INDEPENDENT MARKET OPERATOR

Market Advisory Committee

Agenda

Meeting No.	67
Location:	IMO Board Room Level 17, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Wednesday 11th December 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 66**	**Chair**	5 min
4.	**ACTIONS ARISING**	**Chair**	10 min
5.	**IMPROVEMENTS TO THE ENERGY MARKET**	**IMO**	40 min
6.	**MARKET RULES**		
	a) Market Rule Change Overview	**IMO**	5 min
	b) PRC_2013_15: Outage Planning Phase 2	**IMO**	20 min
	c) PRC_2013_20: Changes to the Reserve Capacity Price and the Dynamic Refunds Regime	**IMO**	20 min
	d) PRC_2013_21: Limit for Early Capacity Payments	**IMO**	20 min
7.	**MARKET PROCEDURES**		
	a) Overview	**IMO**	5 min

8.	**WORKING GROUPS**		
	a) Overview and membership updates	**IMO**	5 min
9.	**GENERAL BUSINESS**		
	a) Ancillary Services Review: Draft Scope	**IMO**	15 min
	b) LFAS Update	**System Management**	10 min
	c) 2013 Year in Review	**IMO**	5 min
	d) Short Term Spinning Reserve Opportunity	**System Management**	15 min
10.	**NEXT MEETING: Wednesday 12th February 2013**		

INDEPENDENT MARKET OPERATOR

Market Advisory Committee

Minutes

Meeting No.	66
Location	IMO Board Room Level 17, 197 St Georges Terrace, Perth
Date	Wednesday 13 November 2013
Time	2:00pm – 4:30pm

Attendees	Class	Comment
Allan Dawson	Chair	
Kate Ryan	Compulsory – IMO	
Clayton James	Compulsory – System Management	Proxy
Andrew Everett	Compulsory – Generator	
Matthew Fairclough	Compulsory – Western Power	Proxy
Will Bargmann	Compulsory – Customer	
Geoff Gaston	Discretionary – Generator	
Michael Zammit	Discretionary – Customer	
Shane Cremin	Discretionary – Generator	
Nenad Ninkov	Discretionary – Customer	
Steve Gould	Discretionary – Customer	
Peter Huxtable	Discretionary – Contestable Customer Representative	
Paul Hynch	Minister's appointee – Observer	Proxy (2:37pm-4:30pm)
Wana Yang	Observer – Economic Regulation Authority (ERA)	
Andrew Sutherland	Discretionary – Generator	
Apologies	**From**	**Comment**
Noel Ryan	Compulsory – Western Power	
Phil Kelloway	Discretionary – System Management	
Nerea Ugarte	Minister's appointee – Observer	
Also in attendance	**From**	**Comment**
Fiona Edmonds	Alinta Energy	Presenter (2:00pm-3:00pm)

Jenny Laidlaw	IMO	Presenter
Brendan Clarke	System Management	Presenter
Andy Stevens	Bluewaters Power	Presenter (2:00pm-4:00pm)
Simon Middleton	Merger Implementation Group	Presenter (2:00pm-3:00pm)
Erin Stone	IMO	Presenter
John Rhodes	Synergy	Observer
Paul Troughton	EnerNOC	Observer
Natalia Kostecki	Public Utilities Office (PUO)	Observer
Greg Ruthven	IMO	Observer (2:00pm-3:00pm)
Paul Lingard	King & Wood Mallesons	Observer (2:00pm-3:00pm)
Michael Georgiou	King & Wood Mallesons	Observer (2:00pm-3:00pm)
Alex Penter	IMO	Observer
Courtney Roberts	IMO	Observer
Martin Maticka	IMO	Observer (2:00pm-3:00pm)
George Sproule	IMO	Minutes

Item	Subject	Action
1.	**WELCOME** The Chair opened the meeting at 2:00pm and welcomed members to the 66th meeting of the Market Advisory Committee (MAC).	
2.	**MEETING APOLOGIES / ATTENDANCE** The following **apologies** were received: • Noel Ryan (Compulsory – Network Operator) • Phil Kelloway (Compulsory – System Management) The following **proxies** were noted: • Matthew Fairclough for Noel Ryan (Compulsory – Network Operator) • Clayton James for Phil Kelloway (Compulsory – System Management) • Paul Hynch for Nerea Ugarte (Minister’s appointee – observer) The following **presenters** and **observers** were noted: • Fiona Edmonds (presenter, Alinta Energy) • Jenny Laidlaw (presenter, IMO) • Brendan Clarke (presenter, System Management) • Andy Stevens (presenter, Bluewaters Power)	

	• Simon Middleton (presenter, Merger Implementation Group) • Erin Stone (presenter, IMO) • John Rhodes (observer, Synergy) • Paul Troughton (observer, EnerNOC) • Natalia Kostecki (observer, PUO) • Greg Ruthven (observer, IMO) • Paul Lingard (observer, King & Wood Mallesons) • Michael Georgiou (observer, King & Wood Mallesons) • Alex Penter (observer, IMO) • Courtney Roberts (observer, IMO) • Martin Maticka (observer, IMO) • George Sproule (minutes, IMO)	
3.	**MINUTES OF PREVIOUS MEETING** The minutes of MAC Meeting No. 65, held on 9 October 2013, were circulated to members prior to the meeting. The following amendments were agreed: ***Section 5a: page 4 of 14*** • The Chair questioned if it was normal for generators to have a deadband in place. Mr Kelloway stated this was the case. Mr Andrew Stevens then question if a deadband of ~~3 MW~~ 0.025 Hz was normal or was it deemed small? Mr Kelloway stated he was unsure, noting he was not a member of the Technical Rules committee. *Action Point: The IMO to amend the minutes of Meeting No. 65 to reflect the agreed changes and publish on the Market Web Site as final.*	**IMO**
4.	**ACTIONS ARISING** The Chair introduced Ms Kate Ryan to update the MAC on the current actions. The following points were noted: • **Item 42:** Ms Ryan noted that following further amendments, the minutes of MAC meeting No. 63 had been recirculated to MAC members and that no comments had been received. The recirculated minutes were agreed to be a true record of the meeting. • **Item 43:** Ms Ryan offered MAC members the opportunity to provide input into the IMO's letter to the ERA and PUO, requesting consideration of the proposal to ensure DSP's are subject to licencing, specifically under a separate licencing category. • **Item 47:** Ms Ryan noted that this item was in underway and that the relevant Pre Rule Change Proposal was scheduled to be presented at next MAC meeting in December.	

5a.	**Market Rule Change Overview** Ms Ryan noted that six Rule Changes Proposals were currently being progressed by the IMO.	
5b.	**PRC_2013_17: Correction to estimated output of Intermittent Generation for purposes of Appendix 9** Ms Fiona Edmonds provided MAC members with an overview of Alinta's Pre Rule Change Proposal. The following key comments and queries were made. • Mr Clayton James noted that System Management supported the proposal but had some concerns with its proposed wording. Mr James offered to meet with Alinta to discuss System Management's concerns. • Mr Will Bargmann proposed that where the IMO has been provided a more accurate estimate of the potential output of an Intermittent Generator that was dispatched downwards by System Management, the IMO should be obliged (rather than have the discretion) to use that estimate, should that estimate differ from the current estimate by more than a specified amount. In response the Chair invited Mr Bargmann to propose what the specified amount should be. • In response to a suggestion that System Management could routinely reassess its estimates, the Chair noted that such an approach could be inefficient and that the commercial obligation should be on Market Participants to check the estimates themselves. • Mr Bargmann noted that Participants may not notify the IMO where there has been an overestimate in their favour, and queried whether the IMO actually has the resources to identify instances where there has been an overestimate of the potential output of a Facility. In response Ms Ryan noted that an overestimate may be picked up during the certification process. Ms Jenny Laidlaw noted that it would be difficult to identify instances where an estimate of what an Intermittent Generator would have generated is in fact an overestimate, except where the estimate was above the maximum capacity of the generator.	
5c.	**PRC_2013_18: Market Rule changes arising due to the merger of the Electricity Retail Corporation and Electricity Generation Corporation** The Chair invited Mr Simon Middleton to present the Fast Track Rule Change Proposal submitted on 11 November 2013. • Mr Middleton noted that the Rule Change Proposal covered the changes to address the minor, administrative and manifest errors that need to be corrected to align the Market Rules to the Electricity Corporations Act as expected to be amended early December 2013. He also noted that a wider briefing session would be held on 5 December to cover any questions related to the merger of Synergy and Verve Energy more broadly. • Mr Middleton outlined the key issues to be addressed under the Rule Change Proposal, the Merger Implementation Group's view of the assessment against the criteria to progress the proposal under the Fast Track Rule Change Process and how the proposed	

Amending Rules would better address the Wholesale Market Objectives.

- Mr Middleton also noted that the proposal would not be decided on or commenced prior to changes to the Electricity Corporations Act being in place.

MAC members discussed the presentation. The following key comments and queries were made:

- Mr Matthew Fairclough noted that the proposed drafting of clause 2.3.5 could enlarge the size of the MAC by two members. Ms Ryan noted that it does increase the possible size of the MAC but based on the current membership, the number of members would reduce by one.
- Mr Peter Huxtable questioned if the one Synergy representative would appropriately be able to represent the largest gentailer at the MAC. Mr Shane Cremin noted that it was difficult to determine without a full understanding of the ring fencing and regulations more broadly, whether one, two or three representatives were required. Mr Middleton responded that he believed that based on the proposed structure of Synergy and restrictions on the provision of information it wouldn't be an issue only having one MAC representative.
- Mr Andrew Sutherland noted that members of the MAC ultimately are representing a class rather than a company. He further noted that there was a case for three representatives on the MAC to represent the proposed Generation, Retail and Wholesale Business Units, but it was likely that the representatives would meet prior to MAC which would defeat the purpose. Mr Bargmann noted that the issue had been discussed with the CEO of Verve Energy and Synergy and the view was that a single representative should be informed enough to represent the interests of both.
- Mr Cremin noted that without further information on the preceding regulations it was difficult for stakeholders to comment or make a judgement on the Rule Change Proposal more broadly. He noted that he believed that there were a lot of items in the proposal that shouldn't be dealt with under the Fast Track Rule Change Process and questioned why the IMO had overridden previous precedents. Mr Andrew Everett asked Mr Cremin which aspects he considered shouldn't be included in a proposal in the Fast Track Rule Change Process. Mr Cremin answered that there is nothing to suggest that any change is required or that there are in fact manifest errors in the Market Rules. He noted that the market can work without the proposed amendments and continued to discuss previous issues with the Market Rules that had not been quickly addressed by the IMO. The Chair noted that manifest errors would arise if no changes were made to the Market Rules. The Chair also noted that the changes were primarily because the two entities were named throughout the Market Rules, where, with any other Market Participant, this type of change would only be administered through the registration processes.
- Mr James noted that many Power System Operating Procedures will also need to be changed as a result of the merger but that

System Management has not yet developed a schedule for making the necessary changes.

- Mr Sutherland questioned if there would be further rule changes as a result of the merger. Mr Middleton responded that the submitted Rule Change Proposal was all that is required to give effect to the merger at this time. He noted that there are existing provisions in the Market Rules to monitor the performance of the merged entity and further suggested that as the merged entity began operating, different parties will review its behaviour and form views as to whether the Market Rules are adequate. The Chair clarified that the IMO Board has highlighted this as a potential issue and commenced discussions with the ERA but noted that without visibility of the provisions in the proposed regulations the IMO is not in a position to assess whether any further changes would be required.
- Mr Cremin questioned if Ministerial approval was required. Ms Ryan confirmed that Ministerial approval was required as the Amending Rules proposed changes to Protected Provisions.
- Mr Sutherland made a comment that the merger appeared to have taken a considerable amount to the IMO's resources which were notionally allocated to other issues and rule changes. He questioned whether this was commensurate with any other externally driven Rule Change Proposal and whether the Merger Implementation Group should be paying for extra resources to compensate the IMO. The Chair noted that the IMO estimated the costs to facilitate the merger to be in the region of $300,000 and that it was capturing these costs and reporting them to the Minister quarterly and would report them in the IMO's Annual Report. Mr Sutherland noted that this only represented the direct cost or the merger not the opportunity cost. Mr Middleton noted that the costs associated with this proposal should be treated as other externally driven Rule Change Proposals.
- Dr Natalia Kostecki questioned whether the PUO would be requested to provide advice to the Minister on the approval of the Rule Change Proposal. Mr Middleton confirmed that the Merger Implementation Group would be providing advice to the Minister on this issue.
- Mr Andy Stevens queried whether the Rule Change Proposal would encourage the efficient entry of new competitors as purported in the assessment against the Wholesale Market Objectives and noted that he hoped the other benefits were correct. Mr Everett noted that the Rule Change Proposal is not proposing the merger, rather it is implementing the merger decision.
- Mr Nenad Ninkov questioned whether the IMO was confident that the proposed changes qualified to be progressed under the Fast Track Rule Change Process. Ms Ryan confirmed that the IMO had completed a fast track rule change assessment and was satisfied that it had passed the test. Ms Ryan also reiterated that the IMO Board would not approve the Amending Rules until the amendments to the Electricity Corporations Act have been made.

	The Chair closed the agenda item reminding MAC members that the Rule Change Proposal was open for consultation and they were able to provide any further comments through that process	
5d.	**PRC_2013_16 Outages and the application of Availability and Constraint Payments to Non Scheduled Generators** The Chair invited Ms Erin Stone to present the Pre Rule Change Proposal. Ms Stone noted that the principles in the proposal have not changed since the concept paper was presented at the August MAC meeting but that the Pre Rule Change Proposal contained the proposed Amending Rules to implement the agreed concepts. The Chair opened the floor for questions and comments. The following key comments and questions were discussed: • Mr Sutherland questioned whether the drafting required the logging of ex-ante Consequential Outages, or was intended to allow for it. Ms Stone answered that the intent is that Market Participants are able to but not required to log these Outages in advance. Mr Sutherland requested that the IMO ensure that it is made clear that this is not mandatory in the drafting of the proposed Amending Rules. • Mr James reiterated System Management's support of the principles contained in the Pre Rule Change Proposal but noted that it was large and proposed that the rule change be split into a number of smaller rule changes for the practicality of implementation. • Mr James also requested that two more issues be considered. One regarding the treatment of Outages with respect to shared declared sent out capacity limits and runback schemes and the other regarding temperature dependence. Ms Stone noted that while these issues are becoming more relevant with the prevalence of such schemes they should be reviewed more holistically and addressed as part of a separate piece of work. • Mr Sutherland questioned the application of the proposed Amending Rules to Scheduled Generators rather than just Non-Scheduled Generators as implied by the title and opening paragraphs or the proposal. Ms Stone agreed that the definition of an Outage in particular was common across Facility Classes but that the changes primarily affected Non-Scheduled Generators. • Mr Bargmann noted the complexity of the Rule Change Proposal and, in particular, the translation of words currently in the Market Rules, to formulae in the appendices and questioned what process the IMO were undertaking to ensure that the rules are accurately translated. Ms Stone noted that the formulae as currently drafted reflect what is currently in the settlement system but noted the possibility of an audit of the current clauses in the Market Rules, the proposed formulae and the current systems. • Mr Bargmann also questioned the use of SCADA data to settle parts of the market, noting its unreliable nature. Ms Stone noted that the use of SCADA and Meter Data had not changed under this Rule Change Proposal.	

	• Mr Geoff Gaston questioned whether this Rule Change Proposal would address the last of the incorrect constrained on/off payments. Ms Stone agreed that was the intention. • Mr Sutherland noted that a representative from ERM Power was still considering the Amending Rules with respect to the impact of Load Following Ancillary Service (LFAS) quantities on constraint payments. Ms Stone agreed to contact the ERM representative to discuss the issue further. • Ms Stone also noted that Alinta had arranged a meeting to discuss some potential operational issues arising from the proposal. • Mr Ninkov noted that the issues related to network constraints and quality of connections should be investigated further. *Action Points:* • *The IMO to organise an external audit of the consistency of the existing Market Rules, proposed formulae and current systems with respect to PRC_2013_16;* • *The IMO to review the ability to split PRC_2013_16 into smaller changes and discuss with System Management;* • *ERM Power to check the consistency of application of constraint payments with respect to LFAS that is currently in the Market Rules with that proposed in PRC_2013_16 and notify the IMO of its findings; and* • *The IMO to ensure the proposed Amending Rules in PRC_2013_16 do not require ex-ante logging of Consequential Outages.*	**IMO** **IMO/SM** **ERM** **IMO**
6a.	**CP_2013_13: Collection of Market Fees** The Chair invited Mr Stevens to present the concept paper. • Mr Stevens noted that the concept paper was developed to seek agreement from MAC members that the current method of recovering fees on an energy only basis can be improved upon. Mr Stevens outlined a proposal to collect fees on both a capacity and energy basis. • Mr Stevens discussed the proposed approach, noting that for the allowable revenue period this would result in 72% of fees charged to the energy market and 28% to the capacity market. MAC members discussed the presentation. The following key comments and queries were made: • ~~Mr Cremin questioned~~A question was asked how market fees were charged in the National Electricity Market (NEM). The Chair made the observation that it was difficult to compare Wholesale Electricity Market fees to NEM fees, as the NEM fee structure was very complex but the principle was to allocate costs based on the different services provided. • Mr Paul Troughton commented that he was aware of three other International markets in New England, New York ISO and PJM in the USA that have capacity markets, where primarily market fees are charged on an energy only basis. He noted that PJM charged a small	

percentage of fees to the capacity market, estimating that this was equal to one twentieth of the proposed fees in the SWIS. Mr Stevens questioned whether that was for both supply-side and demand-side resources. Mr Troughton noted he had not looked into that level of detail.

- Mr Troughton noted that as this was not about sending price signals to end-users but rather just a cost recovery of a primarily fixed fee, it was difficult to see why a great deal of effort should be put into changing the regime. Mr Sutherland added that he believed it would create another level of inefficiency as it was likely that the Reserve Capacity Price would rise by the same amount that Market Fees could be charged and therefore would simply be a wealth transfer.
- Mr Sutherland questioned if the amount would be added to the Reserve Capacity Price. Mr Stevens suggested that it should not flow through. Mr Cremin noted that it would have to be added to the Reserve Capacity Price as it is a cost of conducting business. The Chair noted that the IMO had not considered the impact of the proposed changes on the Reserve Capacity Price.
- Mr John Rhodes questioned what the impact would be. Mr Stevens responded that he believed it was approximately $450 per MW per year. Mr Stevens later corrected this to be $750 per MW per year.
- MAC members raised a number of other options including a fixed fee per meter, charging straight to the end-user, charging an application fee and fixed and variable fee splits. The Chair noted that another market had split its fees as fixed and variable and it resulted in some absurd outcomes and barrier to entry for smaller entities and was unwound quite quickly.
- Mr Everett questioned how the proposal could reduce the long-term cost of electricity given that the Market Fees are fixed for the allowable revenue period. Mr Stevens responded that where capacity is not utilised there is no end-user to recover costs from, and therefore operational costs such as Market Fees will be borne by the individual Market Participant. Mr Stevens noted that this will reduce the long-term cost of electricity by ensuring that Market Participants with lower levels of utilisation bear these costs individually rather than the market as a whole.
- MAC members suggested that the IMO consider the construct of the Reserve Capacity Price to determine the impact on it as a result of the redistribution of Market Fees. The Chair agreed that the IMO needed to look at this issue.
- Mr James noted that the allocation between the energy and capacity market was less clear for System Management and it needed to develop a better understanding of its undertakings with respect to the capacity market. The Chair noted that the ERA's costs would also need to be reviewed prior to the agreement of a cost allocation methodology.

Action points:

- *The IMO to conduct further analysis to determine the impact of the allocation of Market Fees to the capacity market, in particular, with* **IMO**

	respect to the Reserve Capacity Price; and • *System Management to review its cost allocation between the energy and capacity market to assist Bluewaters' Rule Change Proposal to amend the Market Fees structure.*	**SM**
7.	**System Restart Service issues and update** Mr Clarke gave a presentation on System Restart Service: Issues and Update. The following key comments and queries were made: • Mr Clarke noted that the purpose of the update was to provide transparency around how System Management currently procures System Restart Services and what opportunities exist for new entrants to provide this service. • Mr Ninkov queried the current cost of the System Restart Services. Mr Clarke responded that the cost of System Restart Services was incorporated into the Cost_LR parameter determined every three years by the ERA, but the actual amount paid is whatever is agreed in the relevant contracts (currently approximately $520,000 per year). Ms Wana Yang disagreed, considering that the actual amount paid could not be more than the Cost_LR value. The Chair noted that the IMO would check this. • Mr Ninkov queried whether there was an extra cost levied where the System Restart Service is actually used. Mr Clarke responded that the costs associated with the Facility actually running (and being tested) were already included in the contract price. Mr Ninkov queried who paid for the costs of testing the Facilities. The Chair noted that the costs were recovered from Market Customers via the settlements process. • Mr Clarke noted that the contracts were re-let every five years and that all existing contracts would expire on 30 June 2016. Mr Clarke also noted that there were very few providers of System Restart Services and that consideration needed to be given as to what the best mechanism for procuring the service is. • Mr Michael Zammit queried how many of the existing generators could conceivably provide System Restart Services. Mr Clarke noted that in addition to those Facilities currently providing the service, some of the other open cycle gas turbines could also provide the service if they invested in the required additional infrastructure. Mr Cremin queried whether any of the generators near to the goldfields could provide System Restart Services. In response Mr Clarke noted that the generators in the goldfields are too small to re-energise the system given the long distances over which their transmission link to Perth spans. Mr Clarke noted that the generator at Merredin faced similar issues. • Mr James noted that the reason why three Facilities were used to provide System Restart Services was to allow for extreme situations, such as where one of the Facilities is on maintenance and another one fails during the restart process. • Ms Yang suggested that consideration should be given to ensuring	

	that System Restart Services have a level of regulatory oversight consistent with that which applies to other Ancillary Services. • Mr Clarke noted that System Management would be coming back to the MAC in the future to seek input from the MAC on the issues relating to System Restart Services. *Action Point: The IMO to check whether the maximum amount paid for System Restart Services is limited to Cost_LR.*	**IMO**
8.a	**Market Procedures overview** Ms Ryan noted that in the next month there would be consultation on the Market Procedures relating to settlement and prudential requirements, as well as one or two System Management Power System Operation Procedures.	
9a.	**Working Groups overview and membership updates** Mr Rhodes was approved by the MAC to be the new representative of Synergy on the System Management Procedure Change and Development Working Group.	
10a.	**GENERAL BUSINESS** **Update on LFAS** Ms Laidlaw provided an update to MAC members on the ongoing investigations into the LFAS Requirement by the IMO and System Management. Ms Laidlaw advised MAC members that the IMO intended to publish the presentation on the Market Web Site. The following points were discussed. • The Chair questioned whether the investigation team had built a sufficient foundation of knowledge to allow it begin sculpting the LFAS Requirement in 2014. Ms Laidlaw considered that while it should be possible to begin sculpting the LFAS Requirement next year there were some key issues that needed to be addressed. In particular, Ms Laidlaw suggested that unless the current load forecasting issues were addressed the occurrence of random load forecasting errors could cloud the analysis results needed to implement sculpting. • The Chair also queried the likely timeframe for the implementation of an accurate "causer pays" LFAS cost allocation methodology. Ms Laidlaw responded that the current plan was to undertake this work following the completion of the five year Ancillary Services Review in November 2014, which would, among other things, consider how to measure some of the quantities that would be required for accurate cost allocation. • In response to a query from Ms Yang, Mr James and Ms Laidlaw confirmed that the team would be investigating how best to identify and deal with errors in the load forecasts used for dispatch. *Action Point: The IMO to publish on the Market Web Site the presentation for the November 2013 MAC: LFAS Requirement Investigation Update.* **MAC annual review** The Chair noted that the annual MAC review process would be underway	 **IMO**

	shortly and that the call for nominations would be published soon. The Chair noted that one customer representative position was up for nomination as was one generator representative position as well. The Chair noted that there would also be some changes to Synergy and Verve Energy's representation due to their merger. The chair then circulated to MAC members the proposed 2014 MAC meeting dates. Ms Ryan noted that the IMO would circulate recent figures for constrained on/off payments to MAC members in the next week. No other general business was noted *Action Point: The IMO would circulate recent figures for constrained on/off payments to MAC members.*	**IMO**
CLOSED: The Chair declared the meeting closed at 4:30pm.		

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
42	2013	The IMO to amend the minutes of Meeting No. 63 and publish as final on the IMO website.	IMO	Oct	Complete.
43	2013	The IMO to write a letter to the ERA and PUO requesting consideration of the proposal to ensure DSP's are subject to licencing, specifically under a separate licencing category.	IMO	Oct	Underway.
47	2013	The IMO to reflect the justifications for the recycling regime and present the PRC to the MAC.	IMO	Oct	Complete.
49	2013	The IMO to amend the minutes of Meeting No. 65 to reflect the agreed changes and publish on the Market Web Site as final.	IMO	Nov	Complete.
50	2013	The IMO to organise an external audit of the consistency of the existing Market Rules, proposed formulae and current systems with respect to PRC_2013_16.	IMO	Nov	Underway.
51	2013	The IMO to review the ability to split PRC_2013_16 into smaller changes and discuss with System Management.	IMO/SM	Nov	Complete.

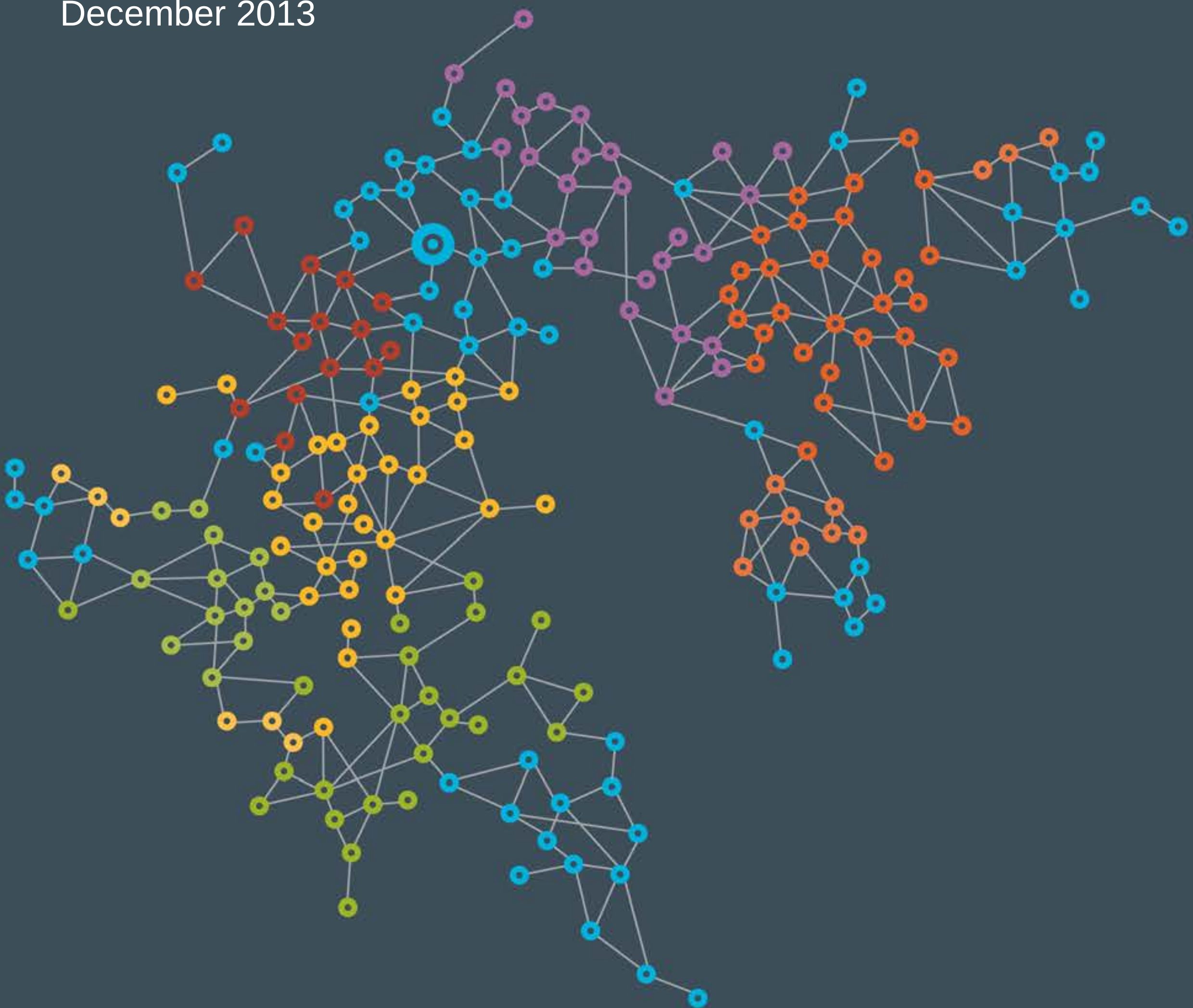
#	Year	Action	Responsibility	Meeting arising	Status/Progress
52	2013	ERM Power to check the consistency of application of constraint payments with respect to LFAS that is currently in the Market Rules with that proposed in PRC_2013_16 and notify the IMO of its findings.	ERM	Nov	
53	2013	The IMO to ensure the proposed Amending Rules in PRC_2013_16 do not require ex-ante logging of Consequential Outages.	IMO	Nov	Complete.
54	2013	The IMO to conduct further analysis to determine the impact of the allocation of Market Fees to the capacity market, in particular, with respect to the Reserve Capacity Price.	IMO	Nov	Complete. Update to be given at December 2013 MAC.
55	2013	System Management to review its cost allocation between the energy and capacity market.	SM	Nov	
56	2013	ERA to review its cost allocation between the energy and capacity market.	ERA	Nov	
57	2013	The IMO to check whether the maximum amount paid for System Restart Services is limited to Cost_LR.	IMO	Nov	Complete. Update to be given at December MAC. Further information is included in the Final Rule Change Report for RC_2010_33: Cost_LR.
58	2013	The IMO to publish on the Market Web Site the presentation for the November 2013 MAC: LFAS Requirement Investigation Update.	IMO	Nov	Complete.
59	2013	The IMO would circulate recent figures for constrained on/off payments to MAC members.	IMO	Nov	Complete.

INDEPENDENT
MARKET
OPERATOR

Enhancements to the Energy and LFAS Markets

Prepared by Jim Truesdale

December 2013



Contents

1. Introduction

I have been asked to consider a number of development issues relating to the Balancing and LFAS Markets and the STEM and Bilateral Submissions processes.

By way of background I understand that:

- At the October 2013 MAC meeting a Market Rules Evolution Plan (MREP) update paper[1] and an LFAS investigation paper[2] were discussed. There was general support for advancing the removal of Resource Plans, reduction of Balancing and LFAS gate closure times, and investigating rolling LFAS Gate Closure. This paper considers implementation issues, including some consequential effects.

- The possibility of Verve Energy facility-based participation in the Balancing and LFAS Markets has been raised in stakeholder discussions, including regarding the Verve Energy-Synergy merger. This paper considers the rationale for making such a change and the potential implications.

- At the October 2013 MAC meeting there was general support for splitting out changes to the STEM and Bilateral Submissions included in the top ranked MREP item, from the issues discussed above. These issues require more consideration, including the timeframes over which participants wish to hedge and how, and may also be impacted by the Verve Energy-Synergy merger, details of which are yet to be confirmed. This paper therefore canvasses issues and options at a relatively high level to promote discussion with and feedback from MAC members.

The rest of this paper is structured along the above lines.

2. LFAS and Balancing Issues

2.1. Removal of Resource Plans

Rationale

Independent Power Producers (IPPs) are required to submit Resource Plans by 12:50 pm each day to indicate how they would operate their Facilities during the following Trading Day to meet their contractual commitments including any shortfall. However, System Management now dispatches IPP Facilities and the Verve Energy Balancing Portfolio (VEBP) in accordance with the Balancing Merit Order (BMO) and LFAS Merit Order. Resource Plans are therefore not binding and actual Facility operation may not match day-ahead contractual positions. Balancing and LFAS market forecasts should therefore provide more meaningful indications of expected dispatch. That would enable Resource Plan requirements and processes to be dismantled. However, initial market forecasts are currently available after 6:00 pm, around 5 hours after Resource Plan submissions.

[1] “Market Rules Evolution Plan: 2013-2016, October 2013 Update”.

[2] “LFAS Requirement Investigation: Analysis of LFAS causes and usage”.

Consequential issues

In principle, Resource Plans provide early insights into potential generation schedules in advance of market forecasts, enabling System Management to assess likely facility commitment decisions, check network load flow implications and develop the initial Verve Energy Dispatch Plan. Absent Resource Plans, these processes would need to commence later in the Scheduling Day once initial market forecasts are available. System Management could attempt to use Net Contract Positions for that purpose but in some instances would need to make assumptions about how commitments would be spread between Facilities. Verve Energy would also need to prepare its initial VEBP Balancing Submission without information from System Management regarding IPP Resource Plans. It would be preferable to bring forward the timing of initial Balancing Submissions to replace Resource Plans and provide a better basis for System Management and participant planning.

Removing Resource Plans would involve a number of detailed changes to the Market Rules. This would largely be a drafting exercise but some design issues would also need to be addressed.

- The time at which initial Balancing and LFAS Submissions are required would need to be confirmed. Notwithstanding the possibility of changes to market timeframes for other reasons, initial Balancing and LFAS Submissions could be advanced to around the time participants are currently required to submit Resource Plans, maintaining consistency with the timing of fuel nominations. Verve Energy would have to make its VEBP Balancing Submission without the information about aggregate IPP Resource Plans it currently receives indirectly under the Market Rules from System Management[3]. However, Verve Energy could form its initial submission around its Net Contract Position[4] which should be a reasonable proxy. Verve Energy would be able to make another submission at 6:00 pm as it can now[5].

- In submitting Resource Plans, participants are required to include any shortfall relative to their Net Contract Position[6], which is then factored into Capacity Refund calculations. Refund calculations already take account of Forced Outages prior to STEM Submissions and in balancing/ real time so removing the Resource Plan shortfall element should not have any material impact.

- Where a Scheduled Generator does not meet the Balancing Facility Requirements, the participant must make Balancing Submissions with respect to the Facility's Resource Plan[7], i.e. capacity up to the Facility Resource Plan level must be offered at the Minimum STEM Price and remaining capacity must be offered at the relevant Maximum STEM Price. This requirement could be reworded by removing the

[3] Rule 7.6A.2 requires that System Management provide to Verve Energy by 4:00 pm each day a forecast of VEBP generation taking into account overall system requirements less (among other things) aggregate energy associated with Resource Plans and forecast non-scheduled generation.

[4] Following the merger, Verve Energy will also need to account for self-supply.

[5] In fact Verve Energy appears to frequently make its initial submissions before the 6:00 pm deadline, sometimes a few hours beforehand (observation based on submissions for the three months ending Oct 2013).

[6] Rule 6.11.1 (e) [Resource Plans must include] "…*any shortfall in MWh for each Trading Interval between the net energy scheduled in the Resource Plan Submission and the Net Contract Position of the Market Participant".*

[7] Balancing Facility Requirements Procedure (s4.1).

reference to the Resource Plan and requiring that generation from the Facility must only be offered at the Minimum STEM Price or relevant Maximum STEM Price and, subject to Forced Outage, the MW profile fixed for the day.

- Market Customers with Dispatchable Loads are currently required to submit Resource Plans[8] and prices for dispatch which are incorporated into the Non-Balancing Dispatch Merit Order[9]. An alternative mechanism would need to be provided for Dispatchable Loads to submit MW profiles.

- Participants are required to include in their Resource Plans the times when they expect to synchronise or desynchronise their Scheduled Generators[10]. However, whether a Facility operates at its Resource Plan level now depends on Balancing Submissions and, as noted previously, market forecasts should provide a more meaningful indication of commitment decisions. Note also that participants are required to accurately reflect in their Balancing Submissions all information reasonably available to them[11]. Participants are also required to confirm with System Management decisions to commit or de-commit Scheduled Generators at least 1 hour beforehand[12]. Accordingly additional provisions requiring participants to advise System Management of expected synchronisation/ de-synchronisation times are not considered necessary.

Implementation overview

Impacts on	High level overview of changes required
Rules and procedures	Provisions relating to Resource Plans would be removed and other changes made where necessary to address the consequential issues noted above.
IMO Market Systems	The IMO would need to adapt its market systems so as to remove Resource Plans; provide for Balancing Submissions, LFAS Submissions and market forecasts to commence earlier; provide an alternative means for Dispatchable Loads to submit their load profiles[13]; and modify settlement systems to account for the removal of Resource Plan shortfalls.
System Management	Instead of Resource Plans, System Management would be able to use market forecasts for assessing expected generation schedules and any impacts on network load flows, Verve Energy commitment decisions, Network Control Service Contracts etc. Participant Net Contract Positions would still be available to System Management, as now[14], to consider in developing the VEBP Dispatch Plan which it would provide to Verve Energy, as now, at 4:00 pm each Scheduling Day.

[8] Rule 6.5.1A.

[9] It is understood that there are currently no Dispatchable Loads in the WEM.

[10] Rule 6.11.1b(ii)

[11] E.g. Rule 7A.2.8 and following.

[12] Rule 7.9.

[13] In practice, retaining Resource Plans solely for this residual purpose may the simplest way to give effect to this.

[14] Rule 6.4.2. requires the IMO to provide System Management the total Bilateral Contracts and cleared STEM quantities by Market Participant by 10:30 am for each interval in the following Trading Day.

Impacts on	High level overview of changes required
Verve Energy	Verve Energy would make its initial portfolio submissions earlier in the day absent Resource Plan information from System Management and in advance of the VEBP Dispatch Plan System Management provides at 4:00 pm on the Scheduling Day.
IPPs	Instead of preparing Resource Plans, IPPs would, in a similar timeframe, prepare their initial Balancing and LFAS Submissions. It would be a requirement that where a generation facility does not meet the Balancing Facility Requirements, capacity must be bid only at the Minimum STEM Price or the relevant Maximum STEM Price, with strict limitations on rebidding. Submissions could also be formulated in this manner should an IPP wish to replicate the current Resource Plan approach (if it intends to operate at its Net Contract Position).
Dispatchable Loads	Dispatchable Loads would still be required to submit Consumption Increase Prices and Consumption Decrease Prices, as now, with MW profiles (which could be a residual use for Resource Plans or an alternative arrangement).

2.2. Reducing LFAS and Balancing Gate Closure

Rationale

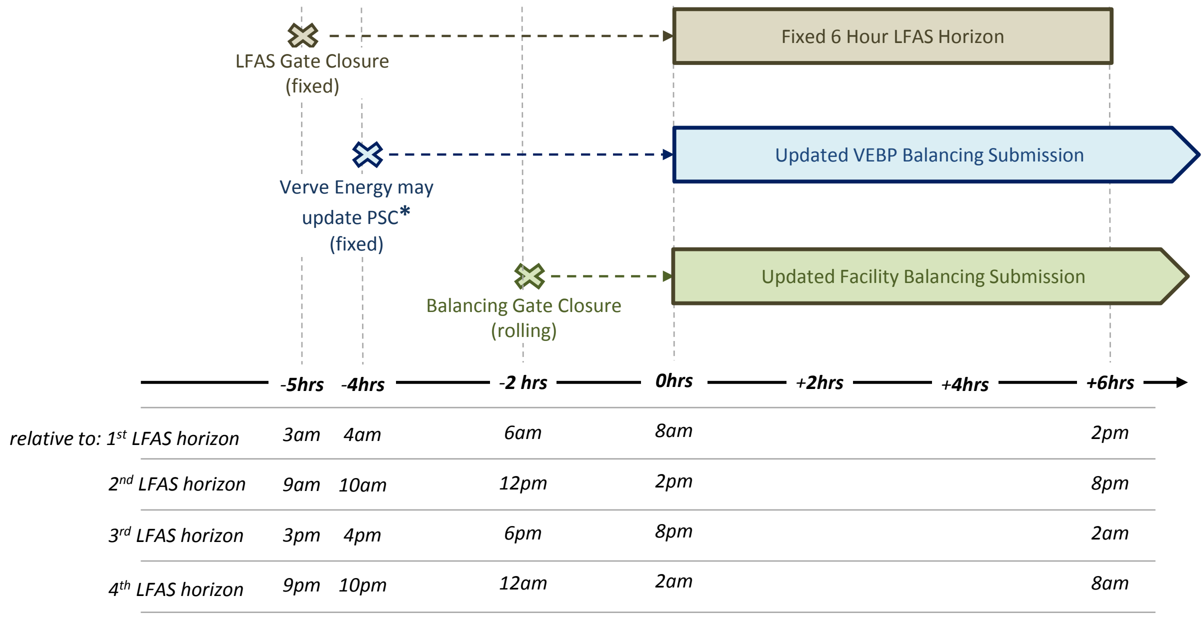
Reducing gate closure times could assist short term participation and risk management in the physical markets, improving overall market efficiency.

Reducing LFAS and Balancing Gate Closure times should provide more flexibility for participants to respond to changing market conditions resulting from changes to demand or non-scheduled generation forecasts, unexpected generation outages (or early return to service) and/or fuel supply constraints. Participants would also have greater certainty about their own fuel and plant status when making their final submissions. It may also better enable System Management to adjust the LFAS Requirement to suit expected system conditions[15] and, if System Management were to determine that a lower level of LFAS is required in a Trading Interval, both potentially reduce LFAS costs and allow LFAS participants to adjust their Balancing submissions to include any capacity that was not required for LFAS.

Options for reducing gate closure times

The current relationships between LFAS Gate Closure, the final times at which VEBP Balancing Submissions may be updated and gate closure for facility based Balancing Submissions are illustrated below.

[15] Currently Rule7B.1.5 enables System Management to update forecast LFAS Requirements up to 1 hour before LFAS Gate Closure. However that is 6 hours before the LFAS Horizon starts and 12 hours before it ends.



** Verve Energy may also update LFAS Submissions at this time for the LFAS Horizon after next*

Points of note:

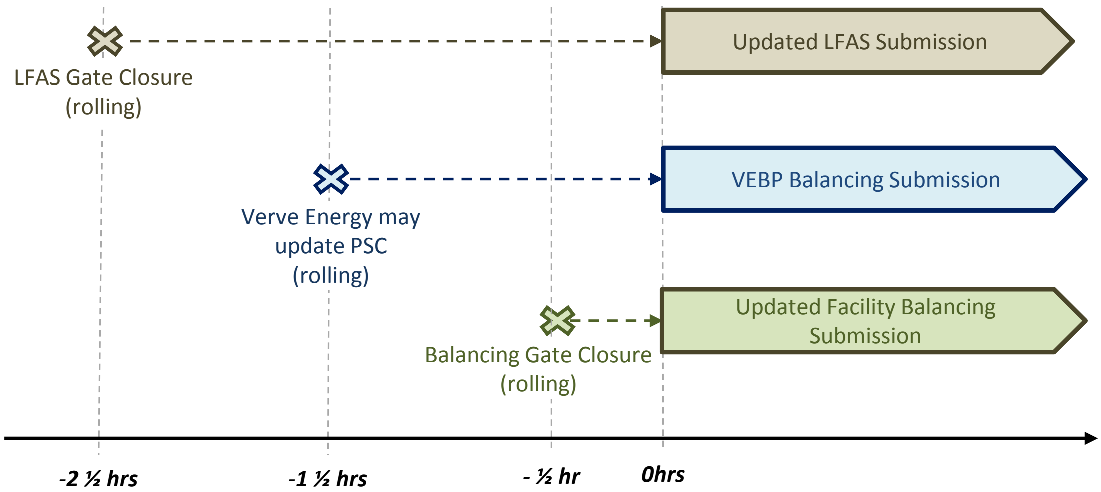
- Facility-based Balancing Submissions are subject to rolling gate closure 2 hours prior to the relevant Trading Interval.
- LFAS is scheduled in four fixed 6 hour horizons, the first starting at 8:00 am, the second at 2:00 pm and so on.
- LFAS Gate Closure (for IPPs) is currently 5 hours prior to the first Trading Interval in the LFAS Horizon (set in the Market Rules as 3 hours prior to Balancing Gate Closure for the first Trading Interval in the LFAS Horizon).
- Within an hour after LFAS Gate Closure, Verve Energy is able to make final VEBP Balancing Submissions for Trading Intervals from the start of the LFAS Horizon and final LFAS Submissions for the LFAS Horizon after next.

The rolling gate closure for facility based Balancing Submissions could be reduced from 2 hours to 30 minutes[16]. However, the extent to which LFAS Gate Closure can be reduced is limited by the sequential approach to clearing the LFAS and Balancing Markets. i.e. Verve Energy is able to update the VEBP Balancing Submission within an hour after LFAS Gate Closure taking into account the cleared LFAS schedule and, given concerns about market power, two hours before IPPs make their final Balancing Submissions for the first interval in the LFAS Horizon. The fixed LFAS Horizon is also a limitation.

[16] It may be practical to have a shorter Balancing Gate Closure depending on market system capabilities to update the BMO, publish forecasts etc and on System Management's ability to implement a new BMO prior to the interval.

For example, reducing Balancing Gate Closure to a ½ hour and allowing Verve Energy to update the VEBP Balancing Submission an hour (instead of two)[17] before Balancing Gate Closure for the first interval in the LFAS Horizon is unlikely to have any material impact. IPP LFAS Submissions would be locked in 2½ hours before the start of the relevant LFAS Horizon and 9 hours before the end of the last interval. The corresponding times for the VEBP would be 7½ hours and 14 hours[18]. If the LFAS Horizon were also reduced, to say 4 hours, then final IPP LFAS Submissions could be made 7 hours before the end of the last interval in the LFAS Horizon. Verve Energy would be able to update LFAS Submissions 10 hours before the end of the last interval in an LFAS Horizon. Shortening the LFAS Horizon would also require additional opportunities for Verve Energy to update VEBP Balancing Submissions after LFAS Gate Closure. It may be better to consider rolling LFAS Gate Closure.

A paper presented to the MAC in October 2013 indicated a number of potential improvements to LFAS arrangements but noted that LFAS Gate Closure times may need to be reduced to achieve significant results. It also recommended that rolling LFAS Gate Closure be considered. To properly account for LFAS clearing outcomes with rolling gate closure, Verve Energy would need rolling opportunities to update VEBP Balancing Submissions to reflect cleared LFAS schedules[19]. The sequencing of submission updates would still be a limiting factor but a rolling LFAS Horizon would provide greater flexibility than fixed LFAS Horizons. The following diagram illustrates how such an arrangement could operate.



Because Facility LFAS Submissions could be updated on a rolling basis they would only be 'locked in' for 3 hours[20]. Assuming the sequential approach to submission updates was to be

[17] In effect the window would be less than 1 hour depending on how quickly market forecasts are updated and available to participants.

[18] Verve Energy is able to update LFAS Submissions for the LFAS Horizon after next at the same time as it updates VEBP Balancing Submissions.

[19] Note that Verve Energy would also need additional opportunities to update VEBP Balancing Submissions if the fixed LFAS Horizon were to be reduced.

[20] The final update for an LFAS Submission for a particular Dispatch Interval would be 2½ hours before the interval so in effect that lock-in period is 3 hours.

retained the effective lock-in time for VEBP LFAS submissions would be 4 hours[21]. The corresponding times under the 4 hour fixed LFAS Horizon option discussed above would be 7 hours for IPPs[22] and 14 hours for Verve Energy[23].

System Management would be able to update forecast LFAS Quantities until within 3½ hours of a Trading Interval, providing greater flexibility to tailor requirements to system conditions. Verve Energy would need to offer a specified minimum amount of LFAS as its gate closure falls before this time.

Note that the timeframes above assume that opportunities for Verve Energy VEBP Balancing Submission updates would be 1 hour after LFAS Gate Closure (as now) and 1 hour before Balancing Gate Closure (instead of 2 hours as at present). It may be possible to reduce these timeframes further.

A potential implication of moving to rolling gate closure for LFAS as proposed is that there could be more active participation in the LFAS Market. That and moving to a more flexible approach to the amount of LFAS required could result in more frequent changes in cleared LFAS quantities. If so that could result in participants, including Verve Energy for the VEBP, needing to update submissions more regularly.

Overall, moving to rolling LFAS and Balancing Gate Closure would offer the greatest potential benefits.

Implementation overview

The following assumes that Resource Plans have been removed and initial Balancing and LFAS Submissions advanced as proposed in section 2.1. It is intended for discussion purposes rather than being a specific blue print for changes.

Impacts on	High level overview of changes required
Rules and procedures	Amend the rules enabling the IMO to set Balancing Gate Closure so that the lower limit of the range is a ½ hour[24]. Amend the defined term “LFAS Horizon” to be along similar lines to the Balancing Horizon (reflecting rolling gate closure) and the term “LFAS Gate Closure” to specify 2 (instead of 3) hours prior to Balancing Gate Closure. Amend the rules to provide for VEBP Balancing Submission updates after LFAS Gate Closure for Trading Intervals for which Balancing Gate Closure is more than one hour (instead of 2) into the future[25].

[21] Verve Energy would be able to make its final LFAS Submission for an interval an hour after LFAS Gate Closure so in effect the lock-in period is 4 hours to the end of the interval for which the submission applies.

[22] LFAS Gate Closure (2½) hours plus 4 ½ hours to the end of the last interval in the 4 hour fixed LFAS Horizon.

[23] The final Verve Energy LFAS Submission for an interval would be an hour after the fixed LFAS Gate Closure for the previous LFAS Horizon so in effect the lock-in period would be 9½ to the start of the relevant LFAS Horizon plus 4½ hours to end the last interval.

[24] Under Rule 7A.1.17 the IMO may notify, at least 2 months in advance, a change in Balancing Gate Closure time. It appears, through reference to Rule 7A.1.16, that the IMO’s selection is limited to between 6 hours and 2 hours.

[25] Rule 7A.2.9(d) currently specifies 2 hours.

Impacts on	High level overview of changes required
	Consider whether it would be feasible to further reduce the times between LFAS Gate Closure, VEBP Balancing Submission updates and Balancing Gate Closure.
IMO Market Systems	Confirm functionality for changing gate closure times (LFAS and Balancing) and VEBP submission update times. Similarly with regard to rolling LFAS Submissions and VEBP Balancing Submissions. It is understood that subject to more detailed evaluation these changes are likely to be relatively straightforward to implement.
System Management	With shorter and rolling LFAS Gate Closure would be able to forecast LFAS requirements closer to real time. May need to adjust LFAS schedules more often If rolling gate closure leads to more active participation in the LFAS market. May need to amend Power System Operation Procedures regarding revised LFAS arrangements.
Verve Energy	Would be able (and may have to) to update LFAS Submissions and update VEBP Balancing Submissions closer to real time and on a rolling basis. If System Management looks to vary LFAS forecasts according to system conditions, given the ability to update LFAS forecasts up to an hour before LFAS Gate Closure (after Verve Energy's final LFAS Submission) Verve Energy would be required to offer a minimum amount of LFAS[26].
IPPs	Would be able to update LFAS and Balancing Submissions much closer to real time. Would have 1 hour (rather than 2) to update Balancing Submissions after VEBP Balancing Submission updates.

3. Facility based offers and dispatch

This would involve Verve Energy making submissions for each of its Facilities to be dispatched on the same basis as other participants' Facilities (including the form of submissions, gate closure, surveillance etc).

3.1. Rationale

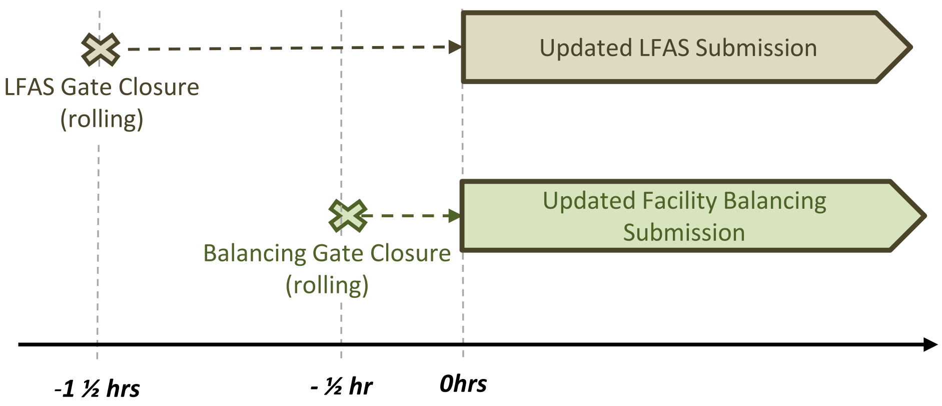
Moving all participants to facility-based submissions and dispatch would:

- Align the WEM more closely with conventions in other markets and alleviate concerns about Verve Energy receiving special treatment.
- Enable better monitoring of offers and dispatch relating to Verve Energy Facilities because short run marginal cost (SRMC) based offers, including ramp rates, would

[26] At present System Management does not vary the LFAS requirement, the same amount being carried for all Trading Intervals.

be specified for each Facility rather than as an aggregated supply curve within which individual Facilities cannot be identified.

- Achieve a clear delineation between the dispatch of energy and Ancillary Services within the VEBP and relative to the dispatch of other participants' Facilities.
- Remove any ambiguity about System Management's roles in the market.
- Simplify the Market Rules relating to Balancing and Ancillary Services.
- Improve overall transparency and participant confidence in entering and participating in the WEM.
- Enable Verve Energy to more actively manage its Facilities, including for Ancillary Services, with shorter and rolling gate closure for Balancing and LFAS. Verve Energy[27] would be able to make its final LFAS and Balancing Submissions at the same time as IPPs.
- Allow further reductions in LFAS Gate Closure for all participants, as illustrated below, and therefore also enable System Management to finalise LFAS forecasts closer to real time.



- Out of merit dispatch within the portfolio would no longer be internalised to Verve Energy, providing greater transparency (such costs will tend to be recovered one way or other, for example through risk premiums in VEBP submissions).
- Where out of merit dispatch within the portfolio might otherwise occur for system reasons, there would be opportunities for other generators to participate.

As for all participants, the dispatch of Verve Energy Facilities would still be subject to System Management intervention for system security purposes.

[27] It could be practical to move LFAS Gate Closure closer to Balancing Gate Closure. With co-optimisation, sequential clearing of LFAS and Balancing Markets would not be necessary and LFAS and Balancing Gate Closures would be aligned at a ½ hour.

Facility based submissions would require more active participation, with some cost to Verve Energy and System Management, but with a sharper focus on pricing and the dispatch of all Facilities.

3.2. Implementation

Verve Energy and System Management would need to alter their internal processes. In particular, under normal circumstances Verve Energy would make and express unit commitment decisions in its facility-based offers. System Management would monitor Verve Energy pre-dispatch schedules on the same basis as for other participants, with the ability to intervene if necessary to ensure system security requirements are met. Verve Energy may also need to establish some additional trading capability outside normal hours. Note that it is possible that moving to shorter and rolling LFAS Gate Closure as proposed in section 2.2 will require Verve Energy to update LFAS and VEBP Balancing Submissions more often outside normal hours.

The Market Rules currently include Stand Alone Facility (SAF) provisions. These could provide a way of transitioning the VEBP towards facility based submissions and dispatch. However, that regime is permissive and to date it is understood Verve Energy has not sought to exercise the SAF option for any of its Facilities.

If it were to be a requirement that all submissions and dispatch be facility based, provisions relating to VEBP Balancing Submissions and dispatch could be removed from the Market Rules. For example, the SAF concept and associated approvals process, separate portfolio gate closure requirements and portfolio constrained on and off provisions, etc., would be redundant. In more actively managing its own Facilities, and therefore fuel resources, Verve Energy would not need to provide System Management with portfolio dispatch guidelines in their current form. System Management would receive Verve Energy Standing Data, availability, fuel declarations, etc., as for IPP Facilities.

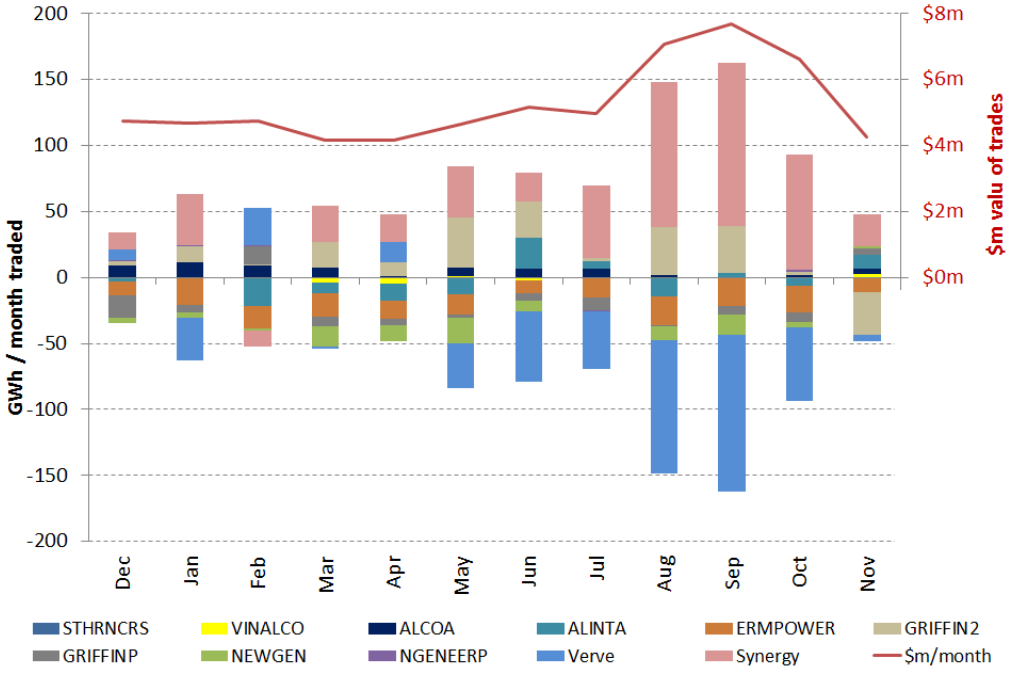
Treating all Facilities on the same basis would simplify the Market Rules but require a significant number of changes. It is understood that it may be relatively straightforward to adapt market systems given that they already provide for facility based submissions from IPPs.

A reasonable timeframe would need to be provided for Verve Energy and System Management to move to facility based operation, perhaps with a staged approach.

4. Risk management issues

Risk management occurs over a range of timeframes spanning new investment and long term fuel and electricity contracts through to real time operation. In the WEM, the capacity regime, the market price caps and the requirement for Verve Energy to bid at SRMC mean that half hourly energy prices are significantly less volatile than in energy only markets such as the National Electricity Market, New Zealand, Singapore, etc.

Nevertheless there is a reasonable level of trading in the STEM[28] as illustrated below[29], indicating that participants find it useful for managing short term exposures in the Balancing Market.



In relation to Bilateral Submissions and the STEM, the MREP[30] includes the following suggestions:

- Investigate removal of the requirement to make STEM Submissions, or allow multiple STEM windows catering for multiple STEM transactions within the Trading Day, aligned to the balancing windows;
- Investigate closer to real time bilateral nominations/updates/adjustments; and
- Start the submissions process at 9:00 am or 10:00 am instead of 8:00 am.

However, it may be better to step back and take a high level view of how the market arrangements might best serve participants' risk management needs. This is suggested because:

- Unlike the issues discussed in section 2, the MREP issues listed above are less clearly defined.

[28] At present, participants holding Capacity Credits for Scheduled Generators must make capacity available in STEM Submissions to cover their Reserve Capacity Obligations (or face Capacity Cost Refunds for any deficit). The market converts STEM Submissions for each participant into STEM Offers and Bids relative to their Net Bilateral Position. The market then creates aggregate STEM Offer and Bid curves, the intersection of which determines the STEM Price and cleared quantities. Participant Net Contract Positions are formed from their Net Bilateral Position being adjusted by any STEM purchases or sales.

[29] The chart shows data for the year ended November 2013. The total value was approximately $65m, varying from around $4m to almost $8m per month.

[30] The MREP (Market Rules Evolution Plan: 2013-2016, October 2013 Update).

- The Verve Energy - Synergy merger may have some bearing on requirements, noting also that Verve Energy and Synergy currently account for a large proportion of the volumes traded in the STEM[31].

- The STEM is now more of a day-ahead financial risk management/ hedging instrument than a short term energy market per se. Originally, the dispatch of energy was determined by Bilateral Submissions and STEM outcomes, with Verve Energy providing the balancing service. Now all generation is subject to dispatch in the Balancing Market according to price-based submissions and the market settles ex post differences from Net Contract Positions at the Balancing Price.

Accordingly, this section is intended to facilitate discussion about risk management development options. It is framed more in terms of questions to aid discussion rather than specific proposals and is not intended to limit the range and scope of any discussion. However, it may be helpful to structure discussions around:

- Potential quick wins.

- Future directions for facilitating risk management.

4.1. Potential Quick Wins

- Is the timing of the bilateral/ STEM process appropriate?
    - Could the timing of STEM and Bilateral Submission windows and the STEM auction be improved?
    - Does removal of Resource Plans and earlier Balancing Submissions change anything?

- Should the STEM be voluntary?
    - Is the link to Reserve Capacity refunds still appropriate or should Reserve Capacity Obligations relate solely participation in the physical Balancing Market? i.e. consistent with repositioning the Balancing Market as the physical market and the STEM as a hedging mechanism.
    - Would the merged Verve Energy-Synergy need to participate to ensure liquidity?
    - Would there be other consequences if the STEM were to be voluntary?

- Should the STEM, which is now really a day-ahead hedging market, and the Balancing Market, which is really a real-time physical spot market, be renamed?

4.2. Future Directions?

- Should the STEM be retained in its current form?

[31] Noting also that Synergy currently holds some contracts with IPPs.

- Would it be better to move to a more conventional day-ahead buy/sell exchange[32]?
- Is day-ahead the appropriate time frame?
    - o What lay behind the suggestion in the MREP of multiple STEM windows within the Trading Day?
- Would it assist participants if the market were to provide additional risk management opportunities?
    - o e.g. week or month or longer STEM style opportunities?
        - ▪ A fully commoditised STEM style arrangement would enable anonymous transactions, certainty about participation including prudential requirements, and more liquidity, especially if the new merged Verve Energy/Synergy entity was required to participate.
    - o Bulletin board to facilitate short to medium term bilateral agreements?
        - ▪ A bulletin board would not necessarily require a high degree of standardisation, leaving scope for tailoring innovation etc?
    - o Could a market platform assist Synergy-Verve to meet its obligations to offer contracts in a transparent manner?

5. Conclusions

It should be practical to relatively quickly remove Resource Plans and reduce Balancing Gate Closure for facility based bids to a half hour.

It would make sense to reduce LFAS Gate Closure at the same time, subject to a decision on the preferred option. Adopting rolling LFAS Gate Closure is likely to offer greater potential benefits than shortening the fixed LFAS Horizon but would require significantly more flexibility than now for Verve Energy to update its VEBP Balancing and LFAS Submissions. However, other participants would retain the ability as now to adjust their final submissions after Verve Energy's final VEBP Balancing Submissions.

Moving to shorter and rolling gate closure would also be consistent with potential longer term directions including the possibility of co-optimisation, which would enable LFAS Gate Closures to be synchronised with Balancing Gate Closure, further shortening the LFAS/Balancing Market cycle, and facility based bidding for all participants.

Participant preferences will be important in identifying potential enhancements to the STEM and future directions for supporting risk management in the WEM in general. This paper aims to initiate discussion on these issues.

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[32] Simple offers to buy/ bids to sell on a direct net basis rather than creating offers and bids from supply and demand curves relative to net bilateral positions.

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)	4th December 2013
Fast track with Consultation Period open	0
Standard Rule Changes with 1st Submission Period Open	1
Fast Track Rule Changes with Consultation Period Closed (final report being prepared)	1
Standard Rule Changes with 1st Submission Period Closed (draft report being prepared)	1
Standard Rule Changes with 2nd Submission Period Open	2
Standard Rule Changes with 2nd Submission Period Closed (final report being prepared)	0
Rule Changes - Awaiting Minister's Approval and/or Commencement	1
Total Rule Changes Currently in Progress	**6**

The following table provides an update of the items the Market Development team anticipates progressing to the MAC over coming months.

Issue	Likely timing
Outage Planning Phase 2 – Outage Process Refinements	Pre Rule Change Proposal – December MAC Meeting
Changes to the Reserve Capacity Price and Dynamic Refunds Regime	Pre Rule Change Proposal – December MAC Meeting
Limits to Early Certified Reserve Capacity payments in period of excess capacity	Pre Rule Change Proposal – December MAC
Improvements to the Energy Market - options for STEM, Bilaterals and Resource Plans (MREP)	Discussion Paper and presentation – December MAC
Merger of Synergy and Verve Energy – review of market power protections	If required – Pre Rule Change Proposal – Early 2014
Settlements package	Pre Rule Change Proposal – Early 2014

Issue	Likely timing
Minor Typographical and Manifest Errors	Pre Rule Change Proposal – Early 2014
Ancillary Services 5 Yearly Review	Draft Scope – December MAC Review Commencing – Early 2014
Dispatch Issues (from log)	Concept Paper or PRC – Late 2014

Please note these timings are only indicative and may be affected by other issues that arise.

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 6th November 2013)

Standard Rule Change with First Submission Period Open

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2013_17	22/11/2013	Correction to estimated output of Intermittent Generation for the purposes of Appendix 9	Alinta Energy	Submissions Close	14/01/2014

Fast Track Rule Change with Consultation Period Closed

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2013_18	11/11/2013	Market Rule changes arising due to the merger of the Electricity Retail Corporation and Electricity Generation Corporation	IMO	Final Rule Change Report published	9/12/2013

Standard Rule Change with First Submission Period Closed

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2013_10	21/08/2013	Harmonisation of Supply-Side and Demand-Side Capacity Resources	IMO	Draft Rule Change Report published	05/12/2013

Standard Rule Change with Second Submission Period Open

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2012_23	14/08/2013	Prudential Requirements	IMO	Submissions Close	19/12/2013
RC_2013_09	18/06/2013	Incentives to Improve Availability of Scheduled Generators	IMO	Submissions Close	16/01/2014

Rule Changes Awaiting Commencement/Ministerial Approval

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2013_08	21/05/2013	Market Participant Fees - Clarification of GST Treatment	IMO	Commencement	01/01/2014

INDEPENDENT
MARKET
OPERATOR

Wholesale Electricity Market
Pre Rule Change Proposal

Rule Change Proposal ID: PRC_2013_15
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 Terrace, Perth 6000
Date submitted:	TBA
Urgency:	2-medium
Change Proposal title:	Outage Planning Phase 2 – Outage Process Refinements
Market Rule(s) affected:	Clauses 3.4.1, 3.18.2, 3.18.2A, 3.18.3, 3.18.4, 3.18.4A, 3.18.5, 3.18.5C, 3.18.5D, 3.18.6, 3.18.7, 3.18.8, 3.18.9, 3.19.1, 3.19.2, 3.19.2A (new), 3.19.2B (new), 3.19.2C (new), 3.19.2D (new), 3.19.3, 3.19.3A, 3.19.3B (new), 3.19.4A (new), 3.19.11, 3.19.12, 3.20.1, 7A.2.4, 7A.2.4A (new), 7A.2.4B (new), 7A.2.4C (new), 7A.2.9, 7A.2A.1 (new), 7A.2A.2 (new), 7A.2A.3 (new), 7A.2A.4 (new), 7A.2A.5 (new), 7A.2A.6 (new), 7A.2A.7 (new) 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
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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:

<u>Background</u>

In accordance with clause 3.18.18 of the Wholesale Electricity Market (WEM) Rules (Market Rules), during 2011 the Independent Market Operator (IMO) completed the first five year review of the outage planning process as described in the Market Rules and supported by the Power System Operation Procedure (PSOP): Facility Outages (2011 Outage Planning Review).

The review, completed by PA Consulting in October 2011, assessed the performance of the outage planning process since market start against the Wholesale Market Objectives. The review included an assessment of the need for, and the nature of, any reforms to the outage planning process. Overall, PA Consulting concluded the WEM outage planning process was working well, but could benefit from some 'fine tuning' in the areas of outage planning information transparency and the technical functioning of the outage planning process.

Following the completion of the 2011 Outage Planning Review, the IMO began to considered the recommendations made by PA Consulting, as well as several outage planning issues that were either identified internally, or else raised by members of the Market Advisory Committee (MAC) in response to a request by the IMO in June 2012.

Following the completion of this consultation process, the IMO updated the list of issues to reflect the feedback provided by MAC members. A revised issues list was presented to the MAC at its 11 July 2012 meeting.

Since the July 2012 MAC meeting, some of the recommendations and issues on the list have been addressed by the IMO and System Management. Most notably, the Rule Change Proposal: Transparency of Outage Information (RC_2012_11), which commenced on 1 October 2013. This was prioritised as phase 1 of the reforms from the 2011 Outage Planning Review because it was considered a more significant reform than implementing the technical changes being made in this reform package (phase 2).

Since the July 2012 MAC meeting, the IMO and System Management identified further issues around the outage planning process. All the issues on this updated list were included into the Concept Paper CP_2013_04: Outage Planning Phase 2 – Outage Process Refinements (Concept Paper) which the IMO presented to the 7 August 2013 MAC meeting. At the meeting, the MAC supported the development of a Pre Rule Change Proposal, whilst raising a number of issues for further consideration. Further details of the August 2013 MAC meeting are available on the following webpage: http://www.imowa.com.au/MAC_63.

In the Concept Paper the IMO proposed that Network Operators be required to give System Management and the relevant Market Participant at least three Business Days' notice of a proposed outage that would limit the output of a Scheduled Generator, Non-Scheduled Generator or generation system to which clause 2.30B.2(a) applies, that is not on the Equipment List. The IMO also sought the views of MAC members on the extent to which a Network Operator should be required to proactively report Forced Outages of its distribution system.

Following the MAC meeting the IMO:

- consulted with Verve Energy in relation to how the proposed changes to the Opportunistic Maintenance process could work appropriately with Verve Energy's different bidding timeframes.

- consulted with ERM Power Limited regarding the possibility of allowing short extensions to Scheduled Outages.

- on 29 August 2013, requested the views of MAC members regarding the appropriate deadlines for Opportunistic Maintenance requests and approvals, and the need for the proactive reporting of Forced outages affecting distribution-connected generators by the Network Operator.

- undertook further consultation with System Management on the timing of approvals of Planned Outages.

- undertook further consultation with System Management and Western Power on the obligations on a Network Operator to notify affected participants about outages, agreeing that the network equipment on the Equipment List should follow the same processes as other items on the list and noting that Network Operators already have obligations to notify affected participants of Planned Outages.[1]

[1] It may also be appropriate for a Network Operator to have a similar obligation, on a best endeavours basis, to advise affected participants of a Forced Outage that the Network Operator is aware of in advance of the outage. The IMO ins considering this for inclusion in the proposed Rule Change Proposal: Availability, Outages and Constraint Payments for Non-Scheduled Generators (PRC_2013_16).

Following the outcome of further internal IMO analysis and the post MAC consultations, the IMO prepared this pre Rule Change Proposal.

Issues and proposed solutions

The purpose of this Rule Change Proposal is to:

- clarify the obligations of Rule Participants around the outage planning process;
- provide greater flexibility for Rule Particpants in outage planning; and
- improve the transparency and consistency of outage planning and Balancing Market processes.

The issues addressed in the proposal relate to:

- obligations to participate in the outage planning process;
- interactions between Planned Outages and Balancing Submissions;
- timelines for Planned Outages;
- availability criteria for the approval of Planned Outages; and
- a number of minor enhancements to improve the integrity and clarity of the outage planning provisions in the Market Rules.

Obligations to participate in the outage planning process

Clause 3.18.2(a) of the Market Rules requires System Management to maintain a list (Equipment List) of the equipment on the South West interconnected system (SWIS) it determines should be subject to outage scheduling. Network Operators and Market Participants with Facilities or items of equipment on the Equipment List (Equipment List Facilities) are required to request approval of Planned Outages and notify System Management of Forced Outages and Consequential Outages in accordance with the provisions outlined in sections 3.18, 3.19, 3.20 and 3.21.

Clause 3.18.2(c) prescribes the equipment that must be included on the Equipment List, while allowing System Management (under clause 3.18.2(c)(iv)) to include any additional equipment it determines must be subject to outage scheduling to maintain Power System Security and Power System Reliability.

Unless specifically included on the Equipment List by System Management, generation systems with a nameplate capacity less than 10 MW (Small Outage Facilities) are exempt from the normal outage planning processes. Instead the relevant Market Participant is only required to notify System Management of proposed Planned Outages for these Facilities. Market Participants are still however required to follow the standard processes for Forced Outages and Consequential Outages of Small Outage Facilities.

Issue 1: Equipment List: Demand Side Programmes and Associated Loads, Dispatchable Loads and Interruptible Loads

Clause 3.18.2(c)(ii) requires all Registered Facilities holding Capacity Credits to be included on the Equipment List, except those to which clause 3.18.2A applies. This includes not only Scheduled Generators and Non-Scheduled Generators but also Demand Side Programmes

(DSPs), Dispatchable Loads and Interruptible Loads. (The reference to clause 3.18.2A excludes Registered Facilities with a Standing Data nameplate capacity of less than 10 MW.)

Currently there is some ambiguity in the Market Rules about the definition of an outage and the outage planning obligations for a DSP. In particular, there is some uncertainty around whether a DSP is experiencing an Outage when:

- it is not consuming electricity at its Relevant Demand level; and/or
- it does not reduce its consumption in response to a Dispatch Instruction.

The IMO considers a DSP that is not consuming at its Relevant Demand level is not undergoing an Outage. While a consistently low consumption level for a DSP may be an issue that needs to be considered in relation to its Reserve Capacity Obligations, the outage framework is not appropriate for this purpose. For example, it does not make sense that System Management to refuse permission for a DSP to reduce its consumption due to a low reserve margin. It should be noted that the telemetry requirements for DSPs being proposed in the Rule Change Proposal: Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10) would provide System Management with improved visibility of the current consumption levels of each DSP.

Further, the IMO considers that a DSP should be expected to make its capacity available (i.e. reduce its consumption) whenever it is dispatched by System Management, as it is not subject to the periodic maintenance requirements affecting generators and network equipment. Nor is it likely in practice that a DSP provider would volunteer in advance that a DSP would not reduce its consumption over a period if dispatched by System Management. For these reasons, the IMO considers a Market Participant should not be able to request (or notify) System Management of a Planned Outage of a DSP.

Based on these considerations, the IMO does not consider that DSPs or their Associated Loads need to be included on the Equipment List, or to log Planned Outages or Forced Outages.

To date no Dispatchable Loads have been registered in the WEM or assigned Capacity Credits. Under the current Market Rules, a Dispatchable Load would be dispatched from the Non-Balancing Dispatch Merit Order (NBDMO) in a similar manner to a DSP, and so the same arguments for their exclusion from the Equipment List apply.

To date no Interruptible Loads have been assigned Capacity Credits and the Market Rules do not contemplate their 'dispatch' under either the Balancing Merit Order (BMO) or the NBDMO. In practice these Facilities are used to provide Spinning Reserve Service under an Ancillary Service Contract, and so are already required to be included on the Equipment List under clause 3.18.2(c)(iii) (renumbered in the proposed amendments to be clause 3.18.2(c)(iv)). The IMO considers that it is therefore unnecessary to prescribe their inclusion on the Equipment List under clause 3.18.2(c)(ii).

Proposed solution:

The IMO proposes to restrict the Facilities that must be included on the Equipment List under clause 3.18.2(c)(ii) to Scheduled Generators and Non-Scheduled Generators holding Capacity Credits with a Standing Data nameplate capacity of at least 10 MW.

Issue 2: Equipment List: Network equipment

Currently under clause 3.18.2(c)(i) of the Market Rules "all transmission network Registered

Facilities" must be on the Equipment List. The IMO does not consider that it is efficient to require System Management to schedule outages for all components of the transmission system as only some components have the potential to affect system security and reliability.

On the other hand, clause 3.18.2(c) does not require the inclusion of any components of the distribution system on the Equipment List, except where System Management considers they "must be subject to outage scheduling to maintain Power System Security and Power System Reliability" under clause 3.18.2(c)(iv) (renumbered in the proposed amendments to be clause 3.18.2(c)(v)). However, there are situations where an outage in the distribution system can limit the output of a generation system on the Equipment List.

The IMO considers that if a generation system is required on the Equipment List then it follows that any network equipment (whether transmission or distribution) that could limit that generation system's output should also be on the Equipment List. However the IMO also considers that other network equipment should only be included on the Equipment List at System Management's discretion, i.e. in accordance with clause 3.18.2(c)(v).

Proposed solution:

The IMO proposes to amend clause 3.18.2(c)(i) to require the Equipment List to include any transmission or distribution system equipment that could limit the output of a generation system that is on the Equipment List. Provided this requirement is met, System Management will have the flexibility to define the specific Equipment List Facilities in the way that it finds most operationally efficient. This may involve the use of 'notional' network circuits, for example a notional circuit comprising any distribution system equipment that could limit the output of a particular distribution-connected generation system.

It should be noted that the proposed amendment does not limit System Management's ability under clause 3.18.2(c)(v) to include on the Equipment List any other network equipment which it considers should be subject to outage scheduling in order to maintain system security and reliability.

Issue 3: Requirements to follow the outage planning process

The obligation on a Rule Participant to request (or report, as applicable) a Planned Outage prior to undertaking discretionary maintenance is not explicit in the Market Rules, although it is implied by various clauses such as clause 3.19.8, which obliges a participant to comply with System Management's decision to reject an outage request, except where this would endanger the safety of any person, damage equipment, or violate an applicable law.

While there is a clear financial incentive for Market Participants with Facilities holding Capacity Credits to seek to be granted a Planned Outage, with the progression of the Rule Change Proposal: Incentives to Improve Availability of Scheduled Generators (RC_2013_09)[2] a generator that has breached its 1000 Trading Day Planned Outage limit will be liable for Facility Reserve Capacity Deficit Refunds for a Planned Outage, reducing the financial incentive to follow the normal outage planning process.

Proposed solution:

The IMO proposes to include new clauses 3.18.2A(b) and 3.19.2A to clarify the requirement for a Market Participant to follow the outage scheduling processes. Clause 3.18.2A(b) requires a Market Participant to notify System Management of a proposed Planned Outage of a Small Outage Facility if:

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[2] For further details see: http://www.imowa.com.au/RC_2013_09.

- the Market Participant intends to make some or all of the Small Outage Facility's capacity unavailable; and

- the capacity would otherwise be available for dispatch for the duration of the proposed Planned Outage.

Clause 3.19.2A requires a Market Participant in the same position with regard to an Equipment List Facility to request approval for a Planned Outage from System Management in accordance with sections 3.18 and 3.19.

Interactions between Planned Outages and Balancing Submissions

There are a number of areas in the Market Rules where it is not entirely clear how 'unavailble' capacity (capacity that is the subject of a Planned Outage request) should be treated in a Balancing Submission. One of the most obvious areas of ambiguity is in relation to requests for on-the-day Opportunistic Maintenance (ODOM).

Under the current Market Rules, an ODOM outage requested under clause 3.19.2(b) "must not require any changes in scheduled energy or ancillary services". Prior to 1 July 2012, System Management was able to determine the compliance of an Independent Power Producer (IPP) Facility with this requirement from its Resource Plan. However, since the implementation of the Balancing Market this determination is not so simple, as the scheduled output of an IPP Facility is no longer determined by its Resource Plan but by its relative position in the BMO.

Although a Market Participant may bid capacity that is intended to be unavailable due to an ODOM request at a high price (to limit the likelihood that it will be dispatched), the capacity is still available for dispatch, which in some situations may force System Management to exercise discretion in determining whether an ODOM request meets the requirements of clause 3.19.2(b)(ii). Further, in order to allow Forecast BMOs to be as accurate as possible, it is essential that Market Participants provide the market, through their Balancing Submissions, with as much forewarning as possible of capacity that is expected to be unavailable for dispatch due to an outage.

For these reasons, the IMO considers that as a general principle any capacity of a Market Participant subject to a Planned Outage request should appear as 'unavailable' in the Forecast BMO. The following sections discuss how this principle is proposed to be applied I the Market Rules.

Issue 4: Balancing Submission unavailability declarations

Currently some ambiguity exists in the Market Rules around how unavailable capacity is indicated in a Balancing Submission. While various clauses (e.g. clauses 7A.2.8(b), 7A.2.9(a)(ii), 7A.2.10(a) and 7A.2.10(b)) imply that a Balancing Submission must indicate how much of a Balancing Facility's Sent Out Capacity is unavailable for dispatch, clause 7A.2.4 and the Glossary definition of the term 'Balancing Submission' do not explain how this is to be done. Further, the Glossary definition suggests that for a Scheduled Generator the Balancing Price-Quantity Pairs should cover the full Sent Out Capacity of the Facility, regardless of whether any of that capacity is unavailable for dispatch.

<u>Proposed solution:</u>

The IMO proposes to amend the Glossary definition of a Balancing Submission and the requirements for a Balancing Submission in clause 7A.2.4, and include new clauses 7A.2.4A, 7A.2.4B and 7A.2.4C, to clarify how 'available' and 'unavailable' capacity are to be included.

For a Balancing Facility that is a Scheduled Generator, for each Trading Interval the sum of the MW quantities in the Balancing Price-Quantity Pairs and the 'unavailable' quantity should equal the Sent Out Capacity of the Facility.

For a Non-Scheduled Generator, the 'available' quantity provided in its single Balancing Price-Quantity Pair should reflect the Market Participant's estimate of its MW output at the end of the Trading Interval, assuming it is not dispatched down by System Management. The 'unavailable' quantity should reflect any Outages but should not include that part of the Sent Out Capacity that is not expected to be reached because its 'fuel supply' (e.g. wind or sunlight) is not at an optimal level. The two quantities are not therefore expected to sum to the Sent Out Capacity of the Facility.

Similarly, the MW quantities in a Balancing Submission for the Verve Energy Balancing Portfolio (VEBP) are not expected to sum to the total Sent Out Capacity of the component Facilities, since these Facilities include some Non-Scheduled Generators.

Issue 5: Deadline for approval of a Planned Outage

Currently the Market Rules do not set a deadline for making decisions on whether to approve a Planned Outage, although clause 3.19.2(b) sets a deadline for ODOM requests of one hour before the proposed start time. This creates a risk that a request could be rejected after Balancing Gate Closure, leaving the relevant capacity unavailable for dispatch in the BMO and the Market Participant obliged to log a Forced Outage.

The IMO proposed a number of possible approaches for dealing with this concern in CP_2013_04 and sought the views of MAC members on the options. No responses were received from MAC members on the issue. The IMO has since discussed the issue further with System Management to develop the following agreed approach.

Proposed solution:

The IMO proposes to amend clause 3.19.2 to to set the deadline for requesting approval of an Opportunistic Maintenance request to 30 minutes before Balancing Gate Closure for the Trading Interval in which the outage is due to commence. The IMO also proposes to include a new clause 3.19.4A which prescribes that if System Management has not provided a Rule Participant with a decision on a request for approval of a Planned Outage (including a Scheduled Outage or Opportunistic Maintenance) by this time then for the purposes of the Market Rules the request is deemed to be rejected.

The proposed amendments will ensure that Market Participants have sufficient time to adjust their final Balancing Submissions to reflect the approval or rejection of any Planned Outage requests for their Facility.

Issue 6: Clarification of requirements for Balancing Facilities (excluding the Verve Energy Balancing Portfolio)

Currently the Market Rules are unclear about how capacity subject to a Planned Outage request should be reflected in the Balancing Submissions for a Balancing Facility. As noted above, the IMO considers that in general any capacity subject to an approved Planned Outage or to an outstanding request for approval of a Planned Outage should be bid as 'unavailable' capacity in the relevant Balancing Submissions.

The reason for requiring the relevant capacity of a Market Participant to be bid as unavailable prior to approval of the outage is that it is expected these requests will be approved more often than not, and so making the capacity unavailable in the BMO earlier will improve transparency and the likely accuracy of the forecast Balancing Price. This approach also removes any requirement on System Management to exercise discretion about the likelihood of a Balancing Facility being dispatched based on its position in the Forecast BMO.

However, the IMO also notes that Balancing Facilities are expected to participate in the Balancing Market and considers any capacity declared as unavailable in a Balancing Submission (apart from minor temperature related de-ratings) should be subject to an Outage.

On rare occasions System Management may reject a previously approved Planned Outage before it commences under clause 3.19.5. The IMO considers that in these situations the Market Participant should be required to update its Balancing Submission for any Trading Intervals in the Balancing Horizon for which Balancing Gate Closure has not yet occurred, to make the relevant capacity available for dispatch. (Note this requirement should apply to all Scheduled Generators and Non-Scheduled Generators, including those in the VEBP.)

Similarly, where the SWIS is in an Emergency Operating State or High Risk Operating State System Management may direct a Market Participant that a Facility be returned to service early from a Planned Outage under clause 3.20.1. In these situations the IMO considers that the Market Participant should be required to update its Balancing Submission, to reflect the change in available capacity due to System Management's direction, for any Trading Intervals for which Balancing Gate Closure has not yet occurred.

Proposed solution:

The IMO proposes to add new clauses 7A.2A.1 and 7A.2A.3 to clarify that for non-VEBP Balancing Facilities:

- a Market Participant must, for each of its Balancing Facilities and for each Trading Interval in the Balancing Horizon, use its best endeavours to ensure that, at all times, any of the Facility's capacity that is:
    - subject to an approved Planned Outage; or
    - subject to an outstanding request for approval of a Planned Outage,

  is declared as unavailable in the Balancing Submission for the Facility and the Trading Interval, unless the Balancing Facility is undertaking a Commissioning Test in that Trading Interval; and

- a Market Participant must, as soon as practicable after Balancing Gate Closure for each Trading Interval, for each of its Balancing Facilities that is either an Equipment List Facility or a Small Outage Facility (collectively referred to as an Outage Facility), ensure that it has notified System Management of a Forced Outage or Consequential Outage for any capacity declared unavailable in the Facility's Balancing Submission that:
    - was not subject to an approved Planned Outage or Consequential Outage at Balancing Gate Closure for the Trading Interval; and
    - is not attributable to a difference between the expected temperature at the site during the Trading Interval and the temperature at which the Sent Out Capacity for the Facility was determined.

The latter requirement will not apply to capacity that was subject to a previously approved Planned Outage but then rejected by System Management less than 30 minutes before Balancing Gate Closure (see proposed new clause 7A.2A.5).

The IMO also proposes to add new clauses to clarify a Market Participant's obligations around its Balancing Submissions in the event of a late rejection of a previously approved Planned Outage (clause 7A.2A.6) or the recall of Planned Outage that is underway (clause 7A.2A.7).

The implications of this proposal are as follows.

- A Market Participant must use its best endeavours to ensure that its initial Balancing Submission for a Trading Interval declares any of the Balancing Facility's capacity that is subject to an approved Planned Outage or an outstanding request for a Planned Outage as unavailable.

- If a Market Participant wishes to make a request for Opportunistic Maintenance that covers Trading Intervals within the Balancing Horizon, it will need to amend its Balancing Submission to make the relevant capacity unavailable <u>before</u> it requests the outage.

- If, at any time prior to 30 minutes before Balancing Gate Closure, System Management approves the Opportunistic Maintenance request then the Market Participant will not need to update its Balancing Submission as it will have already reflected the relevant capacity as being unavailable.

- If, at any time prior to 30 minutes before Balancing Gate Closure, System Management rejects the request then the Market Participant will need to update its Balancing Submission as soon as practicable to make the relevant capacity available for dispatch (or be liable for a Forced Outage for the affected Trading Intervals).

- If System Management has not provided a decision in relation to the request (i.e. neither rejected nor approved it) by 30 minutes prior to Balancing Gate Closure, then the Market Participant must assume that the outage has been rejected and update its Balancing Submission as soon as practicable (before Balancing Gate Closure) to make the relevant capacity available for dispatch (or be liable for a Forced Outage for the affected Trading Intervals).

- If a Market Participant wishes to end an approved Planned Outage early, then it must notify System Management of the revised outage end time before amending its Balancing Submission for any affected Trading Intervals in the Balancing Horizon (to ensure its compliance with clause 7A.2A.1). Note that a Market Participant is not permitted to update a Balancing Submission for a Trading Interval for this reason after Balancing Gate Closure.

- If an approved Planned Outage is rejected under clause 3.19.5 or the Facility is recalled to service under clause 3.20.1 then the Market Participant must as soon as practicable update its Balancing Submisssion to reflect any capacity that will now be available, for any Trading Intervals in the Balancing Horizon for which Balancing Gate Closure has not occurred.

Issue 7: Clarification of requirements for the Verve Energy Balancing Portfolio

In CP_2013_04 the IMO proposed that the arrangements outlined above for outstanding approval requests should apply to all Scheduled Generators and Non-Scheduled Generators. However, during the discussion on CP_2013_04 at the August 2013 MAC meeting Verve Energy suggested that this could restrict the timeframes for VEBP Facility Opportunistic Maintenance requests, in a way that was contrary to the intent of the changes. Following the MAC meeting the IMO met with Verve Energy to discuss its concerns further.

Currently Verve Energy has fewer opportunities to revise its (VEBP) Balancing Submissions than other Market Participants, and the deadline for VEBP Balancing Submissions (between four and 9.5 hours prior to the start of the Trading Interval) falls well before Balancing Gate Closure. To require final decisions on VEBP Planned Outage approval requests before the deadline for VEBP Balancing Submissions (so that Verve Energy has time to amend its Balancing Submission to make capacity subject to a rejected request available) would significantly limit the time window available to Verve Energy for Opportunistic Maintenance requests, when compared with the current arrangements.

On the other hand, allowing Verve Energy to make significant changes to VEBP Balancing Submissions after the normal deadlines would undermine the effectiveness of these deadlines in mitigating concerns around market power. The VEBP also provdes Verve Energy with the opportunity to optimise the dispatch of its Facilities within the VEBP without the same restrictions as IPP Facilities with regards to updating Balancing Submissions.

Proposed solution:

In order to address Verve Energy's concerns while minimising any impacts on the BMO, the IMO proposes that the requirements for Facilities in the VEBP should be similar to those for other Balancing Facilities (taking into account the different deadlines for VEBP Balancing Submissions) with the following exceptions.

- Capacity that is subject to an outstanding request for approval of a Planned Outage should be declared as available (i.e. included in the Balancing Portfolio Supply Curve) in the Balancing Submissions for the relevant Trading Intervals.

- If Verve Energy receives approval of an Opportunistic Maintenance request later than its usual gate closure time, it will be required to amend its Balancing Submission for the affected Trading Intervals to make the relevant capacity unavailable, but must remove the capacity from its highest price Balancing Price-Quantity Pairs, leaving its lower price Balancing Price-Quantity Pairs unchanged. This means that the update will have minimal impact on the BMO.

The VEBP specific requirements are outlined in proposed new clauses 7A.2.9(g), 7A.2A.2 and 7A.2A.4. The implications on Verve Energy are as follows.

- Verve Energy must ensure that its initial VEBP Balancing Submission for a Trading Interval declares any of the VEBP's capacity that is subject to an approved Planned Outage as unavailable. Capacity subject to an outstanding request must be included in the Balancing Portfolio Supply Curve and assumed to be available for dispatch (e.g. for the purposes of compliance with SRMC bidding obligations).

- Verve Energy will not need to amend its VEBP Balancing Submission before making a request for Opportunistic Maintenance that covers Trading Intervals within the Balancing Horizon.

- If System Management approves a request for Opportunistic Maintenance that covers Trading Intervals in the Balancing Horizon <u>before</u> the latest time allowable under clause 7A.2.9(d) (i.e. the normal deadline for VEBP Balancing Submissions) then Verve Energy must, in accordance with its normal submission timeframes, amend its Balancing Submission to make that capacity unavailable and may adjust its prices accordingly.

- If System Management approves a request for Opportunistic Maintenance that covers Trading Intervals in the Balancing Horizon <u>after</u> the normal VEBP Balancing

Submission deadline, then Verve Energy must as soon as practicable update its Balancing Submission, taking into account the restrictions on changes to its offer prices described above.

- If System Management rejects (or is deemed to reject) an outstanding Opportunistic Maintenance request for a VEBP Facility affecting Trading Intervals in the Balancing Horizon then no change is required, as the relevant capacity will already be declared as available.

- If Verve Energy wishes to end an approved Planned Outage of a VEBP Facility early, then it must notify System Management of the revised end time of the Outage before amending its Balancing Submission for any affected Trading Intervals in the Balancing Horizon (to ensure its compliance with new clause 7A.2A.2). Verve Energy is not permitted to update a VEBP Balancing Submission for this reason after the normal VEBP Balancing Submission deadline for the relevant Trading Intervals.

- If an approved Planned Outage is rejected under clause 3.19.5 or a Facility in the VEBP is recalled to service under clause 3.20.1 then Verve Energy must as soon as practicable update its VEBP Balancing Submisssion to reflect any capacity that will now be available, for any Trading Intervals in the Balancing Horizon for which Balancing Gate Closure has not occurred.

It should also be noted that Verve Energy also has the option of treating its Facilities as Stand Alone Facilities, meaning they are no longer part of the VEBP and are subject to the same Balancing Submission processes as IPP Facilities.

Timelines for Planned Outages

Issue 8: Clarification of deadline for Scheduled Outage approval requests

Currently the exact deadline for Scheduled Outage approval requests is unclear. Clause 3.19.1 requires a Network Operator or Market Participant to request approval of a Scheduled Outage “no later than two days prior to the date of commencement” of the outage, but no time is specified. In practice, System Management requires requests to be made by 8:00 am on the day prior to the Scheduling Day for the Trading Day in which the proposed outage is due to commence.

Proposed solution:

The IMO proposes to amend clause 3.19.1 to clarify that approval of a Scheduled Outage must be requested no later than 8:00 am on the day prior to the Scheduling Day for the Trading Day in which the proposed outage is due to commence.

Issue 9: Prohibition on Opportunistic Maintenance Outages spanning two Trading Days

Currently, clauses 3.19.2(a) and 3.19.2(b)(iii) require an Opportunistic Maintenance Outage to be completed by the end of the Trading Day in which it commences. Additionally, under clause 3.19.3A(b) System Management must not approve Opportunistic Maintenance requests on two consecutive days. The effect of these clauses is to restrict the period over which an Opportunistic Maintenance Outage can occur to the Trading Day within which the outage commences. The IMO considers there is no reason to require an Opportunistic Maintenance Outage to take place within a single Trading Day.

Proposed solution:

The IMO proposes to amend clause 3.19.2 to allow Opportunistic Maintenance requests to be for any period up to 24 hours in length.

Issue 10: Restrictions on the timeframes for making Opportunistic Maintenance requests

Currently an Opportunistic Maintenance request cannot be made between 8:00 am and 10.00 am on the day before the Scheduling Day or between 10:00 am on the Scheduling Day and the start of the Trading Day. The IMO considers that these restrictions are unnecessary and removing them would improve the efficiency of the outage planning process.

Proposed solution:

The IMO proposes to amend clause 3.19.2 to allow a Market Participant to submit an Opportunistic Maintenance request at any time between:

- the proposed deadline for Scheduled Outage requests, i.e. 8:00 am on the day before the Scheduling Day for the Trading Day in which the requested outage is due to commence; and

- the proposed deadline for System Management's decisions on Opportunistic Maintenance requests, i.e. 30 minutes before Balancing Gate Closure for the Trading Interval in which the requested outage is due to commence.

It should be noted that the IMO is not proposing any change to the requirement under clause 3.19.4 for System Management to approve or reject a Planned Outage request and inform the Market Participant of its decision *as soon as practicable*. The IMO notes that System Management has documented its timelines for the approval of outage requests in the PSOP: Facility Outages. The timelines give a Market Participant certainty about when it can expect a response from System Management to an outage approval request submitted at a specific time. For example, System Management commits to respond to an Opportunistic Maintenance request submitted between 6:00 am and 10:00 am on the Scheduling Day by 12:00 pm on that Scheduling Day.

The IMO does not propose that the changes should create any additional resourcing requirements for System Management. Instead the IMO proposes that System Management revise its current approval timelines to provide as flexible a result as possible given its current staffing arrangements. For example, during preliminary discussions with the IMO, System Management suggested that it should have no difficulty in processing Opportunistic Maintenance requests received between 10:00 am and 3:00 pm on the Scheduling Day by 5:00 pm on that day, one hour before the Balancing Horizon is extended to cover the relevant Trading Day.

It should also be noted that System Management will retain the ability to reject an Opportunistic Maintenance request if it is unable to assess the impact of the request in the time available. Further, the proposed new clause 3.19.4A will ensure that where System Management has been unable to provide a decision to the Rule Participant by 30 minutes before Balancing Gate Closure the request must be deemed to be rejected. Market Participants will need to bear this in mind when making such Opportunistic Maintenance requests, particularly as the proposed amendments will allow Opportunistic Maintenance requests to be made for periods that extend well into the day after the Trading Day in which the outage commences.

Issue 11: Restrictions on the timeframes for making consecutive Opportunistic Maintenance requests

Clause 3.19.3A(b) states that System Management must not approve Opportunistic Maintenance for an Equipment List Facility "on two consecutive Trading Days". It is not clear from the wording whether the restriction applies to the approvals or the outages, but the clause has generally been interpreted as referring to the latter.

The IMO considers it appropriate that Rule Participants should not be able to request a series of consecutive Opportunistic Maintenance Outages, effectively undertaking the equivalent of a Scheduled Outage without due notice. However, the current restriction will no longer be appropriate if Opportunistic Maintenance is allowed to span two Trading Days.

Proposed solution:

The IMO proposes to amend clause 3.19.3A(b) to require a 24 hour period to elapse between the end of one Opportunistic Maintenance Outage for an Equipment List Facility and the start of the next.

Issue 12: Notification timelines for Small Outage Facilities

Currently clause 3.18.2A(b) requires a Market Participant to notify System Management of proposed Planned Outages for a Small Outage Facility "not less than 2 Business Days prior to their commencement". There are no provisions allowing for the equivalent of Opportunistic Maintenance for a Small Outage Facility.

The IMO considers that for Small Outage Facilities the notification deadline for short Planned Outages (up to 24 hours in duration) should not exceed the Opportunistic Maintenance request deadline for Equipment List Facilities. Similarly, the IMO considers there is no necessity for the notification deadline for longer Planned Outages to exceed the deadline for Scheduled Outage approval requests for Equipment List Facilities.

Proposed solution:

The IMO proposes to amend clause 3.18.2A to align the notification deadlines for Planned Outages of Small Outage Facilities with the approval request deadlines for Planned Outages of corresponding duration for Equipment List Facilities. The proposed amendments to clause 3.18.2A also clarify that a Market Participant must notify System Management oif the timing of an outage changes or the outage is no longer required.

Criteria for approval of Planned Outages

Issue 13: Availability declarations for Planned Outage approval requests

In its final report for the 2011 Outage Planning Review, PA Consulting raised two concerns about the implicit requirement in the PSOP: Facility Outages for a Facility to be available prior to a Planned Outage commencing. The PSOP states that "System Management may at its sole discretion require a Market Participant's or Network Operator's authorised personnel included in the relevant contact list to make a written declaration that the unit is available prior to the outage commencing".

PA Consulting supported System Management's efforts to identify and reject outage requests made principally to avoid exposure to refunds rather than to perform (discretionary) maintenance, but suggested that the current PSOP requirement:

- *creates an incentive to apply for outages which are longer than needed:* PA Consulting noted that while the requirement to be available while requesting an outage translates to an inability to extend an existing outage, there is no such prohibition on shortening outage periods. PA Consulting considered that this asymmetry creates an incentive to apply for an outage period longer than is likely to be required, which in turn can reduce the availability of outage slots for other Market Participants[3]; and

- *adds cost to the provision of generation:* in particular, PA Consulting considered that the inability to apply for Opportunistic Maintenance while on a Forced Outage means that generators are compelled to make their plant available again as soon as possible, so as to minimise Reserve Capacity refund payments. Specifically, this encourages them to make short term temporary fixes to the problem, then apply for an outage to fix the problem properly whereas it would have made most sense to fix the problem properly in the first instance.

PA Consulting recommended that:

- System Management should develop for consideration by the IMO proposed changes to sections 13.5, 14.7 and 15.5 of the PSOP: Facility Outages to the effect that the written declaration pertain to the period of the outage, rather than a period prior to the outage commencing;
- given the interaction with the capacity market and the incentive for Market Participants to manipulate the Market Rules to avoid exposure to Reserve Capacity refunds, the requirement to provide a written declaration should be mandatory; and
- in the interests of transparency and facilitating compliance monitoring, all such declarations should be published by System Management.

Additionally System Management, in feedback provided to the IMO, sought greater clarity on its obligations with respect to:

- clause 3.18.7, which requires Outage Plans submitted by a Market Participant or Network Operator to represent its good faith intention to remove from service, or de-rate, the relevant Facility of item of equipment, for maintenance; and
- clause 3.19.3A(c), which permits System Management to decline an Opportunistic Maintenance request where it considers the request has been made principally to avoid exposure to Reserve Capacity refunds, rather than to perform maintenance.

In particular, System Management sought clarity around the approval of extensions to Scheduled Outages. System Management also suggested that its ability to reject an Opportunistic Maintenance request under clause 3.19.3A(c) should be extended to cover Scheduled Outages.

The IMO agrees with PA Consulting that the requirement on a Market Participant requesting a Planned Outage should be that the relevant capacity would otherwise be available during the outage period requested, rather than prior to it. In other words, if the request was rejected by System Management the Market Participant should not be in a position where it needed to log a Forced Outage for the relevant period. The IMO also agrees with System Management that it is reasonable for this requirement to apply to both Scheduled Outages and Opportunistic Maintenance.

The IMO also considers that the requirement to be “otherwise available” should extend

[3] System Management has advised that in practice it does approve some extensions to Scheduled Outages, using its discretion as to whether to require an availability declaration.

beyond the specific situations in which System Management currently requests a written availability declaration.

Proposed solution:

The IMO proposes to strengthen and clarify the requirements in the Market Rules by adding:

- new clause 3.19.2B, which prohibits a Market Participant from requesting approval of a Planned Outage for a Scheduled Generator or Non-Scheduled Generator if the Market Participant does not expect in good faith that, if System Management rejected the request, the capacity to which the request applies would be available for dispatch for the duration of the proposed outage;

- new clause 3.18.2A(h), which imposes a similar requirement on Market Participants around notifications of Planned Outages for Small Outage Facilities; and

- new clause 3.19.2C, which requires a Market Participant with a Planned Outage request that has not yet been approved or rejected by System Management to immediately notify System Management and withdraw the request if it ceases to expect that the capacity would be otherwise available (e.g. in the event of a Forced Outage of the Facility).

Two exceptions (outlined in new clause 3.19.2D) are proposed:

- where the proposed Planned Outage will immediately follow a Scheduled Outage of the relevant capacity (i.e. the outage is effectively an extension of a Scheduled Outage); and

- where the Market Participant reasonably expects that the capacity would be subject to a Consequential Outage if the proposed Planned Outage did not proceed.

The IMO also proposes to replace clause 3.19.3A(c) with new clause 3.19.3B, which allows System Management to decline to approve a Scheduled Outage or Opportunistic Maintenance for an Equipment List Facility where it considers that the capacity to which the request applies would not otherwise be available for dispatch for the duration of to the proposed outage.

The implications of the proposed amendments are as follows.

- Generally there should be no requirement for Market Participants to provide written availability declarations to System Management, as these would be implicit in the request for approval of the outage.

- If a Facility experiences a Forced Outage after a Planned Outage has been approved but before the outage commences, then this would not affect the status of the Planned Outage.

- Requests for extensions of Planned Outages will be managed as a request for a new, separate Planned Outage, and treated no differently from any other Planned Outage request except that the implicit availability declaration prescribed new clause 3.19.2B is not required. The extension outage may be either a Scheduled Outage or an Opportunistic Maintenance Outage.

- At this stage the IMO does not propose any limit on the length of extension outages[4],

[4] Apart from the usual timing requirements for Scheduled Outages and Opportunistic Maintenance.

to avoid encouraging Market Participants to request Scheduled Outages that are longer than necessary. The IMO proposes to monitor outage extensions for any abuse of this flexibility and, if necessary, propose further amendments to the Market Rules in the future to set an overall time limit for these extensions.

Other issues

The IMO also proposes the following enhancements to improve the clarity and integrity of the outage planning provisions in the Market Rules.

- ***Use of defined terms:*** The IMO proposes to create defined terms in the Glossary for Equipment List, Equipment List Facility, Small Outage Facility and Outage Facility to provide clarity and reduce unnecessary repetition in the drafting.

- ***Removal of unnecessary cross-references to clause 3.18.2A:*** The IMO proposes to amend clause 3.18.2(c) to replace the two cross-references to clause 3.18.2A with their substantive meaning, i.e. that the generation systems in question must have a nameplate capacity of at least 10 MW.

- ***Removal of clause 3.18.5D:*** As Planned Outages by Facility are now public information under clause 10.5.1(zD) (following the commencement of the Amending Rules for the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10)), clause 3.18.5D, which allows System Management to provide a Network Operator with the Scheduled Outage information of a Market Participant's Facility, is no longer required and is proposed to be removed.

- ***Contents of System Management's outage schedule:*** The IMO proposes to amend clause 3.18.4 to clarify which Outage Plans are to be considered Scheduled Outages and included in System Management's outage schedule.

The IMO has also proposed a number of other minor and typographical changes to improve the clarity and integrity of the drafting.

Impact on the Regulations

<u>Reviewable Decisions</u>

No clauses which have Reviewable Decisions attached to them have been affected by the proposed amendments.

<u>Civil Penalties</u>

Existing civil penalty clauses

The proposed Amending Rules include amendments to a number of civil penalty provisions.

The following civil penalty provisions are proposed to be amended, however the IMO believes the proposed amendments do not alter the general intent of the provisions and the IMO does not believe and amendments to the current civil penalties are required.

- Clause 3.18.7*: Good Faith intention for Planned Outage requests* – this clause has had a minor amendment made to it. However, the amendment does not change the meaning or the intent of the clause.

- Clause 3.18.8: *Requirement on Market Participant to provide notification where it wishes to cancel a Planned Outage* - this clause has had a minor amendment made to it. However, the amendment does not change the meaning or the intent of the clause.

- Clause 3.19.1: *Must seek approval of a Scheduled Outage* – this clause has been amended to better clarify the deadline for approval of a Scheduled Outage. However, the amendment does not change the intent of the clause.

- Clause 7A.2.9: *details what the Balancing Portfolio Supply Curve must accurately reflect.* This clause has been amended to:

    - qualify that Verve Energy's reasonable expectation of the capability of the Verve Energy Balancing Portfolio to be dispatched in a Trading Interval, is subject to the requirement on Verve Energy to declare as available in its Balancing Submission, any capacity subject to an outstanding outage request; and

    - allow Verve an ability to update its Balancing Submission after the latest time specified in clause 7A.2.9(d), subject to certain conditions.

  The IMO considers that these amendments do not change the overall intent of this clause.

New Clauses which the IMO proposes should have civil penalties attached to them:

This Pre Rule Change Proposal includes a number of proposed new clauses. The IMO believes a number of these proposed new clauses would be appropriate civil penalty provisions.

- *Clause 3.19.2A*: Clause 3.19.2A requires a Market Participant to request approval for a Planned Outage from System Management in accordance with sections 3.18 and 3.19 if:

    - the Market Participant intends to make some or all of the Equipment List Facility's capacity unavailable; and

    - the capacity would otherwise be available for dispatch for the duration of the proposed Planned Outage.

- *Clause 3.19.2B*: This clause prohibits a Market Participant from requesting approval of a Planned Outage for a Scheduled Generator or Non-Scheduled Generator if the Market Participant does not expect in good faith that, if System Management rejected the request, the capacity to which the request applies would be available for dispatch for the duration of the proposed outage.

- *Clause 3.19.2C*: This clause requires a Market Participant with an outstanding Planned Outage approval request to immediately notify System Management and withdraw the request if it ceases to expect that the capacity would be otherwise available (e.g. in the event of a Forced Outage of the Facility).

- *New clauses 7A.2.1, 7A.2.2, 7A.2.3, 7A.2.4, 7A.2.6 and 7A.2.7:*

    - Clauses 7A.2.1, 7A.2.2 – require Market Participants to ensure Balancing Submissions correctly reflect approved outages and outstanding outage requests.

- Clauses 7A.2.3, 7A.2.4 – require Market Participants to notify System management of a Forced Outage or Consequential Outage for capacity declared unavailable in Balancing Submissions.
- Clauses 7A.2.6 and 7A.2.7 - require Market Participants to update Balancing Submissions where System Management rejects or cancels an approved Planned Outage.

Consistent with other similar obligations under the Market Rules, the IMO considers that it may be appropriate to treat these clauses as Category C civil penalty provisions.

Other considerations in relation to civil penalty provisions

The IMO does not consider that the proposed amendments applicable to outages of Small Outage Facilities under 3.18.2A should have civil penalties attached to them, despite these clauses being broadly equivalent to clauses which have civil penalties attached to them, which relate to Equipment List Facilities. The rationale for this is consistency with the current approach – Small Outage Facilities do not have civil penalties associated with the timing of when they notify System Management of a proposed Planned Outage under existing clause 3.18.2A(b).

The IMO will liaise with the Public Utilities Office on any changes to civil penalty provisions.

2. Explain the reason for the degree of urgency:

The IMO proposes that the Rule Change Proposal be progressed via the Standard Rule Change Process.

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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)*

3.4.1. The SWIS is in a ~~High-risk~~<u>High Risk</u> Operating State when System Management considers that any of the following circumstances exist, or are likely to exist within the next fifteen minutes, or are likely to exist at a time beyond the next fifteen minutes; and actions other than those allowed under the Normal Operating State must be implemented immediately by System Management so as to moderate or avoid the circumstance:

3.18.2.

~~(a) System Management must compile a list of all equipment on the SWIS that is required to be subject to outage scheduling by System Management. The list must also include equipment for which System Management requires notice of partial outages or de-ratings.~~

<u>(a) System Management must maintain a list of all equipment on the SWIS that it determines should be subject to outage scheduling in accordance with this section 3.18 and sections 3.19, 3.20 and 3.21.</u>

~~(b) System Management must review the list described in clause 3.18.2(a) from time to time and may update the list.~~

(b) System Management must review and update the Equipment List from time to time. If System Management updates the Equipment List, it must provide the IMO with a copy of the updated Equipment List as soon as practicable.

(c) The ~~list described in clause 3.18.2(a)~~Equipment List must include:

~~i. all transmission network Registered Facilities;~~

i. any part of a transmission system or a distribution system (however defined by System Management) that could limit the output of a generation system that System Management has included on the Equipment List;

~~ii. all Registered Facilities holding Capacity Credits, except those to which clause 3.18.2A applies;~~

ii. all Scheduled Generators and Non-Scheduled Generators holding Capacity Credits with a Standing Data nameplate capacity of at least 10 MW;

~~iiA.~~iii. all generation systems to which clause 2.30B.2(a) relates~~, except those to which clause 3.18.2A applies~~ with a nameplate capacity of at least 10 MW;

~~iii.~~iv. all Registered Facilities subject to an Ancillary Services Contract; and

~~iv.~~v. any other equipment that System Management determines must be subject to outage scheduling to maintain Power System Security and Power System Reliability.

(d) The ~~list described in clause 3.18.2(a)~~Equipment List may specify that ~~a piece of equipment on the list~~an Equipment List Facility is subject to outage scheduling by System Management only at certain times of the year.

~~(e) System Management must provide the list described in clause 3.18.2(a) and any updated list to the IMO. The IMO must publish any list provided by System Management.~~

(e) The IMO must publish an updated Equipment List on the Market Web Site as soon as practicable after receiving it from System Management.

~~(f) If a Market Participant's or Network Operator's Facility (or an item of equipment forming part of that Facility) is on the list described in clause 3.18.2(a), then the Market Participant or Network Operator, as applicable, must schedule outages for the equipment in accordance with this clause 3.18 and clauses 3.19, 3.20 and 3.21.~~

(f) A Market Participant or a Network Operator must schedule outages for each of its Equipment List Facilities. Outages must be scheduled in accordance with this section 3.18 and sections 3.19, 3.20 and 3.21.

3.18.2A.

~~(a) Except where clause 3.18.2(c)(iv) applies, Registered Facilities with a Standing Data nameplate capacity of less than 10 MW and generation systems to which clause 2.30B.2(a) relates and which have a nameplate capacity of less than 10 MW are not required to schedule outages for that equipment in accordance with this clause 3.18 and clauses 3.19 and 3.20 other than as required by this clause 3.18.2A.~~

(a) If a generation system:

i. is either:

1. a Scheduled Generator or Non-Scheduled Generator with a Standing Data nameplate capacity of less than 10 MW; or

2. a generation system, with a nameplate capacity of less than 10 MW, to which clause 2.30B.2(a) relates; and

ii. is not included in the Equipment List under clause 3.18.2(c)(v),

then the relevant Market Participant is not required to schedule outages in accordance with this section 3.18 and sections 3.19 and 3.20 for that generation system ("**Small Outage Facility**") other than as required by this clause 3.18.2A.

~~(b) If clause 3.18.2A(a) applies to a Market Participant's Facility or generation system then that Market Participant must notify System Management of proposed Planned Outages of that Facility or generation system not less than 2 Business Days prior to their commencement and must specify the duration of the Planned Outage;~~

(b) A Market Participant must notify System Management of a proposed Planned Outage if:

i. the Market Participant intends to make some or all of a Small Outage Facility's capacity unavailable; and

ii. the capacity would otherwise be available for dispatch for the duration of the proposed Planned Outage.

~~(c) Where System Management is advised of a proposed Planned Outage in accordance with clause 3.18.2A(b) then System Management must record that outage as an approved Planned Outage.~~

(c) The notice under clause 3.18.2A(b) must be given:

i. for an outage exceeding 24 hours in duration, no later than 8:00 AM on the day prior to the Scheduling Day for the Trading Day in which the requested outage is due to commence; and

ii. for an outage of up to 24 hours in duration, no later than 30 minutes before Balancing Gate Closure for the Trading Interval in which the requested outage is due to commence.

(d) The notice under clause 3.18.2A(b) must include the information specified in clause 3.18.6. For the purposes of this clause 3.18.2A(d), each reference to an “Equipment List Facility” in clause 3.18.6 is to be read as a reference to a “Small Outage Facility”.

(e) System Management is deemed to have approved each outage that is notified under clause 3.18.2A(b) and in accordance with clauses 3.18.2A(c) and (d). The deemed approval takes effect when System Management receives the notice.

(f) Where a Market Participant no longer plans to de-rate or remove a Small Outage Facility from service, it must inform System Management as soon as practicable.

(g) Where a Market Participant intends to de-rate or remove a Small Outage Facility from service for maintenance at a different time than indicated in its notice under clause 3.18.2A(b), it must submit a revised notice to System Management as soon as practicable.

(h) Subject to clause 3.19.2C, a Market Participant must not notify System Management of a proposed Planned Outage for a Scheduled Generator or Non-Scheduled Generator under clause 3.18.2A(b) if the Market Participant does not expect in good faith that the capacity to which the notice applies would otherwise be available for dispatch for the duration of the proposed Planned Outage.

3.18.3.

(a) If a Market Participant’s or Network Operator’s Facility (or an item of equipment forming part of a Facility or an item of equipment which is a generation system to which clause 2.30B.2(a) relates) is on the ~~list described in clause 3.18.2(a)~~Equipment List, then the Market Participant or Network Operator may request that the IMO reassess the inclusion of the Facility or item of equipment on the ~~list~~Equipment List in accordance with this clause 3.18.3.

(b) Following a request by a Market Participant or Network Operator under clause 3.18.3(a), the IMO must consult with System Management and the Market Participant or Network Operator concerning whether the ~~Facility or item of equipment~~Equipment List Facility should remain on the ~~list~~Equipment List.

(c) The IMO may give a direction to System Management that ~~a Facility or item of equipment~~an Equipment List Facility should not remain on the ~~list~~Equipment List where it finds that:

i. System Management has not followed the Market Rules or the Power System Operation Procedure in compiling the ~~list under clause 3.18.2~~Equipment List; and

ii. if the Market Rules and the Power System Operation Procedure had been followed, then the ~~Facility or item of equipment~~Equipment List Facility would not have been on the ~~list~~Equipment List.

(d) ~~Where~~If the IMO gives a direction to System Management ~~that the Facility or item of equipment does not need to remain on the list,~~under clause 3.18.3(c), then System Management must remove the ~~Facility or item~~relevant Equipment List Facility from the ~~list~~Equipment List.

~~3.18.4. System Management must maintain an outage schedule, containing information on all Scheduled Outages.~~

3.18.4. System Management must maintain an outage schedule that contains details of each Outage Plan:

(a) that System Management has accepted under clause 3.18.13; and

(b) that the IMO has directed System Management to include in the outage schedule, under clause 3.18.15(f).

3.18.4A. A proposal submitted to System Management in accordance with this clause 3.18 by a Market Participant or Network Operator in which permission is sought from System Management for the scheduling of the removal from service (or ~~derating~~de-rating) of an ~~item of equipment~~Equipment List Facility is a proposed outage plan (“**Outage Plan**”).

3.18.5. Market Participants:

(a) must, subject to clause 3.18.5A, submit to System Management details of a proposed Outage Plan at least one year but not more than three years in advance of the proposed outage, where:

i. the outage relates to ~~a Facility or item of equipment~~an Equipment List Facility in respect of which a Market Participant holds Capacity Credits at any time during the proposed outage;

ii. the ~~Facility or item of equipment~~Equipment List Facility has a nameplate capacity greater than 10 MW; and

iii. the proposed outage has a duration of more than one week; and

(b) otherwise may submit an Outage Plan to System Management not more than three years and not less than two days in advance of the proposed outage.

…

3.18.5C. Where a Network outage is likely to unduly impact the operation of one or more Market Participant Registered Facilities, System Management may require that, in developing their Outage Plans, the relevant Network Operator and affected Market Participants coordinate the timing of their outages so as to minimise the impact of the Network outage on the operation of the Market Participant Registered Facilities.

~~3.18.5D Notwithstanding the requirements in chapter 10, in exercising the obligation set out in clause 3.18.5C, System Management may make such information in the outage~~

~~schedule maintained in accordance with clause 3.18.4 available to a Network Operator to coordinate outage timing.~~

3.18.6. The information submitted in an Outage Plan must include:

(a) the identity of the ~~Facility or item of equipment~~Equipment List Facility that will be unavailable;

(b) the quantity of any de-rating where, if the Facility is a generating system, this quantity is in accordance with clause 3.21.5;

(c) the reason for the outage;

(d) the proposed start and end times of the outage;

(e) an assessment of risks that might extend the outage;

(f) details of the time it would take the ~~Facility or item of equipment~~Equipment List Facility to return to service, if required;

(g) contingency plans for the early return to service of the ~~Facility or item of equipment~~Equipment List Facility ("**Outage Contingency Plans**"); and

(h) if the Outage Plan is submitted by a Network Operator, a confirmation that the Network Operator has used its best endeavours to inform any Market Generator with a Scheduled Generator or Non-Scheduled Generator impacted by the unavailability of the relevant ~~item of equipment~~Equipment List Facility of the proposed outage.

3.18.7. Outage Plans submitted by a Market Participant or Network Operator must represent the good faith intention of the Market Participant or Network Operator to remove from service, or de-rate, the relevant ~~Facility or item of equipment~~Equipment List Facility, for maintenance.

3.18.8. Where a Market Participant or Network Operator no longer plans to remove from service, or de-rate, the relevant ~~Facility or item of equipment~~Equipment List Facility, for maintenance it must inform System Management as soon as practicable.

3.18.9. Where a Market Participant or Network Operator intends to remove from service, or de-rate, the relevant ~~Facility or item of equipment~~Equipment List Facility, for maintenance at a different time than indicated in an -Outage Plan, it must submit a revised Outage Plan to System Management as soon as practicable.

~~3.19.1. No later than two days prior to the date of commencement of any outage ("**Scheduled Outage**") in System Management's outage schedule, the Market Participant or Network Operator involved must request that System Management approve the Scheduled Outage proceeding, specifying the Trading Day and Trading Intervals during which the Scheduled Outage will occur.~~

3.19.1. No later than 8:00 AM on the day prior to the Scheduling Day for the Trading Day in which the requested outage in System Management's outage schedule

("**Scheduled Outage**") is due to commence, the relevant Market Participant or Network Operator must request that System Management approve the Scheduled Outage proceeding. The request must specify the Trading Intervals during which the Scheduled Outage will occur.

3.19.2. Market Participants and Network Operators may request that System Management approve an outage of ~~a Facility or item of equipment~~an Equipment List Facility that is not a Scheduled Outage ("**Opportunistic Maintenance**")~~ to be carried out during a Trading Day,~~:

~~(a) at any time between 10:00 AM on the day prior to the Scheduling Day and 10:00 AM on the Scheduling Day for that Trading Day, where the request relates to an outage to occur at any time and for any duration during the following Trading Day; or~~

(a) at any time between:

i. 8:00 AM on the day prior to the Scheduling Day for the Trading Day in which the requested outage is due to commence; and

ii. 30 minutes before Balancing Gate Closure for the Trading Interval in which the requested outage is due to commence,

(b) ~~at any time on the Trading Day not later than 1 hour prior to the commencement of the Trading Interval during which the requested outage is due to commence, ~~where:

i. the outage must be to allow minor maintenance to be performed;

ii. the outage must not require any changes in scheduled energy or ~~ancillary services~~Ancillary Services; and

~~iii. the outage may be for any duration and must end before the end of the Trading Day;~~

iii. the duration of the outage must not exceed 24 hours; and

iv. the request must include all of the information specified in clause 3.18.6.

~~where the request must include all of the information specified in clause 3.18.6, and must specify the Trading Intervals during which the Opportunistic Maintenance will occur.~~

3.19.2A. If:

(a) a Market Participant intends to make some or all of an Equipment List Facility's capacity unavailable; and

(b) the capacity would otherwise be available for dispatch for the duration of the Planned Outage,

then the Market Participant must request approval for a Planned Outage from System Management in accordance with section 3.18 and this section 3.19.

3.19.2B. Subject to clause 3.19.2D, a Market Participant must not request approval of a proposed Planned Outage for a Scheduled Generator or Non-Scheduled Generator under clauses 3.19.1 or 3.19.2 if the Market Participant does not expect in good faith that, if System Management rejected the request, the capacity to which the request applies would be available for dispatch for the duration of the proposed Planned Outage.

3.19.2C. Subject to clause 3.19.2D, if:

(a) a Market Participant has requested approval under clauses 3.19.1 or 3.19.2 for a proposed Planned Outage of a Scheduled Generator or Non-Scheduled Generator;

(b) System Management has not yet approved or rejected the request under clause 3.19.4; and

(c) the Market Participant ceases to expect in good faith that, if System Management were to reject the request, the capacity to which the request applies would be available for dispatch for the duration of the proposed Planned Outage,

then the Market Participant must immediately notify System Management of the change in circumstances and withdraw the Market Participant's request for approval of the proposed Planned Outage.

3.19.2D. Clauses 3.18.2A(h), 3.19.2B, 3.19.2C and 3.19.3B do not apply where:

(a) the proposed Planned Outage will immediately follow a Scheduled Outage of the relevant capacity; or

(b) the Market Participant reasonably expects that the relevant capacity would be subject to a Consequential Outage if the proposed Planned Outage did not proceed.

3.19.3. Subject to clauses 3.19.3A and 3.19.3B, System Management must assess the request for approval of a Scheduled Outage or Opportunistic Maintenance, based on the information available to System Management at the time of the assessment, and applying the criteria set out in clause 3.19.6.

3.19.3A. In assessing whether to grant a request for Opportunistic Maintenance, System Management:

(a) must not grant permission for Opportunistic Maintenance to begin prior to the first Trading Interval for which Opportunistic Maintenance is requested;

(b) must not approve an Opportunistic Maintenance request for ~~a Facility or item of equipment~~an Equipment List Facility ~~on two consecutive Trading Days;~~where the Opportunistic Maintenance outage would commence within 24 hours of the end time of the most recent Opportunistic Maintenance for that Equipment List Facility; and

(c) [Blank]~~may decline to approve Opportunistic Maintenance for a Facility or item of equipment where it considers that the request has been made principally to avoid exposure to Reserve Capacity refunds as described in clause 4.26 rather than to perform maintenance; and~~

(d) may decline to approve Opportunistic Maintenance for a facility where it considers that inadequate time is available before the proposed commencement time of the outage to adequately assess the impact of that outage.

3.19.3B. Subject to clause 3.19.2D, System Management may decline to approve a Scheduled Outage or Opportunistic Maintenance for an Equipment List Facility where it considers that the capacity to which the request applies would not otherwise be available for dispatch for the duration of the proposed Planned Outage.

3.19.4A. If System Management does not provide a Market Participant or Network Operator with its decision on a request for approval of a Planned Outage by 30 minutes before Balancing Gate Closure for the Trading Interval during which the outage is proposed to commence, then, for the purposes of the Market Rules, the request is deemed to be rejected.

~~3.19.11. An outage, including Opportunistic Maintenance, that is approved by System Management under clause 3.19.4 is a Planned Outage.~~

3.19.11. An outage, including Opportunistic Maintenance, is a Planned Outage if it is:

(a) approved by System Management under clause 3.19.4; or

(b) deemed to be approved by System Management under clause 3.18.2A(e).

3.19.12.

(a) Where, under clause 3.19.5, System Management informs a Market Participant or Network Operator that an Outage Plan previously scheduled in System Management's outage schedule is rejected within 48 hours of the time when the outage would have commenced in accordance with the Outage Plan, the Market Participant or Network Operator may apply to the IMO for compensation.

…

(d) The Market Participant or Network Operator must submit a written request for compensation to the IMO within three months of System Management's decision, including invoices and other documents demonstrating the costs referred to in clause 3.19.12(b)~~paragraph (b)~~.

…

3.20.1. Where the SWIS is in an Emergency Operating State or High Risk Operating State, System Management may direct a Market Participant or Network Operator that ~~a Facility or item of equipment~~an Outage Facility be returned to service from a

Planned Outage~~s~~ in accordance with the relevant Outage Contingency Plan, or take other measures contained in the relevant Outage Contingency Plan.

7A.2.4. A Balancing Submission must:

(a) be in the manner and form prescribed and published by the IMO;

(b) constitute a declaration by an Authorised Officer;

(c) have Balancing Price-Quantity Pair prices within the Price Cap;

(d) specify, for each Trading Interval covered in the Balancing Submission, whether the Balancing Facility is to use Liquid Fuel or Non-Liquid Fuel;~~ and~~

~~(e) specify, for each Trading Interval covered in the Balancing Submission, Ramp Rate Limits.~~

(e) specify the Ramp Rate Limit or the Portfolio Ramp Rate Limit (as applicable) for each Trading Interval covered in the Balancing Submission; and

(f) specify the available capacity and the unavailable capacity as determined under clause 7A.2.4A, 7A.2.4B or 7A.2.4C (as applicable) for each Trading Interval covered in the Balancing Submission.

7A.2.4A. A Balancing Submission for a Balancing Facility (other than the Verve Energy Balancing Portfolio) that is a Scheduled Generator must specify the following details for each Trading Interval covered in the Balancing Submission:

(a) a ranking of Balancing Price-Quantity Pairs covering available capacity; and

(b) a declaration of the MW quantity that will be unavailable for dispatch,

where the sum of:

(c) the quantities in the Balancing Price-Quantity Pairs; and

(d) the declared MW quantity of unavailable capacity,

must be equal to the Scheduled Generator's Sent Out Capacity.

7A.2.4B. A Balancing Submission for a Balancing Facility (other than the Verve Energy Balancing Portfolio) that is a Non-Scheduled Generator must specify the following details for each Trading Interval covered in the Balancing Submission:

(a) the Market Participant's best estimate of the Facility's output at the end of the Trading Interval (based on an assumption, for the purposes of this clause 7A.2.4B(a), that no Dispatch Instruction will be issued in respect of the Facility for that Trading Interval); and

(b) a declaration of the MW quantity that will be unavailable for dispatch (excluding any unavailable capacity to the extent that it relates to a temporary limitation in the intermittent energy source used by the Non-Scheduled Generator to generate electrical energy).

7A.2.4C. A Balancing Submission for the Verve Energy Balancing Portfolio must specify the following details for each Trading Interval covered in the Balancing Submission:

(a) the Balancing Portfolio Supply Curve; and

(b) a declaration of the MW quantity that will be unavailable for dispatch (excluding any unavailable capacity to the extent that it relates to a temporary limitation in the intermittent energy source used by a Non-Scheduled Generator in the Verve Energy Balancing Portfolio to generate electrical energy).

7A.2.9. Verve Energy, in relation to the Verve Energy Balancing Portfolio:

(a) must, subject to clauses 7A.2.9(e) and 7A.2.9(f), ensure that its Balancing Portfolio Supply Curve accurately reflects:

i. all information reasonably available to it, including Balancing Forecasts published by the IMO and the latest information available to it in relation to any Forced Outage for a Facility in the Verve Energy Balancing Portfolio;

ii. subject to clause 7A.2A.2(b), Verve Energy's reasonable expectation of the capability of its Verve Energy Balancing Portfolio to be dispatched in the Balancing Market for that Trading Interval; and

iii. the price at which Verve Energy intends to have the Verve Energy Balancing Portfolio participate in Balancing;

…

(e) may update its Balancing Portfolio Supply Curve in relation to any Trading Interval in the Balancing Horizon for which Balancing Gate Closure is more than two hours in the future if a Facility in the Verve Energy Balancing Portfolio has experienced a Forced Outage since the last Balancing Submission;~~ and~~

(f) may after the time specified in clause 7A.2.9(d), update its Balancing Portfolio Supply Curve to reflect the impact of a Forced Outage which Verve Energy expects will cause a Facility to run on Liquid Fuel, where the Facility would not have run on Liquid Fuel but for the Forced Outage, in order to meet Verve Energy's Balancing obligations in relation to the Verve Energy Balancing Portfolio under this Chapter 7A~~.~~; and

(g) must, if System Management approves a Planned Outage for a Facility in the Verve Energy Balancing Portfolio and a Trading Interval after the latest time specified in clause 7A.2.9(d), update its Balancing Submission for the Trading Interval as soon as practicable, but before Balancing Gate Closure for the Trading Interval, to:

i. make the capacity subject to the outage unavailable; and

ii. remove or reduce the quantity of the highest price Balancing Price-Quantity Pair or Balancing Price-Quantity Pairs (excluding any

Balancing Price-Quantity Pairs that are required to be offered at the Price Caps under clause 7A.2.9(c)) to remove the capacity subject to the outage from its Balancing Portfolio Supply Curve.

7A.2A.1. A Market Participant (other than Verve Energy in respect of the Verve Energy Balancing Portfolio) must, for each of its Balancing Facilities, and for each Trading Interval in the Balancing Horizon, use its best endeavours to ensure that, at all times, any of the Facility's capacity that is:

(a) subject to an approved Planned Outage; or

(b) subject to an outstanding request for approval of a Planned Outage,

is declared as unavailable in the Balancing Submission for the Facility and the Trading Interval, unless the Balancing Facility is undertaking a Commissioning Test in that Trading Interval.

7A.2A.2. Verve Energy must, to the extent it is able to update its Balancing Submissions subject to clauses 7A.2.9(d)-(g) (as applicable), for each Facility in the Verve Energy Balancing Portfolio, and for each Trading Interval in the Balancing Horizon, use its best endeavours to ensure that, at all times, any of the Facility's capacity that is:

(a) subject to an approved Planned Outage is declared as unavailable in the Balancing Submission for the Verve Energy Balancing Portfolio and that Trading Interval, except where that Facility is subject to a Commissioning Test; and

(b) subject to an outstanding request for approval of a Planned Outage is declared as available in the Balancing Submission for the Verve Energy Balancing Portfolio and that Trading Interval.

7A.2A.3. Subject to clause 7A.2A.5, a Market Participant (other than Verve Energy in respect of the Verve Energy Balancing Portfolio) must, as soon as practicable after Balancing Gate Closure for each Trading Interval, for each of its Balancing Facilities that is an Outage Facility, ensure that it has notified System Management of a Forced Outage or Consequential Outage for any capacity declared unavailable in the Facility's Balancing Submission that:

(a) was not subject to an approved Planned Outage or Consequential Outage at Balancing Gate Closure for the Trading Interval; and

(b) is not attributable to a difference between the expected temperature at the site during the Trading Interval and the temperature at which the Sent Out Capacity for the Facility was determined.

7A.2A.4. Subject to clause 7A.2A.5, Verve Energy must, as soon as practicable after the latest time specified in clause 7A.2.9(d) for a Trading Interval, for each Facility in the Verve Energy Balancing Portfolio that is an Outage Facility, ensure that it has notified System Management of a Forced Outage or Consequential Outage for any capacity declared unavailable in the Facility's Balancing Submission that:

(a) was not subject to an approved Planned Outage or Consequential Outage at that time for the Trading Interval; and

(b) is not attributable to a difference between the expected temperature at the site during the Trading Interval and the temperature at which the Sent Out Capacity for the Facility was determined.

7A.2A.5. Clauses 7A.2A.3 and 7A.2A.4 do not apply to any capacity that was subject to a previously approved Planned Outage for the Trading Interval that was rejected by System Management under clause 3.19.5 less than 30 minutes before:

(a) Balancing Gate Closure, for a Facility that is not in the Verve Energy Balancing Portfolio; or

(b) the latest time specified in clause 7A.2.9(d), for a Facility in the Verve Energy Balancing Portfolio.

7A.2A.6. If System Management rejects a previously approved Planned Outage of a Balancing Facility (or a Facility in the Verve Energy Balancing Portfolio) under clause 3.19.5, then the relevant Market Participant must, as soon as practicable, update its Balancing Submission for any relevant Trading Intervals in the Balancing Horizon for which Balancing Gate Closure has not yet occurred, to reflect that the capacity will not be subject to a Planned Outage.

7A.2A.7 If System Management directs a Market Participant to return a Balancing Facility or a Facility in the Verve Energy Balancing Portfolio from a Planned Outage in accordance with the relevant Outage Contingency Plan under clause 3.20.1, then the Market Participant must, as soon as practicable, update its Balancing Submission for any relevant Trading Intervals in the Balancing Horizon for which Balancing Gate Closure has not yet occurred, to reflect the impact of System Management's direction on the proposed end time of the Planned Outage.

Glossary

Balancing Portfolio Supply Curve: Means a ranking of the Balancing Price-Quantity Pairs covering available capacity in~~provided for~~ the Verve Energy Balancing Portfolio.

Balancing Submission: Means~~:~~ a submission by a Market Participant to the IMO, for a Balancing Facility or the Verve Energy Balancing Portfolio, and for one or more Trading Intervals, that includes the information specified in clause 7A.2.4.

~~(a) for a Balancing Facility, other than the Verve Energy Balancing Portfolio, that is:~~

~~i. a Scheduled Generator, for each Trading Interval or Trading Intervals, a ranking of Balancing Price-Quantity Pairs for each MW of its Sent Out Capacity from zero capacity to the maximum Sent Out Capacity, together with associated Ramp Rate Limit for each Trading Interval; and~~

~~ii. a Non-Scheduled Generator, for each Trading Interval or Trading Intervals, the Market Generator's best estimate of the quantity for the Balancing Price-Quantity Pair, in MW, the Facility is able to reduce its output, together with the associated Ramp Rate Limit for each Trading Interval; and~~

~~(b) for the Verve Energy Balancing Portfolio, the Balancing Portfolio Supply Curve together with the Portfolio Ramp Rate Limit.~~

<u>**Equipment List**: Means the list maintained by System Management under clause 3.18.2(a).</u>

<u>**Equipment List Facility**: Means a Facility or item of equipment that is included on the Equipment List.</u>

<u>**Outage Facility**: Means an Equipment List Facility or a Small Outage Facility.</u>

<u>**Small Outage Facility**: Has the meaning given in clause 3.18.2A.</u>

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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 better achieve Wholesale Market Objectives (a), (b) and (d), and are consistent with the other Wholesale Market Objectives.

The IMO's assessment is presented below:

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

1. The proposed amendments relating to which Network Equipment which should be on the Equipment List, promote:

    - <u>Economic efficiency</u> by removing the requirement (and associated cost) on the Network Operator to schedule outages for transmission network Facilities which do not have a material impact on system security; and.

    - <u>The safe and reliable supply of energy</u> by requiring any distribution equipment which has the potential to materially impact system security, to be on the equipment list.

2. The proposed amendment to clarify the requirement for a participant to request a Planned Outage before making capacity unavailable to perform maintenance, will promote the <u>safe and reliable supply of energy</u> in the WEM, by ensuring that System Management has accurate information in relation to whether a Facility is actually available for dispatch.

3. The proposed amendments relating to the interactions between Planned Outages and Balancing Submissions will encourage <u>economic efficiency</u> by providing a more accurate picture of a Facility's available and unavailable capacity in a given Trading Interval. This will result in more accurate Forecast Balancing Prices which will allow Market Participants to make better informed decisions.

4. The proposed amendments relating to:

    - when Opportunistic Maintenance requests can be made; and
    - the period over which Opportunistic Maintenance outages can span

    will remove existing unnecessary timing restrictions, which limit the opportunities for Market Participants to request and carry out bona fide maintenance that is both discretionary and preventative. The IMO considers that enhancing the opportunities for Market Participants to carry out preventative maintenance will promote the safe and reliable production and supply of electricity in the SWIS.

5. The proposed amendments to the criteria for the approval of Planned Outages will enable more flexibility and certainty to generators seeking to take an outage or extend an outage. In particular, the proposals will promote:

    - Economic efficiency and the safe and reliable supply of energy – explicitly allowing extensions to unavailable capacity currently on a Planned Outage will reduce the incentive for Market Participants to apply for outages which are longer than necessary will have the benefit of increasing the quantity of outage slots available to other participants also seeking an outage.

      It will also provide a more accurate and reliable picture to System Management and other Market Participants as to the likely length of a requested Planned Outage which may increase confidence in the outage planning system;

    - Economic efficiency and the safe and reliable supply of energy by allowing capacity currently on a Forced Outage to receive approval for a future Planned Outage allowing Market Participants to fix a problem properly in the first instance rather than make short term temporary fixes to the problem, in order to be eligible to apply for a subsequent Planned Outage.

      This is economically efficient because it removes the incentive (and cost) for Market Participants to undertake unnecessary quick fixes. It also potentially improves the reliability of generation plants by ensuring that these plants are properly repaired in the first instance, improving overall availability and reliability.

(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 remove the need for System Management to exercise discretion in determining whether:

- an ODOM request meets the requirements of clause 3.19.2(b)(ii); and
- to request an availability declaration for Outages and extensions to Outages.

This reduces the potential for bias which consequently may reduce perceptions of discrimination. This has the potential to encourage competition among generators and retailers in the SWIS, including by facilitating efficient entry of new competitors.

The proposed amendments relating to the interactions between Planned Outages and Balancing Submissions will encourage economic efficiency by providing a more accurate picture of a Facility's available and unavailable capacity in a given Trading Interval. The increased transparency may improve the acccuracy of the Forecast Balancing Price and confidence in the Balancing Market, potentially encouraging greater competition among generators and retailers in the SWIS.

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

Removing the requirement (and associated cost) on the Network Operator to schedule outages for network facilities which do not have a material impact on system security, may reduce the long-term cost of electricity to customers from the SWIS.

In addition, many of the changes provide greater flexibility for Market Participants in scheduling outages (including allowing Opportunistic Maintenace over consecutive Trading Days and extensions of Planned Outage), which may avoid some costs associated with undertaking temporary fixes or over-estimating the duration of an outage and increase overall plant availability.

Provide any identifiable costs and benefits of the change:

System Management noted in its preliminary cost estimate that the proposal required updates of the validations in the Market Participant Interface, representing a total estimated end to end project cost of approximately $23,000.

The IMO will incur some costs associated with implementing the necessary changes to the IMO's IT and compliance monitoring systems. These costs are not anticipated to be significant.

The benefits of these changes include:

- better clarifying the obligations of Rule Participants around the outage planning process;
- provide greater flexibility for Rule Particpants in outage planning; and
- improving the transparency and consistency of outage planning and Balancing Market processes.

Wholesale Electricity Market
Pre Rule Change Proposal

Rule Change Proposal ID: **PRC_2013_20**
Date received: **TBA**

Change requested by:

Name:	Allan Dawson
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Organisation:	IMO
Address:	Level 17, 197 St Georges Terrace, Perth WA 6000
Date submitted:	TBA
Urgency:	2-medium
Change Proposal title:	Changes to the Reserve Capacity Price and the dynamic Reserve Capacity Refund regime
Market Rules affected:	Table of Contents, 1.4.1, 2.26.1, 2.26.2, 2.26.3, 4.1.19, 4.3.1, 4.13.2, 4.16.1, 4.16.2, 4.16.3, 4.16.5, 4.16.6, 4.16.7, 4.16.8, 4.18.2, 4.22.2, 4.26.1, 4.26.1A, 4.26.3, 4.26.3A, 4.26.4, 4.26.7(new), 4.26.8(new), 4.28.4, 4.28A.1, 4.28C.9, 4.29.1, 4.29.3, 9.7.1, 10.5.1 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:

Background

The Reserve Capacity Mechanism (RCM) is designed to support the Wholesale Electricity Market (WEM) in the South West interconnected system (SWIS) by ensuring there is sufficient Reserve Capacity to meet peak demand. Through the RCM, the IMO procures capacity from supply-side resources (generation facilities) or temporary curtailments in demand from Demand Side Programmes (DSP).

In 2011, the IMO Board engaged The Lantau Group to conduct a comprehensive review of the design and performance of the RCM. The Lantau Group prepared a report concluding that while the RCM has promoted capacity development and reliability of supply in the WEM, refinements were needed to improve its responsiveness to changing market conditions. In 2012, the Market Advisory Committee (MAC) decided to constitute the RCM Working Group (RCMWG) to discuss issues and develop solutions with respect to the recommendations put forward by The Lantau Group.

The RCMWG explored four major work-streams[1] encompassing the WEM Rules (Market Rules):

[1] The RCMWG outcomes in each work-stream are detailed on page 13 of the RCMWG meeting 10 papers:
http://www.imowa.com.au/f5415,3566068/Combined_RCMWG_Mtg_10_Papers.pdf

1. adjustments to the Reserve Capacity Price (RCP);
2. the obligations of DSPs and their harmonisation with supply-side capacity resources[2];
3. a dynamic Reserve Capacity Refund regime; and
4. the calculation of the Individual Reserve Capacity Requirements[3].

Work-stream 1 focused on the market-responsiveness of the price signal which the IMO applies through the administrative RCP formula in clause 4.29.1 of the Market Rules. The RCMWG members discussed the issue that the current RCP formula is unable to send efficient signals for investment in or withholding investment from new capacity.

Work-stream 3 explored the issue that the refund factors[4] outlined in the Refund Table in clause 4.26.1 of the Market Rules that determine the value of Capacity Cost Refunds, do not necessarily align with time periods of greatest system need. As a result, the current Reserve Capacity Refund regime does not signal appropriate incentives to capacity providers for presenting capacity to the market when system need is the greatest.

The IMO considered that the recommendations in work-streams 1 and 3 needed to be progressed as a comprehensive package because of their interdependencies. The RCM impacts a Market Participant's refund exposure through the RCP because it is determined by multiplying the applicable refund factor in the Refund Table by the Monthly RCP. The Reserve Capacity Refund regime may impact on the value expected to be recovered by a Market Participant through the RCM based on an assessment of the availability of a Facility. Together, the RCP and the Reserve Capacity Refund regime signal the attractiveness of investment in the WEM. In particular, new investment will only be economic if the combination of energy revenues plus Capacity Credit revenues less any lost revenue from the Reserve Capacity Refund regime is at least equal to the long-run marginal cost of new capacity. Therefore, adjustments to the RCP should only be made with supporting changes to the Reserve Capacity Refund regime to avoid perverse outcomes.

Consultation

A concept paper exploring the proposed changes to the RCP and the introduction of a dynamic Reserve Capacity Refund regime was presented at the MAC meeting held on 9 October 2013[5]. In the concept paper, the IMO recommended the following proposals, in addition to the proposals that were previously presented to the RCMWG:

(a) the minimum refund factor applicable to a Market Participant's unavailable capacity would be 0.25 and would apply when the spare capacity in a Trading Interval is at 1500 MW or more;

(b) the minimum refund factor applicable to a Market Participant's unavailable capacity would scale up from 0.25 towards one depending on the level of unavailability of a

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[2] More details on this Rule Change Proposal are available on the Market Web Site: http://www.imowa.com.au/RC_2013_10
[3] More details on this Rule Change Proposal are available on the Market Web Site: http://www.imowa.com.au/rc_2013_11
[4] The Refund Table outlines the determination of the applicable Trading Interval Rate as the product of a 'factor'(0.25, 0.5, 0.75, 1.5, 4 and 6) and the Monthly RCP.
[5] CP_2013_06 is available on page 66 of the meeting papers of the MAC meeting no.65: http://www.imowa.com.au/governance/market-advisory-committee-(mac)/2013/mac-65

Facility over the previous 90-day period up to and including that Trading Interval; and

(c) the revenue collected from the application of the dynamic Reserve Capacity Refund regime would be distributed as rebates to Facilities that have been dispatched for a non-zero MW value in any one Trading Interval in the previous 30-day period up to and including the Trading Interval in which refunds were applied. Rebates for that Trading Interval would be allocated to Facilities based on their share of available Capacity Credits in that Trading Interval. Intermittent Generators would be excluded from the rebate pool on the basis that Intermittent Generators that are in Commercial Operation and have operated at their Required Level are not liable for Capacity Cost Refunds.

The IMO also presented additional analyses on the minimum refund factor and the application of the recycling of Capacity Cost Refund revenue in response to feedback received from some RCMWG members.

At the October meeting, some members raised the following comments and issues:

- Clarification was sought on the application of the eligibility criterion for the rebate pool in cases where the 30-day rolling period coincided with Reserve Capacity Testing as conducted under clause 4.25 of the Market Rules. The IMO clarified that in principle, dispatch to meet Reserve Capacity Tests would also qualify the Facility for rebate eligibility.
- Confirmation was sought on the application of the principle that a delayed new Facility would automatically have a minimum refund factor of one because of no availability. The IMO confirmed that this would be the case.
- Clarification was also sought on the determination of spare capacity in a Trading Interval. The IMO proposed to provide further detail in the pre Rule Change Proposal.

Two MAC members noted their disagreement with the recycling of Capacity Cost Refund revenue on the grounds that it would result in a monetary gain for generators that have already received payments for their capacity and that there was no evidence that the recycling of Capacity Cost Refund revenue would incentivise more efficient decision-making on availability of capacity. The IMO agreed to provide further details on the economic arguments for the recycling of Capacity Cost Refund revenue in the pre Rule Change Proposal.

MAC members generally agreed that the recommended proposals should proceed to the pre Rule Change Proposal stage.

This pre Rule Change Proposal elaborates on the proposed solutions as discussed in the concept paper and includes the necessary amendments to the relevant Market Rules. The issues raised at the MAC have also been addressed in this proposal.

Issues to be addressed in the Market Rules

1. Changes to the Reserve Capacity Price formula

Where the number of Capacity Credits to be traded bilaterally (as determined through the Bilateral Trade Declaration process in clause 4.14 of the Market Rules) exceeds the Reserve Capacity Requirement (RCR), the IMO determines the cost of Capacity Credits by applying the RCP formula in clause 4.29.1 of the Market Rules. The formula is set at 85% of the Maximum Reserve Capacity Price (MRCP) and is further adjusted downward if there is excess capacity. This downward adjustment of the RCP is intended to reduce the value of a Capacity Credit, thereby sending signals to investors to defer new investment in capacity.

The RCMWG noted that despite the existing downward adjustment of the RCP, excess capacity has continued to increase, and stands at 11% (~564 MW) of the RCR in the 2015/16 Capacity Year. Excess capacity can be considered an unnecessary cost to the market in the sense that consumers end up paying more than the efficient economic value of a Capacity Credit. The RCMWG discussed that a number of factors such as Government policy decisions, cessation of demand growth, forecasted large Loads not entering the market as expected and the poor market-responsiveness of the RCP have contributed to the consistent increase in excess capacity[6].

In evaluating different solutions to address the issue of excess capacity[7], The Lantau Group noted that the most feasible solution should seek to address the two key issues associated with the current operation of the RCM:

(a) it is not sufficiently dynamic to respond appropriately to market conditions; and

(b) it creates asymmetrical incentives for capacity providers and capacity users to manage their risk exposure through Bilateral Contracts.

Based on the recommendations of The Lantau Group and the discussions at various RCMWG meetings, the IMO proposed to implement the following amendments to the RCP formula:

(a) the ability for the RCP to move above the MRCP such that the RCP is 110% of the MRCP when 97% of the RCR has been fulfilled; and

(b) a steeper slope function of -3.75 replacing the current -1 slope embedded into the 'excess capacity adjustment' component of the RCP formula such that the rate of downward adjustment is accelerated as excess capacity increases.

The IMO considers that the proposed amendments to the RCP would achieve a more balanced RCM where the RCP would be lower than under the current formula for levels of excess capacity above approximately seven percent, while enhancing the investment incentives necessary to assure capacity adequacy as the excess capacity level declines. The increased responsiveness of the RCP formula resulting from the steeper slope and the ability to exceed the MRCP would create stronger commercial and behavioural incentives.

Proposed Amendments

The IMO proposes to amend clause 4.29.1 of the Market Rules such that a new RCP formula is introduced from the 2016 Capacity Year where no Reserve Capacity Auction is required.

2. The applicable ceiling price in a Reserve Capacity Auction

Clause 4.18 of the Market Rules outlines the Reserve Capacity Offer format that must be followed by a Market Participant to submit capacity into a Reserve Capacity Auction. Clause 4.18.2(b) of the Market Rules specifies that the Reserve Capacity Price- Quantity Pairs that are offered in a Reserve Capacity Auction (if called) must not have an offer price greater than the MRCP.

The IMO notes that the changes proposed to the RCP formula (as discussed under Issue 1)

[6] A detailed discussion on various factors contributing to excess capacity is provided on Page 45 in RCMWG Meeting 3 papers:http://www.imowa.com.au/f5415,2873678/Combined_RCMWG_Mtg_3_Papers.pdf
[7] A detailed discussion on various solutions can be accessed on the Market Web Site: http://www.imowa.com.au/f5415,2873740/IMO_RCM_October_WG_to_IMO_Updated.pdf

would also affect the ceiling price that will apply if a Reserve Capacity Auction is called. Given that the proposed amendment to the RCP formula allows the RCP to reach 110% of the MRCP when 97% of the RCR is met, the IMO proposes to amend the ceiling price that will apply in a Reserve Capacity Auction accordingly.

Proposed Amendments

The IMO proposes to amend clause 4.18.2(b) of the Market Rules to reflect that the ceiling price of a Reserve Capacity Price-Quantity Pair in a Reserve Capacity Auction is 110% of the MRCP.

This amendment will also be reflected in clause 2.26.3 of the Market Rules which outlines the aspects of Reserve Capacity Offers that the Economic Regulation Authority's (ERA) review must examine when reviewing the methodology for setting the MRCP. Specifically, under clause 2.26.3(d), the ERA must examine historical Reserve Capacity Offers and the proportion of Reserve Capacity Offers with prices equal to the ceiling price. The IMO proposes to include a new sub-clause reflecting that the applicable ceiling price for a Reserve Capacity Offer from the 2014 Reserve Capacity Cycle onwards is 110% of the MRCP.

Additionally, this amendment will also be reflected in the definition of the Reserve Capacity Price in the Glossary which outlines that the RCP has a value between zero and the MRCP. In accordance with the proposed amendments, this definition is proposed to be amended such that the RCP can have a value up to 110% of the MRCP.

3. Renaming the Maximum RCP to the Benchmark RCP

In accordance with clause 4.16 of the Market Rules, the IMO determines the MRCP to reflect the marginal cost of providing additional Reserve Capacity in each Capacity Year. The MRCP is established by undertaking a technical bottom-up cost evaluation of the entry of a 160MW open cycle gas turbine generation facility entering the WEM in the relevant Capacity Year.

The RCMWG members noted that following the five-yearly MRCP review completed in 2011, the MRCP has become more representative of a benchmark price that signals the expected rather than the maximum price for providing Reserve Capacity. Based on this, the RCMWG members generally considered it appropriate that the MRCP be renamed to a more appropriate term such as the Benchmark RCP to reflect its underlying intent.

Proposed Amendments

Based on the recommendations of the RCMWG, the IMO proposes to replace all references to the 'Maximum' RCP with the 'Benchmark' RCP in the Market Rules. This proposed amendment affects clauses 2.26.1, 2.26.2, 2.26.3, 4.1.19, 4.3.1, 4.13.2, 4.16.1, 4.16.2, 4.16.3, 4.16.5, 4.16.6, 4.16.7, 4.16.8, 4.22.2, 4.28C.9, 4.29.1, 10.5.1, the Table of Contents, the Title for clause 4.16 and the definitions of the Maximum Reserve Capacity Price and the Reserve Capacity Price in the Glossary.

4. Dynamic Reserve Capacity refund factors

The current Reserve Capacity Refund regime requires Market Generators who have been paid to provide capacity (through Capacity Credits) to pay Capacity Cost Refunds if that capacity is not made reliably available to the market. The refund factors are currently set on a time-based schedule specified in the Refund Table in clause 4.26.1 of the Market Rules. The refund factors are weighted to times when high demand is more likely and spare capacity may be low. They range from a minimum of 0.25 applicable at off-peak times in winter and shoulder seasons to a maximum of six applicable at peak times in summer.

The RCMWG members noted that a key issue with the current Reserve Capacity Refund regime is that at different times, the refund factors result in under or over-pricing the value of capacity leading to inefficient decisions on the scheduling of maintenance and presentation of capacity. The current regime is also more punitive for generators with high utilisation rates, such as baseload generators as they can be exposed to the risk of Capacity Cost Refunds in most Trading Intervals of the year.

The IMO proposed a dynamic Reserve Capacity Refund regime as an alternative to the current regime in its paper titled "*Review of Capacity Cost Refunds*"[8]. The Lantau Group examined the proposed framework further and presented it to the RCMWG at its 22 November 2012 meeting[9].

The RCMWG members agreed that a dynamic Reserve Capacity Refund regime should be implemented to improve the alignment of the magnitude of refunds with the prevalent system conditions. However, in adopting dynamic refund factors, the RCMWG members emphasised the need to retain a maximum and a minimum refund factor to provide certainty of the potential financial exposure to Market Participants. The RCMWG members agreed to retain the maximum refund factor of six which would apply when the spare capacity in a Trading Interval reduces to 750MW or below.

A minimum refund factor of one was initially proposed to ensure that a Facility that was unavailable for an entire Capacity Year would not retain any Capacity Credit revenue. However, the IMO undertook additional analyses arising out of suggestions received from some RCMWG members that a minimum refund factor of one would create perverse consequences for Facilities with high utilisation factors. These members noted that under the current regime, Market Participants are exposed to 'refund factors' below one (0.25, 0.50 and 0.75) in off-peak periods. With the proposed minimum refund factor of one, the increased potential financial exposure could ultimately be manifested in the form of higher energy prices.

Based on the additional analyses, the IMO outlined the following recommendations on the minimum refund factor in the concept paper presented to the MAC on 9 October 2013:

(a) A minimum refund factor of 0.25, applicable when the spare capacity in a Trading Interval exceeds 1500 MW, would be adopted to protect Facilities with high utilisation factors from overly punitive refund exposure.

(b) The minimum refund factor would scale up from 0.25 towards one depending on the level of unavailability of a Facility over the previous 90-day period up to and including that Trading Interval.

The IMO considers that this approach will appropriately reflect the greater value of capacity when the spare capacity in a Trading Interval is low. This will focus the incentives for Market Participants to maximise their availability and reduce their risk of exposure to Capacity Cost

[8] The IMO presented this paper to the Rules Development and Implementation Working Group (RDIWG) in April 2011. Subsequently, the recommendations were examined further in the RCMWG. The paper is available from page 45 in RCMWG meeting no. 5 papers: http://www.imowa.com.au/f5415,2873627/Combined_Papers_Mtg_5.pdf

[9] The Lantau Group's presentation can be accessed at: http://www.imowa.com.au/f5415,4028778/Agenda_Item_6._IMO_Refund_Regime_20121122_Final_Read-Only_.pdf

Refunds arising from plant failure at times when spare capacity is low. Additionally, the proposed application of the minimum refund factor would achieve a balance between implementing the principle that capacity payments should be forfeited by Market Participants that are unable to deliver capacity during the Capacity Year and ensuring the protection for Facilities with better availability performance from punitive refund exposure when spare capacity in the system is relatively high.

Proposed Amendments

The IMO proposes the following amendments to the Market Rules:

(a) The Refund Table in clause 4.26.1 of the Market Rules is replaced with a formula for the applicable refund factor for a Facility f in a Trading Interval t such that the refund factor is equal to the lesser of:

   a. six; and

   b. the greater of the dynamic refund factor and the floor refund factor.

(b) The dynamic refund factor is determined as a function of the spare capacity in a Trading Interval t. Spare capacity is calculated as the sum of the capacity available from different types of Facilities taking into account shortfalls and consumption.

(c) The floor refund factor is determined as a function of the available capacity for dispatch for a Facility f in a Trading Interval t where the available capacity for dispatch is determined as one minus the percentage of capacity on Forced Outage over the previous 90-day rolling period up to and including that Trading Interval. Additionally, where a Facility is a generating system that has yet to commence operation or is a DSP with a non-zero Reserve Capacity Deficit value, the floor refund factor is set to one.

(d) The concepts of the Off-Peak and Peak Trading Interval Rate as outlined in the Refund Table in clause 4.26.1 of the Market Rules, are replaced with a Trading Interval Refund Rate which is determined as the product of the applicable refund factor in a Trading Interval t and the applicable Monthly RCP determined in accordance with clause 4.29.1 of the Market Rules.

5. The applicable refund rate for DSPs

In the Rule Change Proposal titled *RC_2013_10: Harmonisation of Supply-Side and Demand-Side Capacity Resources*[10], the IMO proposed amendments to clause 4.26.3A of the Market Rules which outlines the Demand Side Programme Capacity Cost Refund. To maintain consistency with the supply-side capacity resources, the IMO considered that the magnitude of the refund for DSPs should be reflective of that faced by generators. As such, the IMO proposed to link the proposed Demand Side Programme Capacity Cost Refund formula in clause 4.26.3A to the Refund Table in clause 4.26.1 of the Market Rules.

The proposed amendments to the Refund Table as discussed under Issue 4 of this Rule Change Proposal affect the calculation of the Demand Side Programme Capacity Cost Refund in clause 4.26.3A as proposed to be amended in RC_2013_10, so that the reference to the Off-Peak or Peak Trading Interval Rate is replaced by the Trading Interval Refund

[10] The Rule Change Proposal is available on the Market Web Site: http://www.imowa.com.au/rules/rule-changes/wem-rule-changes/under-development/rule-change-rc_2013_10

Rate.

Proposed Amendments

The IMO proposes additional amendments to clause 4.26.3A (as proposed to be amended in RC_2013_10) to reflect the inclusion of the Trading Interval Refund Rate in the calculation of the Demand Side Programme Capacity Cost Refund.

6. Recycling of Capacity Cost Refund revenue

In accordance with clause 4.26.4 and 4.28.4 of the Market Rules, the revenue collected through the current Reserve Capacity Refund regime is distributed to Market Customers in proportion to their Individual Reserve Capacity Requirements.

In its presentation of issues with the current refund regime at various RCMWG meetings, The Lantau Group noted that the distribution of Capacity Cost Refund revenue to Market Customers constitutes a value loss from Market Generators because it is the RCM as a whole that is responsible for ensuring adequate capacity and building resilience, not the performance of individual capacity resources. The distribution of Capacity Cost Refund revenue amounts to an uncertain revenue stream for Market Customers with no long-term benefits. Ultimately, the inefficient value transfer from Market Generators to Market Customers would need to be offset by higher energy costs or higher capacity prices.

The Lantau Group recommended that the Capacity Cost Refund revenue should be re-distributed as a rebate to Market Generators with better availability performance to compensate for the higher risk they undertake in the event of an unplanned outage in the energy system. At the MAC meeting on 9 October 2013, two MAC members disagreed with the principles behind the proposed recycling of Capacity Cost Refund revenue. It was agreed at that MAC meeting that the IMO would provide more detail on the economic arguments underpinning the recycling of Capacity Cost Refund revenue as rebates to Market Generators.

Benefits of recycling of Capacity Cost Refund revenue

For the payment for Capacity Credits made by Market Customers, end-users receive the benefits of an energy system capable of meeting demand despite the reasonable risk of unplanned Outages of generation capacity. As long as there is uninterrupted electricity supply to end-users implying that the risk of unplanned Outages is absorbed within the energy system, the distribution of Capacity Cost Refund revenue to Market Customers represents a loss of value relative to what had been charged through the RCM.

It would be appropriate to distribute Capacity Cost Refund revenue to Market Customers if they have paid in advance for a quality of service that they are not receiving or if the Capacity Credit payments incorporated an extra cost associated with Outage risk.

However, if the quality of service remains unaffected, then it would be appropriate to consider compensating Market Generators for the burden of risk undertaken to respond to an unplanned Outage. Further, the MRCP does not currently incorporate any provision for expected Capacity Cost Refunds payable by a capacity provider as a result of unplanned Outage. It could be argued that the RCP could be uplifted by an amount corresponding to the expected Capacity Cost Refund payments. However, this uplift would be applicable to all Capacity Credits irrespective of the actual performance of the associated Facilities. Furthermore, this approach would not improve any incentives for maximising availability beyond what is currently achieved.

The recommended approach is to distribute the Capacity Cost Refund revenue paid by unavailable capacity resources in a zero sum[11] fashion to those capacity resources that are available for dispatch. Under this approach, Market Customers pay for and receive the predictable value of a Capacity Credit without the need to pay for better performance than that which is reasonably expected of a capacity resource. Additionally, limiting the inefficient value transfer implies that the cost of energy no longer needs to account for the higher risk undertaken by Market Generators responding to an unplanned Outage. As a result, Market Customers also receive the benefit of a potential reduction in the volatility of energy prices.

A key advantage of the proposed Capacity Cost Refund revenue recycling regime is that it improves the alignment of risk (refund) and reward (rebate) exposure. In doing so, the expected value of a Capacity Credit remains unchanged. Capacity that is reasonably available receives the predictable value of a Capacity Credit. There is no loss of value and there is no consequential need to adjust the payment for Capacity Credits in advance to account for expected receipts of Capacity Cost Refund revenue throughout the year.

A further advantage of the proposed Capacity Cost Refund revenue recycling regime is that it is self-adjusting. There is no requirement for the IMO to estimate the "expected refund cost" to be added to the MRCP or RCP each year so that the Capacity Cost Refund revenue paid to Market Customers is linked to the value of a Capacity Credit they have paid for. Instead, the incentive of the recycling regime is constantly adjusted based on the average refund exposure of all available capacity. As capacity with better availability performance is added, capacity with lesser availability is exposed to higher refunds and receives lower rebates.

A further benefit of the proposed Capacity Cost Refund revenue recycling regime is to strengthen the incentives to promote more efficient energy market outcomes. The proposed refund regime collects Capacity Cost Refunds applicable to unavailable capacity and then redistributes the collected revenues as rebates to capacity that was available for dispatch at the time (with availability being determined based on specific conditions). The result is to strengthen incentives to compete in the energy market and to recognise that unplanned Outages must be catered for in a resilient energy system. The way to reduce the cost of achieving and maintaining this resilience is to promote incentives that consistently reward timely availability.

Determining eligibility for rebates

In the concept paper presented at the MAC, the IMO proposed to introduce an eligibility criterion for Facilities to qualify for rebates based on dispatch in the previous 30-day period (determined on a rolling basis). Facilities that have been dispatched for a non-zero MW value in any one Trading Interval in the previous 30-day period would qualify for rebates. Rebates for a Trading Interval would be allocated to Facilities based on their share of available Capacity Credits in that interval.

The IMO considers that the introduction of the eligibility criterion would minimise the inefficient value transfers from Facilities with better availability to Facilities with less availability by promoting a balance between risk and reward. It would also promote efficient scheduling of maintenance so that capacity is readily available for dispatch during periods of high demand. Additionally, it may reduce administrative costs for the IMO and System Management with regard to Reserve Capacity Tests, based on the principle that Facilities that have successfully dispatched to demonstrate their eligibility for rebates may no longer be required to do so under a Reserve Capacity Test. This principle strengthens the incentives for Market Participants to increase the likelihood for their Facilities to be dispatched of their

[11] A zero-sum situation is that in which whatever is gained by one party is lost by the other.

own accord, thereby reducing the need for specific Reserve Capacity Tests to be conducted for those Facilities.

DSPs would be eligible for rebates based on actual dispatch. With the harmonisation of demand and supply-side resources underway, the likelihood of dispatch for DSP is expected to be higher. The IMO considers that it is appropriate to provide rebates to a DSP if it has reliably curtailed demand in response to a Dispatch Instruction.

Intermittent Generators would not be eligible for rebates because under clauses 4.26.1 and 4.26.1A of the Market Rules, Intermittent Generators that are in Commercial Operation and have operated at their Required Level are not liable for Capacity Cost Refunds. Given this arrangement where the risk of exposure to refunds is minimal, the IMO considers that it is appropriate to exclude them from eligibility for a reward.

Proposed Amendments

The IMO proposes the following amendments to the Market Rules:

(a) Clause 4.26.4 of the Market Rules is amended to reflect that the revenue generated from the application of clause 4.26.2E is applied to Market Participants holding Capacity Credits in respect of Scheduled Generators and DSPs based on the fulfillment of the eligibility criterion.

(b) New clauses 4.26.7 and 4.26.8 are proposed to determine the application of rebates for eligible Scheduled Generators and DSPs.

(c) Clause 4.28.4 of the Market Rules is amended to remove Capacity Cost Refunds from the calculation of the Shared Reserve Capacity Cost of a Market Customer.

(d) Clause 4.29.3 of the Market Rules is amended to reflect the inclusion of rebates in the Settlement Systems.

(e) Clause 9.7.1 of the Market Rules is amended to include the payment of rebates to Market Participants.

Protected Provisions

The IMO notes that clause 4.1.19 and section 4.16 of the Market Rules are Protected Provisions under clause 2.8.13(d) of the Market Rules. Under clause 2.8.3 of the Market Rules, amendments to a Protected Provision require the Amending Rules in this Rule Change Proposal to be approved by the Minister.

The IMO will engage with the Public Utilities Office to progress these amendments.

2. Explain the reason for the degree of urgency:

The cost of excess capacity that is borne by the market should be minimised as soon as practicable to allow for the overall RCM to become responsive to changing market conditions. The IMO noted in its concept paper presented to the October 2013 MAC meeting that updated information for the 2015/16 Capacity Year indicated that the proposed amendments to the RCP formula would not result in a significantly different result than using the current formula. Additionally, the IMO noted that the potential revenue loss to Market Customers as a result of the application of the dynamic Reserve Capacity Refund regime is expected to be small and would be offset by the adjustments to the RCP formula.

Therefore, the IMO proposes that the proposed amendments be applied from 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)*

The IMO proposes to make the following amendments to the relevant Market Rules. To the extent that the proposed Amending Rules are similar to those in the Draft Rule Change Report of RC_2013_09: *Incentives to Improve Availability of Scheduled Generators* and the Rule Change Proposal for RC_2013_10, the IMO has used the wording of the proposed Amending Rules as proposed to be amended by the Rule Change Proposals. Specifically, the proposed Amending Rules for clauses 1.4.1 and 4.26.3A and the Glossary definitions for Off-peak Trading Interval Rate, Peak Trading Interval Rate and Refund Table are provided below. Additionally, the proposed amendments to clause 4.26.1are based on the proposed Amending Rules in the pre Rule Change Proposal for RC_2013_16: *Outages and the Application of Availability and Constraint Payments to Non-Scheduled Generators.*

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...

1.4.1. In these Market Rules, unless the contrary intention appears:

...

(r) (**Headings and comments**): headings and comments appearing in boxes in these Market Rules (other than ~~the Refund Table in clause 4.26 and~~ the Outage Rate Limit Table in clause 4.11.1D) are for convenience only and do not affect the interpretation of these Market Rules.

...

[Note: Drafting of clause 1.4.1(r) reflects the proposed amendment in the Draft Rule Change Report for RC_2013_09: Incentives to improve availability of Scheduled Generators]

...

2.26.1. Where the IMO has proposed a revised value for the ~~Maximum~~Benchmark Reserve Capacity Price in accordance with clause 4.16 or a change in the value of one or more Energy Price Limits in accordance with clause 6.20, the Economic Regulation Authority must:

(a) review the report provided by the IMO, including all submissions received by the IMO in preparation of the report;

(b) make a decision as to whether or not to approve the revised value for the ~~Maximum~~Benchmark Reserve Capacity Price or any value comprising the Energy Price Limits;

(c) in making its decision, only consider:

i. whether the proposed revised value for the ~~Maximum~~Benchmark Reserve Capacity Price or Energy Price Limit proposed by the IMO reasonably reflects the application of the method and guiding principles described in clauses 4.16 or 6.20 (as applicable);

...

2.26.2. Where the Economic Regulation Authority rejects a revised ~~Maximum~~Benchmark Reserve Capacity Price or the Energy Price Limits submitted by the IMO it must give reasons and may direct the IMO to carry out all or part of the review process under clause 4.16 or 6.20 (as applicable) again in accordance with any directions or recommendations of the Economic Regulation Authority.

2.26.3. The Economic Regulation Authority must review the methodology for setting the ~~Maximum~~Benchmark Reserve Capacity Price and the Energy Price Limits not later than the fifth anniversary of the first Reserve Capacity Cycle and, subsequently, not later than the fifth anniversary of the completion of the preceding review under this clause 2.26.3. A review must examine:

(a) the level of competition in the market;

(b) the level of market power being exercised and the potential for the exercise of market power;

(c) the effectiveness of the methodology in curbing the use of market power;

(d) historical Reserve Capacity Offers and the proportion of Reserve Capacity Offers with prices equal to the ~~Maximum~~Benchmark Reserve Capacity Price, in the case of Reserve Capacity Cycles up to and including 2013;

(dA) the proportion of Reserve Capacity Offers with prices equal to 110 percent of the Benchmark Reserve Capacity Price, in the case of Reserve Capacity Cycles from 2014 onwards;

(e) historical STEM Bids and STEM Offers and the proportion of STEM Bids and Offers with prices equal to the Energy Price Limits;

(f) the appropriateness of the parameters and methodology in clauses 4.16 and the Market Procedure referred to in clause 4.16.3 for recalculating the ~~Maximum~~Benchmark Reserve Capacity Price;

…

…

4.1.19. The IMO must commence a review of the ~~Maximum~~Benchmark Reserve Capacity Price as required by clause 4.16.3 with the objective of completing the review, including consideration of public submissions in relation to that review, so as to allow a reasonable time for the Economic Regulation Authority to approve any proposed change in value and for that value to be implemented prior to the date and time specified in clause 4.1.4 that relates to the following Reserve Capacity Cycle.

…

4.3.1. A Request for Expression of Interest for a Reserve Capacity Cycle must include the following information:

...

(c) for each of the three previous Reserve Capacity Cycles (if applicable):

...

v. the ~~Maximum~~Benchmark Reserve Capacity Price;

...

(f) the then current ~~MaximumB~~enchmark Reserve Capacity Price;

...

4.13.2. For the purposes of clause 4.13 the amount of Reserve Capacity Security is:

(a) at the time and date referred to in clause 4.1.13, twenty-five percent of the ~~Maximum~~Benchmark Reserve Capacity Price included in the most recently issued Request for Expressions of Interest at the time the Certified Reserve Capacity is assigned, expressed in $/MW per year, multiplied by an amount equal to:

i. the Certified Reserve Capacity assigned to the Facility; less

ii. the total of any Certified Reserve Capacity amount specified in accordance with clause 4.14.1(d) or referred to in clause 4.14.7(c)(ii); and

(b) at the time and date referred to in clause 4.1.21, twenty-five percent of the ~~Maximum~~Benchmark Reserve Capacity Price included in the most recently issued Request for Expressions of Interest at the time the Certified Reserve Capacity is assigned, expressed in $/MW per year, multiplied by an amount equal to the total number of Capacity Credits assigned to the Facility under clause 4.20.5A.

...

4.16. The ~~Maximum~~Benchmark Reserve Capacity Price

4.16.1. For all Reserve Capacity Cycles, the IMO must publish a ~~Maximum~~Benchmark Reserve Capacity Price as determined in accordance with this clause 4.16 prior to the time specified in clause 4.1.4.

4.16.2. The ~~Maximum~~Benchmark Reserve Capacity Price to apply for the first Reserve Capacity Cycle is $150,000 per MW per year.

4.16.3 The IMO must develop a Market Procedure documenting the methodology it uses and the process it follows in determining the ~~Maximum~~Benchmark Reserve Capacity Price, and:

(a) the IMO and Rule Participants must follow that documented Market Procedure when conducting any review and consultations in accordance with that Market Procedure and clause 4.16.6; and

(b) the IMO must follow the documented Market Procedure to annually review the value of the ~~Maximum~~Benchmark Reserve Capacity Price in accordance with this clause 4.16 and in accordance with the timing requirements specified in clause 4.1.19.

...

4.16.5. The IMO must propose a revised value for the ~~Maximum~~Benchmark Reserve Capacity Price using the methodology described in the Market Procedure referred to in clause 4.16.3.

4.16.6. The IMO must prepare a draft report describing how it has arrived at a proposed revised value for the ~~Maximum~~Benchmark Reserve Capacity Price under clause 4.16.5. The IMO must publish the report on the Market Web-Site and advertise the report in newspapers widely distributed in Western Australia and request submissions from all sectors of the Western Australia energy industry, including end-users.

4.16.7. After considering of the submissions on the draft report described in clause 4.16.6 the IMO must propose a final revised value for the ~~Maximum~~Benchmark Reserve Capacity Price and publish that value and its final report, including submissions received on the draft report on the Market Web-Site.

4.16.8. A proposed revised value for the ~~Maximum~~Benchmark Reserve Capacity Price becomes the ~~Maximum~~Benchmark Reserve Capacity Price after the IMO has posted a notice on the Market Web Site of the new value of the ~~Maximum~~Benchmark Reserve Capacity Price with effect from the time specified in the IMO's notice.

...

4.18.2. Each Reserve Capacity Price-Quantity Pair must comprise:

(a) the identity of the Facility to which it relates;

(b) an offer price in units of dollars per MW per year expressed to a precision of $0.01/MW between zero and 110 percent of the ~~Maximum~~Benchmark Reserve Capacity Price;

...

…

4.22.2. If a Market Participant nominates to have Capacity Credits covered by a Long Term Special Price Arrangement, it must at the same time nominate:

...

Where the Long Term Special Price Arrangement is conditional on evidence being provided to the IMO prior to that Long Term Special Price Arrangement taking effect that capital costs in excess of 10~~%~~ percent of the ~~Maximum~~Benchmark Reserve Capacity Price have been incurred on average with respect to the provision of each Capacity Credit covered by the arrangement; and

...

...

4.26.1. If a Market Participant holding Capacity Credits associated with a ~~generation system~~Facility fails to comply with its Reserve Capacity Obligations applicable to any given Trading Interval then the Market Participant must pay a refund to the IMO calculated in accordance with the following provisions.

(a) The refund factor RF(f,t) for a Facility f in a Trading Interval t is the lesser of:

i. six; and

ii. the greater of RF_dynamic(t) and RF_floor(f,t);

(b) The dynamic refund factor RF_dynamic(t) in a Trading Interval t is equal to:

$$11.75 - \left(\frac{5.75}{750}\right) \times Spare(t)$$

Where $Spare(t)$ in a Trading Interval t is equal to the sum of the quantities calculated as follows:

i. for a Scheduled Generator for which a Market Participant holds Capacity Credits:

1. the MW quantity of Capacity Credits; less

2. the MW quantity of Outage determined in accordance with clause 7.13.1A(b)(ii); less

3. the Sent Out Metered Schedule multiplied by two so as to be a MW quantity; and

[Note: Drafting of clause 4.26.1(b)(i)(2) is based on the proposed amendment to clause 7.13.1A in the pre Rule Change Proposal for RC_2013_16: Outages and the Application of Availability and Constraint Payments to Non-Scheduled Generators]

ii. for a Non-Scheduled Generator that received a Dispatch Instruction to decrease its output under clause 7.6.1C and for which a Market Participant holds Capacity Credits:

1. the estimate of sent out energy which would have been provided had a Dispatch Instruction not been issued, as provided by System Management in accordance with clause 7.13.1(eF), multiplied by two so as to be a MW quantity; less

2. the Sent Out Metered Schedule multiplied by two so as to be a MW quantity; and

iii. for a Demand Side Programme within the periods specified in clause 4.10.1(f)(vi) and for which a Market Participant holds Capacity Credits:

1. the Demand Side Programme Load multiplied by two so as to be a MW quantity; less

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

[Note: Drafting of clause 4.26.1(b)(iii) is based on the proposed amendments to clause 4.10.1(f)(vi) in the Rule Change Proposal for RC_2013_10: Harmonisation of demand-side and supply-side capacity resources]

(c) Subject to clause 4.26.1(d), the minimum refund factor RF_floor(t) in a Trading Interval t is equal to:

$$1 - 0.75 \times Dispatchable(f,t)$$

Where $Dispatchable(f,t)$ for a Facility f in a Trading Interval t is determined as the sum over the 4,320 Trading Intervals prior to and including that Trading Interval of:

$$1 - (\sum \frac{FO(t)}{Cap(t)})$$

Where:

i. $FO(t)$ is the quantity of Forced Outage determined in accordance with Appendix 10; and

ii. $Cap(t)$ is the capacity for the Facility determined in accordance with Appendix 10;

[Note: Drafting of clause 4.26.1(c)(i) and (ii) are based on the proposed amendments in new Appendix 10 proposed in the pre Rule Change Proposal for RC_2013_16: Outages and the Application of Availability and Constraint Payments to Non-Scheduled Generators]

(d) For a Facility to which clauses 4.26.1A(a)(iv), 4.26.1A(a)(v) or 4.26.1A(a)(vi) apply or for which a non-zero value is determined under clause 4.26.1A(vii), RF_floor(t) in a Trading Interval t is equal to one;

(e) The Trading Interval Refund Rate for a Facility f in a Trading Interval t is equal to:

$$RF(f,t) \times Y$$

Where:

i. For a Non-Scheduled Generator that has either:

1. operated at a level equivalent to its Required Level, adjusted to 100 percent of the level of Capacity Credits currently held, in at least two Trading Intervals; or

2. provided the IMO with a report under clause 4.13.10C, where this report specifies that the Facility can operate at a level equivalent to its Required Level, adjusted to 100 percent of the level of Capacity Credits currently held;

and is, following a request to the IMO by a Market Participant, considered by the IMO to be in Commercial Operation, Y equals 0;

ii. For all other Facilities, Y is determined by dividing the Monthly Reserve Capacity Price (calculated in accordance with clause 4.29.1) by the number of Trading Intervals in the relevant Trading Month.

~~REFUND TABLE~~

~~Dates~~	**~~1 April to 1 October~~**	**~~1 October to 1 December~~**	**~~1 December to 1 February~~**	**~~1 February to 1 April~~**
~~Business Days Off-Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)~~	~~0.25 x Y~~	~~0.25 x Y~~	~~0.5 x Y~~	~~0.75 x Y~~
~~Business Days Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)~~	~~1.5 x Y~~	~~1.5 x Y~~	~~4 x Y~~	~~6 x Y~~
~~Non-Business Days Off-Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)~~	~~0.25 x Y~~	~~0.25 x Y~~	~~0.5 x Y~~	~~0.75 x Y~~
~~Non-Business Days Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)~~	~~0.75 x Y~~	~~0.75 x Y~~	~~1.5 x Y~~	~~2 x Y~~
~~Maximum Participant Generation Refund~~	~~The total value of the Capacity Credit payments paid or to be paid under these Market Rules to the relevant Market Participant for the 12 Trading Months commencing at the start of the Trading Day of the previous 1 October (excluding any payments relating to a Demand Side Programme) assuming the IMO acquires all of the Capacity Credits held by the Market Participant (excluding any Capacity Credits held for Demand Side Programmes) and the cost of each Capacity Credit so acquired is determined in accordance with clause 4.28.2(b), (c) and (d) (as applicable).~~			

~~Where:~~

~~For an Intermittent Generator that has:~~

~~(a) either:~~

~~i. operated at a level equivalent to its Required Level, adjusted to 100 percent of the level of Capacity Credits currently held, in at least two Trading Intervals; or~~

~~ii. provided the IMO with a report under clause 4.13.10C, where this report specifies that the Facility can operate at a level equivalent to its Required Level, adjusted to 100 percent of the level of Capacity Credits currently held; and~~

~~(b) is, following a request to the IMO by a Market Participant, considered by the IMO to be in Commercial Operation:~~

~~Y equals 0~~

~~For all other facilities: Y is determined by dividing the Monthly Reserve Capacity Price (calculated in accordance with clause 4.29.1) by the number of Trading Intervals in the relevant Trading Month.~~

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 Refund Rate determined in accordance with ~~the Refund Table~~clause 4.26.1 applicable to the Facility in Trading Interval t; and

…

ivA. if the Facility is an Intermittent Generator which is considered by the IMO to have been in Commercial Operation, but for which Y does not equal zero ~~in the Refund Table~~ in clause 4.26.1, the minimum of:

...

…

4.26.3. The Generation Capacity Cost Refund for Trading Month m for a Market Participant p holding Capacity Credits associated with a generation system is the lesser of:

(a) the Maximum Participant Generation Refund determined for Market Participant p and Trading Month m ~~in accordance with the Refund Table,~~ less all Generation Capacity Cost Refunds applicable to Market Participant p in previous Trading Months falling in the same Capacity Year as Trading Month m; and

(b) the Generation Reserve Capacity Deficit Refund for Market Participant p and Trading Month m, plus the sum over all Trading Intervals t in Trading Month m of the Net STEM Refund,

where the Net STEM Refund is the product of:

i. the ~~Off-Peak Trading Interval Rate or Peak~~ Trading Interval Refund Rate determined in accordance with ~~the Refund Table~~clause 4.26.1 applicable to Facility f in Trading Interval t; and

ii. the Net STEM Shortfall for Market Participant p in Trading Interval t.

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:

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

Where:

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

H is the maximum number of hours per Trading Day that the Facility is available to provide Reserve Capacity in accordance with clause 4.10.1(f)(iii); and

$TIRR$ is the ~~Off-Peak Trading Interval Rate or Peak~~ Trading Interval Refund Rate applicable to the Facility in Trading Interval t; and

ii. the Facility Reserve Capacity Deficit Refund for Trading Month m for the Facility.

[Note: Drafting of clause 4.26.3A reflects the proposed amendments in the Rule Change Proposal for RC_2013_10: Harmonisation of demand-side and supply-side capacity resources]

4.26.4. ~~The IMO must apply any revenue generated from the application of clause 4.26.2E to Market Customers~~For each Market Participant holding Capacity Credits associated with a Scheduled Generator or a Demand Side Programme, the IMO must determine the amount of the rebate (Participant Capacity Rebate) to be applied for Trading Month m as the sum of all Facility Capacity Rebates determined in accordance with clause ~~4.28.4~~4.26.7.

...

4.26.7 The Facility Capacity Rebate for Facility f, being either a Scheduled Generator or a Demand Side Programme for which a Market Participant holds Capacity Credits, is the sum over all Trading Intervals t in Trading Month m of:

$$\frac{CC(f,t) \times E(f,t)}{\sum_{f=1}^{F} CC(f,t) \times E(f,t)} \times \sum CCR(t)$$

Where:

$\sum CCR(t)$ is the refund revenue determined as the sum over all Market Participants of the Capacity Cost Refund for Trading Interval t, determined in accordance with clause 4.26.2E; and

$\sum_{f=1}^{F} CC(f,t) \times E(f,t)$ is the sum, over all Facilities F in Trading Interval t, being either Scheduled Generators or Demand Side Programmes for which Market Participants hold Capacity Credits, of the product of:

(a) $CC(f,t)$ which equals:

i. for a Scheduled Generator, the MW value of Capacity Credits less the MW quantity of Outage as determined in accordance with clause 7.13.1A(b)(ii); and

ii. for a Demand Side Programme, the Demand Side Programme Load multiplied by two so as to be a MW quantity less the sum of the minimum load MW quantities provided under clause 2.29.5B(c) for the Facility's Associated Loads; and

(b) $E(f,t)$ which is the eligibility of the Facility f in Trading Interval t, where eligibility is equal to one if, subject to clause 4.26.8, Facility f has dispatched for a non-zero MW value in any one Trading Interval of the 1,440 Trading Intervals prior to and including Trading Interval t, or zero otherwise.

4.26.8 For the purposes of clause 4.26.7(b), a Facility is considered to have met the eligibility criteria where the requirements for a Reserve Capacity Test in accordance with clause 4.25.1(a) have been met in any one Trading Interval of the 1,440 Trading Intervals prior to and including Trading Interval t.

...

4.28.4. For each Trading Month, the IMO must calculate a Shared Reserve Capacity Cost being the sum of:

(a) the cost defined under clause 4.28.1(b); and

(~~aA~~b) the net payments to be made by the IMO under Supplementary Capacity Contracts less any amount drawn under a Reserve Capacity Security by the IMO and distributed in accordance with clause 4.13.11A(a); less

~~(b) the Capacity Cost Refunds for that Trading Month; less~~

(~~b~~A<u>c</u>) the Intermittent Load Refunds for that Trading Month; less

(~~c~~<u>d</u>) any amount drawn under a Reserve Capacity Security by the IMO and distributed in accordance with clause 4.13.11A(b)

and the IMO must allocate this total cost to Market Customers in proportion to each Market Customer's Individual Reserve Capacity Requirement.

...

4.28A.1 The IMO must determine for each Intermittent Load registered to Market Participant p the amount of the refund ("Intermittent Load Refund") to be applied for each Trading Month m in respect of that Intermittent Load as the sum over all Trading Intervals t of Trading Day d in the Trading Month m of the product of:

(a) the applicable value of Y ~~in the Refund Table~~ described in clause 4.26.1 is that which applies for Scheduled Generators; and

…

...

4.28C.9. The amount for the purposes of clauses 4.28C.8 and 4.28C.12 is twenty-five percent of the ~~Maximum~~<u>Benchmark</u> Reserve Capacity Price included in the most recent Request for Expressions of Interest at the time and date associated with either clause 4.28C.8 or 4.28C.12 as applicable, multiplied by an amount equal to the Early Certified Reserve Capacity assigned to the Facility.

...

4.29.1. The Monthly Reserve Capacity Price to apply during the period specified in clause 4.1.29 is to equal:

(a) if a Reserve Capacity Auction was run for the Reserve Capacity Cycle, the Reserve Capacity Price for the Reserve Capacity Cycle divided by 12; or

(b) if no Reserve Capacity Auction was run for the Reserve Capacity Cycle:

i. prior to 1 October 2008, 85% of the ~~Maximum~~<u>Benchmark</u> Reserve Capacity Price for the Reserve Capacity Cycle divided by 12;

ii. ~~from 1 October 2008~~<u>up to and including the 2013 Reserve Capacity Cycle</u>, 85% of the ~~Maximum~~<u>Benchmark</u> Reserve Capacity Price for the Reserve Capacity Cycle multiplied by the ~~E~~<u>e</u>xcess ~~C~~<u>c</u>apacity ~~A~~<u>a</u>djustment and divided by 12;

(c) the ~~E~~<u>e</u>xcess ~~C~~<u>c</u>apacity ~~A~~<u>a</u>djustment is equal to the minimum of:

i. one, and

ii. the Reserve Capacity Requirement for the Reserve Capacity Cycle divided by the total number of Capacity Credits assigned by the IMO in accordance with clause 4.20.5A for the Reserve Capacity Cycle.

(d) if no Reserve Capacity Auction was run for the Reserve Capacity Cycle from 2014 onwards, the value calculated as below and divided by 12:

$$MIN\{\left(\frac{BRCP \times 1.1}{1-((surplus+0.03)\times -3.75)}\right), BRCP \times 1.1\}$$

Where:

i. $BRCP$ is the Benchmark Reserve Capacity Price determined in accordance with clause 4.16; and

ii. $surplus$ is the percentage of excess capacity calculated as:

1. the total number of Capacity Credits assigned by the IMO in accordance with clause 4.20.5A for the Reserve Capacity Cycle; less

2. the Reserve Capacity Requirement for the Reserve Capacity Cycle,

divided by the Reserve Capacity Requirement for the Reserve Capacity Cycle, multiplied by 100.

4.29.3. The IMO must prepare and provide the following information to the Settlement Systems in time for settlement of Trading Month m:

...

(d) subject to clause 4.29.4, for each Market Participant p and for Trading Month m:

...

v. the Individual Reserve Capacity Requirement for each Market Customer for that Trading Month; ~~and~~

vi. the total Capacity Cost Refund to be paid by the Market Participant to the IMO; and

vii. the total Participant Capacity Rebate to be paid to the Market Participant by the IMO.

...

9.7.1. The Reserve Capacity settlement amount for Market Participant p for Trading Month m is:

RCSA(p,m) =

Monthly Reserve Capacity Price(m) $\times$ (CC_NSPA(p,m)

– Sum(q $\in$ P,CC_ANSPA(p,q,m)))

+ Sum(a $\in$ A, Monthly Special Price(p,m,a) $\times$ (CC_SPA(p,m,a)

– Sum(q $\in$ P,CC_ASPA(p,q,m,a))))

- Capacity Cost Refund(p,m)
- Intermittent Load Refund(p,m)
+ Participant Capacity Rebate (p,m)
+ Supplementary Capacity Payment(p,m)
- Targeted Reserve Capacity Cost(m) × Shortfall Share(p,m)
- Shared Reserve Capacity Cost(m) × Capacity Share(p,m)
+ LF_Capacity_Cost(m) × Capacity Share(p,m)

Where:

...

LF_Capacity_Cost(m) is the total Load Following Service capacity payment cost for Trading Month m as specified in clause 9.9.2(q)~~.~~; and

Participant Capacity Rebate(p,m) is the Participant Capacity Rebate payable to the Market Participant p for Trading Month m, as specified in clause 4.26.4.

...

10.5.1. The IMO must set the class of confidentiality status for the following information under clause 10.2.1, as Public and the IMO must make each item of information available from the Market Web Site after that item of information becomes available to the IMO:

...

(e) details of bid, offer and clearing price limits as approved by the Economic Regulation Authority including:

i. the ~~Maximum~~Benchmark Reserve Capacity Price;

...

...

11 Glossary

...

~~Maximum~~Benchmark Reserve Capacity Price: In respect of a given Reserve Capacity Cycle, the price in clause 4.16.2 as revised in accordance with clause 4.16.

...

Facility Capacity Rebate: means the amount of rebate determined for a Facility f in accordance with clause 4.26.7.

Maximum Participant Generation Refund: ~~Has the meaning given in clause 4.26.1.~~The total value of the Capacity Credit payments paid or to be paid under these Market Rules to the relevant Market Participant for the 12 Trading Months commencing at the start of the Trading Day of the previous 1 October (excluding any payments relating to a Demand Side Programme) assuming the IMO acquires all of the Capacity Credits held by the Market Participant (excluding any Capacity Credits held for Demand Side Programmes) and the cost of each Capacity Credit so acquired is determined in accordance with clause 4.28.2(b), (c) and (d) (as applicable).

...

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

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

...

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

[Note: Drafting of the definitions for Off-Peak Trading Interval Rate, Peak Trading Interval Rate and Refund Table reflects the proposed amendments in the Rule Change Proposal for RC_2013_10: Harmonisation of demand-side and supply-side capacity resources]

...

Reserve Capacity Price: In respect of a Reserve Capacity Cycle, the price for Reserve Capacity determined in accordance with clause 4.29.1 and multiplied by 12, where this price is expressed in units of dollars per megawatt per year and has a value between zero and 110 percent of the ~~Maximum~~Benchmark Reserve Capacity Price.

...

Trading Interval Refund Rate: The refund rate applicable in a Trading Interval as calculated in accordance with clause 4.26.1(e).

…

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 Market Rules as a whole, if amended to reflect the recommendations in this pre Rule Change Proposal will allow the Market Rules to better achieve Wholesale Market Objectives (a), (b), (c) and (d). A detailed assessment against the Wholesale Market Objectives is outlined in the table below:

Proposal	Benefits	Wholesale Market Objective assessment
Proposed RCP formula	• Improve the market-responsiveness of the RCP thereby promoting economically efficient supply of electricity; • Facilitate efficient entry of new competitors by supporting an appropriate level of new investment in capacity; and • Minimise the long-term cost of electricity supply by reducing the cost of excess capacity borne by Market Participants.	Better achieves Wholesale Market Objectives (a), (b) and (d)
Dynamic refund factors	• Improve incentives for efficient scheduling of plant maintenance thereby promoting economically efficient and reliable supply of electricity; • Avoid discrimination against Facilities with high utilisation factors by aligning Refund Factors with prevalent system conditions; and • Avoid discrimination between demand-side and supply-side capacity sources by applying refund factors consistently.	Better achieves Wholesale Market Objectives (a) and (c)
Recycling of refunds	• Improve incentives for Market Generators to provide capacity at times of greatest need thereby promoting efficient supply in peak periods; • Encourage competition between Market Generators by rewarding better availability performance; • Improve economic efficiency of the market by allocating the Capacity Cost Refund revenue to Market Generators instead of Market Customers thereby reducing the value loss in the RCM; • Minimise the long-term cost of electricity by reducing the risk of price spikes (through incentives to increase availability) in the event of unforeseen supply interruptions; and • Minimise the long-term cost of electricity by reducing the administrative costs of the IMO and System Management incurred with respect to Reserve Capacity Testing.	Better achieves Wholesale Market Objectives (a), (b), (c) and (d)

The IMO also considers that the proposed amendments are consistent with Wholesale Market Objective (e).

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

Costs

The IMO considers that it would incur significant costs to build and test the proposed changes in its settlement systems. The IMO considers that Market Participants may decide to build additional functionality into their business forecasting models to account for the proposed recommendations. Some Market Participants may also decide to re-negotiate their Bilateral Contract terms in response to the proposed amendments. Market Participants may incur some costs to incorporate these proposed changes. However, the IMO is unable to quantify those costs.

Benefits

As a result of the proposed amendments, the market is likely to experience a net economic benefit over time as a result of:

- maximising the availability of generation capacity in the energy markets through efficient scheduling of maintenance, increasing competition and reducing the risk of price spikes in the event of unforeseen supply interruptions;
- increasing accountability for Market Participants with Facilities that have poor availability;
- reducing the loss of value for capacity providers in the RCM; and
- strengthening the economic signals for investing in capacity where it is efficient to do so.

INDEPENDENT MARKET OPERATOR

Wholesale Electricity Market
Pre Rule Change Proposal

Rule Change Proposal ID: **PRC_2013_21**
Date received: **TBA**

Change requested by:

Name:	Allan Dawson
Phone:	08 9254 4333
Fax:	08 9254 4399
Email:	Allan.Dawson@imowa.com.au
Organisation:	IMO
Address:	Level 17, 197 St Georges Terrace, Perth WA 6000
Date submitted:	TBA
Urgency:	Medium
Change Proposal title:	Limit for Early Entry Capacity Payments
Market Rules affected:	Clauses 4.1.26, 4.5.12A (new), 4.5.13 and 4.28C.13

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:

The Reserve Capacity Mechanism requires Certified Reserve Capacity to be available from the beginning of the Capacity Year on 1 October. Under clause 4.1.26(c) of the Market Rules, to incentivise the prompt arrival of new capacity, Facilities may enter the market and begin receiving early entry capacity payments at any time throughout the four months leading up to start of the Capacity Year (specifically 1 June to 30 September).

Early entry capacity payments were introduced by *RC_2009_11: Changing the Window of Entry into the Reserve Capacity Market* recognising that generators may be prone to being unreliable for several months after commissioning as issues not discoverable throughout the lead up to and during commissioning become evident and are rectified. The change of timing and earlier access to Capacity Credit payments was based on a market consideration that it incentivises generators to arrive early. The early payment was preferred against the possibility of the risk of a new generator arriving late, and missing part or all of the generator's first summer, meaning it could be at risk of missing the critical summer peak, where system reliability is essential to minimise the risk of blackouts when the load is at its peak.

The IMO notes that RC_2009_11 was implemented when reserve deficits were of a concern in the market, at a time when the benefit of encouraging the timely delivery of capacity was considered likely to exceed any potential costs to the market. Since the commencement of RC_2009_11, excess capacity has developed in the WEM and now is around 11% (~564 MW) of the Reserve Capacity Requirement for the 2015/16 Capacity Year.

The IMO considers that after several years of providing access to early entry capacity payments for new Facilities, it is now appropriate to reconsider the value that the market derives from this incentive under all market conditions, including times of excess capacity.

In October 2012, Synergy proposed *RC_2012_10: Limits to Early Entry Capacity Payments* to minimise the early entry capacity payments to DSPs on the basis that due to the short lead time to develop demand-side capacity, the incentive was unnecessary and therefore inefficient. However, the IMO rejected the Rule Change Proposal on the basis that it was discriminatory against Market Customers providing Demand Side Programmes, and therefore inconsistent with Wholesale Market Objective (c).

Even though RC_2012_10 was rejected by the IMO, the Market Advisory Committee (MAC) has expressed support for reforming the concept of early entry capacity payments, particularly in times of excess capacity. The following opinions have been expressed by MAC members:

- in October 2010[1], System Management queried the validity of having early entry capacity payments available when the usability of the new capacity at that time of year is questionable;
- in June 2012[2], Griffin Power expressed the view that there is sufficient incentive to ensure capacity is available by 1 October in order to avoid Capacity Cost Refunds; and
- in October 2013[3], the MAC discussed the continuing priorities of the Market Rules Evolution Plan, where the reform of early entry capacity payments was agreed as a priority for the IMO to remove the unnecessary inefficient cost to the market.

Since the introduction of early entry capacity payments, the yearly level of payments has been between $144,000 in 2008/09 and $6.9 million in 2012/13, at a total cost of $12.4 million.

Based on the above, the IMO has developed this pre Rule Change Proposal to remove early entry capacity payments for new capacity in times of excess capacity. The IMO proposes that, where the Reserve Capacity Requirement has already been met for a Capacity Year, as determined by the IMO by June of the second Capacity Year and documented in the

[1] Available in minutes for agenda item 5h, http://www.imowa.com.au/governance/market-advisory-committee-(mac)/2010/mac-32.
[2] Available in minutes for agenda item 5a, http://www.imowa.com.au/governance/market-advisory-committee-(mac)/2012/mac-50.
[3] Available in minutes for agenda item 6, http://imowa.com.au/governance/market-advisory-committee-(mac)/2013/mac-65.

Statement of Opportunities, early entry payments would not be available for new capacity that year.

The IMO considers that, in years of excess capacity, the market receives little benefit from the incentive for early entry that is currently available. In these circumstances, the early entry capacity payments represent an unnecessary cost to Market Customers.

In addition, the IMO has taken the opportunity to include the ability to provide early entry capacity payments for Market Participants where Facilities are provided Early Certified Reserve Capacity (ECRC) under clause 4.28C of the Market Rules.

When commencing *RC_2009_10: Early Certified Reserve Capacity* in February 2010, there was an oversight in that the Amending Rules introduced inconsistent treatment between standard Certified Reserve Capacity and ECRC, where a Facility assigned Capacity Credits via the ECRC process is not entitled to the early entry capacity payments that are available to Facilities that are certified in the typical two-year-ahead process. The IMO therefore proposes to amend clause 4.28C.13 of the Market Rules to provide consistency between Facilities that enter the Reserve Capacity Mechanism via the ECRC and standard certification processes, whereby early entry capacity payments are available except for in periods of excess Certified Reserve Capacity.

2. Explain the reason for the degree of urgency:

The IMO proposes to commence the proposed Amending Rules set out in this pre Rule Change Proposal in order to apply to the 2014 Capacity Cycle thus impacting the 2016/17 Capacity Year.

The IMO considers that this will provide appropriate signals for future investment decisions regarding new capacity from the 2016/17 Capacity Year onwards, while not adversely affecting any pre-existing contractual arrangements between Market Customers and Market Generators.

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)*

4.1.26 Reserve Capacity Obligations apply:

(a) …

iii. from the Trading Day commencing on 1 October 2007 for Interruptible Loads, Curtailable Loads or Dispatchable Loads commissioned after Energy Market Commencement;~~ and~~

INDEPENDENT MARKET OPERATOR

(b) …

iii. from the Trading Day commencing on 30 November of Year 3, for new generating systems undertaking Commissioning Tests after 30 November of Year 3;~~ and~~

(c) for subsequent Reserve Capacity Cycles ~~from 2010 onwards~~ up to and including 2013:

…

iii. from the Trading Day commencing on 1 October of Year 3, for new generating systems undertaking Commissioning Tests after 1 October of Year 3; and

(d) for subsequent Reserve Capacity Cycles from 2014 onwards:

i. where the IMO has determined in accordance with clause 4.5.12A that the Reserve Capacity Target has been met or exceeded by the Capacity Credits assigned for Year 3 for which no Reserve Capacity Security was required to be provided, from the Trading Day commencing on 1 October of Year 3;

ii. where the IMO has determined in accordance with clause 4.5.12A that the Reserve Capacity Target has not been met by the Capacity Credits assigned for Year 3 for which no Reserve Capacity Security was required to be provided:

1. from the Trading Day commencing on 1 October of Year 3, for Facilities that were commissioned as at the scheduled time of the Reserve Capacity Auction for the Reserve Capacity Cycle as specified in clause 4.1.18(a) or for Facilities which have provided Capacity Credits in one or both of the two previous Reserve Capacity Cycles;

2 from the Trading Day commencing on the scheduled date of commissioning, as specified in accordance with clause 4.10.1(c)(iii)(7), or as revised in accordance with clause 4.27.11A or clause 4.27.11B, for Facilities commissioned between 1 June of Year 3 and 1 October of Year 3; or

3. from the Trading Day commencing on 1 October of Year 3, for new generating systems undertaking Commissioning Tests after 1 October of Year 3.

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4.5.12A For the second Capacity Year of the Long Term PASA Study Horizon, the IMO must determine whether the Reserve Capacity Target has been met or exceeded by the Capacity Credits assigned for which no Reserve Capacity Security was required to be provided under clause 4.13.

4.5.13 …

(cA) the IMO's determination of whether the Reserve Capacity Target has been met or exceeded by the Capacity Credits assigned for the second Capacity Year of the Long Term PASA Study Horizon for which no Reserve Capacity Security was required to be provided, in accordance with clause 4.5.12A;

4.28C.13 If the IMO approves the granting of Capacity Credits to the Facility under this clause 4.28C then the Capacity Credits and the Reserve Capacity Obligation associated with that Facility will apply from the commencement of the Trading Day commencing on the start date until the end of the Trading Day ending on the end date where:

~~(a) the start date is 1 October of year 3 of the capacity cycle the application relates to under clause 4.28C.2 ; and~~

(a) the start date is:

i. where the IMO has determined in accordance with clause 4.5.12A that the Reserve Capacity Target has been met or exceeded by the Capacity Credits assigned for Year 3 for which no Reserve Capacity Security was required to be provided, then 1 October of Year 3 of the Reserve Capacity Cycle the application relates to under clause 4.28C.2; and

ii. where the IMO has determined in accordance with clause 4.5.12A that the Reserve Capacity Target has not been met by the Capacity Credits assigned for Year 3 for which no Reserve Capacity Security was required to be provided:

1. from the Trading Day commencing on the scheduled date of commissioning, as specified in accordance with clause 4.10.1(c)(iii)(7), or as revised in accordance with clause 4.27.11A or clause 4.27.11B, for Facilities commissioned between 1 June of Year 3 and 1 October of Year 3; or

2. from the Trading Day commencing on 1 October of Year 3, for new generating systems undertaking Commissioning Tests after 1 October of Year 3.

INDEPENDENT
MARKET
OPERATOR

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

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

The IMO considers that this pre Rule Change Proposal will better achieve Wholesale Market Objectives (a) and (b) and is consistent with the remaining Wholesale Market Objectives.

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

This pre Rule Change Proposal will better achieve objective (a) as it removes the instances of inefficient incentives for the early entry of capacity from Facilities when it is not required, thereby reducing the cost to the market where such payment does not provide commensurate market benefits.

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

This pre Rule Change Proposal will better achieve objective (d) by removing the unnecessary cost of early entry capacity payments where the market has adequate existing capacity, while retaining the payment to minimise the risk of costly capacity shortfalls at times when capacity is tight.

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

The benefits of the proposed amendments to the market as a whole include:

- removing the cost to the marker of inefficient and ineffective payments to incentivise the early entry of capacity when it is not required, such as during times of excessive capacity;
- potential savings of an average of $1.55 million per annum during periods of excess capacity, if early entry capacity payments are removed at these times; and
- by retaining the ability to provide early entry capacity payments where existing capacity cannot meet the Reserve Capacity Requirement, the Reserve Capacity Mechanism will continue to incentivise early entry of capacity at times it is required, mitigating against the risk of late entry.

Costs

It is likely that the IMO will incur some minor costs to implement the necessary process changes to facilitate this pre Rule Change Proposal. However, these costs are not expected to be significant, and are included in the IMO's existing operational budget.

INDEPENDENT MARKET OPERATOR

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_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.	• PC_2012_11: Notices and Communications was published on 18 June 2013.	• Submissions closed on 16 July 2013. The IMO is currently preparing the Procedure Change Report.	TBA
PC_2013_04 **Prudential Requirements**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Move more of the prescriptive detail from the Market Rules to the Procedure to make the rules more principles-based; • Include some minor and typographical amendments to improve the integrity of the Market Procedure; and	• The IMO rejected this Rule Change Proposal on 19 November 2012. • Modified Rule Change Proposal and updated Market Procedure presented to the March 2013	• Updated Market Procedure presented at 20 September IMOPWG. Updated Procedure to be re-circulated to IMOPWG	Dec 2013

ID	Summary of Changes	Status	Next Step	Date
	• Include amendments required as a result of the Pre Rule Change Proposals: o Prudential Requirements (RC_2012_23); o Acceptable Credit Criteria (RC_2010_36); and o Removal of Network Control Services Expression of Interest and Tender Process (RC_2010_11).	MAC. • Procedure Change Proposal and updated Procedure was submitted to 20 September 2013 IMOPWG. • .	members	
PC_2013_05 Reserve Capacity Security	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; • Include some minor and typographical amendments to improve the integrity of the Market Procedure; and • Include amendments required as a result of the Pre Rule Change Proposal: Prudential Requirements (PRC_2012_23).	• Procedure has been updated following the discussion on Prudentials at the 20 September 2013 IMOPWG.	• Updated Market Procedure to be circulated to the IMOPWG for comment prior to being formally submitted into the process.	Dec 2013
PC_2013_06 **Certification of Reserve Capacity**	The proposed updates are to: • Reflect the revised consideration of outages in the assessment of applications for Certified Reserve Capacity, including; o new outage rates scale in table form; and o addition of IMO discretions and report requests; • Reflect the IMO's new format; • Explain the IMO discretion to assign a level of Reserve Capacity less than full; • Refine the assessment of fuel and other restrictions by the IMO; • Outline the proposed changes to the Availability Classes; and • Reflect the treatment of Facilities that share a Declared Sent Out Capacity.	• Underway	• Updated Market Procedure presented at 20 September IMOPWG. Updated Procedure to be re-circulated to IMOPWG members.	Dec 2013

ID	Summary of Changes	Status	Next Step	Date
PC_2013_07 **Settlement**	The proposed updates are to: • Reflect the necessary changes arising from RC_2013_08: Market Participant Fees - Clarification of GST Treatment; • Reflect the IMO's new format; • Provide greater clarity to potential and existing Rule Participants on the settlement process by improving the information provided around: o STEM and Non-STEM settlement processes and timelines; o Adjustment processes and timelines; o Process for settlement of the market in case of default situations; o Invoicing and the application of GST and interest to settlement transactions; and o Disagreement and dispute processes and timelines; • Improve the structure of the Procedure; and • Define new terms.	• PC_2013_07 was published on 21 November 2013. Submissions are currently open and will close on 19 December 2013.	• Submissions close	19/12/2013
PC_2013_09 **Reserve Capacity Performance Monitoring**	The proposed updates are to: • Reflect the additional performance monitoring steps proposed in RC_2013_09; • Reflect the IMO's new format; • Remove steps made redundant by deleted clauses; and • Describe the new performance reports that may be requested by the IMO, including; o performance improvement reports; and o the format of reports.	• Underway.	• Updated Market Procedure presented at 20 September IMOPWG. Updated Procedure to be re-circulated to IMOPWG members.	Dec 2013
TBC **Undertaking the LT**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures	• As advised at the August 2012 working group	• Updated procedure to be presented back	TBA

ID	Summary of Changes	Status	Next Step	Date
PASA and conducting a review of the Planning Criterion	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).	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.	to the Working Group for discussion	
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
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

ID	Summary of Changes	Status	Next Step	Date
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 **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
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				
PPCL0025 **Commissioning and Testing**	The proposed updates are to: • Include amendments required as a result of RC_2012_12 and RC_2012_15; • Expand Appendix C to clarify Load Following and Spinning	• PPCL0025: Commissioning and Testing was published on 28 June 2013.	• System Management are currently preparing the Procedure	TBA

ID	Summary of Changes	Status	Next Step	Date
	Reserve requirements around commissioning inline with the Ancillary Services Report; and • Include 'plus ramp range' in Load Following for Maximum Ramp Rate tests.	Submissions closed on 26 July 2013.	Change Report.	
PPCL0026 **Facility Outages**	The proposed updates are to: • Reflect the new outage transparency rules resulting from RC_2012_11.	• Draft amended PSOP was circulated to the System Management PSOP WG for comment. The IMO provided feedback on 31 July 2013. • Amended draft was circulated to the WG on 26 November 2013.	• Subject to feedback from the System Management PSOP WG, formally submit into process.	TBA
PPCL0027 **Dispatch**	The proposed updates are to: • Reflect the updated commitment/de-commitment rules resulting from RC_2012_22.	• PPCL0027 was initially submitted to the IMO to be put into the formal process. The IMO provided feedback to System Management on 6 August 2013 and discussed at the PSOP WG on 14 August 2013. Subsequently the PSOP change was withdrawn to be updated based on IMO feedback and re-circulated to WG members.	• System Management are updating the Procedure to reflect feedback received prior to re-circulating to WG members.	TBA

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	14/08/2013	TBA
IMO Procedures WG	Active	Dec 07	Ongoing	20/09/2013	TBA

Agenda item 9a – Proposed scope of work for the 2014 Ancillary Services Review

Background

Under clause 3.15.1 of the Market Rules the IMO, with the assistance of System Management, must at least once in every five year period carry out a study on the Ancillary Service Standards and the basis for setting Ancillary Service Requirements (Ancillary Services Review). The Ancillary Services Review must include:

- technical analyses determining the relationship between the level of Ancillary Services provided and the SWIS Operating Standards set out in clause 3.1;
- identification of the expected costs that would result from an increase in the requirements for Ancillary Services due to additional Facilities connecting to the SWIS;
- a cost-benefit study on the effects on stakeholders of providing and using a variety of levels of each Ancillary Service; and
- a public consultation process.

The IMO published the Final Report for the last review on 6 November 2009. The next review is therefore due for completion by 6 November 2014.

The IMO intends to engage a consultant in early 2014 to assist with the 2014 Ancillary Services Review. The proposed scope of work for the consultant is provided below.

Proposed scope of work

The consultant is to undertake a review of the current Ancillary Service definitions, Ancillary Service Standards and arrangements for setting Ancillary Service Requirements in the Wholesale Electricity Market (WEM) and propose any amendments that are, in the consultant's opinion, required in order to better achieve the Wholesale Market Objectives.

The scope of the study includes Load Following Service (LFAS), Spinning Reserve Service, Load Rejection Reserve Service and System Restart Service. Dispatch Support Services are excluded from the study as the appropriate standards and requirements for each service must be determined on a case by case basis and no general standard applies.

The study must include, but is not limited to:

- technical analyses determining the relationship between the level of Ancillary Services provided and the SWIS Operating Standards set out in clause 3.1;
- a technical and financial benchmark analysis comparing the Ancillary Service provisions in the WEM with those in comparable electricity markets;
- a review of the appropriateness of the current Ancillary Service definitions and Ancillary Service Standards, including as a minimum:
    - consideration of the impact of the new Balancing Market and the current 10 minute dispatch cycle on the Ancillary Service Standards;

  - consideration of the impact of the new Balancing Market and the current 10 minute dispatch cycle on the Ancillary Service Standards;
  - a technical review of whether the current boundaries between governor response, LFAS, Balancing, Spinning Reserve Service and Load Rejection Reserve Service achieve a best practice outcome in terms of addressing the Wholesale Market Objectives;
  - a review of any potential disconnect between "performance based" definitions in the SWIS Operating Standards and "volume based" Ancillary Service Standards and whether the Ancillary Service Standards should be volume based or performance based;
  - a review of the appropriateness of the current Minimum Frequency Keeping Capacity definition as the standard for LFAS;
  - a review of the appropriateness of the requirement for Upwards LFAS capacity to be counted towards the Spinning Reserve Service requirement and the absence of a corresponding provision for Downwards LFAS and Load Rejection Reserve Service;
  - a review of the appropriateness of the response time requirements on Facilities providing Spinning Reserve Service and Load Rejection Reserve Service in clauses 3.9.3 and 3.9.7 of the Market Rules and in the Power System Operation Procedure (PSOP): Ancillary Services; and
  - a review of the technical standards which Facilities should be required to meet to provide Spinning Reserve Service and Load Rejection Reserve Service in the WEM;
- a review of best practice methodologies in other electricity markets for the measurement of actual usage of LFAS, Spinning Reserve Service and Load Rejection Reserve Service;
- a review of best practice in other comparable electricity markets with regard to the setting of requirements for LFAS, Spinning Reserve Service and Load Rejection Reserve Service;
- a review of the appropriateness of the current Ancillary Service Requirements for System Restart Service;
- a review of initiatives undertaken in other comparable electricity markets to minimise Ancillary Service Requirements;
- a cost-benefit study on the effects on stakeholders of providing and using a variety of levels of each Ancillary Service, including but not limited to:
  - adjusting the current Spinning Reserve Service level prescribed in clause 3.10.2(i) from 70 percent down to 50 percent and up to 90 percent; and
  - adjusting the current Load Rejection Reserve level from 120 MW down to 90 MW and up to 150 MW;
- technical analyses to identify the expected costs that would result from an increase in the requirements for Ancillary Services due to additional Facilities connecting to the SWIS, including but not limited to:
  - increased penetration of photovoltaic generation of up to 50 percent; and
  - increased penetration of wind generation of up to 50 percent;
- an update on technological developments in intermittent generation and demand response since the last review which may have a significant impact on either:

  - the provision of Ancillary Services; or
  - the requirement for Ancillary Services;
- details of any proposed amendments to the Ancillary Service provisions of the Market Rules and the PSOP: Ancillary Services;
- if amendments are proposed, an assessment of how these amendments will allow the Market Rules to better address the Wholesale Market Objectives; and
- an assessment of the impact of any proposed amendments on other areas of the Market Rules.

The Draft Report and subsequent Final Report to be delivered by the Consultant must cover the requirements under clauses 3.15.1 and 3.15.2 of the Market Rules.

Recommendation

It is recommended that the MAC:

- Note the proposed scope of work for the 2014 Ancillary Services Review.

INDEPENDENT
MARKET
OPERATOR

Agenda Item 9c: 2013 Year in Review

What	2011	2012	2013
MAC and Working Group meetings	27	25	**11**
MAC meetings	9	10	**7**
Rules Development Implementation Working Group	10	4	**n/a**
IMO Procedures Working Group	3	2	**2**
System Management Procedures Working Group	1	0	**1**
Reserve Capacity Mechanism Working Group	n/a	9	**1**
Rule Changes Developed/Underway	33	25	**29**
Procedure Changes	10	11	**10**
Stakeholder Workshops (i.e. Rule Changes, Procedure Changes, Market Design reviews, etc.)	11	5	**2**
RulesWatch issued	**49**	49	**48**

Year	Significant Pieces of Work
2011	Required Level and Reserve Capacity Security (RC_2010_12) Calculation of Capacity Value for Intermittent Generation (RC_2010_25 & 37) Outage Planning 5 Year Review MRCP Market Procedure 5 Year Review
2012	Competitive Balancing and Load Following Market (RC_2011_10) Ancillary Services payment Equations (RC_2010_27) Transparency of Outage Information (RC_2012_11) Reserve Capacity Mechanism Working Group 5-Yearly Review of Planning Criterion 5-Yearly Review of SWIS Forecasting Processes
2013	Prudential Requirements (RC_2012_23) Incentives to Improve Availability of Scheduled Generators (RC_2013_09) Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10) Analysis of Load Following Ancillary Services and its Causes (IMO and System Management)

11 December 2013 MAC
Spinning Reserve Service
Short Term Cost Reduction Opportunity

By Brendan Clarke

System Management

westernpower

Synopsis

- This presentation is to give Market Participants a heads up of an opportunity to provide Spinning Reserve prior to the commencement of a Spinning Reserve Market
    - Current Services
    - Service Opportunities
    - Service Requirements
    - Next Steps
    - MAC consultation

Spinning Reserve Overview

SPINNING RESERVE DEFINITION

3.9.2. Spinning Reserve Service is the service of holding capacity associated with a synchronised Scheduled Generator, Dispatchable Load or Interruptible Load in reserve so that the relevant Facility is able to respond appropriately in any of the following situations:

(a) to retard frequency drops following the failure of one or more generating works or transmission equipment; and

(b) in the case of Spinning Reserve Service provided by Scheduled Generators and Dispatchable Loads, to supply electricity if the alternative is to trigger involuntary load curtailment.

SRAS PROCUREMENT

3.11.8. <u>System Management may enter into an Ancillary Service Contract</u> with a Rule Participant other than Verve Energy for Spinning Reserve Ancillary Services, where:

(a) it does not consider that it can meet the Ancillary Service Requirements with Verve Energy's Registered Facilities; or

(b) <u>the Ancillary Service Contract provides a less expensive alternative to Ancillary Services provided by Verve Energy's Registered Facilities.</u>

Spinning Reserve Overview 2

SRAS Payment

Payment (to Verve) is made in accordance with an administered price and detailed in clause 9.9, essentially

Payment in trading interval = 0.5 x Spinning Reserve Quantity provided in trading interval (in MW) x balancing price in interval (in $/MWh) x margin

For 2013/14 margin is 17% during peak and 27% during off peak* as proposed by IMO and approved by ERA (see link below). ERAWA determination for 2014/15 is not completed

For an average balancing price of $50/MWh this equates to approximately $8,000/MW/month or $100,000/MW/year

The administered price is based upon provision of 220MW during peak and 197 MW during off peak

http://www.erawa.com.au/cproot/11213/2/20130318%20-%20Determination%20of%20the%20Ancillary%20Service%20Margin_Peak%20and%20Margin_Off-Peak%20Parameters.pdf

Future Spinning Reserve Market

Appendix 1. Market Rules Evolution Plan: 2013-2016 Issue list

A summary of the issues in the current MREP is provided in the following table.

Rank	Issue	Explanation (from MREP)	Source	Status
1	Additional Improvements to the Balancing Mechanism	• Remove requirement to submit Resource Plans; • Investigate removal of STEM submissions requirement, or allow multiple STEM windows catering for multiple STEM transactions within the Trading Day, aligned to the balancing windows; • Investigate closer to real time bilateral nominations/updates/adjustments; • Link between Balancing Submissions and Facility limit so that a Balancing Submission may contain more capacity than the Facility limit but not less; and • Timing of submissions: consider starting at 9:00am or 10:00am instead of 8:00am.	Multiple Stakeholders	Preliminary investigations are underway, may be impacted by the proposed merger of Synergy and Verve Energy. It may be useful to consider changes to Bilateral Submissions and the Short Term Energy Market (STEM) separately from changes to Resource Plans. For discussion at the October 2013 MAC meeting.
2	Emissions Intensity Index (EII)	Amendments to the Market Rules have been proposed to formalise the provision of emissions data by Market Participants to the IMO and the publication by the IMO of an Emissions Intensity Index for the WEM.	IMO	Preliminary investigations are underway. Priority may be affected by the recent Federal election results.
3	Transition to half hour gate closure	It has been suggested that a half hour gate closure would lead to more efficient market outcomes.	ERM Power	Outstanding.
4	Introducing Market in Spinning Reserve	Suggestions have been expressed at MAC that the introduction of a Spinning Reserve Market will increase competition in the WEM.	Multiple Stakeholders	Outstanding, waiting on the outcomes of the five yearly Ancillary Services review.
5	Settlement simplification	A number of participants have commented that the complexity in the Market Rules around market settlements may benefit from simplification.	MREP 2009-2013	Outstanding

SRAS Short Term Opportunity

A Market Participant (Simcoa) has offered System Management Spinning Reserve Services at a discount to the Administered Price

This facility is technically capable of providing this service immediately as a result of infrastructure installed during construction of third furnace

This pricing offer is a requirement under Market Rule

"3.11.8E The scope of any Ancillary Services Contract entered into by System Management for the purposes of clause 3.11.8 must:

(a) not include components for the payment of energy; and

(b) only include the availability of the service based on a proportion of the values determined under clause 3.13.3."

SRAS Short Term Opportunity

System Management has reviewed the opportunity for displacement of spinning reserve provided by Verve Energy

During Peak times the spinning reserve requirement is generally 240MW based on the largest contingency being Collie Power station operating at full output 340MW

During Off Peak times the spinning reserve requirement is generally 140MW based on the largest contingency being Collie/Bluewaters/Newgen Kwinana at reduced output 200MW

Load Following Raise Ancillary Services is a component of SRAS (circa 72MW) as is the existing interruptible Load Contract with SIMCOA (42MW)

This gives an opportunity of 26MW during off peak and higher during peak

System Management considers that an opportunity of 26MW of Spinning Reserve Services continuously available is worthy of pursuit if regulatory/commercial/operational costs are minimal. (gives a total of 68MW of Interruptible load)

To be fair, this opportunity must be transparent and available to others whom are willing to offer the service at a better discount

SRAS Short Term Opportunity

For simplicity and low cost this is not intended to be a real time offer/clearing process that would be integrated into the current balancing / market process. A competitive Spinning Reserve Market would facilitate this type of process

This may be provided by a continuous service such as an interruptible load with a minimum load.

This equates to a contract value of approximately $2M/year with savings to the market of $100k/year, assuming a 5% discount was offered.

Interruptible Load Provider Requirements as per current contract

Interruptible Load offerings must be 10 MW or more (same as LFAS)

Load must be disconnected within 500ms and reconnectable after instruction from System Management within 15 minutes

Set up requirements:

- Real time telemetry of the interruptible being offered must be made – communication link to the nearest Western Power Substation is required. Providers must determine cost and timing to connect to Western Power communication links prior to submitting tender.
- An Under Frequency Load Shedding system must be installed and tested.
- In place no later than 1 July 2014

Commercial Offers must be made in the form of a discount to the Administered Price. The minimum discount must be 5%

Contracts will terminate upon the start of a Spinning Reserve Market or 1/7/2015 which ever is the earliest, may be extended if Spinning Reserve market not started.

Next Steps for SM

- Mid January 2014 seek Market Participants wish to provide interruptible load services for 26MW of Interruptible Load.
- If 26MW or less offered direct negotiations with providers.
- If more than 26MW offered consider Tender process, selects those with highest discount until 26MW is filled. A partial acceptance may be made if the last block causes acceptance above 26MW, provider may decline.

Affirmation of Next Steps from MAC

- Discussion - is this sufficiently transparent and fair