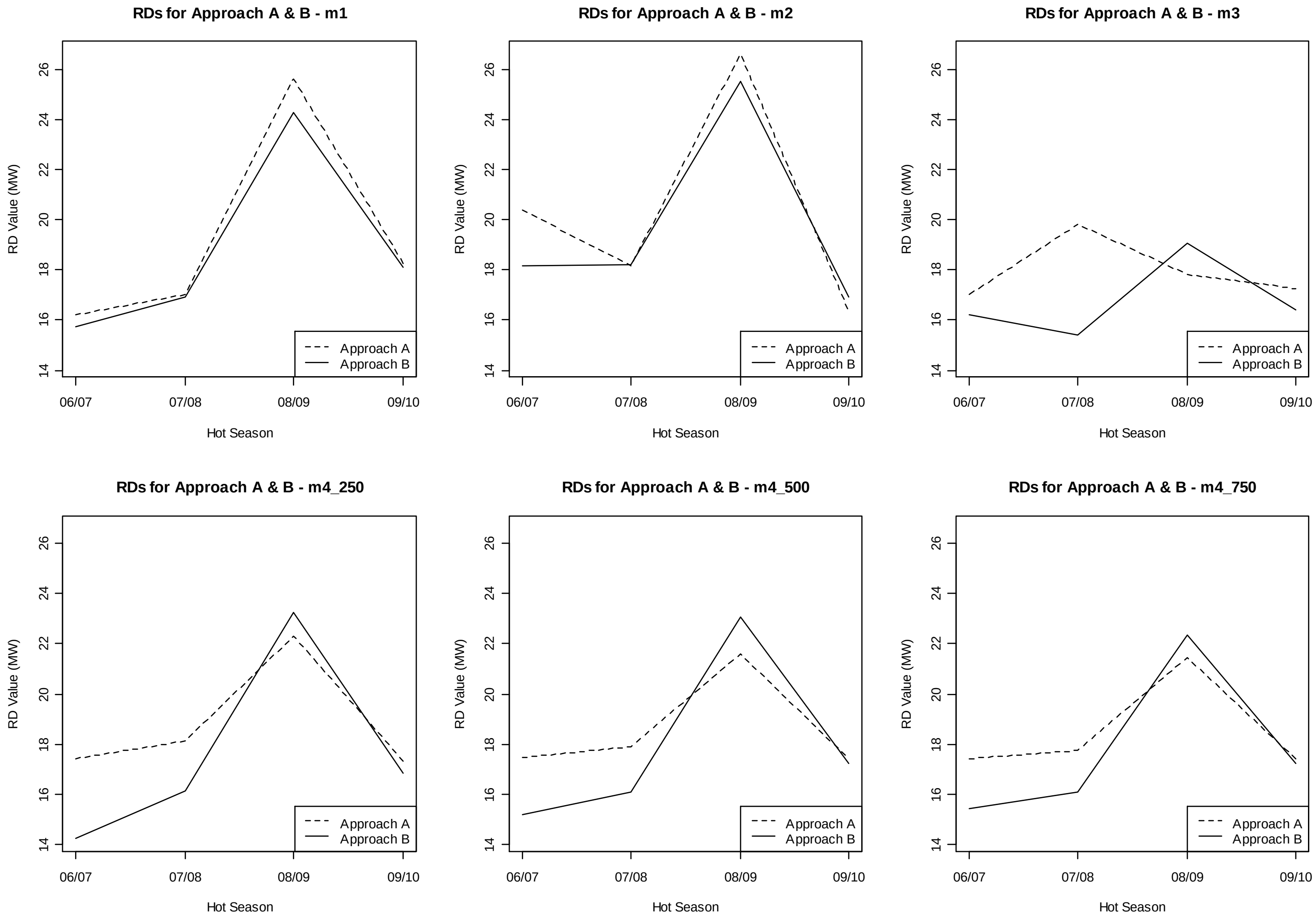

Figure 24. Comparison between Approach A and Approach B for each Method (for DSM Scenario 2 only).

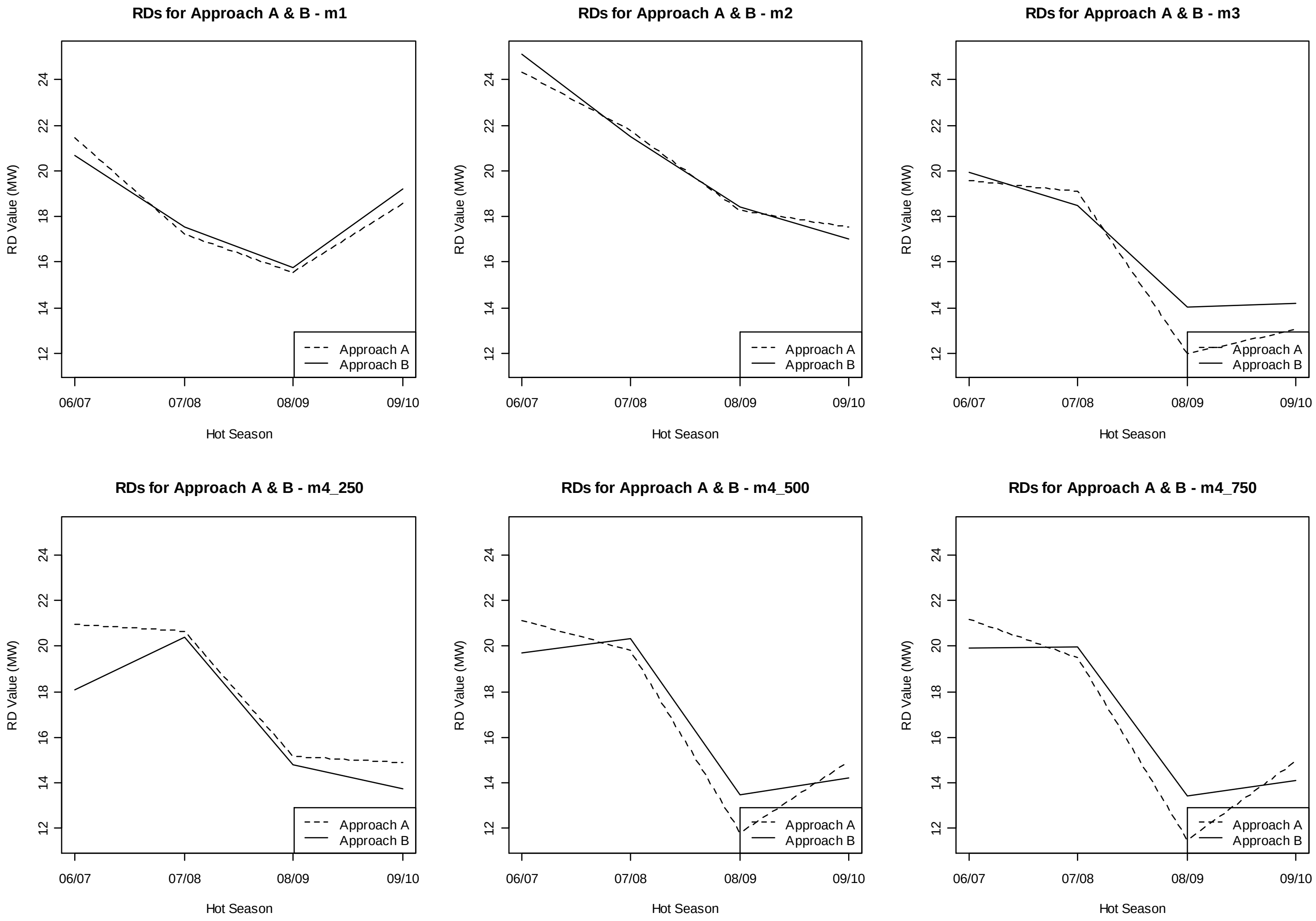

Figure 25. Comparison between Approach A and Approach B for each Method (for DSM Scenario 4 only).

Agenda Item 8(c)

Behind-the-meter generation affecting a facility's Non-temperature Dependence (NTDL) status

This discussion paper raises questions relating to the *intent* of TDL/NTDL statuses for loads, and how the installation of a behind-the-meter (BTM) generation system may cause a customer to shift from being NTDL to TDL (and the financial consequence of that).

This paper demonstrates, at a high level, the impact on NTDL calculations for an existing NTDL load, to show the economic impacts of adding a behind the meter (Solar PV) generator to reduce their electricity demand/consumption from the grid.

The analysis period is three years starting from 2016 to 2018. For this example, it has been assumed a flat load of 40 MW that is considered as a Non-Temperature Dependent Load and in 01/01/2016 it has been connected to a Solar PV generator behind the meter with a capacity of 9.9MWac.

To analyse the impact of the PV connection the Median Peak Load (MPL) is calculated without the BTM generation, and then with the BTM generator.

Figure 1 below shows the calculations of the MPL for both scenarios, with and without solar contribution during the 12 PTI of the relevant hot season.

Hot season	Capacity Year	Peak interval	Current Load (MW)	PV Output (MW)	Load incl PV (MW)	Difference (MW)	MPL Current Load [MW]	MPL Load incl PV [MW]
1 December 2015 to 31 March 2016	2016-2017	8/02/2016 16:30	40 MW	8 MW	32 MW	8.2 MW	40.0 MW	36.3 MW
	2016-2017	8/02/2016 17:00	40 MW	8 MW	32 MW	7.6 MW		
	2016-2017	8/02/2016 17:30	40 MW	5 MW	35 MW	5.0 MW		
	2016-2017	9/02/2016 16:30	40 MW	7 MW	33 MW	7.4 MW		
	2016-2017	9/02/2016 17:00	40 MW	7 MW	33 MW	6.8 MW		
	2016-2017	9/02/2016 17:30	40 MW	4 MW	36 MW	4.5 MW		
	2016-2017	10/02/2016 16:30	40 MW	2 MW	38 MW	2.4 MW		
	2016-2017	10/02/2016 17:00	40 MW	2 MW	38 MW	1.8 MW		
	2016-2017	10/02/2016 17:30	40 MW	1 MW	39 MW	1.1 MW		
	2016-2017	14/03/2016 16:30	40 MW	3 MW	37 MW	2.9 MW		
	2016-2017	14/03/2016 17:00	40 MW	3 MW	37 MW	2.9 MW		
	2016-2017	14/03/2016 17:30	40 MW	2 MW	38 MW	1.6 MW		
1 December 2016 to 31 March 2017	2017-2018	1/03/2017 17:00	40 MW	0 MW	40 MW	0.1 MW	40.0 MW	32.8 MW
	2017-2018	4/01/2017 16:30	40 MW	8 MW	32 MW	8.0 MW		
	2017-2018	3/03/2017 16:00	40 MW	9 MW	31 MW	9.2 MW		
	2017-2018	3/03/2017 17:00	40 MW	5 MW	35 MW	5.2 MW		
	2017-2018	3/03/2017 16:30	40 MW	7 MW	33 MW	7.2 MW		
	2017-2018	1/03/2017 16:30	40 MW	1 MW	39 MW	0.6 MW		
	2017-2018	1/03/2017 17:30	40 MW	0 MW	40 MW	0.1 MW		
	2017-2018	4/01/2017 17:00	40 MW	8 MW	32 MW	7.5 MW		
	2017-2018	4/01/2017 16:00	40 MW	9 MW	31 MW	8.5 MW		
	2017-2018	21/12/2016 17:30	40 MW	5 MW	35 MW	5.0 MW		
	2017-2018	21/12/2016 17:00	40 MW	7 MW	33 MW	7.2 MW		
	2017-2018	21/12/2016 16:30	40 MW	8 MW	32 MW	7.9 MW		
1 December 2017 to 31 March 2018	2018-2019	15/02/2018 17:00	40 MW	8 MW	32 MW	7.6 MW	40.0 MW	37.9 MW
	2018-2019	15/02/2018 17:30	40 MW	5 MW	35 MW	4.8 MW		
	2018-2019	15/02/2018 18:00	40 MW	2 MW	38 MW	2.1 MW		
	2018-2019	12/03/2018 17:30	40 MW	1 MW	39 MW	1.2 MW		
	2018-2019	12/03/2018 18:00	40 MW	0 MW	40 MW	0.0 MW		
	2018-2019	12/03/2018 18:30	40 MW	0 MW	40 MW	0.0 MW		
	2018-2019	13/03/2018 17:00	40 MW	4 MW	36 MW	4.2 MW		
	2018-2019	13/03/2018 17:30	40 MW	2 MW	38 MW	2.1 MW		
	2018-2019	13/03/2018 18:00	40 MW	0 MW	40 MW	0.0 MW		
	2018-2019	21/03/2018 16:30	40 MW	6 MW	34 MW	5.8 MW		
	2018-2019	21/03/2018 17:00	40 MW	3 MW	37 MW	3.2 MW		
	2018-2019	21/03/2018 17:30	40 MW	2 MW	38 MW	1.6 MW		

Figure 1 - Median peak load with and without Solar PV during 12 PTI for capacity year 2016-2017, 2017-2018 and 2018-2019

The PV contribution reduces the MPL during the 12 PTI for all capacity years studied, although for the later, the PTI are occurring later on the day, therefore the contribution from the solar generator is lower.

Figure 2 shows the Solar contribution during a peak day is shown in Figure 2.

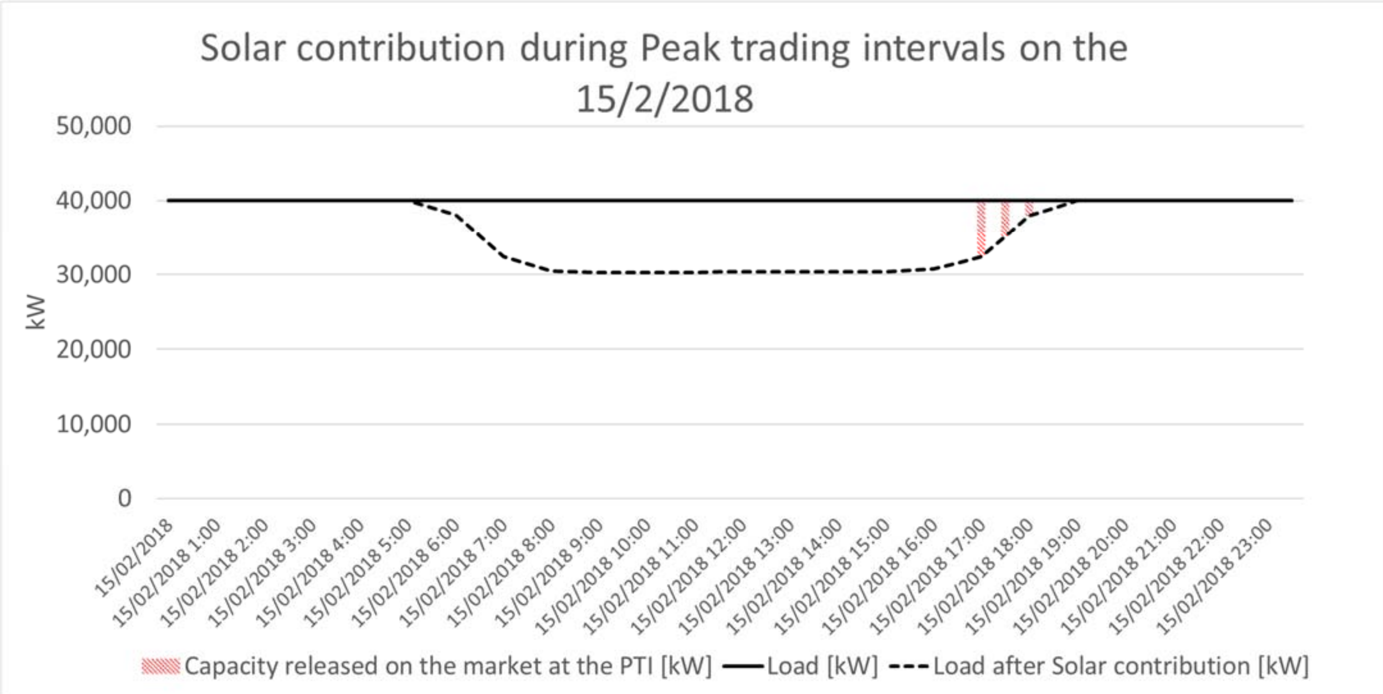

Figure 2 - Load profile and Solar PV contribution over three of the 12 PTI of the hot season

When the NTDL status of the load is calculated it changes from NTDL to a Temperature Dependent load (TDL) due to the impact of the BTM (solar) contribution. The calculations are attached in Appendix A for more detail.

The following procedure from wholesale electricity market rules explains the methodology followed to determine the requirements to be classified as a NTDL (Non-Temperature Dependent Load):

Non-Temperature Dependent Load Requirements

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

Step 1:

- If, in accordance with clause 4.28.8(a), AEMO is provided by a Market Customer in Trading Month (n-2) with a list that includes an interval meter associated with that Market Customer that it wants AEMO to treat as a Non-Temperature Dependent Load from Trading Month (n); and
- If the list including the interval meter is provided by the date and time specified in clause 4.1.23; and
- If the load was treated as a Non-Temperature Dependent Load in Trading Month (n-8),

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

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

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

i. the consumption was 0 MWh; or

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

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

Appendix B shows the (IRCR) economics for the capacity years 2016-2017, 2017-2018 and 2018-2019 (some missing data for the last capacity year, therefore FY results extrapolated).

The effects on Shared Reserve Capacity Cost (SRCC) have not been included in the analysis though the same disadvantage of connecting a Solar Generator behind the meter will apply (ie. SRCC costs increase due to the installation of a BTM generator).

The table below comparing the financial impact of changing the status from NTDL to TDL shows scenarios where the Solar PV is connected behind the meter without changing TD status (ie. Retaining NTDL status) and the scenario where the load does change to TDL. Refer to in appendix B:

- Current Load scenario, load without PV generator and NTDL status;
- Load incl PV (NTDL), load with PV generator and keeping NTDL status; and
- Load incl PV (TDL), load with PV generator and changing to TDL status

If the customer retained NTDL status they would benefit in all sample capacity years while also reducing its reserve capacity requirements. However, changing the NTDL status to TDL results in the customer incurring more costs due to a higher IRCR.

Capacity Year	Capacity Charge Current Load (NTDL)	Capacity Charge Load incl PV (NTDL)	Capacity Charge Load incl PV (TDL)	Savings (NTDL)	Savings (TDL)	Delta (Absolute)
2016-2017	$5,314,818	$4,825,048	$5,606,504	$489,770	($291,686)	$781,456
2017-2018	$4,874,432	$3,993,994	$5,178,301	$880,438	($303,869)	$1,184,307
2018-2019 (1Q)	$1,514,127	$1,435,259	$2,031,446	$78,869	($517,319)	$596,188
2018-2019 (FY)	$1,514,127	$1,435,259	$2,031,446	$78,869	($2,100,000)	$2,178,869

Table 1 - Reserve Capacity costs of adding behind the meter Solar PV

Presently a load installing a BTM generator, reducing its demand on the network, is likely to incur greater costs due to a calculation showing it contributes to peak demand, when in fact it reduces its demand.

- Should a load that would otherwise qualify as NTDL, be relegated to TDL status, increasing costs, despite the benefits such a system provides?

- In the same way that ‘outage/maintenance’ intervals are removed from an NTDL’s meter data in thje NTDL calculations – could BTM generation data be added back on to the customers meter data (provided it is meter data from a suitably accredited meter)?

Appendix A

4 Peak SWIS Trading Intervals	Load incl Solar @ PTI	MPL	Consumption MWh	Step 1 a) Median value > 1 MWh	Yes / No	Step 1 b) % of Time below 10% of median	Yes / No
7/01/2016 17:30	38 MW	37 MW	19 MWh	20 MWh	Yes	0%	Yes
7/01/2016 17:00	37 MW		18 MWh				
7/01/2016 18:30	39 MW		20 MWh				
7/01/2016 16:30	36 MW		18 MWh				
8/02/2016 17:30	35 MW	34 MW	18 MWh	20 MWh	Yes	0%	Yes
8/02/2016 17:00	32 MW		16 MWh				
8/02/2016 16:30	32 MW		16 MWh				
8/02/2016 18:00	38 MW		19 MWh				
14/03/2016 16:30	37 MW	38 MW	19 MWh	20 MWh	Yes	0%	Yes
14/03/2016 17:30	38 MW		19 MWh				
14/03/2016 17:00	37 MW		19 MWh				
14/03/2016 18:30	40 MW		20 MWh				
12/04/2016 18:00	40 MW	40 MW	20 MWh	20 MWh	Yes	0%	Yes
13/04/2016 18:30	40 MW		20 MWh				
18/04/2016 18:00	40 MW		20 MWh				
18/04/2016 18:30	40 MW		20 MWh				
31/05/2016 18:00	40 MW	40 MW	20 MWh	20 MWh	Yes	0%	Yes
30/05/2016 18:00	40 MW		20 MWh				
31/05/2016 18:30	40 MW		20 MWh				
30/05/2016 18:30	40 MW		20 MWh				
7/06/2016 18:00	40 MW	40 MW	20 MWh	20 MWh	Yes	0%	Yes
7/06/2016 17:30	40 MW		20 MWh				
7/06/2016 18:30	40 MW		20 MWh				
8/06/2016 18:00	40 MW		20 MWh				
4/07/2016 18:00	40 MW	40 MW	20 MWh	20 MWh	Yes	0%	Yes
12/07/2016 18:00	40 MW		20 MWh				
12/07/2016 18:30	40 MW		20 MWh				
12/07/2016 19:00	40 MW		20 MWh				
8/08/2016 18:00	40 MW	40 MW	20 MWh	20 MWh	Yes	0%	Yes
8/08/2016 18:30	40 MW		20 MWh				
8/08/2016 19:00	40 MW		20 MWh				
9/08/2016 18:00	40 MW		20 MWh				
15/09/2016 18:30	40 MW	40 MW	20 MWh	20 MWh	Yes	0%	Yes
19/09/2016 18:30	40 MW		20 MWh				
27/09/2016 18:30	40 MW		20 MWh				
27/09/2016 19:00	40 MW		20 MWh				
3/10/2016 18:30	40 MW	40 MW	20 MWh	20 MWh	Yes	0%	Yes
3/10/2016 19:00	40 MW		20 MWh				
3/10/2016 19:30	40 MW		20 MWh				
1/10/2016 19:00	40 MW		20 MWh				
14/11/2016 17:30	38 MW	35 MW	19 MWh	20 MWh	Yes	0%	Yes
26/11/2016 16:30	33 MW		17 MWh				
26/11/2016 17:00	34 MW		17 MWh				

4 Peak SWIS Trading Intervals	Load incl Solar @ PTI	MPL	Consumption MWh	Step 1 a) Median value > 1 MWh	Yes / No	Step 1 b) % of Time below 10% of median	Yes / No
26/11/2016 17:30	36 MW		18 MWh				
21/12/2016 16:00	32 MW	32 MW	16 MWh	20 MWh	Yes	8%	Yes
21/12/2016 16:30	32 MW		16 MWh				
21/12/2016 17:00	33 MW		16 MWh				
21/12/2016 17:30	35 MW		17 MWh				
4/01/2017 15:30	31 MW	32 MW	16 MWh	20 MWh	Yes	8%	Yes
4/01/2017 16:00	31 MW		16 MWh				
4/01/2017 16:30	32 MW		16 MWh				
4/01/2017 17:00	32 MW		16 MWh				
19/02/2017 16:30	32 MW	34 MW	16 MWh	20 MWh	Yes	6%	Yes
19/02/2017 17:00	33 MW		16 MWh				
19/02/2017 17:30	36 MW		18 MWh				
19/02/2017 18:00	38 MW		19 MWh				
1/03/2017 16:30	39 MW	40 MW	20 MWh	20 MWh	Yes	17%	No
1/03/2017 17:00	40 MW		20 MWh				
1/03/2017 17:30	40 MW		20 MWh				
1/03/2017 18:00	40 MW		20 MWh				
3/04/2017 18:30	40 MW	40 MW	20 MWh	20 MWh	Yes	28%	No
4/04/2017 18:30	40 MW		20 MWh				
5/04/2017 18:00	40 MW		20 MWh				
5/04/2017 18:30	40 MW		20 MWh				
23/05/2017 18:00	40 MW	40 MW	20 MWh	20 MWh	Yes	36%	No
29/05/2017 17:30	40 MW		20 MWh				
29/05/2017 18:00	40 MW		20 MWh				
29/05/2017 18:30	40 MW		20 MWh				
26/06/2017 18:00	40 MW	40 MW	20 MWh	20 MWh	Yes	36%	No
26/06/2017 18:30	40 MW		20 MWh				
29/06/2017 18:00	40 MW		20 MWh				
29/06/2017 18:30	40 MW		20 MWh				
6/07/2017 18:30	40 MW	40 MW	20 MWh	20 MWh	Yes	36%	No
5/07/2017 17:30	40 MW		20 MWh				
5/07/2017 18:30	40 MW		20 MWh				
5/07/2017 18:00	40 MW		20 MWh				
9/08/2017 18:30	40 MW	40 MW	20 MWh	20 MWh	Yes	36%	No
9/08/2017 18:00	40 MW		20 MWh				
2/08/2017 18:30	40 MW		20 MWh				
9/08/2017 19:00	40 MW		20 MWh				
28/09/2017 18:30	40 MW	40 MW	20 MWh	20 MWh	Yes	36%	No
28/09/2017 19:00	40 MW		20 MWh				
28/09/2017 19:30	40 MW		20 MWh				
4/09/2017 18:30	40 MW		20 MWh				
4/10/2017 18:30	40 MW	40 MW	20 MWh	20 MWh	Yes	36%	No
4/10/2017 19:00	40 MW		20 MWh				
10/10/2017 18:30	40 MW		20 MWh				
10/10/2017 19:00	40 MW		20 MWh				
16/11/2017 16:00	31 MW	34 MW	16 MWh	20 MWh	Yes	31%	No

4 Peak SWIS Trading Intervals	Load incl Solar @ PTI	MPL	Consumption MWh	Step 1 a) Median value > 1 MWh	Yes / No	Step 1 b) % of Time below 10% of median	Yes / No
16/11/2017 16:30	33 MW		17 MWh				
16/11/2017 17:00	35 MW		17 MWh				
16/11/2017 17:30	37 MW		19 MWh				
11/12/2017 17:30	36 MW	32 MW	18 MWh	20 MWh	Yes	19%	No
11/12/2017 13:00	31 MW		15 MWh				
11/12/2017 12:30	31 MW		15 MWh				
11/12/2017 17:00	33 MW		17 MWh				
2/01/2018 17:00	32 MW	35 MW	16 MWh	20 MWh	Yes	8%	Yes
2/01/2018 17:30	34 MW		17 MWh				
2/01/2018 18:00	36 MW		18 MWh				
2/01/2018 18:30	38 MW		19 MWh				
15/02/2018 17:30	35 MW	34 MW	18 MWh	20 MWh	Yes	8%	Yes
15/02/2018 17:00	32 MW		16 MWh				
15/02/2018 18:00	38 MW		19 MWh				
15/02/2018 16:30	32 MW		16 MWh				
13/03/2018 18:30	40 MW	39 MW	20 MWh	20 MWh	Yes	19%	No
13/03/2018 18:00	40 MW		20 MWh				
13/03/2018 17:00	36 MW		18 MWh				
13/03/2018 17:30	38 MW		19 MWh				
3/04/2018 17:00	39 MW	39 MW	19 MWh	20 MWh	Yes	25%	No
3/04/2018 16:30	37 MW		19 MWh				
3/04/2018 17:30	39 MW		20 MWh				
3/04/2018 18:30	40 MW		20 MWh				
28/05/2018 18:00	40 MW	40 MW	20 MWh	20 MWh	Yes	33%	No
31/05/2018 17:30	40 MW		20 MWh				
31/05/2018 18:30	40 MW		20 MWh				
31/05/2018 18:00	40 MW		20 MWh				
7/06/2018 17:30	40 MW	40 MW	20 MWh	20 MWh	Yes	31%	No
7/06/2018 18:00	40 MW		20 MWh				
7/06/2018 18:30	40 MW		20 MWh				
7/06/2018 19:00	40 MW		20 MWh				
5/07/2018 18:00	40 MW	40 MW	20 MWh	19 MWh	Yes	25%	No
16/07/2018 18:00	40 MW		20 MWh				
16/07/2018 18:30	40 MW		20 MWh				
19/07/2018 18:30	40 MW		20 MWh				

Appendix B

Capacity Year	Year	Month	NTDL RATIO	TDL RATIO	TOTAL RATIO	IRCR Current Load (NTDL)	IRCR Load incl PV (NTDL)	IRCR Load incl PV (TDL)	RCP [$/MW/month]	Capacity Charge Current Load (NTDL)	Capacity Charge Load incl PV (NTDL)	Capacity Charge Load incl PV (TDL)	Capacity Charge Current Load (NTDL)	Capacity Charge Load incl PV (NTDL)	Capacity Charge Load incl PV (TDL)	Savings (NTDL)	Savings (TDL)
2016-2017	2016	10	1.0973	1.2709	0.9969	43.8 MW	39.7 MW	46.0 MW	$10,157	$444,447	$403,490	$467,325	$5,314,818	$4,825,048	$5,606,504	$489,770	-$291,686
2016-2017	2016	11	1.0973	1.2708	0.9968	43.8 MW	39.7 MW	46.0 MW	$10,157	$444,402	$403,450	$467,242					
2016-2017	2016	12	1.0973	1.2709	0.9967	43.7 MW	39.7 MW	46.0 MW	$10,157	$444,358	$403,409	$467,231					
2016-2017	2017	1	1.0973	1.2711	0.9972	43.8 MW	39.7 MW	46.0 MW	$10,157	$444,581	$403,612	$467,539					
2016-2017	2017	2	1.0973	1.2740	0.9938	43.6 MW	39.6 MW	46.0 MW	$10,157	$443,065	$402,236	$467,008					
2016-2017	2017	3	1.0973	1.2784	0.9909	43.5 MW	39.5 MW	46.0 MW	$10,157	$441,772	$401,062	$467,254					
2016-2017	2017	4	1.0973	1.2785	0.9910	43.5 MW	39.5 MW	46.0 MW	$10,157	$441,817	$401,102	$467,338					
2016-2017	2017	5	1.0973	1.2764	0.9924	43.6 MW	39.5 MW	46.0 MW	$10,157	$442,441	$401,669	$467,229					
2016-2017	2017	6	1.0973	1.2785	0.9897	43.4 MW	39.4 MW	45.9 MW	$10,157	$441,237	$400,576	$466,724					
2016-2017	2017	7	1.0973	1.2766	0.9927	43.6 MW	39.6 MW	46.0 MW	$10,157	$442,575	$401,790	$467,443					
2016-2017	2017	8	1.0973	1.2769	0.9918	43.5 MW	39.5 MW	46.0 MW	$10,157	$442,173	$401,426	$467,129					
2016-2017	2017	9	1.0973	1.2773	0.9913	43.5 MW	39.5 MW	46.0 MW	$10,157	$441,950	$401,224	$467,040					
2017-2018	2017	10	1.0972	1.4157	0.9966	43.7 MW	35.8 MW	46.2 MW	$9,313	$407,327	$333,754	$430,637	$4,874,432	$3,993,994	$5,178,301	$880,438	-$303,869
2017-2018	2017	11	1.0972	1.4163	0.9960	43.7 MW	35.8 MW	46.2 MW	$9,313	$407,081	$333,553	$430,560					
2017-2018	2017	12	1.0972	1.4178	0.9962	43.7 MW	35.8 MW	46.3 MW	$9,313	$407,163	$333,620	$431,103					
2017-2018	2018	1	1.0972	1.4216	0.9961	43.7 MW	35.8 MW	46.4 MW	$9,313	$407,122	$333,586	$432,215					
2017-2018	2018	2	1.0972	1.4237	0.9938	43.6 MW	35.7 MW	46.4 MW	$9,313	$406,182	$332,816	$431,854					
2017-2018	2018	3	1.0972	1.4243	0.9930	43.6 MW	35.7 MW	46.4 MW	$9,313	$405,855	$332,548	$431,688					
2017-2018	2018	4	1.0972	1.4235	0.9939	43.6 MW	35.7 MW	46.4 MW	$9,313	$406,223	$332,850	$431,837					
2017-2018	2018	5	1.0972	1.4250	0.9922	43.5 MW	35.7 MW	46.3 MW	$9,313	$405,528	$332,280	$431,553					
2017-2018	2018	6	1.0972	1.4259	0.9913	43.5 MW	35.6 MW	46.3 MW	$9,313	$405,160	$331,979	$431,433					
2017-2018	2018	7	1.0972	1.4253	0.9923	43.6 MW	35.7 MW	46.4 MW	$9,313	$405,569	$332,314	$431,687					
2017-2018	2018	8	1.0972	1.4252	0.9927	43.6 MW	35.7 MW	46.4 MW	$9,313	$405,733	$332,448	$431,831					
2017-2018	2018	9	1.0972	1.4263	0.9921	43.5 MW	35.7 MW	46.4 MW	$9,313	$405,487	$332,247	$431,903					
2018-2019	2018	10	1.0956	1.5458	0.9970	43.7 MW	41.4 MW	58.4 MW	$11,563	$505,233	$478,916	$675,710	$1,514,127	$1,435,259	$2,031,446	$78,869	-$517,319
2018-2019	2018	11	1.0956	1.5473	0.9953	43.6 MW	41.3 MW	58.4 MW	$11,563	$504,371	$478,099	$675,213					
2018-2019	2018	12	1.0956	1.5590	0.9956	43.6 MW	41.4 MW	58.9 MW	$11,563	$504,523	$478,243	$680,523					
2018-2019	2019	1	…	…	…	…	…	…	…	…	…	…					
2018-2019	2019	2	…	…	…	…	…	…	…	…	…	…					
2018-2019	2019	3	…	…	…	…	…	…	…	…	…	…					
2018-2019	2019	4	…	…	…	…	…	…	…	…	…	…					
2018-2019	2019	5	…	…	…	…	…	…	…	…	…	…					
2018-2019	2019	6	…	…	…	…	…	…	…	…	…	…					
2018-2019	2019	7	…	…	…	…	…	…	…	…	…	…					
2018-2019	2019	8	…	…	…	…	…	…	…	…	…	…					
2018-2019	2019	9	…	…	…	…	…	…	…	…	…	…					

Review of the method for capacity valuation of variable generation

5 February 2019

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Background

- AEMO assigns capacity credits to generators and demand-side resources.
  - For variable generation: relevant level method (RLM)
- **Current RLM**

Capacity value of a facility (MW) = output average - [constant parameters X output variance]

- Average and variance calculated based on observed data – when load for scheduled generation (LSG) has been the largest.

Background…

- The ERA reviews relevant level method
  - Every three years
  - Examine its effectiveness (market objectives)
  - Determine values of constant parameters for the current method (K and U parameters)
- Previous review: the Independent Market Operator, 2014
  - Revised the value of constant parameters
  - No change in the method

Background…

- Collgar Wind Farm proposed a rule change in 2018
  - Proposed to use observed generators' output during peak periods (rather than peak LSG periods).
  - Collgar referred to the requirement for capacity to be available to meet peak demand and argued the use of LSG is not consistent with this requirement.

Review questions

- Is the current method reasonably accurate?
- If the current method is accurate, is it possible to improve it?
- If not, what methods could replace it?
- Is the method suitable for the capacity valuation of storage resources?
- On 21 December 2018, the ERA published a draft report for consultation with stakeholders.
  - Submissions close on 18 February 2019.

Basis of the current method

- Current method is based on a simple formula (original formula) published in 2012:
  - Based on some assumptions that should be fully understood before using the formula.
  - Basis of the formula: *effective load carrying capability*
    - How much additional load the system can cover with the addition of a resource without a change in reliability risk of the system.
    - This additional load is the capacity value of the resource.
    - The formula is based on the loss of load expectation (LOLE) as the measure of reliability risk.

Current RLM has several shortcomings

- The RLM is not consistent with the original formula developed in 2012.
- Incorrect identification of periods with the minimum level of capacity surplus.
- Incorrect calculation of parameter K.
- Ad-hoc addition of parameter U.
- Capacity valuation for each generator individually:
  - Can underestimate the contribution of the fleet of variable generators.

The current method can not be enhanced

- The only practical way to use the (original) formula:
  - estimating the capacity contribution of the fleet of variable generators in the SWIS.
  - Fleet capacity value then could be allocated to individual generators.
- One problem remains: results would be inaccurate
  - Only when the penetration of variable generation is low, the (original) formula can provide reasonable results.
- Value of K would be highly sensitive to assumptions underpinning its calculation.

Replacement options

- Using probabilistic models: as recommended by IEEE expert groups and used by Midcontinent ISO and California ISO.
- Simple time-based methods: eg, used in the PJM
  - Based on the average capacity factor of resources during high reliability risk hours.
  - time-based method are not accurate.
  - They also require probabilistic methods for their calibration.

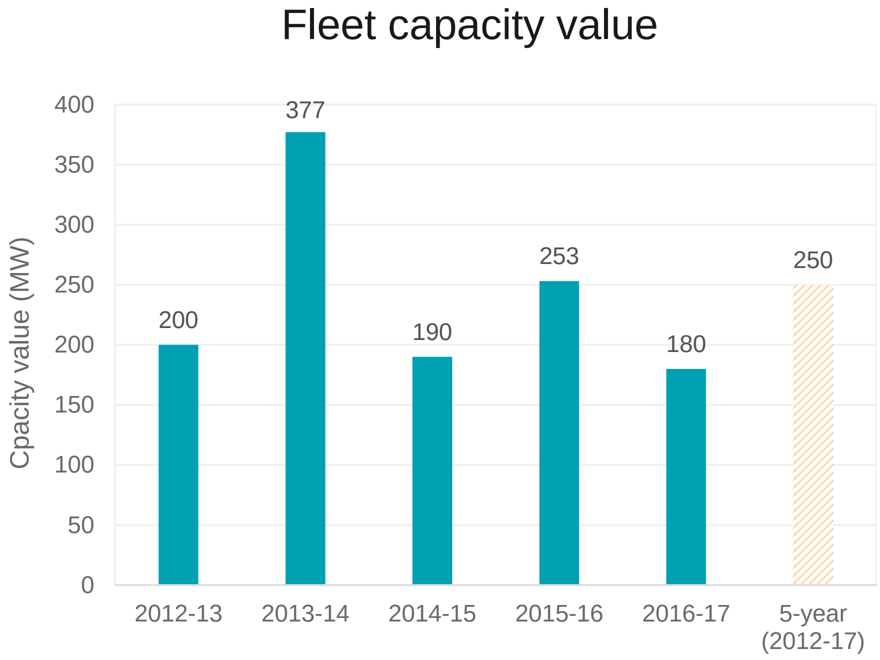
The ERA's proposed method

Using a probabilistic model to estimate the effective load carrying capability of resources:

- No change in the capacity value measurement concept, but a change in the solution method
  - effective load carrying capability is the basis of capacity valuation.
- Low incremental cost.
- Robust to possible changes in the system and in the rules.

Sample model results

- ERA developed a sample model to estimate the capacity value of the fleet of variable generators for the 2019/20 capacity year.
- High variation in the capacity contribution of variable generation.
- The current RLM: AEMO assigned 183 MW of capacity credits to the fleet.
- Allocation to individual facilities



Implementation considerations

- Development of guidelines in the market rules
  - how the model should be developed
  - what the model should deliver
  - quality assurance mechanism.
- Detailed specification of the model in a market procedure.
- Transitional arrangements to dampen possible financial impacts.
- While rule change process is in development, the current method will apply (the ERA will publish unchanged values of K and U).

Thank you

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RCP | Rule Change Panel
Market Advisory Committee

Agenda Item 11: MAC Schedule

Meeting 2019_02_05

At its meeting on 20 November 2018, the Market Advisory Committee's (**MAC**) agreed to a schedule of MAC meetings for the first six months of 2019. RCP Support has now developed a schedule for the remainder of 2019, as indicated below. MAC Members are asked to confirm their availability for the MAC meeting schedule for 2019.

MAC Meeting Schedule for 2019	
Month	**Date**
January 2019	No meeting
February 2019	Tuesday, 5 February 2019
March 2019	Tuesday, 12 March 2019
April 2019	Tuesday, 30 April 2019
May 2019	No meeting
June 2019	Tuesday, 11 June 2019
July 2019	Tuesday, 30 July 2019
August 2019	No meeting
September 2019	Tuesday, 3 September 2019
October 2019	Tuesday, 15 October 2019
November 2019	Tuesday, 26 November 2019
December 2019	No meeting