Market Advisory Committee

Agenda

Meeting No.	61
Location:	IMO Board Room Level 17, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Wednesday 12th June 2013
Time:	2.00pm – 5.00pm

Item	Subject	Responsible	Time
1.	**WELCOME**	**Chair**	2 min
2.	**MEETING APOLOGIES / ATTENDANCE**	**Chair**	2 min
3.	**MINUTES FROM MEETING 59**	**Chair**	5 min
4.	**ACTIONS ARISING**	**Chair**	10 min
5.	**CONCEPT PAPERS**		
	a) CP_2013_10: DSM Harmonisation	**IMO**	30 min
6.	**MARKET RULES**		
	a) Market Rule Change Overview	**IMO**	5 min
	b) PRC_2013_09: Incentives to Improve Availability of Scheduled Generators	**IMO**	15 min
	c) PRC_2012_13: TES Equations	**IMO**	15 min
7.	**MARKET PROCEDURES**		
	a) Overview	**IMO**	5 min
8.	**WORKING GROUPS**		
	a) Overview and membership updates	**IMO**	5 min
9.	**GENERAL BUSINESS**		
10.	**NEXT MEETING: Wednesday 10th July 2013**		

INDEPENDENT MARKET OPERATOR

Market Advisory Committee

Minutes

Meeting No.	59
Location	IMO Board Room Level 17, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date	Wednesday 10 April 2013
Time	2.05pm – 4.12pm

Attendees	Class	Comment
Allan Dawson	Chair	
Kate Ryan	Compulsory – IMO	
Noel Ryan	Compulsory – Network Operator	
Phil Kelloway	Compulsory – System Management	
Andrew Everett	Compulsory – Generator	
Stephen MacLean	Compulsory – Customer	
Fiona Edmonds	Discretionary – Customer	Proxy
Andrew Sutherland	Discretionary – Generator	
Shane Cremin	Discretionary – Generator	Arrived at 2:10 pm
Steve Gould	Discretionary – Customer	
Michael Zammit	Discretionary – Customer	
Peter Huxtable	Discretionary – Contestable Customer Representative	
Paul Hynch	Minister's appointee – Observer	Proxy
Wana Yang	Economic Regulatory Authority – Observer	Arrived at 2:10 pm
Apologies	**Class**	**Comment**
Nerea Ugarte	Minister's appointee – Observer	
Nenad Ninkov	Discretionary – Customer	
Geoff Gaston	Discretionary – Generator	

Also in attendance	From	Comment
Sam Beagley	IMO	Minutes
Anne Hill	IMO	Presenter
George Sproule	IMO	Presenter
Lizzie O'Brien	IMO	Observer
Neetika Kapani	IMO	Observer
Natasha Cunningham	IMO	Observer
Jenny Laidlaw	IMO	Observer
Courtney Roberts	IMO	Observer
Johann Seneviratne	Australian Taxation Office	Observer (departed at 3:15pm)
Mark Edwards	Australian Taxation Office	Observer (departed at 3:15pm)
Anastasia Papadopoulos	Ernst & Young	Observer (departed at 3:15pm)
Emily Sargent	Ernst & Young	Observer (departed at 3:15pm)
Andy Wearmouth	Verve Energy	Observer
Cameron Parrotte	System Management	Observer
Andrew Stevens	Bluewaters Power	Observer

Item	Subject	Action
1.	**WELCOME** The Chair opened the meeting at 2.05 pm and welcomed members to the 59th meeting of the Market Advisory Committee (MAC).	
2.	**MEETING APOLOGIES / ATTENDANCE** The following apologies were received: • Geoff Gaston (Discretionary – Generator) • Nerea Ugarte (Minister's appointee - Observer) • Nenad Ninkov (Discretionary – Customer) The following other attendees were noted by the Chair: • Paul Hynch (proxy for Nerea Ugarte) • Fiona Edmonds (proxy for Nenad Ninkov) • Anastasia Papadopoulos (Observer) • Emily Sargent (Observer) • Andrew Stevens (Observer) • Andy Wearmouth (Observer) • Johann Seneviratne (Observer) • Mark Edwards (Observer)	

3.	**MINUTES OF PREVIOUS MEETING** The minutes of MAC Meeting No. 58, held on 20 March 2013, were circulated prior to the meeting. The following points were raised by members during the meeting: • The Chair noted that Paul Hynch was recorded in the minutes as Peter Hynch. The IMO would amend the minutes to correct this. ***Section 4a: PRESENTATION: Impact of Changes to the Allocation of Capacity Credits to Intermittent Generators*** • Ms Fiona Edmonds requested that comments made by Mr Nenad Ninkov regarding the MAC's role in considering the impacts of changes on a specific Market Participant be minuted. Ms Ryan agreed to review the minutes and seek clarification if required. ***Section 5b: CP_2013_01: Incentives to Improve Availability of Scheduled Generators*** • Mr Andrew Sutherland requested that the minutes be amended to more accurately reflect his view that "*any review which considers a reduction or cancellation of Capacity Credits that may result in the premature forced closure of a facility must consider the net effect to the market rather than considering capacity in isolation*" (page 8). The Chair agreed to review the minutes and, if necessary, seek clarification on proposed wording from Mr Sutherland. • Mr Andrew Stevens requested the minutes be amended to clarify that he agreed to the consideration of a two-pronged approach, not that he specifically agreed with the two-pronged approach outlined by the Chair which was included in the minutes (page 10). The Chair agreed to amend the minutes. • Mr Andrew Everett stated the same comment that Mr Stevens had requested be clarified had been reflected in the Pre Rule Change Proposal which was circulated and that he would raise this when the relevant agenda item was discussed. • Mr Shane Cremin stated that the minutes incorrectly specified that he did not agree with recycling refunds to generators (page 10). The Chair apologised and agreed to amend the minutes. • Ms Edmonds stated that Mr Ninkov's comment was that the Rule Change would not be required, not that if the outcome was unlikely to affect anyone that it should proceed (page 10). The Chair agreed to review the transcript and amend the minutes if necessary. ***Section 6c: PRC_2012_23: Prudential Requirements*** • Ms Edmonds suggested that the MAC did not agree to endorse the submission of the Rule Change into the formal process but rather the circulation of information on Credit Limits was the only agreed outcome (page 13). Ms Ryan agreed to review the transcript and make amendments if necessary. ***Section 6d: PRC_2013_01: Clarification of Dispatch Compliance Obligations***	

	• Mr Phil Kelloway requested the minutes be amended to reflect he had asked the IMO if they considered System Management was already providing the necessary data and that the IMO had responded that the data was already being provided (page 13). The Chair agreed to amend the minutes. ***Section 6f: PRC_2013_05: LoadWatch, EOI and RDQ Provision*** • Mr Kelloway requested the minutes be clarified such that the use of the term 'cleaned' could be misconstrued as applying to EOI data released which was not the subject of a Market Procedure or refinement process in the same manner that the energy data was. Ms Laidlaw clarified that the minutes sought to refer to SCADA data released two days following the trading interval which would have undergone the necessary processes. The Chair agreed to check the minutes and if necessary amend the minutes to remove any ambiguity in the wording (page 14). ***Section 6g: PRC_2013_06: Exclusion of LFAS Quantities from Daily Ancillary Service Files*** • Mr Kelloway flagged concern that while the minutes reflected that his suggestion of further simplifications to the processes such as the complete elimination of the daily Ancillary Service files would be logged for future consideration that this would be lost. He requested the IMO highlight the point in the minutes (page 14). Subject to the circulation and out of session endorsement of the proposed changes, the MAC agreed that the minutes were a true and accurate record of the meeting. *Action Point: The IMO to amend the minutes of Meeting No. 58 and circulate for final endorsement.*	**IMO**
4.	**ACTIONS ARISING** The following comments were noted on the action items: • **Items 2, 11 and 29:** Ms Kate Ryan noted that items 11 and 29 could be closed, as System Management (had provided this information prior to the meeting. Mr Kelloway confirmed that item 2 could also be closed for the same reason. • **Item 61:** Ms Ryan noted that an email had been sent to the Public Utilities Office (PUO) to address this item. • **Item 62:** Ms Ryan noted the IMO was still waiting on over $600,000 of adjustments to be collected. The Chair noted that the remaining amount was the residual figure from payments already received. • **Item 3:** Ms Ryan noted this item could be closed as the information required was circulated with the MAC papers at the meeting. • **Item 5:** Ms Ryan noted this item could be closed as the information was circulated by Collgar and the IMO on the fifth and ninth of April 2013, respectively. • **Item 10:** Ms Ryan noted that the IMO was addressing the Credit Limit information and it would be disseminated to Market Participants when it was available.	

	• **Item 13:** Ms Ryan noted that RC_2013_03 was published on 10 April 2013 and this item was closed. • **Item 17:** Ms Ryan and the Chair said this would be addressed during the General Business section of the meeting.	
5a.	**MARKET RULE CHANGE OVERVIEW** Ms Ryan stated there had been one more issue added to the log between the March and April MAC. The issue related to Resource Plans for Non-Scheduled Generators: • Mr Andrew Sutherland queried whether the scope of the work on Resource plans for Non-Scheduled Generators could be widened to investigate if the IMO systems are able to calculate the relevant aspects of Facilities Resource Plans. • Ms Ryan noted this suggestion would be investigated as part of this issue. *Action Point: The IMO to include this suggestion in the scope of this issue.* • Mr Andrew Stevens suggested the IMO could remove the Capacity Refunds element if the Market Participant does not put in a Resource Plan • Ms Jenny Laidlaw noted this approach may have effects on Gentailers serving their own load additional to their Net Contract Position. Mr Stevens noted this would not affect Gentailers and he and Ms Laidlaw could discuss this further outside of the MAC.	**IMO**
5b.	**PRC_2013_11: Selection of the 12 Peak Trading Intervals Used for Calculation of IRCR** The Chair introduced Mr George Sproule to present the proposal. The following discussion points were noted: • Mr Stephen MacLean proposed an alternative method of calculating the IRCR. Mr MacLean suggested keeping the four highest consumption days but ensuring they are only Business Days. He suggested that this would provide continuity with the current IRCR methodology. • The Chair noted the days WA consumes the highest quantity of electricity are not necessarily the days when WA experiences its peak load events. Mr MacLean requested to see the evidence to demonstrate the comment made by the Chair. • The Chair and Mr Sproule agreed to provide the information requested by Mr Maclean either by circulation or at the next MAC *Action Point: The IMO to provide analysis in regard to whether the days selected in the current IRCR calculation (based on highest aggregated daily demand) corresponded to the Trading Days with the Highest Trading Interval demand.*	**IMO**
5c.	**PRC_2013_09: Incentives to Improve Availability of Scheduled Generators** Ms Ryan introduced Ms Anne Hill to present the proposal:	

	• Ms Hill presented this Pre Rule Change Proposal and provided an update to the MAC about the changes since the Concept Paper CP_2013_01 was presented at the previous meeting in March. • Mr Sutherland queried how the IMO had come to the conclusion that the Market Rules provide inadequate incentives to Market Participants to maximise the number of Trading Intervals that their Scheduled Generators are available. Ms Hill stated this was the case under the Market Rules. • Mr Sutherland suggested that the comment in the proposal stating that "there is currently no direct financial consequence" in relation to excessive planned outages was not accurate, indicating that other operational costs and opportunity costs should be considered. Ms Ryan mentioned the term "inadequate" was used to describe the incentives and believed the considerations mentioned by Mr Sutherland were factored into the proposal. Ms Hill concurred. Mr Sutherland noted he had not seen any analysis on the net effect of a decision by the IMO to not certify a Facility. • Ms Hill mentioned the analysis was done treating all Facilities the same rather than looking at individual Facilities. Mr Everett stated that the IMO did not have to treat all the Facilities the same and the assertion that such an approach was in accordance with the Rules was fallacious. Ms Hill disagreed with Mr Everett's opinion. • Mr MacLean stated that clause 4.11.1(h) was a binary approach to the problem and the proposal was an attempt to give the IMO more flexibility. He believed that this approach was only going to make the decision process harder for the IMO. Mr Cremin agreed with Mr MacLean and mentioned procedural fairness might be compromised if the IMO moved away from a binary approach. • Mr MacLean also recommended that the Pre Rule Change Proposal required more work and discussion by the market prior to its progressing into the Rule Change Process. Mr MacLean also complimented Ms Hill on her hard and comprehensive work in preparing the Concept Paper and subsequent proposal. • The Chair re-joined the MAC at 2:41 pm. Ms Hill provided an update to the Chair on the discussions. The Chair noted the concern and desire of Mr MacLean to have a forum or discussion group to discuss the proposal in more detail. • Mr Stevens noted, that, despite not being a voting member of the MAC, he would like to express his agreement with Mr MacLean. • The MAC endorsed the action point to hold a half-day discussion regarding this proposal. *Action Point: The IMO to hold a half-day discussion group in the next six to eight weeks to work through PRC_2013_09 Incentives to improve availability of scheduled generators.* • Ms Wana Yang queried if the MAC had come to a consensus that the current Market Rules result in inefficient outcomes. If that was the case then a change should occur. Both Mr Sutherland and MacLean stated they did not agree that the Market Rules result in inefficient outcomes. Specifically Mr Sutherland believed an	**IMO**

	additional level of bureaucracy would not result in efficiencies. • Ms Hill noted the heart of the proposal was limiting the exempt planned outages. Mr Sutherland provided the example that a plant that had not been certified had the potential to remove capacity from the market. Ms Hill stated that the example provided by Mr Sutherland assumed that a plant that was not certified would close down. Mr Sutherland said that was correct. • Ms Hill noted that the assumption was unknown and Mr Sutherland noted, regardless, the IMO would be contributing to the potential a facility closure. Mr Stevens agreed with Mr Sutherland's assertion. The Chair noted the capacity mechanism was in place to incentivise all plant that is not on planned outage to be available and in the BMO. The risk associated with them not being in the BMO is the market paying a higher price. Mr Sutherland reiterated the point that the IMO were contributing to the potential of a facility closing down and hence removing capacity from the market. Ms Hill noted that the rule behind that assertion had always existed. • Mr Shane Cremin noted that removing the binary nature of clause 4.11.1(h) would still enable facilities to provide capacity. He also mentioned removing the requirement for the IMO to provide consultants to inspect plants from the Concept Paper was a positive move. The Chair mentioned that it would be at the discretion of the IMO to conduct any audits of individual facilities. • Mr Kelloway stated that the current Market Rules place a large onus on System Management to define outage requests. He requested that the proposal should also analyse this aspect of the issue with the view to relieve some of the current pressure where warranted. The Chair noted that Ms Hill had looked at some of the current definitions if Planned and Forced Outages in the WEM against international standards. The Chair requested System Management to provide some details at the proposal discussion forum regarding the types and level of outage requests System Management receive. *Action Point: System Management to provide details at the PRC_2013_09 discussion forum regarding the types and level of outage requests it receives.* • Ms Hill agreed with Mr Kelloway that the current outage definitions were not specific enough and placed additional pressure on System Management. • Mr MacLean noted he would not like to see the Market Rules refer to definitions outside the Market Rules and if the Market was going to adapt a particular definition it should be set out in the Market Rules. Mr MacLean noted the proposed defined term "Equivalent Planned Outage Hours" referred to the Market Procedure. Mr MacLean stated that this was placing the obligation in a subordinate document to the Market Rules which was the wrong way around. • Mr MacLean noted the proposed drafting of clause 4.12.9 was poorly worded and the reference "subject to clause 4.12.10" was incorrect because there was no obligation in clause 4.12.10 and the words "subject to" should be changed.	**System Mgmt**

	• Mr Everett noted that the proposal inferred that the MAC agreed to use the 14.8% figure in calculating an average annual planned outage factor. Mr Stevens noted that using the 14.8% figure would be detrimental to a Facility that has a significant major outage. Mr Stevens noted it was not uncomprehendable that a major outage would mean 14.8% was not very generous. Ms Hill stated she had done scenario analysis based on data from 2007 and the concern raised by Mr Stevens would have only affected the plants that have experienced planned outage rates over 30% for the past 3 years. Mr Kelloway noted that the proposal could incorporate certain exclusions such as Facility overhauls. Ms Hill added an appeal system could also be considered. The Chair noted this could be discussed at the half-day forum. • Ms Yang noted further analysis was required to address other potential market incentives that have not been explored in the proposal. Mr MacLean acknowledged the point.	
5d.	**PRC_2013_08: Market Participant Fee – Clarification of GST Treatment** Ms Ryan presented the proposal to the MAC. The following discussion points were noted: • Mr MacLean noted that the drafting in the proposal was not the final proposed drafting. Ms Ryan confirmed that to be the case. • Mr MacLean noted that while there was little point commenting on the drafting if it was not finalised, he did suggested that the IMO consider whether it was good drafting practice to have two definitions for "GST" and the "GST Act". Ms Ryan acknowledged the point and noted it may be a drafting convention but it would be looked at. • The Chair noted the intent of the proposal was to continue to deliver a single invoice to Market Participants for monthly Non-STEM settlements with the only impact of the Rule Change being on 1 January 2014 when GST may not be attached to some market fees. Mr MacLean sought clarification on the date when this change would take effect. The Chair confirmed the tentative date as 1 January 2014. • Mr Kelloway commented whether there would be an impact on System Management's budgets for the second half of the 2014 financial year. The Chair noted Mr Kelloway's point but clarified that the budget provided by System Management did not include GST and as such this should not be affected by any changes to the GST treatment of System Management fees. Mr Kelloway also noted Western Power would be seeking its own ATO ruling in relation to whether the System Operation Fee would be subject to GST. • Ms Wana Yang raised the point that the ERA had not been issued the tax invoices at the beginning of the market. The Chair stated that the IMO had provided multiple copies to the ERA of the historical invoices since market start, all of which itemised GST. Ms Yang noted she would go back to the ERA finance team and seek clarification.	

	• The Chair stated the final Pre Rule Change Proposal including final drafting would be circulated as soon as it was prepared since it was time sensitive. Mr Kelloway questioned if it would be progressed through the Standard Rule Change process. The Chair confirmed it would. *Action Point: The IMO to finalise drafting and progress PRC_2013_08 Market Participant Fee – Clarification of GST Treatment as soon as practical.*	**IMO**
6a.	**MARKET PROCEDURES** Ms Ryan presented the status of the current Market Procedures: • Ms Ryan noted that an IMO Procedures Working Group meeting would be held on 23 April 2013. • Mr Kelloway encouraged members of the MAC to read the System Management PSOP: Change to Monitoring and Reporting Protocol that was currently out for consultation.	
7a.	**WORKING GROUPS** The Chair and Ms Ryan presented the status of the current IMO Working Groups. Ms Ryan noted there had been no changes since the last MAC meeting.	
8.	**GENERAL BUSINESS** The Chair introduced Mr Kelloway to present on the System Management Load Following Ancillary Services (LFAS) initiatives. The following discussion points were noted: • Mr Kelloway noted that System Management and the IMO were working together to investigate Load Following services in the market. • The Chair sought clarification on how System Management had picked people to take place in the industry survey. Mr Kelloway noted it was a random cross-section of the industry but the amount of individuals surveyed was relatively small and did not cover all stakeholders. • Mr Kelloway noted, at this stage, System Management believed no change was required to the LFAS frequency control standard. Mr Kelloway noted that the analysis completed by System Management required further consultation and that it was beyond System Management to complete because it required more input from industry. • The Chair requested clarification from Mr Kelloway on the current regulatory standard for LFAS Minimum Frequency Keeping Capacity. Mr Kelloway confirmed the accuracy of the Chair's understanding of the regulatory standard but mentioned there was also an obligation under the Market Rules. Mr Kelloway noted that System Management annually produces an Ancillary Services report which recommends a standard of 99.9% and is approved by the IMO. Mr Kelloway stated this was the standard currently applied to the market. The Chair noted the IMO would pursue clarification on why System Management uses the standard of 99.9%, which is	

	different to the technical standards of 99.0%. Mr Kelloway noted this was a standard adopted by other markets. • The Chair and Mr Peter Huxtable queried why the survey conducted by System Management did not question how the relaxation on the LFAS Minimum Frequency Keeping Capacity would impact an entity's commercial business. Mr Kelloway noted it was just how the questions were drafted. • Mr Stevens noted that there would be a net saving by relaxing the standard on some generation equipment in Western Australia. Mr Kelloway noted it was beyond the power of System Management and Western Power to relax the frequency keeping standard. Mr Stevens noted the current tolerance to Generators was ambiguous and sought clarification from Mr Kelloway on the upper and lower bounds that equipment had to abide by. • Mr Andy Wearmouth noted technical analysis conducted in other countries endorsed a standard of 99.9%. Mr Wearmouth emphasised that until the analysis was completed to fully understand the impact on relaxing the standard it should remain at 99.9%. Mr Stevens questioned the current standard that most countries had settled at. Mr Wearmouth noted it was at 99.9% and Mr Parrotte confirmed this was the standard in New Zealand, the east coast and Tasmania. Mr Stevens commented some markets have a much more relaxed standard and noted this must have a net commercial value. • The Chair noted that only a few submitters to the Western Power survey had mentioned they would incur extra costs as a result of relaxing the standard. • Mr Kelloway noted that System Management had been working with a Market Participant to assist with the technical and commercial introduction into the LFAS market. Mr Kelloway also noted SM was working with the IMO to identify commercial and technical changes that could improve the LFAS market. • Mr Kelloway noted that System Management and the IMO would share their findings with the MAC at the next meeting. In response to a question from the Chair Ms Laidlaw clarified that these would include the actual MW quantity of Load Following being used and a breakdown of the main causes of the requirement. *Action Point: The IMO/SM Working Group to share finding of the LFAS analysis at the next MAC meeting.* • Ms Laidlaw noted that it was likely that changes to the rules around dispatch could help to reduce the overall LFAS requirement. • The Chair noted that one of the reasons the IMO was looking at the LFAS market was to determine who should be paying for it. • The Chair sought clarification from Mr Kelloway if the IMO should seek input from the CEO of Western Power, PUO or the ERA regarding the adoption of 99.9% and its difference between the standard in the Technical Rules. Mr Kelloway noted that stakeholders had already been engaged and the CEO of Western Power endorsed the approach that any decision to relax the	**IMO & System Mgmt**

	standard from 99.9% was bigger than System Management or Western Power. Mr Parrotte noted the Technical Rules were owned by the ERA. • Mr MacLean sought clarification from Mr Kelloway if the standard was relaxed to 99.0% how that would impact the market. Mr Kelloway stated that after the analysis being conducted with the IMO was complete they should have a better idea. Ms Laidlaw noted without this analysis it would be hard for System Management to translate a standard of 99.0% into a new megawatt figure. Mr Kelloway agreed with Ms Laidlaw. • Mr MacLean and Mr Kelloway noted that before a decision can be made on any changes to the standard of 99.9% further information and consultation is required. • Mr Kelloway noted that the Ancillary Service Standards in the Market Rules detail the Minimum Frequency Keeping Capacity. Specifically the Market Rules define the Minimum Frequency Keeping Capacity as the capacity sufficient to cover 99.9% of the short term fluctuations. *Clause 3.10.1(a)(ii) - The capacity sufficient to cover 99.9% of the short term fluctuations in load and output of Non-Scheduled Generators and uninstructed output fluctuations from Scheduled Generators, measured as the variance of 1 minute average readings around a thirty minute rolling average.* Mr Kelloway confirmed System Management should use the Minimum Frequency Keeping Capacity to drive the outcomes for LFAS. • The Chair reiterated the action point to present the findings of the analysis conducted by System Management and the IMO at the next MAC. • Mr Wearmouth commented that the background to the figure of 99.0% maybe due to the historical development of the Technical Rules, which existed well before market start. • Mr Stevens noted that adjusting the 99.90% requirement may not be the only solution. Mr Stevens mentioned efficiencies may be found in how this standard is achieved. • Mr Sutherland noted that there are significant inefficiencies built into pricing. Mr Sutherland noted that efficiencies could be found by moving LFAS bidding closer to real-time, which could deliver a more efficient price. • The Chair closed the discussion on the LFAS initiative presentation. The Chair raised the request from Collgar Wind Farm at the previous MAC in March to bring forward the review of the valuation methodology pending Collgar releasing data relating to the assignment of its Certified Reserve Capacity and the performance of it Facility. The Chair noted that Mr Greg Ruthven had circulated this information via email on 9 April 2013. The Chair sought feedback from the MAC. The following discussion points were noted:	

	• The Chair noted he had received comments via email from Mr Peter Huxtable from the Water Corporation. Ms Ryan noted the rest of the MAC may need some time to consider the information received from Collgar. • Mr Everett noted that Collgar had failed on 3 occasions to demonstrate that they have been unfairly treated. • The Chair confirmed the MAC would have one week to provide feedback to the IMO about the information provided by Collgar and their opinions on bringing forward the review of the valuation methodology. *Action Point: MAC members to provide feedback to the IMO regarding Collgar's requests by no later than 17 April 2013.*	**MAC**
CLOSED: The Chair declared the meeting closed at 4.12 pm.		

Agenda item 4: 2013 MAC Action Points

Legend:

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

#	Year	Action	Responsibility	Meeting arising	Status/Progress
61	2012	The IMO to contact the PUO to seek clarification and advice on the Metering Code and the confidentiality status of data captured by Notional Wholesale Meters.	IMO	Dec	Email sent to PUO.
10	2013	The IMO to disseminate Credit Limit information to individual Market Participants.	IMO	Mar	Completed. Emailed to MAC members 9 May 2013.
11	2013	The IMO submit PRC_2012_23: Prudential Requirements into the formal process and progress the proposal under the Standard Rule Change Process.	IMO	Mar	Deleted – removed as a result of amendments to the Minutes of Meeting No. 58. PRC_2012_23 will be brought to the next MAC meeting.
18	2013	The IMO to amend the minutes of Meeting No. 58 and circulate for final endorsement.	IMO	Apr	Completed. Emailed to MAC members on 28 May 2013.

#	Year	Action	Responsibility	Meeting arising	Status/Progress
19	2013	The IMO to consider whether the scope of the work on Resource plans for Non-Scheduled Generators could be widened to investigate if the IMO systems are able to calculate the relevant aspects of Facilities Resource Plans for the Pre Rule Change Proposal for Resource Plans for Non-Scheduled Generators.	IMO	Apr	Completed. This has been added to the IMO issues log for consideration in the future.
20	2013	The IMO to provide analysis in regard to whether the days selected in the current IRCR calculation (based on highest aggregated daily demand) corresponded to the Trading Days with the Highest Trading Interval demand.	IMO	Apr	Completed. Information sent 26 April 2013.
21	2013	The IMO to hold a half-day discussion group in the next six to eight weeks to work through PRC_2013_09.	IMO	Apr	Completed. Public Forum scheduled for 8 May 2013.
22	2013	System Management to provide details at the PRC_2013_09 discussion forum regarding the types and level of outage requests it receives.	SM	Apr	
23	2013	The IMO to finalise drafting and progress PRC_2013_08 as soon as practical.	IMO	Apr	Completed. Drafting circulated to MAC on 9 May 2013 and RC_2013_08 submitted into formal process on 21 May 2013.
24	2013	The IMO/SM Working Group to share finding of the LFAS working group at the next MAC meeting.	IMO/SM	Apr	
25	2013	MAC members to provide feedback to the IMO regarding Collgar's requests by no later than 17 April 2013.	MAC	Apr	Completed. Comments from MAC members circulated along with papers for the June 2013 MAC.

Wholesale Electricity Market
Concept Paper

Rule Change Proposal ID: **CP_2013_10**
Date received: **TBA**
Change requested by:

Name:	Allan Dawson
Phone:	9254 4333
Fax:	9254 4399
Email:	allan.dawson@imowa.com.au
Organisation:	IMO
Address:	Level 17, 197 St Georges Tce, Perth 6000
Date submitted:	TBA
Urgency:	Medium
Change Proposal title:	Harmonisation of Supply-Side and Demand-Side Capacity Resources
Market Rules affected:	Clauses 4.5.12, 4.5.13, 4.10.1, 4.10.2, 4.11.1, 4.11.4, 4.12.2, 4.12.4, 4.12.8, 4.26.2CA, 4.26.3A, 6.12.1, 7.6.10, 7.7.10 and 7.10.4. Glossary, Appendix 1, 3 and 5.

Introduction

Market Rule 2.5.1 of the Wholesale Electricity Market Rules provides that any person (including the IMO) may make a Rule Change Proposal by completing a Rule Change Proposal Form that must be submitted to the Independent Market Operator.

This Change Proposal can be posted, faxed or emailed to:

Independent Market Operator
Attn: Group Manager, Development and Capacity
PO Box 7096
Cloisters Square, Perth, WA 6850
Fax : (08) 9254 4339
Email : market.development@imowa.com.au

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

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

The objectives of the market are:

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

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

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

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

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

Details of the Proposed Rule Change

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

Background

The Reserve Capacity Mechanism (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 addition in supply-side resources (predominantly thermal generators) or through reductions in demand, known as Demand Side Management (DSM).

The Reserve Capacity Mechanism Working Group (RCMWG) was established 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 current minimum availability requirements for DSM;
- real-time data requirements for DSM;
- alignment between the Individual Reserve Capacity Requirement (IRCR) and Relevant Demand (RD) for a customer providing DSM; and

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

- fuel requirements for generators.

While not unanimously accepted, the RCMWG members generally supported the changes proposed in this concept paper.

Substantial analysis was conducted by Dr Richard Tooth of Sapere Research Group to support the RCMWG. Three reports on the *Performance requirements for demand-side and supply-side capacity resources* were presented by Dr Tooth at several RCMWG meetings. These reports are available on the Market Web Site: http://www.imowa.com.au/n5415.html. The Working Group discussions and analysis of these reports are also available via the link above.

This concept paper discusses seven key issues for which changes to the Market Rules may be required to ensure adequate harmonisation of DSM and supply-side capacity. These issues and proposed changes to the Market Rules are detailed below.

Issue 1 – Fuel Requirements

To receive Certified Reserve Capacity in relation to a Scheduled Generator, the Market Participant must demonstrate that the fuel storage, supply and transport arrangements for the generator are sufficient to allow 14 hours of continuous operation. The fuel requirements that are placed on Scheduled Generators stem from clause 4.11.1(a) of the Market Rules, which states:

"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 [...] assuming an ambient temperature of 41^{O} C"

This rule has been interpreted to mean that participants must demonstrate that fuel storage, supply and transport arrangements are sufficient to allow 14 hours of continuous operation by Scheduled Generators.

The third report[2] by Dr Tooth considered the commercial incentives to ensure that adequate fuel supplies are maintained for Scheduled Generators.

The analysis concluded that there are sufficient commercial incentives for Scheduled Generators to provide reliable supply, irrespective of the certified fuel requirements. The combination of the market for energy, ancillary services and capacity refunds provide incentives for many Market Generators to ensure the availability of their Facility, including the availability of sufficient fuel for operation. The RCMWG noted that the magnitude of capacity refunds currently varies according to the time of year, time of day and day of the week. The RCMWG considered that a dynamic capacity refund mechanism would enhance the incentives to ensure the availability of adequate fuel for Scheduled Generators[3].

Consequently, the RCMWG concluded that this requirement could be relaxed if it expected that the Facility owner would have sufficient incentives to take appropriate measures to ensure fuel would be available. For example, under such a change the IMO might simply require that the Facility has the potential to source the fuel supplies when required from the spot market.

The RCMWG considered the analysis in the report discussed above and concluded that the

[2] http://www.imowa.com.au/f5415,2873627/Combined_Papers_Mtg_5.pdf

[3] The IMO is currently analysing future rule changes that will consider dynamic refunds

appropriate approach was to relax the “firm fuel” requirements for Facilities. This would involve minor amendments to the Market Rules and Market Procedures.

Proposal

The IMO proposes to relax the requirement for Facilities to have “firm fuel” supply contracts in place. This will be achieved through amending clauses 4.10.1(e)(v), 4.10.2, 4.11.1 and 4.12.2(d) of the Market Rules and the Market Procedure for Certification for Reserve Capacity.

Issue 2 – Revised DSM Availability Requirements

The cornerstone of the DSM harmonisation analysis completed during the RCMWG was the proposed changes to the DSM availability requirements. Dr Tooth presented his initial analysis on *Performance Requirements for Demand-Side and Supply-Side Capacity Resources* at the April 2012 meeting of the RCMWG. This report is available on the Market Website: http://www.imowa.com.au/f5415,2873678/Combined_RCMWG_Mtg_3_Papers.pdf

This first paper of three examined the current performance requirements of both demand and supply-side resources and the impact of harmonisation. Additionally, the report discussed such issues as:

- the design and use of Availability Classes; and
- the current limitations on the use of DSM.

The paper identified two options for the RCMWG to consider for effective harmonisation of demand and supply-side capacity. They were as follows:

- modify the minimum availability requirements; and
- refine other DSM performance requirements.

The second paper delivered by Dr Tooth was at the July RCMWG. This paper focused on the key aspects discussed at the April meeting. This paper is available on the Market Web Site: http://www.imowa.com.au/f5415,2873627/Combined_Papers_Mtg_5.pdf

This paper analysed the following key aspects of the DSM availability requirements:

- changes to the number of dispatch events for a DSP;
- the hours of availability for DSP’s;
- the use of Availability Classes;
- the start and finish times for DSP availability; and
- a reduction in the notice period for dispatch.

The key availability requirements above were discussed by the RCMWG during the July and September meetings. The working group agreed to progress changes to implement the following DSM availability requirements for the 2014 Reserve Capacity Cycle:

Requirement	Current Rule	Proposed Change
Days of Availability	All Business Days	All Business Days
Dispatch events per year	At least 6	Unlimited
Hours per day	4 hours	6 hours
Total hours available per year	24 hours	Unlimited
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 + day before notice (best endeavours) of probable dispatch

The changes to the availability requirements for DSM have implications for the Availability Class definitions in the Market Rules. Further analysis has been conducted by the IMO since the final RCMWG meeting and the IMO proposes the current four Availability Classes should be reduced to two, as follows:

1. capacity that is available all the time (with the exception of Outages); and

2. all other capacity.

Additionally, the IMO has engaged PA Consulting to conduct analysis predicated on this proposed change. The analysis will focus on the impact that two Availability Classes will have on the Availability Curves and the Reserve Capacity Target. The results from this analysis will be presented to the Market Advisory Committee (MAC) as part of the Pre Rule Change Proposal planned for presentation at the August 2013 meeting.

The proposed changes to the availability requirements will also impact the refund calculations for DSP's. Suggested changes to the formula in clause 4.26.3A are still under consideration by the IMO, but a suggested formula is attached in section 3 of this concept paper.

Proposal

The IMO intends to amend clauses 4.5.12, 4.10.1, 4.11.4, 4.12.4, 4.26.3A and 7.7.10 of the Market Rules to account for the shift in availability requirements.

The IMO also proposes to amend the defined term; Availability Class, to factor in the change from four classes to two.

Changes will also be required to Appendices 1 and 3 of the Market Rules based on the factors discussed above. The specific amendments are currently in development and will be presented in the Pre Rule Change Proposal when it goes to the MAC for endorsement.

Issue 3 – "Real-Time" Telemetry Service for DSP's

Currently System Management does not have real-time information on the availability and performance of DSP's. This lack of information means that System Management is likely to be less confident in the use of DSM and less able to efficiently use DSP's. The availability of

real-time information would also enhance System Management's ability to maintain the security and reliability of the SWIS.

The IMO believes for this purpose, it is appropriate that the information provided to System Management is on the availability and performance of the DSP's and not the underlying loads.

Real-time information (telemetry) is possible and is a requirement by ISO-New England[4] for participation in 'Real Time Emergency Generation Resource' demand response. However, telemetry is not a mandatory requirement for participation in other markets.

The inevitable cost associated with a telemetry capability both to DSP's in providing it and System Management in being able to make use of the information is noted. However, in the interest of harmonisation and consistency across resources there is a benefit to a consistent provision of real-time information on availability and performance.

Without the implementation of a "real-time" telemetry service the intent and effect of the other issues identified in this concept paper are somewhat limited. With this in mind, the IMO engaged System Management during the development of this concept paper to assist in identifying and considering the possible options to receive and use the required data. This consultation is ongoing.

Proposal

The IMO proposes to amend the Market Rules and the relevant Procedures to require that all DSP's must provide a telemetry service that provides real-time information on availability and performance. This is intended to take effect from the 2014 Reserve Capacity Cycle onwards.

Specifically, the IMO will leverage off the existing rule (clause 2.35.4), which requires System Management, Market Participants and Network Operators to comply with the communications and control system requirements necessary to support the dispatch process. This approach will require amendment to the relevant PSOP.

The IMO also proposes to amend clause 7.10.4 which currently excludes DSP's from having to comply with Dispatch Instructions in accordance with clause 7.10.1. The amendment will remove this restriction.

Issue 4 – The "Third Day" Rule

Under clause 4.12.8, a DSP that has been dispatched on two consecutive days will have a Reserve Capacity Obligation Quantity (RCOQ) of zero on the third day.

Scenarios in which a DSP may be required for three continuous days include:

- a major fuel disruption, in which DSP's may be required for three continuous days to help manage a risk to fuel stocks; and
- a series of very hot days coupled with some unexpected large Outages.

In accordance with the purpose of this concept paper, to improve the harmonisation of demand-side and supply-side capacity resources, it is appropriate to remove this restriction on dispatch of a DSP.

[4] http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf

Proposal

The IMO proposes to remove clause 4.12.8 from the Market Rules for the 2014 Reserve Capacity Cycle onwards.

Issue 5 – Non-Balancing Dispatch Merit Order (DMO)

The Non-Balancing DMO currently orders Non-Balancing Facilities (including DSP's) firstly by price. In the event that one or more DSPs have the same price, they are ordered from largest to smallest by Load size.

The RCMWG agreed that ranking according to Facility size was inappropriate and created a disincentive to aggregation of Loads within DSP's. Instead, the RCMWG agreed to re-organise the Non-Balancing DMO to ensure the "rank-based-on Load size" rule in the Non-Balancing DMO is removed and replaced with a ranking based on time since last dispatch.

This means a No-Balancing DMO will need to be generated twice per trading interval, rather than four times each day. The practical implications of this change are currently being considered by the IMO and System Management.

Proposal

The IMO also proposes to implement changes to the Market Rules so that Facilities are ranked based on time since last dispatch rather than Load size. The exact drafting is still being discussed and analysed by the IMO and System Management.

Issues 6 – Dispatch of DSPs outside nominated availability

In the same vein as issues four and five, the RCMWG agreed that some DSP's may be able to provide availability outside their nominated availability limits. In such cases where additional availability is needed it seems prudent that System Management should have the ability to request a DSP to curtail consumption if it can.

It is proposed that changes be made to the Market Rules to enable DSPs to be dispatched in these circumstances on a best efforts basis (i.e. with no implications for capacity refunds for non-performance)

Proposal

The IMO proposes to incorporate into the Market Rules the ability for DSP's to be dispatched outside of nominated availability limitations on a best efforts basis. This will require amendment to clause 7.6.10(b).

The exact drafting is still being discussed and analysed by the IMO and System Management.

The IMO notes that under the Market Rules currently, DSP's are not subject to refunds when RCOQ is equal to zero.

Issue 7 – Relationship between IRCR and RD

The amount of Reserve Capacity that DSP's can currently provide is determined by Relevant Demand (RD). RD is currently based on a separate calculation to IRCR. As a result of separate calculations, an Associated Load may be credited with more Capacity Credits than its IRCR obligation.

The RCMWG agreed in February 2013[5] to pursue an approach that focused on the principle that a DSP Load may not sell more capacity (through DSM) than it buys (through IRCR).

Proposal

The IMO proposes to amend the Market Rules to implement the principle that a Load may not sell more capacity (through DSM) than it buys (through IRCR).

Specifically, the IMO proposes to amend clause 4.26.2CA to restrict a DSP from selling more capacity than it buys through IRCR. The IMO also anticipates amendments to Appendix 5: Individual Reserve Capacity Requirements.

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2. Explain the reason for the degree of urgency:

The IMO proposes to commence the amended rules pertaining to this concept paper in order for them to apply for the 2014 Reserve Capacity Cycle. Market Participants should note:

- Changes related to certification of Reserve Capacity are proposed to commence no later than 1 May 2014 (opening of the window for applications for Certified Reserve Capacity for the 2014 Capacity Cycle);
- Changes that impact the operation of DSP's are proposed to commence on 1 October 2016; and
- The IMO considers that the commencement of the proposed Market Rules will provide Market Participants adequate time for IT and operational system and process changes.

As such, the IMO proposes to present a harmonisation Pre Rule Change Proposal to the August MAC. Pending support from the MAC, the IMO would then progress this rule change through the Standard Rule Change Process. This would allow adequate time to commence the amendments before the 2014 Reserve Capacity Cycle.

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

Issue 1 – Proposed Drafting

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 details and evidence of both firm and non-firm fuel supplies~~ and the factors that determine restrictions on fuel~~

[5] http://www.imowa.com.au/f5415,3854323/Minutes_Meeting_10_v5.0_FINAL.pdf

~~availability that could prevent the Facility operating at its full capacity;~~ that will enable the Facility to operate at its full capacity for a period of 14 hours;

~~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:

...

(i) the Certified Reserve Capacity assigned to a Facility is to be expressed to a precision of 0.001 MW; ~~and~~

(j) the Certified Reserve Capacity for a Demand Side Programme for a Reserve Capacity Cycle must not exceed the IMO's reasonable expectation of the amount of capacity likely to be available from that Facility during the periods specified in clause 4.10.1(f)(vi), after netting off capacity required to serve minimum loads, from the Trading Day starting on 1 October in Year 3 of the Reserve Capacity Cycle to the end of July in Year 4 of the Reserve Capacity Cycle~~.~~; and

(k) the IMO may assign Certified Reserve Capacity to a Facility on the basis of a primary fuel and an alternative fuel where the applicant provides details of both fuels under clause 4.10.1(e)(v) and the IMO reasonably expects that the capacity is likely to be available on each fuel for Peak Trading Intervals on Business Days.

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

(a) the Market Participant must comply with 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;

(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.~~

Issue 2 – Proposed Drafting

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 year; 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:

(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 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;

…

4.11.4. 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 Availability Class is applicable to that Reserve Capacity where this Availability Class must be:

(a) ~~reflect the maximum number of hours per year that the capacity will be available and must not be~~ Availability Class 1 if the IMO reasonably expects the Facility to be available for all Trading Intervals in a 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.

…

4.12.4. 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).

…

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

(a) twelve times the Monthly Reserve Capacity Price for Trading Month m multiplied by the number of Capacity Credits associated with the Facility, less all Demand Side Programme Capacity Cost Refunds applicable to the Facility in previous Trading Months falling in the same Capacity Year as Trading Month m; and

(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)~~

S/2 * (Alternative Maximum STEM Price * 24/H)

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 per day that the Facility was certified to be available in accordance with clause 4.10.1(f)(ii); and

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

…

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.~~

…

Availability Class: ~~Any o~~One of ~~4~~two 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.~~

(a) Availability Class 1 includes all generation Facilities and any Interruptible Loads, Demand Side Programmes or Dispatchable Loads that the IMO allocates to Availability Class 1 under clause 4.11.4(a); and

(b) Availability Class 2 includes all remaining Interruptible Loads, Demand Side Programmes or Dispatchable Loads.

Note: Changes also required to Appendix 1 and 3.

Issue 3 – Proposed Drafting

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~~.

Note: No change required to clause 2.35.4.

Issue 4 – Proposed Drafting

~~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.~~

Issue 5 – Proposed Drafting

Note: Under Development.

Issue 6 – Proposed Drafting

Note: Under Development.

Issue 7 – Proposed Drafting

4.26.2CA. The Relevant Demand of a Demand Side Programme for a Trading Day d in a Capacity Year is the lesser of: ~~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).~~

(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)~~.~~; and

(b) the sum of Individual Reserve Capacity Requirement contributions of the Associated Loads as determined in accordance with Step 11 of Appendix 5.

Note: Changes also required to Appendix 5.

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

The IMO proposes that the key issues identified in this concept paper better achieve Wholesale Market Objectives (a), (c) and (e) and are consistent with Wholesale Market

Objectives (b) and (d).

Objective (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 and demand side availability the IMO contends electricity related services would be more economically efficient and provides significantly more reliability to the market.

Having more flexibility to how DSP's are used will give System Management the ability to dispatch DSM as the network requires it, without onerous restriction.

Objective (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 concept paper is to provide more consistent treatment of the capacity provided by generators and DSP's. Certain obligations placed on generators can be perceived onerous in comparison to those placed on DSP's. By implementing the changes suggested in this concept paper the IMO proposes to better achieve Market Objective (c) through treating, where possible, all capacity equitably.

Objective (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 DSP's. Through the changes stipulated in this concept paper the IMO proposes to better manage the amount of electricity used and when it is used. Having a greater understanding on the amount of DSM available to the market coupled with the changes in the availability requirements of DSP's the IMO contends the Rule Changes suggested in this concept paper better achieve Wholesale Market Objective (e).

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

Costs:

As the proposed changes detailed in this concept paper have implications for the roles of System Management, the Network Operator, Market Participants and the IMO it is acknowledged that the associated costs may be material.

The IMO has begun consultation with System Management about the potential impact on systems and processes. This consultation will be extended to Market Participants prior to submitting the proposed rule changes into the formal process.

The IMO is conducting a preliminary analysis on the costs to internal resources and systems and intends to articulate these in a Pre Rule Change Proposal which the planned to be presented to the MAC in August 2013.

Benefits:

- greater achievement of Wholesale Market Objectives (a), (c) and (e);

- consistency with Wholesale Market Objectives (b) and (d); and
- improved reliability and transparency of DSM within the WEM.

Agenda Item 6a: Overview of Market Rule Changes

Below is a summary of the status of Market Rule Changes that are either currently being progressed by the IMO or have been registered by the IMO as potential Rule Changes to be progressed in the future.

Rule changes: Formally submitted (see appendix 1)	5th June 2013
Fast track with Consultation Period open	0
Standard Rule Changes with 1st Submission Period Open	2
Fast Track Rule Changes with Consultation Period Closed (final report being prepared)	0
Standard Rule Changes with 1st Submission Period Closed (draft report being prepared)	2
Standard Rule Changes with 2nd Submission Period Open	2
Standard Rule Changes with 2nd Submission Period Closed (final report being prepared)	1
Rule Changes - Awaiting Minister's Approval and/or Commencement	4
Total Rule Changes Currently in Progress	**11**

The Market Development Team is currently reviewing its work program in order to provide MAC with an indication of the rule changes that are likely to be progressed in coming months. This will be included regularly in this paper from the next MAC meeting.

The IMO also notes that it keeps logs of potential issues that may require rule changes, minor and typographical issues and rule change suggestions that is updated on a regular basis. These logs form the basis of the IMO's future rule change work program, including development of the Market Rules Evolution Plan.

APPENDIX 1: FORMALLY SUBMITTED RULE CHANGES (Current as of 5th June 2013)

Standard Rule Change with First Submission Period Open

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2013_08	21/05/2013	Market Participant Fees – Clarification of GST Treatment	IMO	Submissions close	03/07/2013
RC_2013_11	14/05/2013	Selection of the 12 Peak Trading Intervals used for the Calculation of IRCR	IMO	Submissions close	26/06/2013

Standard Rule Change with First Submission Period Closed

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2012_03	27/03/2013	Assignment of Capacity Credits to Network Control Facilities	IMO	Draft Rule Change Report Published	11/06/2013
RC_2013_05	09/04/2013	LoadWatch, EOI and RDQ Provision	IMO	Draft Rule Change Report Published	19/06/2013

Standard Rule Change with Second Submission Period Open

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2012_02	03/09/2012	Relevant Demand of a Demand Side Program	EnerNOC	Submissions close	20/06/2013
RC_2012_10	22/06/2012	Limits to Early Entry Capacity Payments	Synergy	Submissions close	02/07/2013

Standard Rule Change with Second Submission Period Closed

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2012_20	21/01/2013	Consideration of Network Constraints for Certified Reserve Capacity	IMO	Final Rule Change Report Published	11/06/2013

Fast Track Rule Change Awaiting Ministerial Approval

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2013_01	12/04/2013	Clarification of Dispatch Compliance Obligations	IMO	Ministerial Approval	By 11/06/2013

Standard Rule Change Awaiting Commencement

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2011_02	10/03/2012	Reassessment of Allowable Revenue during a Review Period	ERA	Commencement	01/07/2013
RC_2012_11	30/07/2012	Transparency of Outage Information	IMO	Commencement	01/10/2013
RC_2012_22	11/12/2012	Commitment and De-commitment Notification Requirements	System Management	Commencement	01/09/2013

INDEPENDENT MARKET OPERATOR

Wholesale Electricity Market
Pre Rule Change Proposal

Rule Change Proposal ID: **PRC_2013_09**
Date received: **TBA**

Change requested by:

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Address:	Level 17, 197 St Georges Terrace, Perth WA 6000
Date submitted:	TBA
Urgency:	2-medium
Change Proposal title:	Incentives to Improve Availability of Scheduled Generators
Market Rules affected:	Clauses 4.9.9, 4.11.1, 4.11.1A (new), 4.11.1B (new), 4.11.1C (new), 4.11.1D (new), 4.11.1E (new), 4.12.6, 4.12.9 (new), 4.12.10 (new), 4.26.1A, 4.26.2, 4.27.2A (new), 4.27.3, 4.27.3A (new), 4.27.3B (new), 4.27.4, 4.27.4A (new), 4.27.5, 4.27.6, 4.27.7, 4.27.8, 4.27.9 and the Glossary.

Introduction

Market Rule 2.5.1 of the Wholesale Electricity Market Rules provides that any person (including the IMO) may make a Rule Change Proposal by completing a Rule Change Proposal Form that must be submitted to the Independent Market Operator.

This Change Proposal can be posted, faxed or emailed to:

Independent Market Operator
Attn: Group Manager, Development and Capacity
PO Box 7096
Cloisters Square, Perth, WA 6850
Fax: (08) 9254 4339
Email: market.development@imowa.com.au

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

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

The objectives of the market are:

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

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

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

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

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

Details of the Proposed Rule Change

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

1.1 Background

In July 2012, the IMO noted that five Scheduled Generators in receipt of Capacity Credits since market commencement had demonstrated total outage levels of over 30% over the preceding 36 months. For three of those Facilities, this level of outages was apparent over the previous five years. Two had total outages of over 42% over four years. These outage levels were almost entirely due to Planned Outages, for which there are no direct financial consequences under the Market Rules. By contrast, Forced Outages, for which Capacity Cost Refunds must be paid, are at comparatively low levels.

Total outage levels of over 30% over a 36 month period constitute a performance level that permits the IMO to decline to assign Certified Reserve Capacity to a Facility under Clause 4.11.1(h) of the existing Wholesale Electricity Market Rules (Market Rules).

While to date the IMO has not exercised this discretion, both the IMO and the Economic Regulation Authority (ERA) have expressed concern that this persistent level of low availability is inconsistent with the Wholesale Market Objectives. Analysis commissioned by the ERA showed a correlation between unexpectedly high market prices and the unavailability of these Facilities due to Planned Outages[1].

[1] ERA 2011 Annual Wholesale Electricity Market Report for the Minister of Energy – Public Version

According to statistics published by the Energy Supply Association of Australia (ESAA)[2], the availability factor of the Western Australian generation sector over the ten years prior to 2006 was stable in the range 85%-90%. Availability performance has deteriorated in the last five years, despite the entry of new generators with availability of well over 85% and Planned Outage factors under 10%. The ESAA statistics show that WA now has the worst overall generation availability factor (<80%) and highest Planned Outage factor (20%) in Australia.

This suggests that there are circumstances where the existing Market Rules provide inadequate incentives to Market Participants to maximise the number of Trading Intervals during which their Scheduled Generators are available to the energy markets.

The ERA has also queried whether the Reserve Capacity Mechanism may act to mask signals that would otherwise lead to the retirement of old and unreliable plant. Potentially, the existing Reserve Capacity Mechanism blunts the market signals that would be received by a high maintenance/low availability Scheduled Generator in an energy-only market. Such an effect may be most evident for written-down plant with low fixed costs where the "guaranteed" Reserve Capacity revenue means that a commercial rate of return can be earned with a low capacity factor, which in an energy-only market may trigger a retirement decision.

The implications of this situation for the South West interconnected system (SWIS) include:

- Poor value for money – customers are paying a significant amount for Reserve Capacity for which the probability of availability is low.
- Inefficiency – the unavailability, due to frequent Planned Outages, of Scheduled Generators with low short run marginal costs (SRMC) reduces competitive pressure in the Short Term Energy Market (STEM) and Balancing Market, potentially resulting in higher than necessary average energy prices.
- Higher risk – the frequent unavailability of large amounts of capacity due to Planned Outages reduces the effective reserve margin and increases the risk that a generation plant failure will result in price spikes.
- Inequity within facility class – the worst-performing generators (from an availability perspective) are receiving capacity revenue per available hour that is significantly higher than the best-performing generators[3].
- Retention of inefficient and unreliable generating plant – subsidising unreliable plant with capacity payments mutes the normal commercial incentives for retirement of inefficient, unreliable or obsolete generation facilities.
- Misleading supply signals – the assignment of full Reserve Capacity to frequently unavailable Scheduled Generators may discourage investors by suggesting an apparent system reserve margin higher than the generation capacity that is actually reliably available.

The situation is inconsistent with the Wholesale Market Objectives of economically efficient, safe and reliable supply of electricity (a), encouraging competition (b), and minimising the long-term cost of electricity to customers (d).

The IMO acknowledges that Scheduled Generators require periodic testing, inspections and

[2] ESAA: Electricity Gas Australia, published annually.

[3] For example, the capacity revenue received per Capacity Credit per available hour by the Scheduled Generators with the lowest availability in the 2010/11 and 2011/12 capacity years was $35.49 and $27.06 respectively, while those with the highest availability received $16.51 and $15.06 per Capacity Credit per available hour.

overhauls to maintain them in a reliable and efficient condition. Traditional industry practice for steam turbines has involved minor outages/overhauls (typically two to four weeks duration) every two to four years and major overhauls (typically four to eight weeks duration) every three to nine years, with allowance for the number of starts and operating hours. Gas turbines have tended to have a higher-frequency overhaul cycle. Many operators now use risk-based or condition-based maintenance strategies in which operating conditions and test results, rather than elapsed time or operating hours, dictate overhaul frequency. The aim of this approach is generally to reduce the frequency of overhauls.

The IMO also appreciates that occasionally an overhaul will reveal a previously unknown problem that requires rectification. However three or more successive years with annual Planned Outages in excess of 15 weeks is a significant variation from accepted industry practice for a commercial generator. This indicates either an extremely unreliable plant for which retirement should be a serious option, or a need to improve availability incentives.

The ERA and a number of industry stakeholders have expressed concern about the very high levels of unavailability among some large generating Facilities, the potential impact that this has on the energy markets, and whether the existing Market Rules provide an effective mechanism for ensuring the economically efficient provision of generation capacity to the SWIS.

1.2 Effect of existing Market Rules

Clause 4.11.1(h)

(h) the IMO may decide not to assign Certified Reserve Capacity to a Facility if:

i. the Facility has operated for at least 36 months and has had a Forced Outage rate of greater than 15% or a combined Planned Outage rate and Forced Outage rate of greater than 30% over the preceding 36 months; or

ii. the Facility has operated for less than 36 months, or is yet to commence operation, and the IMO has cause to believe that over a period of 36 months the Facility is likely to have a Forced Outage rate of greater than 15% or a combined Planned Outage rate and Forced Outage rate of greater than 30%,

where the Planned Outage rate and the Forced Outage rate for a Facility for a period will be calculated in accordance with the Power System Operation Procedure[4]. The IMO may consult with System Management in deciding whether or not to refuse to grant Certified Reserve Capacity under this clause 4.11.1(h);

The clause 4.11.1(h) threshold criteria were set at a time when the average Forced Outage factor of SWIS-connected generation was around 4% and the Planned Outage factor was approximately 10% (equating to an Availability Factor[5] of 86%) and Availability Factors had been mostly in the range 85-92% for the previous decade. A combined outage rate of >30% over multiple years was (and still is) indicative of the worst-performing decile of thermal

[4] The outage definitions used in the Market Rules and the outage performance indicators defined in the Power System Operation Procedure: Facility Outages are not standard industry definitions. The terms “Forced Outage rate” and “Planned Outage rate” used in the Market Rules and Power System Operation Procedure are approximately aligned to the IEEE-762 standard definitions of “Equivalent Forced Outage Factor” and “Equivalent Planned Outage Factor”. However, many outages classified as “Planned” in the WEM would be classified as “Forced” under standard industry definitions.

[5] “Availability Factor” (and “Equivalent Availability Factor”) are standard industry performance indicators. They measure the proportion of a given operating period in which a generating unit is available without any outages.

generating plant performance by comparison with international benchmarks.

To support the IMO in making a decision under clause 4.11.1(h), it may use information provided by the applicant under clause 4.10.1 including expected (clause 4.10.1(e)(vi)) and actual (clause 4.10.1(e)(vii)) forced and unforced outage rates. Further, the Reserve Capacity Procedure for Certification of Reserve Capacity allows for the IMO to seek additional information from the applicant, including the causes of the past outages, the steps being taken by the applicant to reduce the outage rates, and the applicant's expectation of the level of future outages. The IMO may assess the likelihood that the applicant's actions will reduce the outage rates and decide whether the expected outages are likely to compromise the security and reliability of the SWIS. It may consult with System Management in making its decision under clause 4.11.1(h).

The Market Rules do not explicitly state the purpose of clause 4.11.1(h). Clause 4.11.1(h) provides no guidance to the IMO in identifying and assigning relative importance to the factors to be considered in the exercise of its discretion under this clause.

Clause 4.11.1(h) is a "go/no go" filter. The IMO has the discretion to refuse to assign any Certified Reserve Capacity to a Facility that breaches the 36 month outage rate threshold. However, if it does not exercise this discretion, it has no power to adjust the quantity of Capacity Credits to be assigned to reflect the Facility's reliability.

Clauses 4.11.1(a), (b) and (g) place upper limits on the level of Certified Reserve Capacity that the IMO may certify for a Facility, which implies that in certain circumstances a lower level may be assigned. However, there are no provisions in clause 4.11.1 or Appendix 3 of the Market Rules, or in the Reserve Capacity Procedure for Certification of Reserve Capacity, that make provision for considering outage-related availability when Certified Reserve Capacity amounts are determined for a Scheduled Generator.

Clause 4.12.3

4.12.3. The IMO must use the information described in clauses 4.10.1 and 4.25.12 to set the Reserve Capacity Obligation Quantity to apply to a Facility in each Trading Interval. The Reserve Capacity Obligation Quantity to apply to a Facility may differ between Trading Intervals.

The information provided by the applicant under clause 4.10.1 of the Market Rules includes previous and expected outage rates for the Facility as well as other restrictions on availability identified by the applicant.

In effect, the Market Rules require the IMO to consider the previous and expected outage rates of a Scheduled Generator when determining the Reserve Capacity Obligation Quantity for a Facility, but do not permit the IMO to consider outage rates when assessing the number of Capacity Credits for which it will be paid.

Clause 4.12.6(b)

(b) subject to clause 4.27.9, during Trading Intervals where there is a Consequential Outage or a Planned Outage for a Facility provided to the IMO by System Management in accordance with clause 7.3.4, the IMO must reduce the Reserve Capacity Obligation Quantity for that Facility, after taking into account any adjustments in accordance with paragraph (a), to reflect the amount of capacity unavailable due to that outage;

The effect of clause 4.12.6(b) is to grant Facilities an uncapped entitlement to have their

Reserve Capacity Obligation Quantity reduced for the Trading Intervals during which their capacity is unavailable due to Planned Outages.

This protects Market Participants from the Facility Reserve Capacity Deficit Refund which would otherwise apply under clause 4.26.1A to a Facility that fails to deliver its Reserve Capacity Obligation Quantities in any Trading Interval.

Clause 4.27.9 suspends the operation of clause 4.12.6(b) under specified circumstances for selected Facilities. The criteria for the operation of the existing clause 4.27.9 relate to total system capacity availability over an extended period, and are unlikely to be met in practice.

The protection that clause 4.12.6(b) provides for unreliable Facilities is significantly increased by the very broad definition of Planned Outages, defined in clause 3.19.11 as any outage that is approved by System Management under clause 3.19.4.

Clauses 3.18.5 and 3.18.5A allow Market Participants to submit an Outage Plan to System Management for approval up to two days prior to the proposed commencement of the Outage.

Clause 3.19.2 allows Market Participants to seek System Management's approval for unscheduled Opportunistic Maintenance with as little as one hour's notice, for an outage confined to a single Trading Day for minor maintenance that does not require changes to scheduled energy or Ancillary Services. Opportunistic Maintenance is specifically classified as a Planned Outage under clause 3.19.11.

Clause 4.27

Clause 4.27 provides the potential for greater scrutiny and intervention by the IMO regarding Facilities with excessive Planned Outage rates. The effectiveness of this clause is severely limited by being dependent on *"the number of days in the preceding 12 calendar months where the total available capacity in the SWIS dropped below 80% (during the Hot Season), and 70% (in either the Intermediate Season or Cold Season), of the total Capacity Credits held by Market Participants for more than six hours on the day"*.

If these criteria are met for more than 40 days, clause 4.27.3 obliges the IMO to require reports from Market Participants responsible for Scheduled Generators that are unavailable due to Planned Outages for more than 1,000 hours (Planned Outage rate of 11.4%) in the preceding 12 calendar months.

Under clause 4.27.4, these reports must include explanations of the Planned Outages and measures proposed by the Market Participant to increase the availability of the Facility, and a statement of the expected maximum number of Planned Outage days to be taken in each of the next 24 months, with reasons for each Planned Outage.

Clause 4.27.7 permits the IMO, at its discretion, to limit the number of Planned Outage days that may be taken in each of the next 24 months if it considers that the Market Participant's proposed level of Planned Outages is unjustified based on good industry practice. This limit does not prevent the Market Participant seeking approval from System Management for Planned Outages in excess of this limit, and only has a tangible effect if clause 4.27.9 is triggered.

Clause 4.27.9 is triggered only if the total available system capacity is reduced significantly for 80 days in the previous 12 months. This clause obliges the IMO to cease adjusting Reserve Capacity Obligation Quantities for the Scheduled Generators referred to in clause 4.27.3 once they exceed the number of days of Planned Outage predicted by the Market

Participant under clause 4.27.4(b) or determined by the IMO under clause 4.27.7. The Facility would then be exposed to the risk of being liable for Facility Reserve Capacity Deficit Refunds for Planned Outages in excess of the limit.

The IMO does not have any discretion to apply clauses 4.27.3 – 4.27.9 unless the thresholds for reduction of total system available capacity are first exceeded. The 40 day threshold has not been exceeded since the commencement of the market, and the probability of it being exceeded in the future is very low.

1.3 Proposed changes to the Market Rules

A Concept Paper was prepared and circulated to members of the Market Advisory Committee (MAC), proposing a number of options to address the issues identified above and improve incentives for Market Participants to maximise the number of Trading Intervals during which their Scheduled Generators are available in the energy markets.

An industry forum was held on 8 May 2013 to allow the expression of views from potentially affected Market Participants, and to allow for a more detailed discussion of the proposals and the issues raised at the MAC meeting. Attendees were also invited to provide written comments on the proposal to the IMO following the conclusion of the forum.

The IMO has considered the matters raised and views expressed by members of the MAC and attendees at the industry forum, and proposes to amend the Market Rules to:

- **Improve the practicality and effectiveness of Clause 4.11.1(h)** by:
    - permitting the IMO more flexibility in assigning a quantity of Certified Reserve Capacity (between zero and full allocation) to Scheduled Generators displaying excessive outage rates over 36 months;
    - specifying a range of factors for the IMO to consider in making its decision, adding certainty, structure and transparency to the process; and
    - progressively tightening the combined Planned Outage rate and Forced Outage rate thresholds that trigger clause 4.11.1(h), from 30% to 20% over five years, commencing in 2016, with corresponding changes to the Forced Outage rate threshold, with provision for review in 2018;
- **Clarify the nature of the Reviewable Decision under clause 4.9.9** by:
    - including an explicit obligation on the IMO to decide whether to assign Certified Reserve Capacity to a Facility, and if so, the quantity to assign. Currently this decision is implicit and the clause only explicitly mentions actions that the IMO must take if it assigns Certified Reserve Capacity to a Facility. This will clarify that the IMO's decisions regarding the quantity of Certified Reserve Capacity to assign to a Facility are reviewable (as clause 4.9.9 is a Reviewable Decision), including where the IMO decides to assign a lesser quantity of Certified Reserve Capacity to a Facility under clause 4.11.1(h);
- **Impose an upper limit on the number of Trading Intervals in any 36 month period for which a generator can claim a reduction of its Reserve Capacity Obligation Quantities due to Planned Outages**.
    - After the Facility reaches this cap, the IMO will no longer reduce the Reserve Capacity Obligation Quantity for that Facility to reflect the amount of capacity unavailable due to Planned Outages.

- The relevant Market Participant will be liable to pay Facility Reserve Capacity Deficit Refunds for subsequent Planned Outages taken by that Facility, as well as for its Forced Outages, until its total Planned Outage hours over the previous 36 months no longer exceed the cap.
- The cap will be applied over a rolling 36 month period to allow Facilities to accommodate periodic major overhauls by smoothing their Planned Outage rates over a longer period. The cap will not apply to Planned Outage hours taken before the implementation of the Rule Change.
- The proposed initial cap of 7,800 Trading Intervals (3,900 hours or 23.2 weeks) over three years is equivalent to an average annual Planned Outage Factor of 14.8%. Only nine of the existing Scheduled Generators have exceeded this figure over the last three years, and it is substantially higher than the historical rates for most Scheduled Generators. It is proposed that this cap be reviewed within five years of operation.
- Trading Intervals will not count towards the cap if no adjustment to Reserve Capacity Obligation Quantities was made and the Market Participant was required to pay a Facility Reserve Capacity Deficit Refund in relation to that Trading Interval.

- **Improve the practicality and effectiveness of Clause 4.27** by:
  - granting the IMO a discretionary power to require a performance report and performance improvement reports from the relevant Market Participant concerning a Scheduled Generator with an excessive Planned Outage rate, regardless of the availability of total system capacity;
  - deleting clauses 4.27.7 and 4.27.8, which become redundant as a result of the change to clause 4.12 that imposes a cap on Planned Outages for which a reduction in Reserve Capacity Obligation Quantities may be claimed; and
  - permitting the IMO to temporarily adjust the cap on the number of Trading Intervals eligible for a reduction of Reserve Capacity Obligation Quantities if the system capacity availability criterion in clause 4.27.9 is met. This is a consequential change required to maintain the intent of clause 4.27.9 in the event that the total system is under extreme capacity stress due to generator unavailability. The probability of the criterion in clause 4.27.9 being met is considered very low.

2. Explain the reason for the degree of urgency:

Some Scheduled Generators have demonstrated poor availability over several years, with little indication to date that the frequent and extended Planned Outages taken over that period have improved the availability of the Facilities. Previous assurances that availability would improve for these Facilities have not been met. Incentives to change behaviour need to be put in place to discourage further deterioration in performance, and the consequential negative impact on the market.

Delays in making these changes will increase the cost to the market of the continued high level of generation unavailability.

Some of the proposed rule changes will include a transition time, to allow affected Market Participants to implement remedial measures and if necessary adjust business plans and maintenance strategies to manage the impact of the changes. Notification of the timetable for the commencement of the rule changes should be provided as soon as possible.

The currently planned timelines would enable the proposed changes to sections 4.12, 4.26 and 4.27 to take effect from the commencement of the Amending Rules (targeted for 1 January 2014), with the proposed changes to section 4.11 taking effect in the 2014 Reserve

Capacity Cycle for the certification of capacity for the 2016/17 Capacity Year.

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

4.9.9. The IMO must decide whether or not to assign Certified Reserve Capacity to a Facility in respect of a Reserve Capacity Cycle, and if so, the quantity to be assigned. If the IMO decides to assign~~s~~ Certified Reserve Capacity to a Facility in respect of a Reserve Capacity Cycle, the IMO must advise the applicant:

(a) of the amount of Certified Reserve Capacity assigned to the Facility in respect of the Reserve Capacity Cycle, as determined in accordance with clause 4.11 or clause 4.9.5(c) (as applicable);

(b) of the initial Reserve Capacity Obligations Quantity set for the Facility, as determined in accordance with clause 4.12 or clause 4.9.5(c) (as applicable);

(c) of any Reserve Capacity Security required as a condition of a Market Participant holding the Certified Reserve Capacity, as determined in accordance with clause 4.13.2 or clause 4.9.5(c) (as applicable);

(d) in the case of Conditional Certified Reserve Capacity, that the certification is subject to the conditions in clause 4.9.5(a) and (b);

(e) upon the request of the applicant, of the calculations upon which the IMO's determinations are based; and

(f) whether the IMO accepted or rejected a proposed alternative value to be used in the calculation of the Required Level for a Facility for which a Market Participant nominated to use the methodology described in clause 4.11.2(b) in its application for certification, as determined in accordance with clause 4.11.2A, if applicable.

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:

…

(h) subject to clauses 4.11.1B and 4.11.1C, the IMO may decide not to assign, or to assign a specified quantity of Certified Reserve Capacity to a Facility if:

i. the Facility has ~~operated~~ been in Commercial Operation for at least 36 months and has had a Forced Outage rate ~~of greater than 15%~~ or a combined Planned Outage rate and Forced Outage rate ~~of~~ greater than ~~30%~~ the applicable percentage specified in clause 4.11.1D over the preceding 36 months; or

ii. the Facility has ~~operated~~ been in Commercial Operation for less than 36 months, or is yet to commence Commercial Operation~~operation~~, and the IMO has cause to believe that over ~~a period of~~ the first 36 months of Commercial Operation the Facility is likely to have a Forced Outage rate ~~of greater than 15%~~ or a combined Planned Outage rate and Forced Outage rate ~~of~~ greater than ~~30%,~~ the applicable percentage specified in clause 4.11.1D,

where the Planned Outage rate and the Forced Outage rate for a Facility for a period will be calculated in accordance with the Power System Operation Procedure~~. The IMO may consult with System Management in deciding whether or not to refuse to grant Certified Reserve Capacity under this clause 4.11.1(h)~~;

…

4.11.1A. The IMO must publish the reasons for a decision made under clause 4.11.1(h) on the Market Web Site to the extent those reasons do not contain any confidential information.

4.11.1B. In making a decision under clause 4.11.1(h), the IMO may:

(a) seek such additional information from the relevant Market Participant that the IMO considers is relevant to the exercise of its discretion;

(b) use information provided in reports related to the Facility submitted by:

i. the Market Participant under clauses 4.27.3 or 4.27.3A; and

ii. another person under clause 4.27.6; and

(c) consult with:

i. System Management; and

ii. any person the IMO considers suitably qualified to provide an opinion on issues relevant to the exercise of the IMO's discretion.

4.11.1C. In making a decision under clause 4.11.1(h), the IMO must:

(a) consider the extent to which the Reserve Capacity that can be provided by the Facility is necessary to meet the Reserve Capacity Target;

(b) consider whether the Reserve Capacity provided by the Facility is of material importance to the SWIS, having regard to:

i. the size of the Facility;

ii. the operational characteristics of the Facility;

iii. the extent to which the Facility contributes to the security of the system through fuel diversity or location; and

iv. the demonstrated reliability of the Facility;

(c) assess the effectiveness of strategies undertaken by the applicant in the previous three years to reduce outages, and consider the likelihood that strategies proposed by the applicant to maximise the availability of the Facility in the relevant Capacity Cycle will be effective;

(d) consider whether a decision to not assign Certified Reserve Capacity to the Facility is likely to result in a material decrease in competition in at least one market;

(e) consider any positive or negative impacts on the long term price of electricity supplied to consumers that might arise if Certified Reserve Capacity was not assigned to the Facility;

(f) consider any other matter the IMO determines to be relevant; and

(g) be satisfied that its decision under clause 4.11.1(h) would not, on balance, be contrary to the Wholesale Market Objectives.

4.11.1D. The relevant outage criteria to apply under clause 4.11.1(h) in a particular Capacity Year is as set out in the following table:

For IMO decisions related to the Capacity Year	Forced Outage rate greater than	Combined Planned Outage rate and Forced Outage rate greater than
Prior to 2016/17	15%	30%
2016/17	14%	28%
2017/18	13%	26%
2018/19	12%	24%
2019/20	11%	22%
2020/21 onwards	10%	20%

4.11.1E. The IMO must undertake a review, to be completed by 31 December 2018, of the operation of clause 4.11.1(h) in which it must consider the appropriate thresholds under clause 4.11.1D for Capacity Years after 2020/2021. The review must include, at a minimum, an assessment of:

(a) the availability performance of the generation sector in the Wholesale Electricity Market compared with analogous generating plant in other markets, using Industry Standard Generation Performance Indicators for benchmarking;

(b) the number of Facilities in the SWIS to which the criteria in clause 4.11.1(h) have applied in each of the previous five Capacity Years; and

(c) the impact on the Wholesale Electricity Market of decisions made by the IMO under clause 4.11.1(h) in the previous five Capacity Years.

4.12.6. Subject to clause 4.12.7, any initial Reserve Capacity Obligation Quantity set in accordance with clauses 4.12.4, 4.12.5, 4.28B.4, or 4.28C.4 is to be reduced once the Reserve Capacity Obligations take effect, as follows:

…

(b) subject to clause ~~4.27.9, during Trading Intervals where there is a Consequential Outage or a Planned Outage for a Facility provided to the IMO by System Management in accordance with~~ 4.12.9, where System Management notifies the IMO of a Planned Outage or Consequential Outage for a Facility under clause 7.3.4, the IMO must reduce the Reserve Capacity Obligation Quantity for that Facility, after taking into account any adjustments in accordance with ~~paragraph (a)~~ clause 4.12.6(a), to reflect the amount of capacity unavailable due to that outage; and

…

4.12.9. The IMO must not reduce the Reserve Capacity Obligation Quantity of a Facility for a Trading Interval under clause 4.12.6(b) in respect of a Planned Outage, if this would result in the RCOQ Reduced Planned Outage Count for that Facility over the 36 months up to and including the Trading Interval exceeding 7800.

4.12.10. The IMO must undertake a review, to be completed by 31 December 2018, of whether the limit for the RCOQ Reduced Planned Outage Count referred to in clause 4.12.9 should be altered to better meet the Wholesale Market Objectives.

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:

i the Off-Peak Trading Interval Rate or Peak Trading Interval Rate determined in accordance with the Refund Table applicable to Trading Interval t; and

ii the Reserve Capacity Deficit in Trading Interval t,

where the Reserve Capacity Deficit for a Facility is equal to whichever of the following applies:

iii. if the Facility is required to have submitted a Forced Outage under clause 3.21.4, or has taken a Non-RCOQ Adjusted Planned Outage, the total Forced Outage and Non-RCOQ Adjusted Planned Outage in that Trading Interval measured in MW; or

…

4.26.2. The IMO must determine the net STEM shortfall ("Net STEM Shortfall") in Reserve Capacity supplied by each Market Participant p holding Capacity Credits associated with a generation system in each Trading Interval t of Trading Day d and Trading Month m as:

SF(p,m,d,t) = Max(RTFO(p,d,t), RCOQ(p,d,t) - A(p,d,t)) - RTFO(p,d,t)

Where:

A(p,d,t) = Min(RCOQ(p,d,t), CAPA(p,d,t));

RCOQ(p,d,t) for Market Participant p and Trading Interval t of Trading Day d is equal to:

(a) the total Reserve Capacity Obligation Quantity of Market Participant p's unregistered facilities that have Reserve Capacity Obligations, excluding Loads that can be interrupted on request; plus

(b) the sum of the product of:

i. the factor described in clause 4.26.2B as it applies to Market Participant p's Registered Facilities; and

ii. the Reserve Capacity Obligation Quantity for each Facility,

for all Market Participant p's Registered Facilities, excluding Demand Side Programmes,

CAPA(p,d,t) is for Market Participant p and Trading Interval t of Trading Day d:

(c) equal to RCOQ(p,d,t) for a Trading Interval where the STEM Auction has been suspended by the IMO in accordance with clause 6.10;

(d) subject to clause 4.26.2(c), for the case where Market Participant p is not Verve Energy, the sum of:

i. the Reserve Capacity Obligation Quantities in Trading Interval t of that Market Participant's Interruptible Loads; plus

ii. the MW quantity calculated by doubling the net MWh quantity of energy sent out by Facilities registered by that Market Participant during that Trading Interval calculated as the Net Contract Position less the shortfall as indicated by the applicable Resource Plan; plus

iiA. if a STEM submission does not exist for that Trading Interval, the MW quantity calculated by doubling the total MWh quantity of energy to be consumed by that Market Participant including demand associated with any Interruptible Load, but excluding demand associated with any Dispatchable Load during that Trading Interval as indicated by the applicable Resource Plan; plus

iii. the MW quantity calculated by doubling the total MWh quantity covered by the STEM Offers which were not scheduled and the STEM Bids which were scheduled in the relevant STEM Auction, determined by the IMO for that Market Participant under clause 6.9 for Trading Interval t,

corrected for Loss Factor adjustments so as to be a sent out quantity in accordance with clause 4.26.2A; plus

iv. double the total MWh quantity to be provided as Ancillary Services as specified by the IMO in accordance with clause 6.3A.2(e)(i) for that Market Participant corrected for Loss Factor adjustments so as to be a sent out quantity in accordance with clause 4.26.2A; plus

v. the greater of zero and (BSFO(p,d,t) – RTFO(p,d,t)); and

(e) subject to clause 4.26.2(c), for the case where Market Participant p is Verve Energy, the sum of:

i. the sum of the Reserve Capacity Obligation Quantities in Trading Interval t of that Market Participant's Interruptible Loads; plus

ii. the MW quantity calculated by doubling the total MWh quantity of the Net Contract Position quantity of that Market Participant for Trading Interval t, corrected for Loss Factor adjustments so as to be a sent out quantity in accordance with clause 4.26.2A; plus

iii. the MW quantity calculated by doubling the total MWh quantity of the STEM Offers which were not scheduled and the STEM Bids which were scheduled in the relevant STEM Auction, determined by the IMO for that Market Participant under clause 6.9 for Trading Interval t, corrected for Loss Factor adjustments so as to be a sent out quantity in accordance with clause 4.26.2A; plus

iv. double the total MWh quantity to be provided as Ancillary Services as specified by the IMO in accordance with clause 6.3A.2(e)(i) for Verve Energy corrected for Loss Factor adjustments so as to be a sent out quantity in accordance with clause 4.26.2A; plus

v. the greater of zero and (BSFO(p,d,t) – RTFO(p,d,t)).

BSFO(p,d,t) is the total MW quantity of Forced Outage and Non-RCOQ Adjusted Planned Outage associated with Market Participant p before the STEM Auction for Trading Interval t of Trading Day d, where this is the sum over all the Market Participant's Registered Facilities of the lesser of the Reserve Capacity Obligation Quantity of the Facility for Trading Interval t and the sum of the MW Forced Outage and MW Non-RCOQ Adjusted Planned Outage of the Facility for Trading Interval t as provided to the IMO by System Management in accordance with clause 7.3; and

RTFO(p,d,t) is the total MW quantity of Forced Outage and Non-RCOQ Adjusted Planned Outage associated with Market Participant p in real-time for Trading Interval t of Trading Day d, where this is the sum over all the

Market Participant's Registered Facilities of the lesser of the Reserve Capacity Obligation Quantity of the Facility for Trading Interval t and the sum of the MW Forced Outage and MW Non-RCOQ Adjusted Planned Outage of the Facility for Trading Interval t as provided to the IMO by System Management in accordance with clause 7.13.1A(b).

4.27.2A. By the twenty fifth day of each month, the IMO must assess the number of Equivalent Planned Outage Hours taken in the preceding 12 calendar months by each Facility assigned Capacity Credits for the current Capacity Year.

4.27.3. If the number of days determined in accordance with clause 4.27.2 exceeds 40, then the IMO must require reports to be filed by those Market Participants holding Capacity Credits for each Facility which:

(a) has ~~been unavailable due to Planned Outages for more than 1000 hours~~ taken more than 1000 Equivalent Planned Outage Hours during the preceding 12 calendar months; and

(b) has not been included in such a report during the preceding 12 calendar months.

4.27.3A. If the number of Equivalent Planned Outage Hours for a Facility, as determined under clause 4.27.2A, exceeds 1750 hours for the preceding 12 calendar months, the IMO may require the Market Participant holding Capacity Credits for that Facility to provide to the IMO:

(a) an explanatory report as described in clause 4.27.4; and

(b) performance improvement reports at specified intervals (not more frequently than once per quarter) on the effectiveness of measures being taken by the Market Participant to improve the availability of the Facility.

4.27.3B. In making its decision whether to require a report under clause 4.27.3A, the IMO must assess whether the number of Equivalent Planned Outage Hours taken by the Facility in the previous 12 months was attributable to a specific, infrequent occurrence or is indicative of an underlying performance deficiency, and may consider any matters it considers relevant in making this assessment. The IMO may consult System Management in deciding whether or not to require a report.

4.27.4. The reports described in clause 4.27.3 and 4.27.3A(a) must include:

(a) explanations of all Planned Outages taken by the Facility in the preceding 12 calendar months;

(b) a statement of the expected maximum number of days of Planned Outages to be taken by the Facility in each of the next ~~24~~ 36 months commencing from the month in which the report is requested, including adequate explanation to make clear the reason for each Planned Outage; ~~and~~

(bA) the relationship of the Planned Outages to the long term asset management strategy and established maintenance plan for the Facility;

(c) measures being undertaken or proposed by the Market Participant to increase the availability of the Facility~~.~~, and their actual and anticipated effect on the frequency of Planned Outages; and

(d) any other information concerning the availability of the Facility that the IMO may request.

4.27.4A. The reports described in clause 4.27.3A(b) must include:

(a) descriptions of the measures proposed, being undertaken or already undertaken by the Market Participant to increase the availability of the Facility;

(b) the target and actual availability and reliability of the Facility as measured by Industry Standard Generation Performance Indicators; and

(c) explanation of any variation between expected and actual improvement of the availability of the Facility as a result of the measures taken.

4.27.5. A Market Participant must:

(a) provide a report described in clause 4.27.3 or clause 4.27.3A(a) to the IMO in a format specified in the Reserve Capacity Procedure within 20 Business Days of being requested to do so~~.~~; and

(b) provide a report described in clause 4.27.3A(b) to the IMO in a format specified in the Reserve Capacity Procedure by the time specified by the IMO under clause 4.27.3A(b).

4.27.6. The IMO must consult with System Management on the implications of ~~the~~ a report provided under clause 4.27.5, and may also consult, at the Market Participant's expense, with any person the IMO considers suitably qualified to provide an opinion on the report. The IMO may ask the person to provide an opinion on the report generally, or to limit the scope of the opinion to specified matters covered in the report.

4.27.7. ~~If the IMO considers the number of days reported in accordance with clause 4.27.4(b) to be unjustified based on good industry practice it may, at its sole discretion, limit the number of days on which Planned Outages are to be taken by the Facility in each of the next 24 months for the purposes of clause 4.27.8 and 4.27.9 and must notify the Market Participant who filed the report described in clause 4.27.3 of the limit.~~ [Blank]

4.27.8. ~~If the IMO limits the number of days in accordance with clause 4.27.7 then the modified value is to supersede the corresponding value specified in the report described in clause 4.27.4.~~ [Blank]

4.27.9. If the number of days determined in accordance with clause 4.27.2 exceeds 80 then the IMO ~~must~~:

(a) must notify all Market Participants that this has occurred; and

(b) during the 12 ~~months~~ Trading Months commencing from the first Trading Day of the following ~~month,~~ Trading Month, may adjust the limit for the RCOQ Reduced Planned Outage Count specified in clause 4.12.9.~~cease to adjust Reserve Capacity Obligation Quantities under clause 4.12.6(b) in response to Planned Outages for Facilities:~~

~~i. referred to in clause 4.27.3; and~~

~~ii. for which the number of days of Planned Outage during that 12 month period has exceeded the total number of days of Planned Outage predicted for that 12 month period in accordance with clause 4.27.4(b), as modified by clause 4.27.8.~~

Glossary

Equivalent Planned Outage Hours: means, in respect of a Facility, the sum of the "Planned Outage Hours" and the "Equivalent Planned Derated Hours" for the Facility as calculated in accordance with the Power System Operation Procedure.

Industry Standard Generation Performance Indicators: means the most recent edition of the IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity (IEEE 762), as published by the Institute of Electrical and Electronics Engineers, or appropriate equivalent.

Non-RCOQ Adjusted Planned Outage: means a Planned Outage for which the IMO has not adjusted the Facility's Reserve Capacity Obligation Quantity under clause 4.12.6(b).

RCOQ Adjusted Planned Outage: means a Planned Outage for which the IMO has adjusted the Facility's Reserve Capacity Obligation Quantity under clause 4.12.6(b).

RCOQ Reduced Planned Outage Count: means, in respect of a Facility and a period of time, the sum over all Trading Intervals in that period of:

(a) zero, if the Trading Interval occurs before 8:00 AM on 1 January 2014 or if no Capacity Credits were associated with the Facility in the Trading Interval; or

(b) the MW quantity of RCOQ Adjusted Planned Outage for the Facility in the Trading Interval, divided by the number of Capacity Credits associated with the Facility in the Trading Interval.

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

The Reserve Capacity Mechanism is intended to serve a multiple purpose in pursuit of the Wholesale Market Objectives of economically efficient and reliable electricity supply, encouraging competition and minimising the long term cost of electricity to customers. It provides a capacity revenue stream as an incentive for the provision of competitive generation capacity to meet peak summer demand with a reserve margin (Reserve Capacity Target).

The Reserve Capacity Mechanism is designed to improve generator viability by

compensating for low capacity factors attributable to market demand. It is not intended to compensate for low capacity factors attributable to operational decisions by Market Participants that result in a Scheduled Generator being unavailable for dispatch.

All generators in receipt of an allocation of Certified Reserve Capacity are expected to participate in the energy markets unless their plant is unavailable due to a Forced or necessary Planned Outage.

Scheduled Generators that are unavailable due to Forced Outages are required to pay a Facility Reserve Capacity Deficit Refund, providing an effective incentive to minimise unavailability due to Forced Outages. However, there is no corresponding incentive in the Reserve Capacity Mechanism to minimise unavailability due to Planned Outages.

Under the existing Market Rules, a Scheduled Generator may take Planned Outages as frequently as System Management is prepared to approve, without any consequential reduction in capacity revenue. System Management, appropriately, makes its decision only on the basis of whether system security might be impaired by the capacity being unavailable. When forecast demand is low relative to available capacity, approval can generally be expected.

However, the absence from the market of a Scheduled Generator with a low SRMC reduces competitive pressure. This may result in energy prices being higher than they would have been had the Facility bid into the market, and increase the risk of price spikes should an unexpected supply reduction or demand peak occur. Failing to hold Market Participants accountable for excessive Planned Outages of their Scheduled Generators results in shifting these risks to the market.

The proposed changes to sections 4.12 and 4.26 of the Market Rules will encourage Scheduled Generators to maintain plant availability at high levels by addressing this asymmetry in market incentives, while recognising the critical role that legitimate Planned Outages play in safeguarding system security and reliability.

In determining the quantity of Certified Reserve Capacity to assign to a Scheduled Generator, the existing Market Rules value Reserve Capacity on the basis of system security and reliability during hot-weather-related peak demand periods. Capacity Credits are allocated based on the reasonable expectation of the maximum summer sent-out capacity of which the Facility is capable. There is no consideration in the allocation mechanism of how frequently this capacity may be available from a Scheduled Generator (in contrast to the approach taken with Intermittent Generators).

The proposed changes to sections 4.11 and 4.27 allow the IMO to recognise the value of the availability of generation capacity in stimulating competition and efficiency in the energy market. The potential capacity available from a Scheduled Generator with chronically high outage rates may be discounted (in whole or in part) by the IMO to reflect the fact that it is available significantly less frequently than most other generators that have been allocated Certified Reserve Capacity. Scheduled Generators with availability below a certain level would therefore see a future reduction in their capacity revenue.

This would provide a strong financial signal that the impact of excessive Planned Outages on market competition and market price is considered to be inconsistent with the Wholesale Market Objectives.

Should the IMO decide under clause 4.11.1(h) not to allocate the maximum Certified Reserve Capacity to a Facility, the decision would only affect the Facility's potential capacity revenue. The Facility remains entitled to fully compete in the energy markets in which it is

eligible to participate.

Assessment against the Market Objectives

The IMO considers that the proposed amendments would better address Wholesale Market Objectives (a), (b) and (d).

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

The proposed amendments would better address Wholesale Market Objective (a) by:

- providing the IMO with the discretion to value frequently unavailable capacity lower than high-availability capacity when assigning Certified Reserve Capacity to a Scheduled Generator;
- providing for the IMO to ensure that Scheduled Generators with high outage rates or excessive Planned Outage rates do not receive a higher effective Reserve Capacity Price per available hour than Scheduled Generators with low outage rates;
- reducing incentives for Market Participants to retain inefficient, high-maintenance Scheduled Generators with poor Availability Factors;
- improving accountability for unavailability by limiting the number of Planned Outage hours that can be taken by a Facility without exposure to Facility Reserve Capacity Deficit Refunds;
- establishing a mechanism for the IMO to independently monitor the performance of individual Scheduled Generators with high outage rates, and consider that performance in assigning Certified Reserve Capacity; and
- improving the information available to the IMO in making Certified Reserve Capacity decisions under clause 4.11.1(h).

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

The proposed amendments would better address Wholesale Market Objective (b) by:

- better matching nominal Reserve Capacity to reliably available capacity;
- increasing the transparency of the IMO's decisions under clause 4.11.1(h); and
- reducing incentives for retention of unreliable, high-maintenance Scheduled Generators, providing greater opportunities for investment in more efficient and reliable generation plant.

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

The proposed amendments would better address Wholesale Market Objective (d) by:

- ceasing to pay the full Reserve Capacity Price for frequently unavailable capacity;
- increasing the competitive pressure on energy prices by increasing the availability of registered Scheduled Generators bidding into the energy markets;
- requiring Scheduled Generators with excessive Planned Outage rates to compensate the market for their unavailability through payment of Facility Reserve Capacity Deficit Refunds;

- closer scrutiny of the efficiency and effectiveness of Market Participants in improving the availability of their low-availability Scheduled Generators; and
- encouraging the replacement of inefficient, unreliable and high-maintenance Scheduled Generators with more efficient and reliable generating Facilities.

The IMO considers that the proposed amendments are consistent with Wholesale Market Objectives (c) and (e).

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

These changes will reduce the capacity revenue earned and retained by Market Participants holding Capacity Credits for Scheduled Generators with high total outage rates, unless they take steps to reduce those outage rates. The cost incurred by Scheduled Generators with very high Planned Outage rates may be substantial. However, the Market Participant holding the Capacity Credits for those Scheduled Generators has considerable discretion concerning the level of risk, which is directly affected by its outage decisions.

Further, the changes clarify the nature of the Reviewable Decision under clause 4.9.9 (whether to assign Certified Reserve Capacity to a Facility, and if so, the quantity to be assigned). A decision by the IMO under clause 4.11.1(h) relates to the quantity of Certified Reserve Capacity to be assigned and, therefore, is within the scope of the Reviewable Decision under clause 4.9.9.

The financial cost of the proposed amendments for the market as a whole is expected to be neutral or minimal.

- Reserve Capacity Revenue refunded by Market Participants operating high-outage Scheduled Generators would be retained and redistributed within the market.
- The IMO will incur some IT costs to implement the proposed changes to clauses 4.12.6, 4.26.1A and 4.26.2.
- Some additional administrative cost for the IMO will be incurred through greater performance monitoring of individual Scheduled Generators, but this is expected to diminish as the incentives for lower Planned Outage rates take effect and fewer Facilities meet the criteria for individual reporting under clause 4.27.3A.
- Reporting costs for the Market Participants are not expected to be significant, as it is anticipated that a competent operator would already be collecting the information requested as standard asset management practice.

It is difficult to quantify the economic benefits that accrue from incentives targeting behavioural change, because the effectiveness of the incentives depends on multiple factors. These include the various market and other incentives for the affected party, the net financial impact and the Market Participants' perception of the IMO's willingness to apply sanctions.

However, the market is likely to experience a net economic benefit as a result of:

- increasing the number of available Scheduled Generators in the energy markets, increasing competition and reducing the risk of price spikes in the event of unforeseen supply interruptions;
- imposing greater accountability for poor availability performance;
- reducing subsidies to frequently unavailable Scheduled Generators;
- improving the quality of information available to the IMO to inform its decisions regarding Reserve Capacity allocation; and

- reducing perverse incentives that encourage the retention of inefficient, obsolete, unreliable and high-maintenance Scheduled Generators, leading to efficiency and competition benefits in the longer term.

All Market Participants will be better placed to monitor the value for money being provided by the Reserve Capacity Mechanism, and to identify emerging trends that may need to be addressed through market incentives.

INDEPENDENT MARKET OPERATOR

Wholesale Electricity Market
Pre Rule Change Proposal

Rule Change Proposal ID: **PRC_2013_02**
Date received: **TBA**

Change requested by:

Name:	Allan Dawson
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Organisation:	IMO
Address:	Level 17, 197 St Georges Tce, Perth 6000
Date submitted:	TBA
Urgency:	Fast Track
Change Proposal title:	Clarification of the Minimum TES calculation
Market Rule affected:	Clause 6.15.2

Introduction

Market Rule 2.5.1 of the Wholesale Electricity Market Rules provides that any person (including the IMO) may make a Rule Change Proposal by completing a Rule Change Proposal Form that must be submitted to the Independent Market Operator.

This Change Proposal can be posted, faxed or emailed to:

Independent Market Operator
Attn: Group Manager, Development and Capacity
PO Box 7096
Cloisters Square, Perth, WA 6850
Fax: (08) 9254 4339
Email: market.development@imowa.com.au

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

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

The objectives of the market are:

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

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

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

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

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

Details of the Proposed Rule Change

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

Background

The Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10[1]) introduced a new Balancing Market that enables greater participation of Independent Power Producers in the provision of Balancing. The Balancing Market commenced on 1 July 2012.

Under the Balancing Market arrangements, if a Balancing Facility is dispatched "out of merit" (i.e. not in accordance with the Balancing Merit Order), then subject to certain exceptions it is entitled to receive constrained on compensation or constrained off compensation. Constrained on compensation is paid to ensure that a Market Generator receives at least its bid price for any energy it generates, while constrained off compensation is paid to ensure that a Market Generator does not pay more for a quantity of energy purchased in the Balancing Market than the price at which it offered to generate that energy.

To determine the amount of compensation required, for each Balancing Facility (including the Verve Energy Balancing Portfolio) and Trading Interval the IMO calculates a Maximum Theoretical Energy Schedule (Maximum TES) and a Minimum Theoretical Energy Schedule (Minimum TES), which together define a MWh output range for which the Balancing Price provides appropriate compensation. Again subject to various exceptions, if a Facility's actual output falls outside this range by more than the applicable Settlement Tolerance, the Facility is paid either constrained on compensation (for output in excess of the Maximum TES) or

[1] Available on the Market Web Site: www.imowa.com.au/RC_2011_10

constrained off compensation (for shortfalls in output compared with the Minimum TES) as applicable.

For a Scheduled Generator or the Verve Energy Balancing Portfolio, the Maximum TES and Minimum TES for a Trading Interval depend on[2]:

- the Price-Quantity Pairs and Ramp Rate Limit specified in the Balancing Submission for the Balancing Facility and Trading Interval;
- the Balancing Price for the Trading Interval; and
- the MW output level of the Balancing Facility at the start of the Trading Interval (SOI Quantity).

The Maximum TES is the MWh output that the Balancing Facility could have produced in the Trading Interval if it had been dispatched to the *maximum* MW output level consistent with the Balancing Price, given its Balancing Submission. This target level is equal to the sum of the MW quantities in the Facility's Balancing Submission's Price-Quantity Pairs that have a bid price *less than or equal to* the Balancing Price.

For example, assume a Scheduled Generator has the following Balancing Submission for a Trading Interval where the Balancing Price is $120/MWh.

Ramp Rate Limit:	1 MW/minute	
Price-Quantity Pairs	10 MW	-$1000/MWh
	20 MW	$10/MWh
	10 MW	$50/MWh
	20 MW	$120/MWh
	10 MW	$420/MWh

The target level would be 60 MW, the sum of the MW quantities in the four Price-Quantity Pairs with a bid price less than or equal to $120/MWh.

If the SOI Quantity is equal to the 60 MW target level, then the Facility is assumed to maintain its output at that level throughout the Trading Interval. This is presented graphically in Figure 1 (Case A). (Note that in these diagrams the red dotted line indicates the MW output of the Facility over time, while the shaded area under this line represents the Maximum TES (in MWh)).

[2] Outages are also taken into consideration for the calculation of Minimum TES, but they do not affect the issue addressed in this proposal.

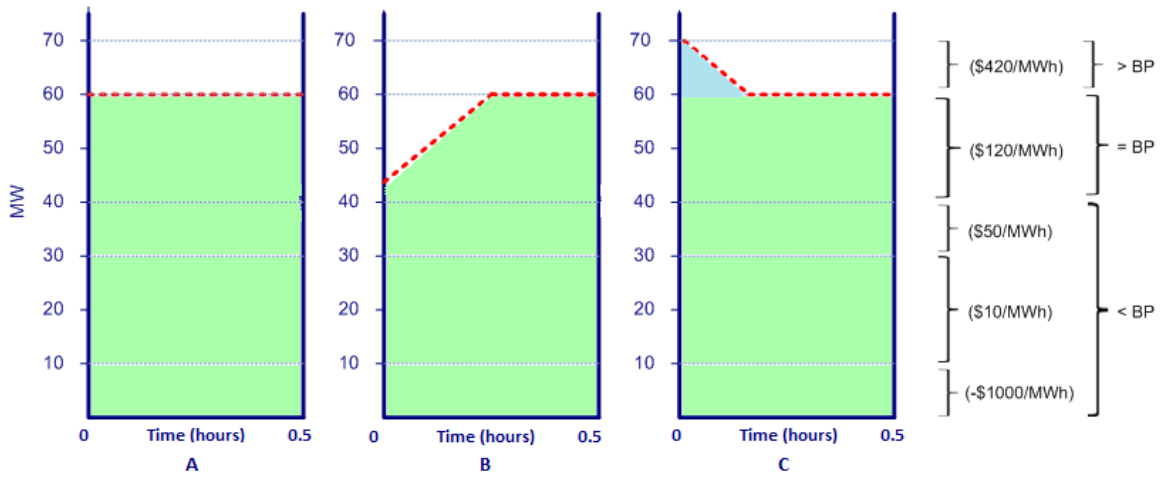

Figure 1 – Maximum TES examples for a Balancing Price (BP) of $120/MWh

If the SOI Quantity is less than the target level (Case B), then the Facility is assumed to ramp up to the target level at the ramp rate specified in its Balancing Submission and then, if it reaches the target, maintain that output level for the remainder of the Trading Interval.

It is also possible that the SOI Quantity is greater than the target level (Case C). In this case the Facility is assumed to ramp down from its SOI Quantity to its target level at the nominated ramp rate and then, if it reaches the target, maintain that output level for the remainder of the Trading Interval.

If the actual output of the Facility is greater than the Maximum TES, then the Facility may be eligible for constrained on compensation.

The Minimum TES is the MWh output that the Balancing Facility could have produced if it had been dispatched to the *minimum* MW target value consistent with the Balancing Price. Minimum TES is determined using the same assumptions as Maximum TES, except that the target level is equal to the sum of the MW quantities in the Facility's Balancing Submission's Price-Quantity Pairs that have a bid price *less than* the Balancing Price. In the example above this would be 40 MW, the sum of the MW quantities in the three Price-Quantity Pairs with a bid price less than $120/MWh.

Figure 2 shows the Minimum TES quantities (shaded areas) for SOI Quantities that are equal to, below and above the 40 MW target level.

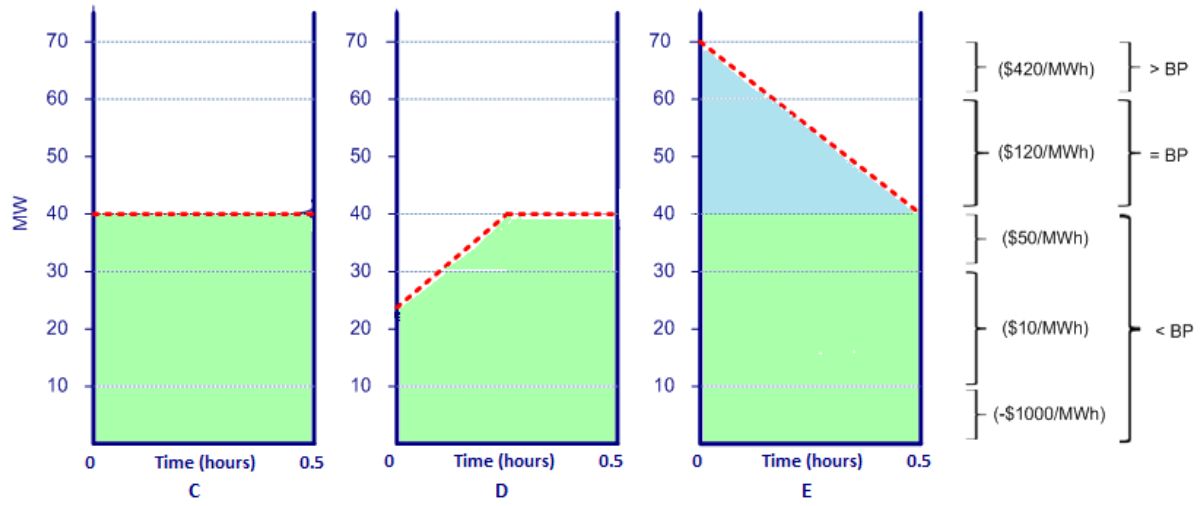

Figure 2 – Minimum TES examples for a Balancing Price (BP) of $120/MWh

If the actual output of the Facility is less than the Minimum TES, then the Facility may be eligible for constrained off compensation.

It should be noted that the Minimum TES and Maximum TES are likely to be different if there is a Price-Quantity Pair in the Facility's Balancing Submission with a bid price equal to the Balancing Price. This is because the Balancing Facility may be instructed to provide all, part or none of the output offered at that price, depending on the system demand. In other situations (apart from where an Outage has occurred) the two values will be equal.

Issue

Clause 6.15.2(a)(i) defines the Minimum TES for a Balancing Facility that is a Scheduled Generator (subject to adjustment where necessary to reflect Outages):

> *i. the sum of:*
>
> *1. the maximum amount of sent out energy, in MWh, which could have been dispatched in the Trading Interval from Balancing Price-Quantity Pairs in respect of the Balancing Facility with a Loss Factor Adjusted Price less than the Balancing Price; plus*
>
> *2. <u>if the Facility's SOI Quantity is greater than the sum of the quantities in the Facility's Balancing Price-Quantity Pairs which have a Loss Factor Adjusted Price less than or equal to the Balancing Price</u>, the minimum amount of sent out energy, in MWh, if any, which could have been dispatched in the Trading Interval from any of the Facility's Balancing Price-Quantity Pairs which have a Loss Factor Adjusted Price greater than or equal to the Balancing Price,*
>
> *taking into account the Balancing Facility's SOI Quantity and Ramp Rate Limit; and …[emphasis added]*

Clause 6.15.2(a)(i)(1) describes the energy generated from Price-Quantity Pairs below the target level, that is with a bid price less than the Balancing Price (shown as the green shaded areas in Figures 2 and 3). If the SOI Quantity is greater than the target level, then any additional energy generated from the remaining Price-Quantity Pairs as the Facility ramps

down to its target level (the blue shaded areas) is meant to be included under clause 6.15.2(a)(i)(2). However, the test specified at the start of clause 6.15.2(a)(i)(2) is incorrect, comparing the SOI Quantity with the sum of the MW quantities in the Price-Quantity Pairs with a bid price *less than or equal to* the Balancing Price.

The result is that when the SOI Quantity lies within the MW range associated with the Price-Quantity Pair bid at the Balancing Price (the "marginal tranche"), the test fails and so the additional energy required to ramp down to the target level is incorrectly excluded from the Minimum TES.

Figure 3 shows an example of the problem, based on the Balancing Submission and Balancing Price used in the previous examples. The energy represented by the blue shaded area will be excluded because the test checks whether the SOI Quantity (55 MWh) is greater than 60 MW (the sum of the MW quantities in the four Price-Quantity Pairs with a bid price less than or equal to the $120/MWh Balancing Price), rather than 40 MW (the target level for the Facility, being the sum of the MW quantities in the three Price-Quantity Pairs with a bid price less than $120/MWh). Note that if the SOI Quantity lies above the marginal tranche (as in Figure 2's Case E), then the test is passed and the energy shown in the blue shaded area is included.

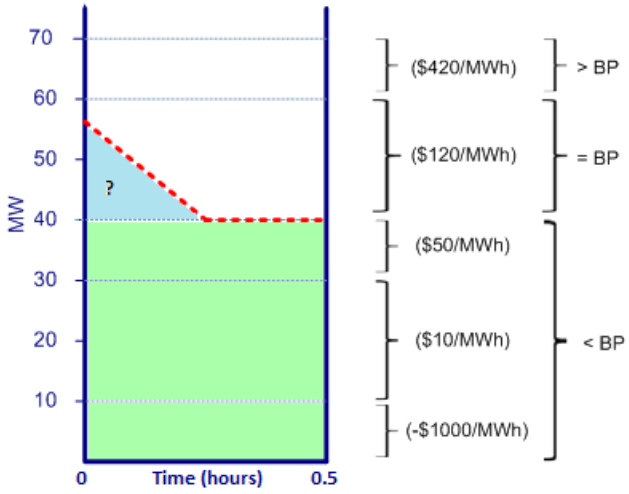

Figure 3 - Minimum TES example for a Balancing Price (BP) of $120/MWh and SOI Quantity in the marginal tranche

The same error exists in clause 6.15.2(c)(i)(2), which defines the corresponding component of the Minimum TES for the Verve Energy Balancing Portfolio.

Proposal

The IMO proposes to amend clauses 6.15.2(a)(i)(2) and 6.15.2(c)(i)(2) to ensure Minimum TES is correctly calculated in situations where the SOI Quantity is within the marginal tranche.

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2. Explain the reason for the degree of urgency:

The IMO considers that this Rule Change Proposal corrects a manifest error in the Market Rules. Under the current drafting, energy from Price-Quantity Pairs "above" the deemed target level is excluded from Minimum TES if the SOI Quantity is within the marginal tranche,

but included if the SOI Quantity falls above this tranche. This is an absurd outcome and inconsistent with the basic TES design, under which these quantities should always be included.

As such, the IMO considers that this Rule Change Proposal should be progressed using the Fast Track Rule Change Process, on the basis that it satisfies the criterion in clause 2.5.9(b) of the Market Rules.

Clause 2.5.9 states:

The IMO may subject a Rule Change Proposal to the Fast Track Rule Change Process if, in its opinion, the Rule Change Proposal:

(a) is of a minor or procedural nature; or

(b) is required to correct a manifest error; or

(c) is urgently required and is essential for the safe, effective and reliable operation of the market or the SWIS.

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

6.15.2 The Minimum Theoretical Energy Schedule in a Trading Interval equals:

(a) for a Balancing Facility which is a Scheduled Generator, the amount which is the lesser of:

i. the sum of:

1. the maximum amount of sent out energy, in MWh, which could have been dispatched in the Trading Interval from Balancing Price-Quantity Pairs in respect of the Balancing Facility with a Loss Factor Adjusted Price less than the Balancing Price; plus

2. if the Facility's SOI Quantity is greater than the sum of the quantities in the Facility's Balancing Price-Quantity Pairs which have a Loss Factor Adjusted Price less than ~~or equal to~~ the Balancing Price, the minimum amount of sent out energy, in MWh, if any, which could have been dispatched in the Trading Interval from any of the Facility's Balancing Price-Quantity Pairs which have a Loss Factor Adjusted Price greater than or equal to the Balancing Price,

taking into account the Balancing Facility's SOI Quantity and Ramp Rate Limit; and

ii. where the Balancing Facility is subject to an Outage, the maximum amount of sent out energy, in MWh, which could have been dispatched given the Available Capacity for that Trading Interval;

….

(c) for the Verve Energy Balancing Portfolio, the amount which is the lesser of:

i. the sum of:

1. the maximum amount of sent out energy, in MWh, which could have been dispatched in the Trading Interval from Balancing Price-Quantity Pairs within the Balancing Portfolio Supply Curve with an associated price less than the Balancing Price; plus

2. if the Verve Energy Balancing Portfolio's SOI Quantity is greater than the sum of the quantities in the Balancing Price-Quantity Pairs within the Balancing Portfolio Supply Curve which have an associated price that is less than ~~or equal to~~ the Balancing Price, the minimum amount of sent out energy, in MWh, if any, which could have been dispatched in the Trading Interval from any of the Balancing Price-Quantity Pairs within the Balancing Portfolio Supply Curve which have an associated price greater than or equal to the Balancing Price,

taking into account the Portfolio Ramp Rate Limit and SOI Quantity; and

ii. where a Facility in the Verve Energy Balancing Portfolio is subject to an Outage, the maximum amount of sent out energy, in MWh, which could have been dispatched given the sum of the Available Capacity of Facilities in the Verve Energy Balancing Portfolio for that Trading Interval.

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

The IMO considers that the proposed amendments will correct a manifest error in the Market Rules and are consistent with the Wholesale Market Objectives.

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

Costs:
No costs have been identified with implementing the proposed changes. In particular, the IMO has confirmed that its IT systems calculate Minimum TES in accordance with the proposed Amending Rules and so no changes to these systems are required.

Benefits:

- Corrects a manifest error in the Market Rules.
- Provides clarity to stakeholders around how Minimum TES is calculated.

Agenda Item 7a: Overview of Recent and Upcoming IMO and System Management Procedure Change Proposals

Legend:

Shaded	Shaded rows indicate procedure changes that have been completed since the last MAC meeting.
Unshaded	Unshaded rows are procedure changes still being progressed.
Red Text	Red text indicates any updates to information

ID	Summary of Changes	Status	Next Step	Date
IMO Procedure Change Proposals				
PC_2011_04 **Prudential Requirements**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Include some minor and typographical amendments to improve the integrity of the Market Procedure; • Include amendments required as a result of the Pre Rule Change Proposal: Prudential Requirements (PRC_2011_09) and o RC_2010_36 Acceptable Credit Criteria; and o RC_2011_04 List of entities meeting Acceptable Credit Criteria	• The IMO rejected this Rule Change Proposal on 19 November 2012. • Modified Rule Change Proposal and updated Market Procedure presented to the March 2013 MAC. • Procedure Change Proposal submitted to April 2013 IMOPWG meeting, but discussion deferred.	• Rule Change Proposal and updated Market Procedure presented at next MAC and IMOPWG meetings prior to being submitted into formal rule and procedure change processes.	TBA

ID	Summary of Changes	Status	Next Step	Date
PC_2012_09 **Loss Factors**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; and • Better clarify the processes in the Market Procedure. • Ensure consistency with amendments to the Market Rules which have occurred since Market Start; and • Reflect proposed changes under PRC_2012_07: Determination of Loss Factors	• Closed. This Procedure Change commenced on 20 May 2013	• Commenced	20/05/2013
PC_2012_10 Amendments to Market Procedure for IMS Interface	The proposed updates are to: • Clarify and amend the Market Procedure to ensure transparency and improve overall integrity and to address a number of minor technical inconsistencies in the practical implementation of the procedure.	• Closed. This Procedure Change commenced on 22 April 2013	• Commenced	22/04/2013
PC_2012_11 **Notices and Communications**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project. • Reflect the IMO's updated contact details.	• The Procedure was presented and discussed at the 27 November 2012 IMOWG.	• The Market Procedure to be updated to reflect the amendments agreed by the IMOWG and submitted into the formal process.	TBA

ID	Summary of Changes	Status	Next Step	Date
TBC **Undertaking the LT PASA and conducting a review of the Planning Criterion**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Include some minor and typographical amendments to improve the integrity of the Market Procedure, including re-ordering some sections; and • Include both reviews required under clause 4.5.15 of the Market Rules (Planning Criterion and forecasting processes).	• As advised at the August 2012 working group meeting, the IMO is currently undertaking the five yearly review of the IMO's forecasting processes. Following the completion of the review the IMO may make further changes to the Market Procedure.	• Updated procedure to be presented back to the Working Group for discussion	TBA
TBC **Participant Registration and Deregistration**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Revise the Market Procedure to provide more details of the relevant processes, including restructuring the Market Procedure to better present the process; • Reflect the new MPR system; • Ensure consistency with the Amending Rules from the Rule Change Proposal: Change of Review Board Name (RC_2010_18)	• Presented at the April 2013 IMOPWG meeting.	• To be updated to reflect IMOPWG discussions and submitted into the formal process.	TBA

ID	Summary of Changes	Status	Next Step	Date
TBC **Facility Registration, Deregistration and Transfer**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Reflect the new MPR system; • Revise the Market Procedure to provide more details of the relevant processes including: o restructuring the Market Procedure to better present the process; o providing further details of the consultation processes with System Management; o clarifying that there should not be any restriction on the ability to provide notifications in a manner outlined in the Market Procedure for Notifications and Communications; and o reflect the new processes for digital certificates • Ensure consistency with the Amending Rules from the following Rule Change Proposals; o Curtailable Loads and Demand Side Programmes (RC_2010_29); and o Change of Review Board Name (RC_2010_18), Including the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10)	• Presented at the April 2013 IMOPWG meeting.	• To be updated to reflect IMOPWG discussions and submitted into the formal process.	TBA

ID	Summary of Changes	Status	Next Step	Date
TBC **Settlement**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with the Amending Rules from the following Rule Change Proposals: o Settlement in Default Situations (RC_2010_04) o Change of Review Board Name (RC_2010_18); o Minor and typo (RC_2010_26) o Settlement Cycle Timelines (RC_2010_19) o Acceptable Credit Criteria (RC_2010_36)	• Underway.	• To be discussed by IMO Procedures Working Group	TBA
TBC **Meter Data Submission**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Clarify that the Procedure is part of the Settlement Market Procedures; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by the IMO Procedures Working Group	TBA
TBC **Capacity Credit Allocation**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Clarify that the Procedure is part of the Settlement Market Procedures; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by IMO Procedures Working Group	TBA

ID	Summary of Changes	Status	Next Step	Date
TBC **Intermittent Load Refund**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by IMO Procedures Working Group	TBA
TBC **Individual Reserve Capacity Requirements**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by IMO Procedures Working Group	TBA
TBC **Reserve Capacity Performance Monitoring**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with the Amending Rules from the Rule Change Proposal: Reserve Capacity Performance Monitoring (RC_2009_19)	• Underway.	• To be discussed by IMO Procedures Working Group	TBA
TBC **Treatment of Small Generators**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by IMO Procedures Working Group	TBA

ID	Summary of Changes	Status	Next Step	Date
TBC **Reserve Capacity Testing**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Reflect the new Temperature Dependence Curve • Ensure consistency with the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10)	• Underway.	• To be discussed by IMO Procedures Working Group	TBA
TBC **Information Confidentiality**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10) along with all other rule changes which have occurred since Market Start.	• Underway.	• To be discussed by IMO Procedures Working Group	TBA

System Management Procedure Change Proposals				
PPCL0024 **Monitoring and Reporting Protocol**	The proposed updates are to: • address a current SM non-compliance issue. The issue is that the Tolerance Range formula set out in the PSOP: Monitoring and Reporting differs to the Tolerance Range formula applied in practice in regards to the definition of the Rate of Change component within the formula; • remove the reference to Non-Scheduled Generators in the Section 4.1 as the formula applies only to Scheduled Generators; • Include several changes have also been made to clarify Section 4.3 of the PSOP in regards to the process for determining a Facility Tolerance Range; • Include some minor revisions to correct typographical errors and improve consistency throughout the PSOP; and • Include amendments required as a result of PRC_2013_01	• The IMO published System Management's Procedure Change Report on 22 May 2013.	• The IMO to publish its decision on PPCL0024.	06/06/2013

Agenda Item 8a: Working Group Overview

Working Group (WG)	Status	Date commenced	Date concluded	Latest meeting date	Next scheduled meeting date
System Management Procedures WG	Active	Jul 07	Ongoing	12/12/2011	TBA
IMO Procedures WG	Active	Dec 07	Ongoing	23/04/2013	TBA