INDEPENDENT MARKET OPERATOR

Market Advisory Committee

Agenda

Meeting No.	69
Location:	IMO Board Room Level 17, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Wednesday 19th March 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 67**	**Chair**	5 min
4.	**ACTIONS ARISING**	**Chair**	10 min
5.	**MARKET RULES**		
	a) Market Rule Change Overview	**IMO**	5 min
	b) PRC_2013_16: Outages and the Application of Availability and Constraint Payments to Non-Scheduled Generators	**IMO**	15 min
	c) PRC_2013_14: Adjustment of Spinning Reserve Block Sizes	**Bluewaters**	15 min
	d) PRC_2014_01: Improvements to the Energy Market	**IMO**	20 min
6.	**MARKET PROCEDURES**		
	a) Overview	**IMO**	5 min

7.	**WORKING GROUPS**		
	a) Overview and membership updates	**IMO**	5 min
8.	**MAC CONSTITUTION AND APPOINTMENT GUIDELINES**	**IMO**	10 min
9.	**MUJA BUS-TIE TRANSFORMER FAILURE UPDATE**	**SM**	15 min
10.	**LFAS UPDATE**	**IMO/SM**	10 min
11.	**WIND FORECASTING UPDATE**	**IMO**	15 min
12.	**LOAD FORECASTING UPDATE**	**SM**	15 min
13.	**GENERAL BUSINESS**	**IMO**	10 min
	a) Regulation of Demand Side Management Aggregators	**IMO**	5 min
14.	**NEXT MEETING: Wednesday 14th May 2014**		

INDEPENDENT MARKET OPERATOR

Market Advisory Committee

Minutes

Meeting No.	67
Location	IMO Board Room Level 17, 197 St Georges Terrace, Perth
Date	Wednesday 11 December 2013
Time	2:00pm – 5:30pm

Attendees	Class	Comment
Allan Dawson	Chair	
Kate Ryan	Compulsory – IMO	
Dean Sharafi	Compulsory – System Management	Proxy
Andrew Everett	Compulsory – Generator	
Dean Frost	Compulsory – Western Power	Proxy
Will Bargmann	Compulsory – Customer	
Geoff Gaston	Discretionary – Generator	
Shane Cremin	Discretionary – Generator	
Andrew Sutherland	Discretionary – Generator	
Michael Zammit	Discretionary – Customer	
Nenad Ninkov	Discretionary – Customer	
Steve Gould	Discretionary – Customer	
Peter Huxtable	Discretionary – Contestable Customer Representative	
Paul Hynch	Minister's appointee – Observer	Proxy
Elizabeth Walters	Observer – Economic Regulation Authority (ERA)	Proxy
Apologies	**From**	**Comment**
Phil Kelloway	Compulsory– System Management	
Noel Ryan	Compulsory – Western Power	
Nerea Ugarte	Minister's appointee – Observer	
Wana Yang	Observer – Economic Regulation Authority (ERA)	
Also in attendance	**From**	**Comment**
Jim Truesdale	Concept Consulting	Presenter

Jenny Laidlaw	IMO	Presenter
Aditi Varma	IMO	Presenter & Minutes
Alex Penter	IMO	Presenter
Brendan Clarke	System Management	Presenter
Fiona Edmonds	Alinta Energy	Observer
Chris Campbell	Alinta Energy	Observer
Andy Stevens	Bluewaters Power	Observer
Rob Rohrlach	Amanda Australia	Observer
Paul Troughton	EnerNOC	Observer
Greg Ruthven	IMO	Observer 3:30pm-4:15pm and 5:00pm-5.30 pm)
Erin Stone	IMO	Observer
George Sproule	IMO	Observer
Courtney Roberts	IMO	Observer

Item	Subject	Action
1.	**WELCOME** The Chair opened the meeting at 2:00pm and welcomed members to the 67th meeting of the Market Advisory Committee (MAC).	
2.	**MEETING APOLOGIES / ATTENDANCE** The following **apologies** were received: • Phil Kelloway (Compulsory – System Management) • Noel Ryan (Compulsory – Network Operator) • Nerea Ugarte (Minister's appointee – Observer) • Wana Yang (Observer – ERA) The following **proxies** were noted: • Dean Sharafi for Phil Kelloway (Compulsory – System Management) • Dean Frost for Noel Ryan (Compulsory – Network Operator) • Paul Hynch for Nerea Ugarte (Minister's appointee – observer) • Elizabeth Walters (Observer – ERA) The following **presenters** and **observers** were noted: • Jim Truesdale (presenter, Concept Consulting) • Jenny Laidlaw (presenter, IMO) • Brendan Clarke (presenter, System Management) • Aditi Varma (presenter and minutes, IMO)	

	• Alex Penter (presenter, IMO) • Fiona Edmonds (observer, Alinta Energy) • Chris Campbell (observer, Alinta Energy) • Andy Stevens (observer, Bluewaters Power) • Rob Rohrlach (observer, Amanda Australia) • Paul Troughton (observer, EnerNOC) • Greg Ruthven (observer, IMO) • Erin Stone (observer, IMO) • George Sproule (observer, IMO) • Courtney Roberts (observer, IMO)	
3.	**MINUTES OF PREVIOUS MEETING** The minutes of MAC Meeting No. 66, held on 13 November 2013, were circulated to members prior to the meeting. The following amendments were agreed: ***Section 5c: page 6 of 12*** • Mr Nenad Ninkov questioned whether the IMO was confident that the proposed changes qualified to be progressed under the Fast Track Rule Change Process. The Chair and Ms Ryan confirmed that the IMO had completed a fast track rule change assessment and ~~was~~were satisfied that it had passed the test. Ms Ryan also reiterated that the IMO Board would not approve the Amending Rules until the amendments to the Electricity Corporations Act have been made. ***Section 6a: page 10 of 12*** *Action points:* • *System Management to review its cost allocation between the energy and capacity market to assist Bluewaters' Rule Change Proposal to amend the Market Fees structure during the rule change process.* Mr Dean Sharafi and Mr Brendan Clarke observed that System Management did not segregate its costs on energy and capacity and was unable to provide such a cost allocation. The Chair noted that this cost allocation would be required when this rule change was progressed further and added that the action item would become applicable for System Management during the rule change process. *Action Point: The IMO to amend the minutes of Meeting No. 66 to reflect the agreed changes and publish on the Market Web Site as final.*	**IMO**
4.	**ACTIONS ARISING** The Chair introduced Ms Kate Ryan to update the MAC on the current actions. The following points were noted: • **Item 43:** Ms Ryan noted that the IMO had sent a letter to the ERA and the Public Utilities Office (PUO) prior to the MAC meeting on 11	

	December 2013, thereby closing the action item. • **Item 50:** Ms Ryan noted that the external audit to assess consistency between the existing Market Rules, the proposed formulae and the current systems with respect to PRC_2013_16 had also been completed. She noted that the IMO intended to submit the Rule Change Proposal into the formal process before Christmas. • **Item 52:** Ms Ryan noted that this item had also been closed after incorporating necessary amendments in the Rule Change Proposal. • **Item 55 and 56:** Ms Ryan noted that these items would need to be amended based on the discussion on the minutes. *Action Point: The IMO to amend action item 55 to reflect the update based on the discussion on the minutes.*	**IMO**
5.	**IMPROVEMENTS TO THE ENERGY MARKET** The Chair invited Mr Jim Truesdale to lead a discussion on the issues raised in the paper: *Enhancements to the Energy and LFAS Markets*. The following key comments and queries were made: ***Removal of Resource Plans and changes to gate closure timeframes*** • Mr Truesdale requested the views of MAC members on the proposal to remove the requirement to submit Resource Plans and to replace the information currently provided by Resource Plans with an earlier Balancing Market forecast. There was general support from MAC members for the proposal. • Mr Sharafi considered that the change would be workable for System Management if the opening of the Balancing Horizon for a Trading Day was brought forward to 1:00 pm on the Scheduling Day (i.e. around the current deadline for Resource Plan submission), with the first Balancing Merit Order (BMO) generated shortly afterwards. MAC members raised no objections to moving the deadline for initial Balancing Submissions from 6:00 pm to 1:00 pm on the Scheduling Day. It was also agreed that it should be possible for the submissions to be made earlier, e.g. as soon as Market Participants were aware of their Net Contract Positions (NCPs). • Mr Truesdale provided an overview of the IMO's proposal to move to a half hour rolling gate closure for Balancing and a 2.5 hour rolling gate closure for LFAS. Mr Sharafi noted that from a System Management perspective the shortening of gate closures was a positive move that would lead to a number of good outcomes. However, Mr Sharafi considered that the proposed timeframes could at this point in time cause difficulties for system controllers. A one hour gate closure for Independent Power Producers (IPPs) and a two hour gate closure for the Verve Energy Balancing Portfolio (VEBP) would produce a more manageable outcome in the short term. • Mr Truesdale questioned for how long System Management thought the transitional arrangements should apply. In response, Mr Sharafi suggested that System Management's proposed timeframes should apply for a year, after which a move to half hour gate closure could be considered. Mr Sharafi noted that increasing the number of generators under Automatic Generation Control (AGC) or other electronic control would help to reduce System Management's concerns. Mr Truesdale	

considered that in order to achieve changes of this type it was important to set out a clear transition path with agreed timeframes.

- The Chair considered it was reasonable to suggest a transition but sought further information from Mr Sharafi as to why it would be necessary. There was some discussion about the nature and extent of the difficulties that would be faced by controllers if Balancing Gate Closure was reduced to half an hour. The Chair suggested that Mr Sharafi provide some examples of his concerns about the impact of half hour gate closure at the February 2014 MAC meeting.
- Mr Sharafi also suggested that the LFAS Merit Order provided by the IMO to System Management should not be restricted by the LFAS Requirement but instead should include all LFAS Submissions. Mr Truesdale responded that LFAS providers needed to know whether they would be providing LFAS in a Trading Interval prior to Balancing Gate Closure, so that they could update their Balancing Submissions accordingly.
- Mr Truesdale asked Mr Andrew Everett if Verve Energy would have any concerns about moving to rolling gate closure for the VEBP. Mr Everett noted that Verve Energy did not currently operate a 24 hour trading desk and its views on the proposal would depend on whether it resulted in any additional obligations, and if so on what the implications of those obligations would be. There was some discussion about Verve Energy's current obligations to update its Balancing Submissions and how these would be affected by a move to rolling gate closure.
- The Chair confirmed with MAC members that, subject to System Management's reservations about moving to half hour gate closure immediately, the concepts of shortening the gate closure times as outlined in the paper and moving to rolling gate closure for all Facilities for both Balancing and LFAS was, in principle, supported by the MAC.
- Mr Truesdale noted that there could be an opportunity to shorten the process further. Mr Clarke suggested that most markets did not allow participants to change their offer prices so close to the start of a Trading Interval. Mr Truesdale replied that while most markets would not allow price changes after gate closure, prior to gate closure price changes were usually permitted. Dr Paul Troughton explained that in the National Electricity Market (NEM) participants could bid their capacity in up to 10 tranches, and while the tranche prices were set in advance a participant could move capacity from one tranche to another up to five minutes before dispatch.
- Mr Clarke considered that the smaller number of participants in the Wholesale Electricity Market (WEM) would increase the opportunities for gaming. Mr Truesdale replied that this would also make any gaming attempts more visible. The Chair noted that the IMO had not seen any evidence of such behaviour in the Balancing Market to date.
- Mr Andrew Stevens considered that the only time a participant was likely to be amending its Balancing Submission so close to the start of a Trading Interval was when it was having physical issues with the plant. Half hour gate closure would greatly assist both participants and System Management with this process. The Chair noted that the presence of offer quantities in the BMO that related to a generator that

was not able to comply with a Dispatch Instruction was a problem for System Management in that it increased the level of manual intervention required. Mr Truesdale noted that late price changes were not in themselves a problem and did not necessarily indicate gaming behaviour.

Facility based bidding and dispatch for Verve Energy Facilities

- Mr Truesdale explained his views on the advantages of moving to facility based bidding and dispatch for all Facilities in the WEM. Mr Truesdale noted that, as in any market, the dispatch of all Facilities would remain subject to System Management intervention for security reasons. Mr Truesdale acknowledged that the proposed changes would require more active participation from Verve Energy, involve some additional costs for both Verve Energy and System Management and would take some time to implement. However, with commitment and an agreed transition path there was no reason why the change could not be achieved.
- Mr Sharafi noted that System Management agreed in principle with a move to facility based bidding and dispatch. System Management was not in a position to make the change immediately, but would be able to make the transition if a staged approach was adopted. In the short term it would be possible to remove intermittent generation Facilities and some of the Facilities with more stable output levels from the VEBP. However, numerous rule, process and system changes would be needed to go further.
- 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. Mr Truesdale considered that the market's ability to be comfortable about Verve Energy's market power would be much greater with facility based bidding. However, while Verve Energy would be able to adjust its bids in the same timeframes as IPPs it would still continue to be subject to SRMC bidding and scrutiny, given its influence on the market.
- Mr Shane Cremin noted that the Market Rules allow the Minister for Energy to give a policy direction to the IMO and suggested that if the Government considered a move to facility based bidding was warranted then it should direct the IMO to make the change. The Chair noted that to date no Minister had given a policy direction to the IMO and considered it was the job of the MAC to look at improvements to the market and the evolution of the market. Mr Cremin noted that in his view the change needed to happen for the market to reform and there was general agreement on the need for change, but suggested that the normal rule change process may not be sufficient.
- Mr Everett considered that there was a difference between market evolution and setting market policy, and that MAC members need to

contemplate what actually constitutes a change of policy and where that policy direction should come from. Mr Stevens disagreed, considering the changes related to evolving the market so that all participants had the same obligations and were subject to the same transparencies. Mr Stevens did not see this as a policy change. Mr Truesdale agreed with Mr Stevens, considering the changes were similar to the implementation of the Balancing Market, which altered the original market design under which Verve Energy was the default supplier of Balancing.

- Ms Ryan observed that the VEBP was set up as a construct under the Market Rules. The policy was to set up a market subject to Market Rules, with a mechanism for making changes and Wholesale Market Objectives to guide those changes. While a policy direction might make the process of change easier Ms Ryan did not consider it was essential in this case.
- Mr Will Bargmann agreed with Mr Everett on the need for a business case and noted that the upcoming wide scale review of the WEM may impact the progression of the proposed changes. The Chair replied that he did not consider the proposal was inconsistent with any views that had been expressed to him by the Minister, the Public Utilities Office or the Economic Regulation Authority.
- Mr Andrew Sutherland queried whether Verve Energy had assessed the costs and benefits of moving to facility based bidding. Mr Everett responded that an analysis of the expected costs and benefits was in progress. The Chair noted that a lot of the information that would be needed for such an analysis was held by Verve Energy. Mr Truesdale doubted that the costs to Verve Energy would be particularly high, suggesting that System Management's costs were like to be more substantial.
- Mr Sutherland suggested there would be material benefits if the IMO was to indicate the total Balancing Submission quantity associated with Intermittent Generators when it published a Forecast BMO. If System Management was able to provide an updated wind forecast then this would also be of benefit. Mr Truesdale suggested that where wind forecasts were not available an indication of the current Intermittent Generator output levels could provide quite a good proxy for the time frames in question.
- In response to a question from the Chair, Mr Sharafi noted that System Management produces a wind forecast for 24 hours in advance but the forecast is not by individual Facility, as System Management does not have access to wind forecasts for the individual locations. The forecast is produced from numerous inputs.
- The Chair considered that it should be possible to publish both the total wind generation component of the BMO and System Management's forecast wind output over the Balancing Horizon. Mr Cremin noted that System Management's forecast would not take into consideration how many turbines were actually in operation at any time, but considered it would still provide better information than is currently available.

Risk management issues

- Mr Truesdale noted that the discussion paper listed a number of thoughts around risk management options, including both “quick wins” and options for longer term future directions. The intention was not to offer specific solutions but to promote discussion in the MAC. Mr Truesdale suggested the MAC discuss the options for quick wins first before moving on to consider the longer term.
- Mr Sutherland proposed that the opening of the STEM Submission window should be moved earlier to 8:00 am. He was also supportive of removing the association of Capacity Cost Refunds with the STEM and potentially removing the obligation on Market Generators to participate in the STEM. Mr Sutherland did not support the concept of having multiple Bilateral Submission windows.
- Mr Stevens suggested allowing both the STEM and Bilateral Submission windows to be open from 9:00 am until around 10:15 am, with the STEM Auction taking place around 10:20 am. Market Participants would be advised of their NCPs by 10:30 am after which they would be able to make their initial Balancing Submissions for the Trading Day. Mr Stevens considered there was no reason why the Bilateral Submission window needed to close before the STEM Submission window opened.
- Mr Truesdale queried whether the Balancing Submission window could also open at 9:00 am. Mr Stevens agreed that this would be reasonable, but noted participants may need to know their NCP before constructing their Balancing Submission.
- Mr Geoff Gaston supported making the STEM voluntary and removing any associated capacity obligations or liability for Capacity Cost Refunds. Changes to the submission window timeframes were not a concern provided that participation in the STEM was not mandatory. Mr Gaston considered the removal of refunds for Net STEM Shortfalls should be the highest priority, as the Reserve Capacity Obligation should apply to the Balancing Market and the STEM obligation just created additional risks for a Market Participant. The Chair and Mr Truesdale agreed that a Market Generator’s Reserve Capacity Obligations should apply to the Balancing Market as it is the physical energy market.
- Mr Sutherland considered that the link between STEM Submissions and a Market Participant’s Net Bilateral Position (NBP) created unnecessary complexity, increasing the likelihood of submission errors that could cost a Market Participant millions of dollars. Mr Sutherland suggested changing the STEM to be based on simple bids and offers that were completely unrelated to the participant’s NBP. Mr Truesdale noted that this option probably related more to future directions than to quick wins.
- Mr Gaston suggested segregating the proposed changes, with the removal of the refund risk implemented first as a quick win, followed by consideration of further changes. Mr Gaston supported the idea of the STEM being a simple ‘clearing house’ for bids and offers.
- The Chair noted that the process could operate like a stock exchange rather than an auction, with intersecting bids and offers being cleared on an ongoing basis. Mr Sutherland agreed and suggested the market could be open for days or months at a time. The Chair suggested that

the market could initially operate one day ahead (like the current STEM) and then be extended if there was sufficient interest.

- The Chair reiterated his view that capacity obligations should apply to the Balancing Market rather than the STEM. Mr Sutherland noted that even if participation in the STEM was made voluntary, under the current arrangements a Market Participant with a bilateral position would be forced to participate in the STEM. Mr Sutherland did not expect the outcomes would be particularly different if participation in the STEM was discretionary, except in regard to Verve Energy.
- Mr Everett questioned how much volume was likely to be in the STEM after the merger of Synergy and Verve Energy on 1 January 2014. Mr Sutherland noted that the quantities in the supply curves offered into the STEM would be unchanged but the cleared volumes were likely to reduce.
- Mr Truesdale noted there appeared to be general support for removing refunds for Net STEM Shortfalls, but questioned for whom participation in the STEM should be discretionary. Mr Truesdale expected there would be some concern if the new merged Synergy/Verve Energy was not obliged to participate in the STEM. Mr Sutherland noted that the STEM does provide Market Generators some opportunity to purchase electricity to cover their obligations where they do not have time to enter into short term bilateral arrangements.
- Mr Stevens considered that effectively participation in the STEM was only compulsory for Verve Energy as it was the only party obliged to offer its energy at short run marginal cost (SRMC). Mr Stevens saw value in the STEM because it was a marginally priced market. If, for example, he needed to acquire 100 MWh of electricity for a Trading Interval, purchasing 50 MWh in the STEM and 50 MWh through the Balancing Market allowed him to save at least 25% of the cost he would incur if the energy was purchased through a single energy market. However, this was only the case because of the obligation on Verve Energy to offer its energy at SRMC. If this obligation was removed then STEM Clearing Prices could increase significantly. Mr Chris Campbell disagreed, considering that the market would become more efficient as a result of the change.
- Mr Sutherland considered that it was easier for Verve Energy to manage variability in its STEM outcomes as it had a portfolio of Facilities at its disposal. A Market Participant with a single Balancing Facility was more exposed to the outcomes of what is a 'blind auction' and so had more incentive to offer high prices into the STEM to avoid being cleared for an impractical quantity. There was some discussion about how the changes proposed to the STEM earlier in the discussion would affect participant bidding behaviour.
- The Chair concluded that the desire for some transparency around what is being offered before trading suggested a move towards a matching type market rather than an auction based market. Further, there appeared to be a general agreement that participation in the STEM should not be compulsory, although there was uncertainty as to the extent to which Verve Energy should be required to participate.
- Mr Stevens sought clarification on whether the suggestion to remove the STEM completely was still under consideration. The Chair replied

that as participants had indicated the STEM was of still of value the IMO had no intention to remove it.

- There was further discussion about the future obligations on Verve Energy to participate in the STEM and the efficiency impacts of allowing participants to see bids and offers ahead of time. Mr Stevens considered that where a participant needed to buy energy and the seller did not need to sell the buyer was always going to be on the wrong side of the leverage for the trade. Mr Cremin noted that this only applied to buying in the STEM, and that SRMC requirements would continue to apply in the Balancing Market. Mr Campbell noted that the only reason for purchasing energy in the STEM was to gain surety and because you expected to get a better outcome than through the Balancing Market. This would not be the case if STEM prices rose higher than the expected Balancing Price.
- Mr Sutherland and Mr Stevens noted their concerns that if the STEM became discretionary but retained the same mechanism then a participant needing to buy energy to meet its bilateral obligations would be forced to be a price taker in the STEM and potentially exposed to very high energy prices. Mr Stevens considered the mechanism would need to be changed to allow generators in this situation to choose to purchase the energy in the Balancing Market rather than the STEM.
- Mr Truesdale noted that there were limits to the risks faced by participants, as Balancing Prices were limited by the Price Caps and Verve Energy was still required to offer its energy into the Balancing Market at SRMC. Mr Truesdale questioned what issues could arise for participants between the STEM Auction and dispatch. Mr Gaston responded that a generator may experience a Forced Outage or else come back from an Outage earlier than expected.
- The Chair queried whether there would be benefit in opening the Balancing Horizon earlier still so that a forecast Balancing Price was available before the closure of the STEM Submission window. Mr Truesdale considered that the early availability of a forecast Balancing Price could be useful. Mr Everett noted however that Verve Energy needed to know its NCP in order to construct its initial Balancing Portfolio Supply Curve. Mr Everett also noted that there was a significant difference between a party dumping volume in the STEM and a party being bilaterally contracted to another party that is dumping volume in the STEM.
- The Chair asked Mr Truesdale if he would be able to develop a high level design based on the MAC discussion. Ms Ryan suggested a two stage approach, starting with an investigation of options for quick wins to improve the STEM as it currently operates, and then looking at the longer term redesign of the STEM, for example moving to simpler bid/offer arrangements.
- Mr Nenad Ninkov queried whether anyone knew the shortest length proposed for the new standard products to be offered by the merged Synergy/Verve Energy. Mr Everett responded that this had not yet been determined although work on the new products was underway. The number of distinct standard products was likely to be smaller than originally proposed. For example, there may be a five MW product and a 10 MW product for one month, three months, six months and 12

	months. If a participant sought a variation (for example a four month product) then this would likely be treated as a customised product. The products were to be developed by July 2014 and so there was still six months of work to go. There was some discussion around the potential impact of these products on participation in the STEM. • Mr Peter Huxtable queried who would make the final decision on the standard products to be offered by Synergy. Mr Everett considered this would be decided by the team assigned to development once the merger had commenced. The structure of the products had been contemplated throughout the merger design but the focus of the Merger Implementation Group (MIG) had been on more immediate priorities. Mr Huxtable assumed that the MIG would continue to operate in some form until July 2014, but the Chair noted that the group was expected to disband before this time. Mr Bargmann expected that there would still be some project work continuing after the merger, involving people from Verve Energy, Synergy and the Minister's office. *Action Points:* • *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.* • *The IMO to investigate options for publishing the total intermittent generation quantity in each Forecast BMO and System Management's wind forecast for Trading Intervals in the Balancing Horizon.*	**System Mgmt** **IMO**
6a.	**Market Rule Change Overview** The Chair requested Ms Ryan to provide an update. • Ms Ryan noted that six Rule Change Proposals were currently underway and three out of them were open for consultation. Ms Ryan added that other updates had been provided for information.	
6b.	**PRC_2013_15: Outage Planning Phase 2- Outage Process Refinements** Ms Laidlaw invited MAC members to ask questions or provide comments on the Pre Rule Change Proposal. The following key points were discussed. • Mr Clarke noted that the proposal stated that Demand Side Programmes (DSPs) would no longer be required to log Forced Outages, and queried whether this meant that DSPs would not be liable for Capacity Cost Refunds. Ms Laidlaw responded that that it was already the case that DSPs do not log Forced Outages. DSPs would continue to incur Capacity Cost Refunds if they either failed to secure sufficient Associated Loads to meet their Relevant Demand requirement or else failed to reduce their consumption sufficiently in response to a Dispatch Instruction. • Mr Stevens noted that the current deadline for requesting approval of a Scheduled Outage in the System Management Market Information Technology System (SMMITS) is 10:00 am on the day before the Scheduling Day. Mr Stevens suggested that this time should be	

retained and not changed to 8:00 am as suggested in the proposal. Ms Laidlaw responded that if Market Participants preferred the 10:00 am deadline and this time was already used in SMMITS then the IMO would amend the proposal to use this time instead of 8:00 am.

- Mr Andrew Sutherland queried why the IMO had proposed not to allow Market Participants to request a series of consecutive Opportunistic Maintenance outages. Ms Laidlaw responded that the rationale was to encourage Market Participants to plan their outages and to provide maximum transparency to the market of an upcoming Planned Outage.
- Mr Sutherland suggested that if during the course of an Opportunistic Maintenance outage it was realised that a slightly longer than 24 hour Opportunistic Maintenance outage would be beneficial, the IMO's proposal to restrict Opportunistic Maintenance outages to 24 hours would mean that the relevant Market Participant would be required to return the Facility to service and then undertake another outage if it wished to complete the work. Ms Laidlaw responded that as Planned Outages were for discretionary maintenance, it should be possible (and would be more appropriate) for the Market Participant to apply for a Scheduled Outage in the scenario described. Mr Sutherland responded that if something happened to a Facility on a Friday, it may be better for work to be done on that Facility over the weekend rather than delay the work until a Scheduled Outage can begin on the following Monday or Tuesday. Ms Laidlaw suggested that if the outage was truly discretionary then it should be able to be delayed until the following weekend.
- Mr Stevens considered that if System Management has enough time to assess an outage request and can accommodate the outage, then that outage should be allowed. The Chair responded that if consecutive Opportunistic Maintenance outages were allowed this would reduce the incentive for Market Participants to plan their outages. Mr Sutherland disagreed, suggesting that there are sufficient commercial incentives on Market Participants to ensure that they plan their outages. Mr Sutherland also suggested that the proposed rules were arbitrary. The Chair reiterated that the proposed rules would provide an incentive for Market Participants to plan outages and would also provide transparency and notice to the market of events that could affect prices.
- Mr Sharafi warned that Market Participants should not assume that an Opportunistic Maintenance outage request will be approved.
- Ms Laidlaw observed that as yet no good reason had been presented as to why Opportunistic Maintenance outages should be longer than 24 hours. Mr Steven suggested 48 hours might be an appropriate time limit for Opportunistic Maintenance outages as it would allow a pre-accepted Planned Outage to back directly on to an Opportunistic Maintenance outage. Ms Laidlaw noted that this would be equivalent to removing the concept of Opportunistic Maintenance and simply reducing the lead time required for a Scheduled Outage.
- The Chair sought and received the support of MAC members for the progression of the proposal into the formal rule change process.

Action Point: The IMO to amend the pre Rule Change Proposal: Outage Planning Phase 2 – Outage Process Refinements (PRC_2013_15) to

IMO

	change the deadline for requests for Scheduled Outages from 8:00 am to 10:00 am on the day before the Scheduling Day, and then submit the proposal to into the Standard Rule Change Process.	
6c.	**PRC_2013_20: Changes to the Reserve Capacity Price and the Dynamic Refunds Regime** The Chair invited Ms Aditi Varma to present the pre Rule Change Proposal. The following points were noted: • Mr Gaston queried how spare capacity in a Trading Interval had been defined. Ms Varma responded that the detailed formula was provided in the proposed amendments to clause 4.26.1 which outlined the calculation of spare capacity by Facility type for each Trading Interval. In response to a question from Mr Sutherland, Ms Varma confirmed that the calculation included the spare capacity from DSPs. The Chair added that the IMO could potentially publish the spare capacity information for each Trading Interval as it is available in the forecast Balancing Merit Order. • 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 any more~~now of limited relevance in the current situation of excess capacity. Mr Sutherland observed that the refund factor formulae and the recycling of refund revenue meant that the risk profile for all generators would change. Mr Gaston agreed with the principle behind the definition of spare capacity but noted that 750 MW seemed a large number and should be reviewed. • Mr Gaston also queried if the paper addressed the economic justification for the recycling regime. Ms Varma responded that this had been addressed in the relevant sections of the pre Rule Change Proposal. Mr Bargmann noted that he continued to have issues with the recycling regime on the grounds that retailers were already paying for capacity and in the context of the current market, the recycling regime added greater cost to the retailers. Mr Gaston also repeated his concerns with the recycling regime. The Chair noted their concerns and encouraged them to provide submissions during the rule change process. *Action Point: The IMO to submit the pre Rule Change Proposal into the formal Standard Rule Change Process subject to consideration of publishing spare capacity information.*	**IMO**
6d.	**PRC_2013_21: Limit for Early Entry Capacity Payments** The Chair invited Mr Alex Penter to present the Pre Rule Change Proposal.	

	The following points were discussed: • Mr Gaston requested clarification of the timelines applied for the determination of excess capacity, noting that the current proposal would not allow investment decisions to factor this revenue stream. The Chair agreed that the determination should be undertaken in Year 1 of the Capacity Cycle. Mr Ruthven noted that it would need to be determined after Capacity Credits were allocated. • The Chair suggested that a notification of the determination of whether there is excess capacity and the subsequent availability of early entry capacity payments could be built into the process following the assignment of Capacity Credits. *Action Points:* • *The IMO to progress the pre Rule Change Proposal into the formal Standard Rule Change Process subject to a change to the notification process.*	**IMO**
7a.	**Market Procedure overview** Ms Ryan noted that the *Market Procedure: Settlement* was currently open for consultation. She added that *PSOP: Dispatch* had also been published prior to the MAC meeting and was open for consultation.	
8a.	**Working Group overview and membership updates** The Chair reminded MAC members that nominations for MAC annual review were closing on 18 December 2013. He also noted that the ERA had advised of Ms Wana Yang's resignation and would be advising of her replacement on the MAC in the future.	
9.	**GENERAL BUSINESS** **a) Ancillary Services Review: Draft scope** Ms Ryan noted that the draft scope for the next five-yearly Ancillary Services review was provided to MAC members for information purposes. The IMO proposed to start the process of selecting a consultant to assist with the work early next year. Dr Troughton suggested that the review should include consideration of moving towards technology neutrality in various Ancillary Services, for example allowing loads to provide regulation services. Ms Laidlaw noted that the scope included an update on technological developments in intermittent generation and demand response that could have an impact on either the provision of or the requirement for Ancillary Services. The Chair noted that the IMO would ensure that the matter was considered in the review and invited MAC members to send the IMO any further comments they had on the draft scope, noting that the IMO would be seeking a consultant early in the new year. *Action Point: MAC members to provide the IMO with any comments on the draft scope of work for the 2014 Ancillary Services review by 5:00 pm on 10 January 2014.* **b) LFAS update** The Chair invited Mr Brendan Clarke to present an update on the IMO and	**All**

System Management's ongoing investigation into the LFAS Requirement. Mr Clarke noted that the team had further investigated four issues since the November 2014 meeting.

- The team had considered the suggestion made by Sapere Research Group that the conversion of System Management's load forecast (which is created on an 'as generated' basis) to 'sent out' target MW values in Dispatch Instructions could provide an additional source of the LFAS Requirement. The team reviewed the analysis data for March 2013 and July 2013 and found a number of outliers, indicating that this is definitely a fifth LFAS source that needs to be considered. Mr Clarke noted that System Management intended to look into ways of reducing the conversion errors in future.
- The team had reviewed System Management's processes for detecting and correcting load forecast errors. Mr Clarke noted that currently the load forecasts were produced automatically and are only overridden if the controller notices a deviation between forecast and actual load (available through a graphical computer display) and decides to take corrective action. Mr Clarke advised that System Management intended to implement an automated alarm system to warn the controller whenever the actual load deviated from the forecast by more than a given percentage.
- System Management had reviewed forecast and actual load data for November 2013 to investigate the extent to which the accuracy of load forecasts improved with a shortened lead time. System Management had found an average improvement in accuracy of about 30% for the 10 minute dispatch step and 20% for the 20 minute dispatch step. This indicated that reducing the lead times for load forecasts could help to reduce the LFAS Requirement.
- The team had reviewed the current Dispatch Instruction processes for Facilities that experienced Forced Outages or deviated from their Commissioning Plans. Mr Clarke noted that a Facility that failed to comply with its Dispatch Instruction was sent a message each minute, requesting it to return to its required position or for the participant to call System Management and advise its current capability so that new Dispatch Instructions could be issued as appropriate. If the participant does not contact System Management then System Management may not notice the problem. As a result no corrective Dispatch Instructions will be issued and LFAS is required to account for the ongoing deviation from the original Dispatch Instruction.

The following points were discussed:

- The Chair questioned whether the System Management had developed a plan for reducing the LFAS Requirement. Mr Clarke noted that continuous improvement on three of the four identified areas could reduce forecast errors resulting in a potential reduction to the LFAS Requirement. However, he added that a rule change would be required to shorten the range of the forecast.
- Ms Laidlaw questioned what the timing would be on creating alerts for monitoring forecast errors. Mr Clarke observed that this work had not been scoped yet.
- Mr Dean Frost questioned if constrained network access created a

need for LFAS, such as in the eastern Goldfields. Mr Clarke responded that a localised LFAS requirement will occur whenever an island is created on the network. In response to questions from the Chair and other MAC members, Mr Clarke noted that Verve Energy would generally be the default LFAS provider in such situations and would usually be paid for that service under an Ancillary Services Contract for Dispatch Support Service.

Action Point: The IMO to publish the presentation: December 2013 MAC: LFAS Requirement Investigation Update on the IMO Web Site.

IMO

c) 2013 year in review

Ms Ryan observed that the IMO had initiated 29 rule change processes and progressed a few major pieces of work arising out of the Reserve Capacity Mechanism Working Group over the year.

d) Short term Spinning Reserve opportunity

The Chair invited Mr Clarke to present the agenda item.

Mr Clarke observed that Simcoa had offered to provide Spinning Reserve at a discounted price compared to that of Verve Energy. He added that System Management would gauge interest among other stakeholders for providing this service and undertake a tender process if required to give stakeholders an opportunity to bid for Spinning Reserve provision.

The following points were raised:

- Mr Everett queried how Simcoa was able to offer a discount when Verve Energy's price is unknown, as it is determined through the margin value determination. Mr Clarke noted that Simcoa was offering a discount compared to the notional price that Verve Energy would get.
- MAC members also clarified that interested stakeholders would need to be registered as Market Participants to provide Spinning Reserve.

e) Inclusion of public liability insurance into the Maximum Reserve Capacity Price (MRCP)

Dr Steve Gould tabled an issue related to the high dollar value of the public liability insurance which is an input into the IMO's MRCP determination. He observed that the $50 million value for this insurance seemed to have been arbitrarily determined based on ERA's determination on Western Power's Access Arrangement for 2009. He added that this figure should be examined further by Western Power and ERA as it was considered to be the insurance value for a 160 MW open cycle gas turbine plant in the IMO's MRCP determination.

The Chair requested Mr Dean Frost to clarify Western Power's position on this issue at the next MAC meeting.

Action Point: Western Power to clarify the appropriateness of the public liability insurance amount at the next MAC meeting.

Western Power

CLOSED: The Chair thanked the MAC members for their contribution during 2013 and declared the meeting closed at 5:30pm.

Agenda item 4: 2013 MAC Action Points

Legend:

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

#	Year	Action	Responsibility	Meeting arising	Status/Progress
43	2013	The IMO to write a letter to the ERA and PUO requesting consideration of the proposal to ensure DSP's are subject to licencing, specifically under a separate licencing category.	IMO	Oct	Complete.
50	2013	The IMO to organise an external audit of the consistency of the existing Market Rules, proposed formulae and current systems with respect to PRC_2013_16.	IMO	Nov	Complete.
52	2013	ERM Power to check the consistency of application of constraint payments with respect to LFAS that is currently in the Market Rules with that proposed in PRC_2013_16 and notify the IMO of its findings.	ERM	Nov	Complete.
55	2013	System Management to review its cost allocation between the energy and capacity market.	SM	Nov	Closed. System Management has confirmed that its costs directly relating to the capacity mechanism are immaterial. A formal response can be provided as part of the rule change process if Bluewaters submits proposal in relation to Market Fees.

#	Year	Action	Responsibility	Meeting arising	Status/Progress
56	2013	ERA to review its cost allocation between the energy and capacity market.	ERA	Nov	Closed. Information to be provided as part of the rule change process if Bluewaters submits proposal in relation to Market Fees.
57	2013	The IMO to amend the minutes of Meeting No. 66 to reflect the agreed changes and publish on the Market Web Site as final.	IMO	Dec	Complete.
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	Underway.
60	2013	The IMO to investigate options for publishing the total intermittent generation quantity in each Forecast BMO and System Management's wind forecast for Trading Intervals in the Balancing Horizon.	IMO	Dec	Completed. IMO and SM have discussed options. Change will require update to the IMS Market Procedure.
61	2013	The IMO to amend the pre Rule Change Proposal: Outage Planning Phase 2 – Outage Process Refinements (PRC_2013_15) to change the deadline for requests for Scheduled Outages from 8:00 am to 10:00 am on the day before the Scheduling Day, and then submit the proposal to into the Standard Rule Change Process.	IMO	Dec	Complete.
62	2013	The IMO to submit PRC_2013_20: Changes to the Reserve Capacity Price and the Dynamic Refunds Regime into the formal Standard Rule Change Process subject to consideration of publishing spare capacity information.	IMO	Dec	Complete.
63	2013	The IMO to progress PRC_2013_21: Limit for Early Entry Capacity Payments into the formal Standard Rule Change Process subject to a change to the notification process.	IMO	Dec	Complete.
64	2013	MAC members to provide the IMO with any comments on the draft scope of work for the 2014 Ancillary Services review by 5:00 pm on 10 January 2014.	MAC	Dec	Complete.
64	2013	The IMO to publish the presentation: December 2013 MAC: LFAS Requirement Investigation Update on the IMO Web Site.	IMO	Dec	Complete.
66	2013	Western Power to clarify the appropriateness of the public liability insurance amount at the next MAC meeting.	Western Power	Dec	

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)	12th March 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)	3
Standard Rule Changes with 2nd Submission Period Open	1
Standard Rule Changes with 2nd Submission Period Closed (final report being prepared)	2
Rule Changes - Awaiting Minister's Approval and/or Commencement	1
Total Rule Changes Currently in Progress	**7**

The following table provides an update of the items the Market Development team anticipates progressing to the Market Advisory Committee (MAC) over the next two to three months. The Market Development team is currently developing its expected work program for 2014/15 and will provide further details at the next MAC meeting.

Issue	Likely timing
Ancillary Services 5 Yearly Review	Review Commencing March 2014
2014 Energy Price Limits Review	Public Consultation March/April 2014
[Synergy] Facility based offers and dispatch	Pre Rule Change Proposal – May MAC
Changes to Bilateral Submissions and STEM arrangements	High level design – Mid 2014

Issue	Likely timing
Amendments to Market Information Arrangements (review of confidentiality and chapter 10)	Mid 2014

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

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

APPENDIX 1: FORMALLY SUBMITTED RULE CHANGES (Current as of 12th March 2014)

Standard Rule Change with First 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	Draft Rule Change Report published	25/03/2014
RC_2013_21	10/01/2014	Limit to Early Entry Capacity Payments	IMO	Draft Rule Change Report published	25/03/2014
RC_2013_15	24/12/2013	Outage Planning Phase 2 - Outage Process Refinements	IMO	Draft Rule Change Report published	15/04/2014

Standard Rule Change with Second Submission Period Open

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2013_17	22/11/2013	Correction of Estimated Output of Intermittent Generation for Purposes of Appendix 9	Alinta	Submissions Close	25/03/2014

Standard Rule Change with Second Submission Period Closed

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2013_10	21/08/2013	Harmonisation of Supply-Side and Demand-Side Capacity Resources	IMO	Final Rule Change Report	17/03/2014
RC_2013_09	18/06/2013	Incentives to Improve Availability of Scheduled Generators	IMO	Final Rule Change Report	24/03/2014

Rule Changes Awaiting Commencement/Ministerial Approval

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2012_23	14/08/2013	Prudential Requirements	IMO	Commencement	01/05/2014

INDEPENDENT MARKET OPERATOR

Agenda Item 5b: Outages and the Application of Availability and Constraint Payments to Non-Scheduled Generators (PRC_2013_16)

1. BACKGROUND

The pre Rule Change Proposal: Outages and the Application of Availability and Constraint Payments to Non-Scheduled Generators (PRC_2013_16) was first presented as a concept paper to the Market Advisory Committee (MAC) on 7 August 2013.

The IMO then presented proposed Amending Rules in the pre Rule Change Proposal to the MAC on 13 November 2013. At the meeting, the Chair noted that the IMO would provide an updated copy of the pre Rule Change Proposal to the MAC if any of the amendments changed significantly.

2. REVISED PRE RULE CHANGE PROPOSAL

Since November 2013, the IMO has made two significant changes to the proposed amendments:

1. The IMO has revised the definition of an Outage in the proposed amendments to clause 3.21.1 and 3.21.1A (new) to provide greater clarity to Market Participants; and

2. The IMO has streamlined the calculations of the Minimum and Maximum Theoretical Energy Schedule, Out of Merit Generation quantities and constrained on and off compensation payments, which are now provided in a new Appendix 11.

3. RECOMMENDATIONS

The IMO recommends that the MAC:

- **Discuss** the re-drafting of the proposed amendments to clause 3.21.1, 3.21.1A (new) and Appendix 11; and
- **Note** that the IMO intends to formally submit the revised proposal 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_2013_16
Date received: TBA

Change requested by:

Name:	Allan Dawson
Phone:	08 9254 4333
Fax:	08 9254 4399
Email:	Allan.Dawson@imowa.com.au
Organisation:	IMO
Address:	Level 17, 197 St Georges Terrace, Perth WA 6000
Date submitted:	TBA
Urgency:	2-medium
Change Proposal title:	Outages and the Application of Availability and Constraint Payments to Non-Scheduled Generators
Market Rules affected:	Clauses 3.21.1, 3.21.1A (new), 3.21.2, 3.21.2A (new), 3.21.2B (new), 3.21.3, 3.21.4, 3.21.5, 3.21.6, 3.21.7, 3.21.7A (new), 3.21.7B (new), 3.21.8, 4.11.1, 6.15.1, 6.15.2, 6.15.3, 6.15.4, 6.16A.1, 6.16A.2, 6.16B.1, 6.16B.2, 6.17.3, 6.17.3A, 6.17.4, 6.17.4A, 6.17.5, 6.17.5A, 6.17.5B, 6.17.5C, 7.7.5A, 7.7.5B, 7.7.5D, 7.7.6B, 7.13.1A, Glossary, Appendix 10 (new) and Appendix 11 (new).

Introduction

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

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

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

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

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

The objectives of the market are:

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

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

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

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

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

Details of the Proposed Rule Change

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

Background

Currently the Market Rules do not adequately accommodate the circumstances of Non-Scheduled Generators as the concepts of outages, availability and constraint payments apply. This ambiguity has resulted in some Non-Scheduled Generators being paid compensation as the result of being dispatched down due to a Network Outage or the Facility tripping. This is inconsistent with the application of the Market Rules to Scheduled Generators.

This pre Rule Change Proposal seeks to address the ambiguity with respect to the obligations on Non-Scheduled Generators. It will also ensure that the Market Rules that ultimately determine the application of compensation payments are complete and robust.

In particular, the IMO proposes to provide greater clarity on the:

- circumstances under which a Market Participant must log an Outage;
- quantity of an Outage that a Non-Scheduled Generator must log;
- requirement for Market Participants to log Outages which they become aware of, outside of the 15 day reporting timeframe, and for System Management to provide these to the IMO;
- requirement for the IMO to provide System Management with each Facility's available

capacity for the purposes of Outage calculations;

- calculation of the Maximum and Minimum Theoretical Energy Schedules (TES), Out of Merit quantities and constrained on and off compensation payable to Market Participants; and
- application of the Forced Outage Rate and Planned Outage Rate to Non-Scheduled Generators for the purposes of determining the quantity of Certified Reserve Capacity.

A Concept Paper which outlined these issues was presented at the Market Advisory Committee (MAC) meeting held on 7 August 2013. Two key areas were discussed, which have informed the drafting of the proposed changes in this pre Rule Change Proposal. These relate to:

1. The practicalities of logging Outages for a Non-Scheduled Generator, noting that it would be complex to determine pro-rated Outage quantities based on an ex-post review of each minute; and
2. The question of whether it is necessary to further improve incentives by extending the application of the principles in the Rule Change Proposal: Incentives to Improve Availability of Scheduled Generators (RC_2013_09) to make capacity available for Non-Scheduled Generators, given that they already have sufficient commercial incentive to be available when required; and

The IMO considered these issues in the context of the proposed amendments developed in a pre Rule Change Proposal presented to the MAC on 13 November 2013. MAC members discussed:

1. The intention of the proposed amendments required the logging of ex-ante Consequential Outages;
2. The necessity to consider the broader treatment of shared Declared Sent Out Capacity and runback schemes; and
3. A request by MAC members for the IMO to have the formulae proposed in the new Appendix 11 audited.

These issues have been considered in preparing the amendments in this pre Rule Change Proposal.

It should be noted that this pre Rule Change Proposal also reflects the proposed amendments currently being developed in the draft Final Rule Change Report for Rule Change Proposal: Incentives to Improve Availability of Scheduled Generators (RC_2013_09) and the Rule Change Proposal: Outage Planning Phase 2 – Outage Process Refinements (RC_2013_15).

Issues to be addressed in the existing Market Rules

Definition of an Outage

Currently the Market Rules defines an Outage as:

> *…means a Forced Outage, a Planned Outage or a Consequential Outage.*

The definitions of each type of Outage referred to in the glossary definition of an Outage do not provide any specificity about the circumstances under which a Market Participant must log an Outage, particularly as they apply to where:

1. An Outage Facility is able to provide capacity but, due to a Network constraint, the Network is unable to accept its capacity while maintaining operation within the Technical Envelope to ensure a safe, reliable and stable Network, including where it is unavailable due to a restricted network connection as negotiated with Western Power;

2. An Outage Facility's production is limited to reduce the potential of damage to the Facility or to ensure safety of its workers including for example, where a wind farm automatically trips during extreme wind;

3. An Outage Facility is unable to meet a Dispatch Instruction issued by System Management except to the extent this is within its Tolerance Range; and

An Outage Facility has declared the capacity unavailable in its Balancing Submission.This lack of clarity around the requirement to log Outages has resulted in an inconsistent approach from Market Participants and has led to spurious payments of constrained off compensation to Market Participants where Outages should have been logged but the requirement to do so was not explicitly stated in the Market Rules.

Consequently, in order to ensure all Outages are logged and thereby address the spurious constrained off compensation payments, the IMO proposes to provide further clarity around the definition of an Outage by introducing two new clauses, clause 3.21.1 and 3.21.1A, into the Market Rules and amending the definition of 'Outage' in the Glossary to refer to the new clause 3.21.1 of the Market Rules.

In order to improve the integrity of the Market Rules, the current clause 3.21.1 of the Market Rules which provides the definition of a Forced Outage has also been renumbered to clause 3.21.2B to better reflect the Outage approvals process. This amendment will also be reflected in the definition of 'Forced Outage' in the Glossary. The definition of 'Forced Outage' will also be moved to ensure the Glossary is in alphabetical order.

It should be noted that the IMO does not propose to require a Market Participant to log an Outage in circumstance where:

1. a Non-Scheduled Generator which relies on a renewable fuel source may be unable to provide capacity without the appropriate fuel, for example at night for solar generation and during low wind periods for wind farms; and

2. the Facility is a Non-Balancing Facility which is unable to meet its Dispatch Instruction.

Logging of an Outage in advance

The Market Rules currently do not consider the ability for a Market Participant to log a Consequential Outage in advance of the Outage occurring. The ability for a participant to log an Outage in advance will improve the transparency of Facility availability and thereby improve the price signals to other Market Participants.

The IMO proposes to amend clauses 3.21.2, 3.21.3 and 3.21.4 of the Market Rules and introduce the new clause 3.21.2A which will enable Market Participants to log Outages as soon as the participant is notified of an Outage by the Network Operator or other Rule Participant.

Quantity of de-rating for a Non-Scheduled Generator

The Market Rules currently require Market Participants and the Network Operator to inform System Management of an Outage of an Outage Facility as soon as practicable.

Clause 3.21.4 of the Market Rules outlines the information that must be provided to System Management with respect to the notification of an Outage. This includes the time the Outage commenced, an estimate of the time the Outage is expected to end, the cause of the Outage, the Facility or items affected and the expected quantity of the Outage.

However, currently clause 3.21.4(e) of the Market Rules can only be applied to Scheduled Generators as the quantity of an Outage is calculated in accordance with clause 3.21.5 of the Market Rules, which requires the quantity to be determined with respect to a Facility's maximum capacity as adjusted using the Standing Data for temperature dependence under in Appendix 1(b)(iv). This section of Appendix 1 outlines the Standing Data required for Scheduled Generators only, resulting in ambiguity about how to determine the quantity of any reduction in capacity of a Non-Scheduled Generator for the purposes of Outage calculations.

Similarly, clause 3.21.6 of the Market Rules provides the process by which System Management determines the MW reduction of a Facility's output as the result of an Outage. Currently, Market Participants enter an Outage quantity on a sent out basis at 15 degrees Celsius. System Management then converts the quantity to a sent out basis at 41 degrees Celsius and adjusts it based on the Facility's Reserve Capacity Obligation Quantity (RCOQ). System Management then calculates the total MW quantity of Forced, Planned and Consequential Outages for each Outage Facility under clauses 3.21.6(b) to 3.21.6(d) and provides this to the IMO as required under clauses 7.3.4 and 7.13.1A(b). However, the application of clause 3.21.6 to a Non-Scheduled Generator is currently inappropriate because Non-Scheduled Generators have an RCOQ of zero. This would result in a negative Outage quantity where the MW reduction in the output of a Facility is greater than its RCOQ.

The IMO proposes to amend clause 3.21.5 of the Market Rules to add new sub-clauses to explicitly provide alternative calculations for Non-Scheduled Generators and the Balancing Portfolio. The proposed Amending Rules require the quantity of the reduction in capacity of a Non-Scheduled Generator to be calculated by reference to its Sent Out Capacity.

The IMO has also taken the opportunity to propose further changes to clause 3.21.5 of the Market Rules to provide clarity on the Outage quantity required to be logged, by specifying that the quantity is the average reduction in capacity over the Trading Interval. This is not a new requirement but its inclusion will avoid any potential confusion and ensure that all Market Participants provide consistent Outage quantities.

In addition, the IMO proposes to amend clause 3.21.6 of the Market Rules to add new sub-clauses to provide specific calculations to determine the quantity of an Outage for a Non-Scheduled Generator. The proposed calculations use the Outage quantity on a sent out basis, at 15 degrees Celsius to calculate the sum of all Forced, Planned and Consequential Outages, as applicable.

Provision of quantities by the IMO to System Management for the calculation of Outages

Clause 3.21.6(e) of the Market Rules requires the IMO to provide System Management with the RCOQ for each Facility as currently applicable. This is to be used in System Management's calculation of the Outage quantity for Scheduled Generators.

However, practically, the IMO cannot determine in advance of a Trading Interval each Facility's RCOQ. For example, the RCOQ must account for factors including temperature and Outage quantities which may restrict the ability of the Facility to provide energy at any particular point in time. While this is not practical for either the Market Participant to provide the IMO with this type of information, or the IMO to be considering it with respect to the capability of the Facility, it is also not necessary.

To date, the IMO has provided System Management with each Facility's MW value of Capacity Credits rather than its RCOQ. While there is a difference between the two values, it is not expected to result in significantly different outcomes for the purpose of calculating a Facility's Outage values or a Facility's Certified Reserve Capacity.

The IMO therefore proposes to amend clause 3.21.6(e) of the Market Rules to align to current practice by requiring the IMO to provide System Management with each Facility's MW value of Capacity Credits, rather than it's RCOQ. In addition, the IMO proposes to amend clauses 3.21.6(b) to (d) as they apply to Scheduled Generators to reflect this change.

It should be noted that this amendment will align the Market Rules to current operational practices and therefore will not impact market outcomes.

Provision of Outage quantities by System Management to the IMO for certification

Currently, System Management provides Outage quantities for each Outage Facility for each Trading Interval to the IMO as temperature adjusted values (at 41 degrees Celsius) under clause 7.13.1A of the Market Rules. This means that the IMO often does not know the total MW quantity of the reduction associated with an Outage.

To ensure that the IMO can calculate the impact of Outages on availability and also consider a Facility's availability in the certification process, the IMO also requires Outage quantities to be provided on a sent out basis at 15 degrees Celsius for each Trading Interval.

The IMO proposes to amend clause 7.13.1A of the Market Rules to require System Management to provide the MW quantity of the reduction in a Facility's capacity for each Facility for each Trading Interval on a sent out basis at 15 degrees Celsius, for both Scheduled and Non-Scheduled Generators, together with the temperature adjusted values currently provided for Scheduled Generators.

The IMO will also work with System Management to review section 8.1 of the Power System Operation Procedure (PSOP): Dispatch to assess whether greater clarity on calculation of the expected quantity of an Outage for a Non-Scheduled Generator can be provided[1].

Setting Certified Reserve Capacity for Non-Scheduled Generators

The Rule Change Proposal: Incentives to Improve Availability of Scheduled Generators (RC_2013_09) was developed to allow the IMO more flexibility in assigning Certified Reserve Capacity to Scheduled Generators that display excessive Outage rates over a three-year period. The proposed Amending Rules in RC_2013_09 change the IMO's process for setting a Facility's Certified Reserve Capacity under clause 4.11.1(h) of the Market Rules.

Clause 4.11.1(h) of the Market Rules is currently unable to be applied to Non-Scheduled Generators as the calculations of the Planned Outage Rate and Forced Outage Rate referred to in this clause only consider the application to a Scheduled Generator. The

[1] It should be noted that that the RC_2013_17 also addresses this issue, to the extent that it affects the certification of Intermittent Generators.

PSOP: Facility Outages contains the calculations of both the Forced Outage Rate and the Planned Outage Rate that clause 4.11.1(h) refers to. Further, the calculations as they currently stand in the PSOP rely on the MW value of the Outage being reduced from the MW value of Capacity Credits. While this works for a Scheduled Generator, for a Non-Scheduled Generator, the reduction in capacity of an Outage is likely to be significantly greater than the MW quantity of Capacity Credits, resulting in a nonsensical Outage quantity.

The IMO believes that the introduction of greater incentives for Scheduled Generators to maximise the availability of their capacity as provided in RC_2013_09 should equally apply to Non-Scheduled Generators and therefore proposes to introduce amendments to the Market Rules to align such incentives.

The IMO proposes that, for the purposes of calculating the Planned Outage Rate and Forced Outage Rate for a Non-Scheduled Generator, the Outage quantity is specified as the MW quantity by which the Sent Out Capacity of a Facility is reduced.

The IMO also proposes that, with the increasing significance of these calculations as a result of RC_2013_09, they should be removed from the PSOP: Facility Outages and introduced as a new appendix of the Market Rules. The IMO has taken the opportunity to streamline the equations to provide greater clarity over the calculations being undertaken.

The proposed changes to the Planned Outage Rate and Forced Outage Rate equations to provide specific calculations for Non-Scheduled Generators have been included in Appendix 10. In addition, the definitions for Planned Outage Rate and Forced Outage Rate have been introduced in the Glossary and the definition of Equivalent Planned Outage Hours has been amended. The proposed amendments align with the proposed Amending Rules for RC_2013_09 being developed for the Final Rule Change Report.

It should be noted that the proposed amendment will not affect the application of the calculations to Scheduled Generators, as amended by RC_2013_09.

Timeframes for providing information of Outages to System Management

Clause 3.21.7 of the Market Rules provides the timeframe under which Market Participants or Network Operators must provide ‘full and final details’ of the relevant Planned, Forced or Consequential Outage to System Management. However, for an Outage that spans multiple Trading Days, based on the current drafting, it is unclear on which Trading Day the 15 day timeframe should start.

The IMO proposes to amend clause 3.21.7 and 3.21.8 of the Market Rules to refer to 15 calendar days following the Trading Day on which the Outage commenced.

Furthermore, the obligation to provide ‘full and final details’ of an Outage no later than 15 calendar days following the Trading Day on which the Outage commenced is impractical as this information may not yet exist for Outages that extend for more than the 15 days. For example, if an Outage is expected to continue for 20 days, a Market Participant cannot be expected to provide ‘full and final details’ of the entire Outage before it is finished.

The IMO proposes that, given its reference to ‘full and final details’, clause 3.21.7 of the Market Rules should be amended to specifically refer to a particular Trading Day affected by the Outage. This provides Market Participants with the ability to update the Outage information for each affected Trading Day on a rolling basis until the conclusion of the Outage, but retains the requirement to provide final details for each affected Trading Day within the 15 day timeframe.

Timeframes for providing information of Outages to the IMO

Clause 7.13.1A of the Market Rules currently requires System Management to provide the IMO with the Outage quantities for a Trading Day within 15 Business Days. Currently, the drafting of this clause is ambiguous as to whether System Management can accept, or must provide to the IMO, any information for Outages logged after the 15 calendar days. This may result in Facilities being assigned Certified Reserve Capacity based on inaccurate information.

In order to ensure that the IMO is aware of all Outages, the IMO proposes to introduce two new clauses in the Market Rules. Clause 3.21.7A is proposed to be introduced to require Market Participants to provide all Outage data to System Management as soon as practicable, regardless of the reporting timeframes. Clause 3.21.7B is proposed to be introduced to require System Management to provide this information specified in clause 7.13.1A of the Market Rules to the IMO.

Removing constrained on and off compensation where a Facility is non-compliant

Constrained on and off compensation is paid where a Facility is dispatched other than in accordance with the Balancing Merit Order.

Currently, Scheduled Generators receive constrained on and off compensation when they are non-compliant with Dispatch Instructions issued by System Management. For example, where a Scheduled Generator produced more than its target End of Interval quantity, it is paid for a quantity above what it would otherwise produce based on its dispatch in accordance with the Balancing Merit Order. However, this is based on the inherent assumption in the Market Rules that the only reason a generator would deviate from its Dispatch Instruction is because of an Outage, or where they are dispatched Out of Merit.

This has led to Scheduled Generators who are not compliant with Dispatch Instructions being paid constrained on or off compensation in the initial settlement for the total amount of electricity produced, with the determination of a Facility's compliance or otherwise occurring after settlement. The IMO's Compliance team is responsible for investigating the merit of any constrained on or off compensation as it relates to a Facility's compliance with Dispatch Instructions issued by System Management.

Recently, there have been a number of situations where these (often large) incorrect payments have been included in the initial settlement. As they are only able to be removed as part of the first or second settlement Adjustment Process, the delays will lead to an inequity between Market Participants resulting from the time value of money. Furthermore, the payment could result in an increase in the required level of Credit Support to be provided by the Market Participant.

As constrained on and off compensation is intended to be paid only when a Facility is dispatched Out of Merit, the IMO proposes to make a number of changes to the Out of Merit calculations currently contained in clauses 6.16A.1 and 6.16A.2 of the Market Rules. The proposed amendments will cap the quantity to be paid constrained on and off payments to the Dispatch Instruction to remove the instances resulting in incorrect payments.

It should be noted that the other amendments proposed in this pre Rule Change Proposal will result in the Minimum TES reflecting all Outages of a Facility as provided in the Dispatch Schedule, thereby also ensuring that Market Participants are not paid constrained off compensation when a Facility is unavailable due to an Outage. The IMO will calculate a Facility's Minimum TES by reference to its Dispatch Schedule. This will require the IMO to calculate the Dispatch Schedule from the Dispatch Instructions provided by System

Management. This will require changes to the IMO's IT and settlement systems and processes and will also require System Management to provide the IMO with the Dispatch Schedule for the Balancing Portfolio.

The IMO also proposes to move the calculations for:

- Maximum and Minimum TES currently contained in clauses 6.15.1 and 6.15.2;
- Out of Merit Generation currently contained in clauses 6.16A.1, 6.16A.2, 6.16B.1 and 6.16B.2; and
- constrained on and off payments currently contained in clause 6.16.3, 6.17.4, 6.17.4A, 6.17.5, 6.17.5A and 6.17.5B,

to the new Appendix 11 of the Market Rules and present them as mathematical formulae to remove any ambiguity with respect to the calculations. The requirement to determine these values will remain in amended clauses 6.15.1, 6.15.3, 6.16A.1, 6.16A.2, 6.17.3 and 6.17.4 of the Market Rules.

As a result of the removal of clauses 6.17.5, 6.17.5A and 6.17.5B of the Market Rules, clause 6.17.5C will be renumbered to clause 6.17.5. References to current clauses containing the TES calculations in clauses 7.7.5A, 7.7.5B and 7.7.5D of the Market Rules and defined terms Maximum TES and Minimum TES are also proposed to be amended to refer to Appendix 11.

The IMO also notes that, following the initial Dispatch Instruction, System Management is currently able to issue subsequent Dispatch Instructions to Market Participants. This is often used to reflect the expected output when a Facility is unable to comply with a Dispatch Instruction, to rectify the non-compliance as currently required under clause 7.7.6B of the Market Rules.

The IMO needs to be able to differentiate these rectification Dispatch Instructions from others to determine the appropriate Dispatch Schedule on which to base a Facility's constrained on and off payments. The IMO proposes to introduce the defined term 'Rectification Dispatch Instruction' in the Glossary and clarify the Dispatch Instruction inputs in each equation in Appendix 11 with respect to this definition. This ability to differentiate Dispatch Instructions will require changes to both System Management and IMO systems.

Other amendments

The IMO has also taken the opportunity to make minor administrative amendments to improve the integrity of the Market Rules.

Impact on the Regulations

The IMO notes that under the *Electricity Industry (Wholesale Electricity Market) Regulations 2004* (Regulations), clauses 3.21.4 and 7.7.6A of the Market Rules are subject to Category C civil penalties.The IMO considers that under the proposed Amending Rules it is still appropriate for these clauses to remain a Category C civil penalty provisions as the intent of the obligations in these clauses has not changed.

This pre Rule Change Proposal does not amend, remove or add Protected Provisions under clause 2.8.13 of the Market Rules.

2. Explain the reason for the degree of urgency:

The IMO proposes to commence the proposed Amending Rules set out in this pre Rule Change Proposal in order to align the changes with the amendments being developed as a result of Phase 2 of the Outage Planning Review.

This will allow Rule Participants to consider the changes associated with Outages more holistically. Furthermore, this is expected to reduce the implementation costs to Market Participants by aligning any system and IT changes that may be required.

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

~~3.21.1. A Forced Outage is any outage of either a Facility or item of equipment on the list described in clause 3.18.2 or a Facility or generation system to which clause 3.18.2A relates that has not received System Management's approval, including:~~

~~(a) outages or de-ratings for which no approval was received from System Management, excluding Consequential Outages;~~

~~(b) any part of a Planned Outage that exceeds its approved duration; and~~

~~(c) where the Market Participant or Network Operator does not follow a direction from System Management under clause 3.20.1 to return the equipment to service within the time specified in the appropriate contingency plan.~~

<u>3.21.1 Subject to clause 3.21.1A, an **Outage** is a temporary limitation of an Outage Facility that results in a partial or complete reduction in:</u>

<u>(a) the quantity of electricity that the Facility can physically generate;</u>

<u>(b) the quantity of electricity that is available for System Management to dispatch in accordance with clause 7.6.1 or 7.6.1C;</u>

<u>(c) the quantity of electricity generated by a Facility that is able to be transferred through the SWIS including:</u>

<u>i. as a result of an Outage of another Outage Facility; and</u>

<u>ii. as a result of a limited network access agreement negotiated with Western Power,</u>

<u>where the electricity would have otherwise been available;</u>

<u>(d) the quantity of electricity that is made available, to the extent that it is made unavailable in the Facility's Balancing Submission; and</u>

<u>(e) the quantity of electricity that is the difference between a Facility's Dispatch Instruction (other than a Rectification Dispatch Instruction) and the amount generated by the Facility</u>.

<u>3.21.1A An **Outage** does not include a partial or complete reduction in:</u>

(a) the quantity of electricity available to be dispatched by System Management from a Non-Balancing Facility;

(b) the quantity of electricity able to be generated by a Facility to the extent the reduction arises from a reduction in an intermittent energy source used by the Facility to generate electricity; and

(c) the quantity of electricity associated with the temperature de-rating of the Outage Facility in accordance with Standing Data.

3.21.2. A Consequential Outage is an O~~o~~utage that~~of either a Facility or item of equipment on the list described in clause 3.18.2 or a facility or generation system to which clause 3.18.2A relates, for which no approval was received from System Management, but which~~ System Management determines:

(a) was or will be caused by a Forced Outage to another Rule Participant's equipment and would not have occurred if the other Rule Participant's equipment did not suffer a Forced Outage; or

(b) was or will be caused by a Planned Outage to a Network Operator's equipment and would not have occurred if the Network Operator's equipment did not undertake the Planned Outage~~,~~;

but excludes any O~~o~~utage deemed not to be a Consequential Outage in accordance with clause 3.21.10.

3.21.2A System Management must determine, as soon as reasonably practicable, whether an Outage is a Consequential Outage.

3.21.2B A Forced Outage is an Outage other than a Planned Outage or a Consequential Outage, and includes:

(a) any part of a Planned Outage that exceeds its approved duration;

(b) where the Market Participant or Network Operator does not follow a direction from System Management under clause 3.20.1 to return the Facility or equipment to service within the time specified in the relevant Outage Contingency Plan; and

(c) where the Market Participant does not follow a Dispatch Instruction issued by System Management, where this results in System Management issuing a Rectification Dispatch Instruction.

3.21.3. System Management must keep a record of all Forced Outages and Consequential Outages of which it~~ is~~ becomes aware.

3.21.4. If an Outage Facility ~~or item of equipment that is on the list described in clause 3.18.2 or a Facility or generation system to which clause 3.18.2A relates~~ is affected or likely to be affected by~~ suffers~~ a Forced Outage or Consequential Outage, then the relevant Market Participant or Network Operator must inform System Management of that ~~e o~~Outage as soon as practicable, which may be before the Outage occurs. Information provided to System Management must include:

(a) the time the ~~o~~Outage is expected to commence, or did commence~~d~~;

(b) an estimate of the time the ~~o~~Outage is expected to end;

(c) the cause of the ~~o~~Outage;

(d) the Outage Facility ~~or item of equipment or Facilities or items of equipment~~ affected; and

(e) for each affected Outage Facility ~~or item of equipment~~, the expected quantity of any de-rating by Trading Interval, where, if the Facility is a generating system, this quantity is to be submitted in accordance with clause 3.21.5.

3.21.5. The quantity of an outage notification submitted to System Management:

(a) for a Scheduled Generator, is the reduction in capacity from the relevant Facility's maximum capacity measured as an average over the Trading Interval on a sent out basis at 41 degrees Celsius where the maximum capacity is as found in the Standing Data file for Temperature Dependence provided under Appendix 1(b) iv and converted to a sent out basis at 41 degrees Celsius~~. The remaining capacity, determined as the maximum capacity minus the notified outage, must be available to System Management for dispatch.~~; or

(b) for a Non-Scheduled Generator, is the reduction in capacity from the relevant Facility's Sent Out Capacity measured as an average over the Trading Interval.

3.21.6. The following will apply for the purposes of clauses 7.3.4 and 7.13.1A~~-~~(b):

(a) outage data will be entered by Market Participants in System Management's computer interface system on a sent out basis at 15 degrees Celsius;

(aA) for a Scheduled Generator, System Management will use the Outage data entered by Market Participants in System Management's computer interface system on a sent out basis at 15 degrees Celsius and, in addition, convert the outage data to a sent out basis at 41 degrees Celsius by multiplying the outage quantity at 15 degrees Celsius by the ratio of the maximum capacity at 41 degrees Celsius to the maximum capacity at 15 degrees Celsius for the Facility as found in the Standing Data file for temperature dependence provided under Appendix 1(b)~~-~~(iv) on a generated basis for that facility. Market Participants will submit the outage data at 41 degrees Celsius as displayed by System Management's computer interface system;

(aB) for a Non-Scheduled Generator, System Management will use the Outage data entered by Market Participants in System Management's computer interface system on a sent out basis at 15 degrees Celsius;

(b) System Management will calculate the Forced Outage ~~(on a sent out basis at 41 degrees Celsius)~~ for a Facility in a Trading Interval as the greater of:

i. zero; and

ii. for a Scheduled Generator, the sum of all Forced Outages notified for that Facility minus the difference of the Facility maximum capacity and its ~~Reserve Capacity Obligation Quantity~~MW value of Capacity Credits; or

iii. for a Non-Scheduled Generator, the sum of all Forced Outages notified for that Facility;

(c) System Management will calculate the Planned Outage ~~(on a sent out basis at 41 degrees Celsius)~~ for a Facility in a Trading Interval as the greater of:

i. zero; and

ii. for a Scheduled Generator, the sum of all Planned Outages minus the greater of:

1. zero; and

2. the maximum capacity of the Facility minus its ~~Reserve Capacity Obligation Quantity~~ MW value of Capacity Credits minus the sum of all Forced Outages notified for the Facility before the adjustment in (b) above is made by System Management; and

iii. for a Non-Scheduled Generator, the sum of all Planned Outages notified for the Facility before the adjustment in (b) above is made by System Management;

(d) System Management will calculate the Consequential Outage ~~(on a sent out basis at 41 degrees Celsius)~~ for a Facility in a Trading Interval as the greater of:

i. zero; and

ii. for a Scheduled Generator, the sum of all Consequential Outages minus the greater of:

1. zero; and

2. the maximum capacity of the Facility minus its ~~Reserve Capacity Obligation Quantity~~ MW value of Capacity Credits minus the sum of all Forced Outages and the sum of all Planned Outages notified for the Facility before the adjustments in (b) and (c) above are made by System Management; and

iii. for a Non-Scheduled Generator, the sum of all Consequential Outages notified for the Facility before the adjustments in (b) and (c) above are made by System Management;

(e) the IMO will provide System Management ~~the Reserve Capacity Obligation Quantity of~~a MW quantity corresponding to the number of Capacity Credits assigned to each Facility as currently applicable; and

(f) the maximum capacity used in this clause is the value defined in clause 3.21.5.

3.21.7. Notwithstanding the requirements of clause 3.21.4 that a relevant Market Participant or Network Operator must inform System Management of a Forced Outage or Consequential Outage as soon as practicable, a Market Participant or Network Operator must provide full and final details of the relevant Planned Outage, Forced Outage or Consequential Outage to System Management no later than 15~~fifteen~~ calendar days following each ~~the~~ Trading Day on which the Outage occurred or continued to occur.

3.21.7A. If a Market Participant or Network Operator fails to provide full and final details of an Outage to System Management in accordance with clause 3.21.7 for any reason (including where the Market Participant or Network Operator first becomes aware of a Forced Outage or Consequential Outage more than 15 calendar days after the first Trading Day on which the Outage occurred), then the Market Participant or Network Operator must provide those full and final details to System Management as soon as practicable.

3.21.7B. Where System Management is notified of an Outage under clause 3.21.7, it must, as soon as practicable, provide the information specified in clause 7.13.1A to the IMO.

3.21.8. If a Market Participant considers that one of its Facilities has suffered a Consequential Outage then the Market Participant ~~may provide~~ must notify System Management ~~with a notice confirming~~ of the details of the Consequential Outage no later than 15 calendar days following the Trading Day on which the Consequential Outage ~~commenced~~ occurred. The notice must:

(a) be signed by an Authorised Officer of the Market Participant;

(b) confirm that a Consequential Outage has occurred; and

(c) provide details (to the best of its knowledge) of the events which resulted in the Consequential Outage.

…

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

…

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

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

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

where the Planned Outage Rate and the Forced Outage Rate for a Facility for a period will be calculated in accordance with ~~the Power System Operation Procedure~~ Appendix 10;

[Note: Drafting of clause 4.11.1(h) reflects proposed Amending Rules in the Draft Rule Change Report for RC_2013_09: Incentives to Approve Availability of Scheduled Generators]

…

6.15. Maximum and Minimum Theoretical Energy Schedule

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

~~(a) for a Balancing 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 Price-Quantity Pairs in respect of the Balancing Facility with a Loss Factor Adjusted Price less than or equal to the Balancing Price; plus~~

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

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

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

~~i. if the Loss Factor Adjusted Price of the Balancing Price Quantity Pair in respect of the Balancing Facility is less than or equal to the~~

~~Balancing 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 Facility could have generated in the Trading Interval if the Facility had been dispatched downwards at its Ramp Rate Limit from its SOI Quantity,~~

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

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

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

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

6.15.1. The IMO must calculate for each Facility and the Balancing Portfolio, for each Trading Interval, the Maximum Theoretical Energy Schedule and Minimum Theoretical Energy Schedule:

(a) at the times specified in clause 6.15.3; and

(b) in accordance with the methodologies described in Appendix 11.

6.15.2. [Blank]~~The Minimum Theoretical Energy Schedule in a Trading Interval equals:~~

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

~~i. the sum of:~~

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

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

~~Quantity Pairs which have a Loss Factor Adjusted Price greater than or equal to the Balancing Price,~~

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

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

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

~~i. if a Dispatch Instruction was issued to the Balancing Facility to decrease its output and the Loss Factor Adjusted Price of the Balancing Price-Quantity Pair in respect of the Balancing Facility is less than the Balancing Price, then System Management's estimate of the maximum amount of sent out energy, in MWh, which the Balancing Facility would have supplied 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 Portfolio, the amount which is the lesser of:~~

~~i. the sum of:~~

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

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

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

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

6.15.3. The IMO must:

(a) calculate Maximum Theoretical Energy Schedules ~~under clause 6.15.1~~ and Minimum Theoretical Energy Schedules ~~under clause 6.15.1:~~as soon as practicable after receiving applicable SCADA data under clause 7.13.1(cA); and

~~i. using Sent Out Metered Schedules determined using SCADA data and output estimates received from System Management in accordance with clause 7.13.1(cA), notwithstanding any requirement in clause 9.3.4 to use Meter Data Submissions received by the IMO; and~~

~~ii. as soon as practicable after receiving applicable SCADA data under clause 7.13.1(cA); and~~

(b) update Maximum Theoretical Energy Schedules and Minimum Theoretical Energy Schedules calculated under clause 6.15.3(a) as soon as practicable after receiving a relevant schedule of Outages under clause 7.13.1A(b).

6.15.4. The Maximum Theoretical Energy Schedules and Minimum Theoretical Energy Schedules calculated by the IMO in accordance with clause 6.15.3 cannot be altered by:

(a) disagreement under clause 9.20.6; or

(b) disputes under clause 9.21.1.

…

6.16A. ~~Facility~~ Out of Merit Generation

~~6.16A.1. The Upwards Out of Merit Generation in a Trading Interval for a Balancing 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;~~

~~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 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.1. The IMO must calculate the Upwards Out of Merit Generation for a Facility or the Balancing Portfolio, as applicable, in accordance with the methodology described in Appendix 11 as soon as practicable after it:

(a) calculates the Maximum Theoretical Energy Schedule or the Minimum Theoretical Energy Schedule for that Facility or the Balancing Portfolio, as applicable, under clause 6.15.3(a); or

(b) updates the Maximum Theoretical Energy Schedule or the Minimum Theoretical Energy Schedule for that Facility or the Balancing Portfolio, as applicable, under clause 6.15.3(b).

~~6.16A.2. The Downwards Out of Merit Generation in a Trading Interval for a Balancing 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;~~

~~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 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 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).~~

6.16A.2. The IMO must calculate the Downwards Out of Merit Generation for a Facility or the Balancing Portfolio, as applicable, in accordance with the methodology described in Appendix 11 as soon as practicable after it:

(a) calculates the Maximum Theoretical Energy Schedule or the Minimum Theoretical Energy Schedule for that Facility or the Balancing Portfolio, as applicable, under clause 6.15.3(a); or

(b) updates Maximum Theoretical Energy Schedules and Minimum Theoretical Energy Schedules for that Facility or the Balancing Portfolio, as applicable, calculated under clause 6.15.3(b).

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

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

~~2. if Facilities within the Balancing Portfolio were instructed by System Management to provide LFAS, the sum of Upwards LFAS Enablement and 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. Balancing Portfolio Out of Merit~~

~~6.16B.2. The Portfolio Downwards Out of Merit Generation in a Trading Interval for the Balancing 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 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 Portfolio less the sum of any Sent Out Metered Schedules for Facilities in the Balancing 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 Portfolio to provide;~~

2. ~~if Facilities within the Balancing Portfolio were instructed by System Management to provide LFAS, the sum of the Downwards LFAS Enablement plus the 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.~~

…

Constrained On ~~Facility Balancing~~ Quantities and Prices

~~<u>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 Facility that is a Scheduled Generator in a Trading Interval, as follows:</u>~~

(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 Price-Quantity Pair N, with a Loss Factor Adjusted Price (Price N) higher than but closest to the Balancing Price, taking into account the actual SOI Quantity of the Balancing Facility and the applicable Ramp Rate Limit; and~~

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

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

(c) ~~If the Balancing Facility's Upwards Out of Merit Generation exceeds ConQ1 and a Balancing 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 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 Facility's MW level reached the top, or bottom, as applicable, of the quantity associated with the Balancing 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 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 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 Price-Quantity Pairs or, otherwise, until there are no remaining Balancing Price-Quantity Pairs;~~

~~(e) The Non-Qualifying Constrained On Generation for the Balancing 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 Upwards LFAS Backup Enablement, which the Balancing 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).~~

6.17.3. The IMO must attribute any Upwards Out of Merit Generation from a Balancing Facility and the Balancing Portfolio in a Trading Interval as soon as practicable after it calculates the Upwards Out of Merit Generation under clause 6.16A.1, and in accordance with the methodology for calculating Constrained On Quantities and Constrained On Compensation Prices described in Appendix 11.

~~6.17.3A Subject to clause 6.17.5B, for any Balancing 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 Price-Quantity Pair associated with the Balancing Facility for that Trading Interval less the Balancing Price for that Trading Interval.~~

~~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 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 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 Facility and the applicable Ramp Rate Limit, where N is determined from either of the following Balancing Price-Quantity Pairs or, if different, the one with the lower price:~~

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

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

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

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

~~(c) If the Balancing Facility Downwards Out of Merit Generation exceeds CoffQ1 and a Balancing 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 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 Facility's MW level reached the bottom, or the top, as applicable, of the quantity associated with the Balancing 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 Facility less CoffQ1; and~~

ii. ~~Constrained Off Compensation Price2 (CoffP2) equals the Balancing 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 Price-Quantity Pairs or, otherwise, until there are no remaining Balancing Price-Quantity Pairs;~~

~~(e) The Non-Qualifying Constrained Off Generation for the Balancing 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 Downwards Backup LFAS Enablement, which the Balancing 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).~~

Constrained Off ~~Facility Balancing~~ Quantities and Prices

<u>6.17.4. The IMO must attribute any Downwards Out of Merit Generation from a Balancing Facility and the Balancing Portfolio in a Trading Interval as soon as practicable after it calculates the Downwards Out of Merit Generation under clause 6.16A.2, and in accordance with the methodology for calculating Constrained Off Quantities and Constrained Off Compensation Prices described in Appendix 11.</u>

~~6.17.4A. Subject to clause 6.17.5B, for any Balancing 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 Price for that Trading Interval less the Loss Factor Adjusted Price in the Balancing Price-Quantity Pair associated with the Balancing Facility for that Trading Interval.~~

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

~~6.17.5. Subject to clause 6.17.5C, the IMO must attribute any Upwards Out of Merit Generation from the Balancing 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 Price-Quantity Pair N in the Balancing Portfolio Supply Curve with a price (Price N) higher than but closest to the Balancing Price, taking into account the actual Balancing Portfolio SOI Quantity and the Portfolio Ramp Rate Limit; and~~

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

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

~~(c) If the Portfolio Upwards Out of Merit Generation exceeds PConQ1 and a Balancing Price-Quantity Pair exists in the Balancing 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 Portfolio Supply Curve Balancing 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 Portfolio MW level reached the top, or the bottom, as applicable, of Balancing 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. Constrained On Compensation Price2 (PConP2) equals the Price N+1 identified in clause 6.17.5(c)(i) less the Balancing Price;~~

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

~~(e) The Non-Qualifying Constrained On Generation for the Balancing 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 Portfolio:~~

~~i. Upwards LFAS Enablement;~~

~~ii. 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.~~

~~Constrained Off Balancing Portfolio Quantities and Prices~~

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

~~(a) 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 Price-Quantity Pair N, with Price N, in the Balancing Portfolio Supply Curve, taking into account the Available Capacity of the Balancing 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 Price-Quantity Pairs or, if different, the one with the lower price:~~

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

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

~~ii. the Portfolio Downwards Out of Merit Generation;~~

~~(b) Portfolio Constrained Off Compensation Price1 (PCoffP1) equals the Balancing 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 Price-Quantity Pair exists in the Balancing Portfolio Supply Curve with a price lower than Price N, then:~~

~~i. additional 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 Portfolio Supply Curve Balancing Price-Quantity Pair N+1 with a price (Price N+1) lower than but closest to Price N, taking into account when the Balancing Portfolio MW level reached the bottom, or top, as applicable, of Balancing 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 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 Price-Quantity Pair N+1, any PCoffQN+1 and PCoffPN+1 until all Downwards Out of Merit Generation has been attributed to Balancing Price-Quantity Pairs or, otherwise, until there are no remaining Balancing Price-Quantity Pairs in the Balancing Portfolio Supply Curve;~~

~~(e) The Non-Qualifying Constrained Off Generation for the Balancing 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 Portfolio:~~

~~i. Downwards LFAS Enablement;~~

~~ii. 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 Quantities and 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 Portfolio.~~

6.17.5~~C~~. Where the IMO is unable to attribute:

(a) Upwards Out of Merit Generation ~~in~~ accordance with clauses 6.17.3 ~~or 6.17.5, as applicable:~~; or

(b) Downwards Out of Merit Generation ~~in~~ accordance with clauses 6.17.4 ~~or 6.17.5A~~,

for a Market Participant, the Market Participant is not entitled to be paid for any Upwards Out of Merit Generation or Downwards Out of Merit Generation, as applicable.

…

7.7.5A. System Management must develop, in a Power System Operation Procedure, the information that must be provided by a Market Participant to System Management for each of the Market Participant's Non-Scheduled Generators for each Trading Interval to enable an estimation of the output of each Facility, in MWh, to be undertaken by:

(a) System Management, as required under clauses ~~6.15.2(b)(i),~~ 7.7.5B and 7.13.1C(e) and for the purposes of the calculation of the Minimum Theoretical Energy Schedule for a Non-Scheduled Generator under Appendix 11; and

(b) the IMO, as required by the Relevant Level Methodology.

7.7.5B. The quantity to be used ~~in clause 6.15.2(b)(i)~~ for the purposes of the calculation of the Minimum Theoretical Energy Schedule for a Non-Scheduled Generator under Appendix 11, is System Management's estimate, determined in accordance with the Power System Operation Procedure, of the maximum amount of sent out energy, in MWh, which each Non-Scheduled Generator, by Trading Interval, would have supplied in the Trading Interval had a Dispatch Instruction not been issued.

…

7.7.5D. System Management must provide the estimate required ~~under clause 6.15.2(b)(i)~~ for the purposes of the calculation of the Minimum Theoretical Energy Schedule for a Non-Scheduled Generator under Appendix 11 as soon as reasonably practicable but in any event in time for settlement under Chapter 9.

…

7.7.6B. If a Market Participant notifies System Management under clause 7.7.6(b) or clause 7.10.3 that it cannot fully comply with a Dispatch Instruction, then it must, at the same time, provide notice of:

(a) where the Market Participant can comply with the quantity required in the Dispatch Instruction but not the required ramp rate, the different ramp rate with which the Market Participant can comply; or

(b) where the Market Participant cannot comply with the quantity required in the Dispatch Instruction:

i. the reduced quantity (if any) and associated ramp rate with which the Market Participant can comply; and

ii whether the Market Participant needs to desynchronise the Facility in order to provide the reduced quantity,

and System Management must, subject to meeting the Dispatch Criteria, issue a ~~new~~ Rectification Dispatch Instruction or Operating Instruction, as applicable, to the Market Participant in accordance with the advice received.

…

7.13.1A. System Management must provide the IMO with the following data for a Trading Day by noon on the fifteenth Business Day following the day on which the Trading Day ends:

(a) the MWh quantity of non-compliance by Synergy by Trading Interval; and

(b) the schedule of all Planned Outages, Forced Outages and Consequential Outages relating to each Trading Interval in the Trading Day by Market Participant and Facility~~.~~ as measured on a sent out basis at:

i. 15 degrees Celsius; and

ii. 41 degrees Celsius.

…

Glossary

Available Capacity: Means, for a Trading Interval, the sent out capacity, in MW, of a Scheduled Generator or a Non-Scheduled Generator that was not subject to an Outage notified to the IMO under clause 7.13.1A(b)(i).

…

~~**Constrained Off Compensation Price**: Has the meaning given in clause 6.17.4 and 6.17.4A.~~

Constrained Off Compensation Price: Means the price calculated under clause 6.17.4 and in accordance with Appendix 11.

~~**Constrained Off Quantity**: Has the meaning given in clause 6.17.4 and 6.17.4A.~~

Constrained Off Quantity: Means the quantity calculated under clause 6.17.4 and in accordance with Appendix 11.

~~**Constrained Off Portfolio Quantity**: Has the meaning given in clause 6.17.5A.~~

~~**Constrained On Compensation Price**: Has the meaning given in clause 6.17.3, 6.17.3A or clause 6.17.5,.~~

Constrained On Compensation Price: Means the price calculated under clause 6.17.3 and in accordance with Appendix 11.

~~**Constrained On Quantity**: Has the meaning given in clause 6.17.3 and 6.17.3A.~~

Constrained On Quantity: Means the quantity calculated under clause 6.17.3 and in accordance with Appendix 11.

…

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

Equivalent Planned Outage Hours: Means the quantity calculated under clause 4.27.3 and in accordance with Appendix 10.

[Note: Drafting of 'Equivalent Planned Outage Hours' reflects proposed Amending Rules in the Draft Rule Change Report for RC_2013_09: Incentives to Approve Availability of Scheduled Generators]

…

Forced Outage: Has the meaning given in clause 3.21.~~1~~2B.

Forced Outage Rate: Means the rate calculated under clause 4.11.1(h) and in accordance with Appendix 10.

…

Maximum Theoretical Energy Schedule: Means the schedule ~~determined~~ calculated under clause 6.15.1 at the times specified in clause 6.15.3 and in accordance with Appendix 11.

…

Minimum Theoretical Energy Schedule: Means the schedule ~~determined~~ calculated under clause 6.15.~~2~~1 at the times specified in clause 6.15.3 and in accordance with Appendix 11.

…

Outage: ~~Means a Forced Outage, a Planned Outage or a Consequential Outage.~~Has the meaning given in clause 3.21.1.

…

Planned Outage Rate: Means the rate calculated under clause 4.11.1(h) and in accordance with Appendix 10.

…

Rectification Dispatch Instruction: Means a subsequent Dispatch Instruction issued by System Management to a Market Participant in accordance with clause 7.7.6B, following that Market Participant advising System Management of its inability to comply with a Dispatch Instruction in accordance with clause 7.7.6(b)(ii).

…

Appendix 10: Planned and Forced Outage Rate Determination

The IMO must calculate the Equivalent Planned Outage Hours, Planned Outage Rate and Forced Outage Rate for a Facility and a period of time P as follows.

The Equivalent Planned Outage Hours ($EPOH$) for the Facility equals:

$$EPOH = 0.5 \times \sum_{t \in CO} \frac{PO(t)}{Cap(t)}$$

The Planned Outage Rate (POR) as a percentage for the Facility equals:

$$POR = \frac{1}{n} \sum_{t \in CO} \frac{PO(t)}{Cap(t)} \times 100$$

The Forced Outage Rate (FOR) as a percentage for the Facility equals:

$$FOR = \frac{1}{n} \sum_{t \in CO} \frac{FO(t)}{Cap(t)} \times 100$$

Where:

- CO is the set of Trading Intervals in period P for which the Facility has been in Commercial Operation, where t is used to refer to a member of that set;
- n is the number of Trading Intervals in period P for which the Facility has been in Commercial Operation;
- $PO(t)$ is the quantity of Planned Outage in MW for the Facility in Trading Interval t as calculated in accordance with clause 3.21.6(c) and:
  - provided in accordance with clause 7.13.1A(b)(ii) if the Facility holds Capacity Credits and had its Certified Reserve Capacity assigned using the methodology described in clause 4.11.1(a), or
  - provided in accordance with clause 7.13.1A(b)(i) otherwise;

- $FO(t)$ is the quantity of Forced Outage in MW for the Facility in Trading Interval t as calculated in accordance with clause 3.21.6(b) and:

    - o provided in accordance with clause 7.13.1A(b)(ii) if the Facility holds Capacity Credits and had its Certified Reserve Capacity assigned using the methodology described in clause 4.11.1(a), or

    - o provided in accordance with clause 7.13.1A(b)(i) otherwise; and

- $Cap(t)$ is the capacity for the Facility, given by

    - o the number of Capacity Credits held by the Facility in Trading Interval t if the Facility holds Capacity Credits and had its Certified Reserve Capacity assigned using the methodology described in clause 4.11.1(a), or

    - o the Sent Out Capacity of the Facility as recorded in Standing Data (Appendix 1(b)iii if the Facility is a Scheduled Generator and Appendix 1(e)(iiiA) if the Facility is a Non-Scheduled Generator) during Trading Interval t otherwise.

Appendix 11: Constrained On and Off Compensation Determination

Throughout this appendix, the Facility f and Trading Interval t are fixed, and are not included as subscripts in other variables or as inputs in functions.

Variables are defined as they are needed, and definitions apply throughout this Appendix 11.

General Energy Schedule

Let $EnergySchedule(Duration, StartOutput, TargetOutput, RampRate)$ be the total energy generated during the first $Duration$ hours by a facility ramping from $StartOutput$ MW to $TargetOutput$ MW at $RampRate$ MW/min and remaining at $TargetOutput$ MW from then on. This is calculated as follows.

Given $Duration$, $StartOutput$, $TargetOutput$ and $RampRate$, let $EndOutput$ be the facility's output in MW after $Duration$ hours, which is given by

$$EndOutput = \min\Big\{\max\{TargetOutput, StartOutput - 60 \times RampRate \times Duration\}, StartOutput + 60 \times RampRate \times Duration\Big\},$$

and let $RampDuration$ be the time in hours that the facility spends ramping, which is given by

$$RampDuration = \frac{|StartOutput - EndOutput|}{60 \times RampRate}.$$

The total energy generated is the energy that would have been generated if the facility had been running at a constant level of $EndOutput$ MW for $Duration$ hours plus the extra energy generated while the facility is ramping down (which is negative if $TargetOutput > StartOutput$ and the facility is ramping up), and so

$$EnergySchedule(Duration, StartOutput, TargetOutput, RampRate) = EndOutput \times Duration + \frac{1}{2}(StartOutput - EndOutput) \times RampDuration$$

Dispatched Energy Schedule

The following definitions apply:

- DI_0 is the Dispatch Instruction or instruction deemed to be a Dispatch Instruction under clause 7.6.2, excluding Rectification Dispatch Instructions and instructions given under a Network Control Service Contract or Ancillary Services Contract, with the latest response time at or before the start of Trading Interval t.
- DI_i is the Dispatch Instruction or instruction deemed to be a Dispatch Instruction under clause 7.6.2, excluding Rectification Dispatch Instructions and instructions given under a Network Control Service Contract or Ancillary Services Contract,with the ith earliest response time strictly within Trading Interval t.
- K is the number of Dispatch Instructions or instructions deemed to be Dispatch Instructions under clause 7.6.2, excluding Rectification Dispatch Instructions and instructions given under a Network Control Service Contract or Ancillary Services Contract, with response times strictly within Trading Interval .
- $DITime_0 = 0$.
- $DITime_i$ is the number of hours between the start of Trading Interval t and the response time in DI_i for all i with $1 \leq i \leq K$.
- $DITime_{K+1} = 0.5$.
- $DITarget_i$ is the target output in MW in DI_i for all i with $0 \leq i \leq K$.
- $DIRampRate_i$ is the target ramp rate in MW per minute in DI_i for all i with $0 \leq i \leq K$.

For all i with $0 \leq i \leq K$, let $Output_i$ be the output $DITime_i$ hours after the start of the Trading Interval t if the facility follows its Dispatch Instructions (excluding Rectification DIs), which is given by

$$Output_0 = SOI$$

and, for all i with $1 \leq i \leq K$,

$$Output_i = \min\left\{\max\{DITarget_{i-1}, Output_{i-1} - 60 \times DIRampRate_{i-1} \times (DITime_i - DITime_{i-1})\}, Output_{i-1} + 60 \times DIRampRate_{i-1} \times (DITime_i - DITime_{i-1})\right\}.$$

For all i with $0 \leq i \leq K$, let $DIEnergy_i$ be the energy generated between $DITime_i$ and $DITime_{i+1}$ hours after the start of Trading Interval t if the Facility follows its Dispatch Instructions (excluding Rectification DIs), which is given by

$$DIEnergy_i = EnergySchedule(DITime_{i+1} - DITime_i, Output_i, DITarget_i, DIRampRate_i).$$

The Dispatched Energy Schedule is given by:

$$DES = \sum_{i=0}^{K} DIEnergy_i.$$

Theoretical Energy Schedule

The following definitions apply:

- $BalancingPrice$ is the Balancing Price in $/MWh.
- $SentOutCapacity$ is the Sent Out Capacity of f as recorded in Standing Data (Appendix 1(b)iii if the Facility is a Scheduled Generator and Appendix 1(e)(iiiA) if the Facility is a Non-Scheduled Generator) during Trading Interval t.
- N is the total number of Balancing Price-Quantity Pairs.
- $(Price_n, Quantity_n)$ is the Balancing Price-Quantity Pair with the nth lowest price for all n with $1 \leq n \leq N$, where $Price_n$ is in $/MWh and $Quantity_n$ in MW.
- $CumQ_n$ is defined as follows:
  - o $CumQ_0 = 0$;
  - o if f is a Non-Scheduled Generator, then $N = 1$ and $CumQ_1 = SentOutCapacity$; and
  - o if f is not a Non-Scheduled Generator, then $CumQ_n = \sum_{m=1}^{n} Quantity_m$, which is the cumulative quantity in the first n Balancing Price-Quantity Pairs for all n with $1 \leq n \leq N$.
- $LF = 1$ if f is the Balancing Portfolio and equals the Loss Factor of f otherwise.
- $M^+ = \max\left\{n: \frac{Price_n}{LF} \leq BalancingPrice\right\}$, so that $Price_{M^+}$ is the price of the Balancing Price-Quantity Pair with the highest Loss Factor adjusted price less than or equal to the Balancing Price.
- $M^- = \max\left\{n: \frac{Price_n}{LF} < BalancingPrice\right\}$, so that $Price_{M^-}$ is the price of the Balancing Price-Quantity Pair with the highest Loss Factor adjusted price less than the Balancing Price.
- SOI is the SOI Quantity.

- $RampRateLimit$ is the Ramp Rate Limit.

- $AvailableCapacity$ is the Available Capacity

- $TSOMS$ is System Management's estimate provided under clause 7.13.1(eF) of the maximum amount of sent out energy, in MWh, that f would have supplied in t had it not received a Dispatch Instruction to decrease its output, if such an estimate exists, and zero otherwise.

For all n with $0 \leq n \leq N$, let

$$MaxTheoreticalEnergy_n = EnergySchedule(0.5, SOI, CumQ_n, RampRateLimit)$$

and let

$$MinTheoreticalEnergy_n = EnergySchedule\left(0.5, \min\{SOI, AvailableCapacity\}, \min\{CumQ_n, AvailableCapacity\}, RampRateLimit\right).$$

The Maximum Theoretical Energy Schedule is given by

$$MaxTES = MaxTheoreticalEnergy_{M^+}.$$

The Minimum Theoretical Energy Schedule is given as follows:

- if f is a Non-Scheduled Generator to which a Dispatch Instruction was issued to decrease its output and $\frac{Price_1}{LF} < BalancingPrice$, then

$$MinTES = TSOMS;$$

- otherwise,

$$MinTES = MinTheoreticalEnergy_{M^-}.$$

Constrained On Quantities and Prices

The following definitions apply:

- $ActualGeneration$ is the net quantity of energy generated and sent out into the relevant Network or consumed by the Facility during Trading Interval t, 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.

- $STol$ is the Portfolio Settlement Tolerance if f is the Balancing Portfolio and the Settlement Tolerance of f otherwise.

- $ULFAS$ is the Ex-post Upwards LFAS Enablement, in MW provided under clause 7.13.1(e), or zero if this does not exist.

- $UBLFAS$ is the Upwards Backup LFAS Enablement in MW provided under clause 7.13.1(eA), or zero if this does not exist.

- $NCSI$ is the increase in sent out energy in MWh as the result of System Management dispatch the Facility under a Network Control Service Contract under clause 7.13.1(dA) with System Management, or zero if this does not exist.

- $SRRQ$ is the Spinning Reserve Response Quantity in MWh, or zero if this does not exist.

Let

$$UNQ = ULFAS \times 0.5 + UBLFAS \times 0.5 + NCSI + SRRQ.$$

For all n with $1 \leq n \leq N$, if

(a) the IMO has received a report under clause 7.10.7 and has determined that the relevant Market Participant has not adequately complied with a Dispatch Instruction or Dispatch Order as applicable;

(b) the Facility was undergoing a Test or subject to an Operating Instruction; or

(c) $\min\{ActualGeneration - UNQ, DES\} - MaxTES < STol$

then Constrained On Quantity n is given by

$$ConQ_n = 0;$$

otherwise,

$$ConQ_n = LF \times \max\Big\{\min\{ActualGeneration, DES + UNQ, MaxTheoreticalEnergy_n\} - \max\{MaxTES + UNQ, MaxTheoreticalEnergy_{n-1}\}, 0\Big\}.$$

Constrained On Price n is given by

$$ConP_n = \frac{Price_n}{LF} - BalancingPrice.$$

Constrained Off Quantities and Prices

The following definitions apply:

- $DLFAS$ is the Ex-post Downwards LFAS Enablement in MW provided under clause 7.13.1(eC), or zero if this does not exist.

- $DBLFAS$ is the Downwards Backup LFAS Enablement in MW provided under clause 7.13.1(eB), or zero if this does not exist.

- <u>$LRRRQ$ is the Load Rejection Reserve Response Quantity in MWh provided under clause 7.13.1(eD), or zero if this does not exist.</u>

<u>Let</u>

$$\underline{DNQ = DLFAS \times 0.5 + DBLFAS \times 0.5 + LRRRQ.}$$

<u>For all n with $1 \le n \le N$, if</u>

(a) <u>the IMO has received a report under clause 7.10.7 and has determined that the relevant Market Participant has not adequately complied with a Dispatch Instruction or Dispatch Order;</u>

(b) <u>the Facility was undergoing a Test or complying with an Operating Instruction; or</u>

(c) <u>$MinTES - \max\{ActualGeneration + DNQ, DES\} < STol$</u>

<u>then Constrained Off Quantity n is given by</u>

$$\underline{CoffQ_n = 0;}$$

<u>otherwise,</u>

$$\underline{CoffQ_n = LF \times \max\Big\{\min\{MinTES - DNQ, MinTheoreticalEnergy_n\} - \max\{ActualGeneration, DES - DNQ, MinTheoreticalEnergy_{n-1}\}, 0\Big\}.}$$

<u>Constrained Off Price n is given by</u>

$$\underline{CoffP_n = BalancingPrice - \frac{Price_n}{LF}.}$$

…

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

The IMO considers that the Market Rules as a whole, if amended to reflect the recommendations above will not only be consistent with the Wholesale Market Objectives but also generally allow the Market Rules to better achieve Wholesale Market Objectives (a), (c) and (d).

The proposed Amending Rules are designed to align the treatment of Scheduled Generators and Non-Scheduled Generators as far as practicable with respect to availability, Outages and constraint payments. On this basis, the IMO's assessment is presented below:

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

The IMO considers that the proposed amendments would better address Wholesale Market Objective (a) by:

- ensuring that all limitations on a Facility's capacity to generate will be more accurately reflected in a Facility's Minimum TES; thereby improving the accuracy of constrained off compensation and the assignment of Certified Reserve Capacity to Facilities and avoiding any significant costs as a result of inaccurate compensation payments being borne by the market;

- providing for advance notification of Consequential Outages to ensure greater transparency of Facility availability to Market Participants and thereby improving the accuracy of the Balancing Price Forecast; and

- providing greater clarity and transparency with respect to existing obligations in the Market Rules to better equip Market Participants to comply with their obligations and therefore reducing the administrative overheads associated with interpreting the Market Rules.

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

The IMO considers that the proposed amendments would better address Wholesale Market Objective (c) by:

- improving consistency between Scheduled and Non-Scheduled Generators, by providing alternative calculations to determine the quantity of an Outage and Planned and Force Outage Rates for Non-Scheduled Generators, consistent with the obligations on Scheduled Generators; and

- improving clarity with respect to Non-Scheduled Generators' obligations to avoid discrimination between Facility Classes, for example in certification and compliance activities.

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

The IMO considers that the proposed amendments would better address Wholesale Market Objective (d) by:

- reducing the time and effort of the IMO's Compliance team and Market Participants spent investigating the merit of compensation payments and ensuring the recovery of incorrect payments, thereby reducing the long-term compliance cost overall; and

- avoiding potential increases in prudential obligations as a result of the incorrect constrained on and off payments.

The IMO considers that the proposed amendments are consistent with the remaining Wholesale Market Objectives.

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

The cost of the proposed amendments for the market as a whole is expected to be significant and includes:

- for the IMO, approximately $190,000 of costs associated with system and IT changes to allow the calculation of each Facility's Dispatch Schedule to determine TES, the testing of the integrity of amended equations for settlement purposes and transfer of additional Outage information from System Management to the IMO; and
- for System Management, approximately $239,000 of costs associated with system changes to allow logging of Outages after the 15 day timeframes, the provision of Outage quantities by Facility, by Trading Interval, on a sent out basis at 15 degrees Celsius and the addition of a Rectification Dispatch Instruction flag to signal a Market Participant's non-compliance. This includes around $55,000 for System Management to continue the transition from the current system (SMITTS) to the new system (SMARTS) by transferring the capability and functionality for logging and reporting Outages.

It should be noted that reporting costs for Market Participants are not expected to change as a result of the proposed amendments, as it is anticipated that a compliant operator would already be logging the information under the current Market Rules.

It is difficult to quantify the economic benefits that accrue from an improvement in the accuracy of settlements, invoicing and the certification of capacity. However, the market is likely to experience a net economic benefit as a result of:

- reduced IMO and Market Participant legal, financial and compliance costs associated with rectification of incorrect constraint compensation paid to Market Participants;
- greater certainty for Market Participants around the application of the Market Rules to Non-Scheduled Generators which will ensure investment and operational decisions are better informed and therefore less likely to lead to inefficient outcomes;
- more accurate invoicing, removing the need for both the IMO and Market Participants to monitor and rectify over payments through the settlement adjustment process; and
- the improved ability for the Market Rules to be practically applied, resulting in more efficient behaviours.

Wholesale Electricity Market
Rule Change Proposal Form

Change Proposal No: *[to be filled in by the IMO]*
Received date: *[to be filled in by the IMO]*

Change requested by:

Name:	Andrew Stevens
Phone:	(08) 9261 2835
Fax:	(08) 9261 2880
Email:	Andrew.stevens@bluewatersps.com.au
Organisation:	*Bluewaters Power*
Address:	Level 8, 225 St George's Terrace, Perth
Date submitted:	12th August 20113
Urgency:	*2 - Medium*
Change Proposal title:	Adjustment of Spinning Reserve Block Sizes
Market Rule(s) affected:	Market Rules Appendix 2

Introduction

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

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

Independent Market Operator
Attn: Group Manager, Market Development
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 Market Rule Change

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

Bluewaters believes the current Spinning Reserve blocks (refer Appendix 2 of the Market Rules) blocks do not efficiently achieve the Market Objectives, in particular objectives B (promote competition) and D (minimise long term costs) and has identified an opportunity to better achieve the Market Objectives via modifications to the Spinning Reserve block boundaries.

As a result of the current Block sizes there are currently five facilities which incur a fixed cost, disproportionate to the level of additional ancillary service required through their utilisation. The cost incurred is rarely economically unrecoverable on a marginal basis. The five plants in question all have low short run marginal costs (excluding the administered spinning reserve charges).

Three plants on the SWIS have maximum generation and certification of 320-330MW while the next 5 largest plants have maximum generation and certification of 211-232MW, yet all 8 units fall within Block 1 when generating above 200MW. As a result there is up to a 140MW *gross* generation difference between these two sets of plants (accounting for nearly 100MW difference in required Spinning Reserve), yet the Spinning Reserve costs allocated to those plants, when operating above 200MW is identical. Bluewaters is concerned this is not an intended outcome of the current Block structure and while the disparity occurs in all blocks, the magnitude of the disparity and materiality of the costs is largest at the Block 1 levels as a result of the level of cost allocated to this block.

As a direct result of the spinning reserve block sizes, the sum of the thus uneconomic energy is approximately 90MW. That is, there is nearly 90MW of base load energy, which should be priced at 'peaking' prices, as a result of the current Block ranges. If the proposals in this rule change are adopted the market will unlock between 35MW and 90MW of low cost energy while also mitigating a competition issue.

The competition issue arises where a market participant is both providing the large majority of the spinning reserve service (ie. collecting the revenue) and forming part of the cost base[1]. That participant is effectively close to cost-neutral where a participant not providing the spinning reserve service must avoid the same activity (generating marginally over 200MW).

Spinning reserve is the capacity held in reserve by synchronised generation, dispatchable loads and interruptible loads, synchronised and on call, to cover the energy 'dropped' by a plant tripping (or any other event that causes a sudden and significant drop in frequency).

The market rules have set out the minimum level of spinning reserve which must be available on the SWIS at any given point. That level is determined by a formula derived from MR 3.10.12A which states, "…the level must be

[1] Bluewaters is not implying the current main SR provider is the architect of this advantage, nor that they are maliciously abusing it, only that it naturally exists as an outcome of the current block structure, and that it is most obvious around the 200MW production level as this is where the greatest marginal cost occurs.

sufficient to cover the greater of: i. 70% of the total output, including Parasitic Load, of the generation unit synchronised to the SWIS with the highest total output at that time; and ii. the maximum load ramp expected over a period of 15 minutes…"

The cost to maintain spinning reserve is allocated across all generating participants/facilities with a broad "causer pays" bias. The bias is created using energy blocks (ranges of average instantaneous sent out generation per interval) that allocate greater portions of the cost of providing spinning reserve to larger generators. The bias is further achieved by including all units in higher blocks as denominators for that block.

The supporting case for the causer pays bias can be explained as follows: if all generating units had the same size unit (eg. 100MW) the system would require the greater of 70% of the output of largest unit on the or the maximum load ramp expected over 15 minutes. Whereas, if all units were 100MW and one was 200MW, the system would require an additional 70MW of generation to 'cover' that one larger unit.

Bluewaters believes this concept is reasonable as the largest unit is responsible for the delta between it and the next largest unit which results in the need for additional spinning reserve. That said, all units are responsible for a portion the 70% required to cover their own generation and should therefore share in the cost of Spinning Reserve costs. Thus, the premise that everyone pays to cover the cost to carry spinning reserve for their unit (as opposed to *only* the largest unit payin*g)* is also reasonable.

The gross cost is determined on a per interval basis, based on pre-determined constants (which are assessed each year by the ERA) and the prevailing (variable) Balancing Price. That cost is then apportioned across a range of "Blocks". The cost per interval to each participant is the sum of their allocated costs for each block they encounter. That is, a unit generating within the Block 2 range (125-200MW) also pays an equal share of Blocks 3,4 & 5, while a smaller unit, only generating in Block 1 (10-45MW) pays only a share of Block 1's cost.

Anecdotally Bluewaters is informed that the original Block sizes were determined to suit (in some manner) the plants on the SWIS at the time (which may account for the 20MW size of Block 4). Bluewaters notes the somewhat unusual step changes between blocks of 35MW, 20MW, 60MW, 75MW and 100MW+, which appears to support the theory.

At the time the block sizes were developed (around 2004) there may not have been seen to be any great need to consider the effect on the market outcomes, particularly at the top boundary, since Verve would most likely be paying for (and being paid for) the vast majority of these ancillary services costs. As the market now contains other units and heads for more generically market-based outcomes Bluewaters believe it is sensible to review the block structure with the aim of achieving improved outcomes in the near term.

The methodology has some inherent inequities which are functions of the block sizes and characterised by the following outcomes:

1) The maximum spread: The block size determines the maximum generation spread and therefore the relative advantage/disadvantage *within* the block of generating at the top or bottom end of the block size. The larger the spread – the greater the chance for disparity. Small blocks have an inherent advantage over larger blocks which supports the theory that all blocks should preferably be close to same size.

2) Creating Denominators: Each block forms the boundary for creating another denominator for the Blocks below it. Therefore, different sized blocks creates asymmetry around when denominators are formed, conferring an advantage to members of smaller sized lower blocks. Each time a smaller than average block is present within the block structure the greater the advantage to the lower blocks. This indicates that combining current blocks 4&5 to form a 55MW block is more appropriate than retaining a block which is not the lowest block (Block 4) at 20MW where there are block ranges above at 100MW.

Bluewaters believes it would improve the integrity and rationale of the block structure if it the block sizes were more equal.

Fundamentally this rule change proposal seeks a review of the Block boundaries with a view to reshaping the blocks to better align with the causer pays philosophy (particularly in Block 1 where a 100MW+ Spinning Reserve requirement delta can occur); and also to capture some immediate (economic) market benefits as a result (in the form of lower STEM, Balancing prices and lower ancillary service costs as a result).

Bluewaters considers the low hanging fruit is captured by creating more evenly sized blocks and the separation of plants around the 210-230MW range from plants in the 320-330MW range. This will result in:
- Greater availability of low-priced energy to the STEM and Balancing markets with resultant lower STEM and Balancing Prices (Refer Appendix 2: Impact of 'shifting' 50MW of energy from peaking prices, to base-load prices)

- Lower ancillary services costs to the market as a direct result of lower Balancing Prices.
- An improvement in competitive aspects of the market environment

More detail on the Block Method

Current Block Sizes:

Current Block Structure					
Block #	**MW >=**	**< MW**	**Block Size**	**Total Allocation per Block**	**Total Facilities in category**
1	200+	330	100	34.5%	8
2	125	200	75	25.9%	10
3	65	125	60	20.7%	7
4	45	65	20	6.9%	5
5	10	45	35	12.1%	15
			290	100.0%	45

- Blocks 1,2 & 3 (generating units >65MW) account for 81% of total spinning reserve costs.
- Blocks 4 & 5 are allocated 19% of total spinning reserve costs.

Referring to the scenario in Appendix 4, using a SR cost of $1,185 for a peak interval (the 18-month average peak SR cost) we find:

- On a typical trading day (20 generating units, five of which are in Block 1) a facility in Block 5 generating 33MW out of a total 2,570MW will typically pay ~0.6% of the total costs of spinning reserve despite producing proportionally more of the total energy generation at the time (~1.3%). There is no suggestion there is a problem with this outcome.

- Conversely, in the same scenario, a facility at 210MW, producing ~8.2% of that total generation but will pay ~12.4% of total spinning reserve costs that interval.
    - If there were only *two* units in Block 1 each unit would pay ~22% of the total Spinning Reserve cost that interval. Again, this paper is not suggesting this is an unreasonable outcome.

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2. Explain the reason for the degree of urgency:

In our opinion the rule change proposal does not meet the Fast Track rule change criteria, as such Bluewaters believes this rule change should be progressed via the standard rule change process.

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

Bluewaters believes the highest priorities to achieve via this rule change is the separation the three 300+MW plants from units which are more than 100MW different in maximum generation and adjusting the block sizes to be of similar size Ie. that the incremental (arithmetic) demand for Spinning Reserve Capacity is reflected by a block structure that is also similarly incremental.

The two options tabled below are proposed with the intent of improving/optimising the current block sizes to better suit the market while retaining the 'five blocks' structure (facilitating easier adoption of the improvements).

Proposal 1: This proposal expands the block size of Blocks 1, 2 and 3 such that these categories now collectively account for 83.1% of total spinning reserve costs and segregates the 300MW+ units from the units close to 200MW. This achieves the primary aim of this rule change in that it separates the largest three units from the rest of the market, however it does not address the issue of making consistent the block sizes.

Alternate Block Structure - Extend Block 2 to 235MW					
Block #	>=	<	Block Size	Total per Block	Total Facilities in category
1	235	335	100	30.8%	3
2	135	235	100	30.8%	13
3	65	135	70	21.5%	9
4	45	65	20	6.2%	5
5	10	45	35	10.8%	15
			325	100.0%	45

Proposal 2: This proposal combines the current Blocks 4 & 5 into one Block (from 10MW to 64MW, forming a 55MW block), Block 1 as 275MW+, defines Block 2 as 200 – 275MW and retains Blocks 3 & 4 as per present.

Alternate Block Structure - Merge blocks 4&5, make Block 2 and Block 1 75MW each)					
Block #	>	<=	Block Size	Total per Block	Total Facilities in category
1	275	350	75	22.1%	3
2	200	275	75	22.1%	5
3	125	200	75	22.1%	10
4	65	125	60	17.7%	7
5	10	65	55	15.9%	20
			339	100.0%	45

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

Currently five plants on the SWIS have potential maximum generation between 200MW and 235MW: Bluewaters 1, Bluewaters 2, Muja G7, Muja G8 and Cockburn. This energy is (or should be) effectively treated as peaking energy, as a result of incurring the fixed Block1 spinning reserve cost.

On a marginally basis the Block 1 spinning reserve charge is extremely unlikely to be recovered, and virtually cannot be bilaterally contracted on a base-load basis. Implementation of this rule is likely to result in the immediate availability, if not activation, of between 35MW to 95MW of low priced energy to the STEM and Balancing Markets. Additionally, this energy could also be more available for low cost bilateral supply where currently it is available only at higher/peaking prices if at all.

The Market Objectives are better met through:

- More low cost energy than present being available on the market (with no change to the level of installed capacity).
- Lower STEM and Balancing prices
- Lower Spinning Reserve Costs
- Some improvement in competition in the market (by reducing the advantage the main provider of Spinning Reserve has

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

This proposal particularly supports Market Objective (D) by better facilitating the production of lower marginal cost energy through capacity which is already present on the SWIS but which is artificially made more expensive through an inefficient market fee structure. The benefits occur through lower cost energy and lower Ancillary Service costs as a result of lower balancing prices.

Potentially up to 90MW of energy could shift from the peaking zone of the BMO to the base load zone. *Appendix 2* provides guidance on the impact of a shift of 50MW from peaking prices to base load prices.

Analysis for the period Jan 2013 to Dec 2013 shows a 50MW increase in base load energy in the BMO would have reduced the average Balancing price by $2.53 (from $49.74 to $47.20).

The cost of Spinning Reserve is influenced by the interval Balancing price. Any measure which increases the supply of energy at the low cost end of the merit order additionally reduces the cost of Spinning Reserve (and probably load following). Bluewaters analysis shows a $1 drop in average Balancing Price will save the market around $530,000 per annum in SR costs. A $2.53 reduction in Balancing prices would have resulted in a $1.34M saving to the market in Spinning Reserve costs for the corresponding period.

While this rule change does not directly address the issue of the main supplier of the SR service gaining a natural competitive advantage when any (other) unit cannot economically run as a result of being on a Block boundary, it does directly address the point at which this advantage is currently most apparent - at the 200MW boundary of Block 1. Thus, although not the primary aim of this rule change, Market Objective B (encouraging competition) is also better served as a result of this rule change.

Appendix 1: Summary of Spinning Reserve Costs (July 2012 to Dec 2013)

	All	Peak	Off Peak
Count of Intervals	26,352	15,372	10,980
Days	549	---	---
Total Cost	**$31,776,821**	$18,209,369	$13,567,452
Ave/Day	**$57,881.28**		
Min	$104	$104	$134
Max	$7,332	$7,137	$7,332
Average	$1,206	**$1,185**	**$1,236**
Stdev	$526	$547	$494
Count >$2,500	436	282	154
Count >$5,000	107	63	44

Appendix 2: Impact of 'shifting' 50MW of energy from peaking prices, to base-load prices.

Using actual BMO data from the 2013 calendar year this chart summarises the average impact per interval on peak and off peak balancing prices.

The chart shows that 50MW of base load energy (ie. priced at $50 or less) would result in a material downward movement of energy prices with the flow on effect of lower ancillary service costs.

	(Average) Effect of 50MW Capacity Shifting from Peaking Prices to Base Load prices									
	Trade	Original Price (Average)			Additional 50MW of Base Load Capacity			Average Price Variation		
	Month	Daily	Off Peak	Peak	Daily	Off Peak	Peak	Daily	Off Peak	Peak
2013	Jan	$53.76	$39.88	$63.67	$52.67	$39.71	$61.93	-$1.08	-$0.17	-$1.73
	Feb	$63.66	$47.83	$74.96	$62.02	$47.65	$72.29	-$1.63	-$0.17	-$2.66
	Mar	$35.77	$19.52	$47.39	$32.00	$10.92	$47.05	-$3.77	-$8.59	-$0.33
	Apr	$43.73	$37.64	$48.08	$42.95	$36.05	$47.89	-$0.77	-$1.58	-$0.19
	May	$32.92	$12.89	$47.23	$28.45	$2.32	$47.12	-$4.46	-$10.56	-$0.10
	Jun	$45.74	$42.68	$47.91	$45.06	$41.64	$47.50	-$0.68	-$1.04	-$0.41
	Jul	$57.21	$44.72	$66.14	$55.38	$43.66	$63.76	-$1.82	-$1.06	-$2.37
	Aug	$52.63	$49.31	$55.00	$50.09	$47.60	$51.87	-$2.53	-$1.70	-$3.12
	Sep	$50.87	$44.30	$55.56	$48.40	$42.26	$52.78	-$2.47	-$2.03	-$2.77
	Oct	$65.88	$55.38	$73.39	$63.28	$52.70	$70.83	-$2.60	-$2.67	-$2.55
	Nov	$44.32	$32.05	$53.08	$38.31	$19.60	$51.67	-$6.00	-$12.44	-$1.40
	Dec	$50.30	$43.65	$55.04	$47.77	$40.42	$53.02	-$2.52	-$3.23	-$2.02
		$49.73	**$39.15**	**$57.29**	**$47.20**	**$35.38**	**$55.64**	**-$2.53**	**-$3.77**	**-$1.64**

Appendix 3: Example of SR Fees Charges if Block Sizes are Altered

Assumptions:

- Refer Appendix 4 for scenario analysis detail
  - Peak scenario with load of ~2,700MW
  - Column "(Example) # Facilities Running" depicts the composition of the 2,700MW generation.
- Average SR cost per interval of $1,185

	Unit of Size 235+		
	Current	Proposal 1	Proposal 2
Block Allocation	Block 1	Block 1	Block 1
Peak	$259.85	$247.63	$233.70
Off Peak	$271.01	$258.29	$243.76

	Unit of Size 200 to 235		
	Current	Proposal 1	Proposal 2
Block Allocation	Block 1	Block 2	Block 2
Peak	$259.85	$65.33	$102.62
Off Peak	$271.01	$68.14	$107.04

	Unit of Size 125 to 200		
	Current	Proposal 1	Proposal 2
Block Allocation	Block 2	Block 2	Block 3
Peak	$55.51	$65.33	$50.19
Off Peak	$57.90	$68.14	$52.35

	Unit of Size 65 to 125		
	Current	Proposal 1	Proposal 2
Block Allocation	Block 3	Block 3	Block 4
Peak	$27.65	$28.87	$23.97
Off Peak	$28.84	$30.11	$25.00

	Unit of Size 45 to 65		
	Current	Proposal 1	Proposal 2
Block Allocation	Block 4	Block 4	Block 5
Peak	$11.31	$10.63	$8.99
Off Peak	$11.79	$11.09	$9.38

	Unit of Size 10 to 45		
	Current	Proposal 1	Proposal 2
Block Allocation	Block 5	Block 5	Block 5
Peak	$6.50	$6.08	$8.99
Off Peak	$6.78	$6.34	$9.38

Appendix 4: Summary and Description of Current and Proposed Spinning Reserve Block Structures:

Current Block Structure

Block #	Start	End	Total Facilities in category	(Example) # Facilities Running	Block Size	% of total allocation per Block	Per unit / block	Cum. Total Per Unit Per Block	Max Spread (MW)	Cause Spinning Reserve (MW)	Denominator: Total Dividing Units in this Block	Est. Total MW	Total Share Paid per Block
1	200	330	8	2	100	34.5%	17.2%	22.3%	130	91.0	**2**	640	44.62%
2	125	200	10	8	75	25.9%	2.6%	5.1%	75	52.5	10	1392	40.56%
3	65	125	7	4	60	20.7%	1.5%	2.5%	60	42.0	14	400	9.93%
4	45	65	5	2	20	6.9%	0.4%	1.0%	20	14.0	16	110	2.01%
5	10	45	15	5	35	12.1%	0.6%	0.6%	35	24.5	**21**	150	2.87%
			45	**21**	290	100.0%						2692	1

Proposal 1: Alternate Block Structure - Extend Block 2 to 235MW (RECOMMENDED)

Block #	Start	End	Total Facilities in category	(Example) # Facilities Running	Block Size	% of total allocation per Block	Per unit / block	Cum. Total Per Running Unit	Max Spread (MW)	Cause Spinning Reserve (MW)	Denominator: Total Dividing Units in this Block	Est. Total MW	Total Share Paid per Block
1	235	335	3	2	100	30.8%	15.4%	20.9%	100	70.0	2	640	41.79%
2	135	235	13	8	100	30.8%	3.1%	5.5%	100	70.0	10	1392	44.10%
3	65	135	9	4	70	21.5%	1.5%	2.4%	70	49.0	14	400	9.74%
4	45	65	5	2	20	6.2%	0.4%	0.9%	20	14.0	16	110	1.79%
5	10	45	15	5	35	10.8%	0.5%	0.5%	35	24.5	21	150	2.56%
			45	21	325	100.0%						2692	1

Proposal 2: Alternate Block Structure - Merge blocks 4&5, make Block 2 and Block 1 75MW each) (RECOMMENDED)

Block #	Start	End	Total Facilities in category	(Example) # Facilities Running	Block Size	% of total allocation per Block	Per unit / block	Cum. Total Per Running Unit	Max Spread (MW)	Cause Spinning Reserve (MW)	Denominator: Total Dividing Units in this Block	Est. Total MW	Total Share Paid per Block
1	275	350	3	2	75	22.1%	11.1%	19.7%	75	52.5	2	640	39.44%
2	200	275	5	3	75	22.1%	4.4%	8.7%	75	52.5	5	660	25.98%
3	125	200	10	5	75	22.1%	2.2%	4.2%	75	52.5	10	750	21.18%
4	65	125	7	4	60	17.7%	1.3%	2.0%	60	42.0	14	400	8.09%
5	10	64	20	7	54	15.9%	0.8%	0.8%	54	37.8	21	245	5.31%
			42	21	339	100.0%						2695	1

Notes:

Total facilities in block: Based on the schedule generation capacity summary (from IMO website).
Facilities Running: For example purposes to model a generation load of ~2700MW.
Cause Spinning Reserve (MW): is the maximum additional SR required as a result of a unit running at the maximum of that block versus a unit running at the maximum of the previous block.
% of total allocation per Block: The total % of that interval's Spinning Reserve payable by facilities in each Block.
Per Unit / Block: The allocation per unit of that Block's allocated cost (%)
Cum. Total / Unit: The cumulative total per unit in that Block payable of the *total* SR cost for that interval.
Dividing Units in This Block: The total number of units that the SR cost of this Block is divided by.
Total Share Paid per Block: The % of total cost of SR attributable to this Block (per interval).

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 Review 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. Issues for which work was already underway or planned for the 2012/13 Financial Year were excluded from consideration. 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

[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.

removal of the requirement to submit Resource Plans and the investigation of various 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 half hour gate closure immediately.

Following the MAC meeting, the IMO consulted further with System Management about the implementation of the proposals; this Rule Change Proposal is consistent with the original suggestions and further discussions, noting that System Management is continuing to investigate any transitional issues associated with moving to the proposed shorter gate closure times.

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:

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

- 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.

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.

However, the final 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) were 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 actually 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]:

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	Dispatch Forecast Market Procedure
Balancing Gate Closure	REM Gate Closure
Balancing Horizon	Dispatch Horizon
Balancing Market	Real-Time Energy Market or REM
Balancing Market Objectives	REM Objectives
Balancing Merit Order or BMO	Dispatch Merit Order or DMO
Balancing Portfolio	Synergy Portfolio
Balancing Portfolio Supply Curve	Synergy Portfolio REM Curve[8]
Balancing Price	Energy Price
Balancing Price-Quantity Pair	REM Price-Quantity Pair
Balancing Quantity	*Removed*[9]
Balancing Submission	REM Submission
Forecast BMO	Forecast DMO
Non-Balancing Dispatch Merit Order	Non-REM Dispatch Merit Order
Non-Balancing Facility	Non-REM Facility
Non-Balancing Facility Dispatch Instruction Payment or DIP	Non-REM Facility Dispatch Instruction Payment or DIP
Pricing BMO	Pricing DMO
Provisional Balancing Price	Provisional Energy Price
Provisional Pricing BMO	Provisional Pricing DMO

[5] Please note that no changes are proposed to the following defined terms:

- 'Balancing Market Commencement Day', as it refers to an historical event rather than an ongoing market entity; and
- '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.

[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] The Portfolio Supply Curve is already a defined term and is a component of a STEM Submission for all Market Participants. Therefore a new defined term is required and the IMO believes that removing the word 'Supply' reduces ambiguity.

[9] The only use of this defined term, in clause 2.16.2(hC), appears to be intended to be Metered Balancing Quantity.

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

Proposed solution:

The IMO proposes to remove Resource Plans completely from the Market Rules.

Resource Plans are however still used for the following purposes in the Market Rules.

- **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 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 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 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: REM Facility Requirements[10], 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:

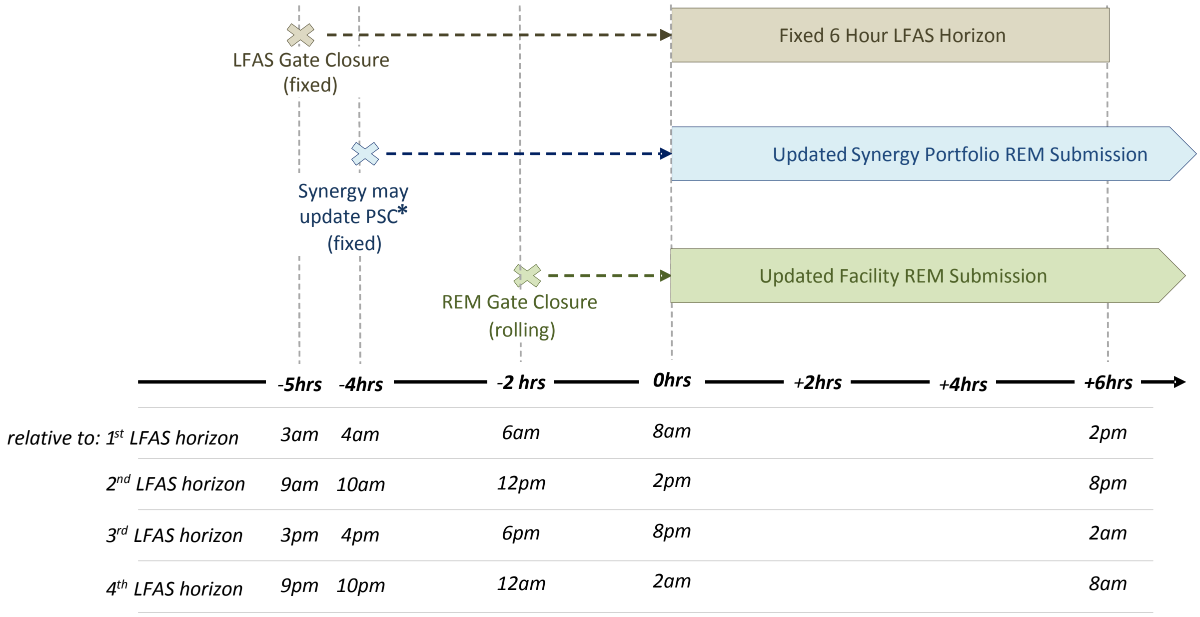
  While no change needs to be made to the Market Rules, the IMO proposes to amend the Market Procedure: REM Facility Requirements, to remove the requirement for REM Submissions for these Facilities to be consistent with their Resource Plan quantities. Market Participants would be able to make and update REM Submissions for these Facilities subject to the same rules as for other REM Facilities, except that the prices offered in the submissions would be restricted to the relevant Price Caps, to reduce uncertainty around how the Facilities would be dispatched.

  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.

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

Issue 3: Gate Closure Changes

The current relationships between LFAS Gate Closure, the final times at which Synergy REM Submissions and LFAS Submissions may be updated and REM Gate Closure are illustrated below.



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

Currently, REM Gate Closure occurs two hours[11] 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 five 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 six 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

[11] 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.

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 four 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:

- reducing REM Gate Closure from two hours to 30 minutes before the start of the relevant 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;
- allowing Synergy to amend its Synergy Portfolio REM Submission for a Trading Interval up to one hour 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. 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.

Discussion Point 1: *The IMO seeks the views of MAC members on whether the proposed deadlines for REM and LFAS Submissions would create operational issues for Rule Participants, and if so how these issues could be resolved in the short to medium term.*

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.

In theory, it would be possible to delay the LFAS Quantity deadline further, perhaps up to LFAS Gate Closure itself, provided Synergy was provided with some certainty around the minimum quantity of LFAS it was required to include in its LFAS Submissions. However, there may be a risk that uncertainty around the LFAS Quantity could make it difficult for LFAS providers to form their LFAS Submissions, potentially leading to increased LFAS costs.

Taking the concept further still, System Management has suggested that the LFAS Quantity decision could be delayed until just before the start of the Trading Interval, with System Management receiving the full LFAS Merit Order and the LFAS Price being determined ex-post based on actual enablement quantities. This approach would however mean that a Market Participant would not know its LFAS position until after REM Gate Closure, which may impose too much risk on LFAS providers to be workable.

Discussion Point 2: *The IMO seeks the views of MAC members on the whether the proposed deadline for updating the LFAS Quantity should be moved closer to the start of the relevant Trading Interval.*

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 from the Market Rules.

In light of recent technological advances in the storage of electrical energy, the IMO anticipates 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 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.

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 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 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 could therefore lead to Backup LFAS being activated for several Trading Intervals in a row, resulting in unnecessary additional costs to the market.

Proposed solution:

The IMO proposes to amend sections 7B.3 and 7B.4 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.

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 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 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 much less severe 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.

Proposed solution:

The IMO proposes to change the outage planning provisions proposed in RC_2013_15 to account for the less severe 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 REM Submission if a Planned Outage approval request is rejected, the IMO proposes to amend the deadline for these requests from 30 minutes before REM Gate Closure to one hour before REM Gate Closure, i.e. 1.5 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 still represent an improvement from the deadline proposed in RC_2013_15 (2.5 hours before the start of the first Trading Interval).

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

Issue 9: Fuel Declarations

Section 7.5 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.

Other Changes

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

- removal of the obsolete transitional provisions in sections 1.10 and 1.11;
- improvements to the consistency of the names used for various LFAS quantities; and
- the correction of minor and typographical errors.

Impact on the WEM Regulations

Reviewable Decisions

Clause 7A.1.11, 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 IMO is currently seeking submissions from interested stakeholders on 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 7A.2.8: *Details what a REM Submission must accurately reflect (category C)* – the only changes proposed are to use the new market names.

- 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.

- 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 would therefore need to 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.

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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 <u>underline</u> 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_23: Prudential Requirements;*
- *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*

- *RC_2013_17: Correction of Estimated Output of Intermittent Generation for Purposes of Appendix 9.*

Comment boxes have been used throughout the proposed Amending Rules to identify the impacted 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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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~~ 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~~ Non-REM Facility 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 DMO 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:

(a) The Market Participant must apply for reassessment in accordance with the Market Procedure for Determining Loss Factors.

(b) The IMO must process an application for reassessment and where required conduct an audit of the relevant Loss Factor calculation in accordance with the Market Procedure for Determining Loss Factors.

(c) The relevant Network Operator must cooperate with an audit of the Loss Factor calculation conducted by the IMO under clause 2.27.15(b) by providing reasonable access to the data and calculations used in producing the Loss Factor.

(d) Where an audit reveals an error in the calculation of a Transmission Loss Factor or Distribution Loss Factor for a Loss Factor Class, the IMO must direct the Network Operator to recalculate the Transmission Loss Factor or Distribution Loss Factor, and may instruct the Network Operator to recalculate other Transmission Loss Factors or Distribution Loss Factors provided by that Network Operator.

(e) Where the IMO directs the Network Operator to recalculate a Transmission Loss Factor or Distribution Loss Factor for a Loss Factor Class, then the Network Operator must do so, and must provide the recalculated Transmission Loss Factor or Distribution Loss Factor to the IMO. The recalculated Transmission Loss Factor or Distribution Loss Factor is substituted for the value previously applied with effect from the time published by the IMO in accordance with clause 2.27.8.

(f) Where an audit reveals an error in the assignment of a connection point to a Loss Factor Class, the IMO must direct the relevant Network Operator to correct the error and re-determine the Loss Factor Class for the connection point in accordance with the classification system prescribed by the IMO for that Network Operator.

(g) Where the IMO directs a Network Operator to re-determine a Loss Factor Class for a connection point, then the Network Operator must do so, and must as soon as reasonably practicable provide to the IMO and the relevant Market Participant the revised Loss Factor Class and the Trading Day from which it should apply.

(h) The costs of an audit conducted by the IMO in response to an application for reassessment, including any costs incurred by the Network Operator and any costs, not otherwise included in the IMO's budget, incurred by the IMO, are payable by the Market Participant who made the application for reassessment, unless the audit reveals:

i. an error of more than 0.0025 in the calculation of a Transmission Loss Factor or Distribution Loss Factor; or

ii. an incorrect assignment of a Connection Point to a Loss Factor Class,

in which case all costs are payable by the relevant Network Operator.

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~~ Non-REM Facility 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.

While clause 2.37.4 contains two references to the "Balancing Price", these references will be deleted by the Amending Rules for the Rule Change Proposal: Prudential Requirements (RC_2012_23), which will provisionally commence on 1 May 2014. As such no change to clause 2.37.4 is required here.

Clause 2.37.5 will also be modified by the Amending Rules for RC_2012_23 and so the modified clause has been used as the base for the changes proposed below.

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.

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 one hour before REM 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 one hour before REM 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. one hour before REM 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 one hour before REM 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 Draft 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, is supported by documented evidence and includes, where applicable, 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 (acting reasonably) and supporting evidence of both firm and any non-firm fuel supplies ~~and the factors that determine restrictions on fuel availability that could prevent the Facility operating at its full capacity~~;

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 blocks of capacity;

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

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

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

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

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

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

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

(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 Draft 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 Draft 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 Draft 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 Non-Refund Exempt 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~~ <u>the REM</u> and ~~Settlement~~ <u>settlement</u>. 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)~~ $\cancel{Target_{LFA} = (NCP + DQ – NonSchGen – Shortfall) \pm Tol}$

~~Where:~~

~~Target~~$\cancel{_{LFA}}$ ~~= 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)~~ $\cancel{Target\ MW_{LFA} = (NCP – NonSchGen – Shortfall) * 2+DQ \pm Tol}$

~~Where:~~

~~Target MW~~$\cancel{_{LFA}}$ ~~= 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 reflect the proposed amendments in the Draft 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 Dispatchable Loads and the requirement for a merit order for increases in consumption.

6.12.1.

(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 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~~.

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

~~Balancing~~ Energy Pricing and Dispatch Quantities

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 the ~~Balancing~~ Synergy Portfolio ~~Supply~~ REM 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~~ REM Price-Quantity Pairs within the ~~Balancing~~ Synergy Portfolio ~~Supply~~ REM 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~~ REM Price-Quantity Pairs within the ~~Balancing~~ Synergy Portfolio ~~Supply~~ REM Curve which have an associated price greater than the ~~Balancing~~ Energy Price,

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

The amendments to clause 6.15.2 reflect the proposed amendments in the Draft Rule

Change Report for the Rule Change Proposal: Correction of Estimated Output of Intermittent Generation for Purposes of Appendix 9 (RC_2013_17). The only change proposed to this clause in RC_2013_17 is to replace the word 'supplied' with 'generated' in clause 6.15.2(b)(i).

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 ~~supplied~~ 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 the ~~Balancing~~ Synergy Portfolio ~~Supply~~ REM 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~~ REM Price-Quantity Pairs within the ~~Balancing~~ Synergy Portfolio ~~Supply~~ REM 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~~ REM Price-Quantity Pairs within the ~~Balancing~~ Synergy Portfolio ~~Supply~~ REM 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;

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;

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~~ Synergy 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~~ Non-REM Facility Dispatch Instruction Payment;

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

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

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

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

in accordance with this clause 6.17.

Constrained On ~~Facility Balancing~~ Quantities and 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 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 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~~ REM Price-Quantity Pair N in the ~~Balancing~~ Synergy Portfolio ~~Supply~~ REM 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 the ~~Balancing~~ Synergy Portfolio ~~Supply~~ REM 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 ~~Supply~~ REM 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 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~~ Synergy Portfolio ~~Supply~~ REM 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 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~~ REM Price-Quantity Pair N, with Price N, in the ~~Balancing~~ Synergy Portfolio ~~Supply~~ REM 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~~ Synergy Portfolio ~~Supply~~ REM 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 the ~~Balancing~~ Synergy Portfolio ~~Supply~~ REM Curve with a price lower than Price N, then:

i. additional 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 ~~Supply~~ REM 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 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~~ Synergy Portfolio ~~Supply~~ REM 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 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~~ Non-REM Facility Dispatch

6.17.6. The ~~Non-Balancing~~ Non-REM Facility 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 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 Prices calculated in accordance with clauses 6.17.4 and 6.17.4A;

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

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

vi. the ~~Non-Balancing~~ Non-REM Facility 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~~ Non-REM Facilities, 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 clause 7.5.1 reflect the proposed amendments in the Draft 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~~ Non-REM Facility 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 7.6 means, for a Trading Interval:

(a) the ~~BMO~~ DMO provided by the IMO to System Management under clause 7A.3.6(b);

(b) if no such ~~BMO~~ DMO is provided, the most recent Forecast ~~BMO~~ DMO for that Trading Interval provided under clause 7A.3.17(b); and

(c) if no such Forecast ~~BMO~~ DMO is provided, the ~~BMO~~ DMO or the Forecast ~~BMO~~ DMO 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.

The IMO notes that the proposed Amending Rules in the Draft Rule Change Report for the Rule Change Proposal: Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10) include a change to clause 7.6.10 to add references to Dispatchable Loads and Interruptible Loads. However, the clause has not been included here as the IMO intends to propose further amendments to it in the Final Rule Change report for RC_2013_10.

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

7.6A.1. Subject to System Management's obligations under clause 7.6, this clause 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~~ Non-REM Facility 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 Draft 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~~ Non-REM Facilities 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~~ Non-REM Facilities based on ~~size of the capacity,~~ response time and availability; and

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

7.7.5. A Dispatch Instruction for a ~~Balancing~~ REM Facility Out of Merit and a ~~Non-Balancing~~ Non-REM Facility 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<u>,</u> ~~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~~ <u>REM</u> Submission.

Advisories, ~~Balancing~~ <u>REM</u> Suspension and Reporting

The amendments to clauses 7.11.1 and 7.11.5 reflect the proposed amendments in the Draft 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 Resource Plans.

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

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

(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 Schedule, 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 Non-REM Facility 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;

(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.

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;

...

The proposed Amending Rules in the Draft Rule Change Report for the Rule Change Proposal: Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10) include a proposed new clause 7.13.1D, which contains a reference to

Dispatchable Loads. A revised version of the clause is shown below; however the IMO notes that it intends to renumber this clause in the Final Rule Change Report for RC_2013_10 (as a clause 7.13.1D already exists in the Market Rules). This proposal (RC_2014_01) removes the reference to Dispatchable Loads in the drafting for RC_2013_10.

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

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.1.3. 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~~ REM Facility Requirements Market Procedure 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 in a ~~Balancing~~ REM Submission in ~~Balancing~~ REM 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 ensure that:

(a) it has made a ~~Balancing~~ REM Submission in accordance with clause 7A.2.4 for each of its ~~Balancing~~ REM Facilities, excluding Facilities in the ~~Balancing~~ Synergy Portfolio;

(b) it has made a ~~Balancing~~ REM Submission for all Trading Intervals in the ~~Balancing~~ Dispatch Horizon for each of its ~~Balancing~~ REM Facilities; and

(c) the ~~Balancing~~ REM Submission is made before ~~Balancing~~ REM Gate Closure or, in the case of the ~~Balancing~~ Synergy 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~~ REM Price-Quantity Pair for a ~~Balancing~~ REM Submission submitted under this clause 7A.2 is at the Minimum STEM Price for the quantity 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 Synergy Portfolio REM Curve; and

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

Scheduled Generator in the 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 clauses 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 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~~ Synergy Portfolio ~~Supply~~ REM Curve 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~~ Synergy Portfolio ~~Supply~~ REM Curve 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~~ Synergy Portfolio ~~Supply~~ REM Curve 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~~ Synergy Portfolio ~~Supply~~ REM Curve 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~~ 1:00 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~~ Synergy Portfolio ~~Supply~~ REM Curve 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~~ Synergy Portfolio ~~Supply~~ REM Curve in accordance with ~~clauses 7A.2.9(e) or~~ clause 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 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.

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.

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 latest 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) Balancing Gate Closure, for a Facility that is not in the Synergy Portfolio; or

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

7A.3. ~~BMO~~ DMO and Pricing ~~BMO~~ DMO

7A.3.1. The IMO must convert the prices for each Trading Interval in ~~Balancing~~ REM Price-Quantity Pairs in ~~Balancing~~ REM Submissions from Market Participants, other than Synergy in respect of the ~~Balancing~~ Synergy Portfolio, into Loss Factor Adjusted Prices.

7A.3.2. The IMO must determine the ~~BMO~~ DMO for a Trading Interval as the ranked list of ~~Balancing~~ REM Submissions which, subject to clause 7A.3.3, is obtained by:

(a) ranking the ~~Balancing~~ REM Price-Quantity Pairs for a Trading Interval and associated ~~Balancing~~ REM Facilities contained in ~~Balancing~~ REM 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~~ REM Submission to reflect that quantity.

7A.3.3. In circumstances where there is a tie in the ranking of ~~Balancing~~ REM Facilities under clause 7A.3.2 in the ~~BMO~~ DMO the IMO must break the tie in accordance with the ~~Balancing~~ Dispatch Forecast Market Procedure, which must give effect to the following descending order of priority:

(a) a ~~Balancing~~ REM Facility that meets the ~~Balancing~~ REM Facility Requirements;

(b) a ~~Balancing~~ REM Facility that is subject to a condition under clause 7A.1.11(b);

(c) a ~~Balancing~~ REM Facility that does not meet the ~~Balancing~~ REM Facility Requirements;

(d) a ~~Balancing~~ REM Facility providing an Ancillary Service other than LFAS;

(e) a ~~Balancing~~ REM Facility providing LFAS; and

(f) priority will be based on the daily random number assigned to the Facility.

7A.3.4. A ~~Balancing~~ REM Facility assigned priority under clause 7A.3.3 means that the Facility will be placed in the ~~BMO~~ DMO so that it will be issued a Dispatch Instruction in priority to the other ~~Balancing~~ REM Facility with which it was tied.

7A.3.5. ~~A~~ Following the provision of the information in clause 7B.3.4(d), or at least 15 minutes after LFAS Gate Closure if this information is not published, 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 in accordance with clause 7A.2.2 for each of its LFAS Facilities in the LFAS Enablement Schedule, 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 capacity 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; 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 capacity in REM Price-Quantity Pairs priced at the Alternative Maximum STEM Price is at least the Upwards LFAS Enablement for the Facility.

7A.3.6. The IMO must:

(a) determine the ~~BMO~~ DMO under clause 7A.3.2 for a Trading Interval using the most recent, valid ~~Balancing~~ REM Submissions available to it; and

(b) each time the IMO creates a ~~BMO~~ DMO for a Trading Interval, to the extent that it is reasonably able, provide this ~~BMO~~ DMO to System Management between 15 to 30 minutes before the start of that Trading Interval.

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 the Pricing ~~BMO~~ DMO, subject to clause 7A.3.13, using the Provisional Pricing ~~BMO~~ DMO 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~~ Energy Price determined under clause 7A.3.8(b), that price is deemed to be the ~~Balancing~~ Energy 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 ~~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);

(b) where the Pricing ~~BMO~~ DMO and the ~~BMO~~ DMO are not available for the Trading Interval the IMO must use the most recent Forecast ~~BMO~~ DMO in place of the ~~BMO~~ DMO in clause 7A.3.13(a); and

(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~~ DMO

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~~ Dispatch Horizon determine a Forecast ~~BMO~~ DMO.

7A.3.17. Where the IMO determines a Forecast ~~BMO~~ DMO under clause 7A.3.16, the IMO must:

(a) provide to each Market Participant the ~~Balancing quantities~~ EOI Quantities expected to be provided by that Market Participant for each future Trading Interval in the ~~Balancing~~ Dispatch Horizon; and

(b) provide to System Management the Forecast ~~BMO~~ DMO.

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~~ Dispatch Forecasts under clause 7A.3.21.

~~Balancing~~ Dispatch 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~~ Dispatch Forecast for each Trading Interval in the ~~Balancing~~ Dispatch Horizon in accordance with the ~~Balancing~~ Dispatch Forecast Market Procedure.

7A.3.20. The IMO must develop the ~~Balancing~~ Dispatch Forecast Market Procedure in accordance with the following principles:

(a) to the extent reasonably practicable, the ~~Balancing~~ Dispatch Forecasts and the Forecast ~~BMO~~ DMOs 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~~ REM Submission or to update a ~~Balancing~~ REM 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~~ Dispatch Forecast for each Trading Interval during the ~~Balancing~~ Dispatch Horizon;

(b) by the end of every half hour thereafter, publish a ~~Balancing~~ Dispatch Forecast for each future Trading Interval in the ~~Balancing~~ Dispatch 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.1.5. System Management may update the forecast LFAS Quantity provided under clause 7B.1.4 for a Trading Interval in the ~~Balancing~~ Dispatch Horizon at any time until 60 minutes before the LFAS Gate Closure for that Trading Interval. System Management may update the forecast LFAS Quantity more than once.~~.~~

7B.2.1. A Market Participant may submit an LFAS Submission:

(a) in accordance with clause 7B.2.7 in respect of any of its LFAS Facilities, other than the ~~Balancing~~ Synergy 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, 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.

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 to be relevant.

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 the 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.3.1. The IMO must determine the ~~LFAS~~ Upwards LFAS 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 LFAS 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 LFAS 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 LFAS 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~~ Dispatch Forecast Market Procedure.

7B.3.4. The IMO must, to the extent that it is reasonably able, as soon as practicable after LFAS Gate Closure and no later than 15 minutes after LFAS Gate Closure for a Trading Interval:

(a) determine the LFAS Merit Order for ~~each~~ the 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)~~ determine the Upwards LFAS Enablement Schedule for the Trading Interval by selecting the lowest priced ~~LFAS Upwards Price-Quantity Pair or LFAS~~ Upwards LFAS Price-Quantity Pairs~~,~~ and associated ~~LFAS Facility or~~ LFAS Facilities from the Upwards LFAS Merit Order determined under clause 7B.3.4(a), so that:

i. ~~the capacity in the lowest priced LFAS Upwards Price-Quantity Pair, or~~ the sum of the ~~capacity~~ quantities in the ~~lowest priced LFAS~~ selected Upwards LFAS Price-Quantity Pairs, equals the LFAS Requirement; and

ii. if only part of the capacity in the highest priced ~~LFAS~~ Upwards LFAS Price-Quantity Pair selected ~~in clause 7B.3.4(b)(i)~~ is required to make up the LFAS Requirement, that ~~LFAS~~ Upwards LFAS Price-Quantity Pair is selected for that part of ~~its capacity~~ the offered quantity only;

(c) ~~select from the LFAS Downwards Merit Order derived under clause 7B.3.4(a)~~ determine the Downwards LFAS Enablement Schedule for the Trading Interval by selecting the lowest priced ~~LFAS Downwards Price-Quantity Pair or LFAS~~ Downwards LFAS Price-Quantity Pairs~~,~~ and associated ~~LFAS Facility or~~ LFAS Facilities from the Downwards LFAS Merit Order derived under clause 7B.3.4(a), so that:

i. ~~the capacity in the lowest priced LFAS Downwards Price-Quantity Pair, or~~ the sum of the ~~capacity~~ quantities in the ~~lowest priced LFAS~~ selected Downwards LFAS Price-Quantity Pairs, equals the LFAS Requirement; and

ii. if only part of the capacity in the highest priced ~~LFAS~~ Downwards LFAS Price-Quantity Pair selected ~~in clause 7B.3.4(c)(i)~~ is required to make up the LFAS Requirement, that ~~LFAS~~ Downwards LFAS Price-Quantity Pair is selected for that part of ~~its capacity~~ the offered quantity only;

(d) provide to System Management ~~the details of:~~ the LFAS Enablement Schedule for the Trading Interval determined under clause 7B.3.4(b) and 7B.3.4(c);

~~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.~~determine and publish:

i. the Upwards LFAS Price for the Trading Interval as the highest price in those Upwards LFAS Price-Quantity Pairs selected in clause 7B.3.4(b); and

ii. the Downwards LFAS Price for the Trading Interval as the highest price in those Downwards LFAS Price-Quantity Pairs selected in clause 7B.3.4(c);

(f) notify each Market Participant with an LFAS Facility in the LFAS Enablement Schedule for the Trading Interval determined under clause 7B.3.4(b) and 7B.3.4(c) of that selection and the associated LFAS Enablement; and

(g) publish the Backup Upwards LFAS Price and Backup Downwards LFAS Price for the Trading Interval, determined from LFAS Submissions made in accordance with clause 7B.2.6.

~~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 Participants 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.3.5. If the IMO does not provide to System Management an LFAS Enablement Schedule for a Trading Interval under clause 7B.3.4(d) within 15 minutes of LFAS Gate Closure then, subject to clause 7B.3.7:

(a) the forecast LFAS Enablement Schedule for the Trading Interval most recently provided to System Management under clause 7B.3.16 is deemed to be the LFAS Enablement Schedule for the Trading Interval;

(b) the forecast LFAS Merit Order used to determine the forecast LFAS Enablement Schedule specified in clause 7B.3.5(a) is deemed to be the LFAS Merit Order for the Trading Interval;

(c) the forecast LFAS Prices determined from the LFAS Merit Order specified in clause 7B.3.5(b) are deemed to be the LFAS Prices for the Trading Interval; and

(d) the forecast Backup Upwards LFAS Price and Backup Downwards LFAS Price for the Trading Interval most recently published under clause 7B.3.15(e) are deemed to be the Backup Upwards LFAS Price and Backup Downwards LFAS Price respectively for the Trading Interval.

7B.3.6. Subject to clauses 7B.2.18, 7B.3.7, 7B.3.8 and 7B.4.1, System Management must ~~use~~ activate the LFAS Facilities ~~referred to in clause 7B.3.4(d)~~ in the LFAS Enablement Schedule for their full LFAS Enablement and use them 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~~ their LFAS Enablement, and those LFAS Facilities must provide those 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)~~ provide the LFAS Enablement Schedule for a Trading Interval in clause 7B.3.4(d) within 15 minutes of the LFAS Gate Closure and has been unable to provide any forecast LFAS Enablement Schedule for the Trading Interval under clause 7B.3.14A, 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 the 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.3.12. If the IMO is unable to determine an LFAS Price under clause~~s 7B.3.9 or 7B.3.10~~ 7B.3.4(e) or 7B.3.5A(c) in time to publish it in accordance with clause 7B.3.11, the IMO must determine the LFAS Price as follows:

(a) if the IMO is determining an LFAS Price for a Trading Interval in a Business Day, the LFAS 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

(b) if the IMO is determining an LFAS Price for a Trading Interval in a day which is not a Business Day, the LFAS 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.

7B.3.14. The IMO must once in each Trading Interval, to the extent it is reasonably able, determine a forecast LFAS Merit Order~~,~~ for each future Trading Interval in the ~~Balancing~~ Dispatch Horizon for which LFAS Gate Closure has not occurred~~, determine a forecast LFAS Merit Order~~.

7B.3.14A. Where the IMO determines the forecast LFAS Merit Order for a Trading Interval under clause 7B.3.14, the IMO must as soon as practicable, to the extent it is reasonably able, provide to System Management a forecast of the LFAS Enablement Schedule for that Trading Interval.

7B.3.15. Where the IMO determines ~~the~~ a forecast LFAS Merit Order for a Trading Interval and provides a forecast LFAS Enablement Schedule to System Management under clause 7B.3.14A, the IMO must as soon as practicable, 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~~the forecast LFAS Enablement for the Market Participant's LFAS Facilities in the forecast LFAS Enablement Schedule provided to System Management under clause 7B.3.14A;

(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 Order~~s~~;

(d) forecasts of ~~LFAS~~ the Upwards LFAS Merit Order~~s~~ and ~~LFAS~~ Downwards LFAS Merit Order~~s~~ in the form of anonymous ~~LFAS~~ Upwards LFAS Price-Quantity Pairs and ~~LFAS~~ Downwards LFAS Price-Quantity Pairs; and

(e) forecasts of the Backup Upwards LFAS Price~~s~~ and Backup Downwards LFAS Price~~s~~ for ~~each future Trading Interval in the Balancing Horizon~~ the Trading Interval.

~~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 the 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 the 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 LFAS in a Trading Interval required by System Management is greater than the most recent LFAS Quantity published under clause 7B.3.15(b) 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(b) 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 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 6.17; and

DIP(p,d,t) is the ~~Non-Balancing~~ Non-REM Facility 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~~ Non-REM Facility 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 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 Price, the Backup Downwards LFAS Price 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 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 Price: Means the cost referred to in clause 7B.2.6 for Synergy providing Backup Downwards LFAS ~~Backup~~ Enablement.

Backup Downwards LFAS 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.

Backup Upwards LFAS 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.

Backup LFAS Enablement: Means Backup Upwards LFAS Enablement and/or Backup Downwards LFAS Enablement, as applicable.

Backup Upwards LFAS Price: Means the cost referred to in clause 7B.2.6 for Synergy providing Backup Upwards LFAS ~~Backup~~ Enablement.

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 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~~ Non-REM Facility 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.~~

...

DIP: See Non-REM Facility Dispatch Instruction Payment.

...

Dispatch Forecast: Means a forecast, determined by the IMO in accordance with the Dispatch 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 REM Facilities for the Trading Interval; and

(c) the Energy Price for the Trading Interval.

Dispatch Forecast Market Procedure: Means the Market Procedure developed under clause 7A.3.20.

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 the ordered list of REM Facilities, and associated quantities, determined by the IMO under clause 7A.3.2.

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 an LFAS Facility, the capacity, or that part of the capacity, in MW, in ~~an LFAS~~ a Downwards LFAS Price-Quantity Pair selected under clause 7B.3.4(c), subject to clause 7B.3.5, which is associated with that Facility or with the ~~Balancing~~ Synergy Portfolio, as applicable.

Downwards LFAS Enablement Schedule: Means, for a Trading Interval, the list of LFAS Facilities and associated Downwards LFAS Enablement quantities determined under clause 7B.3.4(c) or 7B.3.5(a), as applicable.

Downwards LFAS Merit Order: Means the ranked list of LFAS Submissions determined by the IMO under clause 7B.3.2 or 7B.3.5(b), as applicable.

Downwards LFAS Price: Means the price determined under clause ~~7B.3.10~~ 7B.3.4(e)(ii), 7B.3.5(c) or ~~clause~~ 7B.3.12, as applicable, 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.

...

Energy Price: For a Trading Interval means the price determined under clause 7A.3.10.

...

~~**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 a forecast of the DMO for future Trading Intervals in the Dispatch Horizon determined by the IMO in accordance with the Dispatch Forecast Market Procedure.

...

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.~~

...

<u>**LFAS Enablement:** Means the Downwards LFAS Enablement and/or the Upwards LFAS Enablement, as applicable.</u>

<u>**LFAS Enablement Schedule:** Means the Downwards LFAS Enablement Schedule and/or the Upwards LFAS Enablement Schedule, as applicable.</u>

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. the relevant Market Participant has indicated in Appendix 1(j)(i) of Standing Data is intended to participate in the LFAS Market; and

ii. LFAS Standing Data has been accepted by the IMO; or

(b) the ~~Balancing~~ <u>Synergy</u> 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.~~ <u>Means, for a Trading Interval, the point in time 90 minutes before the start of that Trading Interval.</u>

~~**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 <u>LFAS</u> Merit Order and/or the ~~LFAS~~ Upwards <u>LFAS</u> Merit Order, as applicable.

...

LFAS Price-Quantity Pair: Means an ~~LFAS~~ Upwards <u>LFAS</u> Price-Quantity Pair and/or ~~an LFAS~~ <u>a</u> Downwards <u>LFAS</u> Price-Quantity Pair, as applicable.

...

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 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 Facility: Means a Registered Facility that is not a REM Facility.

Non-REM Facility 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 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.

...

Price Cap: Means:

(a) a maximum price of:

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 the Minimum STEM Price.

...

Pricing ~~BMO~~ DMO: Means the ~~Balancing~~ Dispatch Merit Order adjusted to take into account:

(a) the associated Ramp Rate Limits to reflect the physically achievable capacity of the ~~Balancing~~ REM 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~~ DMO determined under clause 7A.3.8(a).

...

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.

The definition of the Synergy Portfolio REM Curve incorporates the changes to the definition of the Balancing Portfolio Supply Curve 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.

Synergy Portfolio REM Curve: Means a ranking of the REM Price-Quantity Pairs covering available capacity in the Synergy Portfolio.

...

~~**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 an LFAS Facility, the capacity, or that part of the capacity, in MW, in an ~~LFAS~~ Upwards LFAS Price-Quantity Pair selected under clause 7B.3.4(b), subject to clause 7B.3.5, which is associated with that Facility or with the ~~Balancing~~ Synergy Portfolio, as applicable.

Upwards LFAS Enablement Schedule: Means, for a Trading Interval, the list of LFAS Facilities and associated Upwards LFAS Enablement quantities determined under clause 7B.3.4(b) or 7B.3.5(a), as applicable.

Upwards LFAS Merit Order: Means the ranked list of LFAS Submissions determined by the IMO under clause 7B.3.1 or 7B.3.5(b), as applicable.

Upwards LFAS Price: Means the price determined under clause ~~7B.3.9~~ 7B.3.4(e)i, 7B.3.5(c) or ~~clause~~ 7B.3.12, as applicable, 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.

...

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 Draft 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.

...

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.

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

The IMO considers that the proposed amendments will better achieve Wholesale Market Objectives (a), (b) and (d), and are consistent with the other Wholesale Market Objectives.

The IMO's assessment is presented below:

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. This will allow Synergy Portfolio REM 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.

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 6a: 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 Report was published on 12 March 2014.	• Commencement.	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).	• Procedure has been updated following the discussion on Prudentials at the 20 September 2013 IMOPWG.	• Updated Market Procedure to be circulated to the IMOPWG for comment prior to being formally submitted into the process.	Mar 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.	• PC_2013_06: Changes to Market Procedure for Certification of Reserve Capacity was published on 10 February 2014.	• Submissions closed on 11 March 2014. The IMO is currently preparing the Procedure Change Report.	May 2014

ID	Summary of Changes	Status	Next Step	Date
PC_2013_07 **Settlement**	The proposed updates are to: • Reflect the necessary changes arising from RC_2013_08: Market Participant Fees - Clarification of GST Treatment; • Reflect the IMO's new format; • Provide greater clarity to potential and existing Rule Participants on the settlement process by improving the information provided around: o STEM and Non-STEM settlement processes and timelines; o Adjustment processes and timelines; o Process for settlement of the market in case of default situations; o Invoicing and the application of GST and interest to settlement transactions; and o Disagreement and dispute processes and timelines; • Improve the structure of the Procedure; and • Define new terms.	• PC_2013_07 commenced on 1 January 2014	• Commenced	01/01/2014
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.	• PC_2013_09: Changes to Market Procedure for Reserve Capacity Performance Monitoring was published on 10 February 2014.	• Submissions closed on 11 March 2014. The IMO is currently preparing the Procedure Change Report.	May 2014

ID	Summary of Changes	Status	Next Step	Date
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.	• Updated Market Procedure was presented at 6 February IMOPWG and submitted into the process on 14 February 2014.	• Submissions are currently open and will close on 17 March 2014.	17/03/2014
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

ID	Summary of Changes	Status	Next Step	Date
TBC **Meter Data Submission**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Clarify that the Procedure is part of the Settlement Market Procedures; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by the IMO Procedures Working Group	TBA
TBC **Capacity Credit Allocation**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Clarify that the Procedure is part of the Settlement Market Procedures; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by IMO Procedures Working Group	TBA
TBC **Intermittent Load Refund**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by IMO Procedures Working Group	TBA
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

ID	Summary of Changes	Status	Next Step	Date
TBC **Reserve Capacity Testing**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Reflect the new Temperature Dependence Curve • Ensure consistency with the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10)	• Underway.	• To be discussed by IMO Procedures Working Group	TBA
TBC **Information Confidentiality**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10) along with all other rule changes which have occurred since Market Start.	• Underway.	• To be discussed by IMO Procedures Working Group	TBA
System Management Procedure Change Proposals				
PPCL0025 **Commissioning and Testing**	The proposed updates are to: • Include amendments required as a result of RC_2012_12 and RC_2012_15; • Expand Appendix C to clarify Load Following and Spinning Reserve requirements around commissioning in line with the Ancillary Services Report; and • Include 'plus ramp range' in Load Following for Maximum Ramp Rate tests.	• PPCL0025: Commissioning and Testing commenced on 1 March 2014.	• Commenced	01/03/2014

ID	Summary of Changes	Status	Next Step	Date
PPCL0026 **Facility Outages**	The proposed updates are to: • Reflect the new outage transparency rules resulting from RC_2012_11.	• PPCL0026: Facility Outages was submitted into the process on 10 February. Submissions closed on 11 March 2014.	• Submissions are now closed. System Management is currently preparing the Procedure Change Report.	TBA
PPCL0027 **Dispatch**	The proposed updates are to: • Reflect the updated commitment/de-commitment rules resulting from RC_2012_22.	• PPCL0027: Commissioning and Testing commenced on 5 March 2014.	• Commenced	05/03/2014

Agenda Item 7a: 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	06/02/2014	TBA

INDEPENDENT MARKET OPERATOR

CONSTITUTION OF THE MARKET ADVISORY COMMITTEE

1. Introduction

1.1. The Wholesale Electricity Market Rules (Market Rules) are made under the *Electricity Industry (Wholesale Electricity Market) Regulations 2004* (Regulations) and in accordance with section 123 of the *Electricity Industry Act 2004* (the Act).

1.2. The Wholesale Market Objectives are as contained within section 122 of the Act ~~(see Appendix 1 of this Constitution)~~ and clause 1.2.1 of the Market Rules (see Appendix 1 of this Constitution).

1.3. The ~~Independent Market Operator (~~IMO~~)~~ is responsible for administering the Wholesale Electricity Market,~~,~~ and, as part of this, for~~ developing~~:

a) developing amendments to the Market Rules and replacements for them; and

b) developing, amending and replacing Market Procedures, ~~and amendments and replacements for them,~~ where required by the Market Rules.

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

1.5. The IMO must ensure that proposed amendments to Market Procedures are:

a) consistent with the Wholesale Market Objectives; and

b) consistent with the Market Rules, the Act, and Regulations.

1.6. This~~e purpose of this document is to set out the~~ Constitution of the Market Advisory Committee is prepared in accordance with clause 2.3.2 of the Market Rules.

~~1.6.~~1.7. Terms used in this Constitution have the same meaning as defined in the Market Rules.

~~1.7. The purpose of this document is to set out the Constitution of the Market Advisory Committee.~~

1.8. This Constitution has been issued under the Market Rules and as such, if a provision of a document which is higher in order of precedence, such as those noted in clause 1.5~~ ~~(b) of this Constitution, is inconsistent with a provision of this Constitution, then the ~~higher~~ provision in the higher order prevails~~,~~ ~~but only~~ to the extent of the inconsistency.

2. Terms of Reference

2.1. The Market Advisory Committee is a committee of industry representatives convened by the IMO:

a) to advise the IMO regarding Rule Change Proposals;

b) to advise the IMO and System Management regarding Procedure Change Proposals;

c) to advise the IMO regarding market operation and South West interconnected system operational matters; and

d) to advise the IMO regarding matters concerning the evolution of the Market Rules.

2.2. In carrying out its functions, ~~T~~the Market Advisory Committee must have regard to the Wholesale Market Objectives as set out in clause 1.2.1 of the Market Rules and any recommendations made by the Market Advisory Committee must be consistent with the Wholesale Market Objectives~~ in carrying out its functions~~.

2.3. Market Advisory Committee members or their proxies are required to act in the best interests of the Wholesale Electricity Market.[1]

2.4. Market Advisory Committee members do not vote on issues. ~~R~~Any recommendations of the Market Advisory Committee are based on a consensus of the views expressed by the members, excluding ~~the~~ observers.

2.5 The Market Advisory Committee may establish Working Groups comprised of representatives of Rule Participants and other interested stakeholders to assist it in advising the IMO.

3. Membership Terms

3.1. In accordance with clause 2.3.4 of the Market Rules, t~~T~~he Market Advisory Committee must comprise:

a) a~~A~~t least three and not more than four members representing Market Generators~~, of whom one will represent the Electricity Generation Corporation (Verve Energy)~~;

b) one member representing Contestable Customers;

[1] It is acknowledged that at times the classes of representation on the Market Advisory Committee may have varying interests. Despite this members or their proxies are required to act in the overall best interests of the Wholesale Electricity Market.

c) at least one and not more than two members representing Network Operators, of whom one will represent ~~the Electricity Networks Corporation (~~Western Power~~)~~;

d) at least three and not more that four members representing Market Customers~~, of whom one will represent the Electricity Retail Corporation (Synergy)~~;

e) one member nominated by the Minister to represent small-use consumers;

f) one member representing System Management;

g) one member representing the IMO; ~~and~~

~~g)~~h) one member representing Synergy; and

~~h)~~i) a Chairperson, who will be a representative of the IMO.

3.2. The Minister may appoint a representative to attend Market Advisory Committee meetings as an observer, as outlined in clause 2.3.6 of the Market Rules.

3.3. The Economic Regulation Authority may appoint a representative to attend Market Advisory Committee meetings as an observer, as outlined in clause 2.3.7 of the Market Rules.

3.4. Observers ~~have full~~are entitled to speak~~ing rights~~ at meetings of the Market Advisory Committee but ~~are excluded from~~~~not members and~~ do not formally participat~~ing~~e in making any recommendations.

3.5. Members who represent a single entity (System Management, the IMO, ~~the Electricity Generation Corporation, the Electricity Retail Corporation~~Synergy, and ~~the Electricity Networks Corporation~~Western Power) are ~~Compulsory~~compulsory class members.

3.6. Members who represent a class of participants but are not compulsory members (Market Generators[2], Market Customers[3], Network Operators[4], small-use consumers, and Contestable Customers) are d~~D~~iscretionary class members.

3.7. Compulsory class members who are unable to attend a meeting can send an appropriate proxy~~ies~~ with similar skills and experience to attend meetings in their place.

3.8. Discretionary class members who are unable to attend a meeting can r~~ecommend~~equest the attendance of an appropriate proxy (from any organisation which belongs to the same class as the member) who must

[2] ~~Excluding the Electricity Generation Corporation~~

[3] ~~Excluding the Electricity Retail Corporation~~

[4] Excluding ~~the Electricity Networks Corporation~~Western Power

have similar skills and experience. Discretionary class members can not send a proxy by right. Permission for the attendance by proxies will be at the Chairperson's discretion.

~~3.8.~~3.9. Observers can send proxies to attend meetings in their place.

~~3.9.~~3.10. The Market Advisory Committee may continue to perform its functions under clause 2.3 of the Market Rules despite any vacancy, provided that the quorum (noted in clause 6.3 of this Constitution) is met.

3.10 Each member is required to make him or herself reasonably available for all meetings. Members who have not been reasonably available for all meetings may be removed by the IMO under clause 4.6 of th~~e~~ise Constitution. Proxies sent by ~~Compulsory~~compulsory class members count towards attendance by the ~~Compulsory~~compulsory class member. Proxies sent by d~~D~~iscretionary class members do not count towards attendance by the d~~D~~iscretionary class members.

3.11 Each member and observer is required to:

a) be prepared for all Market Advisory Committee meetings, to read the papers and to actively contribute to ~~the~~ discussions; and

b) not use their position or information gained as a member or observer improperly to gain an advantage for themself or anyone else, or cause detriment to the IMO or the market;

3.12 Each member and observer must pay their own expenses associated with participating in the Market Advisory Committee.

3.13 At the discretion of the Chairperson, other persons may be allowed to attend Market Advisory Committee meetings as observers from time to time.

4. Appointing and Rotating M~~m~~embers

4.1. The IMO may appoint members and terminate membership of the Market Advisory Committee~~,~~ in accordance with the clause 2.3.11 of the Market Rules, ~~this~~ section 4 of this Constitution and ~~Appendix 2 of this Constitution~~the Market Advisory Committee Appointment Guidelines published by the IMO.

4.2. The IMO will advertise for nominations for~~to~~ the Market Advisory Committee on ~~its public website~~the Market Web Site in writing to all Rule Participants and via direct contact with appropriate industry groups. Any company or individual can make nominations.

4.3. An individual may be nominated Market Advisory Committee for as many categories relevant to the entity ~~to which~~ they ~~belong~~represent and for which the nominee meets the eligibility criteria.

INDEPENDENT MARKET OPERATOR

4.4. ~~4.2~~ For the calendar year beginning on 1 January 2010 Market Advisory Committee members will be appointed for a one or two-year term as determined by a ballot conducted by the IMO in accordance with the Market Advisory Committee Appointment Guidelines.

4.5. ~~4.3~~ Thereafter, each member will be appointed for a two-year term, subject to any earlier termination.

There are no restrictions on the number of times a member can be reappointed to the Market Advisory Committee.

4.6.

4.7. ~~4.4~~ With the exception of the IMO and Western Power[5], there may not be more than one individual from the same employing organisation on the Market Advisory Committee at any one time.

4.8. ~~4.5~~When appointing and removing members of the Market Advisory Committee, the IMO will consult with, and take nominations from, Rule Participants and industry groups, that it considers relevant to the Wholesale Electricity Market. If practicable, and taking into account the requirements of the Market Rules regarding the Market Advisory Committee composition, the IMO will choose members from among those persons nominated. Further details of the nomination process are provided in the Market Advisory Committee Appointment Guidelines.

4.9. Each year the IMO will review the performance and attendance of all Market Advisory Committee members. Following the review the IMO may terminate the membership of, or decide to not reappoint any member~~s~~ that it considers have not met the requirements of members as set out in thi~~se~~s Constitution or the Market Advisory Committee Appointment Guidelines, and may appoint a replacement member~~s~~.

4.10. ~~4.6~~ The IMO may also remove a member of the Market Advisory Committee at any time in the circumstances described in ~~Appendix 2~~clause 2.3.11 of the Market Rules.

~~4.7 There are no restrictions on the number of times a member can be reappointed to the Market Advisory Committee.~~

4.11. ~~4.8~~ A member of the Market Advisory Committee may resign by giving notice to the IMO in writing. As soon as practicable, t~~T~~he IMO will appoint a replacement member for the duration of the previous member's remaining length of tenure.

~~4.9~~ When a position on the Market Advisory Committee is vacant at any time, for any reason, the IMO will use its reasonable endeavours to appoint

[5] Noting that System Management is a ring-fenced entity within Western Power~~Reflecting the operation of the ring fencing provisions between System Management and Western Power the Network Operator for market purposes.~~

a suitable person to fill the position. For ~~Compulsory~~compulsory class members, the IMO will request a suitably qualified replacement nominee is provided to attend meetings, and for discretionary class members, the IMO will appoint a suitable representative~~consistent~~ in accordance with the requirements of the Market Rules and ~~with~~ the Market Advisory Committee Appointment Guidelines.

~~4.10 When appointing and removing members of the Market Advisory Committee, the IMO will consult with, and take nominations from, Rule Participants and industry groups, that it considers relevant to the Wholesale Electricity Market. If practicable, and taking into account the requirements of the Market Rules regarding the Market Advisory Committee composition, the IMO will choose members from among those persons nominated. Further details of the nomination process are provided in the Market Advisory Committee Appointment Guidelines.~~

~~4.11 The IMO will advertise for nominations to the Market Advisory Committee on its public website and via direct contact with appropriate industry groups. Any company or individual can make nominations.~~

4.12.

~~4.12 An individual may be nominated Market Advisory Committee for as many categories relevant to the entity to which they belong and for which the nominee meets the eligibility criteria.~~

5 Convening the Market Advisory Committee

5.1. The IMO will convene the Market Advisory Committee ~~will be convened~~:

a) in relation to a Rule Change Proposal or Procedure Change Proposal where the IMO considers that advice is required from the Market Advisory Committee, in which case the meeting will be called before the due date for submissions on the proposed changes;

b) in relation to a Rule Change Proposal or Procedure Change Proposal where two or more members of the Market Advisory Committee have informed the ~~Secretariat~~ IMO in writing that they consider that advice is required from the Market Advisory Committee;

c) not less than once every six months;

d) on any occasion when two or more members of the Market Advisory Committee have informed the ~~secretariat~~ IMO in writing that they wish to bring a matter ~~regarding market operation, the evolution of the Market Rules or the operation of the Market Rules~~ before the Market Advisory Committee for discussion; and

e) where possible, consistent with the provisional schedule of Market Advisory Committee meetings~~,~~ issued annually by the IMO.

6 Conduct of Meetings

6.1. The Chairperson may determine procedures for meetings of the Market Advisory Committee.

6.2. The Market Advisory Committee may make recommendations on an issue if a consensus is achieved. Any recommendations made by the Market Advisory Committee must be based on the consensus decision of members, excluding the opinion of observers.

6.3. Unless a quorum of members is present at the time, no recommendations will be made. A quorum requires 50~~fifty~~ percent of total current members to be present at the meeting, including at least one member representat~~ive~~ing ~~from each of the~~ Market Generators~~s~~ and one member representing ~~the~~ Market Customers~~s class~~ in that quorum.

6.4. The Chairperson may, in relation to any matter under consideration in the Market Advisory Committee, require all members and observers to treat the matter as confidential until advised otherwise. All members and observers must comply with that requirement.

6.5. Meetings of the Market Advisory Committee may be called or held using any technology determined by the Chairperson and at a location nominated by the Chairperson.

6.6. A communication between Market Advisory Committee members constituting a quorum under clause 6.3 of this Constitution by telephone or audiovisual means is a valid meeting of the Market Advisory Committee, but only if each participating member or observer is capable of communicating with every other member or observer instantaneously at all times during the meetings.

6.7. The Chairperson may, at his or her discretion, approve late papers for a Market Advisory Committee meeting.

~~6.7.~~

7 Role of the Market Advisory Committee Secretariat

7.1. The IMO will provide~~ the~~ s~~S~~ecretariat services ~~for~~to the Market Advisory Committee.

7.2. As the secretariat for the Market Advisory Committee, ~~T~~the ~~Secretariat~~IMO will:

a) develop and issue a provisional schedule of meetings annually and maintain the diary of the Market Advisory Committee;

b) compile the meeting papers and send them by email to all members and observers of the Market Advisory Committee ~~at least five days before each meeting~~and publish the papers on the ~~public website~~Market Web Site. The ~~Secretariat~~IMO will endeavour to issue papers to all members and observers, at least five ~~b~~Business ~~d~~Days before each meeting (subject to any approved late papers in accordance with clause 6.7 of this Constitution);

c) prepare the minutes of each M~~m~~arket Advisory Committee meeting and send them by email to all members and observers of the Market Advisory Committee ~~within ten Business Days of~~ as soon as practicable~~,~~ after the meeting; and

d) subject to the confidentiality status of the matters in meeting minutes (in accordance with clause 10.2 of the Market Rules), publish the minutes on the ~~IMO~~ Market Web Site~~public website~~.

8 Interaction between the Market Advisory Committee and the IMO

8.1. All written communications related to the activities of the Market Advisory Committee from the members and observers of the Market Advisory Committee ~~to the IMO~~ will be sent to the secretariat ~~the Secretariat~~.

8.2. Communications between the members and observers of the Market Advisory Committee and the IMO will be via email to market.development@imowa.com.au wherever practical.

8.3. ~~Subject to clause 10.2.4 of the Market Rules, t~~The IMO will provide the members and observers of the Market Advisory Committee with information in its possession that is directly relevant to the issues being addressed (subject to clause 10.2.4 of the Market Rules) ~~by the Market Advisory Committee~~.

8.4. ~~In accordance with clauses 2.7.4 and 2.10.8 of the Market Rules, W~~W~~w~~ithin one Business Day after the publication of a notice of a Rule Change Proposal or Procedure Change Proposal the IMO will notify the members and observers of the Market Advisory Committee (in accordance with clauses 2.7.4 and 2.10.8 of the Market Rules)~~,~~ via email, as to whether the IMO considers that advice on the proposal is required from the Market Advisory Committee and the reasons why.

8.5. The IMO will include in its Rule Change Reports (in accordance with clauses 2.7.7 and 2.7.8 of the Market Rules) a summary of the views expressed by the members of the Market Advisory Committee, where the Market Advisory Committee has met to consider a Rule Change Proposal, or where a Working Group has been appointed by the Market Advisory Committee to consider a Rule Change Proposal, a summary of the views expressed by that Working Group.

8.6. The IMO will include in its Procedure Change Reports (in accordance with clause 2.10.13 of the Market Rules) a summary of the views expressed by the members of the Market Advisory Committee, where the Market Advisory Committee has met to consider a Procedure Change Proposal, or where a Working Group has been appointed by the Market Advisory Committee to consider a Procedure Change Proposal, a summary of the views expressed by that Working Group.

9 Governance Arrangements ~~b~~Between the Market Advisory Committee and ~~d~~Delegated Working Groups

9.1 ~~In accordance with clause 2.3.17 of the Market Rules, t~~The Market Advisory Committee may establish W~~w~~orking G~~g~~roups made up of representatives from member groups to assist the Market Advisory Committee in dealing with any matter (in accordance with~~as described in~~ clause 2.3.1 of the Market Rules). The Market Advisory Committee may establish or disband any ~~w~~Working ~~g~~Group at any time.

~~9.1 delegate its role of advising the IMO, and System Management in the case of Procedure Change Proposals, described in clause 2.3.1 of the Market Rules to a Working Group. The IMO's ability to establish and disband Working Groups comprised of Representatives of Rule Participants and other interested stakeholders is provided under clause 2.3.17 of the Market Rules.~~

9.2 The Market Advisory Committee must determine the scope of work and t~~T~~erms of ~~R~~reference for each WW~~orking~~ GG~~roup~~. The Market Advisory Committee may approve any amendments to the Terms of Reference or membership of any w~~W~~orking ~~G~~group at any time.

9.3 The t~~T~~erms of ~~R~~reference for a Working Group, will be tailored to the specific requirements of each Working Group and would typically include the:

a) background (reason for the establishment of the Working Group);

b) purpose and scope of work of the Working Group;

c) roles and responsibilities -of members of the Working Group;

d) membership of the Working Group;

e) administration, s~~S~~ecretariat and meeting arrangements for the Working Group; and

f) reporting arrangements to the Market Advisory Committee.

9.4 Working G~~G~~roups must report back to the Market Advisory Committee at least once every two months or as specified in the t~~T~~erms of ~~R~~reference for the W~~w~~orking ~~g~~Group. ~~Routine r~~Reporting will be via the Working Group secretariat. The Working Group will report to the Market Advisory Committee at other ~~milestones agreed with the Market Advisory Committee~~ times requested by the Market Advisory Committee. Day-to-day interaction between the Market Advisory Committee and the Working Groups~~s~~ will be via the IMO.

9.5 Working Groups must refer issues outside the scope of the Working Group's t~~T~~erms of r~~R~~eference back to the Market Advisory Committee for consideration.

[~~16 November 2010~~~~February~~March 2014]

Appendix 1. ~~The~~ Wholesale Market Objectives

The Wholesale ~~m~~Market ~~o~~Objectives, as outlined in section 122 of the *Electricity Industry Act 2004* and clause 1.2.1 of the Market Rules 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.

Appendix 2. Removal of Members

The occurrence of any of the following events will entitle the IMO to remove~~terminate~~ a ~~member's membership~~member of ~~on~~ the Market Advisory Committee (in accordance with clause 2.3.11 of the Market Rules):

a) the person becomes an undischarged bankrupt; or

b) the person becomes of unsound mind or his or her estate is liable to be dealt with in any way under law relating to mental health; or

c) in the IMO's reasonable opinion the person no longer represents the person or class of persons that they were appointed to represent in accordance with clause 2.3.5 of the Market Rules; or

d) the person is not actively participating in the Market Advisory Committee; or

e) the person breaches any part of this constitution of the Market Advisory Committee.

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MARKET ADVISORY COMMITTEE APPOINTMENT GUIDELINES

~~November 2013~~

1. Scope and P~~p~~urpose

1.1 The purpose of these guidelines is to provide transparency as to the process to be followed for the appointment of members to the Market Advisory Committee (~~the~~ MAC). They have been developed to inform industry groups, Rule Participants and ~~their respective~~ nominees of the selection and appointment processes applied by the ~~Independent Market Operator (~~IMO~~)~~.

1.2 These guidelines set out the details of:

a) the background to the MAC;

b) the requisite skills, knowledge and experience of MAC members;

c) the requirements for representation of MAC members;

d) the terms of appointment for MAC members;

e) the steps involved in the appointment process; and

f) any other matters that the IMO considers will contribute to good governance and the effective operation of the MAC.

1.3 The IMO seeks a balanced representation and a diverse mix of knowledge and experience among members of the MAC. These guidelines set out how the IMO aims to achieve this.

2. Related D~~d~~ocuments

2.1 This document has been developed in accordance with, and should be read in conjunction with the following:

a) clauses 2.3.1 to 2.3.17 of the Wholesale Electricity Market Rules (Market Rules); and

b) the MAC Constitution.

3. Background to the Market Advisory Committee

3.1 The MAC is established pursuant to section 2.3 of the Market Rules. The MAC is a committee of industry representatives convened by the IMO:

a) to advise the IMO regarding Rule Change Proposals;

b) to advise the IMO and System Management regarding Procedure Change Proposals;

c) to advise the IMO regarding market operation and South West interconnected system operation matters; and

d) to advise the IMO regarding matters concerning the evolution of the Market Rules.

3.2 In accordance with clause 2.3.5 of the Market Rules, the MAC must comprise~~ of~~:

a) at least three and not more than four members representing Market Generators~~, of whom one will represent Verve Energy~~;

b) one member representing Contestable Customers;

c) at least one and not more than two members representing Network Operators, of whom one will represent Western Power[1];

d) at least three and not more than four members representing Market Customers~~, of whom one will represent Synergy~~;

e) one member nominated by the Minister to represent small-use consumers;

f) one member representing System Management;

g) one member representing the IMO;

~~g)~~h) one member representing Synergy; and

~~h)~~i) a Chairperson, who will be a representative of the IMO.

The Minister and the Economic Regulation Authority (ERA) may also each appoint a representative to attend MAC meetings as an observer~~s~~, as outlined in clauses 2.3.6 and 2.3.7 of the Market Rules.

3.3 The MAC is an advisory committee and does not vote on issues. The MAC may make recommendations to the IMO if a consensus is achieved. Any recommendations made by the MAC are based on the consensus decision of members, excluding the opinion of

[1] Excluding System Management~~,~~ which~~e~~ operates as a ring-fenced entity for market purposes.

observers. ~~However, for the avoidance of doubt, o~~Observers on the MAC otherwise have full speaking rights.

3.4 The MAC must have regard to the Wholesale Market Objectives in carrying out its functions.

4. Skills, K~~k~~nowledge and ~~e~~Experience of M~~m~~embers

4.1 The applicants for appointment to the MAC should collectively possess the skills, knowledge and experience specified in clause 4.2 ~~below~~of these guidelines. The IMO's ~~assessment~~ appointment process will ensure that there is balanced representation of skills knowledge and experience across the MAC.

4.2 The IMO will take into account, but is not limited to, the following expected skills, knowledge and experience of the MAC (as a ~~body~~whole) when making appointment decisions:

a) knowledge and/or demonstrated experience relating to energy sector issues;

b) broad understanding of the technical, design and commercial aspects of the WEM;

c) ability to contribute to the MAC, including;

  i. ability to work as a member of a small team;

  ii. ability to assess proposed rule and procedure changes against the Wholesale Market Objectives;

  iii. ability to understand the subject matter in proposals made to the MAC; and

  iv. ability to consider market design issues and options for the evolution of the Market Rules;

d) u~~U~~nderstanding of the Market Rules and other relevant legislation including the Electricity Industry Act 2004, Electricity Industry (Wholesale Electricity Market) Regulations, Metering Code, ~~and~~ Access Code and Technical Rules along with other relevant regulatory instruments; and

e) k~~K~~nowledge of the powers and obligations of both the IMO and System Management and the frameworks in which they operate.

4.3 Applicants are not required to be full time employees of an entity that is a participant in the class which membership is being sought.

5. Representation of MAC ~~m~~Members

5.1 MAC members are required to act in the best interests of the Wholesale Electricity Market.

5.2 Compulsory c~~C~~lass members are individuals who represent a single entity. During their inaugural appointment c~~C~~ompulsory c~~C~~lass members must demonstrate their eligibility against the criteria for membership and necessary skills, knowledge and experience. During ~~subsequent~~ subsequent annual reviews, details of updates to c~~C~~ompulsory c~~C~~lass members' skills, knowledge and experience will be required to be provided to the IMO, where substantive changes have occurred. This is to allow the IMO to consider the skills and experience of the c~~C~~ompulsory c~~C~~lass members when making discretionary appointment decisions to ensure that the combined skills and experience of the MAC is ~~a well-rounded~~well balanced ~~committee~~.

5.3 Discretionary c~~C~~lass members are individuals that represent a class of participants but are not c~~C~~ompulsory c~~C~~lass members. Discretionary c~~C~~lass members are expected to act in a way that properly reflects the interests of the group that they have been chosen to represent i.e. Market Generators, Market Customers or Contestable Customers. Discretionary ~~C~~class members must demonstrate their eligibility against the criteria for membership and necessary skills, knowledge and experience.

6. Term of A~~a~~ppointment

6.1 Membership on the MAC for the 2010 year for both d~~D~~iscretionary and c~~C~~ompulsory class members will be for either one or two years with the opportunity for reappointment after this time period has lapsed.

6.2 For the calendar year beginning 1 January 2010, the term of membership will be determined by the IMO conducting a ballot. Half of the then current members will be appointed for one year and the remainder will be appointed for a two-year term. The ballot will be designed so that no particular class of membership will be completely rotated out in a single year. For example all Market Generator representatives would not be up for renewal in a single year. Members chosen by ballot for a one year term will be eligible for reappointment to an additional two~~-~~-year term if they meet the appointment criteria at the time.

6.3 Thereafter, the term of appointment of d~~D~~iscretionary c~~C~~lass members will be two years. This is to ensure consistency in decision making and that all sections of the industry are adequately represented as the market matures.

6.4 Compulsory c~~C~~lass membership, after inaugural membership has expired, is for two years to ensure consistency of representation. At the lapse of tenure, c~~C~~ompulsory ~~C~~class members will be able to reconfirm their nominated individual representative to serve on the MAC.

6.5 The IMO may appoint new members into c~~C~~ompulsory and d~~D~~iscretionary c~~C~~lass positions, if necessary, when members are no longer representative of the class. This includes situations where the member's employment changes to being employed by an

INDEPENDENT MARKET OPERATOR

entity outside of the member's class of representation or upon occurrence of any of the events listed clause 2.3.11 of the Market Rules.

6.6 There are no restrictions on the number of times a member can be reappointed to the MAC, but in making appointments the IMO's objective is to get the best representation of the industry over time to ensure a dynamic MAC that is representative of the market.

6.7 MAC members will be reappointed based on the IMO's assessment of individuals against the appointment criteria outlined in section 4 of this guideline to ensure that they conform to the requirements and are representative of their class.

7. The N~~n~~ominations and A~~a~~ppointment P~~p~~rocess

7.1 Each year the IMO will review the performance and attendance of MAC members. If any changes are required these will be addressed at the same time the IMO commences the annual appointment process for ~~D~~discretionary and ~~C~~compulsory Class members whose tenure has lapsed.

7.2 On completion of the annual review the IMO will:

a) ~~a.~~ for ~~D~~discretionary c~~C~~lass members whose tenure has lapsed, seek nominations from industry groups and Rule Participants with respect to the position (i.e. Market Customer or Market Generator representative). Industry consultation includes, but is not limited to:

i. ~~i.~~ Chamber of Commerce and Industry of Western Australia;

ii. ~~ii.~~ Chamber of Minerals and Energy of Western Australia; and

iii. ~~iii.~~ Western Australian Sustainable Energy Association; and

b) ~~b.~~ for c~~C~~ompulsory c~~C~~lass members whose tenure has lapsed, seek reconfirmation from a senior executive of the applicable entity that the member will continue to represent that entity. An updated resume must be provided where the individual's skills, knowledge or experience have changed since the last review. Reconfirmation may be provided to the IMO via email to~~:~~ market.development@imowa.com.au.

~~.~~

7.3 The IMO will advertise for nominations for d~~D~~iscretionary c~~C~~lass positions on ~~its public website~~the Market Web Site and via direct contact with appropriate industry groups. The IMO will also send an email notification to ~~people~~stakeholders and ~~/~~entities on its market advisory mailing list maintained by the Market Development team.

7.4 Any company or individual can~~ make~~ nominat~~ions~~e themself or someone else. Nominations must:

a) be in writing;

b) address the eligibility criteria for appointment to the MAC as set out in the Market~~-~~ Rules, MAC Constitution and these~~is~~ ~~document~~guidelines;

c) have attached a completed MAC application form, available on the ~~IMO webpage~~~~public website~~Market Web Site, outlining the skills set of applicants with respect to the class(es) of nomination;

d) include contact details of the nominee (to demonstrate evidence of the persons willingness for appointment); and

e) be received by the IMO by the published due date.

7.5 Nominee details provided to the IMO will be kept private. A high-level assessment of all the nominees against the appointment criteria may be made ~~publically ~~available by the IMO if requested by an interested party.

7.6 An individual may be nominated for as many categories relevant to the entity to which they belong and for which the nominee meets the eligibility criteria. For example an entity which is both a Market Generator and Market Customer may nominate individuals for both of these categories.

7.7 With the exception of the IMO and Western Power[2], the IMO can only appoint one individual from any one entity to serve on the MAC at any one time.

7.8 The IMO will consider nominations received, determine the appropriate composition of the MAC (taking into account the skills, experience and knowledge of any existing or reconfirmed ~~Compulsory ~~compulsory c~~C~~lass members and o~~O~~bservers appointed by the Minister or Economic Regulation Authority), and finalise appointment arrangements by March of every year, using the following assessment steps:

Step	Event	Date
1	IMO assess the positions up for renewal.	Before November MAC meeting.
2	IMO inform the MAC that the annual review is about to commence.	November MAC meeting.
3	IMO prepare a call for nominations for the available d~~D~~iscretionary c~~C~~lass membership positions and seek reconfirmation from c~~C~~ompulsory c~~C~~lass entities of their members.	End of November, closing late December.

[2] Noting that System Management is a ring-fenced entity within Western Power.

INDEPENDENT MARKET OPERATOR

Step	Event	Date
4	IMO establish an internal evaluation panel (comprising members from across the organisation[3]) to assess all nominations received and ensure a high standard of probity is maintained.	Before close of call for nominations.
5	IMO prepare an Evaluation Panel handbook outlining what each panel member is required to do. This includes: • Assessment of the nominees against the pre-qualification[4] and compliance criteria[5]; • Assessment of the nominees against the qualitative criteria using the information provided in the response to the call for nominations[6]; and • Rating each nominee against the qualitative criteria using a pre-defined rating 0 – 9 point rating scale.	Before close of call for nominations.
6	Panel members assess each nominee in accordance with the Evaluation Panel handbook.	Following close of call for nominations and before the end of January.
7	Evaluation Panel meeting to determine a consensus score for each of the nominees.	
8	Evaluation Panel create a shortlist of candidates for each class based on the consensus qualitative ranking.	
9	To ensure an appropriate balance of skills and experience the Evaluation Panel will undertake the second stage assessment including reviewing the relevant qualifications, years of experience and backgrounds of nominees to determine the best possible composition for the MAC (taking into account the relevant skills and experiences of the compulsory members and appointed observers).	
10	Draft a recommendation report to present to the MAC Chair for review.	
11	Evaluation panel to reassess its recommendations (if required).	
12	Prepare a recommendation report to present to the IMO Board for its review and approval.	February Board meeting.
13	The IMO Board to decide the MAC membership. Following the Board's decision, inform the nominees of the outcome of the assessment process.	End of February.

[3] ~~The Evaluation Panel will contain members from the IMO. Please note,; the IMO member will not be a member of the Evaluation Panel due to the potential conflict of interest arising from the requirement for the panel to assess his application. Additionally, MAC Chair is not a member of the Evaluation Panel. This is to allow for a separate assessment step (as MAC Chair) and to ensure a rigorous process.~~

[4] ~~These are that the: Nnomination is lodged on time and confirmation that the nominee is an employee or consultant employed by thea Rule Participant.~~

[5] ~~These are that the: Nnomination form completed in full, contains the details of the class applying for, and meets the requirements to represent the class it has applied for.~~

[6] ~~Demonstrated knowledge and experience of energy sector issues (20%); Demonstrated understanding of technical, design and commercial aspects of the WEM (20%); Demonstrated ability to contribute actively to the MAC (40%); and Demonstrated understanding of the governance arrangements under which the IMO and System Management operate (20%).~~

Step	Event	Date
14	All MAC members (incoming and outgoing) to attend a handover MAC meeting.	March MAC meeting.

[March 2014]

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imo
INDEPENDENT
MARKET
OPERATOR

ABN 95 221 850 093
Level 17
197 St Georges Tce
Perth WA 6000
PO Box 7096
Cloister Square
Perth WA 6850
T 08 9254 4300
F 08 9254 4399

Our ref: MAD001
Enquiries: Kate Ryan
Phone 9254 4357

Greg Watkinson
Chief Executive Officer
Economic Regulation Authority
PO Box 8469
Perth Business Centre
PERTH WA 6849

Dear Greg,

REGULATION OF DEMAND SIDE MANAGEMENT AGGREGATORS

Since the commencement of the Wholesale Electricity Market (WEM), demand-side resources have become increasingly prominent providing capacity in the South West interconnected system.

In 2010, the IMO introduced Amending Rules[1] to distinguish between the role of a retailer and a Demand Side Management (DSM) aggregator, by creating a new type of Facility, Demand Side Programmes (DSPs). A DSM aggregator provides a portfolio of demand-side capacity, sourced from one or more industrial and commercial Loads but does not sell electricity to these customers.

As part of the introduction of DSPs in the WEM Rules (Market Rules), the IMO wrote to both the Economic Regulation Authority (ERA) and the Public Utilities Office (former Office of Energy) requesting consideration of the introduction of a licensing requirement for DSM aggregators in an effort to reduce the potential risk to its customers, including Small Use customers. The IMO notes that the ERA responded that it was a matter for the then Office of Energy and the Office of Energy responded that it was a matter for the ERA.

Since the introduction of DSPs, the IMO has undertaken significant analysis of the economic value of demand-side capacity. In August 2013, the IMO developed a Rule Change Proposal[2] to improve the alignment of the treatment of demand-side and supply-side capacity in the Market Rules. As part of the assessment of the Rule Change Proposal, Market Advisory Committee (MAC) members expressed their concerns and view that licensing requirements should be introduced for DSM aggregators.

1 For more information on the Rule Change Proposal see www.imowa.com.au/RC_2010_29

2 For more information on the Rule Change Proposal see www.imowa.com.au/RC_2013_10

imo@imowa.com.au www.imowa.com.au

As such, I have again been asked to request that the Public Utilities Office, as the administrator of the governing legislation, and the ERA, as the administrator of the licensing regime, consider amendments to the Electricity Industry Act and its subordinate legislation to align the regulatory obligations of DSM providers to that of similar entities (i.e. retailers) to the extent possible.

If you have any queries please do not hesitate to contact me on 08 9254 4333.

Yours sincerely

ALLAN DAWSON
MARKET ADVISORY COMMITTEE CHAIR

10 December 2013

c.c. Mr Ray Challen, Public Utilities Office

imo@imowa.com.au www.imowa.com.au

Economic Regulation Authority

RECEIVED
18 FEB 2014
BY: Ohlu
14/0018

Your Ref: MAD001
Our Ref: D117641
Contact: Rasmus Moerch

Mr Allan Dawson
Market Advisory Committee Chair
Independent Market Operator
PO Box 7096
Cloister Square
PERTH WA 6850

Dear Allan

Regulation of Demand Side Management Aggregators

Thank you for your letter, dated 10 December 2013. You request that the Public Utilities Office (PUO) and the Economic Regulation Authority (Authority) consider amending the electricity licensing regime to introduce licence obligations for Demand Side Management aggregators similar to those for electricity retailers.

The Authority received a similar request from the Independent Market Operator 8 December 2010. As noted in our letter of 6 January 2011, the role of the Authority is to administer the licensing scheme under the *Electricity Industry Act 2004* (the Act). Amending the Act as proposed in your letter is a policy matter for Government.

I understand that the PUO has replied to your letter outlining the process that must be followed for amending the Act, including the importance of demonstrating the need for licensing Demand Side Management aggregators. I recommend that you provide the necessary supporting information to the PUO to assist the PUO in forming a view as to whether Demand Side Management aggregators should be licensed.

Should you wish to discuss this matter further, or require any further information, please contact Mr Rasmus Moerch, Assistant Director Licensing, on (08) 6557 7900.

Yours sincerely

G. P. Wat

GREG WATKINSON
CHIEF EXECUTIVE OFFICER

14/2/14

Level 4, Albert Facey House
469-489 Wellington Street
Perth Western Australia 6000

PO Box 8469
Perth Business Centre
Western Australia 6849

Telephone 61 8 6557 7900
Email records@erawa.com.au
Website www.erawa.com.au

imo
INDEPENDENT
MARKET
OPERATOR

ABN 95 221 850 093
Level 17
197 St Georges Tce
Perth WA 6000
PO Box 7096
Cloister Square
Perth WA 6850
T 08 9254 4300
F 08 9254 4399

Our ref: MAD001
Enquiries: Kate Ryan
Phone 9254 4357

Ray Challen
Deputy Director General of the Department of Finance
Public Utilities Office
Locked Bag 11
Cloisters Square
PERTH WA 6850

Dear Ray,

REGULATION OF DEMAND SIDE MANAGEMENT AGGREGATORS

Since the commencement of the Wholesale Electricity Market (WEM), demand-side resources have become increasingly prominent providing capacity in the South West interconnected system.

In 2010, the IMO introduced Amending Rules[1] to distinguish between the role of a retailer and a Demand Side Management (DSM) aggregator, by creating a new type of Facility, Demand Side Programmes (DSPs). A DSM aggregator provides a portfolio of demand-side capacity, sourced from one or more industrial and commercial Loads but does not sell electricity to these customers.

As part of the introduction of DSPs in the WEM Rules (Market Rules), the IMO wrote to both the Public Utilities Office (former Office of Energy) and the Economic Regulation Authority (ERA) requesting consideration of the introduction of a licensing requirement for DSM aggregators in an effort to reduce the potential risk to its customers, including Small Use customers. The IMO notes that the Office of Energy responded that it was a matter for the ERA and the ERA responded that it was a matter for the then Office of Energy.

Since the introduction of DSPs, the IMO has undertaken significant analysis of the economic value of demand-side capacity. In August 2013, the IMO developed a Rule Change Proposal[2] to improve the alignment of the treatment of demand-side and supply-side capacity in the Market Rules. As part of the assessment of the Rule Change Proposal, Market Advisory Committee (MAC) members expressed their concerns and view that licensing requirements should be introduced for DSM aggregators.

1 For more information on the Rule Change Proposal see www.imowa.com.au/RC_2010_29

2 For more information on the Rule Change Proposal see www.imowa.com.au/RC_2013_10

imo@imowa.com.au www.imowa.com.au

As such, I have again been asked to request that the Public Utilities Office, as the administrator of the governing legislation, and the ERA, as the administrator of the licensing regime, consider amendments to the Electricity Industry Act and its subordinate legislation to align the regulatory obligations of DSM providers to that of similar entities (i.e. retailers) to the extent possible.

If you have any queries please do not hesitate to contact me on 08 9254 4333.

Yours sincerely

ALLAN DAWSON
MARKET ADVISORY COMMITTEE CHAIR

10 December 2013

c.c. Mr Greg Watkinson, Economic Regulation Authority

imo@imowa.com.au www.imowa.com.au

Government of **Western Australia**
Department of **Finance**

RECEIVED
13 FEB 2014
BY: Chloe
14/0016

Your ref : MAD001
Our ref : 2012/08055
Enquiries : Natalia Kostecki
Telephone : 6551 4649

Mr Allan Dawson
Chief Executive Officer
Independent Market Operator
PO Box 7096
Cloisters Square
PERTH WA 6850

Dear Allan

MANAGEMENT OF DEMAND SIDE MANAGEMENT AGGREGATORS

Thank you for your letter of 10 December 2013, outlining a request by the Market Advisory Committee (MAC) for the Public Utilities Office to consider the licensing of Demand Side Management (DSM) aggregators.

As you have indicated, amendments would need to be made to the *Electricity Industry Act 2004* to provide for the licensing of Demand Side Management (DSM) aggregators. Consequential amendments to subsidiary regulations and codes may also need to be made.

A strong prima facie case for licensing of DSM aggregators would need to be demonstrated for the Public Utilities Office to recommend to the Minister that amendments to the Act and subsidiary legislation are necessary, and for the Office to then engage in the process of legislative change.

This prima facie case has not been established. For the Public Utilities Office to consider MAC's proposal further, detailed information would be required in regard to the following:

- The role and services provided by DSM aggregators to businesses and the market.
- What problems the licensing of DSM aggregator is intended to address, and how this will be addressed through the proposal.
- Whether this can be achieved through alternative measures.
- The expected costs/benefits of the proposal.
- Whether the costs of compliance will outweigh expected benefits.

Locked Bag 11 Cloisters Square WA 6850
Level 1, Albert Facey House, 469 Wellington Street, Perth WA 6000
Telephone (08) 6551 1000 Facsimile (08) 6551 1111
www.finance.wa.gov.au

Ultimately, the Government must agree to any proposal by the Minister to introduce a Bill into Parliament, including Act amendments. The priority list for introducing legislation is at the Government's discretion.

Yours sincerely

Ray Challen
DEPUTY DIRECTOR GENERAL
PUBLIC UTILITIES OFFICE

3 February 2014

cc. Mr Greg Watkinson, Economic Regulation Authority