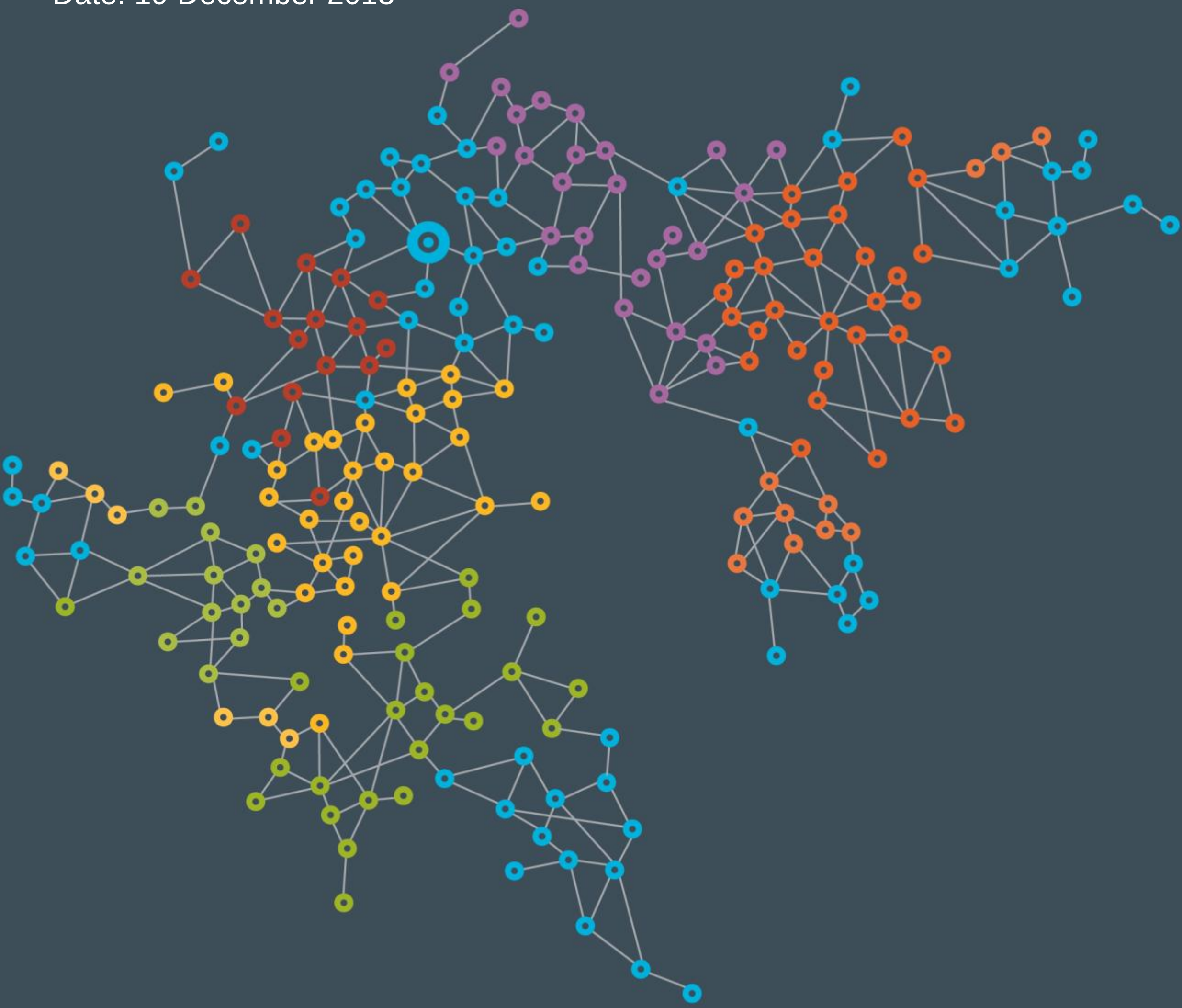
INDEPENDENT
MARKET
OPERATOR

Draft Rule Change Report
Harmonisation of Supply-Side and Demand-Side Capacity Resources

RC_2013_10
Standard Rule Change Process

Date: 19 December 2013



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Executive Summary

Proposed amendments

The Reserve Capacity Mechanism (RCM) Working Group (RCMWG) was established in February 2012 to assess the issues highlighted by the Lantau Group in its report "*Review of RCM: Issues and Recommendations*"[1]. This report was commissioned by the IMO Board to analyse the effectiveness and efficiency of the RCM.

One of the key topics discussed during the RCMWG meetings was the harmonisation of rules relating to supply-side and demand-side capacity resources. Key considerations in these discussions were the:

- fuel requirements for generators;
- minimum availability requirements for Demand Side Programmes (DSPs);
- real-time data requirements for DSPs; and
- alignment between the Individual Reserve Capacity Requirement (IRCR) and Relevant Demand (RD) for a customer providing Demand Side Management (DSM) services.

While not unanimously accepted, the RCMWG members generally supported the proposed changes in the Rule Change Proposal.

Consultation

The IMO first submitted the Rule Change Proposal to the Market Advisory Committee (MAC) on 12 June 2013 as a concept paper for discussion. The proposal was then submitted to the 7 August 2013 MAC meeting as a pre Rule Change Proposal. At this meeting, the proposal received endorsement for progression into the process.

The IMO formally submitted the proposal into the Standard Rule Change Process and published the Rule Change Notice on 21 August 2013.

The first submission period was held between 22 August and 3 October 2013. Submissions were received from Alinta Energy, EnerNOC, Newmont Mining Services, Perth Energy, Synergy and System Management. The majority of submissions from DSM providers raised concerns with the potential increase in costs to Market Participants, particularly around the requirement to provide real-time telemetry. Other submissions were accepting of the IMO's proposal to increase the availability requirements for demand-side resources to improve alignment with supply-side resources.

Assessment against Wholesale Market Objectives

The IMO considers that the proposed amendments will better achieve Wholesale Market Objectives (a), (c) and (e) and are consistent with the remaining objectives.

[1] http://www.imowa.com.au/f5415,2873688/09._Agenda_Item_8_Lantau_Report.pdf

Practicality and cost of implementation

The IMO has identified material costs associated with the implementation of the proposed Amending Rules. These costs are primarily related to the new requirements for telemetry for DSPs.

The IMO has investigated the potential costs for Market Customers related to the requirement for DSPs to implement real-time telemetry. The IMO estimates that the costs are primarily fixed, one-off costs of $350,000 to $450,000 for each Market Customer with a DSP for building and testing new software systems and a further $50,000 to $100,000 per annum for ongoing monitoring and maintenance. However, the requirements for data provision will not be formally defined until the necessary web service is fully defined in changes to be included in the Power System Operation Procedure (PSOP): Communications and Control Systems and Market Procedure: IMS Interface.

In addition, System Management is expected to incur costs of $200,000 to $400,000 to expand the current web service and provide the necessary administration. System Management is currently unable to provide a specific estimate of the cost of the expansion of the current system however, it is expected that the existing functionality can be leveraged.

The IMO is also expected to incur one-off costs of approximately $160,000 to amend IMO systems to provide for the amendments to the validation for certification, methodology for Capacity Credit allocation and settlements and ensure that the necessary telemetry data can be captured and stored as necessary. These costs will be able to be met within the IMO's current resources.

The IMO considers that the greater visibility of the availability of DSM for System Management will increase the efficiency and cost effectiveness of the operation and dispatch of the service in the long-term. The IMO considers that the identified costs are expected to be far outweighed by the benefits to the market of the proposed amendments.

The IMO proposes to commence the majority of the Amending Rules set out in this Rule Change Proposal in order for them to apply for the 2014 Reserve Capacity Cycle. Rule Participants should note:

- changes related to certification of Reserve Capacity are proposed to commence no later than 1 May 2014 in time for the opening of the window for applications for Certified Reserve Capacity for the 2014 Reserve Capacity Cycle; and

- changes that impact the operation of DSPs are proposed to commence on 1 October 2016.

The exception is the proposed changes that relate to the IRCR and RD in clause 4.26.2CA and Appendix 5. These changes are proposed to commence no later than 1 October 2014, in order to apply for the 2014/15 Capacity Year.

The IMO considers that these commencement dates will provide Rule Participants adequate time for the necessary changes to IT and operational systems and processes.

The IMO proposed decision

The IMO's proposed decision is to accept the Rule Change Proposal as modified following the first submission period.

Next steps

The IMO now invites interested stakeholders to make submissions on this Draft Rule Change Report by **5:00 pm, Friday 31 January 2014**.

1. Rule Change Process and Timetable

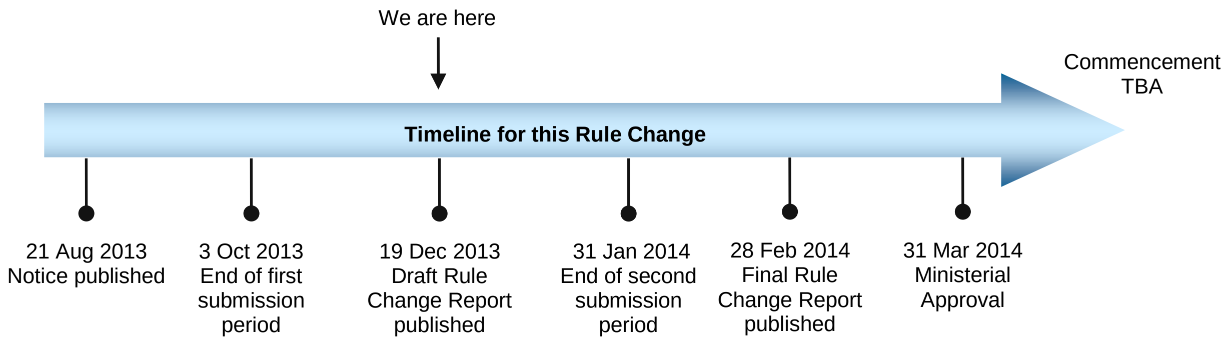
On 21 August 2013 the IMO submitted a Rule Change Proposal regarding:

- amendments to clauses 2.13.9, 2.29.9A, 4.5.12, 4.10.1, 4.10.2, 4.11.1, 4.11.4, 4.12.2, 4.12.4, 4.12.8, 4.25.1, 4.25.13, 4.26.2CA, 4.26.3A, 6.12.1, 7.5.1, 7.6.10, 7.7.4A, 7.7.10, 7.10.4, 7.11.1 and 7.11.5, along with the Glossary, Appendix 1, Appendix 3 and Appendix 5 of the Wholesale Electricity Market Rules (Market Rules); and

- proposed new clauses 2.35.3A, 2.35.3B, 2.35.3C and 7.13.1D of the Market Rules.

This proposal is being processed using the Standard Rule Change Process, described in section 2.7 of the Market Rules.

The key dates in processing this Rule Change Proposal are:



2. Call for Second Round Submissions

As published in the extension notice of 16 December 2013, the submission period has been extended beyond the usual 20 Business Days to provide Market Participants with sufficient time to consider the proposal over the Christmas and New Year period. All other dates have been adjusted accordingly.

The IMO invites interested stakeholders to make submissions on this Draft Rule Change Report. The submission period is 27 Business Days from the publication date of this report. Submissions must be delivered to the IMO by **5.00pm, Friday 31 January 2014**.

The IMO prefers to receive submissions by email (using the submission form available on the Market Web Site: http://www.imowa.com.au/rule-changes) to: market.development@imowa.com.au

Submissions may also be sent to the IMO by fax or post, addressed to:

Independent Market Operator
Attn: Group Manager, Development & Capacity
PO Box 7096
Cloisters Square, PERTH, WA 6850
Fax: (08) 9254 4399

3. Proposed Amendments

3.1. The Rule Change Proposal

The Rule Change Proposal seeks to harmonise the Market Rules related to supply-side and demand-side capacity resources in accordance with the recommendations of the Reserve Capacity Mechanism (RCM) Working Group (RCMWG).

3.1.1. Background

The RCM is a mechanism to support the Wholesale Electricity Market (WEM) in the South West interconnected system (SWIS) in ensuring there is sufficient Reserve Capacity to meet reliability targets. The RCM allows for capacity to be provided by the addition of supply-side resources (predominantly thermal generators) or through reductions in demand by providers of Demand Side Management (DSM) services.

The RCMWG was established by the Market Advisory Committee (MAC) in February 2012 to assess the issues highlighted by the Lantau Group in its report "*Review of RCM: Issues and Recommendations*"[2]. This report was commissioned by the IMO Board to analyse the effectiveness and efficiency of the RCM.

One of the key topics discussed during the RCMWG meetings was the harmonisation of rules relating to supply-side and demand-side capacity resources. Key considerations in these discussions were the:

- fuel requirements for generators;
- minimum availability requirements for Demand Side Programmes (DSPs);
- real-time data requirements for DSPs; and
- alignment between the Individual Reserve Capacity Requirement (IRCR) and Relevant Demand (RD) for a customer providing DSM.

Substantial analysis was conducted by Dr Richard Tooth of Sapere Research Group to support the RCMWG in its consideration of these issues. Three reports on the *Performance Requirements for Demand-Side and Supply-Side Capacity Resources* were presented by Dr Tooth at RCMWG meetings. These reports, together with the Working Group's discussions and analysis, are available on the Market Web Site: http://www.imowa.com.au/rcmwg.

3.1.2. Proposed Amendments to the Market Rules

The IMO proposes to amend clauses 2.13.9, 2.29.9A, 4.5.12, 4.10.1, 4.10.2, 4.11.1, 4.11.4, 4.12.2, 4.12.4, 4.12.8, 4.25.1, 4.25.13, 4.26.1A[3], 4.26.2CA, 4.26.3A, 6.12.1, 7.5.1, 7.6.10, 7.7.4A, 7.7.10, 7.10.4, 7.11.1 and 7.11.5, along with the Glossary, Appendix 1, Appendix 3 and Appendix 5 of the

[2] http://www.imowa.com.au/f5415,2873688/09._Agenda_Item_8_Lantau_Report.pdf

[3] Note that this was not in the Rule Change Proposal but has been included in the Draft Rule Change Report in response to the submission received by System Management.

Market Rules and introduce new clauses 2.35.3A, 2.35.3B, 2.35.3C and 7.13.1D. These proposed amendments will:

- relax the requirement for generation Facilities to have ‘firm fuel’ supply contracts in place (refer to the proposed changes to clauses 2.13.9, 4.10.1, 4.10.2, 4.11.1, 4.12.2, 4.25.1 and 4.25.13);

- increase the minimum availability requirements for DSPs and refine other demand-side requirements as shown in Table 1 (refer to the proposed changes to clauses 2.29.9A, 4.5.12, 4.10.1, 4.11.4, 4.12.4, 4.26.3A, 7.7.10, 7.11.1, 7.11.5, Appendix 1 and Appendix 3);

Table 1: Minimum availability requirements for DSPs

Requirement	Current Rule	Proposed Change
Days of Availability	All Business Days	All Business Days
Dispatch events per year	At least 6	5 x 52 = 260 – (public holidays) = 250*
Hours per day	4 hours	6 hours
Total hours available per year	24 hours	250 x 6 = 1,500 hours*
Earliest Start	12:00 PM	10:00 AM
Latest Finish	8:00 PM	8:00 PM
Minimum notice period of dispatch	4 hours	2 hours [Dispatch Advisory may be released by System Management within 24 hours of the capacity requirement] **

* These requirements will no longer be limited under the Market Rules; figures provided are indicative of the maximum requirement for a DSP.

** The introduction of a Dispatch Advisory was suggested at the June 2013 MAC meeting during the development of the Rule Change Proposal.

- require DSPs to provide real-time telemetry for all Associated Loads to improve the information available to System Management and the market with regard to the quantity of demand-side response available (refer to the proposed changes to clause 7.10.4 and new clauses 2.35.3A, 2.35.3B and 2.35.3C);

- remove the provision that allows DSPs to be unavailable for dispatch on the third consecutive day (the ‘third day rule’) (refer to the proposed changes to clause 4.12.8);

- amend the rules of the Non-Balancing Dispatch Merit Order (DMO) to rank the dispatch of DSPs, after price, on the basis of time since last dispatch, rather than size (refer to the proposed changes to clauses 6.12.1, 7.5.1, 7.7.4A and new clause 7.13.1D);

- allow System Management to dispatch DSPs outside of the nominated availability period on a best endeavours basis (refer to the proposed changes to clause 7.6.10);
- restrict a DSP from selling, via its RD, more capacity than it buys through the IRCR (refer to the proposed changes to clause 4.26.2CA and Appendix 5); and
- ensure that Market Customers pay Reserve Capacity Deficit refunds for any unfilled portion of a DSP, consistent with the application of refunds to any other Market Participant not able to meet its obligations (refer to the proposed changes to clause 4.26.1A(a)(vii)).

For full details of the Rule Change proposal please refer to the Market Web Site: http://www.imowa.com.au/RC_2013_10.

3.2. The IMO's Initial Assessment of the Rule Change Proposal

The IMO decided to proceed with the proposal on the basis that Rule Participants and stakeholders should be given an opportunity to provide submissions on the Rule Change Proposal.

3.3. Protected Provisions, Reviewable Decisions and Civil Penalties

Clause 2.13.9 of the Market Rules is a Protected Provision. The IMO has proposed amendments to this clause to remove the obligation on System Management to monitor Rule Participants for breaches of the requirements under clause 4.10.2, as the clause is proposed to be deleted.

Clause 4.10.2 has an associated Category C civil penalty under the *Electricity Industry (Wholesale Electricity Market) Regulations 2004* (Regulations). The IMO has proposed to delete this clause to relax the requirements for Facilities to have 'firm fuel' supply contracts in place. The Regulations will need to be amended to reflect this change.

The proposed Amending Rules will also introduce three new clauses, 2.35.3A, 2.35.3B and 2.35.3C. The IMO considers that these clauses should have an associated Category A civil penalty under the Regulations to align the treatment with other requirements in clause 2.35.

The IMO has engaged with the Public Utilities Office to discuss the proposed Amending Rules in relation to this Rule Change Proposal.

4. Consultation

4.1. The Market Advisory Committee

The RCMWG was established by the MAC and met on 12 occasions between February 2012 and February 2013. While not unanimously accepted, the RCMWG members generally supported the changes proposed in this Rule Change Proposal. Details of the analysis and discussions of the RCMWG are available at http://www.imowa.com.au/rcmwg.

On 12 June 2013, the MAC discussed a concept paper[4] outlining the changes proposed to harmonise requirements for demand-side and supply-side capacity resources. In particular MAC members discussed the following:

- With respect to fuel requirements for DSPs, Mr Andrew Sutherland suggested that the IMO had correctly captured the sentiments of the RCMWG in the discussion of the issue, however the proposed drafting of the rules seemed inconsistent with these outcomes and appeared to be overly prescriptive.

- With respect to the revised DSM availability requirements, Mr Geoff Gaston noted his concern with how System Management may interpret its "best endeavours" requirement to provide day-ahead notice of potential dispatch to DSPs. Some MAC members noted that System Management should not feel that it could not dispatch if it was unable to provide a "best endeavours" day ahead notice. Ms Jenny Laidlaw suggested that an alternative approach could be a requirement for a Dispatch Advisory to the market if it was likely that a DSP would be dispatched in the next balancing horizon. The MAC generally supported this suggestion. Mr Phil Kelloway noted that System Management would most likely issue a Dispatch Advisory in this circumstance. Mr Stephen MacLean suggested that the requirements could be incorporated into the relevant procedures and be excluded from the Market Rules.

- Mr Steve Gould also suggested that the phrase "unlimited" be removed from the proposed table and replaced by the maximum possible hours per year and dispatch events per year, given the numbers are finite.

- With respect to real-time telemetry for DSPs, Mr Peter Huxtable enquired as to the cost per site for the implementation of a telemetry service. Mr Kelloway responded that it was pertinent to ascertain what the benefits would be in conjunction with what costs would be incurred. Mr Sam Beagley noted that following discussion with System Management it was determined that there was more than one option to achieve this, some of which were more automated than others. He further stated that real-time telemetry was required to achieve the benefits of this package of reforms more broadly.

- Mr Kelloway noted that if DSPs were in the Balancing Merit Order (BMO) and were treated exactly the same as generators than the standards required would be the same as a generator however DSPs are not currently included in BMO.

- With respect to the dispatch of DSPs outside nominated availability, Mr Michael Zammit noted his concerns with the drafting around capacity refunds as he did not believe that it adequately reflected what was discussed in the RCMWG meetings. He indicated his view that refunds should link to the RCM, not an energy price. Mr Beagley replied that the IMO was looking at three options and that the suggested changes to the formula in clause 4.26.3A were still under consideration by the IMO.

- Mr Gaston queried whether a generator would be required to generate at its maximum level, which may be above its level of certified capacity, before facilities on the Non-Balancing DMO were dispatched. MAC members agreed that this was the case

[4] See agenda item 5(a) available at http://www.imowa.com.au/docs/default-source/Governance/Market-Advisory-Committee/combined_mac_mtg_61_papers.pdf?sfvrsn=2

although currently there would be no refunds as a consequence of not being available for capacity over and above a Facility's certified level.

- With respect to the relationship between the IRCR and RD, Mr Gaston queried whether the IRCR was adjusted to reflect any excess capacity, noting that this would mean that the IRCR may be higher than the physical capabilities of a Facility.

These issues were further developed in the IMO's pre Rule Change Proposal which was discussed by MAC members at the 7 August 2013 meeting. At this meeting, the MAC discussion was focused on the proposal to implement the requirement for real-time telemetry for DSPs.

- Mr Shane Duryea noted that the proposed options were ambiguous with regard to the reference between System Management and Western Power Networks. The Chair suggested this confusion might have resulted from the entity that provided the information to the IMO.

- The Chair noted the IMO believed it would be simpler and cause less confusion to proceed with option two, being the web-based solution.

- Mr Gaston questioned whether the intent of issue three was to achieve 'real-time' data from each DSP or every Associated Load. The Chair noted it was the IMO's intent to receive data at the Associated Load level. Mr Gaston supported this approach.

- Mr Kelloway noted that further work will be required before System Management could commit to a solution to receive and manage data at the Associated Load level.

- Dr Paul Troughton highlighted that the costing of option one did not include costs for each DSP to provide its terminal for communication between the Associated Loads, therefore making option one a less attractive choice. Dr Troughton subsequently concurred with the Chair that option two was the premium solution.

The following general comments and questions were also raised by MAC members:

- Dr Troughton identified a potential issue with the current approach to re-designing the Non-Balancing DMO. As there is a lag of 24 hours between the Non-Balancing DMO and the data used to formulate it, the current structure does not account for a DSP that is dispatched on the Scheduling Day. Mr Beagley noted Dr Troughton's concern and committed to consider this further.

- Mr Gaston suggested that this approach to the Non-Balancing DMO incentivised all providers to price the same. Dr Troughton confirmed that this was already the case. Mr Gaston also raised the concern that DSPs were incentivised to disaggregate to make them less likely to be dispatched. Ms Laidlaw stated there was nothing stopping System Management from dispatching multiple DSPs at the same time. Mr Greg Ruthven also stated that under the current Market Rules, System Management must dispatch larger DSPs first but that this PRC_2013_10 would remove that criterion.

- Mr Andrew Sutherland enquired as to the ability of DSM aggregators to move Associated Loads between DSPs. Mr Ruthven stated that this is possible under the Market Rules but was a registration process that took a number of business days.

- Mr Huxtable questioned the new process for the relaxation on the thermal fuel requirements and how the IMO would assess this. Mr Ruthven noted that this would be addressed in the relevant Market Procedure. Mr Beagley noted that proposed amendments to the Market Procedure would be available during the Rule Change Process to allow stakeholders to consider these changes when preparing submissions. Mrs Jacinda Papps highlighted that it could be difficult to make submissions on a rule change without knowing the changes to the relevant Market Procedure. The Chair confirmed the aim was to present the relevant Market Procedure at the next IMO Procedure Working Group due to be held in September 2013. This would provide submitting parties with the opportunity to comment on the changes to the Market Procedure prior to the conclusion of the consultation period for this rule change.

- Mr Gaston requested clarification on the principle presented in issue seven [restricting a market customer from selling more capacity that it buys]. Mr Ruthven confirmed that this was consistent with the principle ultimately accepted by the RCMWG. Mr Gaston noted that it was not unanimously accepted by the RCMWG. Mr Ruthven also noted that he was aware of that it was not unanimous but that the RCMWG on balance accepted this approach. Mr Gaston stated he did not understand the logic behind using the IRCR values multiplied by 1.65 because it would not result in a lower number. Noting that RD was a physical number and IRCR was a value that could never be provided.

The MAC agreed that, subject to clarification of the implementation of telemetry for Market Customers with DSPs and other minor adjustments to the Non-Balancing DMO, the IMO would submit the Rule Change Proposal into the Standard Rule Change Process.

Further details are available in the MAC meeting minutes available on the Market Web Site: http://www.imowa.com.au/MAC.

4.2. Submissions received during the first submission period

The first submission period for this Rule Change Proposal was between 22 August and 3 October 2013. Submissions were received from Alinta Energy, Community Electricity, EnerNOC, Newmont Mining Services, Perth Energy, Synergy and System Management.

An assessment by submitting parties as to whether the proposal would better achieve the Wholesale Electricity Market Objectives is summarised below:

Submitter	Wholesale Market Objective Assessment
Alinta Energy	None provided.
Community Electricity	Considers that the proposed rule change considerably improves Wholesale Market Objective (a) and on balance improves Wholesale Market Objectives (b) and (c). Raised concern that the telemetry requirements discriminate against small participants and potentially exclude small customers from participation.
EnerNOC	Considers that the proposed changes, implemented as a package will facilitate all five of the Wholesale

Submitter	Wholesale Market Objective Assessment
	Market Objectives.
Newmont Mining Services	Considers the proposed rule changes associated with issues 2, 3 and 5 will not facilitate achievement of objective: (a) due to the significant costs which will ultimately be passed on to consumers; (b) because the costs will reduce DSM participation in the market; (c) because of the barriers to entry created by the IT requirements; (d) because the cost of capacity will not change and the cost of implementing the rule change will increase Market Fees; and (e) the changes will discourage measures to manage consumption because consumers will be unwilling to participate in DSPs due to the increase in availability required.
Perth Energy	Considers the proposal will positively impact on the ability to achieve objective (a), (b), (c) and (d) as follows: (a) by improving efficiency of dispatch and utilisation of these capacity providers and removing unnecessary restrictions on providers of generation capacity; (b) and (c) due to the more equitable treatment of supply-side and demand-side capacity; and (d) by removing some of the costs of inefficient over-supply of capacity. Considers that further harmonisation of the obligations on capacity providers would further improve the ability to achieve the Wholesale Market Objectives.
Synergy	None provided.
System Management	Does not believe that all aspects of the proposal support the Wholesale Market Objectives, in particular in relation to objective (a): • the proposal does not promote the reliable production and supply of electricity; and • the proposal does not promote reliability as it reduces the incentive for both generators with non-firm fuel and DSPs to be available.

A copy of all submissions in full received during the first submission period is available on the Market Web Site: http://www.imowa.com.au/RC_2013_10.

4.3. The IMO's response to submissions received during the first submission period

The IMO's response to each of the issues identified in submissions received during the first submission period is presented in the table on the following page.

No	Submitter	Comment/Change Requested	IMO's Response
General			
1.	Alinta	Alinta is generally supportive of the IMO's proposal to harmonise the treatment of DSM with generation resources, but any changes to the Reserve Capacity Mechanism should be postponed and considered as part of the wider review of the WEM.	The IMO notes Alinta Energy's concerns with respect to the wider review of the market expected to be commenced by the Government in the near future. However, the IMO considers it appropriate to continue to progress reforms that are underway to ensure that the Market Rules remain relevant, in particular as it is unclear as to the expected timing and scope of the review.
2.	Alinta	Despite the proposed changes to the treatment of DSM it will not be the case that it is actually harmonised with traditional generation technologies. DSM will continue to not pay market fees; to have reduced availability requirements when compared to generation; to not be in the BMO; to have lower capital costs compared to generation – for which they are over compensated for; and will continue to not have its performance appropriately measured. While some of these differences in the treatment of DSM may be appropriate it is evident that the concept of treating DSM the same as generation capacity is neither practical nor reflective of the actual value contribution that the alternative technologies provide in meeting system peaks. It is simply not true that DSM capacity is the same as generation capacity.	The IMO acknowledges that supply-side and demand-side resources have inherently different characteristics. However, the intent of this Rule Change Proposal is to progress multiple changes to achieve congruity of different resources to improve the alignment between both the compensation and obligations of supply-side and demand-side resources as far as practical. It should be noted that a concept paper regarding the allocation of Market Fees was proposed by Bluewaters Power and was considered by MAC members at the November 2013 meeting. This proposal is likely to be progressed in an attempt to recover costs on a causer-pays basis. In addition, the IMO notes that introducing demand-side capacity into the Balancing Market is item number 17 on the Market Rules Evolution Plan and is expected to be progressed further in the medium term. This Rule Change Proposal is intended to provide a basis for further reforms in this area. The IMO acknowledges that DSPs may have lower capital costs however the actual capital cost of the capacity is not relevant to the Reserve Capacity Price paid for each MW of capacity available in the market. Similarly, different types of generation capacity have differing fixed and variable cost structures but receive the same capacity and energy prices. The proposed treatment therefore ensures that Wholesale
	Alinta	Alinta supports considering the introduction of differential pricing for DSM. That is DSM would receive a lower capacity payment (via either a reduced price or quantity) and a higher energy payment (for example based on an administratively set price cap that would allow DSM to recover its reasonable variable costs) which would provide a greater incentive to DSM to be dispatched off. If DSM were to receive a higher energy payment and	

		lower capacity payment very different behaviour to that currently incentivised under the RCM would likely result. DSM would want to be dispatched during peak periods in order to receive high energy payments, whereas currently DSM is best off if they are not dispatched (particularly given the high opportunity cost of some Associated Loads). Shifting DSM to be a predominantly energy based product would potentially change the nature of the loads that are associated with a DSP by encouraging those loads that actively want to be dispatched in high energy cost periods and removing those loads that are simply hoping to never be called and yet be compensated by the capacity mechanism. Alinta considers that these inherent underlying differences between DSM and traditional peaking generation would be more appropriately accounted for by further incentivising performance of the facility during times where it actually becomes a "physical" facility i.e. during a dispatch event.	Market Objective (c) is met, which is designed to avoid discrimination in the market against particular energy options and technologies. The IMO considers that any discrimination with respect to requirements and/or pricing between supply-side and demand-side resources would be inconsistent with Wholesale Market Objective (c). The IMO notes that the measurement of the performance of DSPs has been raised by Rule Participants and is included in the IMO's suggestions log for further consideration.
	Synergy	In its submission to the ERA's 2012 Annual WEM Report to the Minister for Energy, Synergy noted a number of attributes differentiate DSM from conventional generation capacity such as it being naturally limited in its performance in providing capacity. This is because participating in the RCM is secondary to the primary function of a load which is producing widgets. Synergy posited that a better outcome than seeking to "harmonise demand side" would be achieved by recognising that DSM is a limited product and developing compensation measures that take account of its underlying cost structure and encourage positive dispatch response. In particular, Synergy noted that DSM cost structures do not align with that of a 160 MW OCGT and are typified by a low fixed cost and high opportunity cost of dispatch. Designing a compensation scheme along these lines would	

		undoubtedly improve market efficiencies as total payments by the market would be reduced in a typical load year.	
3.	System Management	System Management believes the “equivalenceing” of DSP to supply side refunds should not be based only on availability, and must recognise that DSP are only expected to be dispatched after all supply side options have been exhausted and so face a minimal risk of facing capacity refunds. Even on Peak load days it is unlikely that DSP’s will be called in the near future as the amount of capacity from generation is well in excess of the demand. System Management also notes that to be truly equivalent, DSP should also be paid the availability payment per trading interval for the trading intervals they are available as per supply side facilities.	The IMO notes that the intent of the Rule Change Proposal is to improve the alignment of the availability requirements of supply-side and demand-side resources to the extent possible. The IMO considers that a change in the capacity payment methodology to be on a Trading Interval basis is out of scope for this Rule Change Proposal. Such a change would require detailed analysis of the economic value of capacity in each trading interval, and would need to be applied on a consistent basis to supply-side and demand-side capacity. However, the IMO notes that when RC_2010_29 was developed, clause 4.26.1A(a)(vii) was drafted such that Market Customers are currently not required to pay Reserve Capacity Deficit refunds for an unfilled portion of a DSP. The IMO considers that this is a further change that should be made to align supply-side and demand-side capacity resources and has therefore proposes to amend clause 4.26.1A(a)(vii) as part of this Rule Change Proposal.
4.	System Management	The Rule Change Proposal includes a letter from PA consulting in regard to the reliability assessment. The letters states that the methodology uses a Load Duration Curve and Expected Unserved Energy criterion. System Management is of the view that a times series analysis is required to be able to account for the unavailability of DSM during non-Business Days. Additionally, this analysis does not indicate Market rule 4.5.12(b) is accounted for in determining the minimum generation quantity.	The methodology used by PA Consulting in formulating the reliability assessment is in line with the methodology used in determining the 2013 Availability Curve Analysis. The IMO notes that PA Consulting specifically states (page 49 of 52) that clause 4.5.12(b) is accounted for in the methodology and assumptions used in determining the reliability assessment. The IMO therefore considers that the underlying analysis and resulting proposed Amending Rules are adequate.

Issue 1 – Fuel requirements			
1.	Alinta	Alinta notes the IMO's assessment that there are sufficient commercial incentives in place to ensure generators secure sufficient fuel supply. However if any facilities fail to perform during peak events because they have failed to secure fuel then it would be appropriate for the IMO to take this into account during subsequent capacity certification processes. This would ensure participant's behaviours remain in line with the intention of the capacity mechanism – that is to provide sufficient reliable capacity to meet the WEM's peak requirements.	As noted by Alinta, the IMO believes that there exists sufficient incentives for Facilities to be available during peak periods. It should also be noted that the IMO is currently developing a Rule Change Proposal to amend the Reserve Capacity Refund regime to increase the incentive to be available for all types of capacity. The IMO agrees with Alinta that performance of Facilities during peak demand events is a valid consideration when assessing applications for Certified Reserve Capacity. The IMO considers that clause 4.11 of the Market Rules allows the IMO to take such performance into consideration.
2.	Perth Energy	Perth Energy agrees with the proposal to remove the requirement to have 14 hours of uninterrupted fuel available for Scheduled Generators as there are other commercial and risk based incentives that support provision of adequate fuel supply. The IMO may wish to consider whether there may be value in having some generators (a system safety net) maintaining verifiable, uninterrupted fuel supplies, for example via a dual fuel set up. This could be set up as an ancillary service to improve reliable operation of the SWIS in a situation similar to the 2008 Varanus Island incident.	The IMO notes Perth Energy's support for the removal of the fixed fuel requirement in the Market Rules. The IMO recognises that the Market Rules currently provide no incentive for generators that are capable of running on more than one fuel type, yet require that additional Reserve Capacity Tests are performed on such Facilities. The IMO has previously highlighted the potential development of incentives for investment in dual fuel equipped electricity generation Facilities. Such an initiative was proposed in the Strategic Energy Initiative *Energy2031* Direction Paper. However, the Strategic Energy Initiative *Energy2013* Final Paper did not include the development of incentives for dual fuelled generation among the listed strategies. Further, the Public Utilities Office advised the MAC in August 2012 that it considered that the market had changed since the initial recommendation was made and the development of such an incentive mechanism was not a high priority at present.
3.	System Management	The proposed rule change deletes Clause 4.10.2 which prevents a facility claiming to be Dual Fuel unless it has alternative fuel for 12 hours on site. This removal has perverse flow on effects for facilities registered as dual fuel facilities. Such a facility can be registered with a non-firm primary fuel (generally gas) and an alternate fuel of liquid. Even with no alternate	The IMO notes that the changes to the Certification of Reserve Capacity for Facilities with dual fuel sources will not change the requirement for these Facilities to meet the Reserve Capacity Testing requirements. Furthermore, the IMO notes that the changes with respect to certification will not affect a Market Participant's ability to offer capacity generated by both its primary and secondary

		fuel available this facility is still able to offer at the Alternative STEM Price.	fuel sources into the energy market.
Issue 2 – Availability requirements			
1.	EnerNOC	Issues 2 and 4, which greatly increase the potential dispatch hours for DSPs, as well as lengthening the hours for which they must be available for dispatch, will cause a reduction in the capacity available from end-use customers currently participating in Demand Side Programs (DSPs). Some customers may need to cap their commitments, and thus rely on being paired with other customers so that between them they can meet the market's requirements in full. In such a scenario, however, reserve capacity payments would need to be shared between participating customers, reducing the attractiveness of the programme compared to current arrangements. Other end-use DSM providers may simply exit and terminate their ongoing participation in a DSP. It may be possible to procure additional capacity from new customers to make up the deficit; otherwise, the capacity offered by demand response providers like EnerNOC may have to be reduced when these changes come into force.	The IMO acknowledges EnerNOC's concern and expected impacts. However, the IMO considers that increasing the required availability of demand-side resources will improve alignment between capacity sources and better serve Wholesale Market Objective (c). The IMO is aware that existing DSM providers have made commitments through to the 2015/16 Capacity Year. Consequently, the IMO proposes that the availability requirements not be changed until the 2014 Reserve Capacity Cycle (2016/17 Capacity Year).
2.	Perth Energy	With the proposed amendments there will continue to be two very different Availability Classes for capacity providers with different obligations attached to delivery of what should be a homogenous product (capacity). Perth Energy questions the value for money and reliability attached to capacity provided by demand side measures compared to conventional capacity provided by Scheduled Generators. Ultimately, it is end users in the SWIS that will be burdened by additional costs and reliability issues flowing from continuing to have an unnecessary and inefficient system where some capacity has more lenient	The IMO notes that many capacity markets around the world, including the RCM in the WEM, allow for the allocation of Capacity Credits to both supply-side and demand-side capacity. This is because, at a point in time, there is no functional difference between a MW of generation and a MW of reduced consumption. As previously noted, this Rule Change Proposal is intended to provide a basis for further reforms in this area, including incorporating demand-side capacity into the Balancing Market.

		performance obligations attached without this being reflected in a reduced price for that capacity Perth Energy urges the IMO to conduct a further review of this part of the Market Rules as soon as possible to remove the remaining differences in treatment of capacity across the system. The review should include the option of removing DSM providers from the capacity mechanism altogether and instead developing a specific ancillary service product for DSM providers to complement capacity and/or energy requirements in the SWIS.	
3.	Perth Energy	Perth Energy agrees with the proposed amendment to the Market Rules to compel System Management to issue Dispatch Advisories to DSM providers 24 hours before a likely dispatch event. However, if System Management, for whatever reason, failed to issue a Dispatch Advisory this should not detract from the DSM provider's obligation to comply with a Dispatch Instruction from System Management to reduce load. Perth Energy would welcome clarification from the IMO in relation to this point.	Under the Market Rules a DSP provider must respond to a Dispatch Instruction from System Management with two hours, regardless of whether a Dispatch Advisory is released. If System Management does not issue a Dispatch Advisory within 24 hours of dispatch and the condition of clause 7.11.5 of the Market Rules is met, then it would be in breach of the Market Rules. The IMO therefore considers it unlikely to occur, but will have appropriate compliance measures in place.
4.	System Management	System Management estimates the current refund mechanism is in the order of 0.25 times the monthly capacity payment per trading interval, a strong incentive for a DSP to make its capacity available. The new formulation of rule 4.26.3A makes this around 0.004 times the monthly capacity payment per trading interval, a significantly weaker incentive. (this assumes a daily availability of 6 hours per day and TIRR is monthly capacity price divided by the number of trading intervals in the month).	This Rule Change Proposal presents multiple changes to better align the requirements and obligations with respect to demand-side capacity with those that currently apply to supply-side capacity. The comparatively punitive refunds that currently apply to DSM providers are a function of the low availability requirements. The IMO considers that it is appropriate to reduce the severity of the refund exposure for DSM providers in line with the increase in availability requirements. In addition, there are other avenues that are provided for in the Market Rules to incentivise the availability of demand-side capacity, including civil penalties for failure to respond to Dispatch Instructions, the Reserve Capacity Testing regime to ensure that a DSP can respond when

			dispatched and an ability for the IMO to reduce of remove capacity payments for future certification.
5.	Newmont Mining Services	The increased availability requirements will act to deter electricity consumers from participating in a DSM program. This additional availability will potentially have a significant impact on the ability of a business to earn revenues. Whilst it is acknowledged that the actual dispatch of the DSM facility may be much less than 1500 hours/year, a prudent business, when making a risk assessment of whether to participate in a DSM program, will adopt a conservative "worst case" view of needing to shut down operations for a figure approaching 1500 hours/year, and in any case much more than the current 24 hours/year. Newmont is of the view that it is highly likely significantly fewer businesses will participate in a DSM program and participation in DSM will fall from the current levels to near zero from 2016/17 onwards. Whilst the initial fall in DSM may well be handled by existing generation capacity, ultimately the proposed changes must result in the construction of new generation being brought forward to fill the gap left by "departing" DSM providers. This will result in unneeded and inefficient capital expenditure by generation providers. The lower level of DSM participation by business will also likely result in more DSM calls on those businesses which do participate as there will be less participants to spread DSM calls over.	The IMO notes the points raised by Newmont. As noted above, the IMO has introduced the Rule Change Proposal to increase the required availability of demand-side resources to better align with that currently required from supply-side capacity and therefore better achieve Wholesale Market Objective (c). The IMO notes that the analysis undertaken by Dr Tooth on behalf of the RCMWG indicates that the dispatch of 100 hours/year is extremely unlikely (for further analysis see http://www.imowa.com.au/docs/default-source/Governance/Market-Advisory-Committee/MAC-Working-Groups/agenda_item_5-_rcm_ircr_-_ws_novdraft_rt_.pdf?sfvrsn=2) Dr Tooth highlighted that a situation where System Management was required to dispatch for a large number of hours would only occur in situations that would likely align to a high risk operating state where large curtailments during peak period are required. It would therefore be likely that Loads would be turned down or off, without payment. In such an event, DSPs' Associated Loads would receive advanced notice of the curtailment and be compensated on dispatch.
Issue 3 – Real-time telemetry			
1.	Community Electricity	We would suggest that extra care be taken in specifying the requirements for real time telemetry and that this should be fit-for-purpose and data should be collected only if it is needed and will be used. In particular, we note that the Amending Clause 2.35.3C	The IMO's intention is to gather information about the capacity able to be provided by a DSP at any one time to improve the ability for System Management to be able to dispatch demand-side capacity. This is consistent with the visibility that System Management has of supply-side

		requires that five minutes prior to a Trading Interval, the participant must provide to System Management (via the B2B Web Service) both the current consumption of the Demand Side Programme, plus the consumption of each Associated Load within the programme. On the face of it, this seems to be an excessive level of detail. We also note that individual market participants are expected to incur a cost in the range of $100,000 to $200,000 each, which is comparable to the costs to be incurred by both System Management and the IMO. The likely upshot of this will be to exclude from the market sufficiently small Associated Loads because of the disproportionate telemetry costs. This will effectively disadvantage small DSM Providers and lock out smaller customers from the cost reduction benefits offered by DSM.	capacity. The IMO notes that real-time telemetry is required to achieve the benefits of this package of reforms more broadly. The IMO understands that many DSM providers already have telemetry at the Associated Load level. The IMO's intention at this stage is to leverage these existing systems. The IMO notes the estimated up-front cost of providing telemetry is between $350,000 and $450,000 for each Market Customer with a DSP and a further ongoing cost of between $50,000 and $100,000 to monitor and maintain systems. While this is a significant cost, the IMO considers that the benefit of increasing the economic value of this capacity far outweighs the cost. The IMO will continue to work with System Management and DSM providers to ensure that the specifications, when developed, are not unduly burdensome. For example, the IMO will explore the possibility of utilising existing metering equipment to meet the telemetry requirements.
	EnerNOC	DSM providers and DSP operators will incur costs implementing the telemetry requirements introduced in Issue 3. It is difficult to estimate these costs without a full appreciation of the details of the obligations and technical requirements, which will be specified in the Power System Operating Procedures.	
	Perth Energy	Perth Energy welcomes the roll-out of telemetry to DSM providers. This will provide System Management with much better tools in real time to understand the availability of capacity from demand side providers. Perth Energy notes that there is a requirement to amend certain Market Procedures to enable this change. We would welcome consultation on any such amendments as soon as possible so that Market Participants can get certainty around the new arrangements to allow them to develop any necessary changes to internal procedures and systems.	
	Newmont Mining Services	The additional cost of the IT requirements will decrease the economic returns to DSM providers, and for smaller providers, eliminate totally any financial	

		benefit from DSM. The IMO has estimated a DSM participant's costs to implement IT systems of $100,000 to $200,000. It is unclear whether this is a one-off cost (in which case the ongoing costs have not been specified) or an annual cost. We note that revenue from a DSM program in the order of 1000kW would be required to cover the cost of such a system. There are several current DSM programs of that size already registered with the IMO and we understand that DSM aggregators active in the SWIS have many small loads associated with their programs. It is likely these smaller loads will exit the DSM programs because of this cost. It is also understood that near real time information about DSM load status is available from existing Western Power metering equipment if configured to suit. It is unclear why the IMO has not given consideration to using this equipment rather than imposing additional costs on potential DSM providers.	
3.	System Management	System Management understands that this proposal for real time data of associated loads was not discussed at the RCMWG or included in the PRC_2013_10 considered at the MAC meeting of 7 August 2013. System Management believes the value of each associated load is not relevant for dispatch, it is the value of the DSP that is important. The requirement to telemeter each associated load is additional cost that has no demonstrable benefit.	The IMO acknowledges that the available capacity at the Associated Load level is not required for dispatch purposes. However, this information is valuable for the IMO and System Management to ensure data integrity and transparency. The availability of this information will also contribute to the IMO's ability to further reform the market to increase the economic value of capacity and the overall efficiency of the market. The IMO understands that, to be able to accurately assess the total consumption of the associated loads within a DSP, a provider will need to capture this information regardless. The only additional cost incurred is to transfer the data to System Management. The IMO does not believe that this is likely to be a significant additional cost.
	Synergy	Synergy has concerns about elements of Issue 3 which addresses the arguments for real-time telemetry services for DSPs. Currently, while the non-balancing dispatch merit order provided by the IMO enables System Management to select and issue dispatch instructions to DSPs in accord with clause 7.6, no information is provided about the real-time status of the DSPs. It is stated in the proposal that the lack of	

		real time information about DSP consumption levels impacts System Management's confidence in the use of DSM and that this justifies imposing a requirement on Market Customers to provide System Management with half-hourly updates of consumption at both the DSP Facility and Associated Load levels. Synergy accepts that there may be merit in providing System Management with information about the consumption status of DSP Facilities. It may assist System Management, in the context of working through the non-balancing dispatch merit order, in deciding how much DSP capacity needs to be dispatched to achieve a targeted reduction in load. However, Synergy can see no reason to mandate that consumption level information in respect of each Associated Load comprising a DSP Facility also be provided to System Management. Synergy doubts this will assist System Management in undertaking their decision-making functions in regard to dispatching DSP Facilities. In fact, given that a DSP Facility may comprise many Associated Loads, some offering less than 100 kW, Synergy suggests that providing such information, merely because of its sheer volume, will hinder rather than assist the dispatch decision process which Synergy notes is taken at Facility level.	
4.	System Management	Dispatch Instructions require a DSP to be given as "a required decrease in consumption, in MW". It is unclear as to how this can be monitored if the initial starting level is not defined. This monitoring obligation will result in additional costs to System Management. As it is unclear what is required by this obligation it is not possible to determine what these costs will be and if there are any additional benefits from the current rule monitoring performed by the IMO.	The IMO considers that, with the telemetry data being provided to System Management, when it is required to dispatch demand-side resources, it should be able to assess the current operating level of the DSP and use that information to appropriately dispatch the necessary Facility. Further, in the interests of harmonising the requirements for supply-side and demand-side capacity, the IMO considers it appropriate that DSPs be subject to the same obligations and monitoring as generators in respect of compliance with Dispatch Instructions.

5.	Synergy	Synergy notes that the cost analysis presented in table 2 of the rule change proposal is limited: it only provides estimated cost information related to the cost for System Management to provide a B2B Web Service for DSPs; it does not include any allowance for the costs to be incurred by DSP providers. Synergy suggests that without such information it is difficult to draw conclusions about the cost-benefit of the proposed changes especially in regard to mandating that consumption status information be provided to System Management at the Associated Load level. Accordingly, until such time as an unambiguously favourable cost benefit can be made in regard to providing information at the Associated Load level, Synergy recommends that proposed new clause 2.35.3C(b) be deleted from the rule change proposal.	The IMO is working with DSPs to get a better understanding of the additional costs for a DSP provider. From initial discussions, it is likely that DSP providers will incur moderate up-front fixed costs to facilitate the data transfer to System Management. However, the IMO considers that the determination of the aggregate consumption of Associated Loads in a DSP would necessarily require monitoring of each of the Associated Loads. Consequently, the only incremental cost should relate to the increased volume of data to be transmitted.
Issue 5 – Non-Balancing DMO			
1.	Perth Energy	Perth Energy supports the proposed amendments to the tie breaker rules in the NBDO to remove the current dis-incentive on aggregating into large DSM programmes. However, to further harmonise the treatment of all capacity providers we would like to see DSM programmes included in the normal Balancing Merit Order with all other providers of capacity.	The IMO notes the issue raised by Perth Energy. It has been agreed by MAC members that introducing demand side capacity into the Balancing Market is an area of reform and is currently item number 17 on the Market Rules Evolution Plan. This Rule Change Proposal is intended to provide a basis for further reforms in this area. Such reforms are expected to be progressed further in the medium term.
2.	System Management	System Management believes there is also a lack of clarity about DSP instructions as it appears in Market rule 7.13.1(b) and (g). System Management believes it should only send this information once and as such this Rule Change Proposal should remove its requirement from 7.13.1 also. This now creates an additional information transfer timeline between System Management and the IMO which requires extra resources to ensure a correct transfer. A rationalisation of these transfers should be considered.	While developing this Rule Change Proposal the IMO worked with System Management to look at the appropriateness of this data transfer time in-line with existing processes. Without this data the Non-Balancing DMO would not take into consideration the Dispatch of a Facility during the Scheduling Day and subsequently make the ability to address several issues identified in this Rule Change Proposal limited. This information is therefore necessary. The IMO considers that the data required for the IMO to release a timely and accurate Non-Balancing DMO is very

			separate to the existing requirements under clause 7.13.1 and therefore should remain separate. However the IMO will continue to work with System Management to determine an appropriate and efficient data transfer solution.
3.	System Management	System Management notes it must give Dispatch Instructions for Dispatchable Loads to the IMO at 6.30 PM. Dispatchable loads are closely related to a scheduled generator and would normally sit within the definition of "Balancing Facility". The balancing rules have essentially deferred treatment of Dispatchable Loads. It is inconsistent to include them at this time.	The IMO notes that Dispatchable Loads are included with DSPs in the Non-Balancing DMO. Therefore, the IMO considers it appropriate that System Management provides the Dispatch Instructions for both DSPs and Dispatchable Loads to the IMO in order to facilitate the development of the Non-Balancing DMO.
4.	Newmont Mining Services	The proposed changes to the DMO state that all facilities (generation and DSM) with the same price will be ranked on the basis of the time since last dispatch. As DSM and many of the liquid generation facilities price at the Alternative Maximum STEM Price the result of the ranking will be that DSM facilities will be dispatched in a "round-robin" with liquid fuelled facilities. Our understanding of the current arrangements is that all generation facilities are dispatched before any DSM is dispatched, perhaps because System Management is holding the limited DSM resource in reserve for when there are more pressures on the SWIS. Thus the proposed changes will result in more frequent dispatch of individual DSM participants. This will also be taken into account by businesses when making a decision to participate or not participate in any DSM program, as it increases the likelihood of being dispatched up to the 1500 hours in a year.	The proposed changes relate to the Non-Balancing DMO, not the Balancing Merit Order. Newmont is correct that all facilities in the Balancing Merit Order are likely to be dispatched prior to the dispatch of Facilities on the Non-Balancing DMO. Liquid-fuelled generators are listed in the Balancing Merit Order, so are not impacted by the proposed changes. It should be noted that System Management has the discretion in a High Risk Operating State to preserve fuel stocks and may dispatch DSM before generation capacity in these circumstances.
Issue 7 – IRCR and Relevant Demand			
1.	Alinta	The IMO's proposal to amend clause 4.26.2CA to restrict a DSP from selling more capacity than it buys through IRCR, while supportive of the general concept, Alinta does not support the IMO artificially	The IMO notes that the calculation of a Facility's Relevant Demand is separate to the calculation of the Facility's IRCR. The IMO is not proposing to merge the determinations of

		inflating the IRCR values by the amount of the relevant NTDL [Non-Temperature Dependent Load] and TDL [Temperature Dependent Load] multipliers (refer to the proposed new step 11 of Appendix 5). Clarification of the rationale for taking into account the multipliers in determining the value of a DSP's Relevant Demand has been raised previously during the deliberations of the MAC on this proposal. Alinta does not consider that clear rationale for the adjustment has been provided at any stage during the relevant consultation process, including within RC_2013_10. It is unclear why the IMO would continue to propose that the multipliers apply for the purposes of determining the "IRCR amount" to cap the DSP's level of capacity credits at without clearly outlining any form of rationale. It is not the case that any other type of facility gets its level of capacity adjusted upwards by any sort of multiplier. The intention of the IRCR is to determine an individual loads' contribution to peak demand and attribute a cost to be borne by the Participant for the installed capacity to service this peak demand requirement. This is different and separate to the intention of Reserve Capacity Certification, which looks to assign a level which reflects the true capability of a facility. The principle of ensuring that a facility is certified at the level which reflects its true ability to provide energy (in this case an energy reduction) at the peak should apply for the purposes of certification across the board. To maintain the adjustment for the multipliers inherently discriminates against generators.	IRCR and Relevant Demand at this time. IRCR estimates the contribution of a customer to the absolute maximum demand on the system and is measured over a very short period of time (only three Trading Intervals on each of four days). Relevant Demand estimates the load reduction that could be achievable over a longer period of time (four hours), on different days across the Hot Season. It also takes into consideration any capacity that it unavailable due to maintenance. For clarification, the Relevant Demand is calculated from the median consumption of Associated Loads in the 32 Trading Intervals described in clause 4.26.2C(a). The calculation uses unscaled meter data and does not include any scaling by the Non-Temperature Dependent Load Ratio or Temperature Dependent Load Ratio. The RCMWG discussed the possible discrepancy that can arise as a result of the separate determinations, whereby a Load may have a Relevant Demand that is higher than its IRCR. This can result in a Load selling more Capacity Credits than it buys, despite it being unable to export energy. The RCMWG agreed that this was a perverse outcome. Further, the IMO considers that the ability to adjust Relevant Demand based on applications to exclude a period where maintenance has been undertaken presents a gaming opportunity for an Associated Load, whereby it can minimise its IRCR obligation and but apply for adjustments to maintain a higher Relevant Demand. To address the possible discrepancy, the RCMWG agreed at its November 2012 meeting to adopt the principle that 'what was not bought could not be sold'. The IMO proposes that this principle is best implemented by capping the Relevant Demand for a DSP at the total IRCR of its Associated Loads, Thus, the NTDL Ratio and TDL Ratio are only relevant to the cap that is proposed to be applied to
	EnerNOC	Issue 7 will result in an artificial limit on the ability of customers to receive value for the full amount of load reduction capability they are capable of providing, to the detriment of both participants and the system operator. However, other changes that were contemplated would have had even worse effects. We	

		are, therefore, able to accept the proposed change as a compromise that will preserve much of the efficacy of the program, albeit with significantly greater effort on the part of DSP operators such as EnerNOC.	Relevant Demand.
	Perth Energy	Perth Energy questions the rationale for using the sum of the IRCR requirement of each individual load within the DSM programme as the constraint in the calculation. The IRCR of an individual load does not in general reflect the amount of demand reduction the load is capable of and therefore the upper limit on the amount of capacity that should be awarded for that load. This is because the IRCR of a load is made up of the following generic components: IRCR = Median MW load during IRCR intervals x specific uplift factor1 x total uplift factor. The uplift factors provide the conduit to allocate additional capacity to loads above and beyond the absolute contribution that the loads made to the system peak. This is necessary to ensure that additional capacity that is required to satisfy the planning criteria (e.g. to meet the 1/10 year peak demand on the system and do so even with the loss of units on the system) is allocated to and paid for by Market Customers. Using the temperature dependent load and total uplift factors published on the IMO's website for October 2013, a load that had a 1MW median read for the IRCR intervals would have an IRCR requirement of 1MW x 1.5925 x 0.9974 = 1.5884MW. Perth Energy suggests that in the example above, the maximum capacity awarded should be 1MW, which represents the actual ability to reduce demand. The higher value represented by the IRCR value is artificially inflated by the uplift factors and that amount of demand reduction is unlikely to be available from the load. Perth Energy proposes to remove the effect of the	

		uplift factors by amending the drafting of clause 4.26.2CA(b). The clause should refer to the "individual median MW Metered Demand during the IRCR intervals" of the Associated Loads in the Demand Side Programme instead of the "Individual Reserve Capacity Requirement Contributions". It will also be necessary to replace the definition of "Individual Reserve Capacity Requirement Contribution" with an appropriate definition of "Individual Median MW Metered Demand during the IRCR Intervals" and amendments to the proposed new step 11 in App 5.	

4.4. Public Forums and Workshops

No public forums or workshops were held with regard to this Rule Change Proposal.

5. The IMO's Draft Assessment

In preparing its Draft Rule Change Report, the IMO must assess the Rule Change Proposal in light of clauses 2.4.2 and 2.4.3 of the Market Rules.

Clause 2.4.2 outlines that the IMO *"must not make Amending Rules unless it is satisfied that the Market Rules, as proposed to be amended or replaced, are consistent with the Wholesale Market Objectives"*.

Additionally, clause 2.4.3 states, when deciding whether to make Amending Rules, the IMO must have regard to the following:

- any applicable policy direction from the Minister regarding the development of the market;
- the practicality and cost of implementing the proposal;
- the views expressed in submissions and by the MAC; and
- any technical studies that the IMO considers necessary to assist in assessing the Rule Change Proposal.

The IMO notes that there has not been any applicable policy direction from the Minister or any technical studies commissioned in respect of this Rule Change Proposal. A summary of the views expressed in submissions and by the MAC is available in section 4 of this report.

The IMO's assessment is outlined in the following sub-sections.

5.1. Additional Amendments to the proposed Amending Rules

Following the first public submission period the IMO has made the following additional changes to the Amending Rules:

- the inclusion of amendments to clause 4.26.1A(a)(vii) to address System Management's concerns raised during the first submission period, by ensuring that DSM providers pay Capacity Cost Refunds for an unfilled portion of a DSP;
- further amendments to clauses 7.11.1 and 7.11.5 to include all Non-Balancing Facilities, rather than just DSPs; and
- further amendments to clauses 4.26.3A and 7.6.10 and Appendix 5 to provide more clarity with regard to the application of the Market Rules.

The changes the IMO has made to the Amending Rules as presented in the Rule Change Proposal are outlined in Appendix 1 of this Draft Rule Change Report.

5.2. Wholesale Market Objectives

The IMO considers that the Market Rules as a whole, if amended as presented in section 7, will not only be consistent with the Wholesale Market Objectives as a whole but also allow the Market Rules to better achieve Wholesale Market Objective (a), (c) and (e).

The IMO's assessment is presented 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.

The key deliverable of any demand-side service is to provide an alternative to generation capacity. Through the harmonisation of supply-side and demand-side capacity the IMO contends that the provision of capacity would be more economically efficient and provide greater reliability to the market. Additionally, it is economically prudent to ensure capacity that is paid for by consumers is available for use.

Having more flexibility in the use of DSPs will give System Management the ability to dispatch DSM as the network requires it, without onerous restrictions. With greater visibility of available DSM for System Management, the operation and dispatch of the service becomes more efficient and cost effective in the long-term.

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

The current Market Rules arguably discriminate between Market Participants who provide demand-side and supply-side capacity. The key principle behind this Rule Change Proposal is to improve the harmonisation of the treatment of the capacity provided by peaking generators and DSPs which provide similar capacity services to the market.

The IMO considers that all Market Participants in the WEM should be treated equally to the extent possible. This Rule Change Proposal provides a basis for further reforms with respect to harmonising the treatment of supply-side and demand-side capacity in the WEM.

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

Through changing the obligations on demand-side resources within the market the IMO intends to enable greater reliability and versatility in the use of DSPs. Through fundamental changes to the way the Non-Balancing DMO is calculated and the way Facilities are dispatched, the IMO is ensuring capacity is appropriately managed. Increasing dispatch hours and events will also give System Management more flexibility in the way in which demand-side capacity is used and when it is used.

With a greater understanding on the amount of DSM available to the market, coupled with the changes in the availability requirements of DSPs, the IMO contends the changes in this Rule Change Proposal better achieve Wholesale Market Objective (e).

5.3. Practicality and cost of implementation

5.3.1. Cost:

The IMO has identified material costs associated with the implementation of the proposed Amending Rules. These costs are primarily related to the new requirements for DSPs.

The IMO has investigated the potential costs for Market Customers related to the requirement for DSPs to implement real-time telemetry. The IMO estimates that the costs are primarily fixed, one-off costs of $350,000 to $450,000 for each Market Customer with a DSP for building and testing new software systems and a further $50,000 to $100,000 per annum for ongoing monitoring and maintenance. However, the requirements for data provision will not be formally defined until the necessary web service is fully defined in changes to be included in the Power System Operation Procedure (PSOP): Communications and Control Systems and Market Procedure: IMS Interface.

In addition, System Management is expected to incur costs of $200,000 to $400,000 to expand the current web service and provide the necessary administration. System Management is currently unable to provide a specific estimate of the cost of the expansion of the current system however, it is expected that the existing functionality can be leveraged.

The IMO is also expected to incur costs of approximately $160,000 to amend IMO systems to provide for the amendments to the validation for certification, methodology for Capacity Credit allocation and settlements and ensure that the necessary telemetry data can be captured and stored as necessary. These costs will be able to be met within the IMO's current resources.

The IMO considers that the identified costs are expected to be far outweighed by the benefits to the market of the increased efficiency and cost effectiveness of the operation and dispatch of the service in the long-term as outlined in section 5.2 of this Draft Rule Change Report.

5.3.2. Practicality:

The IMO proposes to commence the proposed Amending Rules in order for them to apply for the 2014 Reserve Capacity Cycle. Rule Participants should note:

- changes related to certification of Reserve Capacity are proposed to commence no later than 1 May 2014 in time for the opening of the window for applications for Certified Reserve Capacity for the 2014 Reserve Capacity Cycle;

- changes that relate to the IRCR and RD are proposed to commence no later than 1 October 2014 in order to affect year one of the 2014 Reserve Capacity Cycle; and

- changes that impact the operation of DSPs are proposed to commence on 1 October 2016.

The IMO considers that these commencement dates will provide Rule Participants adequate time for the necessary changes to IT and operational systems and processes.

5.3.3. Amendments to associated Market Procedures:

The IMO notes that amendments are required to the associated Market Procedures: IMS Interface, Certification of Reserve Capacity and Reserve Capacity Performance Monitoring, PSOP: Communications and Control Systems and several internal procedures.

6. The IMO's Proposed Decision

The IMO's proposed decision is to accept the Rule Change Proposal as specified in the Rule Change Notice and Proposal with minor changes as reflected in Appendix 1.

6.1. Reasons for the decision

The IMO made its proposed decision on the basis that the Amending Rules:

- better achieve Wholesale Market Objectives (a), (c) and (e);
- are consistent with the remaining Wholesale Market Objectives;
- will improve the reliability and transparency of demand-side resources in the market;
- have the general support of the RCMWG and MAC members.

6.2. Proposed Commencement details

The IMO proposes to commence the majority of the Amending Rules set out in this Rule Change Proposal in order for them to apply for the 2014 Reserve Capacity Cycle as follows:

- changes related to certification of Reserve Capacity are proposed to commence no later than 1 May 2014 in time for the opening of the window for applications for Certified Reserve Capacity for the 2014 Reserve Capacity Cycle; and
- changes that impact the operation of DSPs are proposed to commence on 1 October 2016.

The exception is the proposed changes that relate to the IRCR and RD in clause 4.26.2CA and Appendix 5. These changes are proposed to commence no later than 1 October 2014, in order to apply for the 2014/15 Capacity Year.

7. Proposed Amending Rules

The proposed Amending Rules, as presented in the Rule Change Proposal and amended following the first submission period are as follows (~~deleted text~~, <u>added text</u>):

2.13.9. System Management must monitor Rule Participants for breaches of the following clauses:

…

(h) ~~clause 4.10.2, where System Management is instructed by the IMO under clause 4.25.13~~<u>[Blank]</u>;

…

…

2.29.9A. The IMO must not register a Demand Side Programme where the minimum notice period required for dispatch exceeds <u>two</u>~~four~~ hours as specified in Standing Data.

…

2.35.3A. System Management must develop, in the Power System Operation Procedure, a reasonable method of communication that Market Participants with Demand Side Programmes must use when communicating with System Management under the Market Rules.

2.35.3B Market Participants with Demand Side Programmes must:

(a) have and maintain systems to enable them to use the method of communication referred to in clause 2.35.3A; and

(b) use that method when communicating with System Management under the Market Rules.

2.35.3C. As close as reasonably possible to five minutes prior to the start of a Trading Interval a Market Participant with a Demand Side Programme must provide System Management with the following data:

(a) the then current consumption, in MW, of the Demand Side Programme; and

(b) the then current consumption, in MW, of each Associated Load within the Demand Side Programme,

in the form specified in the Power System Operation Procedure.

…

4.5.12. For the second and third Capacity Years of the Long Term PASA Study Horizon, the IMO must determine the following information:

(a) ~~the forecast capacity, in MW, required for more than 24 hours per year, 48 hours per year and 72 hours per year, determined from the Availability Curve for the Capacity Year developed under clause 4.5.10I;~~[Blank]

(b) the minimum capacity required to be provided by ~~generation~~ Availability Class 1 capacity if Power System Security and Power System Reliability is to be maintained. This minimum capacity is to be set at a level such that if:

i all ~~Demand Side Management~~ Availability Class 2 capacity (excluding Interruptible Load used to provide Spinning Reserve to the extent that it is anticipated to provide Certified Reserve Capacity), were activated during the Capacity Year so as to minimise the peak demand during that Capacity Y~~y~~ear; and

ii the Planning Criterion and the criteria for evaluating Outage Plans set out in clause 3.18.11 were to be applied to the load scenario defined by clause 4.5.12(b)(i), then

it would be possible to satisfy the Planning Criterion and the criteria for evaluating Outage Plans set out in clause 3.18.11, as applied in clause

4.5.12(b)(ii), using, to the extent that the capacity is anticipated to provide Certified Reserve Capacity, the anticipated installed ~~generating~~ Availability Class 1 capacity, the anticipated Interruptible Load capacity available as Spinning Reserve and, to the extent that further ~~generation~~ Availability Class 1 capacity would be required, an appropriate mix of ~~generation~~ Availability Class 1 capacity to make up that shortfall; and

(c) the capacity associated with ~~each~~ Availability Class 2, where this is equal to the Reserve Capacity Target for the Capacity Year less the minimum capacity required to be provided by Availability Class 1 capacity under clause 4.5.12(b).~~:~~

~~i. the capacity quantity associated with Availability Class 4 is the Reserve Capacity Target for the Capacity Year less the greater of the quantity specified under clause 4.5.12(b) and the quantity specified under clause 4.5.12(a) as being required for more than 24 hours per year;~~

~~ii. the capacity quantity associated with Availability Class 3 is:~~

~~1. the Reserve Capacity Target for the Capacity Year less the greater of the quantity specified under clause 4.5.12(b) and the quantity specified under clause 4.5.12(a) as being required for more than 48 hours per year; less~~

~~2. the capacity quantity associated with Availability Class 4;~~

~~iii. the capacity quantity associated with Availability Class 2 is:~~

~~1. the Reserve Capacity Target for the Capacity Year less the greater of the quantity specified under clause 4.5.12(b) and the quantity specified under clause 4.5.12(a) as being required for more than 72 hours per year; less~~

~~2. the sum of the capacity quantities associated with each of Availability Class 3 and Availability Class 4;~~

~~iv. the capacity quantity associated with Availability Class 1 is:~~

~~1. the Reserve Capacity Target for the Capacity Year; less~~

~~2. the sum of the capacity quantities associated with each of Availability Class 2, Availability Class 3 and Availability Class 4.~~

…

4.10.1. Each Market Participant must ensure that information submitted to the IMO with an application for certification of Reserve Capacity pertains to the Reserve Capacity Cycle to which the certification relates, is supported by documented evidence and includes, where applicable, the following information:

…

(e) for a generation system other than an Intermittent Generator:

…

v. ~~subject to clause 4.10.2,~~ details of primary and any alternative fuels, including:

1. where the Facility has primary and alternative fuels:

   i. the process for changing from one fuel to another; and

   ii. the fuel or fuels which the Facility is to use in respect of the application for Certified Reserve Capacity; and

2. details acceptable to the IMO (acting reasonably) and supporting evidence of both firm and any non-firm fuel supplies ~~and the factors that determine restrictions on fuel availability that could prevent the Facility operating at its full capacity~~;

(f) for Interruptible Loads, Demand Side Programmes and Dispatchable Loads:

i. the Reserve Capacity the Market Participant expects to make available from each of up to 3 blocks of capacity;

ii. ~~the maximum number of hours per year the Interruptible Load, Demand Side Programme or Dispatchable Load is available to provide Reserve Capacity, where this must be at least 24 hours;~~ [Blank];

iii. the maximum number of hours per day that the Interruptible Load, Demand Side Programme or Dispatchable Load is available to provide Reserve Capacity if issued a Dispatch Instruction~~called~~, where this must be~~:~~

~~1.~~ not less than ~~four~~ six hours; ~~and~~

~~2. not more than the maximum of the periods specified in clause 4.10.1(f)(vi);~~

iv. ~~the maximum number of times the Interruptible Load, Demand Side Programme or Dispatchable Load can be called to provide Reserve Capacity during a 12 month period, where this must be at least six times;~~[Blank];

v. the minimum notice period required for dispatch of the Interruptible Load, Demand Side Programme or Dispatchable Load, where this must not be more than ~~4~~ two hours; and

vi. the periods when the Interruptible Load, Demand Side Programme or Dispatchable Load can be dispatched, which must include the period between ~~noon~~ 10:00 AM and 8:00 PM on all Business Days;

…

…

~~4.10.2. For the purpose of clause 4.10.1(e)(v), an applicant may not claim that a Facility has an alternative fuel unless the Facility has on-site storage, or uninterruptible supply of that fuel, sufficient to maintain 12 hours of operation at the level of capacity specified in clause 4.10.1(e)(ii).~~

…

4.11.1. Subject to clauses 4.11.7 and 4.11.12, the IMO must apply the following principles in assigning a quantity of Certified Reserve Capacity to a Facility for the Reserve Capacity Cycle for which an application for Certified Reserve Capacity has been submitted in accordance with clause 4.10:

(a) subject to clause 4.11.2, the Certified Reserve Capacity for a Scheduled Generator for a Reserve Capacity Cycle must not exceed the IMO's reasonable expectation of the amount of capacity likely to be available, after netting off capacity required to serve Intermittent Loads, embedded loads and Parasitic Loads, ~~for Peak Trading Intervals on Business Days~~ in the period from:

i. the start of December for Reserve Capacity Cycles up to and including 2009; or

ii. the Trading Day starting on 1 October for Reserve Capacity Cycles from 2010 onwards,

in Year 3 of the Reserve Capacity Cycle to the end of July in Year 4 of the Reserve Capacity Cycle, assuming an ambient temperature of 41^{o}C;

…

4.11.4. Subject to clause 4.11.12, when assigning Certified Reserve Capacity to an Interruptible Load, Demand Side Programme or Dispatchable Load, the IMO must ~~indicate what~~ assign the Availability Class to apply ~~is applicable~~ to that Certified Reserve Capacity as follows: ~~where this Availability Class must~~

(a) ~~reflect the maximum number of hours per year that the capacity will be available and must not be~~ Availability Class 1 where the IMO reasonably expects the Facility to be available to be dispatched for all Trading Intervals in a Capacity Year, allowing for Outages and any restrictions on the availability specified by the applicant under clause 4.10.1(g); or

(b) Availability Class 2 otherwise.

…

4.12.2. A Market Participant holding Capacity Credits must also comply with the following obligations:

(a) the Market Participant must comply with the outage planning obligations specified in clauses 3.18, 3.19, 3.20 and 3.21;

(b) the Market Participant must submit to tests of availability of capacity and inspections conducted in accordance with clause 4.25; and

(c) the Market Participant must comply with Reserve Capacity performance monitoring obligations in accordance with clause 4.27~~; and~~.

~~(d) the Market Participant must, in relation to each Facility assigned Certified Reserve Capacity on the basis of having an alternative fuel available, maintain adequate fuel for 12 hours of operation except on any Trading Day for which the IMO has waived this requirement in response to a Planned Outage or in the event of an extended Forced Outage.~~

…

4.12.4. Subject to clause 4.12.5, where the IMO establishes the initial Reserve Capacity Obligation Quantity to apply for a Facility for a Trading Interval:

…

(c) for Interruptible Loads, Demand Side Programmes and Dispatchable Loads, except where otherwise precluded by this clause 4.12.4, the Reserve Capacity Obligation Quantity:

i. ~~will equal zero once the capacity has been dispatched under clause 7.6.1C(d) for the number of hours per year that are specified under clause 4.10.1(f)(ii);~~[Blank]

ii. will equal zero for the remainder of a Trading Day in which the capacity has been dispatched under clause 7.6.1C(d) for the number of hours per day that are specified under clause 4.10.1(f)(iii);

iii. ~~will equal zero once the capacity has been dispatched under clause 7.6.1C(d) for the maximum number of times per year specified under clause 4.10.1(f)(iv);~~[Blank]

iv. must account for staffing and other restrictions on the ability of the Facility to curtail energy upon request; and

v. will equal zero for Trading Intervals which fall outside of the periods specified in clause 4.10.1(f)(vi).

…

~~4.12.8. Where a Demand Side Programme is dispatched under clause 7.6.1C(d) to a level equal to its Reserve Capacity Obligation Quantity on two consecutive~~

~~days the Reserve Capacity Obligation Quantity for the third consecutive day will be zero.~~

…

4.25.1. The IMO must take steps to verify, in accordance with clause 4.25.2, that each Facility providing Capacity Credits can:

(a) in the case of a generation system, during the term the Reserve Capacity Obligations apply, operate at a level equivalent to its Required Level, adjusted to the level of Capacity Credits currently held, at least once during each of the following periods and such level of operation during those periods must be achieved on each type of fuel ~~available to that Facility~~ notified under clause 4.10.1(e)(v)(1)(ii):

i. 1 October to 31 March; and

ii. 1 April to 30 September; and

…

~~4.25.13. The IMO must monitor at all times the on-site fuel storage of each Scheduled Generator required to comply with clause 4.10.2. The IMO may:~~

~~(a) require the relevant Market Participant to submit a weekly report of the current fuel level;~~

~~(b) have a representative of the IMO conduct an on-site inspection to verify the fuel storage level; and~~

~~(c) instruct System Management to use its SCADA systems to monitor the fuel storage level and to report any failure of any Market Participant to comply with clause 4.10.2 to the IMO.~~

…

4.26.1A. The IMO must calculate the Reserve Capacity Deficit refund for each Facility ("**Facility Reserve Capacity Deficit Refund**") for each Trading Month m as the lesser of:

(a) the sum over all Trading Intervals t in Trading Month m of the product of:

…

vii. if the Facility is a Demand Side Programme:

max(0, ~~RCOQ~~CC - max(0, (RD – MinLoad)))

where:

~~RCOQ is the Reserve Capacity Obligation Quantity determined for the Facility under clause 4.12.4;~~

CC is the MW value of Capacity Credits for the Facility;

RD is the Relevant Demand for the Facility determined in accordance with clause 4.26.2CA; and

MinLoad is the sum of the minimum load MW quantities provided under clause 2.29.5B(c) for the Facility's Associated Loads; and

…

…

4.26.2CA. The Relevant Demand of a Demand Side Programme for a Trading Day d in a Capacity Year is the <u>lesser of:</u> ~~median of the historical consumption quantities determined by the IMO for each of the 32 Trading Intervals identified under clause 4.26.2C(a) for the Capacity Year. The historical consumption quantity for each Trading Interval is the sum, over all the Associated Loads associated with the Demand Side Programme during Trading Day d, of the MW quantity determined by the IMO for each Associated Load and the Trading Interval under clause 4.26.2C(b).~~

<u>(a) the median of the historical consumption quantities determined by the IMO for each of the 32 Trading Intervals identified under clause 4.26.2C(a) for the Capacity Year. The historical consumption quantity for each Trading Interval is the sum, over all the Associated Loads associated with the Demand Side Programme during Trading Day d, of the MW quantity determined by the IMO for each Associated Load and the Trading Interval under clause 4.26.2C(b); or</u>

<u>(b) the sum of Individual Reserve Capacity Requirement Contributions of the Associated Loads Demand Side Programmes.</u>

…

4.26.3A. The Demand Side Programme Capacity Cost Refund for Trading Month m for a Demand Side Programme is equal to the lesser of:

…

(b) the sum of:

i. the sum over all Trading Intervals t in Trading Month m of:

~~12 * Monthly Reserve Capacity Price * S / (2 * H)~~

$$\underline{\left(\frac{24}{H}\right) \times TIRR \times S}$$

Where:

S is the Capacity Shortfall in MW determined in accordance with clause 4.26.2D in any Trading Interval; ~~and~~

H is the maximum number of hours <u>per Trading Day that</u>

the Facility is available to provide Reserve Capacity ~~that the Facility was certified to be available~~ in accordance with clause 4.10.1(f)(iii); and

TIRR is the Off-Peak Trading Interval Rate or Peak Trading Interval Rate applicable to Trading Interval t; and

ii. the Facility Reserve Capacity Deficit Refund for Trading Month m for the Facility~~, determined in accordance with clause 4.26.1A~~.

…

6.12.1.

(a) By 8:00~~1:30~~ PM on the Scheduling Day (or within 40 minutes of a closing time extended in accordance with clause 6.5.1(b)) the IMO must determine the Non-Balancing Dispatch Merit Orders identified in clauses 6.12.1(b) and~~to~~ 6.12.1(~~e~~c) for the Trading Day. A Non-Balancing Dispatch Merit Order lists the order in which the Dispatchable Loads and Demand Side Programmes of Market Participants other than Verve Energy will be issued Dispatch Instructions by System Management under clause 7.6.1C(d) to increase or decrease consumption, as applicable.

(b) A Non-Balancing Dispatch Merit Order for a decrease in consumption relative to the quantities included in the applicable Resource Plan (or the current operating level of a Facility not included in a Resource Plan) ~~during Peak~~for a Trading Interval~~s. The IMO must take into account the following principles when determining this Non-Balancing Dispatch Merit Order~~ must:

i. ~~this Non-Balancing Dispatch Merit Order must~~ list all Demand Side Programmes and Dispatchable Loads registered by Market Participants other than Verve Energy; and

ii. ~~this Non-Balancing Dispatch Merit Order must~~ be determined by ranking the Registered Facilities referred to in clause 6.12.1(b)(i) ~~in increasing order of the Consumption Decrease Price for Peak Trading Intervals.~~as follows:

1. Registered Facilities with a Reserve Capacity Obligation Quantity greater than zero in that Trading Interval ranked in increasing order of the Facility's Consumption Decrease Price applicable to that Trading Interval; followed by

2. Registered Facilities with a Reserve Capacity Obligation Quantity of zero in that Trading Interval, ranked in increasing order of the Facility's Consumption Decrease Price applicable to that Trading Interval.

(c) A Non-Balancing Dispatch Merit Order for an increase in consumption relative to the quantities included in the applicable Resource Plan ~~during Peak~~for a Trading Interval~~s. The IMO must take into account the following principles when determining this Non-Balancing Dispatch Merit Order~~ must:

i. ~~this Non-Balancing Dispatch Merit Order must~~ list all Dispatchable Loads registered by Market Participants other than Verve Energy; and

ii. ~~this Non-Balancing Dispatch Merit Order must~~ be determined by ranking the Registered Facilities referred to in clause 6.12.1(c)(i) in increasing order of the Facility's Consumption Increase Price ~~for~~ applicable to that ~~Peak~~ Trading Interval~~s~~.

(d) ~~A Non-Balancing Dispatch Merit Order for a decrease in consumption relative to quantities included in the applicable Resource Plan (or the current operating level of a Facility not included in a Resource Plan) during Off-Peak Trading Intervals. The IMO must take into account the following principles when determining this Non-Balancing Dispatch Merit Order:~~

~~i. this Non-Balancing Dispatch Merit Order must list all Demand Side Programmes and Dispatchable Loads registered by Market Participants other than Verve Energy; and~~

~~ii. this Non-Balancing Dispatch Merit Order must be determined by ranking the Registered Facilities referred to in clause 6.12.1(d)(i) in increasing order of the Consumption Decrease Price for Off-Peak Trading Intervals;~~[Blank]

(e) ~~A Non-Balancing Dispatch Merit Order for an increase in consumption relative to the quantities included in the applicable Resource Plan during Off-Peak Trading Intervals. The IMO must take into account the following principles when determining this Non-Balancing Dispatch Merit Order:~~

~~i. this Non-Balancing Dispatch Merit Order must list all Dispatchable Loads registered by Market Participants other than Verve Energy; and~~

~~ii. this Non-Balancing Dispatch Merit Order must be determined by ranking the Registered Facilities referred to in clause 6.12.1(e)(i) in increasing order of the Consumption Increase Price for Off-Peak Trading Intervals.~~ [Blank]

(f) Where the prices described in Standing Data for two or more Registered Facilities are equal, then, for the purposes of determining the ranking in any Non-Balancing Dispatch Merit Order, the IMO must rank those~~a~~ Registered Facilit~~y~~ies in decreasing order of the time since the Facility was last issued a Dispatch Instruction ~~with a greater load registered in Standing Data in items (h)(iii) or (i)(iii) of Appendix 1~~

~~before a Registered Facility with a lesser load~~. In the event of a tie, the IMO will randomly assign priority to break the tie.

…

7.5.1. The IMO must provide System Management with the Non-Balancing Dispatch Merit Orders and Fuel Declarations for a Trading Day by 8:00~~1:30~~ PM on the Scheduling Day.

…

7.6.10. Where a Market Participant has Capacity Credits granted in respect of an Interruptible Load, Demand Side Programme or Dispatchable Load ~~:~~

~~(a)~~ the IMO must provide System Management with the details of the Reserve Capacity Obligations to enable System Management to dispatch the ~~Demand Side Programme~~ Facility.~~; and~~

~~(b) any Dispatch Instructions issued by System Management to the Demand Side Programme under clause 7.6.1C(d) must be in accordance with those Reserve Capacity Obligations.~~

…

7.7.4A. When selecting Non-Balancing Facilities from the Non-Balancing Dispatch Merit Order, System Management must select them in accordance with the Power System Operation Procedure. The selection process specified in the Power System Operation Procedure must:

(a) only discriminate between Non-Balancing Facilities based on ~~size of the capacity,~~ response time and availability; and

(b) permit System Management to not curtail a Demand Side Programme when, due to limitations on the availability of the Demand Side Programme, such curtailment would prevent that Demand Side Programme from being available to System Management at a later time when it would have greater benefit with respect to maintaining Power System Security and Power System Reliability.

…

7.7.10. When System Management has issued a Dispatch Instruction or an Operating Instruction to a Demand Side Programme to decrease its consumption, System Management may issue a further instruction terminating the requirement for the Demand Side Programme to decrease its consumption providing that~~:~~

~~(a)~~ the further instruction is issued at least ~~four~~two hours before it is to come into effect.~~; and~~

~~(b) the minimum period for which the Demand Side Programme is instructed to decrease its consumption is not less than two hours.~~

…

7.10.4. System Management must monitor the behaviour of Market Participants with Registered Facilities to assess whether they are complying with clause 7.10.1 in accordance with its Monitoring and Reporting Protocol~~, except where it relates to a Demand Side Programme~~.

…

7.11.1. A Dispatch Advisory is a communication by System Management to Market Participants, Network Operators and the IMO that there has been, or is likely to be, an event that will require <u>the </u>dispatch <u>of Non-Balancing Facilities or </u>~~of~~ Facilities Out of Merit<u>,</u> or will restrict communication between System Management and any of the Market Participants, Network Operators, or the IMO.

…

7.11.5. System Management must release a Dispatch Advisory in the event of, or in anticipation of situations where:

…

(h) System Management expects to use LFAS Facilities other than in accordance with the LFAS Merit Order under clause 7B.3.8;~~ or~~

(i) the system is in, or is expected to be in, a High Risk Operating State or an Emergency Operating State~~.~~<u>; or</u>

<u>(j) System Management expects to issue a Dispatch Instruction to a Non-Balancing Facility within the next 24 hours.</u>

…

<u>7.13.1D. System Management must provide to the IMO, by 6:30 PM on the Scheduling Day, a schedule detailing all of the Dispatch Instructions that System Management issued for each Trading Interval occurring in the period 8:00 AM to 6:00 PM during the Scheduling Day for:</u>

<u>(a) any Demand Side Programme; and</u>

<u>(b) any Dispatchable Load.</u>

Glossary

…

Availability Class: <u>Means either Availability Class 1 or Availability Class 2 or both, as applicable.</u>~~Any one of 4 classes of annual availability of Reserve Capacity set out in clause 4.5.12(c), where each class corresponds to Reserve Capacity being available from a Facility for not more than a specified number of hours per year.~~

Availability Class 1: means the Availability Class assigned by the IMO to Certified Reserve Capacity under clause 4.11.4(a).

Availability Class 2: means the Availability Class assigned by the IMO to Certified Reserve Capacity under clause 4.11.4(b).

…

Individual Reserve Capacity Requirement Contribution: Means the contribution of an Associated Load to Individual Reserve Capacity Requirement determined in accordance with Step 11 of Appendix 5.

…

Non-Balancing Dispatch Merit Order: An ordered list of ~~Scheduled Generators,~~ Demand Side Programmes and Dispatchable Loads registered by Market Participants, other than Verve Energy, determined by the IMO in accordance with clause 6.12.1.

…

Off-Peak Trading Interval Rate: means the rate determined for the applicable Off-Peak Trading Interval under the Refund Table.

…

Peak Trading Interval Rate: means the rate determined for the applicable Peak Trading Interval under the Refund Table.

…

Refund Table: The table titled "Refund Table" and set out in ~~Chapter 4~~clause 4.26.1.

…

Appendix 1: Standing Data

…

…

(h) for a Demand Side Programme:

…

viii. ~~the maximum number of hours per year the Demand Side Programme can be curtailed;~~ [Blank]

ix. the Trading Intervals where the Demand Side Programme can be curtailed;

x. any restrictions on the availability of the Demand Side Programme;

xi. the normal ramp up and ramp down rates as a function of output level, if applicable; and

xii. emergency ramp up and ramp down rates, if applicable.~~; and~~

~~xiii. the maximum number of times that the Demand Side Programme can be curtailed during the term of its Capacity Credits.~~

…

Appendix 3: Reserve Capacity Auction & Trade Methodology

…

The parameter "a" denotes the active Availability Class where "a" can have a value of {1,or 2~~, 3, 4~~}. Availability Class 1 has the highest availability requirement, followed by Availability Class 2~~, Availability Class 3 and then Availability Class 4~~. All Certified Reserve Capacity is assigned an Availability Class. However the algorithms in this appendix allow capacity from ~~an~~ Availability Class ~~with higher availability~~1 to be used in place of capacity from ~~an~~ Availability Class ~~with lower availability~~2. ~~For example, a~~Any capacity accepted from Availability Class 1 that is in excess of the capacity requirement for Availability Class 1 will be available to meet the capacity requirement for Availability Class 2.

~~All Certified Reserve Capacity associated with Interruptible Loads, Demand Side Programmes or Dispatchable Loads is assigned an Availability Class according to the following table, where "Hours of Availability" is the maximum number of hours of availability per year specified for the relevant Facility under clause 4.10.1(f)(ii)~~.

~~Hours of Availability~~	~~Availability Class (i.e. value of "a")~~
~~>= 72~~	~~2~~
~~>=48 and <72~~	~~3~~
~~>=24 and <48~~	~~4~~

~~All other Certified Reserve Capacity is automatically in Availability Class 1.~~

The following algorithm applies for both the testing of bilateral trades and for the auction. Terminology that differs in each case is

- "offers"
  - For the testing of bilateral trades the "offer" is a proposed bilateral transaction (as specified in clause 4.14.1 for each Facility or block).
  - For an auction an "offer" is a "Reserve Capacity Offer".

- the capacity requirements of Availability Class “a”
  - For the testing of bilateral trades, for Availability Class a = 1 this is the greater of zero and Q[a] – X[a] while for Availability Classes a = 2~~, 3 or 4,~~ this is the greater of zero and (Q[a]– X[a] - Y[a-1]) where

    Q[a] is the quantity associated with Availability Class “a” in clause 4.5.12(b) or clause 4.5.12(c).

…

…

Step 3: Accept offers from the set of active offers in order of

- In the case of testing bilateral schedules, decreasing availability.
- In the case of the R~~r~~eserve C~~c~~apacity A~~a~~uction, increasing price

…

…

- In the case of the R~~r~~eserve C~~c~~apacity A~~a~~uction, offers from operating facilities and committed facilities are to be accepted ahead of facilities that are not yet committed; then

…

Step 6: If a = ~~4~~2 then go to Step 8A otherwise increase a by 1.

…

Appendix 5: Individual Reserve Capacity Requirements

...

STEP 11: The Individual Reserve Capacity Requirement Contribution of an individual metered Load for Trading Month n of a Capacity Year is determined as follows:

(a) for meter u at an existing connection point measuring Non-Temperature Dependent Load equals (NTDL(u) x NTDL_Ratio x Total_Ratio);

(b) for meter v at an existing connection point measuring Temperature Dependent Load equals (TDL(v) x TDL_Ratio x Total_Ratio);

(c) for meter u at a new connection point measuring Non-Temperature Dependent Load equals (NMNTCR(u) x Total_Ratio); and

(d) for meter v at a new connection point measuring Temperature Dependent Load equals (NMTDCR(v) x Total_Ratio).

Appendix 1. Further Amendments to the Proposed Amending Rules

The IMO has made some amendments to the Amending Rules following the first submission period. These changes are as follows (~~deleted text~~, added text):

4.26.1A. The IMO must calculate the Reserve Capacity Deficit refund for each Facility ("**Facility Reserve Capacity Deficit Refund**") for each Trading Month m as the lesser of:

(a) the sum over all Trading Intervals t in Trading Month m of the product of:

…

vii. if the Facility is a Demand Side Programme:

max(0, ~~RCOQ~~CC - max(0, (RD – MinLoad)))

where:

~~RCOQ is the Reserve Capacity Obligation Quantity determined for the Facility under clause 4.12.4;~~

CC is the MW value of Capacity Credits for the Facility;

RD is the Relevant Demand for the Facility determined in accordance with clause 4.26.2CA; and

MinLoad is the sum of the minimum load MW quantities provided under clause 2.29.5B(c) for the Facility's Associated Loads; and

…

…

4.26.3A. The Demand Side Programme Capacity Cost Refund for Trading Month m for a Demand Side Programme is equal to the lesser of:

…

(b) the sum of:

i. the sum over all Trading Intervals t in Trading Month m of:

~~(24 / H) * TIRR * S~~

$$\left(\frac{24}{H}\right) \times TIRR \times S$$

Where:

~~S is the Capacity Shortfall in MW determined in accordance with clause 4.26.2D in any Trading Interval;~~
H is the maximum number of hours per Trading Day that the Facility is available to provide Reserve Capacity in accordance with clause 4.10.1(f)(iii);~~ and~~

TIRR is the Off-Peak Trading Interval Rate or Peak Trading Interval Rate applicable to Trading Interval t; and

S is the Capacity Shortfall in MW determined in accordance with clause 4.26.2D in any Trading Interval; and

…

…

7.6.10. Where a Market Participant has Capacity Credits granted in respect of an Interruptible Load, Demand Side Programme or Dispatchable Load the IMO must provide System Management with the details of the Reserve Capacity Obligations to enable System Management to dispatch the ~~Demand Side Programme~~ Facility.

…

…

7.11.1. A Dispatch Advisory is a communication by System Management to Market Participants, Network Operators and the IMO that there has been, or is likely to be, an event that will require the dispatch of ~~Demand Side Programmes~~ Non-Balancing Facilities or Facilities Out of Merit, or will restrict communication between System Management and any of the Market Participants, Network Operators, or the IMO.

…

7.11.5. System Management must release a Dispatch Advisory in the event of, or in anticipation of situations where:

…

(h) System Management expects to use LFAS Facilities other than in accordance with the LFAS Merit Order under clause 7B.3.8;

(i) the system is in, or is expected to be in, a High Risk Operating State or an Emergency Operating State; or

(j) System Management expects to issue a Dispatch Instruction to a ~~Demand Side Programme~~ Non-Balancing Facility within the next 24 hours.

…

Appendix 5: Individual Reserve Capacity Requirements

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STEP 11: The Individual Reserve Capacity Requirement Contribution ~~contribution~~ of an individual metered Load for Trading Month n of a Capacity Year is determined as follows: