Market Advisory Committee

Agenda

Meeting No.	71
Location:	IMO Board Room, Level 17, 197 St Georges Terrace, Perth
Date:	Wednesday 14th May 2014
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 69**	**Chair**	5 min
4.	**ACTIONS ARISING**	**Chair**	10 min
5.	**MARKET RULES**		
	a) Market Rule Change Overview	**IMO**	5 min
	b) PRC_2014_01: Improvements to the Energy Market	**IMO**	30 min
6.	**DRAFT SCOPE OF WORK: REVIEW OF RELEVANT LEVEL METHODOLOGY**	**IMO**	10 min
7.	**IMO RULE DEVELOPMENT WORKPLAN 2014**	**IMO**	10 min
8.	**MARKET PROCEDURES**		
	a) Overview	**IMO**	5 min
9.	**WORKING GROUPS**		
	a) Overview and membership updates	**IMO**	5 min
10.	**PRESENTATION: SPINNING RESERVE COST ALLOCATION**	**IMO**	30 min
11.	**GENERAL BUSINESS**	**IMO**	5 min
12.	**NEXT MEETING: Wednesday 11th June 2014**		

INDEPENDENT MARKET OPERATOR

Market Advisory Committee

Minutes

Meeting No.	69
Location	IMO Board Room Level 17, 197 St Georges Terrace, Perth
Date	Wednesday 19 March 2014
Time	2:00 PM – 5:10 PM

Attendees	Class	Comment
Allan Dawson	Chair	
Kate Ryan	Compulsory – IMO	
Dean Sharafi	Compulsory – System Management	Proxy
Dean Frost	Compulsory – Western Power	Proxy
Will Bargmann	Compulsory – Synergy	
Shane Cremin	Discretionary – Generator	
Andrew Stevens	Discretionary – Generator	
Andrew Sutherland	Discretionary – Generator	
Michael Zammit	Discretionary – Customer	
Steve Gould	Discretionary – Customer	
Peter Huxtable	Discretionary – Contestable Customer Representative	
Paul Hynch	Small Use Consumers' Representative	Proxy
Simon Middleton	Minister's appointee – Observer	Proxy
Elizabeth Walters	Economic Regulation Authority (ERA) – Observer	
Apologies	**From**	**Comment**
Geoff Gaston	Discretionary – Customer	
Shane Duryea	Compulsory – Western Power	
Andrew Everett	Compulsory – Generator	
Noel Ryan	Compulsory – Western Power	
Nerea Ugarte	Small Use Consumers' Representative	
Also in attendance	**From**	**Comment**
Phil Kelloway	System Management	Observer

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Mike Davidson	System Management	Observer
Matthew Cronin	Western Power	Observer
Jacinda Papps	Synergy	Observer
Chris Campbell	Alinta Energy	Observer
Fiona Edmonds	Alinta Energy	Observer
Rob Rohrlach	Amanda Australia	Observer
Paul Troughton	EnerNOC	Observer
Richard Wilson	EnerNOC	Observer
Paul Gower	Vinalco	Observer
Erin Stone	IMO	Presenter
Jenny Laidlaw	IMO	Presenter
Martin Maticka	IMO	Presenter
Paul Tetley	IMO	Presenter
Greg Ruthven	IMO	Observer
Bryn Garrod	IMO	Observer
George Sproule	IMO	Observer
Courtney Roberts	IMO	Observer
Aditi Varma	IMO	Observer & Minutes

Item	Subject	Action
1.	**WELCOME** The Chair opened the meeting at 2:00 PM and welcomed incoming members to the 69th meeting of the Market Advisory Committee (MAC). The Chair also thanked outgoing MAC members for their contribution.	
2.	**MEETING APOLOGIES / ATTENDANCE** The following **apologies** were received: • Noel Ryan (Compulsory – Network Operator) • Shane Duryea (Compulsory – Network Operator) • Andrew Everett (Compulsory – Generator) • Geoff Gaston (Discretionary – Customer) • Nerea Ugarte (Small Use Consumers' Representative) The following **proxies** were noted: • Dean Sharafi for Phil Kelloway (Compulsory – System Management) • Dean Frost for Shane Duryea (Compulsory – Network Operator) • Simon Middleton (Proxy, Minister's appointee – Observer) • Paul Hynch for Nerea Ugarte (Small Use Consumers' Representative) The following **presenters** and **observers** were noted: • Erin Stone (Presenter, IMO) • Jenny Laidlaw (Presenter, IMO) • Martin Maticka (Presenter, IMO) • Paul Tetley (Presenter, IMO)	

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	• Phil Kelloway (Observer, System Management) • Mike Davidson (Observer, System Management) • Matthew Cronin (Observer, Network Operator) • Chris Campbell (Observer, Alinta Energy) • Fiona Edmonds (Observer, Alinta Energy) • Rob Rohrlach (Observer, Amanda Australia) • Paul Troughton (Observer, EnerNOC) • Richard Wilson (Observer, EnerNOC) • Paul Gower (Observer, Vinalco) • Greg Ruthven (Observer, IMO) • Bryn Garrod (Observer, IMO) • George Sproule (Observer, IMO) • Courtney Roberts (Observer, IMO) • Aditi Varma (Observer and Minutes, IMO)	
3.	**MINUTES OF PREVIOUS MEETING** The minutes of MAC Meeting No. 67, held on 11 December 2013, were circulated to members prior to the meeting. The following amendments were agreed: ***Section 5: page 6 of 16*** • Mr Everett considered that the changes appeared logical and from a market perspective saw no problems with the proposal being presented and considered by MAC. Mr Everett considered the fundamental issue was that a credible business case needed to be presented for the change. • Mr Everett noted that Verve Energy's position was that if it was determined that Verve Energy did not have market power that needed to be ~~vetted~~fettered then that would be an appropriate time for it to move to facility based bidding so that it could, for example, bid capacity out of the market like other generators can do. ***Section 6c: page 13 of 16*** • Mr Gaston further questioned if analysis had been done on how often the inflection point for the maximum refund factor (750 MW) would apply. The Chair noted that this depended on the quantity of available capacity in any Trading Interval and would change as the excess capacity in the market started to decrease. Mr Cremin observed that this situation was akin to the next Rule Change Proposal (incentivising early entry for Reserve Capacity) which was proposed at a time of scarce Reserve Capacity but ~~that incentivising early entry for Reserve Capacity~~ was ~~not relevant anymore~~ now of limited relevance in the current situation of excess capacity. *Action Point: The IMO to amend the minutes of Meeting No. 67 to reflect the agreed changes and publish on the Market Web Site as final.*	**IMO**
4.	**ACTIONS ARISING** The Chair invited Ms Kate Ryan to update the MAC on the current action items. The following points were noted: • **Item 43:** Ms Ryan noted that this item on licensing arrangements for	

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	Demand Side Management (DSM) aggregators was included in the agenda under general business. • **Item 59:** Mr Dean Sharafi noted that System Management processed three months of data prior December 2013 and did not come across any situations where Market Participants changed their Balancing Submissions close to gate closure. The Chair noted that this suggested that the difficulties System Management may face in maintaining power system security if Balancing Gate Closure was reduced to 30 minutes may be minimal. • **Item 66:** Mr Dean Frost noted that the ERA had the public liability insurance amounts approved in the three Access Arrangements. However, Western Power welcomed queries from any Electricity Transfer Access Contract (ETAC) customer on this value. He further added that Western Power would individually negotiate on these values with its customers. Dr Steve Gould also noted his impending meeting with Western Power on this matter. It was decided that this action item remain open until further notice. *Action Point: The IMO to amend the action items to reflect the updates discussed at the meeting.*	**IMO**
5a.	**MARKET RULE CHANGE OVERVIEW** Ms Ryan informed the MAC that in addition to the summary of current Rule Change Proposals provided in the meeting papers, the IMO would provide further detail on the upcoming work program at the next MAC meeting.	
5b.	**PRC_2013_16: Outages and the Application of Availability and Constraint Payments to Non-Scheduled Generators** The Chair invited Ms Erin Stone to present on this agenda item. Ms Stone noted that this Rule Change Proposal had been discussed by the MAC previously but had been revised in two key areas; the definition of an Outage and the calculations underpinning constrained on and off payments. Ms Stone asked for comments and questions on the revised proposal. The following key points were noted: • Mr Andrew Sutherland reiterated his concern that the definition of an Outage had been included in a Rule Change Proposal primarily about constraint payments. Ms Stone noted that one of the issues that this Rule Change Proposal aims to fix includes where Market Participants are paid constrained off payments as a result of not logging an Outage. This payment is then removed at a later date, incurring compliance and administrative costs for the IMO and the Market Participant. Ms Stone noted that the proposed amendments would automatically remove this payment when it was not warranted. • Mr Sutherland noted that his primary concern was around the practical operation of the proposed amendments to the definition of a Forced Outage, particularly as it applies to starting a Facility. MAC members discussed different operational circumstances in relation to a Facility's starting up, including whether they could be addressed through a Facility's Tolerance Range or Minimum Generation quantity. Ms Stone noted that the IMO had attempted to address the different Outage scenarios and requested that MAC members bring to the	

	IMO's attention any other scenarios that are not appropriately captured in the proposed definition of an Outage. • Mr Sutherland noted that he would never log a Consequential Outage in advance of it occurring. Ms Jacinda Papps said that this provision was included in the drafting at the request of Verve Energy which, on a few occasions, would have benefited from the ability to log Outages in advance. Mr Sutherland reiterated that it should not be a requirement. Ms Stone noted that some Intermittent Generators had expressed interest in providing input to this proposal. The Chair noted that instead of discussing the proposal further at MAC, the IMO will complete its meeting with the Intermittent Generators, resolve other outstanding issues with those members who have raised concerns and circulate the proposal prior to submitting the Rule Change Proposal into the Standard Rule Change Process. MAC members undertook further discussion with respect to progressing this Rule Change Proposal more broadly. • Mr Will Bargmann stated that a number of issues addressed in this Rule Change Proposal would be subject to the Western Australian Electricity Market Review (Review) being undertaken by the State Government. Mr Bargmann noted that the Wholesale Market Objectives should be considered as part of the Review, and expressed concern that therefore, Rule Change Proposals such as this which reflect the objective of anti-discrimination should not be progressed on the basis that it may be removed. Mr Bargmann also noted the IMO's consideration of constrained network access arrangements in this Rule Change Proposal and suggested that the proposed amendments were pre-empting the outcomes of the Review. • Mr Bargmann summarised his position, noting that he is uncomfortable endorsing any Rule Change Proposal that sets things in stone prior to the outcomes of the more comprehensive Review. Mr Stevens said that this would effectively prevent improvements for the next two to three years, on the basis that the market may change. Mr Simon Middleton responded that the IMO should take the Review into consideration to the extent that it may result in a shorter payback period included in the analysis of the costs and benefits of a proposed change. • Mr Sharafi noted System Management's support of the Rule Change Proposal and that IT changes are required to facilitate the proposed amendments. • Mr Chris Campbell agreed with Mr Bargmann's view to delay consideration of the proposed amendments that related to constrained network access arrangements including those in this Rule Change Proposal. The Chair responded clarifying that the current Market Rules exposed Market Customers to paying Market Generators constraint payments where that Market Generator has agreed commercially to accept sub-standard access to the network. MAC members agreed that this was not an optimal outcome for the market. MAC members discussed the recent change in approach by Western Power to connecting customers behind a network constraint and the IMO's ability to take the quality of a network connection into account for certification purposes. Mr Frost offered to provide an overview of the	

	Network Operator's approach to constraints on the network at the next MAC meeting. • Mr Bargmann questioned the cost of the constraint payments. Ms Stone noted that the IMO has circulated the costs previously to MAC members but that they will also be included in the Rule Change Proposal. Ms Papps noted that the previously circulated information indicated that the cost was around $500,000 per annum but did not include Market Participant costs. Ms Ryan noted that the IMO expected that costs to Market Participants to be provided through the submission period. • Mr Bargmann also questioned the process of appeal where System Management does not approve a Consequential Outage. Ms Stone noted that the IMO was not proposing to change the current approval arrangements. Mr Bargmann acknowledged that the arrangements were not changing but questioned whether there was any ability to appeal such a decision. The Chair advised that it was at System Management's discretion but that it was likely that such a decision could be the subject of a settlement dispute and which may ultimately be considered by the Electricity Review Board. *Action Points:* 1. *The IMO to resolve the outstanding issues with those members who have raised concerns with respect to the definition of an Outage and circulate the proposal prior to submitting the Rule Change Proposal into the Standard Rule Change Process.* 2. *Western Power to provide an overview of Western Power's current approach to constrained access to the grid at the next MAC Meeting.*	**IMO** **Western Power**
6b.	**PRC_2013_14: Adjustment of Spinning Reserve Block Sizes** The Chair invited Mr Andrew Stevens to present the pre Rule Change Proposal. Mr Stevens provided an overview of the pre Rule Change Proposal which included two options to adjust the size and boundaries of the Spinning Reserve blocks and noted some of the effects of the current arrangements. The following key points were discussed: • The Chair suggested that the MAC may want to consider a third option which is the runway method of allocating Spinning Reserve costs across generators which would reflect the cost allocation associated with the configuration of generators in each half hour. He noted that many international electricity markets employ this method. The Chair suggested that the IMO could prepare a presentation on the runway method and assess the costs under the different proposals to assist MAC members in assessing a Rule Change Proposal to amend the current arrangements. • Mr Shane Cremin noted that allocative efficiencies may be gained from a proposal to change the current arrangements. He added that the current block sizes for Spinning Reserve may affect investment decisions with respect to the size of a generator to be built. • Mr Bargmann queried if this proposal should be considered as part of the 2014 Ancillary Services review. Ms Jenny Laidlaw responded that the scope of the Ancillary Services review included assessing the standards and requirements for Ancillary Services but did not include	

	the mechanism for allocating Ancillary Services costs. • MAC members agreed that the IMO should present an overview of the runway method at the next MAC meeting and undertake some analysis of the different outcomes under each cost allocation method. *Action Points:* *1. The IMO to clarify whether the work on Spinning Reserve Block Sizes could be included in the Ancillary Services review.* *2. The IMO to present the runway method of Spinning Reserve cost allocation at the next MAC meeting.*	 **IMO** **IMO**
6c.	**PRC_2014_01: Improvements to the Energy Market** Ms Laidlaw explained that the pre Rule Change Proposal followed on from the discussion paper that Mr Jim Truesdale had presented at the December 2013 MAC meeting[1] and was primarily aimed at removing Resource Plans and reducing gate closure times for the Balancing and Load Following Ancillary Services (LFAS) Markets. Ms Laidlaw highlighted the following discussion points: • The proposed timeframes went beyond those that Mr Truesdale had outlined. Ms Laidlaw asked whether MAC members could foresee any major problems with the timeframes that could not be addressed before implementation. • The deadline for System Management to set the LFAS Quantity was proposed to be before Synergy's deadline for LFAS Submissions. However, Ms Laidlaw sought LFAS providers' views on whether it was feasible to make LFAS Submissions before the final LFAS Quantity was known, so that the deadline for setting the LFAS Quantity could occur later. Ms Laidlaw invited MAC members to ask questions or provide comments on either the discussion points or the remainder of the pre Rule Change Proposal. The following key points were discussed: • Ms Papps said that the LFAS Quantity had been static so far, and that the practicality of the deadlines depended on the predictability of the LFAS Quantity. • Mr Sharafi explained that the system controllers currently had a view of five Trading Intervals for short-term planning. He expressed concern that a half-hour gate closure could lead to large sudden changes to how Synergy Facilities needed to be dispatched in this window, particularly as Synergy had large quantities in its bids. He made a number of suggestions that could mitigate the risk, including limiting the size of changes allowed, upgrading the IT system to create alarms for the controllers, and having two controllers on duty. He suggested that a half-hour gate closure could be easier to implement at the same time as Facility-based bidding for Synergy, five-minute dispatch cycles and further automation. • The Chair pointed out that System Management had expressed similar concerns about the current gate closure timeframes during the introduction of the Balancing and LFAS Markets but had not seen them	

[1] Enhancements to the Energy and LFAS Markets, available at: http://www.imowa.com.au/mac_67.

	realised. He explained that bids in electricity markets typically converge as you get closer to gate closure rather than change radically, and that big changes were usually due to unplanned or Forced Outages which needed to be addressed even under the current gate closure timeframes. Mr Sharafi replied that he was not objecting to the proposals but highlighting the costs that the market would have to be prepared to bear if System Management were to accommodate them. • There was a wide-ranging discussion about the practical effect that a half-hour gate closure might have on System Management's short-term dispatch planning, and potential solutions to the problems created. Mr Sharafi and Mr Kelloway agreed that the obstacles could be overcome, although System Management would need to make some changes to its processes and systems. • Mr Bargmann said that the proposals would mean that Synergy would have to move to an automated trading system, which was reasonable. However, he expressed concern about the timing given that the Review was underway, following which the specification for such an automated system would be better known. Mr Cremin agreed and considered that in general, Market Participants needed more certainty about the future state of the market for which their systems would need to be designed. • The Chair noted that LFAS costs had previously been highlighted by the MAC as a significant concern and that these proposals could potentially reduce them. • Mr Sutherland made two points. Firstly, he said that the timing of gate closure was irrelevant if wind farms did not improve their forecasts. Secondly, he suggested that the changes to Synergy's submission deadlines would remove the incentive for it to nominate large baseload Facilities to be Stand Alone Facilities. Under the current arrangements, when such Facilities tripped, Synergy generally had to fulfil commitments to generate low-priced electricity with more expensive plant, which provided an incentive to move towards Stand Alone Facilities. Ms Papps replied that Synergy was already allowed to rebid if an Outage meant that it had to run a liquid-fuelled Facility. • Mr Sutherland stated that LFAS providers needed to know the final LFAS Quantity before finalising their LFAS bids. Ms Papps and Mr Bargmann agreed. Mr Bargmann expressed his concern that Synergy's submission deadline being before LFAS Gate Closure meant that other Market Participants could choose the intervals for which they wished to provide LFAS without Synergy being able to revise its bids. Ms Laidlaw noted that this was already the case in the LFAS Market, with Synergy's deadline for LFAS Submissions falling hours before LFAS Gate Closure. • Mr Sutherland reiterated his view previously shared with the MAC that Market Customers should be able to make bilateral nominations, particularly given that, following its merger with Verve Energy, Synergy was now able to do so. Ms Ryan replied that it may be more appropriate to consider this as part of the proposed redesign of the STEM.	

	• Mr Stevens asked if the IMO had given any consideration to moving the opening of the STEM Submission window to 8:00 AM, so that Bilateral and STEM Submissions could be made at the same time. Although he could see that, as with Mr Sutherland's proposal, this would fit more naturally with the proposed redesign of the STEM, he considered that if it was a simple change then there was no reason not to implement it immediately. The Chair indicated that the IMO would investigate whether the change could be easily incorporated into this pre Rule Change Proposal. • The Chair provided a brief summary of the other issues addressed in the pre Rule Change Proposal and asked MAC members to contact Ms Laidlaw directly to discuss any concerns they had with the proposal. *Action Point: The IMO to investigate whether a proposal to open the STEM Submission window at 8:00 AM could be incorporated in PRC_2014_01: Improvements to the Energy Market.*	**IMO**
6a.	**MARKET PROCEDURES OVERVIEW** Ms Ryan provided an update on the Market Procedures noting that status updates were provided in red text.	
7a.	**WORKING GROUP OVERVIEW AND MEMBERSHIP UPDATES** No changes or updates were noted under this agenda item.	
8.	**MAC CONSTITUTION AND GUIDELINES** The Chair noted that the proposed amendments to the MAC Constitution were prompted by the Amending Rules in the Rule Change Proposal: Market Rule changes arising due to the merger of the Electricity Retail Corporation and Electricity Generation Corporation (RC_2013_18) and invited Ms Ryan to discuss the changes. The following key points were discussed: • Ms Ryan added that there were also some proposed minor changes to improve the integrity of the Constitution and that the Appointment Guidelines had been circulated for MAC members' information. • Ms Ryan noted that Alinta Energy questioned some of the proposed wording and the IMO would attempt to further clarify the intention of the clause. • Mr Peter Huxtable queried whether the IMO's recording of the MAC meetings should also be included in the MAC Constitution. Ms Ryan agreed to consider adding it to the Constitution. The Chair also suggested that the timeframes that the IMO retains recordings of MAC meetings could be included in the MAC Constitution for completeness. • Mr Bargmann noted that the main concern was the change to a best endeavours approach to meeting papers being provided at least five days prior to a meeting. Mr Sutherland also noted the extensive nature of the papers. • Mr Huxtable questioned why the IMO was proposing to remove the footnotes in the Appointment Guidelines which noted that the Chair and the IMO representative were not able to be on the MAC appointment evaluation panel. Ms Ryan noted that the IMO did not	

	believe that these notes were necessary in the first place. The Chair confirmed that despite the removal of the footnote, the Chair of the MAC will continue not to be a member of the evaluation panel. The Chair invited further comments and feedback during the following week before the IMO undertakes public consultation on the proposed amendments. *Action Point: The IMO to update the MAC Constitution and Appointment Guidelines based on feedback already received from MAC members and any other comments provided before submitting for public consultation.*	**IMO**
9.	**MUJA BUS-TIE TRANSFORMER FAILURE UPDATE** The Chair invited Mr Sharafi to present an update on the effects of the recent transformer failures at Muja. The following key points were discussed: • Mr Sutherland questioned what the financial consequences of this event were. The Chair responded that the IMO had prepared a presentation to be presented next to show the financial impact of this event. • Mr Cremin and Mr Stevens had questions about the lifespan and cost of the transformer. In response, Mr Sharafi noted that this transformer was about 25 years old of its expected 50 year life and cost $9 million. • The Chair questioned whether Western Power could provide (not necessarily immediately) more information on other likely single points of failure on the grid. Mr Sharafi observed that Kalgoorlie was currently based on an n-0 network configuration (i.e. there is no credible contingency) along with other single points of failure. • Mr Sharafi noted that the replacement transformer was expected to be available in September provided testing was successfully completed. He said that Western Power was considering options to address the difficulties of obtaining replacement network equipment including sharing spares with other utilities. Mr Frost noted that this would be an economic decision based on a number of practical considerations. The Chair then invited Mr Martin Maticka to present the impact of this event on the market. The following key points were discussed: • Noting the bidding behaviour for Muja AB, Mr Campbell questioned if Vinalco was obliged under the Market Rules to bid at or below the Short Run Marginal Cost (SRMC) of its Facilities. The Chair clarified that the obligation to bid at or below SRMC applies when market power exists. • The Chair provided additional detail noting that after being alerted to the transformer failure and the reliance on Muja AB by System Management, the IMO wrote to Vinalco stating the IMO's view that Vinalco may have market power in these circumstances and it should modify its bidding behaviour to bid at or below SRMC. He noted that Vinalco had shared its operating cost data with the IMO to facilitate further investigation of this issue. He added that Vinalco's bidding behaviour was currently under consideration by the IMO Board. • Mr Campbell noted that Market Participants should be kept informed	

	about the outcomes of the investigations as these circumstances were expected to have significant impact on the overall market. • Mr Sutherland also questioned the financial impact of this event to Market Customers. • Mr Stevens noted that the ERA has the ability to examine contracts in detail and suggested that the ERA should take such action in the given circumstances. • Mr Campbell expressed concern that if it was determined that there was no market power in this case, Vinalco could revert to its previous bidding behaviour (of bidding at the non- liquid price cap) noting that the constrained on payments would then be even larger. MAC members discussed the costs to the market, noting that approximately $7 million will be incurred until the network constraints in the Albany region are rectified in September. MAC members also discussed whether this cost strengthened the incentive for Western Power to expedite repair or replacement works. • In conclusion, MAC members noted that it was important for the market to be aware of other single points of failure on the grid to be prepared to address such events. *Action Points:* 1. *Western Power to provide information on any other single points of failure in the SWIS.* 2. *The IMO to provide Market Participants with the expected financial impact of the Muja bus-tie transformer failure.* 3. *The IMO to publish System Management's and IMO's presentations on the Market Web Site.*	**WP** **IMO** **IMO**
10.	**LFAS UPDATE** Ms Laidlaw provided an update on the recent progress of the joint IMO and System Management investigations into the LFAS Requirement. Ms Laidlaw advised MAC members that the IMO intended to publish the presentation on the Market Web Site along with the LFAS Sources and Usage measures calculated for January 2014 and February 2014. *Action Point: The IMO to publish on the Market Web Site the 'LFAS Requirement Investigation Update' presentation for the March 2014 MAC meeting and the LFAS sources and usage measures calculated for January 2014 and February 2014.*	**IMO**
11.	**WIND FORECASTING UPDATE** The Chair welcomed Mr Paul Tetley to provide an overview of the recent improvements to Market Participant wind forecasting. Mr Tetley discussed the importance of wind forecasts in ensuring accurate Balancing Price forecasts and provided examples of the magnitude of recent wind forecast variations that affected the forecast prices. Mr Tetley explained the recent process that the IMO and Market Participants had gone through to improve the quality of the forecasts. Mr Tetley then showed the impact of the recent changes on the accuracy	

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	of the forecasts and acknowledged the efforts made by wind farms to improve their forecast of expected quantity. Mr Sutherland questioned why it took three days for the IMO to determine a final Balancing Price. The Chair noted that he believed that three Business Days was a worst-case scenario and expected that it was due to the finalisation of the SCADA data but would confirm if this is the case. *Action Points:* *1. The IMO to clarify why the final Balancing Price can take up to three Business Days to calculate.* *2. The IMO to publish the presentation on the Market Web Site.*	 **IMO** **IMO**
12.	**LOAD FORECASTING UPDATE** The Chair introduced Mr Sharafi to outline the challenges and improvements System Management has made with respect to Load Forecasting. Mr Sharafi outlined the process and demonstrated the systems that System Management undertakes to forecast the Load on the SWIS. He discussed challenges associated with photovoltaic (PV) uptake, changes to block Load consumption, generators tripping and other excursion events and showed examples of the impact of such events. Mr Sharafi noted the recent improvements to Load Forecasting including better generation data for PV systems, optimising blending weights in the forecasting equations used, introducing the 'Kalman filter' and introducing an alarm to alert the operator when the forecast is significantly different to the actual quantity. The Chair noted that System Management could introduce a rule change to require estimations of the consumption of larger block Loads to be provided to System Management for the purposes of Load Forecasting. *Action Point: The IMO to publish the presentation on the Market Web Site.*	 **IMO**
13.	**GENERAL BUSINESS** **Regulation of DSM Aggregators** The Chair noted that the IMO had written to the ERA and Public Utilities Office (PUO) on behalf of the MAC with regard to the potential licensing of DSM providers. The Chair said that the PUO noted in its letter that a prima facie case for licensing of DSM aggregators had not been established. The Chair offered to facilitate a discussion session on the issue at the next MAC meeting. Mr Middleton noted that historically the PUO had made legislative changes where it considered that the effect would be beneficial to the overall market. In this case, the PUO would need a compelling case to initiate the legislative process. Mr Cremin also noted that based on previous experience and in the current context it was unlikely that the Government would attach a high priority to this issue unless there was a compelling case. The Chair suggested that the IMO discuss the priority of the issue with Mr Geoff Gaston who initiated the topic for discussion at the last MAC meeting. Dr Gould stated his view that given the correspondence from the ERA and	

	PUO, there was little point in continuing to pursue the issue at this stage. Dr Gould believed that the one material issue was the conflict of interest between the retailer's incentive to have the Individual Reserve Capacity Requirement as low as possible and the DSM aggregator to have it as high as possible so as not to restrict its Relevant Demand. He noted that in these circumstances it may be appropriate to protect small-use customers through the introduction of regulation. Mr Campbell agreed with Dr Gould's comments, noting that he had also experienced similar scenarios particularly in mid-tier customers. Dr Paul Troughton stated that he did not believe that EnerNOC had advised any customer to increase demand so as to increase their Reserve Capacity Requirement. The company only coaches customers to reduce demand reliably when needed. Dr Gould clarified that he was not suggesting that EnerNOC had adopted this practice. However, MAC members generally agreed that Mr Gaston should be given the opportunity to comment on the possible next steps. *Action Point: The IMO to discuss with Mr Gaston the priority of licensing DSM aggregators and include a discussion item on the agenda for the next MAC meeting if requested by Mr Gaston.*	**IMO**
CLOSED: The Chair declared the meeting closed at 5:10 PM.		

Agenda item 4: 2014 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
59	2013	System Management to provide examples of the difficulties that controllers would face in maintaining system security if Balancing Gate Closure was reduced to 30 minutes in the short term.	SM	Dec	Complete.
66	2013	Western Power to clarify the appropriateness of the public liability insurance amount at the next MAC meeting.	Western Power	Dec	Complete.
1	2014	The IMO to amend the minutes of Meeting No. 67 to reflect the agreed changes and publish on the Market Web Site as final.	IMO	Mar	Complete.
2	2014	Dr Steve Gould to provide update on the progress of discussions with Western Power with respect to the public liability insurance amount in Electricity Transfer Access Contracts.	Steve Gould	Mar	
3	2014	The IMO to resolve the outstanding issues with those members who have raised concerns with respect to the definition of an Outage and circulate the proposal prior to submitting the Rule Change Proposal into the Standard Rule Change Process.	IMO	Mar	In progress.
4	2014	Western Power to provide an overview of Western Power's current approach to constrained access to the grid at the next MAC Meeting.	Western Power	Mar	

#	Year	Action	Responsibility	Meeting arising	Status/Progress
5	2014	The IMO to clarify whether the work on Spinning Reserve Block Sizes could be included in the Ancillary Services review.	IMO	Mar	Complete. The IMO considers this is not appropriate for inclusion in the review for two reasons. Firstly, it relates to cost allocation which is outside the intended scope of the study. Secondly, there are no interdependencies between the Spinning Reserve cost allocation methodology and the issues being considered by the study, and so work on the methodology does not need to wait on the study outcomes. The IMO is presenting a discussion paper on Spinning Reserve cost allocation at this meeting.
6	2014	The IMO to present the runway method of Spinning Reserve cost allocation at the next MAC meeting.	IMO	Mar	Complete. Update to be presented at this meeting.
7	2014	The IMO to investigate whether a proposal to open the STEM Submission window at 8:00 AM could be incorporated in PRC_2014_01: Improvements to the Energy Market.	IMO	Mar	Complete. Update to be presented at this meeting.
8	2014	The IMO to update the MAC Constitution and Appointment Guidelines based on feedback already received from MAC members and any other comments provided before submitting for public consultation.	IMO	Mar	Complete. Public consultation underway.
9	2014	Western Power to provide information on any other single points of failure in the SWIS.	Western Power	Mar	
10	2014	The IMO to provide Market Participants with the expected financial impact of the Muja bus-tie transformer failure.	IMO	Mar	Currently being scheduled.
11	2014	The IMO to publish System Management's and IMO's presentations on the Market Web Site.	IMO	Mar	Complete.

#	Year	Action	Responsibility	Meeting arising	Status/Progress
12	2014	The IMO to publish on the Market Web Site the 'LFAS Requirement Investigation Update' presentation for the March 2014 MAC meeting and the LFAS sources and usage measures calculated for January 2014 and February 2014.	IMO	Mar	Complete.
13	2014	The IMO to clarify why the final Balancing Price can take up to three Business Days to calculate.	IMO	Mar	In progress. Response to be provided at meeting.
14	2014	The IMO to publish the presentation on Wind Forecasting on the Market Web Site.	IMO	Mar	Complete.
15	2014	The IMO to publish the presentation on Load Forecasting on the Market Web Site.	IMO	Mar	Complete.
16	2014	The IMO to discuss with Mr Gaston the priority of licensing DSM aggregators and include a discussion item on the agenda for the next MAC meeting if requested by Mr Gaston.	IMO	Mar	In progress.

Agenda Item 5a: 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)	7th May 2014
Fast track with Consultation Period open	0
Standard Rule Changes with 1st Submission Period Open	0
Fast Track Rule Changes with Consultation Period Closed (final report being prepared)	0
Standard Rule Changes with 1st Submission Period Closed (draft report being prepared)	1
Standard Rule Changes with 2nd Submission Period Open	0
Standard Rule Changes with 2nd Submission Period Closed (final report being prepared)	2
Rule Changes – Awaiting Minister's Approval and/or Commencement	2
Total Rule Changes Currently in Progress	**5**

Please refer to Agenda Item 8 for details on the IMO's proposed 2014 rule development activities.

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 7th May 2014)

Standard Rule Change with First Submission Period Closed

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2013_15	24/12/2013	Outage Planning Phase 2 - Outage Process Refinements	IMO	Draft Rule Change Report published	30/05/2014

Standard Rule Change with Second Submission Period Closed

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2013_20	10/01/2014	Changes to the Reserve Capacity Price and the dynamic Reserve Capacity refunds regime	IMO	Final Rule Change Report published	29/05/2014
RC_2013_21	10/01/2014	Limit to Early Entry Capacity Payments	IMO	Final Rule Change Report published	23/05/2014

Rule Changes Awaiting Commencement/Ministerial Approval

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2013_09	18/06/2013	Incentives to Improve Availability of Scheduled Generators	IMO	Ministerial Approval	21/05/2014
RC_2013_10	21/08/2013	Harmonisation of Supply-Side and Demand-Side Capacity Resources	IMO	Ministerial Approval	21/05/2014

INDEPENDENT MARKET OPERATOR

Agenda Item 5b: Improvements to the Energy Market (PRC_2014_01)

1. BACKGROUND

In this Pre Rule Change Proposal the IMO seeks to:

- remove the requirement to submit Resource Plans from the Market Rules;
- reduce gate closure times for the Balancing and LFAS Markets;
- address a number of secondary issues caused by the proposed changes to Resource Plans and gate closure times; and
- address a number of outstanding issues affecting related areas of the Market Rules.

The Pre Rule Change Proposal was first presented to the MAC at its 19 March 2014 meeting. While System Management raised some concerns about the proposed gate closure times and suggested that a transitional approach may be required, there was general agreement from MAC members to continue to pursue the deadlines outlined in the proposal at this stage. The IMO is continuing to work with System Management to identify and resolve any transitional issues associated with moving to the proposed shorter gate closure times.

2. REVISED PRE RULE CHANGE PROPOSAL

Since the 19 March 2014 meeting, the IMO has made the following changes to the proposed amendments:

- moved the proposed deadline for the approval of Planned Outages from 60 minutes before REM Gate Closure (i.e. 1.5 hours before the start of the Trading Interval) to 90 minutes before LFAS Gate Closure (i.e. 3 hours before the start of the Trading Interval), to allow Synergy to know what capacity is available in the Dispatch Merit Order (DMO) before making its final LFAS Submissions for the Synergy Portfolio;
- reworded clause 7A.2.3 to clarify that reflecting an Operating Instruction or Test Plan in a REM Submission may require more than just bidding a specific quantity at the Minimum STEM Price;
- redrafted sections 7A.3 and 7B.3 to clarify the processes for producing forecast and final DMOs and LFAS Merit Orders and remove inconsistencies within these processes;
- removed prescriptive details about the tie-break processes for DMOs in clause 7A.3.3 and for LFAS Merit Orders in clause 7B.3.3, as these are already covered in the Market Procedure for Dispatch Forecasts; and
- removed a number of unnecessary defined terms and obsolete transitional provisions to improve the integrity of the Market Rules.

INDEPENDENT MARKET OPERATOR

3. RECOMMENDATIONS

The IMO recommends that the MAC:

- **Discuss** the revised Pre Rule Change Proposal; and
- **Note** that the IMO intends to submit the revised proposal formally into the Standard Rule Change Process, subject to any comment from the MAC.

Wholesale Electricity Market
Pre Rule Change Proposal

Rule Change Proposal ID: **PRC_2014_01**
Date received: **TBA**

Change requested by:

Name:	Allan Dawson
Phone:	9254 4333
Fax:	9254 4399
Email:	allan.dawson@imowa.com.au
Organisation:	IMO
Address:	Level 17, 197 St Georges Tce, Perth 6000
Date submitted:	TBA
Urgency:	Medium
Change Proposal title:	Improvements to the Energy Market
Market Rules affected:	**Numerous**

Introduction

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

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

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

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

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

The objectives of the market are:

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

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

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

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

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

Details of the Proposed Rule Change

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

Background

The Market Rules Evolution Plan: 2013-2016 (MREP)[1] is a list of the most important Market Rules evolution issues to be addressed over the 2013-2016 period.

The MREP is the third to be developed by the IMO. The MREPs assist the IMO to set work priorities for the next phase of market development and assist the IMO and System Management in developing their Allowable Revenue submissions for each three year Review Period.

To develop the MREP, candidate issues were identified through review of the previous MREP (for 2009-2013) and direct consultation with industry stakeholders. The list of candidate issues was then prioritised by the Market Advisory Committee (MAC) using a ballot process. The final plan was published on the Market Web Site in November 2012.

The MREP was most recently reviewed by the MAC at its 9 October 2013 meeting[2]. During the discussion the MAC confirmed the top priority of the following issues[3]:

- MREP Issue 1: Additional Improvements to the Balancing Mechanism (including the removal of the requirement to submit Resource Plans and the investigation of various

[1] Available at: http://www.imowa.com.au/rules/market-rules-evolution-plan
[2] See http://www.imowa.com.au/MAC_65
[3] Note there was general agreement from MAC members at the meeting that Issue 2 (the development of an Emissions Intensity Index) was no longer a high priority issue.

suggested enhancements to the Bilateral Submission and Short Term Energy Market (STEM) processes); and

- MREP Issue 3: Transition to half hour Balancing Gate Closure.

There was also general support from MAC members to expand the scope of MREP Issue 3 to include the reduction of LFAS Gate Closure timeframes. This change had been recommended in a report, presented to the MAC earlier in the meeting, on the outcomes of an IMO and System Management work team's investigation into the causes and usage of LFAS during March 2013. The work team had suggested that the change could help reduce LFAS costs by supporting the sculpting of the LFAS Requirement and improving the timeliness of the information used by Market Participants to finalise their LFAS Submissions.

MAC members also gave general support for the splitting of MREP Issue 1 into two components:

- the removal of Resource Plans, which could be progressed relatively quickly; and

- consideration of changes to the Bilateral Submission and STEM processes, which would require more consideration and was likely to be impacted by the (then) upcoming Synergy/Verve Energy merger.

Following the October 2013 meeting the IMO engaged Mr Jim Truesdale to prepare a discussion paper for the MAC, addressing MREP Issues 1 and 3 as well as the possibility of Verve Energy (now Synergy) facility-based participation in the Balancing and LFAS Markets. Mr Truesdale presented his discussion paper 'Enhancements to the Energy and LFAS Markets' (Discussion Paper) at the 11 December 2013 MAC meeting[4].

Mr Truesdale discussed the proposal to remove the requirement to submit Resource Plans and replace the information currently provided by them with an earlier Balancing Forecast. There was general support from MAC members for this proposal.

Mr Truesdale also outlined a proposal to move to a half-hour rolling Balancing Gate Closure and a 2.5-hour rolling LFAS Gate Closure. Mr Dean Sharafi raised System Management's concerns that the proposed timelines could at this point in time cause difficulties for system controllers, and suggested that some form of transitional arrangements may be appropriate. However, MAC members confirmed their support for the concepts of shortening gate closure times as outlined in the Discussion Paper and moving to rolling gate closure for all Facilities for both the Balancing and LFAS Markets, subject to System Management's reservations about moving to a half-hour gate closure immediately.

While drafting proposed revised rules, the IMO identified a number of other issues that were affected by or related to this proposal, which it suggests changing at the same time.

Issues and proposed solutions

In this Rule Change Proposal the IMO seeks to:

- remove the requirement to submit Resource Plans from the Market Rules;

- reduce gate closure times for the Balancing and LFAS Markets;

- address a number of secondary issues caused by the proposed changes to Resource Plans and gate closure times; and

[4] See http://www.imowa.com.au/MAC_67

- address a number of outstanding issues affecting related areas of the Market Rules.

In the following discussion, the IMO has sought to present issues in an order that reflects their relative impact and dependencies. However Issue 1, while not having any operational impacts, is presented first as it proposes new names for some market concepts which are then used throughout the rest of the discussion.

Issue 1: Name of the Balancing Market

The Balancing Market was originally conceived to replace Balancing arrangements that had been in operation for the South West interconnected system (SWIS) since the commencement of the Wholesale Electricity Market (WEM). These arrangements were limited to handling real-time deviations from generation plans, which were set the previous day to reflect contractual obligations.

The design of the new market, which commenced operation on 1 July 2012, involved fundamental changes to way in which generators were dispatched in the WEM. All generators (including Independent Power Producer (IPP) Facilities, which had previously operated in accordance with pre-determined Resource Plans) are now dispatched by System Management in real time, based on a Balancing Merit Order (BMO) formed from mandatory Balancing Submissions.

This means that the Balancing Market is a gross dispatch pool, covering all generation and not just deviations from contractual positions. The name 'Balancing Market' could therefore be misleading considering the market's purpose and operation. The potential for confusion is increased by the current Glossary definition, which gives no indication of the role of the market in determining physical dispatch.

With the removal of Resource Plans, there is no remaining sense in which System Management dispatches Facilities to make up the balance between 'scheduled energy' and actual demand, as there is no longer even a notional schedule. The IMO considers that the broad scope of this Rule Change Proposal provides an ideal opportunity to replace the name Balancing Market with a name that appropriately reflects its purpose and operation.

A number of other defined terms inherit their names from the Balancing Market, such as the Balancing Price, Balancing Facilities (and Non-Balancing Facilities), the Balancing Merit Order (and Non-Balancing Dispatch Merit Order), the Balancing Forecast, the Balancing Portfolio and Balancing Price-Quantity Pairs. These terms do not necessarily need to be named after the market, but do need names that are consistent with the market name and with their specific functions.

Proposed solution:

The primary function of the current Balancing Market is to provide a merit order for the economic, real-time dispatch of generation in the SWIS. The Balancing Market also sets the price for energy that is bought or sold as a result of real-time variations from a Market Participant's Net Contract Position (NCP). The IMO proposes to rename the Balancing Market the Real-Time Energy Market, abbreviated to 'REM' where appropriate.

The IMO proposes renaming the following defined terms throughout the Market Rules[5]:

[5] Please note that no change is proposed to the defined term 'Metered Balancing Quantity', as it is the difference between the Net Contract Position and the Metered Schedule, and the IMO considers that it remains appropriate to call it a balancing quantity.

Current defined term	Proposed defined term
Balancing	Balancing Settlement[6]
Balancing Facility	REM Facility
Balancing Facility Requirements	REM Facility Requirements
Balancing Final Rule Change Report	*Removed*[7]
Balancing Forecast	Dispatch Forecast
Balancing Forecast Market Procedure	*Removed*[8]
Balancing Gate Closure	REM Gate Closure
Balancing Horizon	Dispatch Horizon
Balancing Market	Real-Time Energy Market or REM
Balancing Market Commencement Day	*Removed*[9]
Balancing Market Objectives	REM Objectives
Balancing Merit Order or BMO	Dispatch Merit Order or DMO
Balancing Portfolio	Synergy Portfolio
Balancing Portfolio Supply Curve	*Removed*[10]
Balancing Price	Energy Price
Balancing Price-Quantity Pair	REM Price-Quantity Pair
Balancing Quantity	*Removed*[11]
Balancing Submission	REM Submission
Forecast BMO	Forecast DMO
Non-Balancing Dispatch Merit Order	Non-REM Dispatch Merit Order
Non-Balancing Facility	*Removed*[12]
Non-Balancing Facility Dispatch Instruction Payment or DIP	Non-REM Dispatch Instruction Payment[13]
Pricing BMO	Pricing DMO
Provisional Balancing Price	Provisional Energy Price
Provisional Pricing BMO	Provisional Pricing DMO

The IMO also proposes to update the Glossary definition of Real-Time Energy Market

[6] Depending on the context, the IMO proposes replacing single-word instances of 'Balancing' with different defined terms; 'Balancing Settlement' is the only one of these not on this list elsewhere.
[7] The IMO proposes removing section 1.10 of the Market Rules, which contains transitional rules for the Balancing Market and all references to the Balancing Final Rule Change Report.
[8] Both 'Market Procedure' and 'Dispatch Forecast' are currently or proposed to be defined terms, and the IMO proposes referring to the Market Procedure for Dispatch Forecasts where necessary.
[9] The defined term 'Balancing Market Commencement Day' is used in transitional rules and is no longer relevant; the IMO proposes modifying these rules so that it is not needed.
[10] The defined term 'Balancing Portfolio Supply Curve' means the Balancing Portfolio's Balancing Price-Quantity Pairs in rank order. The IMO proposes to remove this term from the Market Rules as it is not required (note no corresponding term is defined for the other REM Facilities).
[11] The only use of this defined term, in clause 2.16.2(hC), appears to be intended to be Metered Balancing Quantity.
[12] The IMO proposes removing Dispatchable Loads, which means that the only Non-Balancing Facilities under consideration are Demand Side Programmes.
[13] The defined term 'DIP' is never used and the IMO therefore proposes removing it.

(formerly Balancing Market), to clarify its role in the dispatch of generation in the WEM.

For clarity, the remainder of this document uses the proposed defined terms.

Issue 2: Resource Plans

The primary purpose of Resource Plans was, prior to the implementation of the REM, to determine the dispatch of IPP Facilities. However, as noted above the REM operates as a gross dispatch pool and so Resource Plans are no longer used for that purpose. The requirement to submit valid Resource Plans for each Trading Day places a significant and unnecessary administrative burden on Market Generators. Further, the support of the Resource Plan process contributes to the IMO's operational and IT costs, which are passed through to Market Participants.

While Resource Plans are no longer required for the earlier primary purpose of dispatch, they are still used for a number of secondary purposes, including:

- provision of information for System Management planning;
- definition of Reserve Capacity Obligations and the calculation of Net STEM Shortfall;
- definition of restrictions placed on REM Facilities not meeting the REM Facility Requirements; and
- determination of consumption baselines for Dispatchable Loads.

Proposed solution:

The IMO proposes to remove Resource Plans completely from the Market Rules and address the four points covered above as follows.

- **Information required for System Management planning:** System Management currently receives the Resource Plans for a Trading Day shortly after 1:00 pm on the Scheduling Day. System Management uses the Resource Plan information to assess likely Facility commitment decisions, check network load flow implications and develop the initial Synergy Dispatch Plan. The information provided is of limited value following the commencement of the REM, as the Resource Plans are not binding and do not necessarily show how the IPP Facilities intend to operate.

  While a Forecast Dispatch Merit Order (DMO) would provide System Management with the information it needs, the first Forecast DMO is not produced until just after 6:00 pm, when the Dispatch Horizon is extended to cover the next Trading Day. During the discussion at the December 2013 MAC meeting, MAC members supported the concept of extending the Dispatch Horizon at 1:00 pm each day rather than 6:00 pm, so that the first Forecast DMO for a Trading Day was available to System Management around the same time it now receives the Resource Plans.

  Proposed Solution:

  The IMO proposes to change the time at which the Dispatch Horizon is extended from 6:00 pm to 1:00 pm. This means that System Management will receive the first Forecast DMO for a Trading Day shortly after 1:00 pm on the Scheduling Day.

  (Note: the IMO is currently working with System Management and Synergy on what information needs to be provided to Synergy by 4:00 pm each Scheduling Day under clause 7.6A.2(c), and in particular whether the forecast specified in clause 7.6A.2(c)(i)

is still required. Synergy has previously advised the IMO that it does not depend on Resource Plan information to form its initial REM Submissions, as these are based on Synergy's NCP and expected consumption for each Trading Interval.)

- **Reserve Capacity Obligations and Net STEM Shortfall:** Clause 4.12.1 of the Market Rules sets out the Reserve Capacity Obligations of a Market Participant holding Capacity Credits, while clause 4.26.2 gives details of the Net STEM Shortfall calculation. For IPPs both clauses refer to two quantities provided in a Resource Plan: the shortfall relative to the Market Participant's NCP provided under clause 6.11.1(e) and, where a STEM Submission does not exist, the demand quantity provided under clause 6.11.1(d).

  As IPPs are no longer required to comply with their Resource Plans the shortfall quantity is no longer an appropriate indicator of whether a Market Generator has met its Reserve Capacity Obligations, and so does not need to be included in the Net STEM Shortfall calculations. Further, while STEM Submissions are not mandatory, in practice Market Generators ensure that they satisfy their obligations under clauses 4.12.1 and avoid a Net STEM Shortfall under clause 4.26.2 by including their entire available capacity in their Portfolio Supply Curves.

  Clauses 4.12.6 and 4.26.2 contain separate provisions for Synergy, which are very similar to the IPP provisions apart from not involving any Resource Plan quantities. The IMO considers that these provisions could also now be used for IPPs.

  Proposed Solution:

  The IMO proposes to amend clauses 4.12.6 and 4.26.2 to make the provisions currently applicable to Synergy applicable to all Market Generators. While in theory this places a new obligation on IPPs to make STEM Submissions covering their own demand (to avoid incurring a Net STEM Shortfall), in practice this is already the approach taken by IPPs.

- **Restrictions on REM Facilities not meeting the REM Facility Requirements:** Clause 7A.1.11 of the Market Rules allows the IMO to impose conditions on the REM participation of REM Facilities not meeting the REM Facility Requirements. These conditions are published in the Market Procedure for REM Facility Requirements[14], and currently require such Facilities to bid their Resource Plan quantities at the Minimum STEM Price and their remaining capacity at the Maximum STEM Price or the Alternative Maximum STEM Price as applicable.

  System Management has indicated in discussions with the IMO that it sees no problem in allowing Market Participants with REM Facilities that do not meet the REM Facility Requirements to amend their REM Submissions up to REM Gate Closure, provided that the prices offered in the submissions are restricted to the relevant Price Caps.

  Proposed Solution:

  While no change needs to be made to the Market Rules, the IMO proposes to amend the Market Procedure for REM Facility Requirements, to remove the requirement for REM Submissions for these Facilities to be consistent with their Resource Plan quantities. Market Participants would be able to make and update REM Submissions for these Facilities subject to the same rules as for other REM Facilities, except that

[14] Currently called the Market Procedure: Balancing Facility Requirements.

the prices offered in the submissions would be restricted to the relevant Price Caps, to reduce uncertainty around how the Facilities would be dispatched.

- **Commitment:** Section 7.9 of the Market Rules outlines the processes that Market Participants and System Management must follow for synchronisation and desynchronisation of Scheduled Generators. For IPPs, clause 7.9.4 allows System Management to refuse permission to synchronise if this synchronisation is not in accordance with the relevant Resource Plan, Dispatch Instruction or Operating Instruction, and clause 7.9.8 does likewise for desynchronisation. Since the commencement of the REM, if System Management intends that an IPP's Scheduled Generator follow its Resource Plan, it sends a Dispatch Instruction for each scheduled change in output.

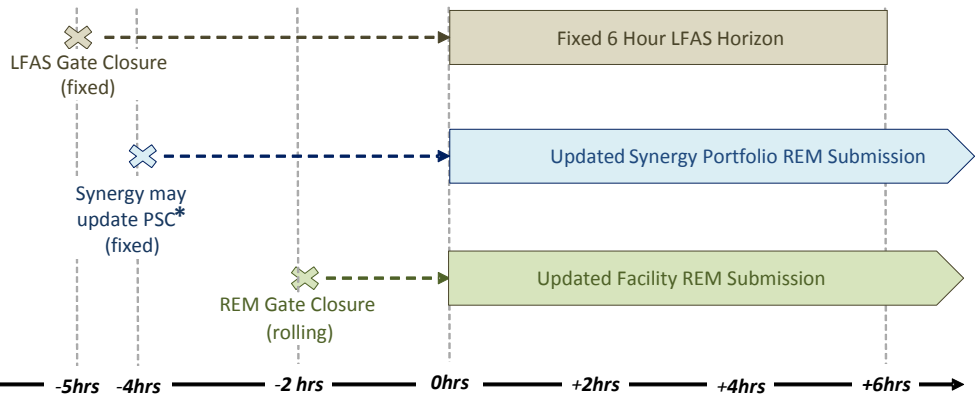
  Proposed Solution:

  The IMO proposes to amend clauses 7.9.4 and 7.9.8 to remove references to Resource Plans.

- **Baseline for Dispatchable Loads:** Market Customers with Dispatchable Loads are required to submit Resource Plans, in order to provide a consumption baseline for settlement in the event that a Dispatchable Load receives a Dispatch Instruction to increase or decrease its consumption. While it would be possible to develop alternative arrangements for the provision of these baselines, for a number of reasons the IMO instead proposes to remove Dispatchable Loads as a Facility Class in the Market Rules. Please refer to Issue 4 for further details.

Issue 3: Gate Closure Changes

The current relationships between LFAS Gate Closure, the final times at which Synergy REM Submissions (referred to as Synergy's "PSC" below) and LFAS Submissions may be updated and REM Gate Closure are illustrated below.



relative to:	-5hrs	-4hrs	-2 hrs	0hrs	+2hrs	+4hrs	+6hrs
1st LFAS horizon	3am	4am	6am	8am			2pm
2nd LFAS horizon	9am	10am	12pm	2pm			8pm
3rd LFAS horizon	3pm	4pm	6pm	8pm			2am
4th LFAS horizon	9pm	10pm	12am	2am			8am

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

Currently, REM Gate Closure occurs two hours[15] before the start of a Trading Interval. Market Participants are only permitted to update their REM Submissions after this time if their Facility experiences an Internal or External Constraint, or receives an Operating Instruction. This means that the information they are using to finalise their REM Submissions, including forecast load and prices, is at least two hours old.

For LFAS the Trading Day is split into four LFAS Horizons, starting at 8:00 am, 2:00 pm, 8:00 pm and 2:00 am. LFAS Gate Closure for IPP LFAS Facilities and Stand Alone Facilities occurs at the same time for each Trading Interval in an LFAS Horizon, namely five hours before the start of the first Trading Interval. Market Participants are therefore expected to make final, binding LFAS Submissions at least 5 hours before and up to 10.5 hours before the start of the relevant Trading Interval.

System Management may update the LFAS Quantity for a Trading Interval in an LFAS Horizon up to one hour before LFAS Gate Closure for that LFAS Horizon, i.e. at least 6 hours and up to 11.5 hours before the start of the relevant Trading Interval. These deadlines can limit the accuracy of some of the information (e.g. weather forecasts) that could be used to 'sculpt' the LFAS Quantity and potentially reduce LFAS costs.

Synergy can only make REM Submissions and LFAS Submissions for the Synergy Portfolio during five fixed periods each day. Just before the extension of the Dispatch Horizon at 6:00 pm, Synergy can submit REM Submissions for Trading Intervals starting at 10:00 pm or later and LFAS Submissions for Trading Intervals starting at 2:00 am or later. Synergy may also update its submissions during the one hour period after LFAS Gate Closure for each LFAS Horizon. During these periods Synergy may update REM Submissions for Trading Intervals starting four hours or more later, and LFAS Submissions for Trading Intervals starting 10 hours or more later. This means that the deadline for Synergy Portfolio submissions is at least 4 hours and up to 9.5 hours before the Trading Interval for REM Submissions, and at least 10 hours and up to 15.5 hours before the Trading Interval for LFAS Submissions.

These timelines are very restrictive. Market Participants and System Management are obliged to make final commitments well ahead of real time, which can encourage overly conservative behaviours and lead to inefficient market outcomes. The current arrangements were originally needed to facilitate a smooth transition to the new market arrangements without risking system security and reliability, and to address concerns around market power. However, as the markets have now been in operation for nearly two years the IMO considers it appropriate to reconsider the need for such stringent requirements.

The IMO still considers that to avoid market power issues it is still important that IPPs remain able to update their REM and LFAS Submissions having seen the final position for the Synergy Portfolio. However it is not in the market's interest for Synergy to base its bids on potentially highly inaccurate information, or for its gate closure restrictions to adversely affect other market outcomes.

Proposed solution:

The IMO proposes a number of changes to the REM and LFAS Submission timelines. The aim is to move the various submission deadlines as close as possible to the start of the relevant Trading Interval, while retaining the ability for IPPs to react to Synergy's bids and for all Market Participants to ensure that their REM Submissions take LFAS results into account. The changes include:

[15] Clauses 7A.1.16 and 7A.1.17 allow the IMO to set this time anywhere between two and six hours. The IMO reduced the time from six hours to two hours on 5 December 2012.

- reducing REM Gate Closure from two hours to 30 minutes before the start of the relevant Trading Interval;
- allowing Synergy to amend its Synergy Portfolio REM Submission for a Trading Interval up to one hour before the start of that Trading Interval;
- removing the concept of LFAS Horizons from the Market Rules and introducing rolling gate closure for LFAS, with LFAS Gate Closure for a Trading Interval set to 1.5 hours before the start of that Trading Interval;
- allowing Synergy to amend its Synergy Portfolio LFAS Submission for a Trading Interval up to two hours before the start of that Trading Interval; and
- allowing System Management to update the LFAS Quantity for a Trading Interval up to 2.5 hours before the start of that Trading Interval.

The impact of the proposed changes is summarised in the table below:

Event	Proposed time	Current worst-case time
Deadline for System Management to update LFAS Quantity	T – 2.5 hours	T – 11.5 hours
Deadline for Synergy Portfolio LFAS Submissions	T – 2 hours	T – 15.5 hours
LFAS Gate Closure	T – 1.5 hours	T – 10.5 hours
Deadline for Synergy Portfolio REM Submissions	T – 1 hour	T – 9.5 hours
REM Gate Closure	T – 0.5 hours	T – 2 hours
Trading Interval starts	T	T

It should be noted that the submission deadlines proposed above are more ambitious than those proposed in the Discussion Paper presented at the December 2013 MAC meeting. The proposed deadlines allow submissions to be made as late as possible and appear feasible given the speed with which DMOs and LFAS Merit Orders are generated at the start of each Trading Interval, although System Management has suggested that a transitional approach to the deadline changes may be required. However the advantages of the shorter timeframes come at the cost of reducing the time available to a Market Participant to react to some key events, such as the publication of the LFAS Merit Order.

It should also be noted that the deadline for final changes to the LFAS Quantity has been set to 30 minutes before the deadline for the Synergy Portfolio's LFAS Submission, allowing Synergy time to assess a final sculpted LFAS Requirement before finalising its LFAS offer. Currently Synergy does not have this option, as its LFAS Submission deadline is earlier than the LFAS Quantity deadline.

While in theory it would be possible to delay the LFAS Quantity deadline further, LFAS providers have indicated that this would leave them with insufficient information on which to base the prices in their LFAS Submissions, and so this is not seen as a workable option.

Issue 4: Dispatchable Loads

Over recent years the IMO has identified a number of issues around the treatment of Dispatchable Loads in the Market Rules. For example:

- the consumption baseline used to calculate Non-REM Facility Dispatch Instruction Payments for Dispatchable Loads is provided by the Market Participant for each Trading Interval through its Resource Plan. However, since the implementation of the REM there is no requirement under the Market Rules for a Dispatchable Load to adhere to its Resource Plan consumption levels, rendering them effectively useless as a baseline;

- the Required Level of a Dispatchable Load is not defined in the Market Rules, although the purported quantity is used in the Reserve Capacity Security and Reserve Capacity Testing provisions for this Facility Class; and

- there are no provisions in the Market Rules to calculate Capacity Cost Refunds for a Dispatchable Load.

These issues mean that the Dispatchable Load provisions are not only confusing for stakeholders and potentially open to gaming, but are likely to prove unworkable in practice. However, the cost of addressing the issues would be significant.

Concerns have also been raised around the usefulness of the Dispatchable Load Facility Class in meeting the Wholesale Market Objectives. While to date no Dispatchable Load has been registered in the WEM, it is reasonable to assume that a facility would need to incorporate some kind of energy storage to be able to adjust its consumption in response to Dispatch Instructions. From preliminary discussions it seems likely that such a facility would be able to not only to reduce its consumption in peak times but to actually provide energy to the SWIS, actively participating in the REM and being dispatched through the DMO, as well as potentially providing Ancillary Services.

The Dispatchable Load Facility Class does not account for a facility of this nature and would require extensive modifications to do so. After investigation of the IT implications the IMO has concluded it would be more practical and cost-effective to design and implement a new Facility Class based on the expected characteristics of a storage facility, rather than attempt to modify the current Dispatchable Load Facility Class.

Finally, the existence of Dispatchable Loads in the Market Rules generates ongoing IT system costs (due to testing and compliance requirements), which are difficult to justify if the Facility Class is not expected to fulfill a useful function in the market.

Proposed solution:

The IMO proposes to remove the Dispatchable Load Facility Class and any requirements that only relate to Dispatchable Loads from the Market Rules.

In light of recent technological advances in the storage of electrical energy, the IMO anticipates the need to consider the introduction of a new Facility Class for energy storage in the future, once sufficient information is available to demonstrate the usefulness of such facilities and identify their key performance characteristics.

Issue 5: Interruptible Loads and the Reserve Capacity Mechanism

Under the current Market Rules, Interruptible Loads can apply for Certified Reserve Capacity and receive Capacity Credits. However, Interruptible Loads cannot be explicitly 'dispatched' to provide Reserve Capacity as they appear in neither the DMO nor the Non-REM DMO.

In practice, Interruptible Loads are used to provide Spinning Reserve under Ancillary Service Contracts. They are also able to provide Reserve Capacity to the market, but this is achieved

by making the Facility an Associated Load of a Demand Side Programme (DSP). In these situations it is the DSP that is assigned the Capacity Credits, rather than the Interruptible Load.

Proposed solution:

The IMO proposes to amend Chapter 4 of the Market Rules to exclude Interruptible Loads as candidates for Certified Reserve Capacity. An Interruptible Load will continue to be able to participate in the Reserve Capacity Mechanism as an Associated Load of a DSP.

While the proposed change does not relate to the energy market, the IMO considers it appropriate to include it in this Rule Change Proposal as many of the affected clauses also refer to Dispatchable Loads, and so are proposed to be amended to address issue 4 above.

Issue 6: Changes allowed after REM Gate Closure

It is important for the IMO to be able to use as accurate information as possible when forming the Pricing DMO, so that the Energy Price accurately reflects the system marginal price. However, changes to REM Submissions made after REM Gate Closure are not received by System Management and this can lead to perverse outcomes if the updated REM Submissions do not reflect Internal and External Constraints correctly.

Proposed solution:

The IMO proposes inserting a new clause 7A.2.10A in the Market Rules to clarify that capacity subject to an Internal Constraint or an External Constraint should be made unavailable in the Facility's REM Submission, and that this capacity should be removed from the highest priced REM Price-Quantity Pairs in that submission.

Issue 7: LFAS Merit Orders and IT outages

Clause 7B.3.7 of the Market Rules obliges System Management to use Backup LFAS when the IMO is unable to publish an LFAS Merit Order for a Trading Interval. This is currently a very rare event, in part because the IMO schedules any routine maintenance of its IT systems so as to avoid the four daily LFAS Gate Closures.

However, the proposed introduction of rolling LFAS Gate Closure means that a new LFAS Merit Order will be due to be published every 30 minutes. Routine IT maintenance may lead to Backup LFAS being activated for a number of Trading Intervals in a row (due to the LFAS Merit Order publication times falling within the maintenance window), resulting in additional costs to the market.

Proposed solution:

The IMO proposes to amend sections 7B.3 and 7B.4 of the Market Rules so that, where the IMO cannot generate the LFAS Merit Order and provide the relevant details (LFAS Enablement Schedule) to System Management within 15 minutes of LFAS Gate Closure, LFAS pricing and enablement will be based on the most recent forecast LFAS Merit Order for the Trading Interval.

If no forecast LFAS Merit Order is available then System Management will use Backup LFAS as per the current arrangements.

Clause 7A.3.15 only obliges Market Participants to update their REM Submissions to reflect their LFAS Enablement quantities following the final publication of an LFAS Merit Order. The IMO does not propose to extend this obligation to forecast LFAS Merit Orders, as this could

lead to Market Participants updating their REM Submissions for every Trading Interval in the Dispatch Horizon every 30 minutes. Instead, System Management would enable LFAS for IPP Facilities in the forecast LFAS Enablement Schedule only if the enablement was consistent with the Facility's position in the DMO, i.e. if the Facility's proposed output level under the DMO allowed it to provide the forecast LFAS Enablement.

IPP LFAS providers will need to take scheduled IT maintenance windows into consideration as the maintenance windows may impact the effective deadlines for REM and LFAS Submissions. An IPP would not be considered in breach of the Market Rules if it was unable to provide LFAS in accordance with a forecast LFAS Merit Order, but in the event of planned IT system maintenance it would be in the IPP's financial interests to bid into the REM early in such a way that it could. Under such circumstances, the IMO would consider last-minute LFAS bids designed to affect another Market Participant's provision of LFAS to be in breach of clauses 7B.2.10 and 7B.2.11.

Issue 8: Impact on Outage Planning Process Refinements (RC_2013_15)

The Rule Change Proposal: Outage Planning Phase 2 – Outage Process Refinements (RC_2013_15) includes a number of proposed changes to the timelines for the request and approval of Planned Outages, as well as a clarification of the obligations on Market Participants to ensure consistency between the status of their Planned Outage requests and the available capacity in their REM Submissions.

The proposed amendments include special arrangements for the Synergy Portfolio, to account for the current timing restrictions placed on its REM Submissions. It has been proposed that any Synergy Portfolio capacity that is subject to an outstanding Planned Outage approval request must be bid as 'available' into the REM, unlike capacity from other REM Facilities which must be reported as 'unavailable'. Further, if System Management approves the request then Synergy must amend its REM Submission to reflect the reduction in its available capacity, but must remove the unavailable capacity from its highest price REM Price-Quantity Pairs, so as to limit the impact on the DMO. RC_2013_15 was formally submitted into the rule change process on 24 December 2013.

The amendments proposed under Issue 3 above would however replace the current restrictions on REM Submissions for the Synergy Portfolio with a more flexible arrangement, whereby the deadline for Synergy Portfolio REM Submissions would be 30 minutes earlier than the deadline for other REM Submissions. Given these changes the IMO considers that the special arrangements for reporting Synergy Portfolio capacity subject to a Planned Outage approval request are no longer necessary.

It was also proposed in RC_2013_15 that the deadline for approval of Planned Outage requests be 30 minutes before REM Gate Closure. This deadline means that LFAS providers must make their final LFAS Submissions without certainty about which Planned Outages have been approved. Prices in LFAS Submissions are affected by the level at which Facilities would be expected to run if not providing LFAS, which depends on the availability of other Market Participants' Facilities. Uncertainty about which Facilities will be taking Planned Outages may result in LFAS providers making more conservative LFAS Submissions, increasing the cost of LFAS to the market.

Ideally the deadline for Planned Outage approvals should be at least an hour before the deadline for making an LFAS Submission, to allow final Planned Outage outcomes to flow through to the Forecast DMO. However, given that LFAS Gate Closure can be up to 10.5 hours before the start of a Trading Interval, a deadline before LFAS Gate Closure was not seen as reasonable in RC_2013_15.

Proposed solution:

The IMO proposes to change the outage planning provisions proposed in RC_2013_15 to account for the proposed new deadlines on Synergy Portfolio REM Submissions set out in this Rule Change Proposal. In particular, the IMO proposes to require Synergy Portfolio REM Submissions to show capacity subject to an outstanding Planned Outage approval request as unavailable.

In order to ensure that Synergy has enough time to amend its LFAS Submission if another Market Participant's Planned Outage approval request is rejected, the IMO proposes to amend the deadline for these requests from 30 minutes before REM Gate Closure to 90 minutes before LFAS Gate Closure, i.e. three hours before the start of the first Trading Interval in the outage period. The IMO considers this to be a simpler approach than implementing different Planned Outage approval request deadlines for Synergy Portfolio Facilities and other Outage Facilities. For IPPs this deadline will represent a slightly earlier deadline than the one proposed in RC_2013_15 (2.5 hours before the start of the first Trading Interval), but the proposed change will allow the LFAS Market to operate more efficiently.

The drafting provided in section 3 includes the relevant changes proposed in RC_2013_15, amended to reflect the proposed new submission timelines.

Issue 9: Fuel Declarations

Section 7.5 of the Market Rules imposes various obligations on the IMO, System Management and Market Participants around the provision to System Management of Fuel Declarations derived from STEM Submissions.

System Management has advised that IMO that it no longer requires these declarations, as it receives the fuel use information it needs through the DMO.

Proposed solution:

The IMO proposes to amend section 7.5 to remove all references to the provision of Fuel Declarations and updates to a Market Participant's proposed fuel use.

It should be noted that no change is proposed to the requirement to provide System Management with fuel use information, via REM Submissions, in the DMO.

Issue 10: Interaction between forecast and final DMOs and LFAS Merit Orders

Section 7A.3 of the Market Rules describes the determination of DMOs and Forecast DMOs, and section 7B.3 does likewise for LFAS Merit Orders and Forecast LFAS Merit Orders. In both cases, the requirements for producing forecast merit orders are virtually the same as those for producing final merit orders, apart from a few minor variations.

In practice, the IMO uses the same IT processes to produce both forecast and final merit orders and their related outputs. This means that where variations exist in the requirements under the Market Rules, the IMO meets the more stringent requirement for both the forecast and final versions. For example, the IMO provides Market Participants with forecast EOI Quantities for their REM Facilities whenever it generates a DMO or a Forecast DMO, even though the Market Rules only require this for Forecast DMOs.

However, the current drafting of sections 7A.3 and 7B.3 is unnecessarily complex, with repetitions and inconsequential variations that make it difficult for a reader to understand how the process works and what information is provided.

Proposed solution:

The IMO proposes to restructure sections 7A.3 and 7B.3, to clarify the processes for the provision of merit orders and related information, and to remove unnecessary inconsistencies between the requirements for forecast merit orders and the requirements for final merit orders.

Other Changes

The IMO has also proposed a number of other minor amendments to the Market Rules to improve the clarity and integrity of the drafting, including:

- removal of the obsolete transitional provisions in sections 1.10 and 1.11 and in clauses 3.13.3AB and 7A.1.2, and their associated Glossary definitions;
- clarification that reflecting an Operating Instruction in a REM Submission might require more than bidding a specific quantity at the Minimum STEM Price in clause 7A.2.3;
- removal of prescriptive detail about the tie-break processes for Forecast DMOs in clause 7A.3.3 and for Forecast LFAS Merit Orders in clause 7B.3.3, which are already included in the Market Procedure for Dispatch Forecasts;
- improvements to the consistency of the names used for various LFAS quantities and constrained on and off payments; and
- the correction of minor and typographical errors.

Impact on the WEM Regulations and Protected Provisions

Reviewable Decisions

Clause 7A.1.11 of the Market Rules, which is a Reviewable Decision under the *Electricity Industry (Wholesale Electricity Market) Regulations 2004* (WEM Regulations), allows the IMO to impose conditions on a REM Facility that does not meet the REM Facility Requirements. The IMO proposes to amend clause 7A.1.11 to use the new market names (e.g. REM instead of Balancing Market).

The IMO considers that the proposed amendments do not alter the general intent of the clause and so it is still appropriate for clause 7A.1.11 to be a Reviewable Decision.

No other Reviewable Decisions are affected by the proposal and no new Reviewable Decisions are proposed.

Civil Penalties

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 considers the proposed changes do not alter the general intent of the provisions (although in some cases they reduce the range of persons that may be subject to the penalty) and so no changes to the current civil penalties are required.

- Clause 2.27.1: *Obligation for a Network Operator to provide Loss Factors to the IMO (category A)* – the only change proposed to this clause is to remove the reference to

Dispatchable Loads. It should be noted that the Public Utilities Office is currently considering which clauses, if any, in section 2.27 (including clause 2.27.1) should be subject to civil penalties.

- Clause 2.34.3: *Requirement to notify the IMO of changes to Standing Data (category B)* – the only change proposed is the removal of a reference to Standing Resource Plans.

- Clause 2.35.1: *Requirement to maintain communications systems to support dispatch (category A)* – the only change proposed is to remove the reference to Dispatchable Loads.

- Clause 2.37.5: *Details what the IMO must take into account when determining a Market Participant's Credit Limit (category B)* – the only changes proposed are to use the new market names.

- Clause 7A.2.8: *Details what a REM Submission must accurately reflect (category C)* – the only changes proposed are to use the new market names and to update a clause reference.

- Clause 7A.2.9: *Details what the Synergy Portfolio REM Curve must accurately reflect (category C)* – the only changes proposed are to use the new market names and reflect the proposed REM Submission timeline changes.

- Clause 7A.2.13: *Requirement to make REM Submissions in good faith (category C)* – the only changes proposed are to use the new market names and replace 'clause 7A.2' with 'section 7A.2'.

- Clause 7A.2.17: *Requirement not to offer prices in REM Submissions in excess of short run marginal cost (category C)* – the only changes proposed are to use the new market names.

- Clause 7B.2.10: *Requirement to ensure LFAS Submissions are accurate (category C)* – the only changes proposed are to amend the description of the Trading Intervals to which the requirement applies to reflect the removal of the LFAS Horizon concept and to make the requirement subject to clause 7B.2.4 (to acknowledge the earlier LFAS Submission deadline for the Synergy Portfolio).

It should be noted that the proposed Amending Rules for RC_2013_15 include changes to clauses 7A.2.8 and 7A.2.9 that have been reversed in this Rule Change Proposal, as they are not required given the proposed changes to the REM Submission deadlines for the Synergy Portfolio.

The following civil penalty provisions are proposed to be deleted, and should therefore be deleted from the WEM Regulations.

- Clause 2.29.8: *Rule Participant requirements in relation to a Dispatchable Load (category B)*.

- Clause 6.5.1A: *Requirement to submit Resource Plans (category B).*

- Clause 7.5.5: *Market Participant requirements in relation to notifications of a change of fuel (category C)*.

In the Rule Change Proposal for RC_2013_15 the IMO considered that the following new clauses would be appropriate civil penalty provisions.

- Clauses 7A.2.8A and 7A.2.9A required Market Participants to ensure that their REM Submissions correctly reflect approved outages and outstanding outage requests. In this Rule Change Proposal clause 7A.2.9A (which relates to the Synergy Portfolio) has been removed and clause 7A.2.8A extended to cover Synergy Portfolio Facilities as well as other REM Facilities.

- Clauses 7A.2.9B and 7A.2.9C (which have been renumbered in this proposal to be 7A.2.9A and 7A.2.9B respectively) require Market Participants to update Balancing Submissions where System Management rejects or cancels an approved Planned Outage.

- Clauses 7A.2A.1 and 7A.2A.2 require Market Participants to notify System Management of a Forced Outage or Consequential Outage for capacity declared unavailable in REM Submissions.

As this Rule Change Proposal does not alter the substantive intent of clauses 7A.2.8A, 7A.2.9B (now 7A.2.9A), 7A.2.9C (now 7A.2.9B), 7A.2A.1 and 7A.2A.2, the IMO still considers that it may be appropriate for these clauses to be subject to category C civil penalties.

The IMO considers that no other new civil penalty provisions are required in relation to this Rule Change Proposal, as no other new obligations are being created. The IMO proposes to work with the Public Utilities Office to progress the necessary amendments to the WEM Regulations to remove clauses 2.29.8, 6.5.1A and 7.5.5 as civil penalty provisions.

Protected Provisions

The IMO notes that clauses 2.1.2, 2.13.6L, 2.16.2, 2.16.4, 2.16.9, 2.16.9A, 2.16.9B, 2.16.9G, 2.16.12, 2.22.1, 2.34.1 and 2.36.1 are Protected Provisions. 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.

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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 underline words added)*

The IMO notes that several Rule Change Proposals currently in progress have an impact on the proposed Amending Rules for this Rule Change Proposal. These include:

- *RC_2013_09: Incentives to Improve Availability of Scheduled Generators;*
- *RC_2013_10: Harmonisation of Supply-Side and Demand-Side Capacity Resources;*
- *RC_2013_15: Outage Planning Phase 2 – Outage Process Refinements; and*

Comment boxes have been used throughout the proposed Amending Rules to identify the affected clauses and the IMO's approach in each case.

Although the Rule Change Proposals: Changes to the Reserve Capacity Price and the dynamic Reserve Capacity refunds regime (RC_2013_20) and Limit to Early Entry Capacity Payments (RC_2013_21) affect some of the clauses listed below, the proposed changes affect different sub-clauses and so have not been repeated here.

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7.5. ~~Non-Balancing~~ Non-REM Dispatch Merit Order~~s and Fuel Declarations~~

...

7.6A. Scheduling and Dispatch of ~~Balancing~~ Synergy Portfolio and Stand Alone Facilities for certain Ancillary Services

...

Dispatch Advisories~~, Balancing Suspension~~ and ~~Reporting~~ Status Reports

...

7A ~~BALANCING MARKET~~REAL-TIME ENERGY MARKET

7A.1. ~~Balancing Market~~Real-Time Energy Market
7A.2. ~~Balancing~~ REM Submissions

The entry for section 7A.2A is included for consistency with the proposed Amending Rules for the Rule Change Proposal: Outage Planning Phase 2 – Outage Process Refinements (RC_2013_15).

7A.2A. Unavailable capacity in a REM Submission
7A.3. ~~BMO~~ Forecast DMO and Pricing ~~BMO~~ DMO

...

7B.4. Synergy ~~Back Up~~ Backup LFAS Provider

...

~~1.10. Specific Transition Provisions – Balancing and Load Following Services~~

~~1.10.1. In this clause 1.10:~~

~~**Balancing Final Rule Change Report:** Means the IMO's Final Rule Change Report for the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10).~~

~~**Pre-Amended Rules:** Means the Market Rules as in force immediately before the amendments made by the Balancing Final Rule Change Report come into effect (and if the amendments come into effect on more than one date, the last date on which the balance of the amendments come into effect).~~

~~**Post-Amended Rules:** Means the Market Rules as in force immediately after the amendments made by the Balancing Final Rule Change Report come into effect (and if the amendments come into effect on more than one date, the last date on which some of the amendments come into effect).~~

~~1.10.2. Before 8:00 AM on the Balancing Market Commencement Day, notwithstanding that the Pre-Amended Rules continue to apply, each Rule Participant must perform all obligations imposed on that Rule Participant under the Post-Amended Rules, in relation to the Balancing Market Commencement Day and subsequent Trading Days, that, if the Post-Amended Rules were in force, the Rule Participant would have been required to perform under the Post-Amended Rules. This includes but is not limited to obligations relating to:~~

(a) updated Standing Data under clause 2.34;

(b) information required to be shared between the IMO and System Management under Chapters 2 and 7, including:

i. Outage schedules under clause 7.3.4;

ii. Resource Plans under clause 7.4; and

iii. Fuel Declarations under clause 7.5.1;

(c) certification of Reserve Capacity under clauses 4.10 and 4.11;

(d) a submission, including:

i. a Bilateral Submission under clause 6.2;

ii. a STEM Submission under clause 6.3B;

iii. a Resource Plan Submission under clause 6.5;

iv. a Balancing Submission under clause 7A.2;

v. the Balancing Portfolio Supply Curve under clause 7A.2.9; and

vi. a LFAS Submission under clause 7B.2;

(e) the STEM Auction under clause 6.4;

(f) a Non-Balancing Dispatch Merit Order under clause 6.12;

(g) Load Forecasts under clause 7.2.1;

(h) a Dispatch Instruction, Dispatch Order and an Operating Instruction under Chapter 7;

(i) information in relation to the Balancing Portfolio under clause 7.6A.2;

(j) a Dispatch Advisory under clause 7.11;

(k) a Forecast BMO under clause 7A.3.16;

(l) an LFAS Quantity forecast under clause 7B.1.4; and

(m) an LFAS Merit Order, a Forecast LFAS Merit Order or the LFAS Price under clause 7B.3.

1.10.3. On the Scheduling Day relating to the Trading Day that is also the Balancing Market Commencement Day set by the IMO under clause 7A.1.2, notwithstanding that the Pre-Amended Rules continue to apply, Rule Participants are not required to perform obligations under the following Pre-Amended Rules:

(a) Resource Plan data under clauses 6.5, 6.5C, 6.11 and 7.4;

(b) Balancing Data under clauses 6.5A and 6.11A;

(c) the Dispatch Merit Order under clause 6.12;

(d) Load Forecast and Ancillary Service Requirements under clause 7.2;

(e) Outages under clause 7.3;

(f) Dispatch Merit Orders and Fuel Declarations under clause 7.5;

~~(g) Dispatch under clause 7.6;~~

~~(h) Scheduling and Dispatch of Synergy under clause 7.6A; and~~

~~(i) Dispatch Instructions under clauses 7.7 and 7.8,~~

~~but only to the extent that these obligations relate to the Trading Day that is also the Balancing Market Commencement Day or subsequent Trading Days.~~

~~1.10.4. After 8:00 AM on the Balancing Market Commencement Day, notwithstanding that the Post-Amended Rules apply, each Rule Participant must perform all obligations imposed on that Rule Participant under the Pre-Amended Rules, arising in relation to each Trading Day (or part of a Trading Day) up to but excluding the Balancing Market Commencement Day, that, if the Pre-Amended Rules were in force, the Rule Participant would have been required to perform under the Pre-Amended Rules. This includes, but is not limited to, obligations relating to:~~

~~(a) administration of the Market under Chapter 2;~~

~~(b) energy scheduling, including calculation of prices and quantities for Balancing and Ancillary Services under Chapter 6;~~

~~(c) Dispatch under Chapter 7;~~

~~(d) settlement under Chapter 9; and~~

~~(e) treatment of information under Chapter 10.~~

~~1.11. Specific Transition Provisions – Electricity Generation and Retail Corporation~~

~~1.11.1. From 12:00 AM until 8:00 AM on 1 January 2014, notwithstanding the definitions of Verve Energy Balancing Portfolio and Non-Balancing Dispatch Merit Order in Chapter 11, the following definitions will apply for the purposes of these Market Rules:~~

~~**Verve Energy Balancing Portfolio**: Means all the Registered Facilities of the body corporate established by section 4(1)(a) of the Electricity Corporations Act, as renamed as the Electricity Generation and Retail Corporation under section 4(2A) of that Act, other than:~~

~~(a) Stand Alone Facilities;~~

~~(b) Demand Side Programmes;~~

~~(c) Dispatchable Loads; and~~

~~(d) Interruptible Loads.~~

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

2.1.2. The functions of the IMO are:

(a) to administer these Market Rules;

(b) to operate the Reserve Capacity Mechanism, the Short Term Energy Market, the LFAS Market, and the ~~Balancing Market~~ Real-Time Energy Market;

(c) to settle such transactions as it is required to under these Market Rules;

…

2.13.6L. System Management must, in the time, form and manner prescribed in the IMS Interface Market Procedure provide to the IMO, for each Scheduled Generator ~~or Dispatchable Load~~ for which an applicable Tolerance Range or Facility Tolerance Range has been determined, the absolute value of the maximum MW boundary of the applicable Tolerance Range or Facility Tolerance Range.

2.16.2. The IMO must develop a Market Surveillance Data Catalogue, which identifies data to be compiled concerning the market. The Market Surveillance Data Catalogue must identify the following data items:

…

(g) ~~Balancing~~ REM Submissions, including associated ~~Balancing~~ REM Price-Quantity Pairs and Ramp Rate Limits;

...

(hC) any substantial variations in ~~Balancing~~ Energy Prices, ~~Non-Balancing Facility~~ Non-REM Dispatch Instruction Payments or Metered Balancing Quantities relative to recent past behaviour;

(i) the capacity available in the DMO ~~through Balancing~~ from ~~Balancing~~ REM Facilities~~, Dispatchable Loads~~ and in the Non-REM Dispatch Merit Order from Demand Side Programmes;

…

2.16.4. The IMO must undertake the following analysis of the data identified in the Market Surveillance Data Catalogue to calculate relevant summary statistics:

(a) where applicable, calculation of the means and standard deviations of values in the Market Surveillance Data Catalogue;

(b) monthly, quarterly and annual moving averages of ~~prices for the STEM Auctions, the Balancing Market and the LFAS Market~~ STEM Clearing Prices, Energy Prices and LFAS Prices;

(c) statistical analysis of the volatility of ~~prices in the STEM Auctions, the Balancing Market and the LFAS Market~~ STEM Clearing Prices, Energy Prices and LFAS Prices;

(cA) any consistent or significant variations between the Fuel Declarations, Availability Declarations, and Ancillary Service Declarations for, and the actual operation of, a Market Participant facility in real-time;

(d) the proportion of time the ~~prices in the STEM Auctions and through Balancing~~ STEM Clearing Prices and Energy Prices are at each Energy Price Limit;

(e) correlation between capacity offered into the STEM Auctions and the incidence of high ~~prices~~ STEM Clearing Prices;

(f) correlation between capacity offered into and made available in the ~~Balancing Market~~ REM and the incidence of high ~~prices~~ Energy Prices;

(fA) correlation between capacity offered into and made available in the LFAS Market and the incidence of high ~~prices~~ LFAS Prices;

(g) exploration of the key determinants for high ~~prices in the STEM, in Balancing, in the Balancing Market and in the LFAS Market~~ STEM Clearing Prices, Energy Prices and LFAS Prices, including determining correlations or other statistical analysis between explanatory factors that the IMO considers relevant and price movements; and

(h) such other analysis as the IMO considers appropriate or is requested of the IMO by the Economic Regulation Authority.

2.16.9. The Economic Regulation Authority is responsible for monitoring the effectiveness of the market in meeting the Wholesale Market Objectives and must investigate any market behaviour if it considers that the behaviour has resulted in the market not functioning effectively. The Economic Regulation Authority, with the assistance of the IMO, must monitor:

(a) Ancillary Service Contracts that System Management enters into and the criteria and process that System Management uses to procure Ancillary Services from other persons;

(b) inappropriate and anomalous market behaviour, including behaviour related to market power and the exploitation of shortcomings in the Market Rules or Market Procedures by Rule Participants including, but not limited to:

i. prices offered by a Market Generator in its Portfolio Supply Curve that do not reflect the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity;

ii. prices offered by a Market Generator in its ~~Balancing~~ REM Submission that exceed the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity;

…

2.16.9A. The IMO must assist the monitoring activities identified in clauses 2.16.9(b)(i), 2.16.9(b)(ii) and 2.16.9(b)(iii) by examining prices in:

(a) ~~Balancing~~ REM Price-Quantity Pairs;

(b) LFAS Price-Quantity Pairs; and

(c) relevant submissions, including:

i. standing submissions; and

ii. STEM Submissions and Standing STEM Submissions used in forming STEM Bids and STEM Offers,

against information collected from Rule Participants in accordance with clauses 2.16.6 and 2.16.7.

2.16.9B. Where the IMO concludes that:

(a) prices offered by a Market Generator in its Portfolio Supply Curve may not reflect the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity;

(aA) prices offered by a Market Generator in its ~~Balancing~~ REM Submission may exceed the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity; or

(b) prices offered by a Market Generator in its LFAS Submission may exceed the Market Generator's reasonable expectation of the incremental change in short run marginal cost incurred by the LFAS Facility in providing the relevant LFAS,

and the IMO considers that the behaviour relates to market power the IMO must:

(c) as soon as practicable, request an explanation from the Market Participant which has made the relevant STEM Submission, ~~Balancing~~ REM Submission or LFAS Submission; and

(d) advise the Economic Regulation Authority of its conclusions. The IMO's advice must outline the reasons for the IMO's conclusions.

2.16.9G. Where the Economic Regulation Authority determines that:

(a) prices in the Portfolio Supply Curve, subject to the investigation, did not reflect the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity;

(b) prices in a ~~Balancing~~ REM Submission, subject to the investigation, exceeded the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity; or

(c) prices in the LFAS Submission, subject to the investigation, exceeded the Market Generator's reasonable expectation of the incremental change in short run marginal cost incurred by the LFAS Facility in providing the relevant LFAS,

the Economic Regulation Authority must request that the IMO applies to the Electricity Review Board for an order for contravention of clauses 6.6.3, 7A.2.17 or 7B.2.15, as applicable.

2.16.12. A report referred to in clause 2.16.11 must contain but is not limited to the following:

(a) a summary of the information and data compiled by the IMO and the Economic Regulation Authority under clause 2.16.1;

(b) the Economic Regulation Authority's assessment of the effectiveness of the market, including the effectiveness of the IMO and System Management in carrying out their functions, with discussion of each of:

i. the Reserve Capacity market;

ii. the market for bilateral contracts for capacity and energy;

iii. the STEM;

iv. ~~Balancing~~the REM;

v. the dispatch process;

vi. planning processes;

vii. the administration of the market, including the Market Rule change process; and

viii. Ancillary Services;

(c) an assessment of any specific events, behaviour or matters that impacted on the effectiveness of the market; and

(d) any recommended measures to increase the effectiveness of the market in meeting the Wholesale Market Objectives to be considered by the Minister.

2.22.1. For the purposes of this clause 2.22, the services provided by the IMO are:

(a) market operation services, including the IMO's operation of the Reserve Capacity ~~market~~ Mechanism, STEM, REM and ~~Balancing~~ LFAS Market and the IMO's settlement and information release functions;

(b) system planning services, including the IMO's performance of the Long Term PASA function; and

(c) market administration services, including the IMO's performance of the Market Rule change process, Market Procedure change process, the operation of the Market Advisory Committee and other consultation, monitoring, enforcement, audit, registration related functions and other functions under these Market Rules.

2.26.3. The Economic Regulation Authority must review the methodology for setting the Maximum 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 Reserve Capacity Price;

(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 Reserve Capacity Price;

(g) the appropriateness of the parameters and methodology in clause 6.20 for recalculating the Energy Price Limits;

(h) the performance of Reserve Capacity Auctions, STEM Auctions and ~~Balancing~~ the REM in meeting the Wholesale Market Objectives; and

(i) other matters which the Economic Regulation Authority considers relevant.

2.27.1. Network Operators must, in accordance with this section 2.27, calculate and provide to the IMO Loss Factors for:

(a) each connection point in their Networks at which any of the following is connected:

i. a Scheduled Generator;

ii. a Non-Scheduled Generator;

iii. an Interruptible Load; or

iv. ~~a Dispatchable Load; or~~[Blank]

v. a Non-Dispatchable Load equipped with an interval meter; and

(b) in the case of Western Power, the Notional Wholesale Meter.

2.27.5. In calculating Loss Factors, Network Operators must apply the following principles:

(a) Transmission Loss Factors must notionally represent the marginal transmission system losses for a connection point relative to the Reference Node, averaged over all Trading Intervals in a year, weighted by the absolute value of the net demand at that connection point during the Trading Interval;

(b) Distribution Loss Factors must notionally represent the average distribution system losses for a connection point over a year;

(c) Loss Factors must be calculated using:

i. generation and load meter data from the preceding 12 months; or

ii. for a new Facility, any other relevant data provided to the Network Operator by the Market Participant and as agreed with the Network Operator and the IMO; and

iii. for Transmission Loss Factors, an appropriate network load flow software package;

(d) a specific Loss Factor must be calculated for each:

i. Scheduled Generator;

ii. Non-Scheduled Generator;

iii. Interruptible Load; and

iv. ~~Dispatchable Load; and~~[Blank]

v. Non-Dispatchable Load above 7000 kVA peak consumption;

(e) Western Power must assign the Notional Wholesale Meter to:

i. a Transmission Loss Factor Class that represents system wide average marginal losses over Western Power's transmission system; and

ii. a Distribution Loss Factor Class that represents the average losses incurred over Western Power's distribution system by Non-Dispatchable Loads not equipped with an interval meter; and

(f) the Transmission Loss Factors calculated for each Transmission Loss Factor Class and the Distribution Loss Factors calculated for each Distribution Loss Factor Class are static, and apply to each connection point in the relevant Loss Factor Class until the time published by the IMO under clause 2.27.8 for the application of an updated Transmission Loss Factor or Distribution Loss Factor to that Loss Factor Class.

2.27.15. A Market Participant may apply to the IMO for a reassessment of any Transmission Loss Factor or Distribution Loss Factor applying to a Scheduled Generator, Non-Scheduled Generator, Interruptible Load~~, Dispatchable Load~~ or Non-Dispatchable Load registered to that Market Participant. The following requirements apply to each application for reassessment:

...

2.29.1A. The Facility Classes:

(a) a Network;

(b) a Scheduled Generator;

(c) a Non-Scheduled Generator;

(d) an Interruptible Load; and

(e) ~~a Dispatchable Load; and~~[Blank]

(f) a Demand Side Programme.

2.29.5. Subject to clauses 2.29.9 and 2.29.8A, a Market Customer that owns, operates or controls a Load~~:~~ may register that Load as an Interruptible Load if that Load has equipment installed to cause it to be interrupted in response to under frequency situations.

~~(a) may register that Load as an Interruptible Load if that Load has equipment installed to cause it to be interrupted in response to under frequency situations;~~

~~(b) [Blank]~~

~~(c) may register that Load as a Dispatchable Load if that Load:~~

~~i. is able to respond to instructions from System Management to increase or decrease consumption; and~~

~~ii. has a rated capacity of not less than 0.2 MW.~~

2.29.5E. The IMO must accept an application submitted under clause 2.29.5B unless:

(a) the IMO considers that the evidence provided by the Market Customer under clauses 2.29.5B and 2.29.5C is not satisfactory;

(b) the relevant Load is not equipped with interval metering;

(c) ~~the relevant Load is an Interruptible Load assigned Capacity Credits for any part of the proposed Association Period;~~[Blank]

(d) the relevant Load is registered as an Intermittent Load for any part of the proposed Association Period; or

(e) the relevant Load is already associated with a Demand Side Programme for any part of the proposed Association Period.

2.29.8. ~~A Rule Participant must ensure a Dispatchable Load registered by that Rule Participant is able to respond to instructions from System Management to increase or decrease consumption.~~[Blank]

2.29.8A. A Rule Participant must ensure an Interruptible Load ~~or Dispatchable Load~~ registered by that Rule Participant is equipped with an interval meter.

2.30B.13. Where a generation system described in clause 2.30B.2(a) satisfies the requirements of clause 2.30B.11 and is associated with an Intermittent Load then that generation system is to be deemed to be at the location of the Intermittent Load with respect to its inclusion in Bilateral Submissions~~,~~ and STEM Submissions ~~and Resource Plans~~.

2.34.1. The IMO must:

(a) maintain a record of the Standing Data described in Appendix 1, including the date from which the data applies; and

(b) provide the Standing Data, excluding any Standing Data described in the following clauses of Appendix 1, and any revisions of that Standing Data, to System Management as soon as practicable:

i. [Blank]

ii. [Blank]

iii. clause (h)(vi);

iv. ~~clause (i)(xA);~~[Blank]

v. clause (k)(i)(7);

vi. [Blank]

vii. clause (l)(iii)(4);

viii. clause (l)(iii)(5); and

ix. clause (m).

2.34.3. A Rule Participant that seeks to change its Standing Data, other than Standing Data changed in accordance with the processes set out in clauses 6.2A~~,~~ or 6.3C ~~or 6.5C~~, must notify the IMO of:

(a) the revisions it proposes be made to its Standing Data;

(b) the reason for the change; and

(c) the date from which the revision will take effect.

2.34.8. Other than Standing Data changed in accordance with the processes set out in clauses 6.2A~~,~~ or 6.3C ~~or 6.5C~~, the IMO must notify the Rule Participant of its acceptance or rejection of the change in Standing Data as soon as practicable, and no later than three Business Days after the later of:

(a) the date of notification described in clause 2.34.3; and

(b) if IMO makes a request under clause 2.34.6, the date on which the information requested is received by the IMO.

2.34.12. The IMO must consult with System Management before making a decision requiring a Rule Participant to provide updated Standing Data under clause 2.34.11, excluding any Standing Data described in the following clauses of Appendix 1:

(a) [Blank]

(b) [Blank]

(c) clause (h)(vi);

(d) ~~clause (i)(xA);~~[Blank]

(e) clause (k)(i)(7);

(f) [Blank]

(g)~~.~~ clause (l)(iii)(4);

(h) clause (l)(iii)(5); and

(i) clause (m).

2.34.14. The IMO must commence using revised Standing Data from:

(a) 8:00 AM on the Scheduling Day following the IMO's acceptance of the revised Standing Data in the case of:

i. Standing STEM Submissions;

iA. Standing Bilateral Submissions;

~~iB. Standing Resource Plan Submissions;~~

ii. ~~Consumption Increase Prices and~~ Consumption Decrease Prices; and

iii. Standing Data changes stemming from acceptance of an application under clause 6.6.9,

with the exception that the previous Standing Data remains current for the purpose of settling the Trading Day that commences at the same time as that Scheduling Day; and

(b) as soon as practicable in the case of any other revised Standing Data.

2.35.1. Market Participants with Scheduled Generators, Non-Scheduled Generators~~, Dispatchable Loads~~ and Demand Side Programmes that are not under the direct control of System Management must maintain communication systems that enable communication with System Management for dispatch of those Registered Facilities.

2.36.1. Where the IMO uses software systems to determine ~~Balancing~~ Energy Prices, to determine ~~Non-Balancing Facility~~ Non-REM Dispatch Instruction Payments, to determine LFAS Prices, in the Reserve Capacity Auction, in the STEM Auction or for settlement processes, it must:

(a) maintain a record of which version of software was used in producing each set of results, and maintain records of the details of the differences between each version and the reasons for the changes between versions;

(b) maintain each version of the software in a state where results produced with that version can be reproduced for a period of at least ~~1~~ one year from the release date of the last results produced with that version;

(c) ensure that appropriate testing of new software versions is conducted;

(d) ensure that any versions of the software used by the IMO have been certified as being in compliance with the Market Rules by an independent auditor; and

(e) require vendors of software audited in accordance with clause 2.36.1(d) to make available to Rule Participants explicit documentation of the functionality of the software adequate for the purpose of audit.

2.37.5. When determining a Market Participant's Credit Limit the IMO must take into account:

…

(e) the Market Participant's historical level of Balancing ~~settlement~~ Settlement payments under clause 9.8.1, or an estimate of the Market Participant's future level of Balancing ~~settlement~~ Settlement payments based on its

expected transactions in the ~~Balancing Market~~ REM where no historical Balancing ~~settlement~~ Settlement payment data is available;

…

3.2.5. The Technical Envelope represents the limits within which the SWIS can be operated in each SWIS Operating State. In establishing and modifying the Technical Envelope under clause 3.2.6, System Management must:

(a) respect all Equipment Limits but only to the extent those limits are not inconsistent with the dispatch of ~~Balancing~~ REM Facilities that, but for the Equipment Limits, would be dispatched under clause 7.6.1C;

(b) respect all Security Limits;

(c) respect all SWIS Operating Standards;

(d) respect all Ancillary Service standards specified in clause 3.10; and

(e) take into account those parts of the SWIS which are not designed to be operated to the planning criteria in the relevant Technical Code.

3.3.2. When the SWIS is in a Normal Operating State, System Management must:

(a) not require a Registered Facility to be operated inconsistently with:

i. the Security Standards; or

ii. its Equipment Limits but only to the extent those limits are not inconsistent with the dispatch of ~~Balancing~~ REM Facilities that, but for the Equipment Limits, would be dispatched under clause 7.6.1C, for the Normal Operating State;

(b) not utilise the overload capacity of Scheduled Generators (as indicated in Standing Data);

(c) schedule and dispatch Ancillary Services in accordance with the Ancillary Service Requirements;

(d) subject to clause 3.19, accept applications for the scheduling of outages unless System Management considers that these would endanger Power System Security or Power System Reliability; and

(e) not take any actions that in its opinion would be reasonably likely to lead to a High-risk Operating State.

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.

~~(c) [Blank]~~

3.9.6. Load Rejection Reserve Service is the service of holding capacity associated with a Scheduled Generator ~~or Dispatchable Load~~ in reserve so that~~:~~ the Scheduled Generator can reduce output rapidly in response to a sudden decrease in SWIS load.

~~(a) the Scheduled Generator can reduce output rapidly; or~~

~~(b) the Dispatchable Load can increase consumption rapidly,~~

~~in response to a sudden decrease in SWIS load.~~

3.13.2. Payments for usage of Ancillary Services are achieved through the operation of the ~~Balancing mechanism~~ Ancillary Service settlement process, and no additional payments will be due by the IMO to System Management for the use of Ancillary Services.

3.13.3A. ~~Subject to clause 3.13.3AB, for~~ For each Financial Year, by 31 March prior to the start of that Financial Year, the Economic Regulation Authority must determine values for the parameters Margin_Peak and Margin_Off-Peak, taking into account the Wholesale Market Objectives and in accordance with the following:

...

~~3.13.3AB. During the period:~~

~~(a) from 8:00 AM on the Balancing Market Commencement Day to 8:00 AM on 1 July 2013:~~

~~i. the Margin_Peak value is, subject to clause 3.13.3AB(b), the value determined by the Economic Regulation Authority and published on the Market Web Site; and~~

~~ii. the Margin_Off-Peak value is, subject to clause 3.13.3AB(b), the value determined by the Economic Regulation Authority and published on the Market Web Site;~~

~~(b) if the Economic Regulation Authority has not determined a Margin_Peak or Margin_Off-Peak value under clause 3.13.3AB(a) by 8:00 AM on the Balancing Market Commencement Day, then any such value is to be the value determined by the IMO and published on the Market Web Site as soon as reasonably practicable after the Balancing Market Commencement Day;~~

~~(c) in determining values for Margin_Peak and Margin_Off-Peak under clause 3.13.3AB(a) the Economic Regulation Authority must undertake a public consultation process, which must include publishing an issues paper and issuing an invitation for public submissions;~~

~~(d) when determining a value for the parameter Margin_Peak under this clause 3.13.3AB the Economic Regulation Authority or the IMO, as applicable, must take account of~~

~~i. the margin Synergy could reasonably have been expected to earn on energy sales foregone due to the supply of Spinning Reserve during Peak Trading Intervals; and~~

~~ii. the loss in efficiency of Synergy's Scheduled Generators that System Management has scheduled to provide Spinning Reserve during Peak Trading Intervals that could reasonably be expected due to the scheduling of those reserves; and~~

~~(e) when determining a value for the parameter Margin_Off-Peak under this clause 3.13.3AB the Economic Regulation Authority or the IMO, as applicable, must take account of:~~

~~i. the margin Synergy could reasonably have been expected to earn on energy sales foregone due to the supply of Spinning Reserve during Off-Peak Trading Intervals; and~~

~~ii. the loss in efficiency of Synergy's Scheduled Generators that System Management has scheduled to provide Spinning Reserve during Off-Peak Trading Intervals that could reasonably be expected due to the scheduling of those reserves.~~

The amendments to clauses 3.18.2A and 3.19.2 and the addition of new clause 3.19.4A reflect the proposed amendments in the Rule Change Proposal: Outage Planning Phase 2 – Outage Process Refinements (RC_2013_15). This proposal (RC_2014_01) additionally updates market names and moves the proposed deadline for Planned Outage notices from 30 minutes before REM Gate Closure to 90 minutes before LFAS Gate Closure.

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 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 10:00 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 90 minutes before LFAS 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.

3.19.2. 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. 10:00 AM on the day prior to the Scheduling Day for the Trading Day in which the requested outage is due to commence; and

ii. 90 minutes before LFAS 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.~~

3.19.4A. 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 90 minutes before LFAS 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.

4.1.26. Reserve Capacity Obligations apply:

(a) in the case of the first Reserve Capacity Cycle:

i. from the Initial Time, for Facilities that were commissioned before Energy Market Commencement;

ii. from the Trading Day commencing on the scheduled date of commissioning, as specified in accordance with clause 4.10.1(c)(iii)(7), for Scheduled Generators and Non-Scheduled Generators commissioned between Energy Market Commencement and 30 November 2007, inclusive; and

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

…

4.8.1. Subject to clause 4.8.2, a Market Participant may apply for certification of the amount of Reserve Capacity which can be provided by a Facility if:

(a) the Facility is a Registered Facility other than a Network or Interruptible Load; or

(b) the Facility is not a Registered Facility but the Market Participant intends to have the Facility registered as a Registered Facility other than a Network or Interruptible Load by the commencement date of the Reserve Capacity Obligations for the relevant Reserve Capacity Cycle as specified in clause 4.1.26.

The amendments to clause 4.10.1 reflect the proposed amendments in the Final Rule Change Report for the Rule Change Proposal: Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10). This proposal (RC_2014_01) additionally updates market names and removes references to Dispatchable Loads and Interruptible Loads.

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

…

(c) if the Facility, or part of the Facility, is yet to enter service:

i. [Blank]

ii. with the exception of applications for Conditional Certified Reserve Capacity, evidence that any necessary Environmental Approvals have been granted or evidence supporting the Market Participant's expectation that any necessary Environmental Approvals will be granted in time to have the Facility meet its Reserve Capacity Obligations by the date specified in clause 4.10.1(c)(iii)(7); and

iii. the Key Project Dates occurring after the date the request is submitted, including, if applicable, but not limited to:

1. when all approvals will be finalised or, in the case of ~~Interruptible Loads and~~ Demand Side Programmes, all required contracts will be in place;

2. when financing will be finalised;

3. when site preparation will begin;

4. when construction will commence;

5. when generating equipment ~~or Dispatchable Load equipment~~ will be installed or, in the case of ~~Interruptible Loads and~~ Demand Side Programmes, all required control equipment will be in place;

6. when the Facility, or part of the Facility, will be ready to undertake Commissioning Tests; and

7. when the Facility, or part of the Facility, will have completed all Commissioning Tests and be capable of meeting Reserve Capacity Obligations in full;

(d) if the Facility is a Registered Facility that will be decommissioned prior to the date specified in clause 4.1.30(a) for the Reserve Capacity Cycle to which the application relates, the planned decommissioning date;

(dA) a description and a configuration of the main components of the Facility;

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

…

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

1. where the Facility has primary and alternative fuels:

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

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

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

vi. the expected forced and unforced outage rate based on manufacturer data; and

vii. for Facilities that have operated for at least 12 months, the forced and unforced outage rate of the Facility;

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

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

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

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

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

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

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

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

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

(g) for all Facilities:

i. any restrictions on the availability of the Facility due to staffing constraints; and

ii. any other restrictions on the availability of the Facility;

…

(l) for a~~ Balancing~~ REM Facility, evidence of the extent to which the Facility will meet the applicable criteria of the~~ Balancing~~ REM Facility Requirements.

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

…

(c) the IMO must not assign Certified Reserve Capacity to a Facility for a Reserve Capacity Cycle if:

i. for Reserve Capacity Cycles up to and including 2009 that Facility is not operational or is not scheduled to commence operation for the first time so as to meet its Reserve Capacity Obligations by 30 November of Year 3 of that Reserve Capacity Cycle;

ii. for Reserve Capacity Cycles from 2010 onwards that Facility is not operational or is not scheduled to commence operation for the first time so as to meet its Reserve Capacity Obligations by 1 October of Year 3 of that Reserve Capacity Cycle;

iii. that Facility will cease operation permanently, and hence cease to meet Reserve Capacity Obligations, from a time earlier than 1 August of Year 4 of that Reserve Capacity Cycle; or

iv. that Facility already has Capacity Credits assigned to it under clause 4.28C for the Reserve Capacity Cycle; ~~or~~

~~v. that Facility is an Interruptible Load and, based on applications accepted under clauses 2.29.5D and 2.29.5K (as applicable), the Facility will be associated with a Demand Side Programme for any period when Reserve Capacity Obligations would apply for the Facility for the Reserve Capacity Cycle;~~

…

The amendments to clause 4.11.4 reflect the proposed amendments in the Final Rule Change Report for the Rule Change Proposal: Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10). This proposal (RC_2014_01) additionally removes references to Dispatchable Loads and Interruptible Loads.

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

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

(b) Availability Class 2 otherwise.

4.11.12. The IMO must not assign Certified Reserve Capacity to a ~~Balancing~~ REM Facility with a rated capacity equal to or greater than 10MW unless the IMO is satisfied the Facility is likely to be able to meet the ~~Balancing~~ REM Facility Requirements.

4.12.1. The Reserve Capacity Obligations of a Market Participant holding Capacity Credits are as follows:

(a) a Market Participant ~~(other than Synergy)~~ must ensure that for each Trading Interval:

i. the aggregate MW equivalent of the quantity of Capacity Credits held by the Market Participant applicable in that Trading Interval for ~~Interruptible Loads and~~ Demand Side Programmes registered to the Market Participant; plus

ii. the MW quantity calculated by doubling ~~the net MWh quantity of energy to be sent out during~~ the Market Participant's Net Contract Position in MWh for the Trading Interval, corrected for loss factor adjustments so as to be a sent out quantity ~~by Facilities registered by that Market Participant~~; plus

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

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

iv. capacity expected to experience a Forced Outage at the time that STEM submissions were due which becomes available in real time,

is not less than the total Reserve Capacity Obligation Quantity for that Trading Interval for Facilities registered to the Market Participants, less double the total MWh quantity to be provided as Ancillary Services as specified by the IMO for that Market Participant in accordance with clause 6.3A.2(e)(i).

(b) ~~Synergy must ensure that for each Trading Interval:~~

~~i. the aggregate MW equivalent of the quantity of Capacity Credits held by Synergy applicable in that Trading Interval for Interruptible Loads and Demand Side Programmes registered to it; plus~~

~~ii. the MW quantity calculated by doubling the total MWh quantity which Synergy is selling to other Market Participants as indicated by the applicable Net Contract Position of Synergy, corrected for loss factor adjustments so as to be a sent out quantity; plus~~

~~iii. the MW quantity calculated by doubling the total MWh quantity covered by STEM Offers which were not scheduled and the STEM Bids which were scheduled in the relevant STEM Auction determined by the IMO for Synergy clause 6.9 for that Trading~~

~~Interval, corrected for loss factor adjustments so as to be a sent out quantity; plus~~

~~iv. capacity expected to experience a Forced Outage at the time that STEM submissions were due which becomes available in real time,~~

~~is not less than the total Reserve Capacity Obligation Quantity for Synergy for that Trading Interval, less double the total MWh quantity to be provided as Ancillary Services as specified by the IMO for Synergy in accordance with clause 6.3A.2(e)(i).~~[Blank]

(c) the Market Participant must make the capacity associated with the Capacity Credits provided by a Facility applicable to a Trading Interval, up to the Reserve Capacity Obligation Quantity for the Facility for that Trading Interval, available for dispatch by System Management in accordance with Chapter 7.

The amendments to clause 4.12.4 reflect the proposed amendments in the Final Rule Change Report for the Rule Change Proposal: Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10). This proposal (RC_2014_01) additionally removes references to Dispatchable Loads and Interruptible Loads.

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

…

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

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

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

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

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

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

4.18.1. A Market Participant must ensure that its Reserve Capacity Offers include the following information:

(a) the identity of the Market Participant submitting the Reserve Capacity Offer;

(b) the identify of the Market Participant's Facility covered by the Reserve Capacity Offer; and

(c) for ~~Interruptible Loads,~~ Demand Side Programmes ~~and Dispatchable Loads~~, a single Price-Quantity Pair for each block of Certified Reserve Capacity associated with the Facility; and

(d) for every other Facility, a single Price-Quantity Pair for each Facility.

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 the Maximum Reserve Capacity Price;

(c) a quantity in units of MW equal to the amount determined in accordance with clause 4.14.10 in respect of that Facility; and

(d) if the Facility is ~~an Interruptible Load,~~ a Demand Side Programme ~~or Dispatchable Load~~, the Availability Class of that Price-Quantity Pair, as specified by the IMO in assigning Certified Reserve Capacity to that Facility in accordance with clause 4.11.

4.25.2. The verification referred to in clause 4.25.1 can be achieved by the IMO:

(a) in the case of a generation system:

i. observing the Facility operate at a level equivalent to its Required Level, adjusted to the level of Capacity Credits currently held, at least once as part of normal market operations as determined from Meter Data Submissions; or

ii. requiring System Management, in accordance with clause 4.25.7, to test the Facility's ability to operate at a level equivalent to its Required Level, adjusted to the level of Capacity Credits currently held, for not less than two Trading Intervals and the Facility successfully passing that test; or

(b) in the case of a Demand Side Programme:

i. observing the Facility operate at a level equivalent to its Required Level, adjusted to the level of Capacity Credits currently held, at least once in response to an activation of the Facility by the relevant Market Customer as measured in metered consumption; or

ii. requiring System Management, in accordance with clause 4.25.7, to test the Facility's ability to reduce demand to a level equivalent to its Required Level, adjusted to the level of Capacity Credits currently held, for not less than one Trading Interval and the Facility successfully passing that test~~; or~~.

~~(c) in the case of an Interruptible Load or Dispatchable Load, requiring System Management, in accordance with clause 4.25.7, to test the Facility's ability~~

~~to reduce demand to a level equivalent to its Required Level, adjusted to the level of Capacity Credits currently held, for not less than one Trading Interval and the Facility successfully passing that test.~~

4.25.4. Subject to clause 4.25.3B, if a Facility fails a Reserve Capacity Test requested by the IMO under clause 4.25.2, the IMO must require System Management to re-test that Facility in accordance with clause 4.25.2, not earlier than 14 days and not later than 28 days after the first Reserve Capacity Test. If the Facility fails this second Reserve Capacity Test, then the IMO must, from the second Trading Day following the Scheduling Day on which the IMO determines that the second Reserve Capacity Test was failed:

(a) if the Reserve Capacity Test related to a generation system, reduce the number of Capacity Credits held by the relevant Market Participant for that Facility to reflect the maximum capabilities achieved in either Reserve Capacity Test performed (after adjusting these results to the equivalent values at a temperature of 41^{o}C and allowing for the capability provided by operation on different types of fuels); or

(b) if the Reserve Capacity Test related to a ~~Dispatchable Load,~~ Demand Side Programme ~~or Interruptible Load~~, reduce the number of Capacity Credits held by the relevant Market Participant for that Facility to the maximum level of reduction achieved in either of the two Reserve Capacity Tests.

4.25.9. In conducting a Reserve Capacity Test, System Management must:

(a) subject to clauses 4.25.9(b), 4.25.9(c) and 4.25.9(d), endeavour to conduct the Reserve Capacity Test without warning;

(b) allow sufficient time for the Market Participant to schedule fuel that it is not required under these Market Rules to be stored on-site;

(c) allow sufficient time for switching a Facility from one fuel to an alternative fuel if operation using the alternative fuel is being tested;

(d) in the case of ~~an Interruptible Load or~~ a Demand Side Programme, give at least as much notice as is specified under clause 4.10.1(f)(v) to allow for arrangements to be made for the Facility to be triggered;

(e) report to the IMO whether the Reserve Capacity Test was successfully performed;

(f) maintain adequate records of the Reserve Capacity Test to allow independent verification of the test results;

(g) conduct the Reserve Capacity Test in the time interval specified by the IMO in accordance with clause 4.25.7(c) unless System Management has notified the IMO of an alternative time interval in accordance with clause 4.25.8, in which case, System Management must conduct the Reserve Capacity Test in the time interval specified in accordance with clause 4.25.8(b); and

(h) issue an Operating Instruction to increase the Facility's output or decrease its consumption to a level specified by, or referred to in, the Operating Instruction.

The amendments to clause 4.26.2 reflect the proposed amendments in the Final Rule Change Report for the Rule Change Proposal: Incentives to Improve Availability of Scheduled Generators (RC_2013_09). This proposal (RC 2014_01) additionally changes the CAPA calculation for IPPs to be the same as that used for Synergy.

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

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

Where:

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

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

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

(b) the sum of the product of:

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

ii. the Reserve Capacity Obligation Quantity for each Facility,

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

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

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

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

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

ii. the MW quantity calculated by doubling ~~the net MWh quantity of energy sent out by Facilities registered by~~ that Market Participant's ~~during that Trading Interval calculated as the~~ Net Contract Position in MWh for Trading Interval t,

corrected for Loss Factor adjustments so as to be a sent out quantity in accordance with clause 4.26.2A ~~less the shortfall as indicated by the applicable Resource Plan~~; plus

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

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

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

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

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

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

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

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

~~iv. double the total MWh quantity to be provided as Ancillary Services as specified by the IMO in accordance with clause~~

~~6.3A.2(e)(i) for Synergy corrected for Loss Factor adjustments so as to be a sent out quantity in accordance with clause 4.26.2A; plus~~

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

RCDF(p,d,t) = RTFO(p,d,t) + RTNREPO(p,d,t);

RTNREPO(p,d,t) = Sum (f∈F, Max(0, NREPO(f,d,t) – BSPO(f,d,t));

NREPO(f,d,t) is the total MW quantity of Refund Payable Planned Outage associated with Facility f for Trading Interval t of Trading Day d;

BSPO(f,d,t) is the total MW quantity of Planned Outage associated with Facility f before the STEM Auction for Trading Interval t of Trading Day d, as provided to the IMO by System Management in accordance with clause 7.3.4;

F denotes the set of Scheduled Generators registered by Market Participant p, where "f" is used to refer to a member of that set;

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

RTFO(p,d,t) is the total MW quantity of Forced Outage associated with Market Participant p in real-time for Trading Interval t of Trading Day d, where this is the sum over all the Market Participant's Registered Facilities of the lesser of the Reserve Capacity Obligation Quantity of the Facility for Trading Interval t and the MW Forced Outage of the Facility for Trading Interval t as provided to the IMO by System Management in accordance with clause 7.13.1A(b).

4.26.2B. The IMO is to set the factor described in the definition of RCOQ(p,d,t) and RCOQ(f,d,t) in clause 4.26.2 to equal one in all situations except for Scheduled Generators~~,~~ and Non-Scheduled Generators ~~and Dispatchable Loads~~ with Loss Factors less than one in which event the factor must equal the facilities Loss Factor.

6.3A.2. By 9:00 AM on the Scheduling Day the IMO must have calculated and released to each Market Participant the following parameters to be applied by that Market Participant in forming its STEM Submissions for each Trading Interval in the Trading Day:

…

(b) the Maximum Consumption Capability where this equals the maximum Loss Factor adjusted quantity of energy, in units of MWh, that could be consumed during a Trading Interval by that Market Participant's Non-

Dispatchable Loads~~,~~ and Interruptible Loads ~~and Dispatchable Loads~~ based on the Standing Data maximum consumption quantities for those Facilities ~~and Non-Dispatchable Loads~~, less an allowance for outages of which the IMO has been made aware by System Management in accordance with clauses 7.3.4 or 7.3.6;

…

6.4.5. If the IMO becomes aware that a Market Participant has been unable to access the information described in clause 6.4.3 for a Trading Day by 10:45 AM of the relevant Scheduling Day, it must use reasonable endeavours to contact the affected Market Participant to ensure that at least the information in clauses 6.4.3(c) and 6.4.3(d) is conveyed to the Market Participant ~~in sufficient time for that Market Participant to make a Resource Plan Submission where required~~ as soon as practicable.

6.5. ~~Resource Plan Submission Timetable and Process~~[Blank]

~~6.5.1. Market Participants, including Synergy but only in respect of its Stand Alone Facilities, may submit Resource Plan Submission data for a Trading Day to the IMO between:~~

~~(a) 11:00 AM on the Scheduling Day, with the exception that if the IMO has delayed any timelines in accordance with clause 6.4.6, the IMO may at its discretion extend this time up to 1:00 PM on the Scheduling Day; and~~

~~(b) 12:50 PM on the Scheduling Day, with the exception that if:~~

~~i. a software system failure at the IMO site has prevented any Market Participant from submitting a Resource Plan; or~~

~~ii. a software system failure at a Market Participant site has prevented that Market Participant from submitting a Resource Plan and that Market Participant has informed the IMO of this failure by 12:30 PM on the Scheduling Day; or~~

~~iii. the opening time for Resource Plan Submissions was delayed,~~

~~the IMO may at its discretion extend the closing time up to 3:00 PM on the Scheduling Day.~~

~~6.5.1A. Market Generators with Registered Facilities, including Synergy but only in respect of its Stand Alone Facilities, that are not undergoing a Commissioning Test or Market Customers with Dispatchable Loads, must provide the IMO with a Resource Plan Submission by:~~

~~(a) submitting Resource Plan Submissions; or~~

~~(b) in accordance with clause 6.5.1B.~~

~~6.5.1B. Where the IMO holds a Standing Resource Plan Submission for a Market Participant as at the time specified in clause 6.5.1(a) where that Standing Resource Plan Submission is applicable to the Trading Day to which clause 6.5.1~~

relates then, provided that Standing Resource Plan Submission data is accepted by the IMO in accordance with clause 6.5.2, it becomes the Resource Plan Submission with respect to the Trading Day as at the time specified in clause 6.5.1(a).

6.5.2. When the IMO receives Resource Plan Submission data from a Market Participant during the time interval described in clause 6.5.1 it must as soon as practicable communicate to that Market Participant whether or not the IMO accepts the data as conforming to the requirements of clause 6.11.2. Where the IMO accepts the data then the IMO must revise the Resource Plan Submission to reflect that data.

6.5.3. Where the IMO has issued a Market Advisory concerning an IT systems failure at the IMO, the IMO may accept Resource Plan submissions from Market Participants by email or facsimile, where this is in accordance with the applicable Contingency Market Procedure.

6.5.3A. Where clause 6.5.3 applies, the times at which a Market Participant may make a submission will remain in accordance with clause 6.5.1.

6.5.4. If the IMO has not accepted a Resource Plan Submission for a Trading Day by the closing time specified in clause 6.5.1(b) from a Market Participant that is required to make a Resource Plan Submission, then the IMO must prepare a default Resource Plan for that Market Participant which must include, for each Trading Interval on the Trading Day:

(a) in respect of a Market Participant (other than Synergy in relation to its Stand Alone Facilities):

i. all the Market Participant's Scheduled Generators and Non-Scheduled Generators having a scheduled output of zero;

ii. all Dispatchable Loads having a scheduled consumption of zero; and

iii. the level of the supply shortfall required pursuant to clause 6.11.1(e) equal to the total Net Contract Position; or

(b) in respect of all of Synergy's Stand Alone Facilities, having a scheduled output of zero.

6.5A. [Blank]

6.5B. [Blank]

6.5C. Standing Resource Plan Submission Timetable and Process

6.5C.1. All references to a Market Participant in this clause 6.5C include Synergy, but only in respect of its Stand Alone Facilities.

6.5C.1A. A Market Participant may submit Standing Resource Plan Submission data on any day between the times of:

~~(a) 1:00 PM; and~~

~~(b) 3:50 PM,~~

~~where, if accepted by the IMO, the data will apply from the commencement of the subsequent Scheduling Day.~~

~~6.5C.2. When the IMO receives Standing Resource Plan data from a Market Participant during the time interval described in clause 6.5C.1A, it must as soon as practicable:~~

~~(a) communicate to that Market Participant whether or not the IMO accepts the received data as conforming to the requirements of clause 6.11.2; and~~

~~(b) where the IMO accepts the data then the IMO must revise the Standing Resource Plan Submission to reflect that data.~~

~~6.5C.3. Standing Resource Plan Submission data must be associated with a day of the week and when used as a Resource Plan Submission will only apply to Trading Days commencing on that day of the week.~~

~~6.5C.4. A Market Participant may cancel Standing Resource Plan Submission data held by the IMO for any Trading Interval of the Trading Day during the time interval specified in clause 6.5C.1.~~

~~6.5C.5. The IMO must confirm to the Market Participant any cancellation of Standing Resource Plan Submission data made in accordance with clause 6.5C.4. Where such cancellation is made then the IMO must remove the relevant data from the Resource Plan Submission.~~

~~6.5C.6. If a Market Participant's ability to consume or supply energy in any Trading Interval of a Trading Day is less than the maximum level of its consumption or supply as indicated by its Standing Resource Plan Submission then that Market Participant must either:~~

~~(a) submit to the IMO Standing Resource Plan Submission data so as to revise its Standing Resource Plan Submission to comply with this clause 6.5C.6; or~~

~~(b) for each Trading Interval for which the Standing Resource Plan Submission over-states the Market Participant's consumption or supply capabilities, submit valid Resource Plan Submission data to the IMO on the Scheduling Day immediately prior to that Trading Day.~~

~~6.5C.7. [Blank]~~

6.6.9. A Market Generator may apply to the IMO for all or part of the capacity of one of its Scheduled Generators that is not Liquid Fuel capable to be treated as if it was dual-fuel capable where one fuel is Liquid Fuel for the purposes of the STEM, ~~Balancing~~ the REM and ~~Settlement~~ settlement. The Market Generator must submit to the IMO an application in a form specified by the IMO, including

supporting evidence of the relevant arrangements, and specifying the dates over which the application will apply.

~~Resource Plans~~

6.11. ~~Format of Resource Plans~~[Blank]

~~6.11.1. A Market Participant submitting Resource Plan Submission data or Standing Resource Plan Submission data must ensure the submission is made in the form and manner prescribed and published by the IMO and include in the submission:~~

~~(a) the sum of the expected Loss Factor adjusted output of each of its Non-Scheduled Generators, in MWh, for each Trading Interval in the Trading Day;~~

~~(aA) [Blank]~~

~~(b) in respect of each Scheduled Generator and Dispatchable Load registered by the Market Participant:~~

~~i. the name of the Facility;~~

~~ii. for a Scheduled Generator, the intended times of synchronisation and de-synchronisation, expressed to the nearest minute, during the Trading Day;~~

~~iii. the target energy, in MWh, to be sent-out or consumed during each Trading Interval of the Trading Day included in the submission where this amount:~~

~~1. must be zero if the Facility is expected not to operate during the Trading Interval; and~~

~~2. must not exceed the expected capability of the Facility at that time, allowing for de-ratings and outages;~~

~~iv. the Ramp Rate Limit, for each Trading Interval; and~~

~~v. the target MW level, which must be consistent with the Ramp Rate Limit, that each Facility must achieve and continue to operate at until the end of each Trading Interval included in the submission;~~

~~(c) [Blank]~~

~~(d) the total Loss Factor adjusted demand, in MWh, to be consumed by that Market Participant for each Trading Interval excluding demand associated with any Dispatchable Load;~~

~~(dA) the end of Trading Interval MW level of demand resulting from the demand in clause 6.11.1(d); and~~

~~(e) other than for Synergy, 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.~~

6.11.2. For Resource Plan Submission data or Standing Resource Plan Submission data to be valid:

(a) it must conform to the form specified by the IMO under clause 6.11.1;

(aA) 48 Trading Intervals of data must be submitted for each Trading Day;

(b) it must only include Facilities registered by the submitting Market Participant;

(bA) it must not include a generator for any Trading Interval if that generator is undergoing a Commissioning Test during that Trading Interval; and

(c) [Blank]

(d) it must meet the requirements of clause 6.11.3.

6.11.3. A Market Participant, other than Synergy, must ensure that either:

(a) $Target_{LFA}$ = (NCP + DQ – NonSchGen – Shortfall) ± Tol

Where:

$Target_{LFA}$ = the sum of the Loss Factor adjusted energy quantities, in MWh, submitted by the Market Participant under clause 6.11.1(b)(iii)

NCP = the Net Contract Position

DQ = the demand quantity, in MWh, provided by the Market Participant in accordance with clause 6.11.1(d)

NonSchGen = the amount, in MWh, provided by the Market Participant under clause 6.11.1(a)

Shortfall = the amount, in MWh, provided by the Market Participant under clause 6.11.1(e)

Tol = min(3MWh, max(0.5, 3% of NCP));

or

(b) $Target\ MW_{LFA}$ = (NCP – NonSchGen – Shortfall) * 2+DQ ± Tol

Where:

$Target\ MW_{LFA}$ = the sum of the Loss Factor adjusted MW quantities provided by the Market Participant under clause 6.11.1(b)(v)

NCP = Net Contract Position

DQ = the demand quantity in MW provided by the Market Participant in accordance with clause 6.11.1(dA)

NonSchGen = the amount provided by the Market Participant under clause 6.11.1(a)

Shortfall = the amount provided by the Market Participant under clause 6.11.1(e)

Tol = min(6MW, max(1, 3% of NCPx2)).

The ~~Non-Balancing~~ Non-REM Dispatch Merit Order

6.12. The ~~Non-Balancing~~ Non-REM Dispatch Merit Order

The amendments to clause 6.12.1, the renumbering of the clause to 6.12.1A and the insertion of a new clause 6.12.1 reflect the proposed amendments in the Final Rule Change Report for the Rule Change Proposal: Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10). This proposal (RC_2014_01) additionally updates market names, removes the reference to the extension of the Resource Plan window closing time and removes the requirements for merit orders specific to Dispatchable Loads.

6.12.1. System Management must provide to the IMO, by 6:30 PM on the Scheduling Day, a schedule detailing all of the Dispatch Instructions that System Management issued for each Trading Interval occurring in the period 8:00 AM to 6:00 PM during the Scheduling Day for any Demand Side Programme.

6.12.1A.

(a) By ~~1:30~~ 8:00 PM on the Scheduling Day ~~(or within 40 minutes of a closing time extended in accordance with clause 6.5.1(b))~~ the IMO must determine the ~~Non-Balancing~~ Non-REM Dispatch Merit ~~Orders identified in clauses 6.12.1(b) to 6.12.1(e)~~ Order for the Trading Day. ~~A Non-Balancing~~ The Non-REM Dispatch Merit Order:

i. lists the order in which the ~~Dispatchable Loads and~~ Demand Side Programmes of Market Participants will be issued Dispatch Instructions by System Management under clause 7.6.1C(d) to ~~increase or~~ decrease consumption~~, as applicable.~~; and

ii. provides for each Facility in the list in clause 6.12.1A(a)(i) the Reserve Capacity Obligation Quantity determined in accordance with clause 4.12.4(c).

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

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

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

1. Registered Facilities with a Reserve Capacity Obligation Quantity greater than zero in that Trading Interval ranked in

increasing order of the Facility's Consumption Decrease Price applicable to that Trading Interval; followed by

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

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

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

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

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

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

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

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

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

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

(f) Where the prices described in Standing Data for two or more Registered Facilities are equal, then, for the purposes of determining the ranking in ~~any Non-Balancing~~ the Non-REM Dispatch Merit Order, the IMO must rank those ~~a~~ Registered Facilit~~y~~ies in decreasing order of the time since the

Facility's consumption was last reduced in response to a Dispatch Instruction ~~with a greater load registered in Standing Data in items (h)(iii) or (i)(iii) of Appendix 1 before a Registered Facility with a lesser load~~. In the event of a tie, the IMO will randomly assign priority to break the tie.

~~Balancing Pricing~~ Real-Time Dispatch Prices and Quantities

6.13. ~~Real Time~~ Real-Time Dispatch Information

6.15.1. The Maximum Theoretical Energy Schedule in a Trading Interval is:

(a) for a ~~Balancing~~ REM Facility which is a Scheduled Generator:

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

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

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

(b) for a ~~Balancing~~ REM Facility which is a Non-Scheduled Generator:

i. if the Loss Factor Adjusted Price of the ~~Balancing Price Quantity Pair~~ REM Price-Quantity Pair in respect of the ~~Balancing~~ REM Facility is less than or equal to the ~~Balancing~~ Energy Price, then the Sent Out Metered Schedule as determined in accordance with clause 6.15.3(a)(i); and

ii. otherwise the minimum amount of sent out energy, in MWh, which the ~~Balancing~~ REM Facility could have generated in the Trading Interval if the Facility had been dispatched downwards at its Ramp Rate Limit from its SOI Quantity; or

(c) for the ~~Balancing~~ Synergy Portfolio:

i. the maximum amount of sent out energy, in MWh, which could have been dispatched in the Trading Interval from ~~Balancing~~ REM Price-Quantity Pairs ~~within~~ in respect of the ~~Balancing~~ Synergy Portfolio ~~Supply Curve~~ with an associated price less than or equal to the ~~Balancing~~ Energy Price; plus

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

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

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

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

i. the sum of:

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

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

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

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

(b) for a ~~Balancing~~ REM Facility which is a Non-Scheduled Generator:

i. if a Dispatch Instruction was issued to the ~~Balancing~~ REM Facility to decrease its output and the Loss Factor Adjusted Price of the ~~Balancing~~ REM Price-Quantity Pair in respect of the ~~Balancing~~ REM Facility is less than the ~~Balancing~~ Energy Price, then System Management's estimate of the maximum amount of sent out energy, in MWh, which the ~~Balancing~~ REM Facility would have generated in the Trading Interval had the Dispatch Instruction not been issued; and

ii. otherwise the Sent Out Metered Schedule for the Facility as determined in accordance with clause 6.15.3(a)(i); or

(c) for the ~~Balancing~~ Synergy Portfolio, the amount which is the lesser of:

i. the sum of:

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

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

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

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

6.16.1A. For the purposes of clauses 6.16A and 6.16B, Sent Out Metered Schedules for a ~~Balancing~~ REM Facility are to be calculated by the IMO.

6.16A.1. The Upwards Out of Merit Generation in a Trading Interval for a ~~Balancing~~ REM Facility equals:

(a) subject to clause 6.16A.1(b), the Sent Out Metered Schedule less the Maximum Theoretical Energy Schedule; or

(b) zero where:

i. System Management has provided a report to the IMO under clause 7.10.7 and the IMO determines that the relevant Market Participant has not adequately or appropriately complied with a Dispatch Instruction in respect of the Facility;

ii. the Facility was undergoing a Test or complying with an Operating Instruction; or

iii. the Sent Out Metered Schedule less the Maximum Theoretical Energy Schedule is less than the sum of:

1. any Upwards LFAS Enablement and, if the Facility is a Stand Alone Facility, any ~~Upwards~~ Backup Upwards LFAS Enablement, which the Facility was instructed by System Management to provide, divided by two so that it is expressed in MWh; and

2. the applicable Settlement Tolerance.

6.16A.2. The Downwards Out of Merit Generation in a Trading Interval for a ~~Balancing~~ REM Facility equals:

(a) subject to clause 6.16A.2(b), the Minimum Theoretical Energy Schedule less the Sent Out Metered Schedule; or

(b) zero if:

i. System Management has provided a report to the IMO under clause 7.10.7 and the IMO determines that the relevant Market Participant has not adequately or appropriately complied with a Dispatch Instruction in respect of the Facility;

ii. the Facility was undergoing a Test or complying with an Operating Instruction;

iii. the Minimum Theoretical Energy Schedule less the Sent Out Metered Schedule is less than the sum of:

1. any Downwards LFAS Enablement and, if the Facility is a Stand Alone Facility, any ~~Downwards~~ Backup Downwards LFAS Enablement, which the Facility was instructed by System Management to provide, divided by two so that it is expressed in MWh; and

2. the applicable Settlement Tolerance; or

iv. the ~~Balancing~~ REM Facility is a Non-Scheduled Generator and System Management has not provided the IMO with a MWh quantity for the Facility and the Trading Interval under clause 7.13.1(eF).

6.16B. ~~Balancing~~ Synergy Portfolio Out of Merit

6.16B.1. The Portfolio Upwards Out of Merit Generation in a Trading Interval for the ~~Balancing~~ Synergy Portfolio equals:

(a) subject to clause 6.16B.1(b), the sum of any Sent Out Metered Schedules for Facilities in the ~~Balancing~~ Synergy Portfolio less the Maximum Theoretical Energy Schedule for the ~~Balancing~~ Synergy Portfolio; or

(b) zero if:

i. System Management has provided a report to the IMO under clause 7.10.7 and the IMO determines that Synergy has not adequately or

appropriately complied with a Dispatch Order ~~in respect of the Balancing Portfolio~~; or

ii. the sum of any Sent Out Metered Schedules for Facilities in the ~~Balancing~~ Synergy Portfolio less the Maximum Theoretical Energy Schedule for the ~~Balancing~~ Synergy Portfolio is less than the sum of:

1. any increase in sent out energy due to a Network Control Service Contract which System Management instructed a Facility within the ~~Balancing~~ Synergy Portfolio to provide;
2. if Facilities within the ~~Balancing~~ Synergy Portfolio were instructed by System Management to provide LFAS, the sum of Upwards LFAS Enablement and Backup Upwards LFAS ~~Backup~~ Enablement, both divided by two so that they are expressed in MWh;
3. if a Spinning Reserve Event has occurred, any Spinning Reserve Response Quantity; and
4. the Portfolio Settlement Tolerance.

6.16B.2. The Portfolio Downwards Out of Merit Generation in a Trading Interval for the ~~Balancing~~ Synergy Portfolio equals:

(a) subject to clause 6.16B.2(b), the Minimum Theoretical Energy Schedule less the sum of any Sent Out Metered Schedules for Facilities in the ~~Balancing~~ Synergy Portfolio; or

(b) zero if:

i. System Management has provided a report to the IMO under clause 7.10.7 and the IMO determines that Synergy has not adequately or appropriately complied with a Dispatch Order; or

ii. the Minimum Theoretical Energy Schedule of the ~~Balancing~~ Synergy Portfolio less the sum of any Sent Out Metered Schedules for Facilities in the ~~Balancing~~ Synergy Portfolio is less than the sum of:

1. any reduction in sent out energy due to a Network Control Service Contract which System Management instructed a Facility within the ~~Balancing~~ Synergy Portfolio to provide;
2. if Facilities within the ~~Balancing~~ Synergy Portfolio were instructed by System Management to provide LFAS, the sum of the Downwards LFAS Enablement plus the Backup Downwards LFAS ~~Backup~~ Enablement, both divided by two so that they are expressed in MWh;
3. if a Load Rejection Reserve Event has occurred, any Load Rejection Reserve Response Quantity; and
4. the Portfolio Settlement Tolerance.

6.17. Balancing Settlement Quantities

6.17.1. The IMO must determine for each Market Participant and each Trading Interval of each Trading Day:

(a) the Metered Balancing Quantity;

(b) the ~~Non-Balancing Facility~~ Non-REM Dispatch Instruction Payment;

(c) ~~Loss Factor adjusted Facility~~ Constrained On Quantities and associated ~~prices~~ Constrained On Compensation Prices;

(d) ~~Loss Factor adjusted Facility~~ Constrained Off Quantities and associated ~~prices~~ Constrained Off Compensation Prices;

(e) ~~Loss Factor adjusted~~ Portfolio Constrained On ~~Balancing Portfolio~~ Quantities and associated ~~prices~~ Portfolio Constrained On Compensation Prices; and

(f) ~~Loss Factor adjusted~~ Portfolio Constrained Off ~~Balancing Portfolio~~ Quantities and associated ~~prices~~ Portfolio Constrained Off Compensation Prices,

in accordance with this clause 6.17.

Constrained On ~~Facility Balancing~~ Quantities and Compensation Prices

6.17.3. Subject to clauses 6.17.5B and 6.17.5C, the IMO must attribute any Upwards Out of Merit Generation from a ~~Balancing~~ REM Facility that is a Scheduled Generator, in a Trading Interval, as follows:

(a) Constrained On Quantity1 (ConQ1) equals the lesser of:

i. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched from the Facility's ~~Balancing~~ REM Price-Quantity Pair N, with a Loss Factor Adjusted Price (Price N) higher than but closest to the ~~Balancing~~ Energy Price, taking into account the actual SOI Quantity of the ~~Balancing~~ REM Facility and the applicable Ramp Rate Limit; and

ii. the Upwards Out of Merit Generation for the ~~Balancing~~ REM Facility;

(b) Constrained On Compensation Price1 (ConP1) equals the Loss Factor Adjusted Price N identified in clause 6.17.3(a) less the ~~Balancing~~ Energy Price;

(c) If the ~~Balancing~~ REM Facility's Upwards Out of Merit Generation exceeds ConQ1 and a ~~Balancing~~ REM Price-Quantity Pair exists for the Facility and Trading Interval with a Loss Factor Adjusted Price higher than Price N, then:

i. additional Constrained On Quantity2 (ConQ2) equals the lesser of:

1. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched from the Facility's ~~Balancing~~ REM Price-Quantity Pair N+1 with a Loss Factor Adjusted Price (Price N+1) higher than but closest to the Price N, taking into account when the ~~Balancing~~ REM Facility's MW level reached the top, or bottom, as applicable, of the quantity associated with the ~~Balancing~~ REM Price-Quantity Pair N in the calculation in clause 6.17.3(a)(i) and the applicable Ramp Rate Limit; and

2. the Upwards Out of Merit Generation for the ~~Balancing~~ REM Facility less ConQ1; and

ii. Constrained On Compensation Price2 (ConP2) equals the Loss Factor Adjusted Price N+1 identified in clause 6.17.3(c)(i) less the ~~Balancing~~ Energy Price;

(d) The IMO must repeat the process set out in clause 6.17.3(c) to identify, from the next highest priced Price N+1, any ConQN+1 and ConPN+1 until all Upwards Out of Merit Generation has been attributed to ~~Balancing~~ REM Price-Quantity Pairs or, otherwise, until there are no remaining ~~Balancing~~ REM Price-Quantity Pairs;

(e) The Non-Qualifying Constrained On Generation for the ~~Balancing~~ REM Facility equals the sum, divided by two so that it is expressed as sent out MWh, of any Upwards LFAS Enablement and, if the Facility is a Stand Alone Facility, any Backup Upwards LFAS ~~Backup~~ Enablement, which the ~~Balancing~~ REM Facility was instructed to provide by System Management;

(f) If:

i. the Non-Qualifying Constrained On Generation exceeds ConQ1, set ConQ1 to zero; or

ii. otherwise reduce ConQ1 by the amount of Non-Qualifying Constrained On Generation;

(g) The IMO must repeat the process set out in clause 6.17.3(f) for each ConQN in ascending order until all Non-Qualifying Constrained On Generation has been deducted from ConQN or, otherwise, until there are no remaining ConQN; and

(h) For settlement purposes under Chapter 9, the IMO must Loss Factor adjust each ConQN calculated in clauses 6.17.3(a) to 6.17.3(f).

6.17.3A. Subject to clause 6.17.5B, for any ~~Balancing~~ REM Facility that is a Non-Scheduled Generator, in a Trading Interval:

(a) ConQ1 equals the Upwards Out of Merit Generation, in MWh, for the Trading Interval, which for settlement purposes under Chapter 9 the IMO must Loss Factor adjust; and

(b) ConP1 equals the greater of:

i. zero; and

ii. the Loss Factor Adjusted Price in the ~~Balancing~~ REM Price-Quantity Pair associated with the ~~Balancing~~ REM Facility for that Trading Interval less the ~~Balancing~~ Energy Price for that Trading Interval.

Constrained Off ~~Facility Balancing~~ Quantities and Compensation Prices

6.17.4. Subject to clauses 6.17.5B and 6.17.5C, the IMO must attribute any Downwards Out of Merit Generation from a ~~Balancing~~ REM Facility that is a Scheduled Generator, in a Trading Interval, as follows:

(a) Constrained Off Quantity1 (CoffQ1) equals the lesser of:

i. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched down from the Facility's ~~Balancing~~ REM Price-Quantity Pair N, with a Loss Factor Adjusted Price (Price N), taking into account the Available Capacity and actual SOI Quantity of the ~~Balancing~~ REM Facility and the applicable Ramp Rate Limit, where N is determined from either of the following ~~Balancing~~ REM Price-Quantity Pairs or, if different, the one with the lower price:

1. the ~~Balancing~~ REM Price-Quantity Pair associated with the intersection of Available Capacity and the quantities in all ~~Balancing~~ REM Price-Quantity Pairs summed in order of lowest to highest price; and

2. the ~~Balancing~~ REM Price-Quantity Pair with a Loss Factor Adjusted Price lower than but closest to the ~~Balancing~~ Energy Price; and

ii. the Downwards Out of Merit Generation for the ~~Balancing~~ REM Facility;

(b) Constrained Off Compensation Price1 (CoffP1) equals the ~~Balancing~~ Energy Price less the Loss Factor Adjusted Price, Price N, identified in clause 6.17.4(a);

(c) If the ~~Balancing~~ REM Facility Downwards Out of Merit Generation exceeds CoffQ1 and a ~~Balancing~~ REM Price-Quantity Pair exists for the Facility and Trading Interval with a Loss Factor Adjusted Price lower than Price N, then:

i. additional Constrained Off Quantity2 (CoffQ2) equals the lesser of:

1. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched down from the Facility's ~~Balancing~~ REM Price-Quantity Pair N+1 with a Loss Factor Adjusted Price (Price N+1) lower than but closest to the Price N, taking into account when the ~~Balancing~~ REM Facility's MW level reached the bottom, or the top, as applicable, of the quantity associated with the

~~Balancing~~ REM Price-Quantity Pair N in the calculation in clause 6.17.4(a)(i) and the applicable Ramp Rate Limit; and

2. the Downwards Out of Merit Generation for the ~~Balancing~~ REM Facility less CoffQ1; and

ii. Constrained Off Compensation Price2 (CoffP2) equals the ~~Balancing~~ Energy Price less the Loss Factor Adjusted Price N+1 identified in clause 6.17.4(c)(i);

(d) The IMO must repeat the process set out in clause 6.17.4(c) to identify, from the next lowest priced Price N+1, any CoffQN+1 and CoffPN+1 until all Downwards Out of Merit Generation has been attributed to ~~Balancing~~ REM Price-Quantity Pairs or, otherwise, until there are no remaining ~~Balancing~~ REM Price-Quantity Pairs;

(e) The Non-Qualifying Constrained Off Generation for the ~~Balancing~~ REM Facility equals the sum, divided by two so that it is expressed as sent out MWh, of any Downwards LFAS Enablement and, if the Facility is a Stand Alone Facility, any Backup Downwards ~~Backup~~ LFAS Enablement, which the ~~Balancing~~ REM Facility was instructed to provide by System Management;

(f) If:

i. the Non-Qualifying Constrained Off Generation exceeds CoffQ1, set CoffQ1 to zero; or

ii. otherwise reduce CoffQ1 by the amount of Non-Qualifying Constrained Off Generation;

(g) The IMO must repeat the process set out in clause 6.17.4(f) for each CoffQN in ascending order until all Non-Qualifying Constrained Off Generation has been deducted from CoffQN or, otherwise, until there are no remaining CoffQN; and

(h) For settlement purposes under Chapter 9, the IMO must Loss Factor adjust each CoffQN calculated in clauses 6.17.4(a) to clauses 6.17.4(f).

6.17.4A. Subject to clause 6.17.5B, for any ~~Balancing~~ REM Facility that is a Non-Scheduled Generator, in a Trading Interval:

(a) CoffQ1 equals the Downwards Out of Merit Generation, in MWh, for that Trading Interval, which for settlement purposes under Chapter 9 the IMO must Loss Factor adjust; and

(b) CoffP1 equals the ~~Balancing~~ Energy Price for that Trading Interval less the Loss Factor Adjusted Price in the ~~Balancing~~ REM Price-Quantity Pair associated with the ~~Balancing~~ REM Facility for that Trading Interval.

Portfolio Constrained On ~~Balancing Portfolio~~ Quantities and Compensation Prices

6.17.5. Subject to clause 6.17.5C, the IMO must attribute any Upwards Out of Merit Generation from the ~~Balancing~~ Synergy Portfolio in a Trading Interval as follows:

(a) Portfolio Constrained On Quantity1 (PConQ1) equals the lesser of:

i. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched from the ~~Balancing~~ Synergy Portfolio's REM Price-Quantity Pair N ~~in the Balancing Portfolio Supply Curve~~ with a price (Price N) higher than but closest to the ~~Balancing~~ Energy Price, taking into account the actual ~~Balancing~~ Synergy Portfolio SOI Quantity and the Portfolio Ramp Rate Limit; and

ii. the Upwards Out of Merit Generation for the ~~Balancing~~ Synergy Portfolio;

(b) Portfolio Constrained On Compensation Price1 (PConP1) equals the Price N identified in clause 6.17.5(a) less the ~~Balancing~~ Energy Price;

(c) If the Portfolio Upwards Out of Merit Generation exceeds PConQ1 and a ~~Balancing~~ REM Price-Quantity Pair exists ~~in~~ for the ~~Balancing~~ Synergy Portfolio ~~Supply Curve~~ with a price higher than Price N, then:

i. additional Portfolio Constrained On Quantity2 (PConQ2) equals the lesser of:

1. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched from the ~~Balancing~~ Synergy Portfolio's ~~Supply Curve Balancing~~ REM Price-Quantity Pair N+1 with a price (Price N+1) higher than but closest to the Price N, taking into account when the ~~Balancing~~ Synergy Portfolio MW level reached the top, or the bottom, as applicable, of ~~Balancing~~ REM Price-Quantity Pair N in the calculation in clause 6.17.5(a)(i) and the Portfolio Ramp Rate Limit; and

2. the Portfolio Upwards Out of Merit Generation less PConQ1; and

ii. Portfolio Constrained On Compensation Price2 (PConP2) equals the Price N+1 identified in clause 6.17.5(c)(i) less the ~~Balancing~~ Energy Price;

(d) The IMO must repeat the process set out in clause 6.17.5(c) to identify, from the next highest priced ~~Balancing~~ REM Price-Quantity Pair N+1, any PConQN+1 and PConPN+1 until all Portfolio Upwards Out of Merit Generation has been attributed to ~~Balancing~~ REM Price-Quantity Pairs or, otherwise, until there are no remaining ~~Balancing~~ REM Price-Quantity Pairs ~~in the Balancing Portfolio Supply Curve~~;

(e) The Non-Qualifying Constrained On Generation for the ~~Balancing~~ Synergy Portfolio equals the sum, expressed in sent out MWh, of any increase in energy due to a Network Control Service Contract and of the following Ancillary Services (if any), which System Management instructed Synergy to provide from Facilities within the ~~Balancing~~ Synergy Portfolio:

i. Upwards LFAS Enablement;

ii. Backup Upwards LFAS ~~Backup~~ Enablement; and

iii. the Spinning Reserve Response Quantity;

(f) If:

i. the Non-Qualifying Constrained On Generation exceeds PConQ1, set PConQ1 to zero; or

ii. otherwise reduce PConQ1 by the amount of Non-Qualifying Constrained On Generation;

(g) The IMO must repeat the process set out in clause 6.17.5(f) for each PConQN in ascending order until all Non-Qualifying Constrained On Generation has been deducted from PConQN or otherwise until there are no remaining PConQN; and

(h) For settlement purposes under Chapter 9, each PConQN calculated in this clause 6.17.5 is to be Loss Factor adjusted by the Portfolio Loss Factor.

Portfolio Constrained Off ~~Balancing Portfolio~~ Quantities and Compensation Prices

6.17.5A. Subject to clause 6.17.5C, the IMO must attribute any Downwards Out of Merit Generation from the ~~Balancing~~ Synergy Portfolio in a Trading Interval as follows:

(a) Portfolio Constrained Off ~~Portfolio~~ Quantity1 (PCoffQ1) equals the lesser of:

i. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched down from ~~Balancing~~ the Synergy Portfolio's REM Price-Quantity Pair N, with Price N, ~~in the Balancing Portfolio Supply Curve,~~ taking into account the Available Capacity of the ~~Balancing~~ Synergy Portfolio, the MW level at the start of the Trading Interval and the Portfolio Ramp Rate Limit, where N is determined from either of the following ~~Balancing~~ REM Price-Quantity Pairs or, if different, the one with the lower price:

1. the ~~Balancing~~ REM Price-Quantity Pair associated with the intersection of Available Capacity and the quantities in all ~~Balancing~~ REM Price-Quantity Pairs ~~in the Balancing Portfolio Supply Curve~~ summed in order of lowest to highest price; and

2. the ~~Balancing~~ REM Price-Quantity Pair with a price lower than but closest to the ~~Balancing~~ Energy Price; and

ii. the Portfolio Downwards Out of Merit Generation;

(b) Portfolio Constrained Off Compensation Price1 (PCoffP1) equals the ~~Balancing~~ Energy Price less the Price N identified in clause 6.17.5A(a);

(c) If the Portfolio Downwards Out of Merit Generation (in MWh) exceeds PCoffQ1 and a ~~Balancing~~ REM Price-Quantity Pair exists ~~in~~ for the ~~Balancing~~ Synergy Portfolio ~~Supply Curve~~ with a price lower than Price N, then:

i. additional Portfolio Constrained Off ~~Portfolio~~ Quantity2 (PCoffQ2) equals the lesser of:

1. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched down from the ~~Balancing~~ Synergy Portfolio's ~~Supply Curve Balancing~~ REM Price-Quantity Pair N+1 with a price (Price N+1) lower than but closest to Price N, taking into account when the ~~Balancing~~ Synergy Portfolio MW level reached the bottom, or top, as applicable, of ~~Balancing~~ REM Price-Quantity Pair N in the calculation in clause 6.17.5A(a)(i) and the Portfolio Ramp Rate Limit; and

2. the Portfolio Downwards Out of Merit Generation less PCoffQ1; and

ii. Portfolio Constrained Off Compensation Price2 (PCoffP2) equals the ~~Balancing~~ Energy Price less the Price N+1 identified in clause 6.17.5A(c)(i);

(d) The IMO must repeat the process set out in clause 6.17.5A(c) to identify, from the next lowest priced ~~Balancing~~ REM Price-Quantity Pair N+1, any PCoffQN+1 and PCoffPN+1 until all Portfolio Downwards Out of Merit Generation has been attributed to ~~Balancing~~ REM Price-Quantity Pairs or, otherwise, until there are no remaining ~~Balancing~~ REM Price-Quantity Pairs ~~in the Balancing Portfolio Supply Curve~~;

(e) The Non-Qualifying Constrained Off Generation for the ~~Balancing~~ Synergy Portfolio equals the sum, expressed in sent out MWh, of any reduction in sent out energy due to a Network Control Service Contract and of the following Ancillary Services (if any), which System Management instructed Synergy to provide from Facilities in the ~~Balancing~~ Synergy Portfolio:

i. Downwards LFAS Enablement;

ii. Backup Downwards LFAS ~~Backup~~ Enablement; and

iii. the Load Rejection Reserve Response Quantity ;

(f) If:

i. the Non-Qualifying Constrained Off Generation exceeds PCoffQ1 set PCoffQ1 to zero; or

ii. otherwise reduce PCoffQ1 by the amount of Non-Qualifying Constrained On Generation;

(g) The IMO must repeat the process set out in clause 6.17.5A(f) for each PCoffQN in ascending order until all Non-Qualifying Constrained Off Generation has been deducted from PCoffQN or there are no remaining PCoffQN; and

(h) For settlement purposes under Chapter 9, each PCoffQN calculated in this clause 6.17.5A is to be Loss Factor adjusted by the Portfolio Loss Factor.

~~Balancing~~ Constrained On and Off Quantities and Compensation Prices – Exceptions

6.17.5B. Clauses 6.17.3, 6.17.3A, 6.17.4 and 6.17.4A do not apply to Facilities in the ~~Balancing~~ Synergy Portfolio.

~~Non-Balancing Facility~~ Non-REM Dispatch

6.17.6. The ~~Non-Balancing Facility~~ Non-REM Dispatch Instruction Payment, DIP(p,d,t), for Market Participant p and Trading Interval t of Trading Day d equals the sum ~~of:~~over all Demand Side Programmes registered to Market Participant p of the amount that is the product of:

(a) the quantity (in MWh) by which the Demand Side Programme reduced its consumption in response to a Dispatch Instruction, excluding any instructions given under a Network Control Service Contract, where this quantity is equal to the least of:

i. half of the Facility's Capacity Credits;

ii. the Dispatch Instruction amount provided by System Management in accordance with clause 7.13.1(eG); or

iii. the greater of zero and the difference between half of the Relevant Demand set in clause 4.26.2CA and the Demand Side Programme Load measured in the Trading Interval; and

(b) the applicable Consumption Decrease Price for the Facility in Trading Interval t.

~~(a) the sum over all Dispatchable Loads registered to Market Participant p of the amount that is the product of:~~

~~i. the quantity, in MWh, by which the Dispatchable Load reduced its consumption in response to a Dispatch Instruction, where this quantity is equal to the lesser of:~~

~~1. the Loss Factor adjusted quantity in the Dispatch Instruction provided to the IMO by System Management under clause 6.17.6A(a); or~~

~~2. the greater of zero and the difference between the Metered Schedule for the Facility in Trading Interval t and the Loss Factor adjusted quantity provided in the Facility's Resource Plan for Trading Interval t under clause 6.11.1(b)(iii); and~~

ii. the applicable Consumption Decrease Price for the Facility in Trading Interval t;

(b) the sum over all Dispatchable Loads registered to Market Participant p of the amount that is the product of:

i. the quantity, in MWh, by which the Dispatchable Load increased its consumption in response to a Dispatch Instruction, where this quantity is equal to the lesser of:

1. the Loss Factor adjusted quantity in the Dispatch Instruction provided to the IMO by System Management under clause 6.17.6A(a); or

2. the greater of zero and the difference between the Loss Factor adjusted quantity provided in the Facility's Resource Plan for Trading Interval t under clause 6.11.1(b)(iii) and the Metered Schedule for the Facility in Trading Interval t and; and

ii. the applicable Consumption Increase Price for the Facility in Trading Interval t; and

(c) the sum over all Demand Side Programmes registered to Market Participant p of the amount that is the product of:

i. the quantity (in MWh) by which the Demand Side Programme reduced its consumption in response to a Dispatch Instruction, excluding any instructions given under a Network Control Service Contract, where this quantity is equal to the least of:

1. half of the Facility's Capacity Credits;

2. the Dispatch Instruction amount provided by System Management in accordance with clause 7.13.1(eG); or

3. the greater of zero and the difference between half of the Relevant Demand set in clause 4.26.2CA and the Demand Side Programme Load measured in the Trading Interval; and

ii. the applicable Consumption Decrease Price for the Facility in Trading Interval t.

6.17.6A. System Management must:

(a) for each Trading Interval in which a Dispatchable Load was subject to a Dispatch Instruction, provide the IMO with the non-Loss Factor adjusted quantity, in MWh, by which the Dispatchable Load was dispatched, where this must be a positive number, together with information regarding whether it was dispatched upwards or downwards from its Resource Plan; and

(b) provide the information in clause 6.17.6A(a) to the IMO as soon as reasonably practicable but in any event in time for the IMO to undertake settlement under Chapter 9.

6.17.7. The Consumption Decrease Price ~~and Consumption Increase Price~~ used in ~~clauses 6.17.6(a)(ii), 6.17.6(b)(ii) and 6.17.6(c)(ii)~~ clause 6.17.6(b) must be at the applicable Peak Trading Interval or Off-Peak Trading Interval price.

6.17.9. The IMO must other than for Facilities in the ~~Balancing~~ Synergy Portfolio, determine a Settlement Tolerance for each Scheduled Generator~~,~~ and Non-Scheduled Generator ~~and Dispatchable Load~~, where this Settlement Tolerance is equal to:

(a) for a Scheduled Generator ~~or Dispatchable Load~~ for which an applicable Tolerance Range or Facility Tolerance Range has been determined by System Management, the applicable value provided by System Management to the IMO for the Facility under clause 2.13.6L, divided by two to be expressed as MWh; or

(b) for Facilities for which no applicable Tolerance Range or Facility Tolerance Range has been determined by System Management, the lesser of:

i. 3 MWh; and

ii. the greater of:

1. 0.5 MWh; and

2. 3% of the Facility's~~:~~ Sent Out Capacity divided by two to be expressed as MWh.

~~i. Sent Out Capacity in the case of a Non-Scheduled Generator and a Scheduled Generator; or~~

~~ii. nominated maximum consumption quantity in the case of a Dispatchable Load,~~

~~as set out in Standing Data divided by two to be expressed as MWh.~~

6.17.10. The Portfolio Settlement Tolerance equals the lesser of:

(a) 3 MWh; and

(b) 3% of the Sent Out Capacity of the ~~Balancing~~ Synergy Portfolio divided by two to be expressed as MWh.

6.21.2. The IMO must provide the following information to the settlement system for each Trading Interval in a Trading Day:

(a) the ~~Balancing~~ Energy Price; and

(b) for each Market Participant:

i. the Metered Balancing Quantity;

ii. the ~~Facility Loss Factor adjusted~~ Constrained On Quantities and ~~Loss Factor Adjusted~~ associated Constrained On Compensation Prices calculated in accordance with clauses 6.17.3 and 6.17.3A;

iii. the ~~Facility Loss Factor adjusted~~ Constrained Off Quantities and ~~Loss Factor Adjusted~~ associated Constrained Off Compensation Prices calculated in accordance with clauses 6.17.4 and 6.17.4A;

iv. the ~~Balancing~~ Portfolio ~~Loss Factor adjusted~~ Constrained On Quantities and ~~prices~~ associated Portfolio Constrained On Compensation Prices calculated in accordance with clause 6.17.5;

v. the ~~Balancing~~ Portfolio ~~Loss Factor adjusted~~ Constrained Off Quantities and ~~prices~~ associated Portfolio Constrained Off Compensation Prices calculated in accordance with clause 6.17.5A; and

vi. the ~~Non-Balancing Facility~~ Non-REM Dispatch Instruction Payment.

Data used in the ~~Non-Balancing~~ Dispatch Process

7.1. Data Used in the ~~Non-Balancing~~ Non-REM and Out of Merit Dispatch Process

7.1.1. System Management must maintain and in accordance with clause 7.6, use the following data set in giving Dispatch Instructions to ~~Non-Balancing Facilities~~ Demand Side Programmes, Dispatch Instructions to ~~Balancing~~ REM Facilities dispatched Out of Merit and in providing Operating Instructions:

(a) Standing Data on Registered Facilities determined in accordance with clause 2.34;

(b) Loss Factors determined in accordance with clause 2.27;

(c) expected Scheduled Generator and Non-Scheduled Generator capacities by Trading Interval determined in accordance with clauses 3.17.5, 3.17.6 and 3.17.8;

(d) transmission Network configuration and capacity by Trading Interval determined in accordance with clauses 3.17.5, 3.17.6 and 3.17.8;

(e) forecasts of load and Non-Scheduled Generation by Trading Interval determined in accordance with clause 7.2;

(f) Ancillary Service Requirements for each Trading Interval determined in accordance with clause 7.2.4;

(g) schedules of approved Planned Outages for generating works and transmission equipment by Trading Interval determined in accordance with clause 3.19;

(h) transmission Forced Outages and Consequential Outages by Trading Interval received from Network Operators in accordance with clause 3.21;

(i) Scheduled Generator, Non–Scheduled Generator~~, Dispatchable Load~~ and Interruptible Load Forced Outages and Consequential Outages by Trading Interval received from Market Participants in accordance with clause 3.21;

(j) [Blank]

~~(jA) the Fuel Declarations received from the IMO and notifications received from Market Participants in accordance with clause 7.5;~~

(k) the ~~Non-Balancing~~ Non-REM Dispatch Merit Order received from the IMO in accordance with clause 7.5;

(l) Supplementary Capacity Contract data, if any, received from the IMO in accordance with clause 4.24; and

(m) Network Control Service Contract data, if any, received from a Network Operator in accordance with clauses 5.3A.3 and 5.3A.4.

7.4. ~~Resource Plans~~[Blank]

~~7.4.1. The IMO must provide System Management with the Resource Plans for a Trading Day it has accepted from Market Participants by 1.30 PM, or by 3:30 PM where the time for submitting Resource Plans is extended by the IMO under clause 6.5.1(b), of the Scheduling Day.~~

~~7.4.2. Upon receipt of the Resource Plans for a Trading Day, System Management must within 5 minutes confirm to the IMO that it has received the Resource Plans.~~

~~7.4.3. In the event that the IMO does not receive confirmation of receipt of the Resource Plans for a Trading Day from System Management within five minutes of providing them under clause 7.4.1, the IMO must contact System Management by telephone. If System Management has not received the Resource Plans, then the IMO must make alternative arrangements to communicate the information.~~

~~7.4.4. At any time between the time that it receives the Resource Plans for a Trading Day from the IMO and the end of the Trading Intervals covered by the Resource Plans, System Management may request that a Market Participant confirm that it can conform to its Resource Plan for the relevant Trading Intervals and, if not, to indicate what lesser level of compliance the Market Participant is capable of achieving.~~

7.5. ~~Non-Balancing~~ Non-REM Dispatch Merit Order~~s and Fuel Declarations~~

The amendments to clauses 7.5.1 to 7.5.3 reflect the proposed amendments in the Final Rule Change Report for the Rule Change Proposal: Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10). This proposal (RC_2014_01) additionally updates market names and removes the requirement to provide Fuel Declarations.

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

7.5.2. Upon receipt of the ~~Non-Balancing~~ Non-REM Dispatch Merit Order~~s and Fuel Declarations~~ for a Trading Day, System Management must within ~~5~~ five minutes confirm to the IMO that it has received the ~~Non-Balancing~~ Non-REM Dispatch Merit Order~~s and Fuel Declarations~~.

7.5.3. In the event that the IMO does not receive confirmation of receipt of the ~~Non-Balancing~~ Non-REM Dispatch Merit Order~~s and Fuel Declarations~~ for a Trading Day from System Management within ~~5~~ five minutes of submission, then the IMO must contact System Management. If System Management has not received the ~~Non-Balancing~~ Non-REM Dispatch Merit Order~~s and Fuel Declarations~~, then the IMO must make alternative arrangements to communicate the information.

~~7.5.4. Subject to clause 7.5.5, a Market Participant other than Synergy may at any time between 1:30 PM on the Scheduling Day and 30 minutes prior to the commencement of the Trading Interval described in clause 7.5.4(b) notify System Management that the Market Participant will change the fuel upon which a Scheduled Generator registered to it will operate on from a Liquid Fuel to a Non-Liquid Fuel, or vice versa, where the notification must include:~~

~~(a) the identity of the Scheduled Generator;~~

~~(b) the first Trading Interval in the Trading Day from which the fuel change will take effect;~~

~~(c) the last Trading Interval in the Trading Day for which the fuel change will apply; and~~

~~(d) the fuel (Liquid Fuel or Non-Liquid Fuel) to be used.~~

~~7.5.5. A Market Participant may only issue a notification in accordance with clause 7.5.4 for a Scheduled Generator if:~~

~~(a) the Scheduled Generator is switching from Non-Liquid Fuel to Liquid Fuel because it has lost its supply of Non-Liquid Fuel; or~~

~~(b) the Scheduled Generator is switching from Liquid Fuel to Non-Liquid Fuel because it has obtained a new supply of Non-Liquid Fuel.~~

~~7.5.6. System Management must retain a record of all notifications provided to it in accordance with clause 7.5.4.~~

7.6.1C. In seeking to meet the Dispatch Criteria System Management must, subject to clause 7.6.1D, issue Dispatch Instructions in the following descending order of priority:

(a) Dispatch Instructions to ~~Balancing~~ REM Facilities in the order and, subject to clause 7.7.6B, for the quantities that appear in the ~~BMO~~ DMO, taking into account Ramp Rate Limits for that Facility;

(b) a Dispatch Instruction to a ~~Balancing~~ REM Facility Out of Merit but only to the next Facility or Facilities, and associated quantity in the ~~BMO~~ DMO that System Management reasonably considers best meets the Dispatch Criteria, taking into account the associated Ramp Rate Limit for that Facility;

(c) a Dispatch Instruction to any ~~Balancing~~ REM Facility Out of Merit, taking into account the Ramp Rate Limit and non-ramp rate Standing Data

limitations relevant to that Facility and any other relevant information available to System Management; and

(d) a Dispatch Instruction to a ~~Non-Balancing Facility~~ Demand Side Programme in accordance with the ~~Non-Balancing~~ Non-REM Dispatch Merit Order, taking into account Standing Data limitations relevant to that Facility.

7.6.2. For the purposes of clauses 7.6.1 and 7.6.1C, the ~~Balancing~~ Synergy Portfolio is to be treated as a ~~Balancing~~ REM Facility but the dispatch of any Facility within the ~~Balancing~~ Synergy Portfolio is to be under the Dispatch Plan or a Dispatch Order in accordance with clause 7.6A, which is deemed to meet the requirements to issue a Dispatch Instruction in respect of the ~~Balancing~~ Synergy Portfolio.

7.6.2A. Where the Dispatch Criteria requires System Management to alter the Dispatch Plan of Synergy, subject to the limitations imposed by this clause 7.6, System Management must employ reasonable endeavours to minimise the change in the Dispatch Plan and to have regard for the merit order of Synergy Facilities in the ~~Balancing~~ Synergy Portfolio.

7.6.2B. A reference to a ~~BMO~~ DMO in this ~~clause~~ section 7.6 means, for a Trading Interval:

(a) the ~~BMO~~ last Forecast DMO for that Trading Interval provided by the IMO to System Management under clause ~~7A.3.6(b)~~ 7A.3.1(b); and

(b) ~~if no such BMO is provided, the most recent Forecast BMO for that Trading Interval provided under clause 7A.3.17(b); and~~if no Forecast DMO is provided, the DMO that was used by System Management for issuing Dispatch Instructions for the same Trading Interval on the most recent Business Day if the Trading Interval occurs on a Business Day, or the most recent non-Business Day if the Trading Interval occurs on a non-Business Day.

~~(c) if no such Forecast BMO is provided, the BMO or the Forecast BMO that was used by System Management for issuing Dispatch Instructions for the same Trading Interval on the previous day if both Trading Intervals occur on a Business Day, or the most recent non-Business Day if the Trading Interval occurs on a non-Business Day.~~

7.6A. Scheduling and Dispatch of ~~the Balancing Portfolio and~~ Stand Alone Facilities for certain Ancillary Services and of the Synergy Portfolio

7.6A.1. Subject to System Management's obligations under ~~clause~~ section 7.6, this ~~clause~~ section 7.6A describes the rules governing the relationship between System Management and Synergy for the purpose of scheduling and dispatching the Stand Alone Facilities for Ancillary Services and for scheduling and dispatching Facilities in the ~~Balancing~~ Synergy Portfolio generally.

The IMO is currently working with System Management on what information needs to be provided to Synergy by 4:00 pm each Scheduling Day under clause 7.6A.2(c), and in particular whether the forecast specified in clause 7.6A.2(c)(i) is still required. The IMO intends to confirm the necessary amendments to clauses 7.6A.2(c) and 7.6A.2(e) prior to the formal submission of the Rule Change Proposal.

7.6A.2. With respect to the scheduling of Stand Alone Facilities for Ancillary Services and the scheduling of Facilities in the ~~Balancing~~ Synergy Portfolio generally:

(a) at least once every month, Synergy must provide to System Management the following information in regard to the subsequent month:

i. a plant schedule describing the merit order in which the Facilities in the ~~Balancing~~ Synergy Portfolio are to be called upon and any restrictions on the operations of such Facilities;

ii. a plan for which fuels will be used in each Facility in the ~~Balancing~~ Synergy Portfolio and guidance as to how that plan might be varied depending on circumstances;

iii. a description as to how Ancillary Services are to be provided from Facilities in the ~~Balancing~~ Synergy Portfolio; and

iv. a description as to how Ancillary Services are to be provided from the Stand Alone Facilities,

where the format and time resolution of this data is to be described in a procedure;

(b) System Management must provide to Synergy by 8:30 AM on the Scheduling Day associated with a Trading Day a forecast of total system demand for the Trading Day where the format and time resolution of this data is to be described in a procedure;

(c) System Management must provide to Synergy by 4:00 PM on the Scheduling Day associated with a Trading Day:

i. a forecast of the requirements for energy in the ~~Balancing~~ Synergy Portfolio, being a forecast of the whole of system energy requirement less:

1. the aggregate energy of all Resource Plans associated with other Market Participants' Scheduled Generators and Dispatchable Loads, including Synergy's Dispatchable Loads; and

2. the aggregate forecast output of other Market Participants' Non-Scheduled Generators, including the aggregate forecast output of any Non-Scheduled Generators which are Stand Alone Facilities, for the Trading Day;

ii. the Dispatch Plan for each Facility for the Trading Day; and

iii. a forecast of the detailed Ancillary Services required from each Facility in the ~~Balancing~~ Synergy Portfolio and Ancillary Services from each Stand Alone Facility,

where the format and time resolution of this data is to be described in a procedure;

(d) System Management must consult with Synergy in developing the information described in clause 7.6A.2(c) and Synergy must provide System Management with any information required by System Management in accordance with a procedure to support the preparation of the information in clause 7.6A.2(c). In the event of any failure by Synergy to provide information required by System Management in a timely fashion then System Management may use its reasonable judgement to substitute its own information;

(e) System Management must provide to the IMO by 4:00 PM on the Scheduling Day associated with a Trading Day the aggregate forecast output of all Non-Scheduled Generators for the Trading Day, referred to in clause 7.6A.2(c)(i)(2);

(f) If after 4:00 PM on the Scheduling Day but prior to the start of a Trading Interval on the corresponding Trading Day, System Management becomes aware of a change in conditions which will require a significant change in the Dispatch Plan it may make such change but must notify Synergy of such change; and

(g) Synergy must notify System Management as soon as practicable if it becomes aware that it is unable to comply with a Dispatch Plan, providing reasons as to why it cannot comply.

7.6A.3. With respect to the dispatch of Stand Alone Facilities for the purposes of Ancillary Services other than LFAS but including ~~LFAS~~ Backup LFAS Enablement, and the dispatch of Facilities in the ~~Balancing~~ Synergy Portfolio generally, during a Trading Day:

(a) System Management may issue an Operating Instruction for Stand Alone Facilities, and instruct Facilities in the ~~Balancing~~ Synergy Portfolio to deviate from the Dispatch Plan, or to change their commitment or output, in accordance with the Dispatch Criteria or in response to System Management's powers under a High Risk Operating State or an Emergency Operating State;

(b) System Management must provide adequate notice to Synergy, based on Standing Data, before a Facility in the ~~Balancing~~ Synergy Portfolio is required to respond to an instruction given under clause 7.6A.3(a); and

(c) Synergy must notify System Management as soon as practicable if Synergy becomes aware that it is unable to comply with an instruction given under clause 7.6A.3(a).

7.6A.4. With respect to the dispatch compliance of Synergy for Facilities in the ~~Balancing~~ Synergy Portfolio:

(a) System Management may deem Synergy to be in non-compliance for a Trading Interval if Synergy fails to comply with the Dispatch Plan, its obligations to provide Ancillary Services, or an instruction given under clause 7.6A.3(a), to an extent that could endanger Power System Security;

(b) In determining whether or not to deem Synergy to be in non-compliance, System Management must give due regard to any reasonable mitigating circumstances of which Synergy has notified it in accordance with clause 7.6A.3(c);

(c) In determining whether or not to deem Synergy to be in non-compliance, System Management may only consider a deviation by an individual Synergy Facility from an output level specified in any instruction from System Management to be in non-compliance if the deviation at any time exceeds 10 MW; and

(d) In the event that System Management deems Synergy to be in non-compliance for a Trading Interval then System Management must determine a single MWh quantity describing the total non-compliance of Synergy for that Trading Interval.

7.7.1. A Dispatch Instruction is an instruction issued by System Management to a Market Participant, other than Synergy in respect of its ~~Balancing~~ Synergy Portfolio, directing that the Market Participant vary the output ~~or consumption~~ of one of its Registered Facilities.

7.7.2. Each Dispatch Instruction issued to a ~~Non-Balancing Facility~~ Demand Side Programme or to a ~~Balancing~~ REM Facility Out of Merit under clause 7.6.1C(c) must:

(a) be consistent with the latest data described in clause 7.1.1 available to System Management at the time the Dispatch Instruction is determined;

(b) be applicable to a specific Registered Facility; and

(c) be issued at a time that takes into account the Standing Data minimum response time for the Registered Facility.

The amendments to clause 7.7.4A reflect the proposed amendments in the Final Rule Change Report for the Rule Change Proposal: Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10). This proposal (RC_2014_01) additionally updates market names.

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

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

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

7.7.5. A Dispatch Instruction for a ~~Balancing~~ REM Facility Out of Merit and a ~~Non-Balancing Facility~~ Demand Side Programme for a Trading Interval must not be issued earlier than 2:00 PM on the Scheduling Day for the Trading Day on which the Trading Interval falls or later than the end of the Trading Interval.

7.9.4. System Management must grant permission to synchronise unless:

(a) the synchronisation is not in accordance with the relevant ~~Resource Plan,~~ Dispatch Instruction, ~~or~~ Operating Instruction or ~~an~~ instruction issued under clause 7.6A.3(a); or

(b) System Management considers that it would not be able to meet the criteria set out in clause 7.6.1 were synchronisation to occur; or

(c) in the case of a Facility that is undergoing a Commissioning Test, synchronisation is not in accordance with the Commissioning Test Plan for the Facility approved by System Management pursuant to clause 3.21A.

7.9.8. System Management must grant permission to desynchronise unless:

(a) the desynchronisation is not in accordance with the relevant ~~Resource Plan or~~ Dispatch Instruction, Operating Instruction or ~~an~~ instruction issued under clause 7.6A.3(a); or

(b) System Management considers that it would not be able to meet the criteria set out in clause 7.6.1 were desynchronisation to occur.

7.10.6A. If a Market Participant receives a warning and a request for an explanation from System Management under clause 7.10.5(c), the Market Participant must as soon as practicable:

(a) provide to System Management an explanation for the deviation; and

(b) ensure it has complied with the requirements of clause 7A.2 in relation to the Market Participant's ~~Balancing~~ REM Submission.

Dispatch Advisories~~, Balancing Suspension~~ and ~~Reporting~~ Status Reports

The removal of clause 7.11.1 and amendments to clauses 7.11.5 and 7.11.6 reflect the proposed amendments in the Final Rule Change Report for the Rule Change Proposal: Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10). This proposal (RC_2014_01) additionally updates market names, removes references to Resource Plans and adds references to LFAS Enablement Schedules.

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

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

(a) involuntary load shedding is occurring or expected to occur;

(b) committed generation at minimum loading is, or is expected to, exceed forecast load;

(c) Ancillary Service Requirements will not be fully met;

(d) significant outages of generation transmission or customer equipment are occurring or expected to occur;

(e) fuel supply on the Trading Day is significantly more restricted than usual~~, or if fuel supply limitations mean it is not possible for some Market Participants to supply in accordance with their Resource Plans~~;

(f) scheduling or communication systems required for the normal conduct of the scheduling and dispatch process are, or are expected to be, unavailable;

(g) System Management expects to issue a Dispatch Instruction Out of Merit including, for the purpose of this clause, issuing a Dispatch Order to the ~~Balancing~~ Synergy Portfolio in accordance with clause 7.6.2, which will result in Out of Merit dispatch of the ~~Balancing~~ Synergy Portfolio;

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

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

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

7.11.6. Subject to clause 7.11.6A, a Dispatch Advisory must contain the following information:

(a) [Blank]

(b) the date and time that the Dispatch Advisory is released;

(c) the time period for which the Dispatch Advisory is expected to apply;

(cA) the Operating State to be applicable, or expected to be applicable, at different times during the time period to which the Dispatch Advisory relates;

(d) details of the situation that the Dispatch Advisory relates to, including the location, extent and seriousness of the situation;

(dA) where System Management is to release a Dispatch Advisory under clause 7.11.5(g), details of the estimated Out of Merit quantities, reasons for the deviation from the ~~BMO~~ DMO and all relevant information about the deviation;

(dB) where System Management is to release a Dispatch Advisory under clause 7.11.5(h), details of the estimated quantities of LFAS that are to be used, reasons for the deviation from the LFAS Merit Order and all relevant information about the deviation;

(dC) where System Management is to release a Dispatch Advisory under clause 7.11.5(j), details of the estimated quantities of Demand Side Management that are to be dispatched;

(e) any actions System Management plans to take in response to the situation;

(f) any actions Market Participants and Network Operators are required to take in response to the situation; and

(g) any actions Market Participants may voluntarily take in response to the situation.

7.12.1. System Management must provide a report to the IMO once every three months on the performance of the market with respect to the dispatch process. This report must include details of:

(a) the incidence and extent of issuance of Operating Instructions and Dispatch Instructions;

(b) the incidence and extent of non-compliance with Operating Instructions and Dispatch Instructions;

(bA) the incidence and reasons for the issuance of Dispatch Instructions to ~~Balancing~~ REM Facilities Out of Merit, including for the purposes of this clause, issuing Dispatch Orders to the ~~Balancing~~ Synergy Portfolio in accordance with clause 7.6.2;

(c) the incidence and extent of transmission constraints;

(d) the incidence and extent of shortfalls in Ancillary Services, involuntary curtailment of load, High Risk Operating States and Emergency Operating States, together with:

i. a summary of the circumstances that caused each such incident; and

ii. a summary of the actions that System Management took in response to the incident in each case; and

(e) the incidence and reasons for the selection and use of LFAS Facilities under clause 7B.3.8.

The proposed Amending Rules in the Final Rule Change Report for the Rule Change Proposal: Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10) make amendments to subclause 7.13.1(eH). This proposal (RC_2014_01) does not affect that subclause, so it is not shown here.

7.13.1. System Management must provide the IMO with the following data for a Trading Day by noon on the first Business Day following the day on which the Trading Day ends:

...

(eA) for each LFAS Facility, the quantity of any Backup Upwards LFAS ~~Backup~~ Enablement that System Management activated by the end of each Trading Interval by that LFAS Facility;

(eB) for each LFAS Facility, the quantity of any Backup Downwards LFAS ~~Backup~~ Enablement that System Management activated by the end of each Trading Interval by that LFAS Facility;

...

7A. ~~Balancing Market~~Real-Time Energy Market

7A.1. ~~Balancing Market~~Real-Time Energy Market

7A.1.1. The IMO must operate the ~~Balancing Market~~ Real-Time Energy Market.

7A.1.2. ~~The IMO must determine the Balancing Market Commencement Day.~~[Blank]

7A.1.3. The objectives of the ~~Balancing Market~~ REM are to:

(a) enable ~~Balancing~~ REM Facilities to participate in the ~~Balancing Market~~ REM;

(b) dispatch the lowest cost combination of Facilities made available ~~for Balancing~~ in the REM;

(c) establish ~~a Balancing~~ an Energy Price which is consistent with dispatch;

(d) seek to ensure timely and accurate ~~Balancing~~ energy pricing and dispatch quantity information, including forecasts, and system security information, is provided to all Market Participants; and

(e) seek to ensure timely and accurate information relevant to the operation and administration of the ~~Balancing Market~~ REM is provided to affected Rule Participants.

7A.1.4. The ~~Balancing Market~~ REM Objectives support, but are subservient to, the Wholesale Market Objectives. To the extent that an application of the ~~Balancing Market~~ REM Objectives results in an inconsistency with the Wholesale Market Objectives, the latter prevails to the extent of the inconsistency.

7A.1.5. All Rule Participants must take into account the ~~Balancing Market~~ REM Objectives in undertaking their functions and obligations under this Chapter 7A.

7A.1.6. The IMO must develop a ~~Balancing Facility Requirements~~ Market Procedure for REM Facility Requirements specifying:

(a) technical and communication criteria that a ~~Balancing~~ REM Facility, or a type of ~~Balancing~~ REM Facility, must meet, including:

i. Facility quantity parameters and limits for participation in ~~Balancing~~ the REM;

ii. the manner and forms of communication to be used while participating in ~~Balancing~~ the REM, including receiving Dispatch Instructions; and

iii. ramp rate limitations; and

(b) the type of conditions the IMO may impose under clause 7A.1.11(b) and the manner and circumstances in which they may be imposed and lifted.

7A.1.7. The IMO must consult with System Management when creating and amending the ~~Balancing~~ REM Facility Requirements.

7A.1.8. A Market Participant must ensure that its ~~Balancing~~ REM Facilities with a rated capacity equal to or greater than 10 MW meet the relevant specifications of the ~~Balancing~~ REM Facility Requirements.

7A.1.9. A Market Participant may inform the IMO that a ~~Balancing~~ REM Facility registered to that Market Participant with a rated capacity less than 10 MW meets the relevant specifications of the ~~Balancing~~ REM Facility Requirements.

7A.1.10. A Market Participant must, when required to do so by the IMO, provide in writing all information reasonably required by the IMO in order to demonstrate that a ~~Balancing~~ REM Facility registered to that Market Participant meets the relevant specifications of the ~~Balancing~~ REM Facility Requirements.

7A.1.11. If based on the information provided to it under clause 7A.1.10, the IMO determines that a ~~Balancing~~ REM Facility, including a ~~Balancing~~ REM Facility with a rated capacity of less than 10 MW, does not meet the relevant specifications of the ~~Balancing~~ REM Facility Requirements, the IMO may impose conditions on the

manner in which that ~~Balancing~~ REM Facility must participate in the ~~Balancing Market~~ REM under these Market Rules, including:

(a) the prices at which the Market Participant may include REM Price-Quantity Pairs in a ~~Balancing~~ REM Submission ~~in Balancing Price-Quantity Pairs~~ for that Facility; and

(b) the manner and time in which a ~~Balancing~~ REM Submission for that ~~Balancing~~ REM Facility must be submitted.

7A.1.13. The IMO must publish a decision to impose a condition on a ~~Balancing~~ REM Facility under clause 7A.1.11 together with the details of such condition.

7A.1.14. For the purposes of this Chapter 7A only, unless otherwise indicated, the ~~Balancing~~ Synergy Portfolio is to be treated as a single ~~Balancing~~ REM Facility and references in this Chapter 7A to a ~~Balancing~~ REM Facility are to be read as including a reference to the ~~Balancing~~ Synergy Portfolio.

~~7A.1.16. With effect on and from the Trading Interval commencing at 8:00 AM on the Balancing Market Commencement Day, the IMO must determine a point in time immediately before the commencement of a Trading Interval for the purpose of setting the Balancing Gate Closure. The point in time must be no shorter than two hours and no longer than six hours before the commencement of a Trading Interval and must be published on the Market Web Site.~~

~~7A.1.17. The IMO may, from time to time, change the point in time determined under clause 7A.1.16 by publishing the new point in time on the Market Web Site and specifying the date from which the new point in time is to take effect, which shall be no earlier than 2 months from the date of publication.~~

7A.2. ~~Balancing~~ REM Submissions

7A.2.1. A Market Participant must at all times ensure that~~:~~ it has made a REM Submission in accordance with clause 7A.2.4 for each Trading Interval in the Dispatch Horizon for each of its REM Facilities.

~~(a) it has made a Balancing Submission in accordance with clause 7A.2.4 for each of its Balancing Facilities, excluding Facilities in the Balancing Portfolio;~~

~~(b) it has made a Balancing Submission for all Trading Intervals in the Balancing Horizon for each of its Balancing Facilities; and~~

~~(c) the Balancing Submission is made before Balancing Gate Closure or, in the case of the Balancing Portfolio, before the times specified in clause 7A.2.9(d), for those Trading Intervals.~~

7A.2.2. A Market Participant may submit a subsequent ~~Balancing~~ REM Submission in accordance with clause 7A.2.4 in respect of any of its ~~Balancing~~ REM Facilities, excluding Facilities in the ~~Balancing~~ Synergy Portfolio, and:

(a) the ~~Balancing~~ REM Submission may be for one or more Trading Intervals in the ~~Balancing~~ Dispatch Horizon; and

(b) the ~~Balancing~~ REM Submission must be made before ~~Balancing~~ REM Gate Closure for any Trading Interval in the submission.

7A.2.3. A Market Participant with a ~~Balancing~~ REM Facility that is:

(a) the subject of an Operating Instruction; or

(b) undergoing a Test that has an approved Test Plan,

must ensure that ~~the price in the Balancing Price-Quantity Pair for~~ a ~~Balancing~~ REM Submission submitted under this clause 7A.2 is ~~at the Minimum STEM Price for the quantity~~ consistent with the proposed operation of the REM Facility for each Trading Interval specified in the Operating Instruction or the Test Plan. The provisions of this clause 7A.2.3 do not apply to the ~~Balancing~~ Synergy Portfolio.

The amendments to clause 7A.2.4 and the addition of new clauses 7A.2.4A, 7A.2.4B and 7A.2.4C reflect the proposed amendments in the Rule Change Proposal: Outage Planning Phase 2 – Outage Process Refinements (RC_2013_15). This proposal (RC_2014_01) additionally updates market names.

7A.2.4. A ~~Balancing~~ REM 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~~ REM Price-Quantity Pair prices within the Price Cap;

(d) specify, for each Trading Interval covered in the ~~Balancing~~ REM Submission, whether the ~~Balancing~~ REM 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.~~specify the Ramp Rate Limit or the Portfolio Ramp Rate Limit (as applicable) for each Trading Interval covered in the REM 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 REM Submission.

7A.2.4A. A REM Submission for a REM Facility that is a Scheduled Generator must specify the following details for each Trading Interval covered in the REM Submission:

(a) a ranking of REM 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 REM 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 REM Submission for a REM Facility that is a Non-Scheduled Generator must specify the following details for each Trading Interval covered in the REM 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 the Facility will not be subject to a Dispatch Instruction that limits its output during 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 REM Submission for the Synergy Portfolio must specify the following details for each Trading Interval covered in the REM Submission:

(a) a ranking of REM Price-Quantity Pairs covering available capacity in the Synergy Portfolio; 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 Synergy Portfolio to generate electrical energy).

7A.2.5. For the purposes of clause 7A.2.4(b), where the IMO accepts a ~~Balancing~~ REM Submission from a Market Participant that complies with clause 7A.2.4(a), the submission will be deemed to constitute a declaration by an Authorised Officer of the Market Participant.

7A.2.6. A subsequent ~~Balancing~~ REM Submission made under clause~~s~~ 7A.2.2, 7A.2.9(d), ~~7A.2.9(e) or~~ 7A.2.9(f), 7A.2.10 or 7A.3.5, in respect of the same ~~Balancing~~ REM Facility covering the same Trading Interval as an earlier ~~Balancing~~ REM Submission, overrides the earlier ~~Balancing~~ REM Submission for, and has effect in relation to, that Trading Interval.

7A.2.7. Where a subsequent ~~Balancing~~ REM Submission is made under clause 7A.2.6, a Market Participant must create and maintain internal records of the reasons for submitting the subsequent ~~Balancing~~ REM Submission, including details of any changed circumstances and the impacts of those circumstances that gave rise to the new ~~Balancing~~ REM Submission.

Please note that the proposed amendment to clause 7A.2.8 in the Rule Change Proposal: Outage Planning Phase 2 – Outage Process Refinements (RC_2013_15) will no longer be required and so is not shown here.

7A.2.8. A ~~Balancing~~ REM Submission for each Trading Interval in the ~~Balancing~~ Dispatch Horizon for which ~~Balancing~~ REM Gate Closure has not occurred must accurately reflect:

(a) all information reasonably available to the Market Participant, including ~~Balancing~~ Dispatch Forecasts published by the IMO, the information provided by the IMO under clause ~~7A.3.17~~ 7A.3.1(d) and the latest information available to it in relation to any Internal Constraint or External Constraint;

(b) the Market Participant's reasonable expectation of the capability of its ~~Balancing~~ REM Facilities to be dispatched in the ~~Balancing Market~~ REM; and

(c) the price at which the Market Participant submitting the ~~Balancing~~ REM Submission intends to have the ~~Balancing~~ REM Facility participate in ~~Balancing~~ the REM.

The addition of new clause 7A.2.8A reflects the proposed amendments in the Rule Change Proposal: Outage Planning Phase 2 – Outage Process Refinements (RC_2013_15), except that the requirement has been extended to include capacity from the Synergy Portfolio.

7A.2.8A. A Market Participant must, for each of its REM Facilities, and for each Trading Interval in the Dispatch 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 REM Submission for the Facility and the Trading Interval, unless the REM Facility is undertaking a Commissioning Test in that Trading Interval.

Please note that the proposed amendments to clause 7A.2.9 in the Rule Change Proposal: Outage Planning Phase 2 – Outage Process Refinements (RC_2013_15) will no longer be required and so are not shown here.

7A.2.9. Synergy, in relation to the ~~Balancing~~ Synergy Portfolio:

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

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

ii. Synergy's reasonable expectation of the capability of its ~~Balancing~~ Synergy Portfolio to be dispatched in the ~~Balancing Market~~ REM for that Trading Interval; and

iii. the price at which Synergy intends to have the ~~Balancing~~ Synergy Portfolio participate in ~~Balancing~~ the REM;

(b) must indicate in a manner and form prescribed by the IMO:

i. which ~~quantities in the Balancing Portfolio Supply Curve~~ of the REM Price-Quantity Pairs that it has priced at the Minimum STEM Price are for Facilities that are to provide LFAS;

ii. Facilities which are likely to provide LFAS; and

iii. for each completed Trading Interval, which Facilities actually provided the LFAS in the Trading Interval;

(c) must:

i. ensure that quantities in the ~~Balancing Portfolio Supply Curve~~ REM Price-Quantity Pairs that are required for the provision of Ancillary Services, other than LFAS, are priced at the Price Caps~~, to reflect that these quantities are not generally available for Balancing~~;

ii. advise the IMO in a manner and form prescribed by the IMO, the Facilities which are likely to provide the quantities specified in clause 7A.2.9(c)(i); and

iii. for each completed Trading Interval, advise the IMO which Facilities actually provided the Ancillary Services referred to in clause 7A.2.9(c)(i) in the Trading Interval;

(d) may update its ~~Balancing Portfolio Supply Curve~~ REM Submission in relation to any Trading Interval in the ~~Balancing~~ Dispatch Horizon ~~for which Balancing Gate Closure for that Trading Interval is more than two hours in the future:~~ up until 30 minutes before REM Gate Closure for that Trading Interval; and

~~i. by submitting its updated Balancing Portfolio Supply Curve to the IMO immediately before 6:00 PM; or~~

~~ii. otherwise by submitting its updated Balancing Portfolio Supply Curve to the IMO within one hour after LFAS Gate Closure;~~

(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 Balancing Portfolio has experienced a Forced Outage since the last Balancing Submission; and~~[Blank]

(f) may after the time specified in clause 7A.2.9(d), update its ~~Balancing Portfolio Supply Curve~~ REM Submission to reflect the impact of a Forced Outage which Synergy 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 Synergy's ~~Balancing~~ REM obligations in relation to the ~~Balancing~~ Synergy Portfolio under this Chapter 7A.

The addition of new clauses 7A.2.9A and 7A.2.9B reflects the proposed amendments in the Rule Change Proposal: Outage Planning Phase 2 – Outage Process Refinements (RC_2013_15). Please note that the clause 7A.2.9A proposed for RC_2013_15 will no longer be required as the relevant requirements for the Synergy Portfolio will be covered by clause 7A.2.8A. Clauses 7A.2.9B and 7A.2.9C (in RC_2013_15) have been renumbered to 7A.2.9A and 7A.2.9B accordingly; the IMO proposes to also renumber these clauses in the Draft Rule Change Report for RC_2013_15. This proposal (RC_2014_01) additionally updates market names.

7A.2.9A. If System Management rejects a previously approved Planned Outage of a REM Facility (or a Facility in the Synergy Portfolio) under clause 3.19.5, then the relevant Market Participant must, as soon as practicable, update its REM Submission for any relevant Trading Intervals in the Dispatch Horizon for which REM Gate Closure has not yet occurred, to reflect that the capacity will not be subject to a Planned Outage.

7A.2.9B. If System Management directs a Market Participant to return a REM Facility or a Facility in the Synergy 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 REM Submission for any relevant Trading Intervals in the Dispatch Horizon for which REM Gate Closure has not yet occurred, to reflect the impact of System Management's direction on the proposed end time of the Planned Outage.

7A.2.10. A Market Participant (other than Synergy in relation to the ~~Balancing~~ Synergy Portfolio) as soon as it becomes aware that a ~~Balancing~~ REM Submission for a Trading Interval for which ~~Balancing~~ REM Gate Closure has occurred is inaccurate:

(a) if the inaccuracy is due to an Internal Constraint, must make a new, accurate ~~Balancing~~ REM Submission so that the quantity in the ~~Balancing~~ REM Submission reflects the available Sent Out Capacity of that Facility and the Ramp Rate Limit is accurate but no prices are altered, in respect of that Trading Interval as soon as reasonably practicable;

(b) if the inaccuracy is due to an External Constraint, may make a new, accurate ~~Balancing~~ REM Submission so that the quantity in the ~~Balancing~~ REM Submission reflects the available Sent Out Capacity of that Facility and the Ramp Rate Limit is accurate but no prices are altered, in respect of that Trading Interval, as soon as reasonably practicable; or

(c) if the inaccuracy is due to the Market Participant receiving an Operating Instruction, may make a new, accurate ~~Balancing~~ REM Submission that reflects the Operating Instruction.

7A.2.10A. A Market Participant making a new REM Submission under clause 7A.2.10(a) or 7A.2.10(b) may:

(a) revise the Ramp Rate Limit; and

(b) reduce the quantity in the highest priced REM Price-Quantity Pairs and increase the unavailable capacity by the same amount,

but may make no other changes.

7A.2.11. Where a Market Participant has submitted a ~~Balancing~~ REM Submission in accordance with clauses 7A.2.10(a) or 7A.2.10(b) after ~~Balancing~~ REM Gate Closure, the Market Participant must, as soon as reasonably practicable, provide the IMO with written details of the nature of the Internal Constraint or External Constraint, when it occurred and its duration.

7A.2.12. Where Synergy has submitted an updated ~~Balancing Portfolio Supply Curve~~ REM Submission for the Synergy Portfolio in accordance with clause~~s 7A.2.9(e) or~~ 7A.2.9(f) because of a Forced Outage of one of the Facilities in the ~~Balancing~~ Synergy Portfolio after the time specified in ~~these clauses~~ clause 7A.2.9(d) it must, as soon as reasonably practicable, provide the IMO with written details of:

(a) the nature of the Forced Outage;

(b) when the Forced Outage occurred;

(c) the duration of the Forced Outage; and

(d) information substantiating the commercial impact, if any, of the Forced Outage.

7A.2.13. A Market Participant must:

(a) make a ~~Balancing~~ REM Submission under this ~~clause~~ section 7A.2 in good faith;

(b) not act in a manner that:

i. is intended to lead; or

ii. the Market Participant should have reasonably known is likely to lead,

to another Rule Participant being misled or deceived as to the existence or non-existence of a material fact relating to the ~~Balancing Market~~ REM; and

(c) not include information in a ~~Balancing~~ REM Submission relating to prices for a purpose of influencing the determination of the Constrained Off Compensation Price, the Constrained Off Quantity which the Facility may provide, the Constrained On Compensation Price or the Constrained On Quantity which the Facility may provide.

7A.2.14. ~~A~~ ~~Balancing~~ REM Submission is made in good faith under clause 7A.2.13 if, at the time it is submitted, the Market Participant had a genuine intention to honour the terms of that ~~Balancing~~ REM Submission if the material conditions and circumstances upon which the ~~Balancing~~ REM Submission was based remained unchanged until the relevant Trading Interval.

7A.2.15. A Market Participant may be taken to have not made a ~~Balancing~~ REM Submission in good faith notwithstanding that the intention of the Market Participant is ascertainable only by inference from:

(a) the conduct of the Market Participant;

(b) the conduct of any other person; or

(c) the relevant circumstances.

7A.2.16.

(a) If a Market Participant does not have reasonable grounds for a price, quantity or Ramp Rate Limit it has included in a ~~Balancing~~ REM Submission at the time it submits that ~~Balancing~~ REM Submission, then the Market Participant is, for the purposes of clause 7A.2.13(b), taken to have known that the ~~Balancing~~ REM Submission was likely to lead to another Rule Participant being misled or deceived as to the existence or non-existence of a material fact relating to the ~~Balancing Market~~ REM.

(b) For the purposes of clause 7A.2.16(a), a Market Participant must adduce evidence that it had reasonable grounds for including a price, quantity or Ramp Rate Limit in the ~~Balancing~~ REM Submission.

(c) To avoid doubt, the effect of clause 7A.2.16(b) is to place an evidentiary burden on a Market Participant, and clause 7A.2.16(b) does not have the effect that, merely because such evidence is adduced, the Market Participant who submitted the ~~Balancing~~ REM Submission is taken to have had reasonable grounds for including a price, quantity or Ramp Rate Limit, as applicable.

(d) Clause 7A.2.16(a) does not imply that merely because the Market Participant had reasonable grounds for making the representation or the conduct referred to in this Chapter 7A, and in particular putting the price, quantity or Ramp Rate Limit in a ~~Balancing~~ REM Submission submitted by a Market Participant, that such representation or conduct is not misleading.

7A.2.17. Subject to clauses 7A.2.3, 7A.2.9(c) and 7A.3.5, a Market Participant must not, for any Trading Interval, offer prices in its ~~Balancing~~ REM Submission in excess of the Market Participant's reasonable expectation of the short run marginal cost of generating the relevant electricity by the ~~Balancing~~ REM Facility, when such behaviour relates to market power.

7A.2.18. In determining whether a Market Participant has made a ~~Balancing~~ REM Submission in accordance with its obligations under this Chapter 7A, the IMO may take into account:

(a) historical ~~Balancing~~ REM Submissions, including changes made to ~~Balancing~~ REM Submissions, in which a pattern of behaviour may indicate an intention to create a false impression in the ~~Balancing Market~~ REM;

(b) the timeliness and accuracy of notification of Forced Outages, Internal Constraints, External Constraints and any information provided under clauses 7A.2.11 or 7A.2.12;

(c) any information as to whether a Facility was not able to comply with a Dispatch Instruction from System Management and the reasons for that non-compliance; and

(d) any other information that considered by the IMO to be relevant.

7A.2.19. For the purpose of regulation 37(a) of the WEM Regulations, where a civil penalty is imposed for a contravention of clauses 7A.2.8, 7A.2.9, 7A.2.13 or 7A.2.17 the civil penalty amount should be distributed amongst all Market Participants in proportion to their Market Fees calculated over the previous full 12 months~~, or part thereof if the Balancing Market Commencement Day was less than 12 months,~~ prior to the date the civil penalty is received.

The addition of new section 7A.2A reflects the proposed amendments in the Rule Change Proposal: Outage Planning Phase 2 – Outage Process Refinements (RC_2013_15). This proposal (RC_2014_01) additionally updates market names and removes the references to the 'latest' time specified in clause 7A.2.9(d) (as there is now only one time specified in that clause).

7A.2A. Unavailable capacity in a REM Submission

7A.2A.1. Subject to clause 7A.2A.3, a Market Participant (other than Synergy in respect of the Synergy Portfolio) must, as soon as practicable after REM Gate Closure for each Trading Interval, for each of its REM 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 REM Submission that:

(a) was not subject to an approved Planned Outage or Consequential Outage at REM 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.2. Subject to clause 7A.2A.3, Synergy must, as soon as practicable after the time specified in clause 7A.2.9(d) for a Trading Interval, for each Facility in the Synergy Portfolio that is an Outage Facility, ensure that it has notified System Management of a Forced Outage or Consequential Outage for any of its capacity declared unavailable in the Synergy Portfolio REM 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.3. Clauses 7A.2A.1 and 7A.2A.2 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) REM Gate Closure, for a Facility that is not in the Synergy Portfolio; or

(b) the time specified in clause 7A.2.9(d), for a Facility in the Synergy Portfolio.

7A.3. ~~BMO~~ Forecast DMO, Dispatch Forecast and Pricing ~~BMO~~ DMO

~~7A.3.1. The IMO must convert the prices for each Trading Interval in Balancing Price-Quantity Pairs in Balancing Submissions from Market Participants, other than Synergy in respect of the Balancing Portfolio, into Loss Factor Adjusted Prices.~~

~~7A.3.2. The IMO must determine the BMO for a Trading Interval as the ranked list of Balancing Submissions which, subject to clause 7A.3.3, is obtained by:~~

~~(a) ranking the Balancing Price-Quantity Pairs for a Trading Interval and associated Balancing Facilities contained in Balancing Submissions in order of lowest to highest prices (where these prices have been adjusted where appropriate in accordance with clause 7A.3.1); and~~

~~(b) where System Management provides a forecast of the EOI Quantity for a Non-Scheduled Generator under clause 7A.3.15, adjusting the Non-Scheduled Generator's Balancing Submission to reflect that quantity.~~

~~7A.3.3. In circumstances where there is a tie in the ranking of Balancing Facilities under clause 7A.3.2 in the BMO the IMO must break the tie in accordance with the Balancing Forecast Market Procedure, which must give effect to the following descending order of priority:~~

~~(a) a Balancing Facility that meets the Balancing Facility Requirements;~~

~~(b) a Balancing Facility that is subject to a condition under clause 7A.1.11(b);~~

~~(c) a Balancing Facility that does not meet the Balancing Facility Requirements;~~

~~(d) a Balancing Facility providing an Ancillary Service other than LFAS;~~

~~(e) a Balancing Facility providing LFAS; and~~

~~(f) priority will be based on the daily random number assigned to the Facility.~~

~~7A.3.4. A Balancing Facility assigned priority under clause 7A.3.3 means that the Facility will be placed in the BMO so that it will be issued a Dispatch Instruction in priority to the other Balancing Facility with which it was tied.~~

7A.3.1. The IMO must, to the extent that it is reasonably able, as soon as practicable during the first 15 minutes of each Trading Interval, for each future Trading Interval in the Dispatch Horizon:

(a) determine the Forecast DMO in accordance with clause 7A.3.2 using the most recent, valid REM Submissions available to it;

(b) provide to System Management the Forecast DMO determined under clause 7A.3.1(a);

(c) provide to each Market Participant the EOI Quantities expected to be provided by each of the Market Participant's REM Facilities in the Forecast DMO determined under clause 7A.3.1(a); and

(d) if the IMO has sufficient information available to it, determine the Dispatch Forecast in accordance with the Market Procedure for Dispatch Forecasts and publish it on the Market Web Site.

7A.3.2. The IMO must determine a Forecast DMO for a Trading Interval under clause 7A.3.1(a) by:

(a) converting the prices in REM Price-Quantity Pairs contained in REM Submissions for that Trading Interval into Loss Factor Adjusted Prices, for all REM Facilities except the Synergy Portfolio;

(b) subject to clause 7A.3.2(c), ranking the REM Price-Quantity Pairs and associated REM Facilities contained in REM Submissions for that Trading Interval in order of lowest to highest price, where these prices have been adjusted where appropriate in accordance with clause 7A.3.2(a);

(c) where there is a tie in the ranking of REM Facilities under clause 7A.3.2(b), breaking the tie in accordance with the Market Procedure for Dispatch Forecasts; and

(d) where System Management provides a forecast of the EOI Quantity for a Non-Scheduled Generator under clause 7A.3.15, adjusting the Non-Scheduled Generator's REM Submission to reflect that quantity.

7A.3.3. The IMO must document in the Market Procedure for Dispatch Forecasts the processes it must follow in:

(a) determining and providing to System Management Forecast DMOs;

(b) preparing and publishing Dispatch Forecasts; and

(c) assigning priority to Facilities in the case where there is a tie in a Forecast DMO or Forecast LFAS Merit Order.

7A.3.3A. The IMO must develop the Market Procedure for Dispatch Forecasts in accordance with the following principles:

(a) to the extent reasonably practicable, Dispatch Forecasts must use the latest information available to the IMO; and

(b) Dispatch Forecasts must provide Market Participants with information upon which to make an assessment regarding whether to make a REM Submission or to update a REM Submission.

7A.3.4. The IMO must, to the extent it is reasonably able, as soon as practicable, publish any aggregate forecast output of Non-Scheduled Generators which is received from System Management under clause 7.6A.2(e).

7A.3.5. ~~A~~ For each Trading Interval, as soon as practicable after the point in time 15 minutes after LFAS Gate Closure, a Market Participant, other than Synergy in respect of the ~~Balancing~~ Synergy Portfolio, must make a new ~~Balancing Submission within 30 minutes of the end of the Trading Interval in which the information is published under clause 7B.3.4(e) as follows:~~ REM Submission for the Trading Interval in accordance with clause 7A.2.2 for each of its LFAS Facilities in the LFAS Enablement Schedules, such that the following conditions hold:

(a) ~~where its LFAS Price-Quantity Pair is selected under clause 7B.3.4(b) for the Trading Interval, so that the price in the selected LFAS Price-Quantity Pair for the quantity of capacity equal to the Upwards LFAS Enablement of the Facility for that Trading Interval is at the Alternative Maximum STEM Price and the quantity of capacity for the Facility specified in item 1(b)(xiii) of Standing Data is at the Minimum STEM Price; and~~ the total quantity in REM Price-Quantity Pairs priced at the Alternative Maximum STEM Price is at least the Upwards LFAS Enablement for the Facility; and

(b) ~~where its LFAS Price-Quantity Pair is selected under clause 7B.3.4(c) for the Trading Interval, so that the price in the selected LFAS Price-Quantity Pair for the sum of the quantity of capacity for the Facility specified in item 1(b)(xiii) of Standing Data, plus the quantity of capacity equal to the Downwards LFAS Enablement of the Facility for that Trading Interval, is at the Minimum STEM Price.~~ the total quantity in REM Price-Quantity Pairs priced at the Minimum STEM Price is at least the quantity of capacity for the Facility specified in item 1(b)(xiii) of Standing Data plus the Downwards LFAS Enablement for the Facility.

7A.3.6. ~~The IMO must:~~

~~(a) determine the BMO under clause 7A.3.2 for a Trading Interval using the most recent, valid Balancing Submissions available to it; and~~

~~(b) each time the IMO creates a BMO for a Trading Interval, provide this BMO to System Management between 15 to 30 minutes before the start of that Trading Interval.~~ [Blank]

7A.3.7. System Management must, no later than two hours after the end of the Trading Day, provide the IMO with an estimate of:

(a) the SOI Quantity and the EOI Quantity for each ~~Balancing~~ REM Facility; and

(b) the Relevant Dispatch Quantity,

for each Trading Interval in the Trading Day, determined in accordance with the Power System Operation Procedure.

7A.3.7A. System Management must make reasonable endeavours to provide to the IMO, no later than five minutes after the end of each Trading Interval, an estimate of:

(a) the SOI Quantity and the EOI Quantity for each ~~Balancing~~ REM Facility; and

(b) the Relevant Dispatch Quantity,

for that Trading Interval, determined in accordance with the Power System Operation Procedure.

7A.3.8. The IMO must, by the end of a Trading Day where it has been provided with the information under clause 7A.3.7 for a Trading Interval in the previous Trading Day:

(a) use that information to determine a Provisional Pricing ~~BMO~~ DMO for that Trading Interval;

(b) use the Provisional Pricing ~~BMO~~ DMO under clause 7A.3.8(a) to determine the Provisional ~~Balancing~~ Energy Price, being the Loss Factor Adjusted Price corresponding to the point where the estimated Relevant Dispatch Quantity plus 1 MW intersects the Provisional Pricing ~~BMO~~ DMO; and

(c) publish the Provisional ~~Balancing~~ Energy Price on the Market Web Site.

7A.3.9. Subject to clause 7A.3.12, System Management must, as soon as reasonably practicable but in any event no later than 24 hours after the start of the Business Day following the time specified in clause 7A.3.7, provide the IMO with any updated adjustments to the information provided under clause 7A.3.7 and the IMO must use any such updated SOI Quantity and EOI Quantity information to revise the Provisional Pricing ~~BMO~~ DMO accordingly.

7A.3.10. The IMO must ~~calculate~~ use the Pricing ~~BMO~~ DMO, subject to clause 7A.3.13, ~~using the Provisional Pricing BMO determined under clause 7A.3.8(a), as revised under clause 7A.3.9,~~ to determine the ~~Balancing~~ Energy Price, being the Loss Factor Adjusted Price corresponding to the point where the Relevant Dispatch Quantity plus 1 MW intersects the Pricing ~~BMO~~ DMO. ~~Where there is no change to the Provisional Balancing Price determined under clause 7A.3.8(b), that price is deemed to be the Balancing Price.~~

7A.3.11. The IMO must, subject to clause 7A.3.12, publish the ~~Balancing~~ Energy Price for each Trading Interval in a Trading Day on the next Business Day after the latest time specified in clause 7A.3.9.

7A.3.13. If the IMO is unable to determine the ~~Balancing~~ Energy Price under clause 7A.3.10 in time to publish it in accordance with clause 7A.3.11, including because it has not received the information required to be provided by System Management under clauses 7A.3.7 or 7A.3.9, the IMO must determine the ~~Balancing~~ Energy Price:

(a) where the Relevant Dispatch Quantity and/or Pricing ~~BMO~~ DMO is not available, the IMO must use the forecast Relevant Dispatch Quantity and/or ~~BMO~~ DMO ~~and/or the Forecast Relevant Dispatch Quantity~~ for the Trading Interval so that the ~~Balancing~~ Energy Price is the point where the Relevant Dispatch Quantity or most recent forecast of the Relevant Dispatch

Quantity (as applicable) intersects the Pricing ~~BMO~~ DMO or ~~most recent BMO~~ DMO (as applicable); and

(b) ~~where the Pricing BMO and the BMO are not available for the Trading Interval the IMO must use the most recent Forecast BMO in place of the BMO in clause 7A.3.13(a); and~~[Blank]

(c) where there is no Forecast ~~BMO~~ DMO:

i. if the IMO is determining the ~~Balancing~~ Energy Price for a Trading Interval in a Business Day, the ~~Balancing~~ Energy Price will be the value for the equivalent Trading Interval in the most recent Trading Day in the past which is also a Business Day; or

ii. if the IMO is determining the ~~Balancing~~ Energy Price for a Trading Interval in a day which is not a Business Day, the ~~Balancing~~ Energy Price will be the value for the equivalent Trading Interval in the most recent Trading Day in the past which is also not a Business Day.

7A.3.14. Once the IMO has published the ~~Balancing~~ Energy Price under clause 7A.3.11 it cannot be altered by:

(a) disagreement under clause 9.20.6; or

(b) disputes under clause 9.21.1.

~~Forecast BMO~~

7A.3.15. System Management must, for each future Trading Interval in the ~~Balancing~~ Dispatch Horizon, provide the IMO with System Management's forecast of the Relevant Dispatch Quantity, and may provide a forecast of the EOI Quantity for Non-Scheduled Generators, each determined in accordance with the Power System Operation Procedure. System Management must, each time it has new information on which to determine these quantities, update these forecasts and provide the update to the IMO, but is not required to do so more than once per Trading Interval.

~~7A.3.16. The IMO must for each future Trading Interval in the Balancing Horizon determine a Forecast BMO.~~

~~7A.3.17. Where the IMO determines a Forecast BMO under clause 7A.3.16, the IMO must:~~

~~(a) provide to each Market Participant the Balancing quantities expected to be provided by that Market Participant for each future Trading Interval in the Balancing Horizon; and~~

~~(b) provide to System Management the Forecast BMO.~~

~~7A.3.18. The IMO must provide the information required under clause 7A.3.17 at approximately the same time as the IMO publishes the Balancing Forecasts under clause 7A.3.21.~~

~~Balancing Forecast~~

~~7A.3.19. The IMO must, if it has sufficient information available to it, determine and publish under clause 7A.3.21 the Balancing Forecast for each Trading Interval in the Balancing Horizon in accordance with the Balancing Forecast Market Procedure.~~

~~7A.3.20. The IMO must develop the Balancing Forecast Market Procedure in accordance with the following principles:~~

~~(a) to the extent reasonably practicable, the Balancing Forecasts and the Forecast BMOs must use the latest information available to the IMO; and~~

~~(b) to provide Market Generators with information upon which to make an assessment regarding whether to make a Balancing Submission or to update a Balancing Submission in accordance with the Market Rules.~~

~~7A.3.21. The IMO must, to the extent it is reasonably able within the Trading Interval, commencing at 6:00 PM on Balancing Market Commencement Day:~~

~~(a) publish on the Market Web Site a Balancing Forecast for each Trading Interval during the Balancing Horizon;~~

~~(b) by the end of every half hour thereafter, publish a Balancing Forecast for each future Trading Interval in the Balancing Horizon; and~~

~~(c) as soon as practicable, publish any aggregate forecast output of Non-Scheduled Generators which is received from System Management under clause 7.6A.2(e).~~

7A.4.4. If the IMO notifies Synergy that it accepts the nomination of the Stand Alone Facility for a trial, then:

(a) the IMO must notify Synergy of the Trading Day from which the trial of the nominated Stand Alone Facility will commence;

(b) subject to clause 7A.4.4(d), Synergy may trial the nominated Stand Alone Facility for a period of one month for the purposes of participating in the ~~Balancing Market~~ REM in accordance with this Chapter 7A;

(c) seven Business Days before the end of that month Synergy must notify the IMO whether it wishes the nominated Stand Alone Facility to:

i. cease being a Stand Alone Facility and to form part of the ~~Balancing~~ Synergy Portfolio; or

ii. permanently become a Stand Alone Facility; and

(d) the nominated Stand Alone Facility will be treated as a Stand Alone Facility until it becomes a permanent Stand Alone Facility under clause 7A.4.9 or the trial ceases under clause 7A.4.8.

7B.1.4. System Management must, by 12:00 PM on the Scheduling Day, provide the IMO with ~~System Management's forecast of~~ the Forecast Upwards LFAS Quantity and the Forecast Downwards LFAS Quantity for each Trading Interval in the next

Trading Day, determined in accordance with the Power System Operation Procedure.

7B.1.5. System Management may update the ~~forecast~~ Forecast LFAS ~~Quantity~~ Quantities provided under clause 7B.1.4 for a Trading Interval in the ~~Balancing~~ Dispatch Horizon at any time until ~~60 minutes~~ one hour before the LFAS Gate Closure for that Trading Interval. System Management may update the ~~forecast~~ Forecast LFAS ~~Quantity~~ Quantities more than once.~~.~~

7B.2.1. A Market Participant may submit an LFAS Submission in respect of any of its LFAS Facilities, other than the Synergy Portfolio:

(a) in accordance with clause 7B.2.7 ~~in respect of any of its LFAS Facilities, other than the Balancing Portfolio~~;

(b) for any or all Trading Intervals in the ~~Balancing~~ Dispatch Horizon; and

(c) before LFAS Gate Closure for those Trading Intervals.

7B.2.2. A Market Participant may submit ~~a new,~~ an updated LFAS Submission in respect of any of its LFAS Facilities other than the Synergy Portfolio:

(a) in accordance with clause 7B.2.7 ~~in respect of any of its LFAS Facilities, other than the Balancing Portfolio~~;

(b) for one or more Trading Intervals in the ~~Balancing~~ Dispatch Horizon; and

(c) before LFAS Gate Closure for those Trading Intervals.

7B.2.3. ~~Subject to clause 7B.2.5,~~ Synergy must immediately before ~~6:00 PM~~ 1:00 PM submit an LFAS Submission, for ~~one or more~~ all Trading Intervals in the ~~Balancing~~ Dispatch Horizon for which ~~LFAS Gate Closure has not occurred~~ it has not already made an LFAS Submission, by submitting it to the IMO in accordance with clauses 7B.2.5, 7B.2.6 and 7B.2.7.

7B.2.4. Subject to clause 7B.2.5, Synergy may submit ~~or update an~~ an updated LFAS Submission~~, for one or more Trading Intervals in the Balancing Horizon for which LFAS Gate Closure has not occurred, by submitting it to the IMO~~ in respect of the Synergy Portfolio:

(a) in accordance with clauses ~~7B.2.5~~ 7B.2.6 and 7B.2.7; ~~and~~

(b) ~~at the time it submits an updated Balancing Portfolio Supply Curve under clause 7A.2.9(d).~~for one or more Trading Intervals in the Dispatch Horizon; and

(c) more than 30 minutes before LFAS Gate Closure for those Trading Intervals.

7B.2.5. Synergy must ensure that, for each Trading Interval for which it has made LFAS Submissions ~~under this Chapter 7B, the sum of the MW quantities contained in those LFAS Submissions equals at least the latest forecast LFAS Quantity for that Trading Interval published under clause 7B.3.15(b), if any.~~:

(a) the sum of the MW quantities contained in the Upwards LFAS Price-Quantity Pairs in those LFAS Submissions equals at least the latest Forecast Upwards LFAS Quantity for that Trading Interval published under clause 7B.3.1(d)(i), if any; and

(b) the sum of the MW quantities contained in the Downwards LFAS Price-Quantity Pairs in those LFAS Submissions equals at least the latest Forecast Downwards LFAS Quantity for that Trading Interval published under clause 7B.3.1(d)(i), if any.

7B.2.6. Synergy, in its LFAS Submission for the ~~Balancing~~ Synergy Portfolio, must include a cost per MW for providing any Backup Upwards LFAS ~~Backup~~ Enablement and for providing any Backup Downwards LFAS ~~Backup~~ Enablement for each Trading Interval in the ~~Balancing~~ Dispatch Horizon.

7B.2.10. ~~A~~ Subject to clause 7B.2.4, a Market Participant with an LFAS Facility must ensure that any LFAS Submission for a Trading Interval in ~~an LFAS Horizon~~ the Dispatch Horizon for which LFAS Gate Closure has not occurred accurately reflects:

(a) all information reasonably available to it;

(b) the Market Participant's reasonable expectation of the capability of the LFAS Facility to provide the LFAS to the LFAS Market; and

(c) the price at which the Market Participant intends to have the LFAS Facility provide LFAS.

7B.2.16. In determining whether a Market Participant has made an LFAS Submission in accordance with its obligations under this Chapter 7B, the IMO may take into account:

(a) historical LFAS Submissions and/or ~~Balancing~~ REM Submissions, including changes made to LFAS Submissions and/or ~~Balancing~~ REM Submissions in which a pattern of behaviour may indicate an intention to create a false impression in the LFAS Market;

(b) any information as to whether a Facility was not able to provide LFAS and the reasons for that failure; and

(c) any other information that ~~considered by~~ the IMO considers to be relevant.

7B.2.17. For the purpose of regulation 37(a) of the WEM Regulations, where a civil penalty is imposed for a contravention of clauses 7B.2.10, 7B.2.11 or 7B.2.15, the civil penalty amount must be distributed amongst all Market Participants in proportion to their Market Fees calculated over the previous full 12 months~~, or part thereof if the Balancing Market Commencement Day was less than 12 months,~~ prior to the date the civil penalty is received.

7B.2.18. ~~Where an LFAS Facility is selected under clauses 7B.3.4(b) or 7B.3.4(c) to provide LFAS in a Trading Interval, then a~~ A Market Participant must, as soon as it becomes aware that ~~the~~ an LFAS Facility in an LFAS Enablement Schedule is

physically unable to provide some or all of ~~the LFAS Quantity for which it has been selected~~ its LFAS Enablement, advise the IMO and System Management, in the manner and form prescribed by the IMO and System Management respectively, whether the LFAS Facility is physically able to provide any LFAS in that Trading Interval and if so, the quantity, in MW.

7B.2.19. ~~Where an LFAS Facility is selected under clauses 7B.3.4(b) or 7B.3.4(c) to provide LFAS in a Trading Interval, then a~~ A Market Participant must, unless it has provided advice to the IMO and System Management under clause 7B.2.18, ensure that its LFAS Facilities in the LFAS Enablement Schedule provide ~~the~~ LFAS in the Trading Interval when required to do so by System Management under the Market Rules.

7B.3. LFAS Merit Order and LFAS Price

~~7B.3.1. The IMO must determine the LFAS Upwards Merit Order for a Trading Interval by deriving a ranked list of LFAS Submissions and associated LFAS Facilities. Subject to clause 7B.3.3, the list is obtained by ranking LFAS Upwards Price-Quantity Pairs for a Trading Interval contained in LFAS Submissions in order of lowest to highest price.~~

~~7B.3.2. The IMO must determine the LFAS Downwards Merit Order for a Trading Interval by deriving a ranked list of LFAS Submissions and associated LFAS Facilities. Subject to clause 7B.3.3, the list is obtained by ranking LFAS Downwards Price-Quantity Pairs for a Trading Interval contained in LFAS Submissions in order of lowest to highest price.~~

~~7B.3.3. In circumstances where there is a tie in the ranking of LFAS Facilities under clauses 7B.3.1 or 7B.3.2 in the LFAS Merit Order the IMO must assign priority to break the tie for the Trading Interval in which the tie occurred. Priority, for the relevant Trading Day, will be based on a daily random number assigned to each LFAS Facility in accordance with the Balancing Forecast Market Procedure.~~

~~7B.3.4. The IMO must to the extent that it is able:~~

~~(a) determine the LFAS Merit Order for each Trading Interval in an LFAS Horizon for which LFAS Gate Closure has occurred, as soon as reasonably practicable after the LFAS Gate Closure, using the most recent, valid LFAS Submissions available to it;~~

~~(b) select from the LFAS Upwards Merit Order derived under clause 7B.3.4(a) the lowest priced LFAS Upwards Price-Quantity Pair or LFAS Upwards Price-Quantity Pairs, and associated LFAS Facility or LFAS Facilities, so that:~~

~~i. the capacity in the lowest priced LFAS Upwards Price-Quantity Pair, or the sum of the capacity in the lowest priced LFAS Upwards Price-Quantity Pairs, equals the LFAS Requirement; and~~

ii. if only part of the capacity in the highest priced LFAS Upwards Price-Quantity Pair selected in clause 7B.3.4(b)(i) is required to make up the LFAS Requirement, that LFAS Upwards Price-Quantity Pair is selected for that part of its capacity only;

(c) select from the LFAS Downwards Merit Order derived under clause 7B.3.4(a) the lowest priced LFAS Downwards Price-Quantity Pair or LFAS Downwards Price-Quantity Pairs, and associated LFAS Facility or LFAS Facilities, so that:

i. the capacity in the lowest priced LFAS Downwards Price-Quantity Pair, or the sum of the capacity in the lowest priced LFAS Downwards Price-Quantity Pairs, equals the LFAS Requirement; and

ii. if only part of the capacity in the highest priced LFAS Downwards Price-Quantity Pair selected in clause 7B.3.4(c)(i) is required to make up the LFAS Requirement, that LFAS Downwards Price-Quantity Pair is selected for that part of its capacity only;

(d) provide to System Management the details of:

i. the LFAS Facility or Facilities determined under clause 7B.3.4(b) and the associated LFAS Facility quantities and the associated Trading Interval; and

ii. the LFAS Facility or Facilities determined under clause 7B.3.4(c) and the associated LFAS Facility quantities and the associated Trading Interval; and

(e) each time the IMO creates an LFAS Merit Order, publish the highest price selected under each of clauses 7B.3.4(b) and 7B.3.4(c) for each Trading Interval in the LFAS Horizon to which the LFAS Merit Order relates, as soon as reasonably practicable after the determination, but no later than 15 minutes after the LFAS Gate Closure to which the LFAS Merit Order relates.

7B.3.5. The IMO must, to the extent it is reasonably able:

(a) provide the information referred to in clause 7B.3.4(d) within 15 minutes of the LFAS Gate Closure to which the information relates; and

(b) notify the Market Participant with the LFAS Facility or Facilities selected under clauses 7B.3.4(b) and 7B.3.4(c) of that selection and the associated LFAS Facility quantities to be provided by Trading Interval, within 15 minutes of the LFAS Gate Closure for that Trading Interval.

7B.3.1. The IMO must, to the extent that it is reasonably able, as soon as practicable during the first 15 minutes of each Trading Interval, for the Trading Interval for which LFAS Gate Closure has most recently occurred and for each later Trading Interval in the Dispatch Horizon:

(a) determine using the most recent, valid LFAS Submissions available to it:

i. the Forecast Upwards LFAS Merit Order in accordance with clause 7B.3.2(a);

ii. the Forecast Downwards LFAS Merit Order in accordance with clause 7B.3.2(b);

iii. the Forecast Upwards LFAS Enablement Schedule in accordance with clause 7B.3.3(a);

iv. the Forecast Downwards LFAS Enablement Schedule in accordance with clause 7B.3.3(b);

v. the Forecast Upwards LFAS Price in accordance with clause 7B.3.4(a); and

vi. the Forecast Downwards LFAS Price in accordance with clause 7B.3.4(b);

(b) provide to System Management the Forecast LFAS Enablement Schedules determined under clauses 7B.3.1(a)(iii) and 7B.3.1(a)(iv);

(c) notify each Market Participant with an LFAS Facility in an LFAS Enablement Schedule determined under clause 7B.3.1(a)(iii) or 7B.3.1(a)(iv) of the details of its LFAS Enablements; and

(d) publish on the Market Web Site to each Market Participant:

i. the Forecast LFAS Quantities, determined from the most recent quantities provided by System Management under clause 7B.1.4 or 7B.1.5;

ii. the Forecast LFAS Merit Orders, determined under clauses 7B.3.1(a)(i) and 7B.3.1(a)(ii), in the form of anonymous LFAS Price-Quantity Pairs;

iii. the Forecast LFAS Prices, determined under clauses 7B.3.1(a)(v) and 7B.3.1(a)(vi); and

iv. the Forecast Backup LFAS Prices, determined from the most recent, valid LFAS Submissions made in accordance with clause 7B.2.6.

The IMO intends to propose changes to the Market Procedure for Dispatch Forecasts so that the random number used to break ties under clause 7A.3.3(c) would also be used to break ties under clause 7B.3.2(c).

7B.3.2. The IMO must:

(a) subject to clause 7B.3.2(c), determine a Forecast Upwards LFAS Merit Order for a Trading Interval under clause 7B.3.1(a)(i) by ranking Upwards LFAS Price-Quantity Pairs and associated LFAS Facilities contained in LFAS Submissions for that Trading Interval in order of lowest to highest price;

(b) subject to clause 7B.3.2(c), determine a Forecast Downwards LFAS Merit Order for a Trading Interval under clause 7B.3.1(a)(ii) by ranking Downwards LFAS Price-Quantity Pairs and associated LFAS Facilities contained in LFAS Submissions for that Trading Interval in order of lowest to highest price; and

(c) in circumstances where there is a tie in the ranking of LFAS Facilities under clauses 7B.3.2(a) or 7B.3.2(b) in an LFAS Merit Order, break the tie for the Trading Interval in which the tie occurred in accordance with the Market Procedure for Dispatch Forecasts.

7B.3.3. The IMO must:

(a) determine a Forecast Upwards LFAS Enablement Schedule for a Trading Interval under clause 7B.3.1(a)(iii) by selecting the lowest priced Upwards LFAS Price-Quantity Pairs and associated LFAS Facilities from the Forecast Upwards LFAS Merit Order determined under clause 7B.3.1(a)(i), so that:

i. the sum of the quantities in the selected Upwards LFAS Price-Quantity Pairs equals the Forecast Upwards LFAS Quantity; and

ii. if only part of the quantity in the highest priced Upwards LFAS Price-Quantity Pair selected is required to make up the Forecast Upwards LFAS Quantity, that Upwards LFAS Price-Quantity Pair is selected for that part of the offered quantity only; and

(b) determine a Forecast Downwards LFAS Enablement Schedule for a Trading Interval under clause 7B.3.1(a)(iv) by selecting the lowest priced Downwards LFAS Price-Quantity Pairs and associated LFAS Facilities from the Forecast Downwards LFAS Merit Order determined under clause 7B.3.1(a)(ii), so that:

i. the sum of the quantities in the selected Downwards LFAS Price-Quantity Pairs equals the Forecast Downwards LFAS Quantity; and

ii. if only part of the quantity in the highest priced Downwards LFAS Price-Quantity Pair selected is required to make up the Forecast Downwards LFAS Quantity, that Downwards LFAS Price-Quantity Pair is selected for that part of the offered quantity only.

7B.3.4. The IMO must:

(a) determine a Forecast Upwards LFAS Price for a Trading Interval under clause 7B.3.1(a)(v) by determining the highest price in those Upwards LFAS Price-Quantity Pairs in the Forecast Upwards Enablement Schedule; and

(b) determine a Forecast Downwards LFAS Price for a Trading Interval under clause 7B.3.1(a)(vi) by determining the highest price in those Downwards LFAS Price-Quantity Pairs in the Forecast Downwards Enablement Schedule.

7B.3.5. [Blank]

7B.3.6. Subject to clauses 7B.2.18, 7B.3.7, 7B.3.8 and 7B.4.1, for each Trading Interval, System Management must ~~use the LFAS Facilities referred to in clause 7B.3.4(d) for meeting LFAS requirements in the associated Trading Interval in reasonable proportion to the quantities selected under clauses 7B.3.4(b) and 7B.3.4(c), as applicable~~ activate each LFAS Facility in each LFAS Enablement Schedule for its full LFAS Enablement and use those LFAS Facilities to provide the relevant LFAS in reasonable proportion to their relevant LFAS Enablement, and those LFAS Facilities must provide ~~those~~ that LFAS ~~requirements~~.

7B.3.7. ~~Where the IMO is unable to publish an LFAS Merit Order for a Trading Interval in accordance with clause 7B.3.4(d)~~Where an LFAS Enablement Schedule for a Trading Interval does not exist, System Management must use Synergy's LFAS Facilities to provide LFAS for that Trading Interval.

7B.3.8. System Management may select and use LFAS Facilities other than in accordance with an LFAS ~~Merit Order~~ Enablement Schedule where System Management considers, on reasonable grounds, that it needs to do so in order to operate the SWIS in a reliable and safe manner.

~~LFAS Price~~

7B.3.9. ~~The IMO must, at the time it makes the selection under clause 7B.3.4(b), determine the Upwards LFAS Price for a Trading Interval as the highest price in those selected LFAS Upwards Price-Quantity Pairs.~~[Blank]

7B.3.10. ~~The IMO must, at the time it makes the selection under clause 7B.3.4(c), determine the Downwards LFAS Price for a Trading Interval as the highest price in those selected LFAS Downward Price-Quantity Pairs.~~[Blank]

7B.3.11. The IMO must, by the end of a Trading Day, publish the LFAS Prices for each Trading Interval for that Trading Day.

7B.3.12. If the IMO is unable to determine an LFAS Price under clauses ~~7B.3.9 or 7B.3.10~~ 7B.3.4(a) or 7B.3.4(b) in time to publish it in accordance with clause 7B.3.11, the IMO must determine ~~the~~ that LFAS Price as follows:

(a) if the IMO is determining an LFAS Price for a Trading Interval in a Business Day, ~~the~~ that LFAS Price will be the value of the equivalent LFAS Price for the equivalent Trading Interval in the most recent Trading Day in the past which is also a Business Day; or

(b) if the IMO is determining an LFAS Price for a Trading Interval in a day which is not a Business Day, ~~the~~ that LFAS Price will be the value of the equivalent LFAS Price for the equivalent Trading Interval in the most recent Trading Day in the past which is also not a Business Day.

~~Forecast LFAS Merit Order~~

~~7B.3.14. The IMO must, for each future Trading Interval in the Balancing Horizon for which LFAS Gate Closure has not occurred, determine a forecast LFAS Merit Order.~~

~~7B.3.15. Where the IMO determines the forecast LFAS Merit Order under clause 7B.3.14, the IMO must, to the extent it is reasonably able, within a Trading Interval, publish on the Market Web Site to each Market Participant:~~

~~(a) the LFAS Quantities expected to be provided by that Market Participant for each Trading Interval in the Balancing Horizon as indicated by the forecast LFAS Merit Orders;~~

~~(b) any quantities provided to the IMO by System Management under clauses 7B.1.4 and 7B.1.5;~~

~~(c) forecasts of LFAS Prices based upon the forecast LFAS Merit Orders;~~

~~(d) forecasts of LFAS Upwards Merit Orders and LFAS Downwards Merit Orders in the form of anonymous LFAS Upwards Price-Quantity Pairs and LFAS Downwards Price-Quantity Pairs; and~~

~~(e) forecasts of Backup Upwards LFAS Prices and Backup Downwards LFAS Prices for each future Trading Interval in the Balancing Horizon.~~

~~7B.3.16. Where the IMO determines the forecast LFAS Merit Order under clause 7B.3.14, the IMO must, to the extent it is reasonably able, within a Trading Interval, provide to System Management the forecast LFAS Merit Order.~~

7B.4. Synergy – ~~Back Up~~ Backup LFAS Provider

7B.4.1. Where:

(a) an LFAS Facility in an LFAS Enablement Schedule has failed to provide all or part of its LFAS Enablement when called upon to do so by System Management in accordance with clause 7B.3.6 or 7B.3.8; ~~or~~

(aA) the LFAS Enablement of an LFAS Facility in an LFAS Enablement Schedule is greater than the LFAS Facility's available capacity, taking into account the DMO, Ramp Rate Limits and the quantities of capacity for the Facility specified in items 1(b)(iii), 1(b)(xiii) and 1(b)(xv) of Appendix 1; or

(b) the quantity of upwards or downwards LFAS in a Trading Interval required by System Management is greater than the Upwards LFAS Quantity or Downwards LFAS Quantity for that Trading Interval,

System Management may use the ~~Balancing~~ Synergy Portfolio or a Stand Alone Facility~~,~~ to provide the LFAS Quantity Balance and/or the Increased LFAS Quantity, as applicable.

7B.4.2. Where System Management has used the ~~Balancing~~ Synergy Portfolio or a Stand Alone Facility to provide LFAS under clause 7B.3.7 or 7B.4.1 in a Trading Interval, System Management must, as soon as reasonably practicable, advise the IMO of

the Facilities which provided the LFAS and the quantity, in MW, of LFAS which was provided by the Facility in the Trading Interval.

9.3.3. The IMO must determine the Metered Schedule for each of the following Facility types for each Trading Interval in accordance with clause 9.3.4:

(a) Non-Dispatchable Loads;

(b) Interruptible Loads;

(c) ~~Dispatchable Loads;~~[Blank]

(d) Scheduled Generators; and

(e) Non-Scheduled Generators.

9.3.4. Subject to clause 2.30B.10, the Metered Schedule for a Trading Interval for each of the following Facilities:

(a) Non-Dispatchable Loads, excluding those Non-Dispatchable Loads referred to in clause 9.3.4A;

(b) Interruptible Loads;

(c) ~~Dispatchable Loads;~~[Blank]

(d) Scheduled Generators; and

(e) Non-Scheduled Generators,

is the net quantity of energy generated and sent out into the relevant Network or consumed by the Facility during that Trading Interval, Loss Factor adjusted to the Reference Node, and determined from Meter Data Submissions received by the IMO in accordance with clause 8.4 or SCADA data received from System Management in accordance with clause 7.13.1(cA) where interval meter data is not available.

9.3.7. The IMO must determine the Consumption_Share(p,m) for Market Participant p in each Trading Month m, to equal

(a) the Market Participant's contributing quantity; divided by

(b) the total contributing quantity of all Market Participants,

where the contributing quantity for a Market Participant for Trading Month m is the sum of the Metered Schedules for the Non-Dispatchable Loads~~,~~ and Interruptible Loads ~~and Dispatchable Loads~~ registered to the Market Participant for all Trading Intervals during Trading Month m.

9.8.1. The ~~balancing settlement~~ Balancing Settlement amount for Market Participant p for Trading Interval t of Trading Day d is:

BSA (p,d,t) = ~~Balancing~~ Energy Price (d,t) x MBQ(p,d,t) + CONC(p,d,t) + COFFC(p,d,t)
+ DIP(p,d,t).

Where:

MBQ(p,d,t) is the Metered Balancing Quantity for Market Participant p for Trading Interval t of Trading Day d calculated in accordance with clause 6.17.2;

~~Balancing~~ Energy Price (d,t) is the ~~Balancing~~ Energy Price for Trading Interval t of Trading Day d calculated in accordance with clause 7A.3.10;

CONC(p,d,t) is the Constrained On Compensation for Market Participant p for Trading Interval t of Trading Day d. For a Market Participant other than Synergy, CONC(p,d,t) is the sum of all ConQN x ConPN for each of the Market Participant's Scheduled Generators and Non-Scheduled Generators for Trading Interval t. For Synergy, CONC(p,d,t) is the sum of all PConQN x PConPN plus the sum of all ConQN x ConPN for each Stand Alone Facility for Trading Interval t, where ConQN, ConPN, PConQN and PConPN are calculated in accordance with ~~clause~~ section 6.17;

COFFC(p,d,t) is the Constrained Off Compensation for Market Participant p for Trading Interval t of Trading Day d. For a Market Participant other than Synergy, COFFC(p,d,t) is the sum of all CoffQN x CoffPN for each of the Market Participant's Scheduled Generators and Non-Scheduled Generators for Trading Interval t. For Synergy, COFFC(p,d,t) is the sum of all PCoffQN x PCoffPN plus the sum of all CoffQN x CoffPN for each Stand Alone Facility for Trading Interval t, where CoffQN, CoffPN, PCoffQN and PCoffPN are calculated in accordance with ~~clause~~ section 6.17; and

DIP(p,d,t) is the ~~Non-Balancing Facility~~ Non-REM Dispatch Instruction Payment for Market Participant p for Trading Interval t of Trading Day d calculated in accordance with clause 6.17.6.

9.9.2. The following terms relate to Load Following Service and Spinning Reserve Service costs in Trading Month m:

…

(f) the total payment to all Market Participants for Spinning Reserve Service in Trading Interval t:

SR_Availability_Payment(t) =
0.5 × Margin(t) × ~~Balancing~~ Energy Price(t)
× max(0,SR_Capacity(t) – LF_Up_Capacity(t)
- Sum(c∈CAS_SR,ASP_SRQ(c,t)))
+ Sum(c∈CAS_SR,ASP_SRPayment(c,m) / TITM)

(g) the total payment to Market Participants for Spinning Reserve Service in Trading Month m:

SR_Availability_Payment(m) =
Sum(t∈T, SR_Availability_Payment(t))

(h) the assumed total cost of Spinning Reserve Service if no Spinning Reserve was provided by Load Following plant and without the Ancillary Service cost saving, in Trading Interval t:

SR_NoLF_Cost(t) =
0.5 × Margin(t) × ~~Balancing~~ Energy Price(t)
× max(0,SR_Capacity(t) – Sum(c∈CAS_SR,ASP_SRQ(c,t)))
+ Sum(c∈CAS_SR,ASP_SRPayment(c,m) / TITM)

(i) the Ancillary Service cost saving, derived through the dual use of plant to simultaneously provide Spinning Reserve Service and Load Following Service in Trading Interval t in Trading Month m:

AS_Cost_Saving(t) =
0.5 × Margin(t) × ~~Balancing~~ Energy Price(t)
× min(LF_Up_Capacity(t),
SR_Capacity(t) – Sum(c∈CAS_SR,ASP_SRQ(c,t)))

…

(l) the Spinning Reserve availability cost share for Market Participant p, which is a Market Generator, for Trading Month m:

SR_Availability_Cost_Share(p,m) =
Sum(t∈T, SR_Share(p,t) ×
((0.5 × Margin(t) × ~~Balancing~~ Energy Price(t)
× max(0, SR_Capacity(t) – LF_Up_Capacity(t)
- Sum(c∈CAS_SR,ASP_SRQ(c,t))))
+ Sum(c∈CAS_SR, ASP_SRPayment(c,m) / TITM)
+ (AS_Saving_Factor(t) × AS_Cost_Saving(t))))

…

(q) the total Load Following capacity cost for Trading Month m:

LF_Capacity_Cost(m) =
Sum(p∈P, LF_Capacity_Cost_Share(p,m))

Where

t denotes a Trading Interval in Trading Month m;

T is the set of Trading Intervals in Trading Month m;

LF_Up(p,t) is the sum of any Ex-post Upwards LFAS Enablement quantities provided under clause 7.13.1(e) for LFAS Facilities registered to Market Participant p in Trading Interval t;

LF_Up_Price(t) is the Upwards LFAS Price for Trading Interval t;

LF_Up_Backup(p,t) is the sum of any Backup Upwards LFAS ~~Backup~~ Enablement quantities for Trading Interval t if Market Participant p is Synergy and 0 otherwise;

LF_Up_Backup_Price(p,t) is the Backup Upwards LFAS Price for Trading Interval t if Market Participant p is Synergy and 0 otherwise;

LF_Down(p,t) is the sum of any Ex-post Downwards LFAS Enablement quantities provided under clause 7.13.1(eC) for LFAS Facilities registered to Market Participant p in Trading Interval t;

LF_Down_Price(t) is the Downwards LFAS Price for Trading Interval t;

LF_Down_Backup(p,t) is the sum of any Backup Downwards LFAS ~~Backup~~ Enablement quantities for Trading Interval t if Market Participant p is Synergy and 0 otherwise;

LF_Down_Backup_Price(p,t) is the Backup Downwards LFAS Price for Trading Interval t if Market Participant p is Synergy and 0 otherwise;

~~Balancing~~Energy Price(t) is the greater of zero and the ~~Balancing~~ Energy Price for Trading Interval t;

c denotes a Contracted Ancillary Service;

…

9.11.1. The Reconciliation Settlement amount for Market Participant p for Trading Month m is:

RSA(p,m) = (-1) x Consumption_Share(p,m) x
(Sum(q∈P,d∈D,t∈T, BSA(q,d,t))
+ Cost_LR_Shortfall(m))

Where

Consumption_Share(p,m) is the proportion of consumption associated with Market Participant p for Trading Month m determined by the IMO in accordance with clause 9.3.7;

BSA (q,d,t) is the Balancing Settlement ~~Amount~~ amount for Market Participant q for Trading Day d and Trading Interval t;

Cost_LR_Shortfall(m) is determined in accordance with clause 9.9.3B;

P is the set of all Market Participants, where “p” and “q” are both used to refer to a member of that set;

D is the set of all Trading Days in Trading Month m, where “d” is used to refer to a member of that set; and

T is the set of all Trading Intervals in Trading Day d, where “t” refers to a member of that set.

9.13.1. The applicable Market Participant Fee settlement amount for Market Participant p for Trading Month m is:

MPFSA(p,m) = (-1) x (Market Fee rate + System Operation Fee rate
+ Regulator Fee rate) x
(Monthly Participant Load(p,m) + Monthly Participant Generation(p,m))

Where

Market Fee rate is the charge per MWh for IMO’s services determined in accordance with clause 2.24.2 for the year in which Trading Month m falls;

System Operation Fee rate is the charge per MWh for System Management's services determined in accordance with clause 2.24.2 for the year in which Trading Month m falls;

Regulator Fee rate is the charge per MWh for funding the Economic Regulation Authority's activities with respect to the Wholesale Electricity Market determined in accordance with clause 2.24.2 for the year in which Trading Month m falls;

Monthly Participant Load(p,m) = (-1) × Sum(d∈D,t∈T,Metered Load(p,d,t));

where

Metered Load(p,d,t) for a Market Participant p for a Trading Interval t is the sum of the mathematical absolute values of the Metered Schedules for the Non-Dispatchable Loads~~, Dispatchable Loads~~ and Interruptible Loads, registered to the Market Participant for Trading Interval t; and

Monthly Participant Generation(p,m) = Sum(d∈D,t∈T, Metered Generation(p,d,t));

where

Metered Generation(p,d,t) for Market Participant p for Trading Interval t is the sum of the mathematical absolute values of the Metered Schedules for Scheduled Generators and Non-Scheduled Generators, registered to the Market Participant for Trading Interval t; and

D is the set of all Trading Days in Trading Month m, where "d" is used to refer to a member of that set;

T is the set of all Trading Intervals in Trading Day d, where "t" is used to refer to a member of that set.

9.18.3. A Non-STEM Settlement Statement must contain the following information:

(a) details of the Trading Days covered by the Non-STEM Settlement Statement;

(b) the identity of the Market Participant to which the Non-STEM Settlement Statement relates;

(c) for each Trading Interval of each Trading Day:

i. the Bilateral Contract quantities for that Market Participant;

ii. the Net Contract Position of the Market Participant;

iiA. the MWh quantity of energy scheduled from each of the Market Participants Facilities;

iii. ~~the energy scheduled to be provided in accordance with a Resource Plan issued by, or applicable to, that Market Participant provided under clause 6.5;~~[Blank]

iv. the Maximum Theoretical Energy Schedule and the Minimum Theoretical Energy Schedule data for each of the Market Participant's Registered Facilities;

v. the meter reading for each Registered Facility associated with the Market Participant;

vi. [Blank]

vii. in the case of Synergy:

1. Notional Wholesale Meter values; and

2. the total quantity of energy deemed to have been supplied by its Registered Facilities;

viii. the value of the ~~Balancing~~ Energy Price; and

viiiA. any ConQN, CoffQN, PConQN, PCoffQN, Non Qualifying Constrained On Generation and Non Qualifying Constrained Off Generation under Chapter 6;

viiiB. details of any ~~Non-Balancing Facility~~ Non-REM Dispatch Instruction Payment;

...

9.24.2. If, under Part 5.7B of the Corporations Act or another law relating to insolvency or the protection of creditors or similar matters, the IMO is required to disgorge or repay an amount, or pay an amount equivalent to an amount, paid by a Market Participant under the Market Rules:

(a) the IMO may Draw Upon any Credit Support held by the IMO in relation to the Market Participant for the amount disgorged, repaid or paid ("**Repaid Amount**"); and

(b) if the IMO is not able to recover all or part of the Repaid Amount by drawing upon Credit Support held by the IMO in relation to the Market Participant, then the IMO must take the Repaid Amount into account the next time it calculates the Reconciliation Settlement amount under clause 9.11.1 as if it was a positive Balancing Settlement ~~Amount~~ amount for a Market Participant for a Trading Day during the relevant Trading Month.

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:

...

(h) for each Trading Interval in each completed Trading Day in the previous 12 calendar months:

i. the sum of the Metered Schedule generation for Scheduled Generators and Non-Scheduled Generators registered to Synergy; and

ii. the sum of the Metered Schedule generation for Scheduled Generators and Non-Scheduled Generators registered to Market Participants other than Synergy; ~~and~~

~~iii. the sum of the Resource Plan schedule generation for Scheduled Generators and Non-Scheduled Generators registered to Market Participants other than Synergy;~~

...

(iA) the following ~~Balancing~~ REM summary information:

i for each Trading Interval in each completed Trading Day in the previous 12 calendar months:

1. where available, each ~~Balancing~~ Dispatch Forecast;

2. where available, the ~~BMO~~ DMO, excluding information that would identify specific Market Participants;

3. where available, the Relevant Dispatch Quantity; and

4. where available, the ~~Balancing~~ Energy Price;

ii. for each Trading Interval in each completed Trading Day in the previous 12 calendar months, before the end of the seventh day from the start of the Trading Day:

1. the prices in ~~Balancing~~ REM Price-Quantity Pairs submitted in ~~Balancing~~ REM Submissions by Market Participant; and

2. the Fuel Declaration, Availability Declaration and, if applicable, Ancillary Service Declaration made by Market Participant;

(iB) the following LFAS summary information for each Trading Interval in each completed Trading Day in the previous 12 calendar months:

i. the ~~LFAS~~ Downwards LFAS Merit Order;

ii. the ~~LFAS~~ Upwards LFAS Merit Order;

iii. where available, the Upwards LFAS Quantity and the Downwards LFAS Quantity; and

iv. where available, the Upwards LFAS Price and the Downwards LFAS Price;

...

(j) for each Trading Interval in each completed Trading Day in the previous 12 calendar months the following dispatch summary information:

i. ~~the values of~~ the ~~Balancing~~ Energy Price, the LFAS Prices~~,~~ and the Backup ~~Downwards~~ LFAS Prices ~~and the Backup Upwards LFAS Price~~;

ii. the Load Forecast prepared by System Management in accordance with clause 7.2.1;

iii. the sum of the Metered Schedule load for all Non-Dispatchable Load~~, Dispatchable Load~~ and Interruptible Load;

iv. estimates of the energy not served due to involuntary load curtailment; and

v. any shortfalls in Ancillary Services;

...

(v) summary information pertaining to the account maintained by the IMO for market settlement for the preceding 24 calendar months, including;

i. the end of month balance;

ii. the total income received for transactions in each of the Reserve Capacity Mechanism, the STEM, Balancing Settlement, Market Fees, System Operation Fees, Regulator Fees and a single value for all other income;

iii. the total outgoings paid for transactions in each of the Reserve Capacity Mechanism (excluding Supplementary Capacity Contracts), Supplementary Capacity Contracts, the STEM, Balancing Settlement and a single value for all other expenses; and

iv. Service Fee Settlement Amount paid to the IMO, System Management and the Economic Regulation Authority;

...

(x) for each Trading Interval of the current Trading Month for which ~~Balancing~~ Energy Price results have been released to Market Participants, the value of the ~~Balancing~~ Energy Price;

...

(zE) the current ~~Non-Balancing~~ Non-REM Dispatch Merit Order;

...

10.7.1. The IMO must set the class of confidentiality status for the following information under clause 10.2.1, as Rule Participant Market Restricted ~~Information~~ and the IMO must make this information available from the Market Web Site:

(a) all Reserve Capacity Offer information issued by that Market Participant and all details of Special Price Arrangements for that Market Participant

prior to the publication of that information in accordance with clause 10.5.1(f);

(b) Market Participant specific Reserve Capacity Obligations;

(c) Market Customer specified Individual Reserve Capacity Requirements partitioned into those associated with Intermittent Loads and those not associated with Intermittent Loads;

(d) for each completed Trading Day for the past 12 months:

i. Market Participant specific Bilateral Submissions ~~and Resource Plan Submissions~~;

ii. Market Participant specific STEM Submissions and Standing STEM Submissions used in the absence of a STEM Submission except that information published in accordance with clause 10.5.1(i);

(e) for the past 12 months:

i. Non-STEM Settlement Statements; and

ii. STEM Settlement Statements

11. Glossary

...

Backup Downwards LFAS Enablement: Means, for a Synergy LFAS Facility, the capacity in MW which System Management has activated under clause 7B.3.7 or 7B.4.1 in a Trading Interval to compensate for a shortfall in Downwards LFAS Enablement, and which has been notified to the IMO under clause 7B.4.2.

Backup Downwards LFAS Price: Means the cost referred to in clause 7B.2.6 for Synergy providing Backup Downwards LFAS ~~Backup~~ Enablement for a Trading Interval, determined from the most recent, valid LFAS Submissions made in accordance with clause 7B.2.6.

Backup LFAS Enablement: Means Backup Downwards LFAS Enablement and/or Backup Upwards LFAS Enablement, as applicable.

Backup LFAS Price: Means the Backup Downwards LFAS Price and/or the Backup Upwards LFAS Price, as applicable.

Backup Upwards LFAS Enablement: Means, for a Synergy LFAS Facility, the capacity in MW which System Management has activated under clause 7B.3.7 or 7B.4.1 in a Trading Interval to compensate for a shortfall in Upwards LFAS Enablement, and which has been notified to the IMO under clause 7B.4.2.

Backup Upwards LFAS Price: Means the cost referred to in clause 7B.2.6 for Synergy providing Backup Upwards LFAS ~~Backup~~ Enablement for a Trading Interval, determined from the most recent, valid LFAS Submissions made in accordance with clause 7B.2.6.

Balancing Settlement: The process for ~~meeting~~ settling supply and consumption deviations from contracted bilateral and STEM positions in each Trading Interval.

~~**Balancing Facility**: Means:~~

~~(a) for a Market Generator other than Synergy:~~

~~i. each of its Scheduled Generators; and~~

~~ii. each of its Non-Scheduled Generators; and~~

~~(b) each Stand Alone Facility.~~

~~**Balancing Facility Requirements**: Means the technical and communication criteria that a Balancing Facility, or a type of Balancing Facility, must meet, which are set out in the Market Procedure developed under clause 7A.1.6.~~

~~**Balancing Final Rule Change Report**: Has the meaning given in clause 1.10.1.~~

~~**Balancing Forecast**: Means a forecast, determined by the IMO in accordance with the Balancing Forecast Market Procedure, for a Trading Interval, of the following:~~

~~(a) the Relevant Dispatch Quantity for the Trading Interval;~~

~~(b) the aggregate output of all Non-Scheduled Generators which are Balancing Facilities for the Trading Interval; and~~

~~(c) the Balancing Price for the Trading Interval. .~~

~~**Balancing Forecast Market Procedure**: Means the Market Procedure developed under clause 7A.3.20.~~

~~**Balancing Gate Closure**: For a Trading Interval means the point in time immediately before the commencement of the Trading Interval determined by the IMO under clause 7A.1.16 or 7A.1.17, as applicable.~~

~~**Balancing Horizon**: Means:~~

~~(a) from 8:00 AM the day before the Balancing Market Commencement Day and to 6:00 PM on the Balancing Market Commencement Day, the 24 hour period occurring for the Trading Day (8:00 AM to 8:00 AM) of the Balancing Market Commencement Day; and~~

~~(b) from 6:00 PM on the Balancing Market Commencement Day, the 38 hour period from 6:00 PM on the Balancing Market Commencement Day to the end of the Trading Day after the end of the Balancing Market Commencement; and~~

~~(c) from 6:00 PM every day thereafter, the 38 hour period from 6:00 PM to the end of the next Trading Day at 8:00 AM.~~

~~**Balancing Market**: Means the market operated under Chapter 7A in which Facilities, including the Balancing Portfolio as a single Facility, can manage their contractual positions~~

and meet supply and consumption deviations from contracted bilateral and STEM positions in each Trading Interval.

Balancing Market Commencement Day: Means the Trading Day determined by the IMO under clause 7A.1.2.

Balancing Market Objectives: Means the objectives listed in clause 7A.1.3.

Balancing Merit Order or BMO: Means the ordered list of Balancing Facilities, and associated quantities, determined by the IMO under clause 7A.3.2.

Balancing Portfolio: Means Synergy's Registered Facilities other than:

(a) Stand Alone Facilities;

(b) Demand Side Programmes;

(c) Dispatchable Loads; and

(d) Interruptible Loads.

Balancing Portfolio Supply Curve: Means a ranking of the Balancing Price-Quantity Pairs provided for the Balancing Portfolio.

Balancing Price: For a Trading Interval means the price determined under clause 7A.3.10.

Balancing Price-Quantity Pair: Means

(a) for a Scheduled Generator, the specified non-Loss Factor adjusted MW quantity at which a Market Participant is prepared to operate a Balancing Facility as at the end of a Trading Interval and the non-Loss Factor Adjusted Price, in $/MWh, at which the Market Participant is prepared to provide that quantity by the end of that Trading Interval;

(b) for a Non-Scheduled Generator the specified non-Loss Factor adjusted MW quantity at which a Market Participant is prepared to reduce its output as at the end of a Trading Interval and the non-Loss Factor Adjusted Price, in $/MWh, at which the Market Participant is prepared to provide that quantity by the end of that Trading Interval; and

(c) for the Balancing Portfolio, the specified MW quantity at which Synergy is prepared to have the Balancing Portfolio dispatched at as at the end of a Trading Interval and the Loss Factor Adjusted Price, in $/MWh, at which Synergy is prepared to provide from the sum of all of its Sent Out Capacity for each Facility in the Balancing Portfolio by the end of the Trading Interval.

Balancing Quantity: Means, in respect of a Trading Interval, the quantity, if any, calculated in accordance with the Market Procedure and published under clause 7A.3.17(a).

Balancing Submission: Means:

(a) for a Balancing Facility, other than the 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 Balancing Portfolio, the Balancing Portfolio Supply Curve together with the Portfolio Ramp Rate Limit.~~

...

Consumption Decrease Price: A price specified in item~~s~~ (h)(vi)~~, (i)(xA)(3) or (i)(xA)(4)~~ of Standing Data, which must be not less than the Minimum STEM Price and not more than the Alternative Maximum STEM Price to apply in forming the~~ Non-Balancing~~ Non-REM Dispatch Merit Order for a Trading Interval for a~~ Dispatchable Load or~~ Demand Side Programme and in the calculation of the~~ Non-Balancing Facility~~ Non-REM Dispatch Instruction Payment for that~~ Dispatchable Load or~~ Demand Side Programme for that Trading Interval, which varies for Peak Trading Intervals and Off-Peak Trading Intervals.

~~**Consumption Increase Price**: A price specified in items (i)(xA)(1) or (i)(xA)(2) of Standing Data, which must be not less than the Minimum STEM Price, not more than the Alternative Maximum STEM Price to apply in forming the Non-Balancing Dispatch Merit Order for a Trading Interval for a Dispatchable Load and in the calculation of the Non-Balancing Facility Dispatch Instruction Payment for that Dispatchable Load for that Trading Interval, which varies for Peak Trading Intervals and Off-Peak Trading Intervals.~~

...

Constrained Off Compensation Price: Has the meaning given in clause~~s~~ 6.17.4 and 6.17.4A.

Constrained Off Quantity: Has the meaning given in clause~~s~~ 6.17.4 and 6.17.4A.

~~**Constrained Off Portfolio Quantity**: Has the meaning given in clause 6.17.5A.~~

Constrained On Compensation Price: Has the meaning given in clause~~s~~ 6.17.3~~,~~ and 6.17.3A ~~or clause 6.17.5,~~.

Constrained On Quantity: Has the meaning given in clause~~s~~ 6.17.3 and 6.17.3A.

...

The proposed Amending Rules in the Final Rule Change Report for the Rule Change Proposal: Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10) move the definition of a Dispatch Advisory from clause 7.11.1 to the Glossary. This proposal (RC_2014_01) further amends the definition proposed in RC_2013_10, by replacing the words "Non-Balancing Facilities" with "Demand Side Programmes" to reflect the proposed removal of Dispatchable Loads.

Dispatch Advisory: ~~Has the meaning given in clause 7.11.1.~~ Means a communication by System Management to Market Participants, Network Operators and the IMO that there has been, or is likely to be, an event that will require dispatch of Demand Side Programmes or Facilities Out of Merit, or will restrict communication between System Management and any of the Market Participants, Network Operators, or the IMO.

...

Dispatch Forecast: Means a forecast, determined by the IMO in accordance with the Market Procedure for Dispatch Forecasts, for a Trading Interval, of the following:

(a) the Relevant Dispatch Quantity for the Trading Interval;

(b) the aggregate output of all Non-Scheduled Generators which are REM Facilities for the Trading Interval; and

(c) the Energy Price for the Trading Interval.

Dispatch Horizon: Means, from 1:00 PM each day, the 43-hour period from 1:00 PM to the end of the next Trading Day at 8:00 AM.

...

Dispatch Merit Order: Means, for a Trading Interval, the last Forecast DMO for that Trading Interval received by System Management.

Dispatch Order: Means an instruction by System Management under clause 7.6A for a Facility or Facilities in the ~~Balancing~~ Synergy Portfolio to vary output or consumption from the Dispatch Plan.

Dispatch Plan: Means the schedule of energy and Ancillary Services to be provided, or to be available to be provided on request, by the Facilities ~~of Synergy~~ in the ~~Balancing~~ Synergy Portfolio, during a Trading Day, where these schedules may be revised by System Management during the course of the corresponding Scheduling Day and the Trading Day.

...

~~**Dispatchable Load**: A Load, with a rated capacity of not less than 0.2 MW, through which electricity is consumed where such consumption can be increased or decreased to a specified level upon instruction to do so by System Management to the person managing the Load, and registered as such in accordance with clause 2.29.5(c).~~

...

DMO: See Dispatch Merit Order.

...

~~**Downwards LFAS Backup Enablement**: Means for a Synergy LFAS Facility, the capacity in MW, which System Management has activated under clause 7B.4.1 in a Trading Interval to compensate for a shortfall in Downwards LFAS Enablement and which has been notified to the IMO under clause 7B.4.2.~~

Downwards LFAS Enablement: Means, for a Trading Interval and an LFAS Facility, the ~~capacity~~ total quantity~~, or that part of the capacity, in MW, in an LFAS Downwards Price-Quantity Pair selected under clause 7B.3.4(c) which is~~ associated with that LFAS Facility ~~or with the Balancing Portfolio, as applicable~~ in the Downwards LFAS Enablement Schedule for that Trading Interval.

Downwards LFAS Enablement Schedule: Means, for a Trading Interval, the Forecast Downwards LFAS Enablement Schedule for that Trading Interval most recently provided by the IMO to System Management under clause 7B.3.1(b) at the point in time 15 minutes after LFAS Gate Closure for that Trading Interval.

Downwards LFAS Merit Order: Means, for a Trading Interval, the Forecast Downwards LFAS Merit Order for that Trading Interval used by the IMO under clause 7B.3.3(b) to determine the Downwards LFAS Enablement Schedule.

Downwards LFAS Price: Means, for a Trading Interval, the ~~price~~ Forecast Downwards LFAS Price for that Trading Interval determined by the IMO under clause ~~7B.3.10 or~~ 7B.3.4(b) from the Downwards LFAS Enablement Schedule, subject to clause 7B.3.12, and published under clause 7B.3.11.

Downwards LFAS Price-Quantity Pair: Means for an LFAS Facility:

(a) the specified non-Loss Factor adjusted capacity, in MW, by which a Market Participant is prepared to have its LFAS Facility activated downwards within a Trading Interval; and

(b) the non-Loss Factor Adjusted Price, in $/MW, the Market Participant wants to be paid to have that capacity available within that Trading Interval.

Downwards LFAS Quantity: Means ~~the capacity, in MW, of downwards Load Following Service required by System Management~~, for a Trading Interval~~.~~, the Forecast Downwards LFAS Quantity for that Trading Interval used by the IMO under clause 7B.3.3(b) to determine the Downwards LFAS Enablement Schedule.

...

Energy Price: For a Trading Interval means the price determined under clause 7A.3.10.

...

Forecast Backup LFAS Price: Means the Forecast Backup Downwards LFAS Price and/or the Forecast Backup Upwards LFAS Price, as applicable.

Forecast Backup Upwards LFAS Price: Means the cost referred to in clause 7B.2.6 for Synergy providing Backup Upwards LFAS Enablement for a Trading Interval, determined from the most recent, valid LFAS Submissions made in accordance with clause 7B.2.6 at the time that that cost is published by the IMO under clause 7B.3.1(d)(iv).

Forecast Backup Downwards LFAS Price: Means the cost referred to in clause 7B.2.6 for Synergy providing Backup Downwards LFAS Enablement for a Trading Interval, determined from the most recent, valid LFAS Submissions made in accordance with clause 7B.2.6 at the time that that cost is published by the IMO under clause 7B.3.1(d)(iv).

~~**Forecast BMO**: Means a forecast of the BMO for future Trading Intervals in the Balancing Horizon determined by the IMO in accordance with the Balancing Forecast Market Procedure.~~

...

Forecast DMO: Means the ordered list of REM Facilities, and associated quantities, determined by the IMO under clause 7A.3.1(a).

Forecast Downwards LFAS Enablement Schedule: Means, for a Trading Interval, a list of LFAS Facilities and associated quantities for that Trading Interval determined by the IMO under clause 7B.3.1(a)(iv).

Forecast Downwards LFAS Merit Order: Means, for a Trading Interval, a ranked list of Downwards LFAS Price-Quantity Pairs for that Trading Interval determined by the IMO under clause 7B.3.1(a)(ii).

Forecast Downwards LFAS Price: Means, for a Trading Interval, the highest price in a Downwards LFAS Price-Quantity Pair selected in a Forecast Downwards LFAS Enablement Schedule for that Trading Interval, determined by the IMO under clause 7B.3.1(a)(vi).

Forecast Downwards LFAS Quantity: Means System Management's estimate of the capacity, in MW, of downwards LFAS required by System Management for a Trading Interval, provided by System Management to the IMO under clause 7B.1.4 or 7B.1.5.

Forecast LFAS Enablement Schedule: Means the Forecast Downwards LFAS Enablement Schedule and/or the Forecast Upwards LFAS Enablement Schedule, as applicable.

Forecast LFAS Merit Order: Means the Forecast Downwards LFAS Merit Order and/or the Forecast Upwards LFAS Merit Order, as applicable.

Forecast LFAS Price: Means the Forecast Downwards LFAS Price and/or the Forecast Upwards LFAS Price, as applicable.

Forecast LFAS Quantity: Means the Forecast Downwards LFAS Quantity and/or the Forecast Upwards LFAS Quantity, as applicable.

Forecast Upwards LFAS Enablement Schedule: Means, for a Trading Interval, a list of LFAS Facilities and associated quantities for that Trading Interval determined by the IMO under clause 7B.3.1(a)(iii).

Forecast Upwards LFAS Merit Order: Means, for a Trading Interval, a ranked list of Upwards LFAS Price-Quantity Pairs for that Trading Interval determined by the IMO under clause 7B.3.1(a)(i).

Forecast Upwards LFAS Price: Means, for a Trading Interval, the highest price in an Upwards LFAS Price-Quantity Pair selected in a Forecast Upwards LFAS Enablement Schedule for that Trading Interval, determined by the IMO under clause 7B.3.1(a)(vi).

Forecast Upwards LFAS Quantity: Means System Management's estimate of the capacity, in MW, of upwards LFAS required by System Management for a Trading Interval, provided by System Management to the IMO under clause 7B.1.4 or 7B.1.5.

...

LFAS: See Load Following Service.

~~**LFAS Backup Enablement**: Means Upwards LFAS Backup Enablement and Downwards LFAS Backup Enablement.~~

~~**LFAS Downwards Merit Order**: Means the ranked list of LFAS Submissions determined by the IMO under clause 7B.3.2.~~

~~**LFAS Downwards Price-Quantity Pair**: Means for an LFAS Facility:~~

~~(a) the specified non-Loss Factor adjusted capacity, in MW, by which a Market Participant is prepared to have its LFAS Facility activated downwards within a Trading Interval; and~~

~~(b) the non-Loss Factor Adjusted Price, in $/MW, the Market Participant wants to be paid to have that capacity available within that Trading Interval.~~

...

LFAS Enablement: Means the Downwards LFAS Enablement and/or the Upwards LFAS Enablement, as applicable.

LFAS Enablement Schedule: Means the Downwards LFAS Enablement Schedule and/or the Upwards LFAS Enablement Schedule, as applicable.

LFAS Facility: Means:

(a) a Stand Alone Facility, or Scheduled Generator or Non-Scheduled Generator registered to a Market Participant other than Synergy~~, for which~~:

i. which the relevant Market Participant has indicated in Appendix 1(j)(i) of Standing Data is intended to participate in the LFAS Market; and

ii. for which LFAS Standing Data has been accepted by the IMO; or

(b) the ~~Balancing~~ Synergy Portfolio.

...

LFAS Gate Closure: ~~Means, for the 12 Trading Intervals in an LFAS Horizon, the point in time which is 3 hours immediately before the Balancing Gate Closure for the first of those Trading Intervals.~~ Means, for a Trading Interval, the point in time 90 minutes before the start of that Trading Interval.

~~**LFAS Horizon**: Means a 6 hour period commencing at 8:00 AM, 2:00 PM, 8:00 PM or 2:00 AM, as applicable.~~

...

LFAS Merit Order: Means the ~~LFAS~~ Downwards LFAS Merit Order and/or the ~~LFAS~~ Upwards LFAS Merit Order, as applicable.

LFAS Price: Means the Downwards LFAS Price and/or the Upwards LFAS Price, as applicable.

LFAS Price-Quantity Pair: Means an ~~LFAS~~ Upwards LFAS Price-Quantity Pair and/or ~~an LFAS~~ a Downwards LFAS Price-Quantity Pair, as applicable.

...

LFAS Quantity: Means~~:~~ the Upwards LFAS Quantity and/or the Downwards LFAS Quantity, as applicable.

~~(a) the Upwards LFAS Quantity; and~~

~~(b) the Downwards LFAS Quantity.~~

LFAS Quantity Balance: Means the capacity, in MW, of LFAS referred to in clause 7B.4.1(a), which an LFAS Facility has failed to provide, or in clause 7B.4.1(aA), which an LFAS Facility is not available to provide.

~~**LFAS Requirement**: Means the most recent forecast LFAS Quantity published by the IMO under clause 7B.3.15(b).~~

...

LFAS Submission: Means:

(a) for an LFAS Facility that is:

i. a Scheduled Generator, for a Trading Interval or Trading Intervals, a ranking of LFAS Price-Quantity Pairs for each MW of capacity which the Market Participant wants to offer for LFAS for each Trading Interval; and

ii. a Non-Scheduled Generator, for a Trading Interval or Trading Intervals, the Market Generator's best estimate of the capacity for

the LFAS Price-Quantity Pair, in MW, the Facility is able to be activated downwards for each Trading Interval; and

(b) for the ~~Balancing~~ Synergy Portfolio for a Trading Interval or Trading Intervals, a ranking of LFAS Price-Quantity Pairs for each MW of capacity which the Market Participant wants to offer for LFAS for each Trading Interval.

~~**LFAS Upwards Merit Order**: Means the ranked list of LFAS Submissions determined by the IMO under clause 7B.3.1.~~

~~**LFAS Upwards Price-Quantity Pair**: Means for an LFAS Facility:~~

~~(a) the specified non-Loss Factor adjusted capacity, in MW, by which a Market Participant is prepared to have its LFAS Facility activated upwards within a Trading Interval;~~

~~(b) the non-Loss Factor Adjusted Price, in $/MW, the Market Participant wants to be paid to have that capacity available within that Trading Interval.~~

...

Load Following Service ~~or LFAS~~: Has the meaning given in clause 3.9.1.

...

Load Rejection Reserve Event: Means an event which causes a Facility in the ~~Balancing~~ Synergy Portfolio, which System Management has instructed to provide Load Rejection Reserve Service, to provide a Load Rejection Reserve Response.

...

Load Rejection Reserve Response Quantity: Means, for a Trading Interval, the quantity of energy reduction, in MWh, provided by a Facility as a Load Rejection Reserve Response due to a Load Rejection Reserve Event, but excluding any such contribution that occurred because System Management had instructed the Facility to provide Downwards LFAS Enablement or Backup Downwards LFAS ~~Backup~~ Enablement.

...

Loss Factor: Means:

(a) a factor representing network losses between any given node and the Reference Node where the Loss Factor at the Reference Node is 1, expressed as the product of a Transmssion Loss Factor and a Distribution Loss Factor and determined in accordance with clause 2.27.5; and

(b) in relation to the ~~Balancing~~ Synergy Portfolio, the Portfolio Loss Factor.

...

~~**Metered Balancing Quantity**: Has the meaning given in clause 6.17.2.~~

...

Meter Registry: A registry maintained by a Metering Data Agent containing information about meters and the persons with which those meters are associated including the information listed in clause 8.3.1.

Metered Balancing Quantity: Has the meaning given in clause 6.17.2.

...

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

~~**Non-Balancing Facility**: Means a Registered Facility that is not a Balancing Facility.~~

~~**Non-Balancing Facility Dispatch Instruction Payment or DIP**: Has the meaning given in clause 6.17.6.~~

...

Non-Dispatchable Load: A Load which is not ~~a Dispatchable Load or~~ an Interruptible Load.

...

Non-REM Dispatch Merit Order: Means, for a Trading Interval, an ordered list of Demand Side Programmes registered by Market Participants, determined by the IMO in accordance with clause 6.12.1.

Non-REM Dispatch Instruction Payment: Has the meaning given in clause 6.17.6.

...

Operating Instruction: Means an instruction issued by System Management requiring a Facility to increase or decrease its output or decrease its consumption to meet the requirements of:

(a) a Network Control Service Contract;

(b) an Ancillary Service Contract;

(c) a Test under these Market Rules;

(d) a Supplementary Capacity Contract; or

(e) Ancillary Services, other than LFAS but including ~~LFAS~~ Backup LFAS Enablement, to be provided by Facilities other than Facilities in the ~~Balancing~~ Synergy Portfolio.

...

Out of Merit: Means dispatch of a ~~Balancing~~ REM Facility for a quantity different to that specified for the Facility in the ~~BMO~~ DMO taking into account the Ramp Rate Limit and the Relevant Dispatch Quantity in the applicable Trading Interval for the ~~Balancing~~ REM Facility.

...

Portfolio Constrained Off Quantity: Has the meaning given in clause 6.17.5A.

Portfolio Constrained On Compensation Price: Has the meaning given in clause 6.17.5.

...

Portfolio Loss Factor: For each Trading Interval = sum(Facility(i) Sent Out Metered Schedule x Loss Factor (i))/sum (Facility (i) Sent Out Metered Schedule) for all Facilities in the ~~Balancing~~ Synergy Portfolio.

Portfolio Ramp Rate Limit: Means Synergy's best estimate, in MW per minute, on a linear basis, of the ~~Balancing~~ Synergy Portfolio's physical ability to increase or decrease its output from the commencement of a Trading Interval.

...

~~**Pre-Amended Rules**: Has the meaning given in clause 1.10.1.~~

~~**Post-Amended Rules**: Has the meaning given in clause 1.10.1.~~

Price Cap: Means:

(a) a maximum price ~~of~~ that is:

i. for a ~~Balancing~~ REM Facility to run on Non-Liquid Fuel, the Maximum STEM Price; or

ii. for a ~~Balancing~~ REM Facility to run on Liquid Fuel, the Alternative Maximum STEM Price; and

(b) a minimum price ~~of~~ that is the Minimum STEM Price.

...

Pricing ~~BMO~~ DMO: Means the ~~Balancing Merit Order~~ Provisional Pricing DMO adjusted ~~to take into account:~~ in accordance with clause 7A.3.9 as appropriate.

~~(a) the associated Ramp Rate Limits to reflect the physically achievable capacity of the Balancing Facility given the SOI Quantity; and~~

~~(b) for Non-Scheduled Generators, the EOI Quantity.~~

...

Provisional ~~Balancing~~ Energy Price: Means the price determined under clause 7A.3.8(b).

Provisional Pricing ~~BMO~~ DMO: Means the ~~provisional Pricing BMO determined under clause 7A.3.8(a).~~ DMO adjusted to take into account:

(a) REM Submissions made under clauses 7A.2.9(f) and 7A.2.10 after the IMO has determined the DMO;

(b) the associated Ramp Rate Limits to reflect the physically achievable capacity of the REM Facility given the SOI Quantity; and

(c) for Non-Scheduled Generators, the EOI Quantity,

where the SOI Quantity and the EOI Quantity are the quantities provided by System Management under clause 7A.3.7.

...

Real-Time Energy Market: Means the mandatory gross pool market operated under Chapter 7A that determines the dispatch of Scheduled Generators and Non-Scheduled Generators based on submitted prices and quantities.

...

Relevant Dispatch Quantity: Means, for a Trading Interval, the sum of the EOI Quantities for each ~~Balancing~~ REM Facility, in MW, at the end of that Trading Interval.

...

REM: See Real-Time Energy Market.

REM Facility: Means:

(a) for a Market Generator other than Synergy:

i. each of its Scheduled Generators; and

ii. each of its Non-Scheduled Generators; and

(b) each Stand Alone Facility.

REM Facility Requirements: Means the technical and communication criteria that a REM Facility, or a type of REM Facility, must meet, which are set out in the Market Procedure developed under clause 7A.1.6.

REM Gate Closure: Means, for a Trading Interval, the point in time 30 minutes before the start of that Trading Interval.

REM Objectives: Means the objectives listed in clause 7A.1.3.

REM Price-Quantity Pair: Means

(a) for a Scheduled Generator, the specified non-Loss Factor adjusted MW quantity at which a Market Participant is prepared to operate a REM Facility as at the end of a Trading Interval and the non-Loss Factor Adjusted Price, in $/MWh, at which the Market Participant is prepared to provide that quantity by the end of that Trading Interval;

(b) for a Non-Scheduled Generator the specified non-Loss Factor adjusted MW quantity at which a Market Participant is prepared to reduce its output as at the end of a Trading Interval and the non-Loss Factor Adjusted Price, in $/MWh, at which the Market Participant is prepared to provide that quantity by the end of that Trading Interval; and

(c) for the Synergy Portfolio, the specified MW quantity at which Synergy is prepared to have the Synergy Portfolio dispatched at as at the end of a Trading Interval and the Loss Factor Adjusted Price, in $/MWh, at which Synergy is prepared to provide from the sum of all of its Sent Out Capacity for each Facility in the Synergy Portfolio by the end of the Trading Interval.

The definition of REM Submission incorporates the changes to the definition of Balancing Submission proposed in the Rule Change Proposal: Outage Planning Phase 2 – Outage Process Refinements (RC_2013_15). This proposal (RC_2014_01) additionally updates market names.

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

...

~~**Resource Plan**: A detailed schedule for all Trading Intervals in a relevant Trading Day, based on a Resource Plan Submission containing the information in clause 6.11 accepted by the IMO under clause 6.5.2 (as part of an accepted Resource Plan Submission) or set in accordance with clause 6.5.4 (in the case of a default Resource Plan).~~

~~**Resource Plan Submission**: A submission by a Market Participant to the IMO made in accordance with clause 6.5.~~

...

Sent Out Capacity: Means:

(a) for a ~~Balancing~~ REM Facility, other than the ~~Balancing~~ Synergy Portfolio, that is:

i. a Scheduled Generator, the capacity provided as the Standing Data in Appendix 1(b)(iii); and

ii. a Non-Scheduled Generator, the capacity provided as the Standing Data in Appendix 1(e)(iiiA); and

(b) for the ~~Balancing~~ Synergy Portfolio, the sum of all of the Standing Data in Appendix 1(b)(iii) and Appendix 1(e)(iiiA) for each Facility in the ~~Balancing~~ Synergy Portfolio.

...

SOI Quantity: Means the quantity, in MW, at which a ~~Balancing~~ REM Facility was operating as at the start of a Trading Interval.

...

Spinning Reserve: Supply capacity held in reserve from synchronised Scheduled Generators~~, Dispatchable Loads~~ or Interruptible Loads, so as to be available to support the system frequency in the event of an outage of a generating works or transmission equipment or to be dispatched to provide energy as allowed under these Market Rules.

Spinning Reserve Event: Means an event which causes a Facility in the ~~Balancing~~ Synergy Portfolio, which System Management has instructed to provide Spinning Reserve Service, to provide a Spinning Reserve Response.

...

Spinning Reserve Response Quantity: Means, for a Trading Interval, the quantity of additional energy, in MWh, provided by a Facility as a Spinning Reserve Response due to a Spinning Reserve Event, but excluding any such contribution that occurred because System Management had instructed the Facility to provide Upwards LFAS Enablement or Backup Upwards LFAS ~~Backup~~ Enablement.

...

~~**Standing Resource Plan**: A submission related in Resource Plans by a Market Generator to the IMO made in accordance with clause 6.5C.~~

...

Synergy Portfolio: Means Synergy's Registered Facilities other than:

(a) Stand Alone Facilities;

(b) Demand Side Programmes; and

(c) Interruptible Loads.

...

~~**Upwards LFAS Backup Enablement**: Means for a Synergy LFAS Facility, the capacity in MW, which System Management has activated under clause 7B.4.1 in a Trading Interval to compensate for a shortfall in Upwards LFAS Enablement, and which has been notified to the IMO under clause 7B.4.2.~~

Upwards LFAS Enablement: Means, for a Trading Interval and an LFAS Facility, the ~~capacity~~ total quantity~~, or that part of the capacity, in MW, in an LFAS Downwards Price-Quantity Pair selected under clause 7B.3.4(b) which is~~ associated with that LFAS Facility ~~or with the Balancing Portfolio, as applicable~~ in the Upwards LFAS Enablement Schedule for that Trading Interval.

Upwards LFAS Enablement Schedule: Means, for a Trading Interval, the Forecast Upwards LFAS Enablement Schedule for that Trading Interval most recently provided by the IMO to System Management under clause 7B.3.1(b) at the point in time 15 minutes after LFAS Gate Closure for that Trading Interval.

Upwards LFAS Merit Order: Means, for a Trading Interval, the Forecast Upwards LFAS Merit Order for that Trading Interval used by the IMO under clause 7B.3.3(a) to determine the Upwards LFAS Enablement Schedule.

Upwards LFAS Price: Means, for a Trading Interval, the ~~price~~ Forecast Upwards LFAS Price for that Trading Interval determined by the IMO under clause ~~7B.3.9 or~~ 7B.3.4(a) from

the Upwards LFAS Enablement Schedule, subject to clause 7B.3.12, and published under clause 7B.3.11.

Upwards LFAS Price-Quantity Pair: Means for an LFAS Facility:

(a) the specified non-Loss Factor adjusted capacity, in MW, by which a Market Participant is prepared to have its LFAS Facility activated upwards within a Trading Interval;

(b) the non-Loss Factor Adjusted Price, in $/MW, the Market Participant wants to be paid to have that capacity available within that Trading Interval.

Upwards LFAS Quantity: Means ~~the capacity, in MW, of upwards Load Following Service required by System Management for a Trading Interval.~~, for a Trading Interval, the Forecast Upwards LFAS Quantity for that Trading Interval used by the IMO under clause 7B.3.3(a) to determine the Upwards LFAS Enablement Schedule.

...

Appendix 1: Standing Data

...

(i) ~~for a Dispatchable Load:~~

~~i. the Market Customer's nominated maximum consumption quantity, in units of MWh per Trading Interval;~~

~~ii. evidence that the communication and control systems required by clause 2.36 are in place and operational;~~

~~iii. the dispatchable capacity of the load, expressed in MW;~~

~~iv. the normal ramp up and ramp down rates as a function of output level;~~

~~v. emergency ramp up and ramp down rates;~~

~~vi. the AGC capabilities of the facility;~~

~~vii. details of any potential Energy Limits of the facility;~~

~~viii. the minimum dispatchable load level of the facility, expressed in MW;~~

~~ix. the maximum dispatchable load level of the facility, expressed in MW;~~

~~x. the capability to provide each of the following Ancillary Services, including information on trade-off functions when more than one other type of Ancillary Service and/or energy is provided simultaneously:~~

~~1. Load Following;~~

~~2. Spinning Reserve; and~~

~~3. [Blank]~~

~~4. Load Rejection Reserve;~~

~~xA. for a facility that is registered to a Market Participant, data comprising:~~

~~1. a Consumption Increase Price for Peak Trading Intervals;~~

~~2. a Consumption Increase Price for Off-Peak Trading Intervals;~~

~~3. a Consumption Decrease Price for Peak Trading Intervals; and~~

~~4. a Consumption Decrease Price for Off-Peak Trading Intervals,~~

~~where these prices must be expressed in units of $/MWh to a precision of $0.01/MWh;~~

~~xi. the minimum response time before the facility can begin to respond to an instruction from System Management to change its output;~~

~~xii. the Metering Data Agent for the facility;~~

~~xiii. the single line diagram for the facility, including the locations of transformers, switches, operational and settlement meters;~~

~~xiv. the point on the network at which the facility can connect; and~~

~~xv. the short circuit capability of facility equipment.~~[Blank]

...

(k) for each Registered Facility:

i. Reserve Capacity information including:

…

5. for ~~Interruptible Loads and~~ Demand Side Programmes, the maximum number of times that interruption can be called during the term of the Capacity Credits;

…

The IMO notes that although Appendix 3 contains references to Dispatchable Loads and Interruptible Loads, the proposed Amending Rules in the Final Rule Change Report for the Rule Change Proposal: Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10) delete the relevant paragraph completely, and so no further amendments are shown here.

Appendix 9: Relevant Level Determination

...

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

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

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

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

...

---

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:

Balancing Market Name Change (Issue 1)

The proposed changes to Balancing Market terminology and definitions will encourage competition in the market by improving the clarity of the Market Rules and helping to eliminate any misconceptions about the operation of the market and the opportunity it offers to new investors (Wholesale Market Objective (b)).

Removal of Resource Plans (Issue 2)

The proposed removal of Resource Plans will promote economic efficiency (Wholesale Market Objective (a)) and contribute to minimising the long-term cost of electricity (Wholesale Market Objective (d)) by eliminating an unnecessary process from the Market Rules. The change will also reduce the burden of participation in the WEM and so facilitate the efficient entry of new competitors (Wholesale Market Objective (b)).

The proposed changes to the bidding restrictions on Facilities not meeting the REM Facility Requirements will promote economic efficiency by providing greater flexibility to these Facilities (Wholesale Market Objective (a)).

The removal of Resource Plans and the changes proposed to clauses 4.12.1 and 4.26.2 will also simplify the Market Rules and improve their readability.

Gate Closure Changes (Issue 3)

Reducing REM and LFAS Gate Closure times will provide greater flexibility for Market

Participants to respond to changes to demand and non-scheduled generation forecasts, unexpected generation outages (or early return to service) and/or fuel supply constraints. Market Participants should also have greater certainty about their own fuel and plant status when making their final submissions.

Allowing Market Participants to base their submissions on more up-to-date information is expected to better promote the economic efficiency of the physical markets (Wholesale Market Objective (a)). The changes will also reduce the level of risk faced by Market Participants, which in turn should encourage more active competition (Wholesale Market Objective (b)) and allow Market Participants to reduce any risk premiums in their submissions, minimising the long-term cost of electricity (Wholesale Market Objective (d)). Moreover, the more flexible arrangements should make investment in the market more attractive, facilitating the efficient entry of new competitors (Wholesale Market Objective (b)).

Moving the deadline for setting the LFAS Quantity closer to the start of the Trading Interval should improve the reliability of key inputs (such as weather conditions) and so allow System Management to more accurately predict the LFAS Quantity, which would be expected to promote economic efficiency (Wholesale Market Objective (a)) and minimise the long-term cost of electricity (Wholesale Market Objective (d)) by reducing unnecessary procurement of LFAS and the need to use the more expensive Backup LFAS.

Finally, the proposed changes will simplify the submission rules for the REM and LFAS Market, facilitating the entry of new competitors (Wholesale Market Objective (b)).

Dispatchable Loads (Issue 4)

The proposed removal of Dispatchable Loads from the Market Rules will promote economic efficiency (Wholesale Market Objective (a)) and contribute to minimising the long-term cost of electricity (Wholesale Market Objective (d)) by eliminating a Facility Class that has provided no benefit to the WEM and imposes ongoing administrative and system costs on the market.

Interruptible Loads and the Reserve Capacity Mechanism (Issue 5)

The proposed changes will facilitate the entry of new competitors by clarifying the mechanism by which an Interruptible Load can provide Reserve Capacity to the market (Wholesale Market Objective (b)).

Changes allowed after REM Gate Closure (Issue 6)

Clarifying the details of the changes allowed to REM Submissions after REM Gate Closure will reduce the likelihood of inappropriate constraint payments, which will promote economic efficiency (Wholesale Market Objective (a)) and contribute to minimising the long-term cost of electricity (Wholesale Market Objective (d)).

LFAS Merit Orders and IT outages (Issue 7)

The proposed change to allow the use of a forecast when the IMO is unable to generate the LFAS Enablement Schedule will promote economic efficiency (Wholesale Market Objective (a)) and contribute to minimising the long-term cost of electricity (Wholesale Market Objective (d)), by allowing System Management to try to enable LFAS capacity based on the forecast LFAS Enablement Schedule before resorting to Backup LFAS.

Impact on Outage Planning Process Refinements (Issue 8)

The proposed additional amendments to the provisions outlined in RC_2013_15 will promote economic efficiency (Wholesale Market Objective (a)) by removing the requirement on

Synergy to bid capacity that is subject to an outstanding Planned Outage approval request as 'available' in its REM Submission and by moving the deadline for applying for Opportunistic Maintenance to an hour before the deadline for Synergy Portfolio LFAS Submissions. This will allow Synergy Portfolio REM and LFAS Submissions to more accurately reflect the Synergy Portfolio's expected costs and availability.

Fuel Declarations (Issue 9)

The proposed removal of the obligations around the provision of Fuel Declarations to System Management will promote economic efficiency (Wholesale Market Objective (a)) and contribute to minimising the long-term cost of electricity (Wholesale Market Objective (d)) by eliminating an unnecessary process from the Market Rules.

Forecast and final DMOs and LFAS Merit Orders (Issue 10)

The proposed changes to the wording of section 7A.3 and 7B.3 of the Market Rules will encourage competition in the market by improving the clarity of the Market Rules (Wholesale Market Objective (b)).

---

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

Both System Management and the IMO will require IT system and internal process changes to implement the proposed amendments. The IMO will work with System Management during the first submission period to identify the extent of these costs.

Changes will also be required to a number of Market Procedures and Power System Operation Procedures (PSOPs), as well as to a range of market documents published by the IMO including market design summaries and user guides.

Some Market Participants are also likely to incur costs associated with IT system and process changes.

The benefits of these changes include:

- clarifying the function and purpose of the REM;
- reducing the burden on Market Participants of having to comply with unnecessary or redundant obligations;
- reducing the burden of maintaining unnecessary system functionality;
- improving the quality of the information used for dispatch and pricing;
- reducing LFAS costs by allowing more reliable information to be used in setting the LFAS Quantity and forming LFAS Submissions;
- reducing risk and providing greater flexibility for Market Participants in the REM and LFAS Market; and
- improving the clarity and integrity of the Market Rules.

Agenda item 7 – Proposed scope of work for the 2014 Review of the Relevant Level Methodology

Background

Under clause 4.11.3C of the Market Rules, the IMO must conduct a review of the Relevant Level Methodology (methodology) every three years. The methodology, which is specified in Appendix 9 of the Market Rules, is used by the IMO to determine the quantity of Certified Reserve Capacity for a Facility for a given Reserve Capacity Cycle, where the Market Participant has applied for certification of the Facility (usually an Intermittent Generator) under clause 4.11.2(b).

The requirements for the review are outlined in clauses 4.11.3C, 4.11.3D and 4.11.3E. In conducting the review, the IMO:

- must examine the effectiveness of the methodology in meeting the Wholesale Market Objectives;
- must determine the values of the parameters K and U in step 17 of the methodology to be applied for each of the three Reserve Capacity Cycles commencing in the period;
- may examine any other matters that the IMO considers to be relevant;
- must publish a draft report and invite submissions from Rule Participants and any other stakeholders the IMO considers should be consulted;
- must, at the conclusion of the review, publish a final report containing:
    - details of the IMO's review of the methodology;
    - a summary of the submissions received during the consultation period;
    - the IMO's response to any issues raised in those submissions;
    - the values of the parameters K and U determined under clause 4.11.3C; and
    - any recommended amendments to the methodology which the IMO intends to progress as a Rule Change Proposal.

The initial review, for the three year period commencing on 1 January 2015, must be completed by 1 April 2015. The IMO proposes to complete the review by October 2014, to allow time for any recommended amendments to the methodology to be progressed through the rule change process in time for certification for the 2015 Reserve Capacity Cycle.

The IMO intends to engage a consultant to assist with the 2014 Review of the Relevant Level Methodology. The proposed scope of work for the consultant is provided below.

Proposed scope of work

The consultant is to undertake a review of the Relevant Level Methodology prescribed in Appendix 9 of the Market Rules.

The review must include:

- a review of developments in international best practice for the valuation of the capacity provided by Intermittent Generators;
- analysis of the methodology since its implementation in 2012, including:
    - the operational and financial impacts of the methodology;
    - the volatility of the Relevant Level values produced by the methodology;
    - the accuracy of the methodology in predicting Intermittent Generator output in periods of peak system demand, Load for Scheduled Generation (LSG) and temperature; and
    - the impact of the methodology on the different Intermittent Generator facility types, including wind, solar and landfill gas;
- consideration of the penetration of Intermittent Generators in the South West interconnected system and whether there is a need to investigate alternative valuation methodologies prior to the next three-year review;
- consideration of whether any changes are warranted to how the peak Trading Intervals are selected for the calculations, including:
    - the number of years considered;
    - the number of Trading Intervals selected from each year;
    - the requirement to select peak Trading Intervals from different Trading Days;
    - the use of LSG to select the peak Trading Intervals; and
    - options to weight the Trading Intervals selected, e.g. to give greater weighting to Trading Intervals with higher peaks;
- consideration of whether any changes to the methodology are warranted to account for the correlation of output between Intermittent Generators;
- consideration of the K and U factor adjustments, including:
    - the correlation between Intermittent Generator output and the periods of high system risk, given the availability of a larger data set than was available when the methodology was first developed;
    - whether the importance of the U factor has diminished due to more information becoming available about the performance of Intermittent Generators at extreme peaks;
    - the structure and size of the U factor adjustment;
    - how greater certainty over the performance of Intermittent Generators during extreme peak periods could be obtained;
    - whether the use of technology-specific U factors is warranted; and
    - the appropriateness of the upper limit placed on the U factor adjustment for a facility;
- consideration of the effectiveness of the methodology in meeting the Wholesale Market Objectives and achieving an appropriate balance between simplicity and accuracy;
- recommended values for K and U to be applied for each of the 2015, 2016 and 2017 Reserve Capacity Cycles;
- details of any proposed amendments to the methodology in the Market Rules;

- if amendments are proposed, an assessment of how these amendments will allow the Market Rules to better address the Wholesale Market Objectives;
- an assessment of the impact of any proposed amendments on other areas of the Market Rules and the Market Procedures;
- preparation of a draft report for consultation;
- consideration of and response to submissions received from Rule Participants and other stakeholders on the draft report; and
- preparation of a final report.

The draft report and final report to be delivered by the consultant must cover the requirements under clauses 4.11.3C, 4.11.3D and 4.11.3E of the Market Rules.

Recommendation

It is recommended that the MAC:

- Note the proposed scope of work for the 2014 Review of the Relevant Level Methodology.

Agenda item 8 – IMO Rule Development Workplan 2014

The IMO prepared a summary of current and proposed rule development activities (Appendix A) for consideration by the Electricity Market Review team in order for the Review team to provide advice to the IMO regarding which items (if any) are intended to be covered by the Review.

The activities fall within five broad categories:

1. **Rule changes currently in the rule change process** – the IMO is required to continue to progress Rule Change Proposals that are already in the formal rule change process in accordance with the process and timelines specified in the Market Rules. This includes:
   - RC_2013_20: Changes to the Reserve Capacity Price and the dynamic Reserve Capacity Refund regime
   - RC_2013_21: Limits to Early Entry Capacity Payments
   - RC_2013_15: Outage Planning Phase 2

2. **Rule change proposals submitted by parties other than the IMO** – the IMO is required to progress externally submitted Rule Change Proposals in accordance with the process and timelines specified in the Market Rules. This may include the following proposals by Bluewaters Power:
   - Proposed RC_2013_13: Market Fees to be payable on a Capacity and Energy Basis
   - Proposed RC_2013_14: Adjustment of Spinning Reserve Block Sizes

3. **Reviews required by the Market Rules** – the IMO is required to undertake reviews required by the Market Rules. The IMO does not anticipate formally submitting any subsequent Rule Change Proposals, if required, until late 2014 at the earliest. This includes:
   - Review of Relevant Level Methodology (three yearly)
   - Ancillary Services Review (five yearly)

4. **Rule changes of an operational or administrative nature**, which are at a level of detail not likely to be covered by the Review – the IMO proposed to continue to develop and submit formal Rule Change Proposals, including:
   - Proposed RC_2013_16: Outages and the Application of Constraint Payments to Non-Scheduled Generators
   - Proposed RC_2014_01: Improvements to the Energy Market
   - Process for Setting the Energy Price Limits and Maximum Reserve Capacity Price
   - Handling of Information in the WEM
   - Other minor or administrative rule change proposals (i.e. Minor and Typographical)

5. **Rule changes relating to key aspects of the design of the Wholesale Electricity Market** – the IMO proposed to commence design work on these items, but does not intend to submit a formal Rule Change Proposal in 2014. This includes:
   - Further stages of the Improvements to the Energy Market work package (including Synergy facility-based bidding and Short Term Energy Market redesign)

Recommendation

It is recommended that the MAC note the proposed 2014 IMO rule development workplan.

Appendix A: Summary of Rule Change Proposals, Market Rules Evolution Plan (MREP) issues and required market reviews (as at March 2014)

Issue and source	Initiated by	Review to cover?	IMO to progress
Rule Change Proposals underway as at 24 March 2014			
RC_2012_23: Prudential Requirements To clarify obligations in relation to prudential requirements	IMO		Awaiting commencement
RC_2013_09: Incentives to Improve Availability of Scheduled Generators Issue also highlighted by ERA in WEM report to Minister	IMO		Approved, awaiting Ministerial approval
RC_2013_10: Harmonisation of Supply-Side and Demand-Side Capacity Resources As a result of Reserve Capacity Mechanism Working Group (RCMWG) work programme	IMO following RCM Review		Approved, awaiting Ministerial approval
RC_2013_17: Correction to estimated output of Intermittent Generation for the purposes of Appendix 9	Alinta Energy		Rule change (RC) process underway, IMO Board to consider in April
RC_2013_20: Changes to the Reserve Capacity Price and the dynamic Reserve Capacity Refund regime As a result of RCMWG work programme	IMO following RCM Review		RC underway, IMO Board to consider in May, subject to Ministerial approval
RC_2013_21: Limits to Early Entry Capacity Payments	IMO at request of MAC in Oct 2013		RC underway, IMO Board to consider in May, subject to Ministerial approval
RC_2013_15: Outage Planning Phase 2 To implement recommendations from 5-yearly review of outage planning process – required under Market Rules	IMO following Outage Planning Review		RC underway, IMO Board to consider in June
Rule Change Proposals under development as at 24 March 2014, anticipated to be progressed by IMO during 2014			
Proposed RC_2013_16: Outages and the Application of Constraint Payments to Non-Scheduled Generators To address inefficient payment of constrained on/off compensation and relieve administrative burden	IMO		PRC considered by MAC 19/3/2014 RC yet to commence
Proposed RC_2013_14: Adjustment of Spinning Reserve Block Sizes Priority 8 on Market Rules Evolution Plan (MREP)	Bluewaters Power		PRC considered by MAC 19/3/2014 RC yet to commence
Proposed RC_2014_01: Improvements to the Energy Market Priority 3 and elements ('low hanging fruit') of Priority 1 on MREP	IMO		PRC considered by MAC 19/3/2014 RC yet to commence

Issue and source	Initiated by	Review to cover?	IMO to progress
Concept Paper CP_2013_14: Collection of Market Fees To allocate a portion of market fee costs to peaking generators and DSM Priority 12 on Market Rules Evolution Plan (MREP)	Bluewaters Power	?	Concept Paper considered by MAC 13/11/2013 RC yet to commence
Further improvements to energy market (Synergy bidding on facility-by-facility basis, STEM replacement) Remaining elements of Priority 1 on MREP	Initial MAC discussion only	?	
Process for Setting the Energy Price Limits and Maximum Reserve Capacity Price An administrative change proposed by ERA in its 2013 Review Proposal to set Maximum Reserve Capacity Price (MRCP) and the Energy Price Limits (ELP) periodically (every 3-4 years) with CPI adjustment in-between	IMO following recommendation by ERA		IMO developing a RC
Handling of Information in the WEM Clarification of processes for management and disclosure of information Likely to require a redraft of Chapter 10 of WEM Rules	IMO		IMO developing a RC
High Level Proposal for the Development of a Gas and Capacity Trading Market in WA Development of proposal that includes a straw man design of a gas trading market, including a high level costing Would require legislative and/or regulation to implement	IMO at GAB's request	?	IMO to provide a proposal directly to Government for consideration
Other issues in MREP yet to be progressed or under development			
Emissions Intensity Index (Priority 2) MAC no longer views this issue as high priority			
Introduction of market for Spinning Reserve (Priority 4) Waiting on outcomes of Ancillary Services Review			
Settlement simplification (Priority 5)			
Market Rule Change Process (Priority 6)			
Non-arrival of new loads (Priority 7)		?	
Feedback on Synergy's demand (including consideration of settlement timing) (Priority 9)			
NTDL (Priority 11)			

Issue and source	Initiated by	Review to cover?	IMO to progress
Reviews (IMO's data gathering powers to support market modelling) (Priority 13)		?	
Intermittent Loads (Priority 14)			
Capacity lead time for Demand Side Programmes (Priority 15)		?	
Calculation of Loss Factors (Priority 16)			
Participation of DSM in Balancing (Priority 17)		?	
Treatment of new small generators (Priority 18)			
IMO periodic reviews required by Market Rules, scheduled for 2014 and 2015			
2014 and 2015 Energy Price Limits – annual Required under Market Rules 6.20 and 2.26.1 2015 process may be subject to rule change process to reduce frequency of determination	IMO		IMO to submit to ERA by May 2014 & 2015 Commencing 1 Jul 2014 & 2015
Ancillary Services Review – 5-yearly Required under Market Rule 3.15.1	IMO		Final report required by Nov 2014
2014 Margin Values – annual Required under Market Rule 3.13.3A	IMO		IMO to submit to ERA by 30 Nov 2014, approval by 31 Mar 2015, To apply from 1 Jul 2015
Review of Relevant Level Methodology – 3-yearly Required under Market Rule 4.11.3C	IMO		Final report required by 1 Apr 2015
Outage Planning Process Review – 5-yearly Required under Market Rule 3.18.18 Review brought forward by one year as a result of issues raised by stakeholders	IMO		Final report due Sept 2016, IMO proposes to complete in 2015.

Rule Change Proposals Currently Underway

The Market Rules prescribe the formal process the IMO must undertake when it receives or develops a Rule Change Proposal (sections 2.5 and 2.7 of the Market Rules).

Amendments to the Market Rules are proposed by the IMO or other persons to either:

- address issues identified with the Market Rules (e.g. an error in the drafting of a clause or provisions which require the market to operate in a manner contrary to the Wholesale Market Objectives (Objectives) set out in the *Electricity Industry Act 2004*); or
- make changes, enhancements or improvements to the market arrangements contained within the Market Rules, including items identified under the Market Rules Evolution Plan (MREP), to enable the market arrangements to better address the Objectives.

Once a Rule Change Proposal has been formally submitted into the process, the IMO is required to process the proposal in accordance with the steps and timelines outlined in the Market Rules. While the IMO is empowered to extend certain deadlines throughout the rule change process, there is no ability for the IMO to do so indefinitely – the process is concluded by the IMO when it makes a decision to either approve or not approve the proposal (noting that some changes will also require Ministerial approval).

The following table provides a summary of the current Rule Change Proposals, including the current stage of progress through the rule change process and next steps. At present, all Rule Change Proposals being progressed by the IMO are in the Standard Rule Change Process which includes two formal rounds of stakeholder consultation.

Table 1: Rule Change Proposals underway as at 24 March 2014

Rule Change and Proponent	Description	Status and Next Steps
RC_2012_23: Prudential Requirements *IMO*	Seeks to simplify calculation of a Trading Margin and clarify when a Margin Call will be made, consistent with current practice. Also formalises the ability for Market Participants to make a voluntary pre-payment. This proposal addresses identified issues in the Market Rules and formalises more flexible payment arrangements.	Final Report published on 12 March 2014. Protected Provisions: No Proposed commencement: 1 May 2014
RC_2013_09: Incentives to Improve Availability of Scheduled Generators *IMO*	The proposal includes three key elements: enable the IMO to grant varying levels of Capacity Credits to Scheduled Generators which have demonstrated poor availability (no longer an "all or nothing" decision), with a transitional reduction in the permissible level of Planned Outages before action can be taken. introduce an upper limit on Planned Outages for Scheduled Generators, with refunds being payable beyond this limit; and allow the IMO to require a performance report in relation to a Scheduled Generator with poor availability, irrespective of the availability of Scheduled Generators overall. This proposal arose from concerns identified by the IMO Board and the Economic Regulation Authority (ERA) regarding the very poor availability performance on some Scheduled Generators in the WEM.	Awaiting approval by the IMO Board. Final Rule Change Report published on 24 March 2014. Protected Provisions: Yes Proposed commencement (subject to Ministerial approval): 1 May 2014

Rule Change and Proponent	Description	Status and Next Steps
RC_2013_10: Harmonisation of Supply-Side and Demand-Side Capacity Resources *IMO*	Seeks to provide for greater consistency in the requirements of supply-side (generation) and demand-side capacity providers. Key proposed changes are: an increase in the minimum availability requirements for Demand Side Programmes (DSPs); the introduction of real-time telemetry to increase the transparency of the availability and performance of DSPs; to restrict a DSP from selling more capacity than it buys through Individual Reserve Capacity Requirement; and the relaxation of fuel requirements for generators. This Rule Change Proposal arose from the work of the Reserve Capacity Mechanism Working Group (RCMWG) which considered the recommendations of the review of the RCM undertaken by the IMO in 2011.	Awaiting approval by the IMO Board. Final Rule Change Report published on 24 March 2014. Protected Provisions: Yes Proposed commencement (subject to Ministerial approval): 1 May 2014; 1 October 2014; and 1 October 2016.
RC_2013_17: Correction to estimated output of Intermittent Generation for the purposes of Appendix 9 *Alinta Energy*	Where System Management dispatches an Intermittent Generator downwards, it is obliged to provide the IMO with an estimate of the energy that the facility would have generated if not dispatched. There is no ability to update this estimate if it is found to be incorrect (e.g. lower than the actual output of the facility). Alinta Energy has proposed changes to allow for the revision of estimates for the purposes of certification of Reserve Capacity.	Second round of consultation closes 25 March 2014. IMO Board approval and publication of Final Rule Change Report by 24 April 2014. Protected Provisions: No Proposed commencement: 1 May 2014
RC_2013_20: Changes to the Reserve Capacity Price and the dynamic Reserve Capacity Refund regime *IMO*	This proposal includes: changes to the Reserve Capacity Price formula to increase the responsiveness of the price signal to the overall level of capacity in the market; and changes to determining the value of Capacity Cost Refunds, to better align them with time periods of greatest system need and create a stronger incentive to generators to be available for dispatch. This Rule Change Proposal arose from the work of the RCMWG which considered the recommendations of the review of the Reserve Capacity Mechanism undertaken by the IMO in 2011.	Draft Rule Change Report to be published by 25 March 2014. Second round of consultation expected to conclude: 24 April 2014. IMO Board approval and publication of Final Rule Change Report by 23 May 2014. Protected Provisions: Yes Proposed commencement (subject to Ministerial approval):
RC_2013_21: Limits to Early Entry Capacity Payments *IMO*	This proposal aims to limit early entry capacity payments in years of excess capacity, where the market receives little benefit from the incentive for early delivery of capacity. The proposal also aligns the treatment of Early Certified Reserve Capacity to provide for early entry capacity payments in times of low excess (or shortfall) to correct an oversight in the existing rules. The Market Advisory Committee (MAC) recommended to the IMO, in October 2013, that this change be progressed as a priority.	Draft Rule Change Report to be published by 25 March 2014. Second round of consultation expected to conclude: 24 April 2014. IMO Board approval and publication of Final Rule Change Report by 23 May 2014. Protected Provisions: Yes Proposed commencement (subject to Ministerial approval): 1 October 2014

Rule Change and Proponent	Description	Status and Next Steps
RC_2013_15: Outage Planning Phase 2 *IMO*	This proposal concerns technical changes to the outage planning process aimed at providing greater flexibility to Rule Participants and provides clarification for the obligations on Rule Participants around the Outage planning process. This Rule Change Proposal is the second package of changes that arose from the recommendations of the five-yearly Outage Planning Review undertaken by the IMO in 2011.	Draft Rule Change Report to be published by 15 April 2014. Second round of consultation expected to conclude: 16 May 2014. IMO Board approval and publication of Final Rule Change Report by 16 June 2014. Protected Provisions: No Proposed commencement: TBC (likely to be staged over 2014 and 2015).

Rule Change Proposals Under Development

In addition, the IMO is undertaking preliminary work on a number of potential changes to the Market Rules, some of which it proposes to submit into the rule change process over the course of 2014.

The IMO is also undertaking preliminary work on a number of other changes to the Market Rules, and the possible evolution of the WA natural gas market.

Table 2 provides a summary of these changes, including an indication of whether the IMO anticipates progressing a formal Rule Change Proposal in 2014, or other action (e.g. a submission to the Electricity Market Review).

Table 2: Rule Change Proposals under development as at 24 March 2014

Proposed Change and Proponent	Description	Proposed approach
Proposed RC_2013_16: Outages and the Application of Constraint Payments to Non-Scheduled Generators *IMO*	This proposal by the IMO intends to propose amendments the Market Rules to provide additional mechanisms and greater clarity for Non-Scheduled Generators, particularly with respect to Outages and constrained on/off compensation. The current Market Rules require payment of constrained on/off compensation in circumstances where a generator is not compliant with Dispatch Instructions, or where it is curtailed in accordance with the terms of its network contract. These payments are frequently recovered following an IMO investigation process, but this is inefficient for the market and administratively burdensome for the IMO. The proposed changes will ensure that constrained on/off compensation is not paid under these circumstances.	Pre Rule Change Proposal considered by MAC in March 2014. The IMO proposes to progress this rule change during 2014 via the Standard Rule Change Process.
Proposed RC_2013_14: Adjustment of Spinning Reserve Block Sizes *Bluewaters Power*	Bluewaters Power has developed a proposal that seeks adjustments to the current 'blocks' which determine liability for Spinning Reserve charges in the market. The MAC requested that the IMO provide further analysis on an alternative methodology in May 2014.	Pre Rule Change Proposal considered by MAC in March 2014. The IMO anticipates a Rule Change Proposal will be formally submitted by Bluewaters Power some

Proposed Change and Proponent	Description	Proposed approach
	Following further discussion by the MAC, Bluewaters Power is expected to submit a Rule Change Proposal some time in 2014. Spinning Reserve cost allocation is an issue identified in the current MREP (item 8).	time in 2014, to be progressed by the IMO under the Standard Rule Change Process.
Concept Paper CP_2013_13: Collection of Market Fees *Bluewaters Power*	Bluewaters Power developed a Concept Paper that proposes to allocate a share of the market fee costs to peaking generators and DSM providers. The current fee allocation is based on energy generated and consumed. Bluewaters Power may submit a Rule Change Proposal some time in 2014. Allocation of market fees to peaking capacity is an issue identified in the current MREP (item 12).	Concept Paper considered by MAC in November 2013. The IMO presented further analysis to the MAC at the following meeting. While this issue may be considered by the Electricity Market Review, Bluewaters Power may formally submit a Rule Change Proposal at any time and the IMO would be obliged to process it.
Proposed RC_2014_01: Improvements to the Energy Market *IMO*	This is a package of changes the IMO is developing to implement the highest priority items on the MREP (item 3 and elements of item 1). This package would propose to: re-name the Balancing Market to the Real-Time Energy Market (REM) to better reflect the nature of the market; remove the requirement on generators to submit Resource Plans, as these no longer serve the purpose they were previously required for; and enable Market Participants to update REM and Load Following Ancillary Service submissions closer to the start of the relevant Trading Interval.	Pre Rule Change Proposal considered by MAC in March 2014. The IMO proposes to progress this rule change during 2014 via the Standard Rule Change Process.
Further improvements to energy market	Further changes to the energy market may be considered to address elements of item 1 of the MREP. These may include: requiring Synergy to bid into the Balancing Market [REM] on a facility-by-facility basis; and design of a replacement to the current Short Term Energy Market (STEM) to develop a more fit-for-purpose trading mechanism to complement bilateral contacting and enable participants to manage their exposure to variable energy prices in the Balancing Market [REM].	The IMO has conducted initial work in these areas. If not covered by the Electricity Market Review, the IMO would progress this work during 2014.
Process for Setting the Energy Price Limits and Maximum Reserve Capacity Price	The IMO is developing proposed changes to the Market Rules to replace the current annual processes for setting these prices with processes to set a price to apply over a number of years (e.g. 3 to 5), which may be indexed and/or subject to reset (in limited circumstances) over the period. This change was proposed by the ERA in its 2013 *Review of methodology for setting the Maximum Reserve Capacity Price and the Energy Price Limits in the Wholesale Electricity Market*.	The IMO proposes to progress this rule change during 2014 via the Standard Rule Change process.

Proposed Change and Proponent	Description	Proposed approach
Handling of Information in the WEM	The IMO is developing proposed changes to Chapter 10 of the Market Rules to include a revised framework for how WEM information is to be managed and disclosed. The current approach in Chapter 10 makes it very difficult to determine what information the IMO is permitted to disclose, to whom and how. The proposed changes are intended to ensure the processes around the management and disclosure of information are both robust and straightforward to apply.	The IMO proposes to progress this rule change during 2014 via the Standard Rule Change process.
High Level Proposal for the Development of a Gas and Capacity Trading Market in WA.	Members of the IMO's Gas Advisory Board (GAB) have requested the IMO's assistance to develop a high level proposal for a gas and capacity trading market in WA. The GAB requested that the IMO facilitate a whiteboard session, which was conducted in February 2014. Following this meeting, the GAB requested that the IMO prepare a straw man design and high level costing to be presented at the next meeting. The IMO has undertaken two days of stakeholder consultation as part of this process. It is intended that the market be relatively low cost and voluntary.	The IMO expects to present the proposal, on behalf of the GAB, to Government in the first half of 2014.

Market Rules Evolution Plan

The MREP is a plan developed by the IMO including proposed changes to the Market Rules that are identified and prioritised by Market Participants and other stakeholders. The current MREP was finalised in late 2012 and covers the period 2013 to 2016.

Table 3: Issues from MREP yet to be progressed or under development

Issue	Description	Status/proposed approach
Emissions Intensity Index (item 2)	Formalised provision of emissions data by Market Participants to allow the IMO to publish an Emissions Intensity Index for the WEM.	Re-prioritised MAC recommended to the IMO in October 2013 that this item should be re-prioritised, due to the anticipated repeal of the carbon price mechanism.
Introduction of market for Spinning Reserve (item 4)	Introduction of market for competitive provision of Spinning Reserve.	On hold Waiting on the outcomes of the Ancillary Services Review (see Table 4).
Settlement simplification (item 5)	Simplification of Market Rules around market settlements.	Outstanding
Market Rule Change Process (item 6)	Review of rule change process	Outstanding
Non-arrival of new loads (item 7)	Consideration of measures related to the arrival of new loads that allocate costs or limit supply to new loads if they do not commence operation in line with forecasts (either early or late)	Outstanding Could be considered by Electricity Market Review?
Feedback on Synergy's demand (including consideration of settlement	Earlier feedback on Synergy's actual demand (may include consideration of settlement timeframes)	Outstanding

timing) (item 9)		
Non Temperature Dependent Loads (item 11)	Limitations on the ability of Market Customers to achieve NTDL status within a Capacity Year	Outstanding
Reviews (IMO's data gathering powers to support market modelling) (item 13)	Consideration of increased information gathering powers for IMO to improve accuracy of market modelling for processes such as Energy Price Limits and Margin Values.	Outstanding Could be considered by Electricity Market Review?
Intermittent Loads (item 14)	Review of incentives in relation to Individual Reserve Capacity Requirements	Outstanding
Capacity lead time for Demand Side Programmes (item 15)	Consideration of shorter lead time for certification of DSPs	Outstanding Could be considered by Electricity Market Review?
Calculation of Loss Factors (item 16)	Potential streamlining of Loss Factor determination process	Outstanding
Participation of DSM in Balancing (item 17)	Inclusion of DSPs in Balancing Merit Order with generation facilities	On hold To be considered in next MREP, subject to approval and implementation of harmonisation rule change (RC_2013_10, see Table 1). Could be considered by Electricity Market Review?
Treatment of new small generators (item 18)	Potential increase in threshold for provisions related to certification of Reserve Capacity for new small generators	Outstanding

Reviews

The Market Rules require the IMO to undertake periodic reviews of specified matters. The periodic reviews to be undertaken during 2014 and 2015 are listed in the table below.

Table 4: Reviews scheduled for 2014 and 2015

Review	Description	Timing
2014 Energy Price Limits (clauses 6.20 and 2.26.1)	Annual review to determine Maximum STEM Price and Alternative Maximum STEM Price. Recommendations made by the IMO for ERA approval.	Process commences January each year in order to submit recommendations to the ERA by end May to enable approval of revised values for the year commencing 1 July.
Ancillary Services Review (clause 3.15.1)	Five yearly Review of Ancillary Service Standards and Requirements. Final report may, but need not, include recommendations for rule changes.	Final Report due November 2014.
2014 Margin Values (clause 3.13.3A)	Annual review to determine Margin_Peak and Margin_Off-Peak to be used in the settlement of Spinning Reserve costs	IMO to submit proposal to ERA by 30 November 2014. ERA to approve by 31 March 2015, with values to apply from 1 July 2015.
Review of Relevant Level Methodology (clause 4.11.3C)	Three-yearly review of methodology which is also required to set certain parameters to apply for coming three years.	Must be completed by 1 April 2015.

2015 Energy Price Limits (clauses 6.20 and 2.26.1)	See above	Subject to Rule Change Proposal in Table 2. Otherwise as per 2014 review.
Outage Planning Review (clause 3.18.18)	Five yearly review of the outage planning process. Final report may, but need not, include recommendations for rule changes	Not due until September 2016, but propose to complete in 2015 in response to issues raised by stakeholders.

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 Procedure Change commenced on 1 May 2014.	• Commenced.	1 May 2014

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).			
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).	• PC_2013_05 was tabled at the 1 May 2014 IMO Procedures Working Group.	• PC_2013_05 has been updated to reflect comments raised at the 1 May meeting and will be submitted into the procedure change process in May.	May 2014
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.	• The Procedure Change Report has been prepared by the IMO and is pending Ministerial approval of RC_2013_09 and RC_2013_10.	• Procedure Change Report published.	May 2014

ID	Summary of Changes	Status	Next Step	Date
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.	• The Procedure Change Report has been prepared by the IMO and is pending Ministerial approval of RC_2013_09.	• Procedure Change Report published.	May 2014
PC_2014_01 **Balancing Market Forecast**	The proposed updates are to: • remove references to Verve Energy in the Market Procedure in response to the changes arising from the Rule Change Proposal RC_2013_18: Market Rule changes arising from the merger of the Electricity Retail Corporation and Electricity Generation Corporation; and • make other minor editorial improvements to the Market Procedure.	• Procedure has been updated following the discussion at the 6 February 2014 IMOPWG.	• Updated Market Procedure to be circulated to the IMOPWG for comment.	TBA
PC_2014_02 **Declaration of Bilateral Trades and the Reserve Capacity Auction**	The proposed updates are to: • remove references to Verve Energy in the Market Procedure in response to the changes arising from the Rule Change Proposal RC_2013_18: Market Rule changes arising from the merger of the Electricity Retail Corporation and Electricity Generation Corporation; and • make other minor editorial improvements to the Market Procedure.	• PC_2014_02 commenced on 16 April 2014.	• Commenced	16/04/2014
PC_2014_03 **Market Procedure for Determining the Benchmark Reserve Capacity**	The proposed updates are to: • rename the Maximum Reserve Capacity Price (MRCP) in the Market Rules as the Benchmark Reserve Capacity Price; and • make other minor editorial improvements to the Market	• PC_2014_03 was tabled at the 1 May 2014 IMO Procedures Working Group.	• PC_2014_03 has been updated to reflect comments raised at the 1 May meeting and will be submitted	May 2014

ID	Summary of Changes	Status	Next Step	Date
Price	Procedure.		into the procedure change process in May.	
TBC **Undertaking the LT PASA and conducting a review of the Planning Criterion**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Include some minor and typographical amendments to improve the integrity of the Market Procedure, including re-ordering some sections; and • Include both reviews required under clause 4.5.15 of the Market Rules (Planning Criterion and forecasting processes).	• As advised at the August 2012 working group meeting, the IMO is currently undertaking the five yearly review of the IMO's forecasting processes. Following the completion of the review the IMO may make further changes to the Market Procedure.	• Updated procedure to be presented back to the Working Group for discussion.	TBA
TBC **Meter Data Submission**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Clarify that the Procedure is part of the Settlement Market Procedures; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by the IMO Procedures Working Group	TBA
TBC **Capacity Credit Allocation**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Clarify that the Procedure is part of the Settlement Market Procedures; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by IMO Procedures Working Group	TBA

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

ID	Summary of Changes	Status	Next Step	Date
System Management Procedure Change Proposals				
PPCL0026 **Facility Outages**	The proposed updates are to: • Reflect the new outage transparency rules resulting from RC_2012_11.	• PPCL0026: Facility Outages commenced on 7 April 2014.	• Commenced.	07/04/2014

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	01/05/2014	TBA