AGENDA.

MEETING TITLE.	Market Advisory Committee
MEETING NO.	77
DATE.	Wednesday 3 December 2014
TIME.	2:00 PM – 5:00 PM
LOCATION.	IMO Board Room, Level 17, 197 St Georges Terrace, Perth

Item	Responsibility	Duration
1. Welcome	Chair	2 min
2. Meeting apologies/attendance	Chair	2 min
3. Minutes of previous meeting	Chair	5 min
4. Actions arising	Chair	10 min
5. IMO website and Data Visualisations (presentation)	IMO	15 min
6. Concept papers		
6.1 Managing Market Information (RC_2014_09)	IMO	20 min
7. Rule Change Proposals		
7.1 Overview	IMO	5 min
7.2 Pre Rule Change Proposal: Removal of Resource Plans and Dispatchable Loads (RC_2014_06)	IMO	15 min
7.3 Pre Rule Change Proposal: Omnibus Rule Change (RC_2014_07)	IMO	5 min
7.4 Pre Rule Change Proposal: Provision of Network Information to System Management (RC_2014_10)	IMO	15 min
8. Discussions and Presentations		
8.1 Development of a Constrained Grid	Western Power	20 min
8.2 LFAS investigation update (presentation)	IMO	20 min
8.3 2014 Market Audit (presentation)	IMO	10 min
8.4 Market Rules Evolution Plan update	IMO	10 min
9. Market Procedures		
9.1 Overview	IMO	5 min
10. Working Groups		

10.1 Overview and membership updates	IMO	2 min
11. General Business	IMO	
11.1 2014 Year in Review	IMO	5 min
11.2 Proposed MAC meeting dates for 2015	IMO	2 min
12. Next meeting: 12 February 2015		

Please note this meeting will be recorded to assist with the preparation of minutes.

INDEPENDENT MARKET OPERATOR

Market Advisory Committee

Minutes

Meeting No.	75
Location	IMO Board Room Level 17, 197 St Georges Terrace, Perth
Date	Wednesday 24 September 2014
Time	2:00 PM – 4:00 PM

Attendees	Class	Comment
Allan Dawson	Chair	
Kate Ryan	Compulsory – IMO	
Dean Sharafi	Compulsory – System Management	
Jacinda Papps	Compulsory – Synergy	Proxy
Matthew Fairclough	Compulsory – Western Power	Proxy
Shane Cremin	Discretionary – Generator	
Andrew Stevens	Discretionary – Generator	
Andrew Sutherland	Discretionary – Generator	
Michael Zammit	Discretionary – Customer	
Steve Gould	Discretionary – Customer	
Geoff Gaston	Discretionary – Customer	
Peter Huxtable	Discretionary – Contestable Customer Representative	
Simon Middleton	Minister's Appointee – Observer	(2:15 PM – 4:00 PM)
Elizabeth Walters	Economic Regulation Authority (ERA) – Observer	
Apologies	**From**	**Comment**
Will Bargmann	Compulsory – Synergy	
Shane Duryea	Compulsory – Western Power	
Also in attendance	**From**	**Comment**
Mike Davidson	System Management	Observer
Paul Hynch	Public Utilities Office (PUO)	Observer
Chris Campbell	Alinta Energy	Observer
Anders Sangkuhl	Alinta Energy	Observer

Jo Garland	Holman Fenwick Willan	Observer (3:00 PM – 3:30 PM)
Richard Wilson	EnerNOC	Observer
Jenny Laidlaw	IMO	Observer
Greg Ruthven	IMO	Observer
Erin Stone	IMO	Presenter
Bryn Garrod	IMO	Presenter
Neil Hay	System Management	Presenter (2:30 PM – 4:00 PM)
Aditi Varma	IMO	Observer and Minutes

Item	Subject	Action
1.	**WELCOME** The Chair opened the meeting at 2:00 PM and welcomed members to the 75th meeting of the Market Advisory Committee (MAC).	
2.	**MEETING APOLOGIES / ATTENDANCE** The following **apologies** were received: • Will Bargmann (Compulsory – Synergy) • Shane Duryea (Compulsory – Western Power) The following **proxies** were noted: • Jacinda Papps for Will Bargmann (Compulsory – Synergy) • Matthew Fairclough for Shane Duryea (Compulsory – Western Power) The following **presenters** and **observers** were noted: • Mike Davidson (Observer – System Management) • Paul Hynch (Observer – PUO) • Chris Campbell (Observer – Alinta Energy) • Anders Sangkuhl (Observer – Alinta Energy) • Jo Garland (Observer – Holman Fenwick Willan) • Richard Wilson (Observer – EnerNOC) • Jenny Laidlaw (Observer – IMO) • Greg Ruthven (Observer – IMO) • Erin Stone (Presenter – IMO) • Bryn Garrod (Presenter – IMO) • Neil Hay (Presenter – System Management) • Aditi Varma (Observer and Minutes – IMO)	
3.	**MINUTES OF PREVIOUS MEETING** The minutes of MAC Meeting No. 74, held on 13 August 2014, were circulated to members prior to the meeting. The minutes were accepted as a true record of the meeting. *Action Points:* • *The IMO to publish the minutes of Meeting No. 74 on the Market Web Site as final.*	**IMO**

4.	**ACTIONS ARISING** The Chair invited Ms Kate Ryan to update the MAC on the current action items. The following points were noted: • **Item 18:** Ms Ryan noted that Western Power had advised that the public liability insurance requirements are specified in the Electricity Transfer Access Contract (ETAC) and that the ERA had approved the insurance value of $50 million in the ETAC for the third Access Arrangement. Ms Ryan also noted that Western Power negotiates individually with consumers on the terms of their contracts. Mr Matthew Fairclough added that he expected that $50 million would be the insurance value applied in most ETACs. Ms Elizabeth Walters noted that this value would have been approved by the ERA to be a standard. Ms Ryan clarified that the context behind the significance of the insurance value was that it was used to determine insurance costs which are a component of the Maximum Reserve Capacity Price (MRCP). In response to a question from the Chair, Mr Fairclough suggested that $50 million was an average level. Mr Andrew Sutherland asked if the IMO could investigate whether different levels of insurance costs have a material impact on premiums which may consequently affect the MRCP. He concurred with the Chair that once the initial insurance cost is covered, further increments are likely to be minimal. The Chair agreed that the IMO would investigate an appropriate cost range and conduct analysis of the effect of different levels of public liability insurance value on the MRCP. • **Item 20:** Ms Ryan noted that the transformer from Merredin was expected to be commissioned that week and that the IMO expected to be updated by Western Power shortly after this occurs. • **Item 29:** Ms Ryan noted that System Management had provided paper that had been circulated to MAC members. No MAC member raised any further questions. • **Item 32:** Ms Ryan noted that the Rule Change Proposal: Administrative Improvements to the Outage Process (RC_2014_03) was expected to be submitted into the formal process shortly. • **Item 37:** Ms Ryan noted that assessing the accuracy of Provisional and Final Balancing Prices remained an open action item. • **Item 38:** Ms Ryan noted that the feedback received from MAC members indicated support for moving the STEM Submission window by one hour but not the Bilateral Submission window. The IMO would progress the Rule Change Proposal on that basis. In response to a query from Ms Jacinda Papps, the Chair noted that this proposal involved administrative changes only and would therefore be progressed shortly. • **Item 40:** Ms Ryan noted that this item would be covered under agenda item 7c. • **Item 42 and 43:** Ms Ryan noted that the Rule Change Proposal: Reduced Frequency of Determining the Energy Price Limits and Maximum Reserve Capacity Price (RC_2014_05) would be progressed shortly on the basis that no significant issues were identified with quarterly indexation of the price limits and this could be	

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	further considered during the consultation periods if required. *Action Point:* • *With regard to action item 18, the IMO to conduct analysis of the effect of different levels of public liability insurance value on the MRCP and present results at an upcoming MAC meeting.*	**IMO**
5.	**CP_2014_08: ANNUAL APPROVAL OF FACILITY COSTS TO STREAMLINE ANCILLARY SERVICE PROCUREMENT** The Chair introduced Ms Erin Stone to provide an overview of the changes made to the concept paper following the last meeting. The following key points were discussed: • Mr Simon Middleton queried if participation by generators would be mandatory or voluntary. The Chair responded that all generators would need to participate to cater for the situation where only one Facility is able to provide the service (i.e. due to locational issues). • Mr Middleton questioned whether generators could submit their price for services more than once and if the submitted price would be binding. Ms Stone responded that the proposal was for an annual process under which generators could submit up to five tranches which would then be stacked in order of increasing prices, allowing System Management to dispatch cheapest Facilities first. • Ms Papps noted that Synergy would support an expedited procurement process but this proposal may not be the most feasible solution as it does not allow generators to take into account several variables that would affect their commercial decision-making to enter into such contracts. Mr Chris Campbell noted that the Short Run Marginal Cost (SRMC) for any Facility varies depending on a number of factors such as transport, prevalent fuel prices etc. and therefore the proposal creates uncertainty around cost recovery for generators. Ms Papps also noted that the proposed Australian Government Bond Yield may not be sufficient to cover the inherent variability in SRMC on the day of service provision. Ms Stone noted that the bond yield was intended to be a profit margin rather than a risk margin. • Ms Papps queried whether any advice could be provided on the difference between Dispatch Support Service and Network Control Service contracts. Ms Stone noted that the IMO had earlier provided advice to the Minister's Office, ERA and Western Power. Mr Andrew Stevens asked whether any feedback was provided. The Chair noted that it had not. Mr Middleton noted that the PUO's discussion paper touched on these issues but that it could be considered in more detail as part of the review into the Muja transformer failure. • Mr Geoff Gaston and Mr Sutherland noted their concerns that the proposal required generators to commit to firm service provision with no guarantee of cost recovery. The Chair noted that firm service provision was required even under the current scenario, for example, when a High Risk Operating State has been declared. Mr Gaston argued that this proposal would only shift the costs to another party and not solve the underlying problem. The Chair noted that the current compensation regime in the Balancing Market had not been developed	

to cover constraints lasting for more than a Trading Interval and therefore often did not cover a Facility's actual cost.

- Mr Stevens and Mr Sutherland noted that the difference between Dispatch Support Service and Network Control Service contract is not clear and therefore it is not clear what participants would be entering into. Mr Sutherland stated that the issue to be addressed is when Dispatch Support Service and Network Control Service should be used. In response, the Chair noted that the proposal recommended a trigger mechanism that would allow for System Management to start dispatching Facilities under this regime after five continuous days of Out of Merit generation.
- Mr Stevens suggested that other methods should also be considered. He noted that different kinds of services could be pre-defined and at the time it is required, generators could bid competitively to provide a particular pre-defined service. However, he acknowledged the problem of a localised shortfall where there may only be one generator (such as the current Muja transformer failure issue) would still exist.
- MAC members discussed how the costs associated with the risks of managing the network could be allocated to Western Power. Mr Middleton asked how the regulatory regime would work when the network contingency standards change. Mr Fairclough clarified that the network is built to the planning standards in the Technical Rules and the planning standard itself would not change when a failure of the network occurs. His understanding was that in the event of failures that exceed the planning standard, the regulatory regime would then require the market to address the problem. He further stated that if Western Power was required to bear the cost of these failures, it is likely that it would be incentivised to over-invest in the network or build in a risk margin.
- Mr Middleton questioned how the risk profile could not change when the N-1-1 contingency has been exceeded. Mr Fairclough noted that the risk of two transformers failing is a one-in-one-hundred-year event. The Chair observed that the risk profile would have changed after the first contingency event happened. Mr Sutherland also observed that the first transformer failure event should have triggered some remedial action from Western Power. Mr Shane Cremin and Mr Stevens echoed this opinion and noted that the costs of the current situation are not being placed on the parties that are best placed to manage those costs.
- Mr Sutherland noted that the proposal would introduce additional compliance burden for generators, in particular if there are civil penalties imposed. The Chair clarified that this was not the intent of the proposal. He added that it was appropriate for generators to recover their costs plus a modest margin for providing the service. However, he reiterated that the market would need protection for situations where market power could be exercised by a generator.
- Dr Steve Gould noted that in his opinion this proposal was too difficult to implement and would not produce much benefit. He added that participation in the proposed scheme was intended to benefit generators and therefore should be voluntary rather than compulsory.
- The Chair noted MAC members' request for clarity on Dispatch

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	Support and Network Control Services. He also noted that MAC members supported an expedited procurement process and the compensation should cover the cost plus a margin. The Chair further added that on behalf of the MAC, the IMO could request the PUO to provide a policy position on the differences between Dispatch Support Services and Network Control Services and when each should be used. He added that the IMO will canvass members' views at a later date to assess if this proposal should be progressed further. *Action Points:* • *The IMO to request the PUO on behalf of MAC members to provide a policy position on the difference between Dispatch Support Services and Network Control Services.* • *The IMO to canvass MAC members' feedback on the proposal to expedite Ancillary Services procurement processes at a later date to assess if it should be progressed further.*	**IMO** **IMO**
6a.	**MARKET RULE CHANGE OVERVIEW** Ms Ryan advised MAC members that the status of current Rule Change Proposals was provided in the MAC papers for their information. No questions or comments were raised.	
7a.	**IMO'S SUBMISSION TO THE ELECTRICITY MARKET REVIEW** The Chair noted that a copy of the IMO's submission to the Electricity Market Review had been provided to the MAC members in the meeting. Ms Papps asked Mr Middleton whether the timeframe for the next report was still the end of October. Mr Middleton confirmed that it was.	
7b.	**CARBON TAX – OPTIONS FOR PROVISIONS OF INFORMATION** The Chair invited Dr Bryn Garrod to present on this agenda item. Dr Garrod noted that the IMO had worked out two simple options for providing energy share information to Market Participants. The following points were discussed: • Mr Gaston questioned whether the information under the first option could be provided without any agreement. The Chair clarified that Market Participants could be provided their individual information without any permission. • Mr Gaston stated that the first option provided him enough information to work out his Facility's residual share of purchases in the market. Dr Gould also noted that that he was happy to be provided this information. • Mr Sutherland asked for clarification on what 'residual share' means. Dr Garrod confirmed that the residual share was an aggregate for the 18 days, of both STEM and Balancing Market purchases with the Net Bilateral Position netted off. • MAC members discussed how this information could be used by Market Participants to refund the carbon tax. • Ms Jo Garland noted that the ACCC's position on carbon tax refunds in wholesale electricity markets had not changed in that it continued to	

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	prove too difficult. • The Chair noted that the IMO would provide letters to individual Market Participants with their residual share and include definitions with respect to the figures provided. *Action Point:* • *The IMO to provide letters to individual Market Participants with their residual share and include definitions with respect to the figures provided.*	**IMO**
7c.	**REPLACEMENT OF SCADA VALUES – OVERVIEW OF METHODOLOGY** The Chair invited Mr Neil Hay to present on this agenda item. The following points were discussed: • Ms Jenny Laidlaw asked whether System Management's checking system was automated or manual. Mr Hay answered that the processes are manual. Mr Hay also noted that these processes are more robust where there is an outage or disruption. • Mr Dean Sharafi queried the effect of Synergy Facilities not having revenue meters if Synergy had to bid in the market as individual Facilities. His concern was that revenue meters are bi-directional whereas SCADA is not, implying that a Facility consuming locally or generating to cover their own consumption would not show up in Synergy's meter data. Mr Sutherland noted that this would get picked up by Synergy's Notional Wholesale Meter. • The Chair queried why the data inaccuracy would be any more of an issue if Synergy had to be bid on an individual Facility basis than on a portfolio basis. In response, Mr Sharafi noted that the revenue meter has 0.2% accuracy whereas SCADA data can be materially inaccurate. He further noted that this issue has existed in the market for a long time. The Chair noted that the IMO had already requested Public Utilities Office to rescind the derogation that is currently in place for Synergy's SCADA meters. • Mr Middleton asked if having revenue meters would be a necessity for Synergy to be able to bid on a Facility basis. MAC members agreed that it was not a pre-requisite. Mr Hay noted that Vinalco bids on an individual Facility basis but currently only has SCADA meter data available. • Mr Middleton also queried whether smart-grid communication management could be used for generation Facilities. In response, the Chair clarified that SCADA is effectively a smart communication system that allows for data to be recorded every four seconds. Mr Hay added that SCADA systems are used not only in the electricity industry but also in railways, water, transport management etc. The Chair added that metering technology had come a long way and the cost of a generation meter has reduced considerably over the last decade. *Action Point:* • *The IMO to publish System Management's presentation on replacement of SCADA values on the Market Web Site.*	**IMO**

Deleted: replacement of scada values – overview of methodology

8.	**MARKET PROCEDURES OVERVIEW** Ms Ryan highlighted that the Procedure Change Report for the Procedure Change Proposal: Change to the Market Procedure for Reserve Capacity Security (PC_2013_05) and the associated amended Market Procedure would be published shortly.	
9.	**WORKING GROUPS** No updates were noted.	
10.	**GENERAL BUSINESS** • Mr Sutherland announced that he was due to join Sumitomo Corporation. As Mr Stevens from Bluewaters Power (a Sumitomo company) is already a MAC member, Mr Sutherland noted that he would resign from the MAC in accordance with the requirements under the governance arrangements. The Chair thanked Mr Sutherland for his contribution to the MAC and added that nominations for the vacant position would be invited in the annual MAC review process which will commence shortly. • Ms Ryan noted the IMO is considering changing the date of the next MAC meeting to combine the November and December meetings and that the IMO would send out a notification to confirm the next meeting date.	
CLOSED: The Chair declared the meeting closed at 4:00 PM.		

Agenda item 4: 2014 MAC action items

3 December 2014

Table 1: 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
4	2014	Western Power to provide an overview of Western Power's current approach to constrained access to the grid at the next MAC Meeting.	Western Power	March	Deferred. To be considered as part of the Electricity Market Review
18	2014	Western Power to provide advice on the appropriate level of insurance coverage for the purposes of determining the Maximum Reserve Capacity Price.	Western Power	May	
20	2014	The IMO to engage with System Management to determine the financial impact of the transformer failures at Muja and provide forecast cost estimates based on the outcomes of that discussion.	IMO/System Management	May	Ongoing.

#	Year	Action	Responsibility	Meeting arising	Status/progress
29	2014	System Management to investigate the process for Out of Merit dispatch events and circulate a proposal to inform affected Market Participants about these events prior to the Dispatch Instruction being issued.	System Management	May/August	Completed.
32	2014	The IMO to submit the Rule Change Proposal: Administrative Improvements to the Outage Process (RC_2014_03) into the formal process and progress it using the Standard Rule Change Process.	IMO	June	Completed.
37	2014	The IMO to assess the accuracy of Balancing Prices for discussion at a MAC meeting in six months' time.	IMO	June	
40	2014	System Management to present an overview of the methodology used to replace SCADA values in its estimates, at an upcoming MAC meeting.	System Management	June/August	Completed.
43	2014	The IMO to consider feedback from MAC members and to progress the pre Rule Change Proposal: Reduced Frequency of Determining the Energy Price Limits and Maximum Reserve Capacity Price (PRC_2014_05) accordingly.	IMO	August	Underway.
44	2014	The IMO to publish the minutes of Meeting No. 74 on the Market Web Site as final.	IMO	September	Completed.
45	2014	With regard to action item 18, the IMO to conduct analysis of the effect of different levels of public liability insurance value on the MRCP and present results at an upcoming MAC meeting.	IMO	September	Completed. See paper attached.
46	2014	The IMO to request the PUO on behalf of MAC members to provide a policy position on the difference between Dispatch Support Services and Network Control Services.	IMO	September	Completed. Copy of letter attached.
47	2014	The IMO to canvass MAC members' feedback on the proposal to expedite Ancillary Services procurement processes at a later date to assess if it should be progressed further.	IMO	September	

#	Year	Action	Responsibility	Meeting arising	Status/progress
48	2014	The IMO to provide letters to individual Market Participants with their residual share and include definitions with respect to the figures provided.	IMO	September	Completed.
49	2014	The IMO to publish System Management’s presentation on replacement of SCADA values on the Market Web Site.	IMO	September	Completed.

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Action item 18

The IMO to conduct analysis of the effect of different levels of public liability insurance value on the MRCP and present results at an upcoming MAC meeting.

Table 1 shows the calculation of the Maximum Reserve Capacity Price (MRCP) with insurance premiums for various public and products liability limits. All other inputs to the MRCP have been held constant according to values derived during the calculation of the draft value of the MRCP for the 2015 Reserve Capacity Cycle. Premiums were sourced from an independent insurance broker in October 2014.

Table 1: Impact of change to public liability insurance limit

Limit of liability	Premium (incl taxes)	MRCP	Difference
$10 million	$72,800	$167,400	-$200
$50 million	$100,800	$167,600	-
$80 million	$120,960	$167,800	+$200
$150 million	$162,400	$168,100	+$500
$200 million	$184,800	$168,300	+$700

Table 1 shows that varying the limit of liability makes a small difference to the MRCP. The difference between the MRCP calculated using the premium associated with a $10 million limit of liability and a $200 million limit of liability is only $900, or about 0.5 per cent of the draft 2015 MRCP of $167,600 per MW.

Recommendation

Due to the relatively small impact, the IMO recommends no change to the level of insurance cover used to determine the MRCP.

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Dear Ray

REQUEST FOR CLARITY ON THE APPROPRIATE ALLOCATION OF COSTS FOR ADDITIONAL SERVICES AS PART OF THE REVIEW INTO THE MUJA BUS-TIE TRANSFORMER FAILURE

At the Market Advisory Committee (MAC) meeting held on 24 September 2014, members discussed a concept paper proposing to expedite the procurement process for Dispatch Support Services[1] in the Wholesale Electricity Market (WEM). This concept paper proposed that Market Participants are required to receive annual approval from the Economic Regulation Authority of the prices at which a Facility could provide additional services. The IMO further proposed that these prices would then be ordered and that System Management would be able to dispatch any Facilities from the order to meet any additional requirement. The concept paper considered by MAC members is provided at Appendix A.

This proposal was developed on the basis that, in the time between an additional Ancillary Services requirement being identified by System Management and a Dispatch Support Service contract being signed, Market Participants bear the cost of these additional services in the form of constraint payments for Out of Merit generation quantities. Furthermore, parties may not be fully compensated by the constraint payments as the mechanism was only designed to address short term interruptions to normal dispatch.

[1] Under clause 3.9.9 of the Market Rules, a Dispatch Support Service is an Ancillary Service that is needed to maintain the Power System Security and Power System Reliability that is not covered by other Ancillary Service categories, including the service of controlling voltage levels, where that service is not already provided under any Arrangement for Access or Network Control Service contract.

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In the case of the Muja bus-tie transformer failure, these constraint payments have been borne by the market for the last seven months and a Dispatch Support Service contract has still not been established. The IMO estimates that it has cost the market in excess of $11 million to date.

During these discussions MAC members noted that in many cases under the current legislative framework the incentives to drive efficient costs are not placed on the right parties. For example, in the case of the transformer failure, Western Power is the party that is best able to manage the cause of the issue, but is not the party who currently bears the direct cost.

In particular, MAC members are concerned that the distinction between Dispatch Support Services (Ancillary Services procured by System Management and paid for by Market Participants) and Network Control Services (procured by Western Power and recovered through network tariffs under the Access Arrangement) is not clear. It is not clear under what circumstances System Management or Western Power should be empowered or required to enter into a Dispatch Support Service or Network Control Service contract, respectively.

As this issue related to the WEM Rules, *Electricity Corporations Act 2005* and Electricity Network Access Code, MAC members asked that I write to you on their behalf to request that you consider the current arrangements under the purview of the review into the response to the Muja bus-tie transformer failure and consider the State Government's policy position on:

1. an appropriate allocation of market and non-market costs (i.e. under Dispatch Support Service contracts and Network Control Service contracts) in the South West interconnected system (SWIS);
2. whether it is appropriate to mandate the use of Network Control Services in certain circumstances to avoid an inefficient cross-subsidy; and
3. the appropriateness of a contingency such as proposed by the IMO in its concept paper.

To inform your consideration, I have provided the advice that the IMO prepared with respect to its view of the most efficient and effective way of addressing the additional Muja bus-tie transformer failure at Appendix B. I have previously shared this advice with Luke O'Callaghan from the Minister's Office, Elizabeth Walters from the Economic Regulation Authority and Paul Italiano and Cameron Parrotte from Western Power.

It should be noted that the current cause of the uneconomic dispatch of generation in the SWIS is the ineffective state of the Western Power Network. As such, MAC members are of the view that the costs arising from the deferred investment to replace the failed assets or hold insurance spares for critical network assets must be borne by the party responsible for the cause, Western Power, under a Network Control Service contract.

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Should you or your staff have any questions with respect to the information provided, please don't hesitate to contact me or Kate Ryan, Group Manager Development and Capacity.

Yours sincerely

ALLAN DAWSON
CHAIR, MARKET ADVISORY COMMITTEE

30 September 2014

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Concept Paper: Annual Approval of Facility Costs to Streamline Ancillary Service Procurement

1. BACKGROUND

The recent transformer failure at Muja has created the need for System Management to consider procuring Dispatch Support Services[1] under an Ancillary Service Contract to support Power System Security and Reliability in the South West and Great Southern regions. The procurement process for Ancillary Service Contracts can be lengthy. Where the process is protracted, inefficient dispatch options and distortions in the market may result.

Currently, under clauses 3.11.8 and 3.11.8A of the Wholesale Electricity Market Rules (Market Rules), System Management may enter into Ancillary Service Contracts with Rule Participants for the purpose of providing Spinning Reserve Services, Load Rejection Reserve Services, System Restart Services or Dispatch Support Services[2].

Clause 3.11 of the Market Rules outlines the process required to procure a Dispatch Support Service Contract as follows:

1. System Management must update the Ancillary Service Requirements (which includes Dispatch Support Services) at any time if it considers that a considerable shortfall of that service relative to the applicable Ancillary Service standard is occurring, or is likely to occur before the next annual update. System Management must submit this to the IMO for approval.
2. The IMO must audit System Management's updated Ancillary Service Requirements.
3. Where System Management intends to enter into an Ancillary Service Contract, it must:
    - seek to minimise the cost of meeting its obligations to schedule and dispatch Facilities to meet the Ancillary Service Requirements in each Trading Interval in accordance with Chapter 7 (Dispatch) of the Market Rules; and
    - give consideration to using a competitive tender process, unless it considers that this would not meet the requirements to minimise the costs.

[1] Under clause 3.9.9 of the Market Rules, a Dispatch Support Service is an Ancillary Service that is needed to maintain the Power System Security and Power System Reliability that is not covered by the other Ancillary Service categories, including the service of controlling voltage levels, where that service is not already provided under any Arrangement for Access or Network Control Service contract.

[2] It should be noted that under clauses 5.1.1 and 5.1.2 of the Market Rules, Network Control Service contracts are to be procured by the Network Operator to cover services that are provided as a substitute for transmission or distribution network upgrades. As a result of Rule Change Proposal: Removal of Network Control Services Expression of Interest and Tender Process from the Market Rules (RC_2010_11), the Market Rules no longer specify how Network Control Service contracts are entered into as they are designed to provide non-market related support to the network.

4. Before entering into an Ancillary Service Contract, System Management must obtain the approval of the contract from the Economic Regulation Authority (ERA). In its approval, the ERA "must only review whether an Ancillary Service Contract.... would achieve the lowest practicably sustainable cost of delivering the services" and may undertake a public consultation process.

Despite the ERA's ability to circumvent the consultation process under clause 3.11.8D of the Market Rules, the IMO considers that there are further opportunities to expedite and streamline the procurement process which could result in more efficient market outcomes.

2. ISSUES WITH THE ANCILLARY SERVICE PROCUREMENT PROCESS

Where System Management considers that a Dispatch Support Service needs to be procured, it currently publishes an expression of interest on its website. Rule Participants are required to submit the technical specifications, quantity of energy available to be used for dispatch support and cost of providing the required service. System Management then evaluates all aspects of the tender submissions to determine the most efficient procurement option.

This requires System Management to make an effective assessment of the least cost solution. However, System Management does not have sufficient information on the expected/benchmark Short Run Marginal Cost (SRMC) of different Facilities to assess the costs submitted in the tenders and therefore inform its decision with regard to the contract. Consequently, the process for procuring Ancillary Services may take longer than required where the ERA does not agree with the System Management's contract arrangements, which would then require the process to be restarted.

By contrast, the ERA (and the IMO) undertakes a range of functions in the market, where it is required to assess economic efficiency (costs and prices) and is best placed to do so. Further, the ERA has access to the information necessary to make a fully informed decision with respect to the efficient cost of the provision of Ancillary Services. While the ERA making the determination is consistent with the current process, under the current arrangements the ERA is only required to make this determination at the end of the process.

In the period between System Management identifying a considerable shortfall of Ancillary Services relative to the applicable standard and the completion of the procurement process, the market bears the associated costs (for example, constraint payments for Out of Merit generation). Where this is a protracted process, the resulting market outcomes are likely to be inefficient and the effect on the market is likely to be significant.

The IMO notes that possible inefficient outcomes include the following:

1. Out of Merit dispatch is likely to be required, which does not ensure that the lowest cost energy is dispatched. This mechanism is only designed to retard brief disruptions to normal dispatch.

2. Constraint payments to Market Participants for the Out of Merit generation of a Facility may not recover the SRMC of that Facility providing energy in that Trading Interval. In particular, this is a problem where the constraint requires a Facility that has market power, and is therefore required to bid at SRMC to run, where the Facility has a low Ramp Rate Limit, where the Facility would otherwise not be running and where the Facility is required to run across multiple Trading Intervals.

3. In most cases, System Management must dispatch Facilities in the order required under clause 7.6.1D of the Market Rules (i.e. each Facility in order of the Balancing Merit Order (BMO), any other Facility in the BMO and then a Non-Balancing Facility). This means that System Management is unable to dispatch other (potentially cheaper) Facilities, potentially resulting in a less efficient outcome than would be achieved under an Ancillary Service Contract.

4. Market Customers bear the costs associated with the constraint payments to Market Participants, for the Out of Merit generation to provide the Ancillary Services, but cannot easily predict them.

5. Market Participants that have Facilities operating near the margin cannot easily determine the reason that the Facility has been dispatched in a certain manner by System Management in a Trading Interval.

3. CONSULTATION WITH THE MARKET ADVISORY COMMITTEE

A concept paper was discussed at the 13 August 2014 Market Advisory Committee (MAC) meeting. MAC members discussed the issues and proposed solution and requested that the IMO considers further:

- whether the proposal would be voluntary or mandatory;
- whether the price would be binding;
- how to cater for the inherent variability in a Facility's SRMC;
- the ability to achieve competitive outcomes where there is more than one Facility that could address the constraint;
- network constraints more holistically as part of the Electricity Market Review, rather than in a piecemeal manner; and
- the circumstances under which a Dispatch Support Service should be provided, in particular compared to those under which a Network Control Service (NCS) should be procured.

As a result of this feedback, the IMO has revised this paper to clarify some aspects of the proposal and provide further details of the proposed operation of the process.

4. PROPOSED SOLUTION

The IMO considers that the process of procuring Ancillary Services can be expedited by instituting a requirement for all Market Participants to receive pre-approval of the price(s) applicable to each Facility with respect to the provision of Ancillary Services.

Who has to participate?

The IMO proposes to make participation in the process mandatory for all generation Facilities to ensure that a full range of Facilities would be available to meet the Ancillary Service Requirements. This is particularly important in the case of localised issues, where only one Facility may be able to effectively address the requirement.

It should be noted that recently DSPs have been supporting the network. Despite the increased flexibility DSPs provide, at this stage, the IMO does not propose to include Demand Side Programmes (DSP) in the process due to the inherent complexities. In particular, in order to include DSPs, the Market Rules would need to provide clarity on a number of broader matters with respect to the operation of DSPs, including but not limited to:

- what an appropriate cost of service is for a DSP;
- how to compare a DSP's cost of service to a generator's SRMC;
- how to consider a DSP's limited availability and subsequent restrictions around dispatch; and
- how system management would be able to determine a DSPs availability at a time when Dispatch Support Services are required.

It is likely that when these issues have been resolved that DSPs will not only be able to participate in the Dispatch Support Service contract process but that the IMO will also be able to integrate DSPs in the Balancing Market.

Who should approve the price?

The IMO proposes that each year Market Participants would submit the proposed price(s) for each Facility to the ERA for assessment and approval.

The IMO considers that the ERA is best placed to perform this function because it currently is required to approve the costs associated with Dispatch Support Service contracts under clause 3.11.8C of the Market Rules and all revisions to those prices under the current Dispatch Support Service contracts. In addition, the IMO considers that the ERA is well placed to perform this function as it is also required to oversee market surveillance activities and approve administered prices such as that proposed.

The ERA currently requests details with respect to each Facility's SRMC to fulfil its market surveillance obligations under clause 2.16.9 of the Market Rules. The IMO considers that the proposed Ancillary Service procurement process could be aligned with the market surveillance process to increase the efficiency and reduce the duplication of effort.

The IMO also considers that there would be additional benefits, including the avoidance of ad-hoc requests for information for market surveillance purposes and improving the accuracy of the data used to monitor the market.

How often can prices be submitted for approval?

The IMO proposes to make the approval of Dispatch Support Service price(s) a process that would be undertaken prior to the start of the Capacity Year. Initially, it would be undertaken annually, however, as the process is bedded down, it could be less frequent (i.e. every two to three years). The IMO considers that this would provide an appropriate balance between the ability for Market Participants to update their prices on the basis of updated input costs (e.g. where a new fuel contract is signed), and minimising the administrative overheads associated with the approval process.

It should be noted that this ability to revise prices annually is also consistent with the Dispatch Support Service contracts currently in place.

What is an appropriate price?

The IMO proposes that the Dispatch Support Service payment would be the SRMC of the Facility, plus a profit margin, less the Balancing Price. The IMO considers that the combination of the capacity payment, energy payment (Balancing Price), and Dispatch Support Service payment will ensure that a Facility does not run at a loss.

The IMO considers that the price(s) offered by each Market Participant for each Facility would have to be based on the Facility's SRMC to prevent the abuse of market power where only one Facility could provide the necessary service. This is consistent with the required bidding behavior in the Balancing Market.

The SRMC of the Facility would provide the Market Participant's expectation of the cost of providing the additional quantity of energy with respect to the Ancillary Service for each Facility and should account for start-up costs and other operating costs. It should be noted that the SRMC does not include fixed costs which do not vary in the short run, as these costs are notionally recovered through Capacity Credit payments under the Reserve Capacity Mechanism.

A requirement to base the order of dispatch on each Facility's SRMC would also ensure that the most efficient solution or combination of solutions would be dispatched where more than one Facility could provide the necessary service.

The IMO considered a more dynamic price setting arrangement. However, the most efficient way to introduce competition (in the absence of a market) is through a tender process, which this proposal is trying to address the shortfalls of. The IMO therefore considers that, despite the lack of competition in an administered price arrangement, as is being proposed, the requirement to dispatch Facilities on the basis of price will still produce and economically efficient outcome. How System Management will dispatch Facilities is discussed further below.

How can a Market Participant ensure that prices are reflective of the costs incurred?

The IMO proposes that the approved price would be binding and apply to the specific Dispatch Support Service for the quantity of the IMO-approved requirement.

The IMO acknowledges that a Facility's SRMC can vary depending on a number of factors. The IMO has taken this into consideration and proposes to allow Market Participants to submit a minimum of one and maximum five price-quantity pairs, where the price associated with each pair is equal to the Facility's SRMC at any particular point. This will allow Market Participants to account for a Facility's SRMC at its minimum stable load and another four points in its production curve.

What is an appropriate return for the services provided?

The IMO considers that Market Participants providing Dispatch Support Services under this process should make a return (above SRMC) at a level equivalent to the associated level of risk. The IMO therefore proposes to include a profit margin based on the 10-year Australian Government Bond Yield rate.

The 10-year Australian Government Bond Yield rate in September 2014 is 3.46%. Over the past 10 years, the rate has fluctuated between 6.5% in 2008, during the financial crisis and 2.95% in 2012. The IMO considers that this rate would provide an appropriate return on the provision of a low risk service.

The IMO notes that the inclusion of a profit margin would offset any implicit bias that a Market Participant may have to avoid providing Ancillary Services.

It should be noted that other markets similarly determine the cost of the provision of Ancillary Services and add a profit margin. For example, the Singapore electricity market uses an open-book method to determine the actual cost of Ancillary Services Contracts (System Restart Services) and includes a margin of 10%.

What form would the governance structure take?

The IMO considers that the development and agreement of contracts significantly extends the time taken to procure Dispatch Support Services.

To expedite the process, the IMO therefore proposes to introduce an ex-ante approval process into the Market Rules to replace the current contract arrangements for procuring Dispatch Support Services in the WEM. This would require the IMO to amend the Market Rules to place obligations on System Management, Market Generators and the ERA.

Should there be a requirement for System Management to dispatch a Facility in the list?

The IMO considers requirements should be put in place to avoid the issues that currently arise from using dispatch processes that are not designed for longer periods.

The IMO therefore proposes to introduce a requirement for System Management to dispatch a Dispatch Support Service under this process where the shortfall or constraint has persisted for more than five Trading Days for a minimum of four hours per day, or is expected to last for an extended period.

How would System Management dispatch a Facility from the ordered list?

The IMO proposes that, once all prices have been approved by the ERA, the IMO would provide System Management with an ordered list of Facilities on the basis of price, with the lowest prices ranked first (similar to the BMO and Non-Balancing Dispatch Merit Order).

Where System Management determines that additional Ancillary Services are required, it would determine which Facilities are able to meet the IMO-approved requirement. The IMO expects that in System Management's assessment of a Facility's ability to meet the requirement, it would overlay an effectiveness factor to consider the amount of energy that would be required to be produced at the generation point to meet the requirement to ensure an efficient overall solution is implemented.

Once it had determined which Facilities should be dispatched to provide the Ancillary Services, System Management would issue Operating Instructions under clause 7.6.1B of the Market Rules to the relevant Facilities in accordance with the price based order of the list. Under clause 7A.2.3 the relevant Market Participant would then be required to price the appropriate quantity at the Minimum STEM Price to ensure that it is dispatched and does not distort the Balancing Merit Order.

The IMO would also take the opportunity to strengthen clause 7.6.1B of the Market Rules to require System Management to issue an Operating Instruction to a Facility to be dispatched under this process. It should be noted that while System Management is currently not required to issue an Operating Instruction in these cases under the Market Rules, section 6.4 of the Power System Operation Procedure: Dispatch does require it to. Nevertheless, if System Management did not issue an Operating Instruction, the Market Participant would not be obliged to bid at the Minimum STEM Price, which:

- would distort the BMO;
- may result in inefficient prices due to unanticipated outcomes such as artificially inflating the Balancing Price and/or attracting constrained on payment; and
- may result in the double payment for the quantity of energy dispatched to meet the Ancillary Service requirement as the settlement system would not be able to determine the type of energy provided.

Should there be a requirement for a Network Operator to procure an NCS?

Under the current electricity market arrangements, there are two alternative options to support the operation of the network where a capital investment solution is deferred:

1. Western Power enters into a network solution in the form of an NCS contract – under clause 5.1.1 of the Market Rules an NCS is "a service provided by generation or demand side management that can be a substitute for transmission or distribution network upgrades".
2. System Management enters into a market solution in the form of a Dispatch Support Service – under clause 3.9.9 of the Market Rules a Dispatch Support Service is any other Ancillary Service that is needed to maintain Power System Security and Power System Reliability that are not covered by the Ancillary Service categories. Dispatch Support Service is to include the service of controlling voltage levels in the SWIS, where that service is not already provided for under any Arrangement for Access or NCS contract.

Currently, these explanations do not provide a clear distinction between network and market driven costs and therefore who should bear the associated costs. The IMO considers that greater clarity over the intention of these services is required and that further guidance is necessary with respect to their classification and the allocation of associated costs.

While the intention of this concept paper is to find a more equitable solution under the current arrangements, the combination of the current definition of Dispatch Support Service and a requirement for System Management to use a Dispatch Support Service may produce unintended outcomes without further consideration of the role of NCS. In particular, without further guidance on the circumstances under which an NCS should be procured, Western Power would have no incentive to remedy network problems, as System Management would first be required to procure Dispatch Support Services to support the continued operation of the system.

The IMO considers that the resolution of this issue requires a policy decision by the Public Utilities Office (PUO).

5. NEXT STEPS

The IMO has consulted with the ERA with respect to the proposal but has not yet received feedback. The IMO will consider any feedback provided by the ERA in the further development of this proposal.

The IMO notes that there are currently two reviews underway that may affect the progression of this proposal:

1. The review of the Muja transformer failure incident – The PUO is currently assessing the response of the organisations involved to the incident and may make recommendations that would negate the requirement to implement such a process.

2. The Electricity Market Review – The review is assessing broad reforms in the electricity sector and may recommend implementing reforms that would negate the requirement to implement such a process. For example, the introduction of a constrained grid model or co-optimised energy and Ancillary Service dispatch.

In light of this, the IMO recommends that MAC members:

- **consider and discuss** the proposed solution;
- **agree** whether the MAC supports the proposed solution in-principle; and
- **note** that, if in-principle support is provided, the IMO will decide whether or not progress the proposed solution as a Rule Change Proposal after considering the outcomes of the PUO's review into the Muja transformer failure and the Electricity Market Review.

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INDEPENDENT MARKET OPERATOR

FILE NOTE.

FROM.	Allan Dawson	**OUR REF.**	N/A
	Click here to enter text.	**DATE.**	27 June 2014
SUBJECT.	Advice on Western Power entering into a Network Control Service Contract		

Background

In September 2012, the Muja Bus-Tie Transformer (BTT) 1 failed. Western Power started the procurement process to replace the failed transformer. The IMO understands that Western Power encountered significant problems through this process. In February 2014, Muja BTT2 also failed, Western Power had not yet procured a replacement for Muja BTT1.

Since February 2014, the network has not operated effectively, requiring System Management to operate the network in a manner contrary to the efficient, economic dispatch of energy. In particular, System Management considers that the Vinalco Muja generators must run[1] to support the operation of this section of the network[2].

As the Vinalco units are currently running, in a manner that is inconsistent with the Balancing Merit Order (i.e. when cheaper cost energy could be provided) in order to support the network, Market Customers have payed an estimated $5.50 million to date in Out of Merit Generation payments and this amount is growing at approximately $250k per day (at current Muja A/B bid prices).

The IMO considers that the ineffective operation of the Western Power Network is causing an unnecessary cost leading to inefficiencies in the Wholesale Electricity Market (WEM) and should be remedied as soon as practical.

Proposed solution

The principle cause of the uneconomic dispatch of generation and the Out of Merit Generation payments is the ineffective state of the Western Power Network. As such, the IMO considers that the costs arising from the deferred investment to replace the failed assets should be borne by the causer, Western Power.

The IMO therefore considers that Western Power should consider entering into a Network Control Service (NCS) contract to provide the support that the network requires to operate effectively.

Key considerations are addressed in the sections below.

[1] It should be noted that System Management presented a number of alternative options of managing the network at the February 2014 MAC meeting which included running the Vinalco units, curtailing the Albany and Grasmere windfarms, line switching, shifting load during the day and load shedding.
[2] Including to provide reactive power support to prevent over-voltage events, to provide MVAR support for load below 100MW and to avoid over-voltage events caused by the fluctuation of windfarms and to ensure that the Collie Power Station and sub-station are not affected by the failure.

What are Western Power's obligations?

The objective of the Access Code is to "promote the economically efficient investment in; and operation and use of, networks and services of networks in Western Australia to promote competition in markets upstream and downstream of the networks".

The Access Code requires Western Power to undertake work if it is "necessary in accordance with good electricity industry practice" (section 2.12(b)). In this context, work is defined as "any activity or undertaking in connection with the covered network, whether of a capital or non-capital nature, including the planning, designing, development, approval, construction, acquisition and commissioning of new facilities and new network assets and the procurement or provision of any good or service".

In its third Access Arrangement, Western Power received $1.2 billion to maintain its average service levels throughout the period. Western Power noted that failing to do so would result in, amongst other things, an increasing gap between practices and prudent network asset management and progressively reduced reliability of the network.

Western Power's 2013 Annual Planning Report further states that "the security and reliability of the network in the Muja Load Area is paramount because of the reliance of neighbouring load areas on the generation capacity connected to it".

Given these commitments, the IMO considers it may be appropriate that Western Power address the current situation by entering into a NSC, rather than the Market Customers of the WEM underwriting the current ineffective operation of the Western Power Network.

Is it necessary for Western Power to do anything in this situation?

Under the Electricity Network Access Code 2004 (Access Code), Western Power must consider 'alternative options' to provide covered services when making an investment decision. Alternative options in relation to a major augmentation, is defined in the Access Code as "alternatives to part or all of the major augmentation, including demand-side management and generation solutions (such as distributed generation), either instead of or in combination with network augmentation".

In previous meetings Western Power and the ERA have stated that the replacement of a failed transformer at Muja does not constitute a "network augmentation". However, the Access Code defines an augmentation in relation to a covered network as "an increase in the capability of the covered network to provide covered services".

On this basis, the replacement of the functionality of the failed transformers would constitute network augmentation on the basis that it will increase the capability of the network from the ineffective state it is currently operating in. Further, Western Power must undertake analysis to determine whether, during the time in which a replacement transformer is unavailable, what interim actions it should take - consistent with its obligations under the Access Code.

Assuming that there were two options for Western Power with respect to maintaining the operation of the network where the capital investment solution is deferred, (do nothing and procure an NCS contract) it may be expected that any business case from Western Power would have supported the establishment of an NCS contract.

What are the alternative options to address the problem where the capital investment solution is deferred?

Under the current electricity market arrangements, there are two alternative options to support the operation of a network where the capital investment solution is deferred to address the circumstances:

1. System Management enters into a market solution in the form of a Dispatch Support Service; or
2. Western Power enters into a network solution in the form of an NCS contract.

Under cause 3.9.9 of the Market Rules a Dispatch Support Service is any other Ancillary Service that is needed to maintain Power System Security and Power System Reliability that are not covered by the Ancillary Service categories. Dispatch Support Service is to include the service of controlling voltage levels in the SWIS, where that service is not already provided for under any Arrangement for Access or NCS contract. In 2008, System Management submitted the Rule Change Proposal: Dispatch Support Ancillary Services (RC_2008_12[3]) to remove the costs of Dispatch Support from its budgetary processes and to instead provide for contracting those services as the need arises and for the ERA's approval of the relevant contracts.

There are currently three Dispatch Support Services operational in the SWIS, all designed to account for load growth:

- **Kalgoorlie** - the 220 kV line between Merredin Terminal and West Kalgoorlie is radial and local gas turbines must be run to meet load and maintain Ancillary Services when the line is out of service;

- **Mungarra** - import capacity of North Country lines is limited by conductor rating and stability conditions and Mungarra GT is required to be run every day to support load in the area; and

- **Geraldton** - if both lines between Mungarra and Geraldton have tripped then System Management runs the Geraldton GT to restore supply.

It should be noted that these were originally discussed as NCS contracts, rather than Dispatch Support Service contracts.

Under clause 5.1.1 of the Market Rules, an NCS is "a service provided by generation or demand side management that can be a substitute for transmission or distribution network upgrades". In 2007 Western Power submitted the Rule Change Proposal: Network Control Service Procurement Requirements (RC_2007_22[4]). The proposal sought to remove the requirement in the Market Rules that all NCS contracts must have a minimum period of 10 years on the basis that short to medium term contracts were necessary. Western Power submitted this proposal into the Fast Track Rule Change Process on the basis that Ravensthorpe required network support within 1 to 2 years.

The National Electricity Market has a similar construct to the WEM in that it has both market and non-market network control ancillary services. This is similar to the WEM's Dispatch Support Services and NCS.

It should be noted that there is not a clear distinction between the services provided under Dispatch Support Services and NCS which means that, both methods are expected to provide

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[3] More information is available at: www.imowa.com.au/RC_2008_12.
[4] More information is available at: www.imowa.com.au/RC_2007_22.

the same outcome and have the same associated costs. However, there are operational differences with respect to the allocation of these costs, including:

- **Potential for price shocks –** If the service is contracted under a Dispatch Support Service, System Management must negotiate the contract, with the ERA approving the arrangements. This cost is then passed through to Market Customers and allocated on the basis of consumption share through the settlement process (i.e. as soon as the costs are incurred), potentially leading to a price shock. If the service is contracted as an NCS, Western Power must establish the contract. Under section 6.80 of the Access Code Western Power may seek approval from the ERA before the contract is established, and the ERA must make a determination if this is over $1.9 million. Western Power's costs are then recovered from its customers over the 5 years of AA4. This cost recovery methodology is significantly less likely to result in a price shock.

- **Ability to pass through costs** - If a Dispatch Support Service is entered into, Market Customers in the WEM ultimately bear the cost of the service. On the basis that tariffs are fixed for a period, it is likely that those Market Customers will not be able to pass these costs on to end-users. This will have varying financial consequences on different participants. If the service is procured under an NCS contract, Western Power is able to collect associated revenue through tariffs (assuming the expenditure is proven to be necessary and efficient) and these costs could be either allocated across the customer base in the SWIS (i.e. transmission customers), or to those affected customers[5].

- **Transparency of the cause –** The costs for the procurement of the network support service should be associated with the cause of the problem been addressed. In particular, the costs should not be attributed to the cost of the operation of the WEM, and instead should be attributed to the operation of the network. This is important, as in the future, if the costs were inappropriately allocated to the market, these costs could distort any economic or financial assessment of the WEM and may materially impact the annual ERA report on the WEM to the Minister for Energy.

The IMO therefore considers that Western Power establishing an NCS contract, rather than System Management contracting a Dispatch Support Service will minimise the financial impact on the operation of the WEM and more equitably allocate the cost of this network disruption.

Can Western Power enter into a NCS contract?

Significant discussion arose between 2007 and 2010 as the MAC considered the operation of NCS through a number of workshops which eventually led to the Rule Change Proposal: Removal of Network Control Services Expression of Interest and Tender Process from the Market Rules (RC_2010_11[6]). The key points were:

- The Office of Energy (OoE) stated its concern that the payment regime for NCS in the Market Rules could lead to cross subsidisation (on the energy payments for the NCS).

- The OoE recommended that Western Power tender for and contract with an NCS provider, with the ERA to conduct regulatory oversight.

- The MAC agreed with the concept that the NCS procurement and contracting functions be shifted to Western Power. The MAC also agreed that NCS energy costs (above MCAP) should be paid by Western Power rather than the market to avoid the

[5] In practice this would require changes to the tariff structures and is not expected to be able to be localised to those customers affected.
[6] Further information is available at: www.imowa.com.au/RC_2010_11.

current cross-subsidy in NCS energy payments from Market Participants to the users benefitting from the NCS.

- Western Power raised concerns about whether it had the necessary powers under sections 41 and 42 of the Electricity Corporations Act to contract for a NCS. Following lengthy discussions, the OoE and Western Power agreed that there were no regulatory/statutory obstacles to Western Power contracting for NCS. This was supported by the legal views (both OoE's and Western Power's) that this does not constitute a purchase of electricity and therefore is not a potential barrier.

In Western Power's submission to the ERA on the third Access Arrangement, the Appendix A – Capital and Operating Expenditure Report noted that it forecast expenditure of $12.6 million over the period on NCS contracts. It described the work to be undertaken as "network control services – payments for generation or demand side management in constrained sections of the network to enable us to efficiently defer major capital investments" and further notes that these services are "aimed at efficiently lowering network investment and asset management costs over time, consistent with section 6.52(a) and 6.40 of the Access Code". Western Power notes that it currently procures NCS to support the distribution network in Ravensthorpe and Bremer Bay.

In its submission to the ERA, Western Power also noted that it intended to spend a further $59 million over the period to establish a further four NCS contracts to support the transmission network in Albany, Geraldton, Eastern Goldfields and Pinjar.

In its Final Decision and Further Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network the ERA described NCS as "payments made to generators to operate at times of peak demand as a means to defer the need for capital expenditure in areas of network constraint".

It is further noted that Western Power has invited "present and aspiring market participants with local generation or demand responses capacity capable of providing network support to alleviate any of the emerging limitations... to contact Western Power".

How can Western Power recover the costs associated with the NCS contract?

Clause 6.41 of the Access Code allows the non-capital cost of 'alternative options' to be included in Western Power's non-capital costs if:

a) The costs of the alternative option are considered to be "efficiently minimising costs"; and

b) At least one of the following tests (under section 6.52.(b) of the Access Code) is satisfied:

   i. **Incremental Revenue Test** -The additional revenue for the alternative option is expected to at least recover the alternative option non-capital costs;

   ii. **Net Benefits Test** - The alternative option provides a net benefit in the covered network over a reasonable period of time that justifies the increased tariffs; or

   iii. **Safety and Reliability Test** - The alternative option is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted, covered services.

On the basis of the ERA's explanatory document (provided as an appendix to Western Power's submissions with respect to New Facilities Investment Tests and Regulatory Tests[7]) the expenses incurred to remedy the transformer failures:

- **Would not pass the Incremental Revenue Test** on the basis that there would not be any increase in sales in response to the expenditure;
- **Would pass the net benefits test** as it is described in the Access Code as "a net benefit (measured in present value terms to the extent that it is possible to do so) to those who generate, transport and consume electricity in (as the case may be) the covered network; or the covered network and any interconnected system"; and
- **Would also pass the Safety and Reliability Test** as the ERA notes that the meaning of safety and reliability is a matter of interpretation and could potentially include, for example investment required to meet best-practice standards or statutory requirements for safety in the operation of the network; or investment required to achieve or maintain reliability of services or capacity of the network sufficient to meet contractual obligations to users or mandatory requirements. It is expected that Western Power would use this test in its business case to support the procurement of the replacement transformers on the basis of the impact on its service standard and reliability performance.

It would appear there is enough information that has already been provided to Western Power by System Management and the IMO to support the position that entering into a NCS contract would meet the requirements of the Net Benefits Test as the ERA clearly considers benefits to Market Generators and Market Customers in its determination.

Therefore any expenditure that Western Power must incur to remedy the current network problems with respect to the Muja BTT failures would be considered by the ERA to be appropriate if it was proven to be undertaken efficiently.

Should Western Power require additional information with respect to the impact on the Wholesale Electricity Market and its participants, the IMO can/will provide it.

What is the financial impact of entering into an NCS contract on Western Power?

In its Final and Further Final Decision on the AA3, the ERA expanded the D-Factor mechanism (under section 6.76 of the Access Code) to include NCS on the basis that this would provide certainty to Western Power that it will be able to recover the costs of all efficiently incurred NCS and ensure that only efficient investment decisions are made.

The D-Factor mechanism allows Western Power to fully recover the operating expenditure incurred under such a scheme in the next access Arrangement period. In its Final Decision, the ERA notes that "the D-Factor Scheme seeks to address the disincentive to implement non-network alternatives to capital projects in resolving network constraints".

Western Power will therefore be able to recover any efficient expenditure incurred in the rectification of the Muja BTT failures under the D-Factor mechanism in the AA4 period commencing in 2017-18.

[7] For example, provided as Appendix A to the Issues Paper on the New Facilities Investment Test Application for a 132-66kV Medical Centre Zone Substation: Submitted by Western Power, available at: http://www.erawa.com.au/cproot/11151/2/20130211%20-%20D102207%20-%20WP%20-%20NFIT%20-%20132%2011%20kV%20Medical%20Centre%20-%20Issues%20Paper.pdf.

It would be beneficial for Western Power to procure a NCS as soon as possible to support its achievement of its Service Standard Benchmarks[8], thereby increasing its ability to obtain incentive payments under the Service Standard Incentive Framework.

What is the risk associated with Western Power entering into an NCS contract?

There would appear to be no commercial risk associated with Western Power entering into an NCS contract. Although Western Power must ensure that its operating expenditure meets the requirement of section 6.40 of the Access Code. Any risk associated with an NCS contract would appear negligible as:

- Western Power currently has a number of NCS contracts in operation;
- We understand that Western Power recently undertook a tender process (albeit for a transmission NCS contract), and therefore would be expected to have a good benchmark of the efficient cost of such a service; and
- Under section 6.76 Western Power may at any time apply to the ERA to determine whether forecast non-capital costs proposed to be incurred are expected to meet the requirements of section 6.40 of the Access Code and under section 6.80, the ERA must make a binding determination with respect to investment over $1.9 million.

Recommendation:

It may be appropriate for the IMO to meet with Western Power and the ERA to discuss the views expressed in this memo.

[8] This framework provides benchmark performance targets for the frequency and duration of interruptions on the network and is linked to financial rewards and penalties and aim to incentivise Western Power to maintain and improve service standard performance over time.

Appendix 1: History of Network Control Services

Pre Market Start

In the IMO's records are a number of old drafts of NCSCs for Kalgoorlie, Mungarra, Geraldton and Bremer Bay (including Western Power documents), dated around October 2005 – January 2006.

Just prior to the start of the WEM the IMO and Verve Energy were negotiating three Network Control Service Contracts, for Mungarra, Kalgoorlie and Geraldton. On 11 September 2006 Verve Energy advised the IMO that it had decided not to enter into the contracts, as they provided no commercial value to Verve Energy as proposed.

Market start to December 2009

In a file note dated 6 July 2007, Patrick Peake summarised a meeting held between System Management, Western Power Networks and the IMO around Network Control Service Contracts. Verve Energy had recently written to the IMO asking it to call tenders for a "Network Support Contract" which Verve Energy wanted in place by 1 October 2007. The list of action items from the meeting included "Western Power will consider offering Verve Energy a four year compensation arrangement for any differences between its operating costs and the balancing price at Mungarra and Geraldton, to be paid for through network charges".

On 15 October 2007 Western Power submitted the Rule Change Proposal: Network Control Service Procurement Requirements (RC_2007_22). The proposal, which had been discussed and supported at the 10 October MAC meeting, sought to remove the requirement in the Market Rules that all NCSCs must have a minimum period of 10 years. Western Power noted in it proposal that "this minimum period appears to be appropriate for contracts for medium to large scale generation, however may not always be appropriate for smaller scale solutions. The optimum solution for a network constraint, which minimises the overall cost, may involve an NCSC for a relatively small amount of generation for a relatively short period followed by a network augmentation in the medium term".

Western Power requested that the proposal be processed using the Fast Track Rule Change Process, noting that "the steady growth in electricity demand in and around the town of Ravensthorpe means that capacity in the existing network will be fully utilised within 1 to 2 years. The optimum development appears to be establishing relatively small scale local generation immediately, followed by a major network augmentation around 2012 (depending on actual load growth)".

The Final Rule Change Report for RC_2007_22 was published on 19 November 2007 and the Amending Rules commenced on 1 December 2007.

At the February 2008 MAC meeting, System Management proposed to amend the Market Rules to remove the costs of Dispatch Support from its budgetary processes and to instead provide for contracting for those services as the need arises and for the ERA's approval of the relevant contracts. The MAC supported the progression of the proposal using the Fast Track Rule Change Process.

System Management submitted the Rule Change Proposal: Dispatch Support Ancillary Services (RC_2008_12) on 14 February 2008. The Amending Rules commenced on 20 April 2008, following Ministerial approval on 17 April 2008.

During the workshop held by the IMO to discuss the proposal, System Management explained there were three main areas in the SWIS where because of transmission constraints there is a need for Dispatch Support Services.

- The 220 kV line between Merredin Terminal and West Kalgoorlie is radial and local gas turbines must be run to meet load and maintain ancillary services when the line is out of service.

- Import capacity of North Country lines is limited by conductor rating and stability conditions. Mungarra GT is required to be run every day to support load in the area.
- Geraldton – if both lines between Mungarra and Geraldton have tripped then System Management runs the Geraldton GT to restore supply.

On 23 April 2008 the ERA published its "Approval of Costs for a Deed of Undertaking between System Management and Verve Energy for Dispatch Support Services". The Deed, which covers the DSS services at Mungarra, Geraldton and Kalgoorlie, was made effective from 20 April 2008 until the date the 330 kV transmission line from Pinjar to Geraldton begins operating. The formula for determining the cost of the DSS provided was determined as:

> *[(MWh generated in a trading interval when generating unit dispatched for DSS) multiplied by (SRMC of generating unit net of any start up component minus MCAP)] plus start-up costs. (Note the data used in the formula is "confidential to Verve Energy".)*

The ERA did not consider that separate public consultation on contract was warranted as the IMO's consultation on RC_2008_12 had canvassed the relevant issues.

In the IMO's records is an internal Western Power discussion paper, dated 17 November 2008, which discusses issues around electricity supply to the Eastern Goldfields (EGF) region, given the expected load growth in the area from both small and large loads. The paper noted that "Both System Management and Western Power may be criticised if Dispatch Support or Dispatch Out of Merit are over relied upon, rather than pursuing other contractual options (i.e. an NCSC). The proposed next steps included approaching the IMO to procure an NCSC for the EGF to handle load growth due to small customers only. WP proposed to engage with the ERA, IMO and OoE by 5 December 2008.

IMO, OoE, ERA and WP started a series of NCS Workshops on 29 January 2009. During these workshops the issue of cross-subsidisation of energy costs was discussed.

During the following months the IMO engaged:

- SKM to provide advice on the magnitude of the potential energy and availability costs and related issues for various alternatives if an NCS contract was entered into for the Eastern Goldfields;
- Jackson MacDonald, to develop an NCSC proforma; and
- Jackson MacDonald, to conduct a review of the Access Code and Market Rules related to NCS.

During this work there was some discussion about the cross subsidy issues and whether the IMO should be running the NCS tender process.

December 2009 MAC meeting

The OoE (Peter Hawken) gave a presentation to the 9 December 2009 MAC meeting on the NCS issues. The OoE stated its concern that the payment regime for NCSCs in the Market Rules could lead to cross subsidisation (on the energy payments for the NCS). The OoE also stated that the reasons for the IMO to contract for NCS may no longer be valid and that it could be more efficient and timely for Western Power to undertake this task. The OoE was assigned an action item to prepare an issues paper on the NCS issue in early 2010.

March 2010 MAC meeting

The OoE was scheduled to present its overview of the NCS issues at this meeting but the agenda item was held over until the April 2010 meeting.

April 2010 MAC meeting

The OoE (Peter Hawken) presented the OoE's issue paper "Network Control Service as an Alternative to Network Augmentation". Mr Hawken noted that, during 2009, the IMO facilitated a number of workshops on NCS between System Management, the ERA, Western Power and the OoE. The goal of these workshops was to try to facilitate the NCS procurement processes within the current legislative framework. Late in 2009, the policy reasons for the original procurement framework were examined in greater detail. As a result the OoE recommended that Western Power tender for and contract with an NCS provider, with the ERA to conduct regulatory oversight.

The MAC agreed with the concept that the NCS procurement and contracting functions be shifted to Western Power. The MAC also agreed that NCS energy costs (above MCAP) should be paid by Western Power rather than the market.

The IMO was assigned an action item to prepare, in consultation with System Management and Western Power, a Rule Change Proposal to:

- remove the requirement for the IMO to conduct an NCS expression of interest and tender process from the Market Rules; and
- facilitate the operation of an NCS (i.e. dispatch and settlement of energy) within the broader market processes.

August 2010 MAC meeting

The IMO presented the Pre Rule Change Proposal: Removal of NCS Procurement from the Market Rules (PRC_2010_11) to MAC members. The IMO noted that in the PRC it had sought to resolve the potential cross subsidy in NCS energy payments from Market Participants to the users benefitting from the NCS. The IMO proposed that the price paid by the market for energy dispatch under an NCSC should be:

- MCAP, if the NCS is provided by generation; and
- zero, of the NCS is provided by DSM.

Western Power (Peter Mattner) noted that the OoE had raised some issues about NCS and suggested that the IMO delay the formal submission of PRC_2010_11 until these issues had been resolved. Mr Neil Gibbney noted one issue was that it was not clear whether Western Power had the necessary powers under sections 41 and 42 of the Electricity Corporations Act. The OoE and Western Power were assigned an action item to discuss their concerns relating to the future provision of NCS and provide an update to the MAC at the September 2010 meeting.

The IMO, ERA and System Management were also assigned various action items in relation to the proposal. The IMO agreed to update the proposal to reflect the advice received from the OoE, Western Power and the ERA and present the updated paper to the MAC.

September 2010 MAC meeting

In relation to the action item raised in the previous meeting (Action Item 90), the OoE (Tony Perrin) noted that Western Power had raised concerns about whether it had the necessary powers under sections 41 and 42 of the Electricity Corporations Act to contract for a NCS. Mr Perrin advised that the Office of Energy had requested a copy of the legal opinion obtained by Western Power, and was considering several options to address the issue, such as inclusion of a heads of power for NCS in the upcoming Electricity Legislation Amendment Bill. There was some discussion about whether the necessary heads of power already existed. Mr Neil Gibbney confirmed that, according to its legal advice, Western Power definitely did not have the necessary powers.

Mr Gibbney noted that regulations would also be needed, and queried whether work on these could be started before the legislation had been passed. Mr Perrin responded that this work could be started if necessary and that he and Mr Gibbney would discuss the matter further off-line and provides an update to the MAC at the next meeting.

October 2010 MAC meeting

The IMO presented an updated version of PRC_2010_11 and provided an update to MAC members on the action items raised during the August 2010 meeting.

In relation to Action Item 90, Mr Perrin noted that the OoE had met with Western Power to discuss the concerns relating to the future provision of NCS. During the meeting Western Power had expressed its legal position as being prohibited under the Electricity Corporations Act to contract for NCS. Mr Perrin noted that the OoE had some concerns with this position which it would be continuing to work with Western Power to address. In the meantime the OoE had initiated the regulatory processes for the necessary legislative amendments to provide the required heads of power. Mr Perrin noted that this would be an eight to ten month process, and was already underway. The Energy Legislation Amendments Bill was with the Minister's office for consideration.

Mr Perrin noted that the OoE was preparing an issues paper to aid consultation with stakeholders. This consultation was scheduled to be undertaken early the next year.

It was agreed that the IMO should progress the Rule Change Proposal into the formal rule change process, subject to any implementation date being tied to the outcomes of the OoE's regulatory changes. The OoE and Western Power agreed to provide bi-monthly updates to the MAC on the status of any regulatory changes relating to NCS procurement.

RC_2010_11 was formally submitted into the rule change process on 15 October 2010.

December 2010 MAC meeting
In relation to the outstanding action item, Mr Mattner noted that the OoE and Western Power had agreed that there are no regulatory/statutory obstacles to Western Power contracting for NCS. <u>This was supported by the legal views (both OoE's and Western Power's) that this does not constitute a purchase of electricity and therefore is not a potential barrier.</u> Notwithstanding, the OoE may consider clarifying the parts of the Access Code relating to NCS at a later date, as part of the formal Access Code review process to begin next year.

Mr Mattner also stated that Albany was expected to be the initial location for deployment of services.

RC_2010_11: Removal of Network Control Services Expression of Interest and Tender Process from the Market Rules

RC_2010_11 was formally submitted into the rule change process on 15 October 2010. The Final Rule Change Report was published on 11 March 2011 and Ministerial approval for the changes was received on 8 April 2011. The Amending Rules commenced on 1 July 2011.

In submissions received during the second submission period, both System Management and Western Power raised concerns about the provisional commencement date of 1 July 2011. Both participants noted that Western Power was at that time putting into place an alternative NCS procurement process. While it was expected that the process should be finalised by 1 July 2011, the possibility of unexpected delays or impediment remained. Both participants considered that the commencement of the proposed Amending Rules should be delayed until Western Power had advised the IMO that the new NCS procurement process was in place.

In response, the IMO noted that should Western Power advise the IMO of a delay in implementing its procurement process then the IMO would extend the commencement date accordingly.

On 13 June 2011 the IMO received confirmation from Mr Mattner that Western Power supported the commencement of the Amending Rules on 1 July 2011.

IMO INDEPENDENT MARKET OPERATOR

Concept paper: Managing market information

MAC Meeting No 77: 3 December 2014

1. Background

Market related information has become increasingly important to the operation of the Wholesale Electricity Market (WEM). The IMO has reviewed the effectiveness and efficiency of the current framework that governs the management of market information under chapter 10 of the WEM Rules (Market Rules) and considers that the framework could be amended to improve its functionality and alignment with the Wholesale Market Objectives.

Currently chapter 10 of the Market Rules:

- sets out six confidentiality classes which govern the disclosure of information to different parties;
- requires the IMO to set and publish the confidentiality for each type of market information and document produced or exchanged in accordance with the Market Rules or Market Procedures;
- provides principles to which the IMO must have regard when determining the confidentiality class of particular information;
- lists the information that the IMO must make available to each of the six confidentiality classes;
- provides the ability for the IMO to charge a fee for any ad-hoc requests for data where it incurs additional costs; and
- requires the IMO to document the process it follows to set and publish confidentiality statuses and the protocols by which it changes the Market Web Site in a Market Procedure.

2. Guiding principles

The IMO considers that a framework designed to appropriately manage the disclosure of market related information should:

- be simple and easy to understand and use;
- maximise the release of market related information;
- treat all market information and participants equitably;
- protect persons against the disclosure of information that would be to their detriment;

- ensure that the information required to effectively operate the South West interconnected system and WEM is available to the relevant parties; and
- be consistent with other applicable laws and regulations as well as the Market Rules, to the extent possible.

3. Assessment of the current framework

The IMO has faced considerable challenges in managing market information under the current framework. In particular, this has resulted in issues for the IMO including difficulty in understanding and using the framework to determine the current confidentiality status of market information and the appropriate confidentiality status of new or amended market information.

Issues with the current framework include:

Market Rules

- Some categories of data are given a confidentiality status under a generic clause and in some instances this is inconsistent with the confidentiality status of a specific piece of data that falls under that category, where the two are different it is not clear which status should prevail.
- There is no distinction between the status of a document and the information in that document, where the two are different it is not clear how the data should be treated.
- The numerous confidentiality classes make the framework complex to administer.
- The framework focuses on information relating to the supply-side of the WEM and does not adequately cover demand-side information.
- The method of disclosing information is not consistent, in some instances the Market Rules identify the method as through the Market Web Site but it is not clear that this could also include the Market Participant Interface.
- The confidentiality classes do not include Meter Data Agents, which makes it unclear as to how the IMO should treat the information produced or transferred from Meter Data Agents.

Market Procedure

- The purpose of the Market Procedure, as it is currently drafted, is unclear.
- The Market Procedure does not provide a process by which the IMO should determine the confidentiality status of market related information.

Confidentiality list

- The information in the confidentiality list is currently categorised by the relevant Market Rule provision, rather than the type of information, which has led to some inconsistencies between the confidentiality statuses assigned to the same information under different clauses.

These difficulties have led to inconsistent interpretations, inconsistent outcomes between applications, inconsistent governing documents and an out of date list of confidentiality statuses, which have resulted in operational inefficiencies, an increased risk of non-compliance with the Market Rules by the IMO and other Rule Participants and an overly conservative approach to sharing information that should be made available.

As a result, the IMO considers that the current framework is unduly difficult to administer and results in outcomes that are inconsistent with the Wholesale Market Objectives. Under the Market Rules, the Wholesale Market Objectives promote the economically efficient supply of electricity, encourage competition among generators and retailers and minimise the long-term cost of electricity. These objectives could be better achieved by promoting the disclosure of information to support more efficient decision-making and improved risk management.

The IMO has assessed the current framework against the guiding principles in Table 3.1.

Table 3.1: Assessment of current framework against principles

Principle	Assessment
Is simple and easy to understand and use	**Not met** • Different confidentiality classes make administration complex • Unclear interaction of Market Rules, Market Procedure and confidentiality list • Determination process not well defined
Maximises the release of market related information	**Not met** • Complexities of the framework create uncertainty of status of information • Inconsistencies between governance documents often leads to conservative view of confidentiality
Treats all market information and participants equitably	**Not met** • Initially developed to focus on supply-side • Demand-side information is not adequately covered
Protects persons against the disclosure of information that would be to their detriment	**Met**
Ensures that the information required to effectively operate the South West interconnected system and WEM is available to the relevant parties	**Met**
Is consistent with other applicable laws and regulations as well as the Market Rules, to the extent possible	**Not met** • Inconsistencies between governance documents

4. Proposed solution

The IMO proposes to implement a more suitable framework to promote the disclosure of market related information and thereby increase transparency in the market under the Market Rules and Market Procedures.

It should be noted that the confidentiality framework that is proposed applies to the disclosure of information in the WEM specifically and does not override other laws and regulations that govern the disclosure of information more broadly, including for example, the *Privacy Act 2008* (Cth) and *Freedom of Information Act 1992* (WA).

4.1 Proposed Market Rule requirements

The IMO proposes to amend relevant clauses of chapter 10 of the Market Rules to contain the principles that form the basis of it determining whether information should be public or confidential and remove the unnecessary prescriptive detail.

The proposed changes to the Market Rules are outlined in the sections below.

4.1.1 Guiding principles

The IMO proposes to introduce guiding principles into chapter 10 of the Market Rules:

1. The IMO must seek to maximise the number of parties to which market related information is made available.
2. Market related information is to be made public unless it is confidential.
3. Confidential information can be shared between the IMO, System Management, the Public Utilities Office, the Economic Regulation Authority and the Electricity Review Board.

4.1.2 Requirement to determine confidentiality

The IMO proposes to introduce an obligation in the Market Rules for the IMO to determine whether each piece of information explicitly provided under the Market Rules should be public or confidential.

In determining the confidentiality of market related information, the IMO proposes to consider:

- whether releasing the information would cause detriment, including where it is commercially sensitive or defamatory;
- whether the public benefit of the disclosure of the information outweighs any detriment caused;
- whether the information is required to be disclosed for safety, reliability or security of the network or the market;
- whether the information is already available, other than as a result of a breach of the confidentiality obligations;

- whether the information is permitted to be disclosed by law or the Market Rules; and
- whether consent for release of that information has been obtained from the person or persons to whom the information is confidential.

The IMO proposes to include the ability for Market Participants to request, and the IMO to determine whether any information not explicitly provided for under the Market Rules or Market Procedures is confidential. This will ensure that all market related information can be assessed with respect to its appropriate disclosure.

4.1.3 Rights and obligations associated with confidential information

The IMO proposes to incorporate some greater direction with respect to the rights and obligations of recipients of confidential information in the Market Rules. For example, the Market Rules must allow:

- confidential information to be made available to the IMO, System Management, the Public Utilities Office, the Economic Regulation Authority and the Electricity Review Board, and treated as confidential (i.e. not disclosed further unless authorised);
- confidential information to be disclosed in accordance with applicable laws and regulations;
- recipients of confidential information, other than as a result of a breach of the confidentiality obligations, to use the information for any purpose connected with the performance of their functions in the WEM;
- the IMO or Market Participants (as agreed by the IMO) to impose conditions to be complied with by the recipient of any confidential information, including for example for information provided for a specific purpose to only be used for that purpose;
- the disclosure of market information where any confidential information is omitted and cannot be determined from other disclosed market information, and the omission is identified in the disclosure; and
- the disclosure of market information where the information is aggregated to the extent that any confidential information cannot be determined from other disclosed market information.

4.1.4 Administrative matters

The IMO proposes to specify any confidential information explicitly required by the Market Rules and Market Procedures, who the information may be disclosed to, when, and how, in the section of the Market Rules to which the information relates.

The IMO proposes to introduce an obligation in the Market Rules for it to develop a Market Procedure outlining the process under which it will determine whether information is public or confidential. The IMO will also need to introduce a head of power clause in the Market Rules for that Market Procedure, outlining what must be covered by that procedure and requiring compliance with the process.

The IMO proposes to retain its ability to charge a fee for the provision of data following a request for data where it incurs additional costs to do so. However, simplifying the

Market Rules relating to publication of information will support the proactive release of more information by the IMO, which should minimise the data that could potentially attract such a charge.

4.2 Proposed Market Procedure requirements

The IMO proposes to amend the Market Procedure for Information Confidentiality to outline the method under which the IMO administers the confidentiality framework.

The IMO proposes to amend the Market Procedure to introduce the following process:

1. Either:
   (a) the IMO identifies new or amended market information to be assessed; or
   (b) a Market Participant requests the IMO to treat information as confidential.
2. Once the IMO has identified new or amended information or it receives a request to treat information as confidential, the IMO must publish its proposed treatment of that information in a document which must include:
   (a) whether the information or document can be made public or whether it, or any part of it should be confidential and the basis for the decision;
   (b) which parties (if any) the information may be disclosed to;
   (c) when the information may be disclosed;
   (d) how the information may be disclosed; and
   (e) any other applicable conditions.
3. The IMO must seek submissions from stakeholders on the proposed treatment of the information through a consultation period of at least 15 Business Days. During this period, where a stakeholder considers that information should be treated confidentially, it must provide reasons and evidence to the IMO's satisfaction to support the classification of information as confidential.
4. Following the consultation period, the IMO must:
   (a) consider any evidence provided by stakeholders;
   (b) determine whether the information is public or confidential;
   (c) publish its determination with the reasons on the Market Web Site; and
   (d) update the list of confidential information, as applicable.

The IMO proposes to use the rule and procedure change processes to facilitate this assessment. It is expected that this should cover the majority of cases where information needs to be assessed. However, the IMO notes that this proposed process could also be conducted outside of the rule or procedure change process, as appropriate.

4.3 Identification of confidential information

In addition to the identification of any confidential information in the section of the Market Rules to which the information relates, the IMO also proposes to publish a list of confidential information, including market information not explicitly required by the Market Rules or Market Procedures, organised by information type.

This should increase the ease of administration of the framework for the IMO and other Rule Participants.

5. Wholesale Market Objective assessment

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

Wholesale Market Objective (a)

The new confidentiality provisions will improve the effectiveness of the operation of the WEM by providing greater information to Market Participants. For example, this information could be used to prepare more competitive and accurate bids and offers than might otherwise be the case.

The IMO notes that the introduction of a streamlined, easy to use confidentiality framework would reduce the effort required to manage market related information under the Market Rules by the IMO and other Rule Participants. The IMO therefore considers that the proposed changes will reduce the overall effort associated with administering the WEM, thereby reducing the overall cost to the market.

Wholesale Market Objective (b)

Greater disclosure of market information is likely to improve competition by providing more participants with a greater level of information about the market, allowing for more efficient decisions and better risk management. The new confidentiality provisions should also make the overall market more attractive to new entrants through increased transparency and availability of market related information. By more accurately signalling the need for and value of energy, the proposal should promote efficient investment (e.g. in relation to the need for and value of flexibility).

Wholesale Market Objective (c)

The revision of the confidentiality status of market related information will ensure that the Market Rules equitably treat supply-side and demand-side market information, thereby ensuring that the confidentiality provisions do not discriminate between energy options.

Wholesale Market Objective (d)

By increasing transparency of information and competition between Market Generators in the WEM, the proposed confidentiality provisions are likely to drive down market costs in the short to medium term. In the longer term, the provision of correct cost reflective prices should help to minimise overall costs by encouraging participants to factor the value of flexibility and/or actual cost impacts into their investment decisions.

6. Cost and practicality of implementation

The IMO proposes to align the consultation with stakeholders on the Rule Change Proposal, Procedure Change Proposal and initial ‘confidentiality list’. This will allow stakeholders to comment on the proposed suite of changes as a package and consider the new framework holistically.

To do this, the IMO will:

1. complete a stocktake of all the market information required under the Market Rules;
2. document each piece of information it determines should be confidential in a proposed ‘confidentiality list’;
3. invite stakeholders to make submissions on the Rule Change Proposal, Procedure Change Proposal and initial ‘confidentiality list’ together over a first submission period of six weeks;
4. finalise the Rule Change Proposal, Procedure Change Proposal and ‘confidentiality list’; and
5. if approved, commence the proposed Amending Rules and proposed amended Market Procedure: Confidentiality of Information and publish the ‘confidentiality list’.

The IMO does not expect any direct costs associated with the implementation of the recommendations.

It should be noted that the necessary amendments to the Market Rules are likely to affect Protected Provisions and therefore, the Rule Change Proposal will require Ministerial approval.

7. Action points

The IMO recommends that MAC members:

- **consider and discuss** the proposed solution; and
- **note** that the IMO will prepare a pre Rule Change Proposal, proposed amended Market Procedure and proposed ‘confidentiality list’, to be presented at an upcoming MAC meeting.

Agenda item 7.1: Overview of Rule Change Proposals

3 December 2014

Below is a summary of the status of Market Rule Change Proposals as at 26 November 2014 that are either currently being progressed by the IMO or have been registered by the IMO as potential Rule Change Proposals to be progressed in the future.

Table 1: Rule Change Proposals in progress

ID	Title	Submitter	Next step	Date
Standard with first consultation open				
RC_2014_03	Administrative Improvements to the Outage Process	IMO	Submissions close	30/01/2015
Standard with first consultation period closed				
RC_2013_15	Outage Planning Phase 2 – Outage Process Refinements	IMO	Draft Rule Change Report published	31/12/2014*
Standard with second consultation period closed				
RC_2013_20	Changes to the Reserve Capacity Price and the Dynamic Reserve Capacity Refunds Regime	IMO	Final Rule Change Report published	31/12/2014*
RC_2013_21	Limit to Early Entry Capacity Payments	IMO	Final Rule Change Report published	31/12/2014*
Awaiting Ministerial approval/commencement				
RC_2014_02	Removal of Facility Aggregation	IMO	Ministerial approval	12/12/2014

* The timeframes for some Rule Change Proposals have been extended on the basis that the IMO considers that these Rule Change Proposals are likely to overlap with issues considered as part of the Review and/or are likely to have significant implementation costs. The extension of the IMO's consideration of these proposed amendments will allow the consideration of the outcomes of the Electricity Market Review (EMR) and any potential impacts. If the outcomes of the EMR are not announced before the end of 2014, the IMO will consider a further extension of these Rule Change Proposals.

INDEPENDENT
MARKET
OPERATOR

Wholesale Electricity Market
Pre Rule Change Proposal

Rule Change Proposal ID: **PRC_2014_06**
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
Rule Change Proposal title:	Removal of Resource Plans and Dispatchable Loads
Market Rules affected:	**Numerous**

Introduction

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

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

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

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

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

The objectives of the market are:

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

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

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

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

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

Details of the Proposed Rule Change

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

Background

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

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

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

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

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

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

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

- MREP Issue 3: Transition to half hour Balancing Gate Closure, which was expanded to also include the reduction of LFAS Gate Closure timeframes.

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. MAC members were generally supportive of the proposal, subject to System Management's reservations about moving to a half-hour gate closure immediately.

Following the December 2013 meeting the IMO developed the Pre Rule Change Proposal: Improvements to the Energy Market (PRC_2014_01). Consistent with the previous MAC discussions, PRC_2014_01 proposed the removal of Resource Plans and the reduction of gate closure times, as well as several other changes to address outstanding issues in related areas of the Market Rules.

PRC_2014_01 was presented at the 19 March 2014[5] and 14 May 2014[6] MAC meetings, with the IMO noting at the latter meeting its intention to submit the proposal into the formal rule change process. However, on 19 May 2014 the Minister for Energy notified the IMO of his decision to not approve two Rule Change Proposals, Incentives to Improve Availability of Scheduled Generators (RC_2013_09) and Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10)[7]. The Minister advised that in making his assessment he had "taken into account that the costs to implement the amendments may not be recovered in light of possible reforms emanating from the Electricity Market Review".

At the MAC meeting on 25 June 2014, the IMO informed MAC members that, given the context of the Electricity Market Review and the reasons provided by the Minister for his rejection of the two Rule Change Proposals, the IMO had revised its 2014-15 work plan to avoid any changes that were likely to have significant implementation costs, such as the gate closure changes proposed in PRC_2014_01.

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[4] See http://www.imowa.com.au/MAC_67.
[5] See http://www.imowa.com.au/MAC_69.
[6] See http://www.imowa.com.au/MAC_71.
[7] See http://www.imowa.com.au/RC_2013_09 and http://www.imowa.com.au/RC_2013_10.

This Rule Change Proposal comprises the remaining, lower cost components of PRC_2014_01.

One additional change has been included in the proposal. During the 19 March 2014 MAC meeting Mr Andrew Stevens proposed modifying the Bilateral and STEM Submission windows so that Market Participants had longer to make Bilateral and STEM Submissions[8]. After several discussions, the MAC agreed to extend the STEM Submission window and to delay the STEM Auction and related processes by one hour, leaving the other submission timelines unchanged[9].

Issues and proposed solutions

In this Rule Change Proposal the IMO seeks to:

- remove the requirement to submit Resource Plans from the Market Rules;
- address a number of secondary issues caused by the proposed removal of Resource Plans;
- remove the Dispatchable Load Facility Class from the Market Rules;
- extend the STEM Submission window by one hour; 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.

Issue 1: Resource Plans

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

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

- provision of information for System Management planning;
- preparation of System Management forecasts for Synergy and the IMO;
- definition of Reserve Capacity Obligations and the calculation of Net STEM Shortfall;
- definition of restrictions placed on Balancing Facilities not meeting the Balancing Facility Requirements;
- specification of the conditions under which System Management may refuse permission for a Scheduled Generator to synchronise or desynchronise; and

[8] See http://www.imowa.com.au/MAC_69
[9] See http://www.imowa.com.au/MAC_75

- determination of consumption baselines for Dispatchable Loads.

Proposed solution:

The IMO proposes to remove Resource Plans completely from the Market Rules, by deleting the Resource Plan, Resource Plan Submission and Standing Resource Plan Glossary definitions, clauses 2.34.14(a)(iB) and 10.5.1(h)(iii) and sections 6.5, 6.5C, 6.11 and 7.4, as well removing any references to Resource Plans in other clauses. The IMO proposes to address the six points covered above as follows.

- **Information required for System Management planning:** System Management currently receives the Resource Plans for a Trading Day shortly after 1:00 pm on the Scheduling Day. System Management uses the Resource Plan information to assess likely Facility commitment decisions, check network load flow implications and develop the initial Synergy Dispatch Plan.

  The information provided is of limited value following the commencement of the Balancing Market as the Resource Plans are no longer binding and do not necessarily show how the IPP Facilities intend to operate.

  While a Forecast Balancing Merit Order (BMO) would provide System Management with the information it needs, the first Forecast BMO is not produced until just after 6:00 pm, when the Balancing 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 Balancing Horizon at 1:00 pm each day rather than 6:00 pm, so that the first Forecast BMO 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 Balancing Horizon is extended from 6:00 pm to 1:00 pm, by amending the Glossary definition of Balancing Horizon and clauses 7A.2.9(d)(i) and 7B.2.3. This means that System Management will receive the first Forecast BMO for a Trading Day shortly after 1:00 pm on the Scheduling Day.

- **System Management forecasts for Synergy and the IMO:** The Market Rules also require System Management to use Resource Plan data to provide the following information for a Trading Day by 4:00 pm on the Scheduling Day:

  - under clause 7.6A.2(c)(i), to Synergy, a forecast of the energy requirements for the Balancing Portfolio; and

  - under clause 7.6A.2(e), to the IMO, the aggregate forecast output of all non-Balancing Portfolio Non-Scheduled Generators, for publication on the Market Web Site.

  Synergy has advised the IMO that it does not require the Resource Plan information provided under clause 7.6A.2(c)(i) to form its initial Balancing Submissions.

  Similarly, the IMO considers that the non-scheduled generation forecasts provided under clause 7.6A.2(e) and published under clause 7A.3.21(c) are of little use to Market Participants, as the Balancing Forecasts published by the IMO for each Trading Interval contain a much more up-to-date non-scheduled generation forecast, derived from the Forecast BMO.

Proposed Solution:

The IMO proposes to:

- o remove the obligation on System Management to provide information to Synergy and the IMO under clauses 7.6A.2(c)(i) and 7.6A.2(e);
- o remove the obligation under clause 7A.3.21(c) for the IMO to publish a non-scheduled generation forecast provided by System Management under clause 7.6A.2(e); and
- o clarify in the Balancing Forecast Market Procedure that the non-scheduled generation forecast component of a Balancing Forecast is calculated from the MW quantities in the Forecast BMO associated with Balancing Facilities that are Non-Scheduled Generators.

- **Reserve Capacity Obligations and Net STEM Shortfall:** Clause 4.12.1 of the Market Rules sets out the Reserve Capacity Obligations of a Market Participant holding Capacity Credits, while clause 4.26.2 gives details of the Net STEM Shortfall calculation. For IPPs both clauses refer to two quantities provided in a Resource Plan: the shortfall relative to the Market Participant's Net Contract Position 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 clause 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 4.12.1 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 4.12.1 and 4.26.2 to make the Reserve Capacity Obligation provisions currently applicable to STEM Submissions made by 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 Balancing Facilities not meeting the Balancing Facility Requirements:** Clause 7A.1.11 of the Market Rules allows the IMO to impose conditions on the Balancing Market participation of Balancing Facilities not meeting the Balancing Facility Requirements. These conditions are published in the Market Procedure: Balancing Facility Requirements, 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 Balancing Facilities that do not meet the Balancing Facility Requirements to amend their Balancing Submissions up to Balancing Gate Closure, provided that the prices offered in the submissions are restricted to the relevant Price Caps.

<u>Proposed Solution:</u>

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

- **Commitment:** Section 7.9 of the Market Rules outlines the processes that Market Participants and System Management must follow for synchronisation and desynchronisation of Scheduled Generators. For IPPs, clause 7.9.4 allows System Management to refuse permission to synchronise if this synchronisation is not in accordance with the relevant Resource Plan, Dispatch Instruction or Operating Instruction, while clause 7.9.8 does likewise for desynchronisation. Since the commencement of the Balancing Market the references in these clauses to Resource Plans have been unnecessary; even if a Scheduled Generator is expected to follow its Resource Plan, System Management must still send a Dispatch Instruction for each scheduled change in output.

  <u>Proposed Solution:</u>

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

- **Baseline for Dispatchable Loads:** Market Customers with Dispatchable Loads are required to submit Resource Plans, in order to provide a consumption baseline for settlement in the event that a Dispatchable Load receives a Dispatch Instruction. While it would be possible to develop alternative arrangements for the provision of these baselines, for a number of reasons the IMO proposes instead to remove Dispatchable Loads as a Facility Class in the Market Rules. Please refer to Issue 2 for further details.

Issue 2: 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-Balancing 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 Balancing Market 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, from preliminary discussions it seems likely that such a facility would incorporate some kind of energy storage. A facility of this type would be able to not only reduce its consumption in peak times but to actually provide energy to the SWIS, actively participating in the Balancing Market and being dispatched through the BMO, as well as potentially providing Ancillary Services.

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

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

Proposed solution:

The IMO proposes to remove the Dispatchable Load Facility Class and any requirements that only relate to Dispatchable Loads from the Market Rules. This involves the deletion of clauses 2.27.1(a)(iv), 2.27.5(d)(iv), 2.29.1A(e), 2.29.5(c), 2.29.8, 3.9.6(b), 4.12.1(a)(iiA), 4.26.2(d)(iiA), 6.12.1(c), 6.12.1(e), 6.17.6(a), 6.17.6(b), 6.17.6A, 9.3.3(c) and 9.3.4(c), the Glossary definitions of Dispatchable Load and Consumption Increase Price and Appendix 1(i), as well as the removal of references to Dispatchable Loads in various other clauses.

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

Issue 3: STEM Submission window

The STEM Submission window is currently open for 50 minutes from 9:00 am to 9:50 am. This can leave little time to correct errors if a Market Participant experiences an IT system failure or has a STEM Submission rejected.

With the proposed removal of Resource Plans, there is no need for the STEM Auction results to be published in time for Market Participants to make Resource Plan Submissions at 11:00 am. Although the IMO proposes that Market Participants make their initial Balancing Submissions by 1:00 pm, the first affected Trading Interval does not start until 8:00 am the following day and Market Participants would be able to revise their Balancing Submissions for this Trading Interval up until 4:00 am for Synergy and 6:00 am for IPPs.

Proposed solution:

The IMO proposes to amend clause 6.3B.1 and section 6.4 of the Market Rules so that the

STEM Submission window closes at 10:50 am rather than 9:50 am. The timelines for the associated STEM Auction processes will be delayed by one hour to reflect the extension of the submission window.

Issue 4: Update of STEM Submission parameters

Under clause 6.3A.3 of the Market Rules the IMO must by 9:05 am each Scheduling Day provide each Market Participant with a set of parameters to assist them with the STEM Submission process. The parameters include details of any STEM Submissions that have already been submitted by the Market Participant and accepted by the IMO for the Trading Day. Clause 6.3A.4 requires the IMO to provide Market Participants with updated versions of these parameters by 9:30 am. In practice, whenever a STEM Submission is accepted the parameters are immediately recalculated and made available to the relevant Market Participant.

Proposed solution:

The IMO also proposes to amend clause 6.3A.4 to clarify that the parameters provided to Market Participants under clause 6.3A.3 are updated whenever a STEM Submission is accepted.

Issue 5: Fuel Declarations

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

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

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 Balancing Submissions, in the BMO.

Issue 6: Interaction between forecast and final BMOs and LFAS Merit Orders

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

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

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

Proposed solution:

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

Issue 7: Requirement for System Management and Synergy to meet monthly

Clause 7.6A.5 of the Market Rules requires representatives of System Management and Synergy to meet at least once per month, to review the procedures operating under section 7.6A of the Market Rules for the scheduling and dispatch of the Balancing Portfolio. Both System Management and Synergy have advised the IMO that they do not find it necessary to meet each month and so the requirement is creating an unnecessary administrative overhead for both parties.

Proposed solution:

The IMO proposes to amend clause 7.6A.5(a) to remove the requirement for mandatory monthly meetings when both System Management and Synergy agree that they are not required.

Issue 8: Clarification of Balancing Submission quantities

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

Proposed solution:

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

Other Changes

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

- update of the Glossary definition of Balancing Market, to clarify its role in the dispatch of generation in the WEM;
- removal of the obsolete transitional provisions in sections 1.10 and 1.11 and in clause 3.13.3AB, and their associated Glossary definitions;
- update of clause 2.16.2(hC) to clarify that the Market Surveillance Data Catalogue must identify any substantial variations in *Metered* Balancing Quantities (i.e. the net sum of Metered Schedules less Net Contract Position) rather than Balancing Quantities (currently defined as the forecast End of Interval (EOI) Quantities provided

to Market Participants by the IMO when it determines a Forecast BMO);

- inclusion of a Glossary definition for the term 'Balancing Settlement';
- removal of the Glossary definitions:
  - Balancing, as the current definition ("the process for meeting supply and consumption deviations from contracted bilateral and STEM positions in each Trading Interval") is obsolete and the term is no longer required;
  - Balancing Portfolio Supply Curve, as there is no requirement for a specific term to describe the set of Balancing Price-Quantity Pairs for the Balancing Portfolio;
  - Balancing Quantity, as the term is only used in clause 2.16.2(hC) and, as discussed above, this reference is incorrect and proposed to be removed; and
  - Non-Balancing Facility, as with the proposed removal of Dispatchable Loads this term becomes synonymous with Demand Side Programme;
- update of clauses 7.6.1C(d), 7.7.2 and 7.7.5 to refer to a 'Demand Side Programme' instead of a 'Non-Balancing Facility';
- clarification that reflecting an Operating Instruction in a Balancing Submission might require more than bidding a specific quantity at the Minimum STEM Price in clause 7A.2.3;
- removal of prescriptive detail about the tie-break processes for Forecast BMOs in clause 7A.3.3 and for Forecast LFAS Merit Orders in clause 7B.3.3, which is already included in the Balancing Forecast Market Procedure;
- improvements to the consistency of the names used for various LFAS quantities and constrained on and off payments;
- removal of references to RCOQ(f,d,t) in clauses 4.26.2B and clause 4.26.5, as the term is no longer used in the Market Rules;
- removal of the requirement to publish the Balancing Price in clause 10.5.1(j) as this requirement is already covered in clause 10.5.1(iA)(i)(4);
- clarification of the requirement in clause 10.5.1(iA)(ii) to publish full Balancing Submission details after seven days; and
- correction of minor and typographical errors.

Impact on the WEM Regulations and Protected Provisions

Reviewable Decisions

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

Civil Penalties

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

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

- Clause 2.27.1: *Obligation for a Network Operator to provide Loss Factors to the IMO (category A)* – the only change proposed to this clause is to remove the reference to Dispatchable Loads. It should be noted that the Public Utilities Office (PUO) is currently considering which clauses, if any, in section 2.27 (including clause 2.27.1) should be subject to civil penalties, following the commencement of the Amending Rules in the Rule Change Proposal: Loss Factor Determination (RC_2012_07).

- Clause 2.34.3: *Requirement to notify the IMO of changes to Standing Data (category B)* – the only changes proposed are the removal of a reference to Standing Resource Plans and the replacement of the word 'clauses' with 'sections'.

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

- Clause 2.37.5: *Factors the IMO must take into account when determining a Market Participant's Credit Limit (category B)* – the only change proposed to the clause is to use the new defined term 'Balancing Settlement'. It should be noted that this clause was substantially altered by the Amending Rules for the Rule Change Proposal: Prudential Requirements (RC_2012_23)[10]. The clause is no longer an appropriate civil penalty provision as it now relates to factors for the IMO to consider, rather than an obligation on a Market Participant. The PUO is currently seeking to delete the clause from the WEM Regulations and replace it with a category B civil penalty on clause 2.37.8(a).

- Clause 7.6A.3: *Requirement for Synergy to notify System Management of its non-compliance with an Operating Instruction or instruction to deviate from the Dispatch Plan (category C)* – the only change proposed is to replace 'LFAS Backup Enablement' with 'Backup LFAS Enablement' in the opening text of clause 7.6A.3 (note that only clause 7.6A.3(c) is subject to civil penalties).

- Clause 7.6A.5(e): *Requirement for Synergy and System Management to make records about the dispatch of Synergy Facilities created under section 7.6A available to the IMO if requested (category B)* – the only change proposed is the replacement of the word 'clause' with 'section'.

- Clause 7A.2.8: *Details what a Balancing Submission must accurately reflect (category C)* – the only change proposed is to update a clause reference.

- Clause 7A.2.9: *Details Balancing Submission requirements for the Balancing Portfolio (category C)* – the only changes proposed are to avoid the use of the term 'Balancing Portfolio Supply Curve' and to remove a redundant phrase.

- Clause 7A.2.13: *Requirement to make Balancing Submissions in good faith (category C)* – the only change proposed is to replace 'clause 7A.2' with 'section 7A.2'.

- Clause 7B.2.10: *Requirement to ensure LFAS Submissions are accurate (category C)*

[10] See http://www.imowa.com.au/RC_2012_23 for further details. The Amending Rules for RC_2012_23 commenced on 1 May 2014.

– the only change proposed is to make the requirement subject to clause 7B.2.4 (to acknowledge the earlier LFAS Submission deadline for the Balancing Portfolio).

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

- Clause 2.29.8: *Rule Participant requirements in relation to a Dispatchable Load (category B)*.
- Clause 6.5.1A: *Requirement to submit Resource Plans (category B).*
- Clause 7.5.5: *Market Participant requirements in relation to notifications of a change of fuel (category C)*.

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

Protected Provisions

The IMO notes that clauses 2.13.6L, 2.16.2, 2.16.4, 2.16.12, 2.22.1, 2.34.1 and 2.36.1 are Protected Provisions. Under clause 2.8.3 of the Market Rules, amendments to a Protected Provision require the Amending Rules in this Rule Change Proposal to be approved by the Minister.

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2. Explain the reason for the degree of urgency:

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

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

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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:

Resource Plans (Issue 1)

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 unnecessary processes 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 Balancing 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.

Dispatchable Loads (Issue 2)

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.

STEM Submission window (Issue 3)

The proposed extension of the STEM Submission window will promote economic efficiency (Wholesale Market Objective (a)) and encourage competition among generators and retailers (Wholesale Market Objective (b)) by reducing the risks for Market Participants of not meeting the deadline for making a valid STEM Submission.

Update of STEM Submission parameters (Issue 4), interaction between forecast and final BMOs and LFAS Merit Orders (Issue 6) and clarification of Balancing Submission quantities (Issue 8)

The proposed changes to the wording of clause 6.3A.4, section 7A.3 and section 7B.3 of the Market Rules and the clarification of how available and unavailable capacity is specified in a Balancing Submission will encourage competition in the market by improving the clarity of the Market Rules (Wholesale Market Objective (b)).

Fuel Declarations (Issue 5) and requirement for System Management and Synergy to meet monthly (Issue 7)

The proposed removal of the obligations around the provision of Fuel Declarations to System Management and the holding of monthly meetings between System Management and Synergy will promote economic efficiency (Wholesale Market Objective (a)) and contribute to minimising the long-term cost of electricity (Wholesale Market Objective (d)) by eliminating unnecessary processes from the Market Rules.

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

Costs:

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 quantify the costs of these changes.

Some Market Participants are also likely to incur costs associated with IT system and process changes.

Benefits:

The benefits of these changes include:

- reducing the burden on Market Participants of having to comply with unnecessary or redundant obligations;
- reducing the cost and burden of maintaining unnecessary system functionality;
- reducing the risk of failing to submit a STEM Submission;
- improving the quality of the information used for dispatch and pricing; and
- improving the clarity and integrity of the Market Rules.

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6. Provide any identifiable issues with respect to the practicality of implementation:

The IMO notes that the proposed Amending Rules will require Ministerial approval as they include changes to Protected Provisions 2.13.6L, 2.16.2, 2.16.4, 2.16.12, 2.22.1, 2.34.1 and 2.36.1.

Amendments to the Schedule 1 of the WEM Regulations (civil penalty provisions and amounts) will also be required, to remove clauses 2.29.8, 6.5.1A and 7.5.5.

Minor changes will be required to a number of Market Procedures and PSOPs, including:

- Market Procedure: Balancing Facility Requirements;
- Balancing Forecast Market Procedure;
- Market Procedure: Data and IT Interface;
- Monitoring Protocol;
- IMS Interface Market Procedure;
- Market Procedure: Determining Loss Factors;
- Market Procedure: Settlement;
- Market Procedure: Certification of Reserve Capacity;
- Market Procedure: Reserve Capacity Testing;
- PSOP: Ancillary Services;
- PSOP: Communications and control systems;
- PSOP: Dispatch;
- PSOP: Monitoring and Reporting Protocol;

- PSOP: Operational Data Points for Generating Plant; and
- PSOP: Operational Data Points for Non-Western Power Networks, Substations and Loads.

Changes will also be required to a range of other market documents published by the IMO, including market design summaries and user guides.

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

~~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~~[Blank]

~~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.~~

2.13.6L. 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:

…

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

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

…

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

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

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

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

…

(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~~ Mechanism;

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

iii. the STEM;

iv. the Balancing Market;

…

2.22.1. For the purposes of this ~~clause~~ section 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 ~~and~~, Balancing Market and LFAS Market and the IMO's settlement and information release functions;

…

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:

…

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

…

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:

…

(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;

…

2.27.15. A Market Participant may apply to the IMO for a reassessment of any Transmission Loss Factor or Distribution Loss Factor applying to a Scheduled

Generator, Non-Scheduled Generator, Interruptible Load~~, Dispatchable Load~~ or Non-Dispatchable Load registered to that Market Participant. The following requirements apply to each application for reassessment:

...

2.29.1A. The Facility Classes:

(a) a Network;

(b) a Scheduled Generator;

(c) a Non-Scheduled Generator;

(d) an Interruptible Load; and

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

(f) a Demand Side Programme.

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

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

~~(b) [Blank]~~

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

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

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

2.29.8. ~~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~~ sections 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~~ sections 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 Prices, to determine Non-Balancing 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;

…

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 where no historical Balancing ~~settlement~~ Settlement payment data is available;

…

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

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

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

~~(c) [Blank]~~

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

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

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

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

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

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

...

~~3.13.3AB. During the period:~~

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

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

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

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

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

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

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

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

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

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

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

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~~

…

4.10.1. 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;

…

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

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

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

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

1. not less than four 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~~,~~ or 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;

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

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

…

4.11.4. Subject to clause 4.11.12, when assigning Certified Reserve Capacity to an Interruptible Load~~,~~ or a Demand Side Programme~~ or Dispatchable Load~~, the IMO must indicate what Availability Class is applicable to that Certified Reserve Capacity where this Availability Class must reflect the maximum number of hours per year that the capacity will be available and must not be Availability Class 1.

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~~ <u>the Market Participant's Net Contract Position in MWh for</u> the Trading Interval<u>, corrected for Loss Factor adjustments so as to be a sent out quantity</u> ~~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~~ <u>section</u> 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.

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

…

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~~ identity of the Market Participant's Facility covered by the Reserve Capacity Offer; and

(c) for Interruptible Loads~~,~~ and 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:

…

(d) if the Facility is an Interruptible Load~~,~~ or 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~~ section 4.11.

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

…

(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:

…

(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.

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

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

Where:

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

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

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

(b) the sum of the product of:

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

ii. the Reserve Capacity Obligation Quantity for each Facility,

for all Market Participant p's Registered Facilities, excluding Demand Side Programmes, CAPA(p,d,t) is for Market Participant p and Trading Interval t of Trading Day d:

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

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~~ section 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)).~~

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~~ section 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~~ Facility's Loss Factor.

4.26.5. To support the calculation of the values of RCOQ(p,d,t)~~ and RCOQ(f,d,t)~~ required by clause 4.26.2:

…

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:

(a) the Maximum Supply Capability where this equals the maximum Loss Factor adjusted quantity of energy, in units of MWh, that could be supplied during the Trading Interval based on the Standing Data of that Market Participant's Scheduled Generators and Non-Scheduled Generators and assuming the use of the fuel which maximises the capacity of each Facility:

i. 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; and

ii. less, for each Market Participant that is a provider of Ancillary Services, the estimated Loss Factor adjusted quantity of energy, in units of MWh, that could potentially be called upon by System Management from that Market Participant after 1:00 PM on the Scheduling Day to meet Ancillary Service requirements for each Trading Interval of the Trading Day, as provided to the IMO by System Management in accordance with clause 7.2.3B;

where the Maximum Supply Capability may be higher than the actual capacity available during the Trading Interval;

(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;

(c) for each Scheduled Generator and Non-Scheduled Generator that is registered as being able to run on Liquid Fuel only, the maximum Loss Factor adjusted quantity of energy, in units of MWh, that could be supplied during the Trading Interval based on the Standing Data of that Scheduled Generator or Non-Scheduled Generator 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;

(d) for each Scheduled Generator and Non-Scheduled Generator that is registered as being able to run on both Liquid Fuel and Non-Liquid Fuel, the maximum Loss Factor adjusted quantity of energy, in units of MWh, that could be supplied during the Trading Interval when run on each of Liquid Fuel and Non-Liquid Fuel based on the Standing Data of that Scheduled Generator or Non-Scheduled Generator 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; and

(e) in the case of each Market Participant that is a provider of Ancillary Services:

i. the estimated Loss Factor adjusted quantity of energy, in units of MWh, that could potentially be called upon by System Management after 1:00 PM on the Scheduling Day to meet Ancillary Service requirements for each Trading Interval of the Trading Day; and

ii. the list of Facilities that System Management might reasonably expect to call upon to provide the energy described in clause 6.3A.2(e)(i),

as provided to the IMO by the System Management in accordance with clause 7.2.3B.

6.3A.4. ~~By 9:30 AM on the Scheduling Day the IMO must have updated its calculations of the quantities specified in clause 6.3A.3(a) to (e), and must release to each Market Participant those updated parameters applicable to that Market Participant.~~If the IMO accepts a STEM Submission from a Market Participant after it has released the parameters required under clause 6.3A.3 for a Trading Day, then the IMO must as soon as practicable update its calculations of the quantities specified in clauses 6.3A.3(d) and 6.3A.3(e) for that Trading Day and release those updated parameters to the Market Participant.

6.3B.1. A Market Participant may submit STEM Submission data for a Trading Day to the IMO between:

(a) 9:00 AM on the Scheduling Day; and

(b) ~~9:50 AM~~ 10:50 AM on the Scheduling Day.

6.4.1. The IMO must undertake the process described in ~~clause~~ section 6.9 and determine the STEM Auction results for a Trading Day ~~no earlier than 10:00 AM~~ after 10:50 AM, and ~~no later than 10:30 AM~~ before 11:30 AM, on the relevant Scheduling Day.

6.4.2. The IMO must communicate to System Management the total quantity of energy scheduled to be supplied under Bilateral Contracts and in the STEM Auction, by each Market Participant, for each Trading Interval of a Trading Day by ~~10:30 AM~~ 11:30 AM on the relevant Scheduling Day.

6.4.3. The IMO must make available to each Market Participant the following information in relation to a Trading Day by ~~10:30 AM~~ 11:30 AM on the relevant Scheduling Day:

(a) the Trading Intervals, if any, in which the STEM Auction was suspended;

(b) the STEM Clearing Price in all Trading Intervals for which the STEM Auction was not suspended;

(c) the quantities scheduled in respect of that Market Participant in the STEM Auction for each Trading Interval; and

(d) the Net Contract Position of the Market Participant in each Trading Interval, as determined in accordance with clause 6.9.13.

6.4.4. Market Participants to which the information described in clause 6.4.3 relates for a Trading Day must access that information by ~~10:45 AM~~ 11:45 AM on the relevant Scheduling Day.

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~~ 11:45 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.

6.4.6. In the event of a software system failure at the IMO site or its supporting infrastructure, or any delay in receiving any of the information as described in clauses 7.2.3B or 7.3.4, which prevents the IMO from completing the relevant processes, the IMO may extend one or more of the timelines prescribed in ~~clauses~~ sections 6.2, 6.3A, 6.3B and this clause 6.4, subject to:

(a) any such extension not resulting in more than a two hour delay to any of the timelines prescribed in ~~clauses~~ sections 6.2, 6.3A, 6.3B and this ~~clause~~ section 6.4; and

(b) any such extension maintaining a ~~50~~ 110 minute window between the timelines prescribed in clauses 6.3B.1(a) and 6.3B.1(b) as extended by the IMO,

and the IMO must advise Rule Participants of any such extension 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, the Balancing Market and ~~Settlement~~ settlement. The Market Generator must submit to the IMO an application in a form specified by the IMO, including supporting evidence of the relevant arrangements, and specifying the dates over which the application will apply.

~~Resource Plans~~

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

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

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

~~(aA) [Blank]~~

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

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

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

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

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

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

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

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

~~(c) [Blank]~~

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

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

~~(e) other than for Synergy, any shortfall in MWh for each Trading Interval between the net energy scheduled in the Resource Plan Submission and the Net Contract Position of the Market Participant.~~

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

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

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

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

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

~~(c) [Blank]~~

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

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

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

~~Where:~~

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

~~NCP = the Net Contract Position~~

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

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

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

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

~~or~~

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

~~Where:~~

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

~~NCP = Net Contract Position~~

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

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

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

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

6.12.1.

(a) By 1:30 PM on the Scheduling Day ~~(or within 40 minutes of a closing time extended in accordance with clause 6.5.1(b))~~ the IMO must determine the Non-Balancing Dispatch Merit Orders identified in clauses 6.12.1(b) ~~to 6.12.1(e)~~ and 6.12.1(d). A Non-Balancing 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~~ The IMO must determine 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~~, taking into account the following principles ~~when determining this Non-Balancing Dispatch Merit Order~~:

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

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

(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~~ The IMO must determine 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~~, taking into account the following principles ~~when determining this Non-Balancing Dispatch Merit Order~~:

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

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

(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~~ Demand Side Programmes are equal, then, for the purposes of determining the ranking in any Non-Balancing Dispatch Merit Order, the IMO must rank a ~~Registered Facility~~ Demand Side Programme with a greater load registered in Standing Data in items (h)(iii) ~~or (i)(iii)~~ of Appendix 1 before a ~~Registered Facility~~ Demand Side Programme with a lesser load. In the event of a tie, the IMO will randomly assign priority to break the tie.

Balancing ~~Pricing~~ Prices and Quantities

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

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

...

(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~~ in respect of 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 Portfolio's 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 Portfolio's 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.

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

...

(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~~ in respect of 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 Portfolio's 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 Portfolio's 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.

6.16A.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 in respect of the Facility;

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

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

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

2. the applicable Settlement Tolerance.

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

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

(b) zero if:

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

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

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

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

2. the applicable Settlement Tolerance; or

iv. the Balancing 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.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 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 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 Backup Downwards LFAS ~~Backup~~ Enablement, both divided by two so that they are expressed in MWh;

3. if a Load Rejection Reserve Event has occurred, any Load Rejection Reserve Response Quantity; and

4. the Portfolio Settlement Tolerance.

6.17. Balancing Settlement Quantities

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

(a) the Metered Balancing Quantity;

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

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

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

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

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

in accordance with this ~~clause~~ section 6.17.

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

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

...

(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 Backup Upwards LFAS ~~Backup~~ Enablement, which the Balancing Facility was instructed to provide by System Management;

...

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

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

...

(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 Backup Downwards ~~Backup~~ LFAS Enablement, which the Balancing Facility was instructed to provide by System Management;

...

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

6.17.5. Subject to clause 6.17.5C, the IMO must attribute any Upwards Out of Merit Generation from the Balancing 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 Portfolio's 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) Portfolio 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~~ for 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's ~~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. Portfolio 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 Portfolio 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. Backup Upwards LFAS ~~Backup~~ Enablement; and

iii. the Spinning Reserve Response Quantity;

(f) If:

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

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

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

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

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

6.17.5A. Subject to clause 6.17.5C, the IMO must attribute any Downwards Out of Merit Generation from the Balancing 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 the Balancing Portfolio's 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~~ for the Balancing Portfolio ~~Supply Curve~~ with a price lower than Price N, then:

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

1. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched down from the Balancing Portfolio's ~~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 Portfolio 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. Backup Downwards LFAS ~~Backup~~ Enablement; and

iii. the Load Rejection Reserve Response Quantity ;

(f) If:

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

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

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

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

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

…

6.17.6. The Non-Balancing 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 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.~~

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

(a) the Balancing Price; and

(b) for each Market Participant:

i. the Metered Balancing Quantity;

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

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

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

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

vi. the Non-Balancing Facility Dispatch Instruction Payment.

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

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

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

(b) Loss Factors determined in accordance with~~ clause~~ section 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~~ non-scheduled generation by Trading Interval determined in accordance with~~ clause~~ section 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~~ section 3.19;

(h) transmission Forced Outages and Consequential Outages by Trading Interval received from Network Operators in accordance with~~ clause~~ section 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~~ section 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 Dispatch Merit Order received from the IMO in accordance with ~~clause~~ section 7.5;

(l) Supplementary Capacity Contract data, if any, received from the IMO in accordance with ~~clause~~ section 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.

7.2.2. The Load Forecasts for a Trading Day described in clause 7.2.1 must:

(a) represent Non-Dispatchable Load and Interruptible Load net of forecast ~~N~~non-~~S~~scheduled ~~G~~generation;

…

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 Dispatch Merit Order~~s and Fuel Declarations~~

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

7.5.2. Upon receipt of the Non-Balancing Dispatch Merit Orders~~ 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 Dispatch Merit Orders~~ and Fuel Declarations~~.

7.5.3. In the event that the IMO does not receive confirmation of receipt of the Non-Balancing Dispatch Merit Orders~~ 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 Dispatch Merit Orders~~ 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:

…

(d) a Dispatch Instruction to a~~ Non-Balancing Facility~~ Demand Side Programme in accordance with the Non-Balancing Dispatch Merit Order, taking into account Standing Data limitations relevant to that~~ Facility~~ Demand Side Programme.

~~7.6.2B. A reference to a BMO in this clause 7.6 means, for a Trading Interval:~~

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

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

~~(c) if no such Forecast BMO is provided, the BMO or the Forecast BMO that was used by System Management for issuing Dispatch Instructions for the same Trading Interval on the previous day if both Trading Intervals occur on a Business Day, or the most recent non-Business Day if the Trading Interval occurs on a non-Business Day.~~

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

7.6A.1. Subject to System Management's obligations under~~ clause~~ section 7.6, this~~ clause~~ section 7.6A describes the rules governing the relationship between System Management and Synergy for the purpose of scheduling and dispatching the Stand Alone Facilities for Ancillary Services and for scheduling and dispatching Facilities in the Balancing Portfolio generally.

7.6A.2. With respect to the scheduling of Stand Alone Facilities for Ancillary Services and the scheduling of Facilities in the Balancing 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 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 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 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 Portfolio, being a forecast of the whole of system energy requirement less:~~ [Blank]

~~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 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);~~[Blank]

(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 Portfolio generally, during a Trading Day:

…

7.6A.5. With respect to administration and reporting:

(a) Representatives of System Management and Synergy must, unless both parties agree otherwise, meet at least once per month to review the procedures operating under this ~~clause~~ section 7.6A. The minutes of these meetings must be recorded by System Management;

(b) At the meetings described in clause 7.6A.5(a), System Management and Synergy must use best endeavours to address any issues arising from the application of the procedures operating under this ~~clause~~ section 7.6A. Where agreement cannot be reached either party may seek arbitration by the IMO;

(c) System Management must report to the IMO any instance where it believes that Synergy has failed to meet its obligations under this ~~clause~~ section 7.6A;

(d) Synergy may report to the IMO any instance where it believes that System Management has failed to meet its obligations under this ~~clause~~ section 7.6A;

(e) Upon request by the IMO, Synergy and System Management must make available to the IMO records created because of the operation of this ~~clause~~ section 7.6A and procedures required by this ~~clause~~ section 7.6A.

7.7.2. Each Dispatch Instruction issued to a ~~Non-Balancing Facility~~ Demand Side Programme or to a Balancing Facility Out of Merit under clause 7.6.1C(c) must:

…

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

(a) only discriminate between ~~Non-Balancing Facilities~~ Demand Side Programmes 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 Facility Out of Merit and a ~~Non-Balancing Facility~~ Demand Side Programme for a Trading Interval must not be issued earlier than 2:00 PM on the Scheduling Day for the Trading Day on which the Trading Interval falls or later than the end of the Trading Interval.

7.9.4. System Management must grant permission to synchronise unless:

(a) the synchronisation is not in accordance with the relevant ~~Resource Plan,~~ Dispatch Instruction, ~~or~~ Operating Instruction or ~~an~~ instruction issued under clause 7.6A.3(a); or

(b) System Management considers that it would not be able to meet the criteria set out in clause 7.6.1 were synchronisation to occur; or

(c) in the case of a Facility that is undergoing a Commissioning Test, synchronisation is not in accordance with the Commissioning Test Plan for the Facility approved by System Management pursuant to clause 3.21A.

7.9.8. System Management must grant permission to desynchronise unless:

(a) the desynchronisation is not in accordance with the relevant ~~Resource Plan or~~ Dispatch Instruction, Operating Instruction or ~~an~~ instruction issued under clause 7.6A.3(a); or

(b) System Management considers that it would not be able to meet the criteria set out in clause 7.6.1 were desynchronisation to occur.

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

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

…

(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~~;

…

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

…

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

...

(eA) for each LFAS Facility, the quantity of any Backup Upwards LFAS ~~Backup~~ Enablement that System Management activated by the end of each Trading Interval by that LFAS Facility;

(eB) for each LFAS Facility, the quantity of any Backup Downwards LFAS ~~Backup~~ Enablement that System Management activated by the end of each Trading Interval by that LFAS Facility;

...

7A.1.3. The objectives of the Balancing Market are to:

(a) enable Balancing Facilities to participate in the Balancing Market;

(b) dispatch the lowest cost combination of Facilities made available for ~~Balancing~~ dispatch in the Balancing Market;

(c) establish a Balancing 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 is provided to affected Rule Participants.

7A.1.6. The IMO must develop a Balancing Facility Requirements Market Procedure specifying:

(a) technical and communication criteria that a Balancing Facility, or a type of Balancing Facility, must meet, including:

i. Facility quantity parameters and limits for participation in the Balancing Market;

ii. the manner and forms of communication to be used while participating in the Balancing Market, 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.2.1. A Market Participant must at all times ensure that~~:~~ it has made a Balancing Submission in accordance with clause 7A.2.4 for each Trading Interval in the Balancing Horizon for each of its Balancing Facilities.

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

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

~~(c) the Balancing Submission is made before Balancing Gate Closure or, in the case of the Balancing Portfolio, before the times specified in clause 7A.2.9(d), for those Trading Intervals.~~

7A.2.3. A Market Participant with a Balancing Facility that is:

(a) the subject of an Operating Instruction; or

(b) undergoing a Test that has an approved Test Plan,

must ensure that ~~the price in the Balancing Price-Quantity Pair for~~ a Balancing Submission submitted under this ~~clause~~ section 7A.2 is ~~at the Minimum STEM Price for the quantity~~ consistent with the proposed operation of the Balancing Facility for each Trading Interval specified in the Operating Instruction or the Test Plan. The provisions of this clause 7A.2.3 do not apply to the Balancing Portfolio.

7A.2.4. A Balancing Submission must:

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

(b) constitute a declaration by an Authorised Officer;

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

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

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

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

7A.2.4A. A Balancing Submission for a Balancing Facility that is a Scheduled Generator must specify the following details for each Trading Interval covered in the Balancing Submission:

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

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

where the sum of:

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

(d) the declared MW quantity of unavailable capacity,

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

7A.2.4B. A Balancing Submission for a Balancing Facility that is a Non-Scheduled Generator must specify, for each Trading Interval covered in the Balancing Submission, a single Balancing Price-Quantity Pair with a MW quantity equal to 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, that the Facility will not be subject to a Dispatch Instruction that limits its output during that Trading Interval).

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

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

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

7A.2.8. A Balancing Submission for each Trading Interval in the Balancing Horizon for which Balancing Gate Closure has not occurred must accurately reflect:

(a) all information reasonably available to the Market Participant, including Balancing Forecasts published by the IMO, the information provided by the IMO under clause ~~7A.3.17~~ 7A.3.1(c) 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 Facilities to be dispatched in the Balancing Market; and

(c) the price at which the Market Participant submitting the Balancing Submission intends to have the Balancing Facility participate in the Balancing Market.

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

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

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

ii. Synergy's reasonable expectation of the capability of its Balancing Portfolio to be dispatched in the Balancing Market for that Trading Interval; and

iii. the price at which Synergy intends to have the Balancing Portfolio participate in the Balancing Market;

(b) must indicate in a manner and form prescribed by the IMO:

i. which ~~quantities in the Balancing Portfolio Supply Curve~~ of the Balancing Price-Quantity Pairs that it has priced at the Minimum STEM Price are for Facilities that are to provide LFAS;

ii. Facilities which are likely to provide LFAS; and

iii. for each completed Trading Interval, which Facilities actually provided the LFAS in the Trading Interval;

(c) must:

i. ensure that quantities in the ~~Balancing Portfolio Supply Curve~~ Balancing Price-Quantity Pairs in its Balancing Submissions that are required for the provision of Ancillary Services, other than LFAS, are priced at the Price Caps~~, to reflect that these quantities are not generally available for Balancing~~;

ii. advise the IMO in a manner and form prescribed by the IMO, the Facilities which are likely to provide the quantities specified in clause 7A.2.9(c)(i); and

iii. for each completed Trading Interval, advise the IMO which Facilities actually provided the Ancillary Services referred to in clause 7A.2.9(c)(i) in the Trading Interval;

(d) may update its Balancing ~~Portfolio Supply Curve~~ Submission in relation to any Trading Interval in the Balancing Horizon for which Balancing Gate Closure for that Trading Interval is more than two hours in the future:

i. by submitting its updated Balancing ~~Portfolio Supply Curve~~ Submission to the IMO immediately before ~~6:00 PM~~ 1:00 PM; or

ii. otherwise by submitting its updated Balancing ~~Portfolio Supply Curve~~ Submission to the IMO within one hour after LFAS Gate Closure;

(e) may update its Balancing ~~Portfolio Supply Curve~~ Submission 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

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

7A.2.12. Where Synergy has submitted an updated Balancing ~~Portfolio Supply Curve~~ Submission for the Balancing Portfolio in accordance with clause~~s~~ 7A.2.9(e) or 7A.2.9(f) because of a Forced Outage of one of the Facilities in the Balancing Portfolio after the time specified in these clauses 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 Submission under this ~~clause~~ section 7A.2 in good faith;

…

7A.3. Forecast BMO and Pricing BMO

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

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

~~(a) ranking the Balancing Price-Quantity Pairs for a Trading Interval and associated Balancing Facilities contained in Balancing Submissions in order of lowest to highest prices (where these prices have been adjusted where appropriate in accordance with clause 7A.3.1); and~~

~~(b) where System Management provides a forecast of the EOI Quantity for a Non-Scheduled Generator under clause 7A.3.15, adjusting the Non-Scheduled Generator's Balancing Submission to reflect that quantity.~~

~~7A.3.3. In circumstances where there is a tie in the ranking of Balancing Facilities under clause 7A.3.2 in the BMO the IMO must break the tie in accordance with the~~

~~Balancing Forecast Market Procedure, which must give effect to the following descending order of priority:~~

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

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

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

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

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

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

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

7A.3.1. The IMO must, to the extent that it is reasonably able, as soon as practicable during the first 15 minutes of each Trading Interval, for each future Trading Interval in the Balancing Horizon:

(a) determine the Forecast BMO in accordance with clause 7A.3.2 using the most recent, valid Balancing Submissions available to it;

(b) provide to System Management the Forecast BMO determined under clause 7A.3.1(a);

(c) provide to each Market Participant the EOI Quantities expected to be provided by each of the Market Participant's Balancing Facilities in the Forecast BMO determined under clause 7A.3.1(a); and

(d) if the IMO has sufficient information available to it, determine the Balancing Forecast in accordance with the Balancing Forecast Market Procedure and publish it on the Market Web Site.

7A.3.2. The IMO must determine a Forecast BMO for a Trading Interval under clause 7A.3.1(a) by:

(a) converting the prices in Balancing Price-Quantity Pairs contained in Balancing Submissions for that Trading Interval into Loss Factor Adjusted Prices, for all Balancing Facilities except the Balancing Portfolio;

(b) subject to clause 7A.3.2(c), ranking the Balancing Price-Quantity Pairs and associated Balancing Facilities contained in Balancing Submissions for that Trading Interval in order of lowest to highest price, where these prices have been adjusted where appropriate in accordance with clause 7A.3.2(a);

(c) where there is a tie in the ranking of Balancing Facilities under clause 7A.3.2(b), breaking the tie in accordance with the Balancing Forecast Market Procedure; and

(d) where System Management provides a forecast of the EOI Quantity for a Non-Scheduled Generator under clause 7A.3.15, adjusting the Non-Scheduled Generator's Balancing Submission to reflect that quantity.

7A.3.3. The IMO must document in the Balancing Forecast Market Procedure the processes it must follow in:

(a) determining and providing to System Management Forecast BMOs;

(b) preparing and publishing Balancing Forecasts; and

(c) assigning priority to Facilities in the case where there is a tie in a Forecast BMO or Forecast LFAS Merit Order.

7A.3.4. The IMO must develop the Balancing Forecast Market Procedure in accordance with the following principles:

(a) to the extent reasonably practicable, Balancing Forecasts must use the latest information available to the IMO; and

(b) Balancing Forecasts must provide Market Participants with information upon which to make an assessment regarding whether to make a Balancing Submission or to update a Balancing Submission.

7A.3.5. A Market Participant, other than Synergy in respect of the Balancing Portfolio, must, within 60 minutes after LFAS Gate Closure for an LFAS Horizon, for each Trading Interval in that LFAS Horizon, use its best endeavours to 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:~~ for each of its LFAS Facilities in the LFAS Enablement Schedules for that Trading Interval, such that the following conditions hold:

(a) ~~where its LFAS Price-Quantity Pair is selected under clause 7B.3.4(b) for the Trading Interval, so that the price in the selected LFAS Price-Quantity Pair for the quantity of capacity equal to the Upwards LFAS Enablement of the Facility for that Trading Interval is at the Alternative Maximum STEM Price and the quantity of capacity for the Facility specified in item 1(b)(xiii) of Standing Data is at the Minimum STEM Price; and~~the total quantity in Balancing Price-Quantity Pairs priced at the Alternative Maximum STEM Price is at least the Upwards LFAS Enablement for the Facility; and

(b) ~~where its LFAS Price-Quantity Pair is selected under clause 7B.3.4(c) for the Trading Interval, so that the price in the selected LFAS Price-Quantity Pair for the sum of the quantity of capacity for the Facility specified in item 1(b)(xiii) of Standing Data, plus the quantity of capacity equal to the Downwards LFAS Enablement of the Facility for that Trading Interval, is at~~

~~the Minimum STEM Price.~~the total quantity in Balancing Price-Quantity Pairs priced at the Minimum STEM Price is at least the quantity of capacity for the Facility specified in item 1(b)(xiii) of Standing Data plus the Downwards LFAS Enablement for the Facility.

7A.3.6. ~~The IMO must:~~[Blank]

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

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

7A.3.10. The IMO must ~~calculate~~ use the Pricing BMO, subject to clause 7A.3.13, ~~using the Provisional Pricing BMO determined under clause 7A.3.8(a), as revised under clause 7A.3.9,~~ to determine the Balancing Price, being the Loss Factor Adjusted Price corresponding to the point where the Relevant Dispatch Quantity plus 1 MW intersects the Pricing BMO. ~~Where there is no change to the Provisional Balancing Price determined under clause 7A.3.8(b), that price is deemed to be the Balancing Price.~~

7A.3.13. If the IMO is unable to determine the Balancing 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 Price:

(a) where the Relevant Dispatch Quantity and/or Pricing BMO is not available, the IMO must use the forecast Relevant Dispatch Quantity and/or Forecast BMO ~~and/or the Forecast Relevant Dispatch Quantity~~ for the Trading Interval so that the Balancing Price is the point where the Relevant Dispatch Quantity or most recent forecast of the Relevant Dispatch Quantity (as applicable) plus 1 MW intersects the Pricing BMO or ~~most recent~~ Forecast BMO (as applicable); and

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

(c) where there is no Forecast BMO:

i. if the IMO is determining the Balancing Price for a Trading Interval in a Business Day, the Balancing 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 Price for a Trading Interval in a day which is not a Business Day, the Balancing 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.

~~Forecast BMO~~

~~7A.3.16. The IMO must for each future Trading Interval in the Balancing Horizon determine a Forecast BMO.~~

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

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

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

~~7A.3.18. The IMO must provide the information required under clause 7A.3.17 at approximately the same time as the IMO publishes the Balancing Forecasts under clause 7A.3.21.~~

~~Balancing Forecast~~

~~7A.3.19. The IMO must, if it has sufficient information available to it, determine and publish under clause 7A.3.21 the Balancing Forecast for each Trading Interval in the Balancing Horizon in accordance with the Balancing Forecast Market Procedure.~~

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

~~(a) to the extent reasonably practicable, the Balancing Forecasts and the Forecast BMOs must use the latest information available to the IMO; and~~

~~(b) to provide Market Generators with information upon which to make an assessment regarding whether to make a Balancing Submission or to update a Balancing Submission in accordance with the Market Rules.~~

~~7A.3.21. The IMO must, to the extent it is reasonably able within the Trading Interval, commencing at 6:00 PM on Balancing Market Commencement Day:~~

~~(a) publish on the Market Web Site a Balancing Forecast for each Trading Interval during the Balancing Horizon;~~

~~(b) by the end of every half hour thereafter, publish a Balancing Forecast for each future Trading Interval in the Balancing Horizon; and~~

~~(c) as soon as practicable, publish any aggregate forecast output of Non-Scheduled Generators which is received from System Management under clause 7.6A.2(e).~~

7B.1.4. System Management must, by 12:00 PM on the Scheduling Day, provide the IMO with~~ System Management's forecast of~~ the Forecast Upwards LFAS Quantity and the Forecast Downwards LFAS Quantity for each Trading Interval in the next Trading Day, determined in accordance with the Power System Operation Procedure.

7B.1.5. System Management may update the~~ forecast~~ Forecast LFAS~~ Quantity~~ Quantities provided under clause 7B.1.4 for a Trading Interval in the Balancing Horizon at any time until~~ 60 minutes~~ one hour before the LFAS Gate Closure for that Trading Interval. System Management may update the~~ forecast~~ Forecast LFAS~~ Quantity~~ Quantities more than once.~~.~~

7B.2.1. A Market Participant may submit an LFAS Submission in respect of any of its LFAS Facilities, other than the Balancing Portfolio:

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

(b) for any or all Trading Intervals in the Balancing Horizon; and

(c) before LFAS Gate Closure for those Trading Intervals.

7B.2.2. A Market Participant may submit~~ a new,~~ an updated LFAS Submission in respect of any of its LFAS Facilities other than the Balancing 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 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 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 Balancing Portfolio:

(a) in accordance with clauses~~ 7B.2.5~~ 7B.2.6 and 7B.2.7;~~ and~~

(aA) for one or more Trading Intervals in the Balancing Horizon; and

(b) at the time it~~ submits~~ makes an updated Balancing~~ Portfolio Supply Curve~~ Submission under clause 7A.2.9(d).

7B.2.5. Synergy must ensure that, for each Trading Interval for which it has made LFAS Submissions~~ under this Chapter 7B, the sum of the MW quantities contained in those LFAS Submissions equals at least the latest forecast LFAS Quantity for that Trading Interval published under clause 7B.3.15(b), if any.~~:

(a) the sum of the MW quantities contained in the Upwards LFAS Price-Quantity Pairs in those LFAS Submissions equals at least the latest Forecast Upwards LFAS Quantity for that Trading Interval published under clause 7B.3.1(d)(i), if any; and

(b) the sum of the MW quantities contained in the Downwards LFAS Price-Quantity Pairs in those LFAS Submissions equals at least the latest Forecast Downwards LFAS Quantity for that Trading Interval published under clause 7B.3.1(d)(i), if any.

7B.2.6. Synergy, in its LFAS Submission for the Balancing 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 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 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 Submissions, including changes made to LFAS Submissions and/or Balancing Submissions in which a pattern of behaviour may indicate an intention to create a false impression in the LFAS Market;

(b) any information as to whether a Facility was not able to provide LFAS and the reasons for that failure; and

(c) any other information that~~ considered by~~ the IMO considers to be relevant.

7B.2.18. ~~Where an LFAS Facility is selected under clauses 7B.3.4(b) or 7B.3.4(c) to provide LFAS in a Trading Interval, then a~~ A Market Participant must, as soon as it becomes aware that~~ the~~ an LFAS Facility in an LFAS Enablement Schedule is physically unable to provide some or all of~~ the LFAS Quantity for which it has been~~

~~selected~~ its LFAS Enablement, advise the IMO and System Management, in the manner and form prescribed by the IMO and System Management respectively, whether the LFAS Facility is physically able to provide any LFAS in that Trading Interval and if so, the quantity, in MW.

7B.2.19. ~~Where an LFAS Facility is selected under clauses 7B.3.4(b) or 7B.3.4(c) to provide LFAS in a Trading Interval, then a~~ A Market Participant must, unless it has provided advice to the IMO and System Management under clause 7B.2.18, ensure that its LFAS Facilities in the LFAS Enablement Schedule provide ~~the~~ LFAS in the Trading Interval when required to do so by System Management under the Market Rules.

7B.3. LFAS Merit Orders and LFAS Prices

~~7B.3.1. The IMO must determine the LFAS Upwards Merit Order for a Trading Interval by deriving a ranked list of LFAS Submissions and associated LFAS Facilities. Subject to clause 7B.3.3, the list is obtained by ranking LFAS Upwards Price-Quantity Pairs for a Trading Interval contained in LFAS Submissions in order of lowest to highest price.~~

~~7B.3.2. The IMO must determine the LFAS Downwards Merit Order for a Trading Interval by deriving a ranked list of LFAS Submissions and associated LFAS Facilities. Subject to clause 7B.3.3, the list is obtained by ranking LFAS Downwards Price-Quantity Pairs for a Trading Interval contained in LFAS Submissions in order of lowest to highest price.~~

~~7B.3.3. In circumstances where there is a tie in the ranking of LFAS Facilities under clauses 7B.3.1 or 7B.3.2 in the LFAS Merit Order the IMO must assign priority to break the tie for the Trading Interval in which the tie occurred. Priority, for the relevant Trading Day, will be based on a daily random number assigned to each LFAS Facility in accordance with the Balancing Forecast Market Procedure.~~

~~7B.3.4. The IMO must to the extent that it is able:~~

~~(a) determine the LFAS Merit Order for each Trading Interval in an LFAS Horizon for which LFAS Gate Closure has occurred, as soon as reasonably practicable after the LFAS Gate Closure, using the most recent, valid LFAS Submissions available to it;~~

~~(b) select from the LFAS Upwards Merit Order derived under clause 7B.3.4(a) the lowest priced LFAS Upwards Price-Quantity Pair or LFAS Upwards Price-Quantity Pairs, and associated LFAS Facility or LFAS Facilities, so that:~~

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

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

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

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

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

~~(d) provide to System Management the details of:~~

~~i. the LFAS Facility or Facilities determined under clause 7B.3.4(b) and the associated LFAS Facility quantities and the associated Trading Interval; and~~

~~ii. the LFAS Facility or Facilities determined under clause 7B.3.4(c) and the associated LFAS Facility quantities and the associated Trading Interval; and~~

~~(e) each time the IMO creates an LFAS Merit Order, publish the highest price selected under each of clauses 7B.3.4(b) and 7B.3.4(c) for each Trading Interval in the LFAS Horizon to which the LFAS Merit Order relates, as soon as reasonably practicable after the determination, but no later than 15 minutes after the LFAS Gate Closure to which the LFAS Merit Order relates.~~

~~7B.3.5. The IMO must, to the extent it is reasonably able:~~

~~(a) provide the information referred to in clause 7B.3.4(d) within 15 minutes of the LFAS Gate Closure to which the information relates; and~~

~~(b) notify the Market Participant with the LFAS Facility or Facilities selected under clauses 7B.3.4(b) and 7B.3.4(c) of that selection and the associated LFAS Facility quantities to be provided by Trading Interval, within 15 minutes of the LFAS Gate Closure for that Trading Interval.~~

7B.3.1. The IMO must, to the extent that it is reasonably able, as soon as practicable during the first 15 minutes of each Trading Interval, for all Trading Intervals for which LFAS Gate Closure occurred at the end of the previous Trading Interval and for each later Trading Interval in the Balancing Horizon:

(a) determine using the most recent, valid LFAS Submissions available to it:

i. the Forecast Upwards LFAS Merit Order in accordance with clause 7B.3.2(a);

ii. the Forecast Downwards LFAS Merit Order in accordance with clause 7B.3.2(b);

iii. the Forecast Upwards LFAS Enablement Schedule in accordance with clause 7B.3.3(a);

iv. the Forecast Downwards LFAS Enablement Schedule in accordance with clause 7B.3.3(b);

v. the Forecast Upwards LFAS Price in accordance with clause 7B.3.4(a); and

vi. the Forecast Downwards LFAS Price in accordance with clause 7B.3.4(b);

(b) provide to System Management the Forecast LFAS Enablement Schedules determined under clauses 7B.3.1(a)(iii) and 7B.3.1(a)(iv);

(c) notify each Market Participant with an LFAS Facility in an LFAS Enablement Schedule determined under clause 7B.3.1(a)(iii) or 7B.3.1(a)(iv) of the details of its LFAS Enablements; and

(d) publish on the Market Web Site to each Market Participant:

i. the most recent Forecast LFAS Quantities provided by System Management under clause 7B.1.4 or 7B.1.5;

ii. the Forecast LFAS Merit Orders, determined under clauses 7B.3.1(a)(i) and 7B.3.1(a)(ii), in the form of anonymous LFAS Price-Quantity Pairs;

iii. the Forecast LFAS Prices, determined under clauses 7B.3.1(a)(v) and 7B.3.1(a)(vi); and

iv. the Forecast Backup LFAS Prices, determined from the most recent, valid LFAS Submissions made in accordance with clause 7B.2.6.

7B.3.2. The IMO must:

(a) subject to clause 7B.3.2(c), determine a Forecast Upwards LFAS Merit Order for a Trading Interval under clause 7B.3.1(a)(i) by ranking Upwards LFAS Price-Quantity Pairs and associated LFAS Facilities contained in LFAS Submissions for that Trading Interval in order of lowest to highest price;

(b) subject to clause 7B.3.2(c), determine a Forecast Downwards LFAS Merit Order for a Trading Interval under clause 7B.3.1(a)(ii) by ranking Downwards LFAS Price-Quantity Pairs and associated LFAS Facilities contained in LFAS Submissions for that Trading Interval in order of lowest to highest price; and

(c) in circumstances where there is a tie in the ranking of LFAS Facilities under clauses 7B.3.2(a) or 7B.3.2(b) in an LFAS Merit Order, break the tie for the Trading Interval in which the tie occurred in accordance with the Balancing Forecast Market Procedure.

The IMO intends to propose changes to the Balancing Forecast Market Procedure so that the random number used to break ties under clause 7A.3.3(c) would also be used to break ties under clause 7B.3.2(c).

7B.3.3. The IMO must:

(a) determine a Forecast Upwards LFAS Enablement Schedule for a Trading Interval under clause 7B.3.1(a)(iii) by selecting the lowest priced Upwards LFAS Price-Quantity Pairs and associated LFAS Facilities from the Forecast Upwards LFAS Merit Order determined under clause 7B.3.1(a)(i), so that:

i. the sum of the quantities in the selected Upwards LFAS Price-Quantity Pairs equals the Forecast Upwards LFAS Quantity; and

ii. if only part of the quantity in the highest priced Upwards LFAS Price-Quantity Pair selected is required to make up the Forecast Upwards LFAS Quantity, that Upwards LFAS Price-Quantity Pair is selected for that part of the offered quantity only; and

(b) determine a Forecast Downwards LFAS Enablement Schedule for a Trading Interval under clause 7B.3.1(a)(iv) by selecting the lowest priced Downwards LFAS Price-Quantity Pairs and associated LFAS Facilities from the Forecast Downwards LFAS Merit Order determined under clause 7B.3.1(a)(ii), so that:

i. the sum of the quantities in the selected Downwards LFAS Price-Quantity Pairs equals the Forecast Downwards LFAS Quantity; and

ii. if only part of the quantity in the highest priced Downwards LFAS Price-Quantity Pair selected is required to make up the Forecast Downwards LFAS Quantity, that Downwards LFAS Price-Quantity Pair is selected for that part of the offered quantity only.

7B.3.4. The IMO must:

(a) determine a Forecast Upwards LFAS Price for a Trading Interval under clause 7B.3.1(a)(v) by determining the highest price in those Upwards LFAS Price-Quantity Pairs in the Forecast Upwards Enablement Schedule; and

(b) determine a Forecast Downwards LFAS Price for a Trading Interval under clause 7B.3.1(a)(vi) by determining the highest price in those Downwards

LFAS Price-Quantity Pairs in the Forecast Downwards Enablement Schedule.

7B.3.5. [Blank]

7B.3.6. Subject to clauses 7B.2.18, 7B.3.7, 7B.3.8 and 7B.4.1, for each Trading Interval, System Management must ~~use the LFAS Facilities referred to in clause 7B.3.4(d) for meeting LFAS requirements in the associated Trading Interval in reasonable proportion to the quantities selected under clauses 7B.3.4(b) and 7B.3.4(c), as applicable~~ activate each LFAS Facility in each LFAS Enablement Schedule for its full LFAS Enablement and use those LFAS Facilities to provide the relevant LFAS in reasonable proportion to their relevant LFAS Enablement, and those LFAS Facilities must provide ~~those~~ that LFAS ~~requirements~~.

7B.3.7. ~~Where the IMO is unable to publish an LFAS Merit Order for a Trading Interval in accordance with clause 7B.3.4(d)~~Where an LFAS Enablement Schedule for a Trading Interval does not exist, System Management must use Synergy's LFAS Facilities to provide LFAS for that Trading Interval.

7B.3.8. System Management may select and use LFAS Facilities other than in accordance with ~~the LFAS Merit Order~~ an LFAS Enablement Schedule where System Management considers, on reasonable grounds, that it needs to do so in order to operate the SWIS in a reliable and safe manner.

~~LFAS Price~~

7B.3.9. ~~The IMO must, at the time it makes the selection under clause 7B.3.4(b), determine the Upwards LFAS Price for a Trading Interval as the highest price in those selected LFAS Upwards Price-Quantity Pairs.~~[Blank]

7B.3.10. ~~The IMO must, at the time it makes the selection under clause 7B.3.4(c), determine the Downwards LFAS Price for a Trading Interval as the highest price in those selected LFAS Downward Price-Quantity Pairs.~~[Blank]

7B.3.11. The IMO must, by the end of a Trading Day, publish the LFAS Prices for each Trading Interval for that Trading Day.

7B.3.12. If the IMO is unable to determine an LFAS Price under clauses ~~7B.3.9 or 7B.3.10~~ 7B.3.4(a) or 7B.3.4(b) in time to publish it in accordance with clause 7B.3.11, the IMO must determine ~~the~~ that LFAS Price as follows:

(a) if the IMO is determining an LFAS Price for a Trading Interval in a Business Day, ~~the~~ that LFAS Price will be the value of the equivalent LFAS Price for the equivalent Trading Interval in the most recent Trading Day in the past which is also a Business Day; or

(b) if the IMO is determining an LFAS Price for a Trading Interval in a day which is not a Business Day, ~~the~~ that LFAS Price will be the value of the equivalent LFAS Price for the equivalent Trading Interval in the most recent Trading Day in the past which is also not a Business Day.

~~Forecast LFAS Merit Order~~

~~7B.3.14. The IMO must, for each future Trading Interval in the Balancing Horizon for which LFAS Gate Closure has not occurred, determine a forecast LFAS Merit Order.~~

~~7B.3.15. Where the IMO determines the forecast LFAS Merit Order under clause 7B.3.14, the IMO must, to the extent it is reasonably able, within a Trading Interval, publish on the Market Web Site to each Market Participant:~~

~~(a) the LFAS Quantities expected to be provided by that Market Participant for each Trading Interval in the Balancing Horizon as indicated by the forecast LFAS Merit Orders;~~

~~(b) any quantities provided to the IMO by System Management under clauses 7B.1.4 and 7B.1.5;~~

~~(c) forecasts of LFAS Prices based upon the forecast LFAS Merit Orders;~~

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

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

~~7B.3.16. Where the IMO determines the forecast LFAS Merit Order under clause 7B.3.14, the IMO must, to the extent it is reasonably able, within a Trading Interval, provide to System Management the forecast LFAS Merit Order.~~

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

7B.4.1. Where:

(a) an LFAS Facility in an LFAS Enablement Schedule has failed to provide all or part of its LFAS Enablement when called upon to do so by System Management in accordance with clause 7B.3.6 or 7B.3.8; ~~or~~

(aA) the LFAS Enablement of an LFAS Facility in an LFAS Enablement Schedule is greater than the LFAS Facility's available capacity, taking into account the BMO, Ramp Rate Limits and the quantities of capacity for the Facility specified in items 1(b)(iii), 1(b)(xiii) and 1(b)(xv) of Appendix 1; or

(b) the quantity of upwards or downwards LFAS in a Trading Interval required by System Management is greater than the ~~most recent~~ Upwards LFAS

Quantity or Downwards LFAS Quantity published ~~under clause (b)~~ for that Trading Interval,

System Management may use the Balancing Portfolio or a Stand Alone Facility~~,~~ to provide the LFAS Quantity Balance and/or the Increased LFAS Quantity, as applicable.

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) ~~Dispatachable 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~~ section 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 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 Price (d,t) is the Balancing Price for Trading Interval t of Trading Day d calculated in accordance with clause 7A.3.10;

CONC(p,d,t) is the Constrained On Compensation for Market Participant p for Trading Interval t of Trading Day d. For a Market Participant other than Synergy, CONC(p,d,t) is the sum of all ConQN x ConPN for each of the Market Participant's Scheduled Generators and Non-Scheduled Generators for Trading Interval t. For Synergy, CONC(p,d,t) is the sum of all PConQN x PConPN plus the sum of all ConQN x ConPN for each Stand Alone Facility for Trading Interval t, where ConQN, ConPN, PConQN and PConPN are calculated in accordance with ~~clause~~ section 6.17;

COFFC(p,d,t) is the Constrained Off Compensation for Market Participant p for Trading Interval t of Trading Day d. For a Market Participant other than Synergy, COFFC(p,d,t) is the sum of all CoffQN x CoffPN for each of the Market Participant's Scheduled Generators and Non-Scheduled Generators for Trading Interval t. For Synergy, COFFC(p,d,t) is the sum of all PCoffQN x PCoffPN plus the sum of all CoffQN x CoffPN for each Stand Alone Facility for Trading Interval t, where CoffQN, CoffPN, PCoffQN and PCoffPN are calculated in accordance with ~~clause~~ section 6.17; and

DIP(p,d,t) is the Non-Balancing Facility 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:

…

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;

…

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:

…

Monthly Participant Load(p,m) = (-1) $\times$ Sum(d$\in$D,t$\in$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

…

9.18.3. A Non-STEM Settlement Statement must contain the following information:

…

(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;

…

ix. details of amounts calculated for the Market Participant under ~~clauses~~ sections 9.7 to 9.14 with respect to:

1. Reserve Capacity settlement;

2. Balancing~~ settlement~~ settlement;

3. Ancillary Services settlement;

4. Outage compensation settlement;

5. Reconciliation settlement;

6. [Blank]

7. Fee settlement; and

8. Net Monthly Non-STEM Settlement Amount;

…

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 Market summary information:

i for each Trading Interval in each completed Trading Day in the previous 12 calendar months:

1. where available, each Balancing Forecast;

2. where available, the latest Forecast BMO, excluding information that would identify specific Market Participants;

3. where available, the Relevant Dispatch Quantity; and

4. where available, the Balancing Price; and

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, full details of the latest Balancing Submissions submitted for each Balancing Facility and for the Balancing Portfolio;~~:~~

~~1. the prices in Balancing Price-Quantity Pairs submitted in Balancing Submissions by Market Participant; and~~

~~2. the Fuel Declaration, Availability Declaration and, if applicable, Ancillary Service Declaration made by Market Participant;~~

(iB) the following LFAS summary information for each Trading Interval in each completed Trading Day in the previous 12 calendar months:

i. the ~~LFAS~~ Downwards LFAS Merit Order;

ii. the ~~LFAS~~ Upwards LFAS Merit Order;

iii. where available, the Upwards LFAS Quantity and the Downwards LFAS Quantity; and

iv. where available, the Upwards LFAS Price and the Downwards LFAS Price;

...

(j) for each Trading Interval in each completed Trading Day in the previous 12 calendar months the following dispatch summary information:

i. ~~the values of the Balancing Price,~~ the LFAS Prices~~,~~ and the Backup ~~Downwards~~ LFAS Prices~~ and the Backup Upwards LFAS Price~~;

ii. the Load Forecast prepared by System Management in accordance with clause 7.2.1;

iii. the sum of the Metered Schedule load for all Non-Dispatchable Load~~, Dispatchable Load~~ and Interruptible Load;

iv. estimates of the energy not served due to involuntary load curtailment; and

v. any shortfalls in Ancillary Services;

...

(v) summary information pertaining to the account maintained by the IMO for market settlement for the preceding 24 calendar months, including;

i. the end of month balance;

ii. the total income received for transactions in each of the Reserve Capacity Mechanism, the STEM, Balancing Settlement, Market

Fees, System Operation Fees, Regulator Fees and a single value for all other income;

iii. the total outgoings paid for transactions in each of the Reserve Capacity Mechanism (excluding Supplementary Capacity Contracts), Supplementary Capacity Contracts, the STEM, Balancing Settlement and a single value for all other expenses; and

iv. Service Fee Settlement Amount paid to the IMO, System Management and the Economic Regulation Authority;

...

10.7.1. The IMO must set the class of confidentiality status for the following information under clause 10.2.1, as Rule Participant Market Restricted ~~Information~~ and the IMO must make this information available from the Market Web Site:

(a) all Reserve Capacity Offer information issued by that Market Participant and all details of Special Price Arrangements for that Market Participant prior to the publication of that information in accordance with clause 10.5.1(f);

(b) Market Participant specific Reserve Capacity Obligations;

(c) Market Customer specified Individual Reserve Capacity Requirements partitioned into those associated with Intermittent Loads and those not associated with Intermittent Loads;

(d) for each completed Trading Day for the past 12 months:

i. Market Participant specific Bilateral Submissions ~~and Resource Plan Submissions~~;

ii. Market Participant specific STEM Submissions and Standing STEM Submissions used in the absence of a STEM Submission except that information published in accordance with clause 10.5.1(i);

(e) for the past 12 months:

i. Non-STEM Settlement Statements; and

ii. STEM Settlement Statements

11. Glossary

...

Backup Downwards LFAS Enablement: Means, for a Synergy LFAS Facility, the capacity in MW which System Management has activated under clause 7B.3.7 or 7B.4.1 in a Trading Interval to compensate for a shortfall in Downwards LFAS Enablement, and which has been notified to the IMO under clause 7B.4.2.

Backup Downwards LFAS Price: Means the cost referred to in clause 7B.2.6 for Synergy providing Backup Downwards LFAS ~~Backup~~ Enablement for a Trading Interval, determined from the most recent, valid LFAS Submissions made in accordance with clause 7B.2.6.

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

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

Backup Upwards LFAS Enablement: Means, for a Synergy LFAS Facility, the capacity in MW which System Management has activated under clause 7B.3.7 or 7B.4.1 in a Trading Interval to compensate for a shortfall in Upwards LFAS Enablement, and which has been notified to the IMO under clause 7B.4.2.

Backup Upwards LFAS Price: Means the cost referred to in clause 7B.2.6 for Synergy providing Backup Upwards LFAS ~~Backup~~ Enablement for a Trading Interval, determined from the most recent, valid LFAS Submissions made in accordance with clause 7B.2.6.

~~**Balancing**: The process for meeting supply and consumption deviations from contracted bilateral and STEM positions in each Trading Interval.~~

...

~~**Balancing Final Rule Change Report**: Has the meaning given in clause 1.10.1.~~

...

Balancing Forecast Market Procedure: Means the Market Procedure developed under ~~clause 7A.3.20~~ clauses 7A.3.3 and 7A.3.4.

…

~~**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 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.

...

Balancing Market: Means the mandatory gross pool 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.~~ that determines the dispatch of Scheduled Generators and Non-Scheduled Generators in each Trading Interval based on submitted prices and quantities.

...

~~**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 Merit Order: Means, for a Trading Interval, the ordered list of Balancing Facilities, and associated quantities, used by System Management for issuing Dispatch Instructions for the Trading Interval, determined as:

(a) the last Forecast BMO for the Trading Interval received by System Management under clause 7A.3.1(b); or

(b) if no Forecast BMO is received, the Balancing Merit Order that was used by System Management for issuing Dispatch Instructions for the same Trading Interval on the most recent Business Day if the Trading Interval occurs on a Business Day, or the most recent non-Business Day if the Trading Interval occurs on a non-Business Day.

Balancing Portfolio: Means Synergy's Registered Facilities other than:

(a) Stand Alone Facilities;

(b) Demand Side Programmes; and

(c) ~~Dispatchable Loads; and~~[Blank]

(d) Interruptible Loads.

~~**Balancing Portfolio Supply Curve**: Means a ranking of the Balancing Price-Quantity Pairs provided for the Balancing Portfolio.~~

...

~~**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 Settlement: Means the process for settling supply and consumption deviations from contracted bilateral and STEM positions in each Trading Interval.

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

~~(a) for a Balancing Facility, other than the 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.~~

...

BMO: See Balancing Merit Order.

...

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 Dispatch Merit Order for a Trading Interval for a~~ Dispatchable Load or~~ Demand Side Programme and in the calculation of the Non-Balancing 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.~~

...

Constrained Off Compensation Price: Has the meaning given in clauses 6.17.4 and 6.17.4A.

Constrained Off Quantity: Has the meaning given in clauses 6.17.4 and 6.17.4A.

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

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

Constrained On Quantity: Has the meaning given in clauses 6.17.3 and 6.17.3A.

...

Dispatch Plan: Means~~ the schedule of~~ System Management's forecast of how it will use each Facility in the Balancing Portfolio to provide energy and Ancillary Services~~ to be provided, or to be available to be provided on request, by the Facilities of Synergy in the Balancing Portfolio, during~~ in each Trading Interval of a Trading Day, where~~ these schedules~~ this forecast 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).~~

...

~~**Downwards LFAS Backup Enablement**: Means for a Synergy LFAS Facility, the capacity in MW, which System Management has activated under clause 7B.4.1 in a Trading Interval to compensate for a shortfall in Downwards LFAS Enablement and which has been notified to the IMO under clause 7B.4.2.~~

Downwards LFAS Enablement: Means, for a Trading Interval and an LFAS Facility, the ~~capacity~~ total quantity~~, or that part of the capacity, in MW, in an LFAS Downwards Price-Quantity Pair selected under clause 7B.3.4(c) which is~~ associated with that LFAS Facility~~ or with the Balancing Portfolio, as applicable~~ in the Downwards LFAS Enablement Schedule for that Trading Interval.

Downwards LFAS Enablement Schedule: Means, for a Trading Interval, the Forecast Downwards LFAS Enablement Schedule for that Trading Interval most recently provided by the IMO to System Management under clause 7B.3.1(b) between LFAS Gate Closure for that Trading Interval and the point in time 15 minutes after LFAS Gate Closure for that Trading Interval.

Downwards LFAS Merit Order: Means, for a Trading Interval, the Forecast Downwards LFAS Merit Order for that Trading Interval used by the IMO under clause 7B.3.3(b) to determine the Downwards LFAS Enablement Schedule.

Downwards LFAS Price: Means, for a Trading Interval, the~~ price~~ Forecast Downwards LFAS Price for that Trading Interval determined by the IMO under clause~~ 7B.3.10 or~~ 7B.3.4(b) from the Downwards LFAS Enablement Schedule, subject to clause 7B.3.12, and published under clause 7B.3.11.

Downwards LFAS Price-Quantity Pair: Means for an LFAS Facility:

(a) the specified non-Loss Factor adjusted capacity, in MW, by which a Market Participant is prepared to have its LFAS Facility activated downwards within a Trading Interval; and

(b) the non-Loss Factor Adjusted Price, in $/MW, the Market Participant wants to be paid to have that capacity available within that Trading Interval.

Downwards LFAS Quantity: Means~~ the capacity, in MW, of downwards Load Following Service required by System Management~~, for a Trading Interval~~.~~, the Forecast Downwards LFAS Quantity for that Trading Interval used by the IMO under clause 7B.3.3(b) to determine the Downwards LFAS Enablement Schedule.

...

Forecast Backup LFAS Price: Means the Forecast Backup Downwards LFAS Price and/or the Forecast Backup Upwards LFAS Price, as applicable.

Forecast Backup Upwards LFAS Price: Means the cost referred to in clause 7B.2.6 for Synergy providing Backup Upwards LFAS Enablement for a Trading Interval, determined from the most recent, valid LFAS Submissions made in accordance with clause 7B.2.6 at the time that that cost is published by the IMO under clause 7B.3.1(d)(iv).

Forecast Backup Downwards LFAS Price: Means the cost referred to in clause 7B.2.6 for Synergy providing Backup Downwards LFAS Enablement for a Trading Interval, determined from the most recent, valid LFAS Submissions made in accordance with clause 7B.2.6 at the time that that cost is published by the IMO under clause 7B.3.1(d)(iv).

~~**Forecast BMO**: Means a forecast of the BMO for future Trading Intervals in the Balancing Horizon determined by the IMO in accordance with the Balancing Forecast Market Procedure.~~

...

Forecast BMO: Means the ordered list of Balancing Facilities, and associated quantities, determined by the IMO under clause 7A.3.1(a).

Forecast Downwards LFAS Enablement Schedule: Means, for a Trading Interval, a list of LFAS Facilities and associated quantities for that Trading Interval determined by the IMO under clause 7B.3.1(a)(iv).

Forecast Downwards LFAS Merit Order: Means, for a Trading Interval, a ranked list of Downwards LFAS Price-Quantity Pairs for that Trading Interval determined by the IMO under clause 7B.3.1(a)(ii).

Forecast Downwards LFAS Price: Means, for a Trading Interval, the highest price in a Downwards LFAS Price-Quantity Pair selected in a Forecast Downwards LFAS Enablement Schedule for that Trading Interval, determined by the IMO under clause 7B.3.1(a)(vi).

Forecast Downwards LFAS Quantity: Means System Management's estimate of the capacity, in MW, of downwards LFAS required by System Management for a Trading Interval, provided by System Management to the IMO under clause 7B.1.4 or 7B.1.5.

Forecast LFAS Enablement Schedule: Means the Forecast Downwards LFAS Enablement Schedule and/or the Forecast Upwards LFAS Enablement Schedule, as applicable.

Forecast LFAS Merit Order: Means the Forecast Downwards LFAS Merit Order and/or the Forecast Upwards LFAS Merit Order, as applicable.

Forecast LFAS Price: Means the Forecast Downwards LFAS Price and/or the Forecast Upwards LFAS Price, as applicable.

Forecast LFAS Quantity: Means the Forecast Downwards LFAS Quantity and/or the Forecast Upwards LFAS Quantity, as applicable.

Forecast Upwards LFAS Enablement Schedule: Means, for a Trading Interval, a list of LFAS Facilities and associated quantities for that Trading Interval determined by the IMO under clause 7B.3.1(a)(iii).

Forecast Upwards LFAS Merit Order: Means, for a Trading Interval, a ranked list of Upwards LFAS Price-Quantity Pairs for that Trading Interval determined by the IMO under clause 7B.3.1(a)(i).

Forecast Upwards LFAS Price: Means, for a Trading Interval, the highest price in an Upwards LFAS Price-Quantity Pair selected in a Forecast Upwards LFAS Enablement Schedule for that Trading Interval, determined by the IMO under clause 7B.3.1(a)(vi).

Forecast Upwards LFAS Quantity: Means System Management's estimate of the capacity, in MW, of upwards LFAS required by System Management for a Trading Interval, provided by System Management to the IMO under clause 7B.1.4 or 7B.1.5.

...

LFAS: See Load Following Service.

~~**LFAS Backup Enablement**: Means Upwards LFAS Backup Enablement and Downwards LFAS Backup Enablement.~~

~~**LFAS Downwards Merit Order**: Means the ranked list of LFAS Submissions determined by the IMO under clause 7B.3.2.~~

~~**LFAS Downwards Price-Quantity Pair**: Means for an LFAS Facility:~~

~~(a) the specified non-Loss Factor adjusted capacity, in MW, by which a Market Participant is prepared to have its LFAS Facility activated downwards within a Trading Interval; and~~

~~(b) the non-Loss Factor Adjusted Price, in $/MW, the Market Participant wants to be paid to have that capacity available within that Trading Interval.~~

...

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

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

LFAS Facility: Means:

(a) a Stand Alone Facility, or Scheduled Generator or Non-Scheduled Generator registered to a Market Participant other than Synergy~~, for which~~:

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

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

(b) the Balancing Portfolio.

...

LFAS Merit Order: Means the ~~LFAS~~ Downwards LFAS Merit Order and/or the ~~LFAS~~ Upwards LFAS Merit Order, as applicable.

LFAS Price: Means the Downwards LFAS Price and/or the Upwards LFAS Price, as applicable.

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

...

LFAS Quantity: Means~~:~~ the Upwards LFAS Quantity and/or the Downwards LFAS Quantity, as applicable.

~~(a) the Upwards LFAS Quantity; and~~

~~(b) the Downwards LFAS Quantity.~~

LFAS Quantity Balance: Means the capacity, in MW, of LFAS referred to in clause 7B.4.1(a), which an LFAS Facility has failed to provide, or in clause 7B.4.1(aA), which an LFAS Facility is not available to provide.

~~**LFAS Requirement**: Means the most recent forecast LFAS Quantity published by the IMO under clause 7B.3.15(b).~~

...

~~**LFAS 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 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.

...

~~**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~~ Means, for a Trading Interval, 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-Dispatchable Load: A Load which is not ~~a Dispatchable Load or~~ an Interruptible Load.

...

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 Portfolio.

...

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

Portfolio Constrained On Compensation Price: Has the meaning given in clause 6.17.5.

...

~~**Pre-Amended Rules**: Has the meaning given in clause 1.10.1.~~

~~**Post-Amended Rules**: Has the meaning given in clause 1.10.1.~~

Price Cap: Means:

(a) a maximum price ~~of~~ that is:

i. for a Balancing Facility to run on Non-Liquid Fuel, the Maximum STEM Price; or

ii. for a Balancing Facility to run on Liquid Fuel, the Alternative Maximum STEM Price; and

(b) a minimum price ~~of~~ that is the Minimum STEM Price.

...

Pricing BMO: Means the ~~Balancing Merit Order~~ Provisional Pricing BMO adjusted ~~to take into account:~~ in accordance with clause 7A.3.9 as appropriate.

~~(a) the associated Ramp Rate Limits to reflect the physically achievable capacity of the Balancing Facility given the SOI Quantity; and~~

~~(b) for Non-Scheduled Generators, the EOI Quantity.~~

...

Provisional Pricing BMO: Means, for a Trading Interval, the ~~provisional Pricing BMO determined under clause 7A.3.8(a).~~ last Forecast BMO generated by the IMO for the Trading Interval, adjusted to take into account:

(a) Balancing Submissions made after the IMO has generated the last Forecast BMO;

(b) the associated Ramp Rate Limits to reflect the physically achievable capacity of the Balancing Facility given the SOI Quantity; and

(c) for Non-Scheduled Generators, the EOI Quantity,

where the SOI Quantity and the EOI Quantity are the quantities provided by System Management under clause 7A.3.7.

...

~~**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.~~

...

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 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.~~

...

~~**Upwards LFAS Backup Enablement**: Means for a Synergy LFAS Facility, the capacity in MW, which System Management has activated under clause 7B.4.1 in a Trading Interval to compensate for a shortfall in Upwards LFAS Enablement, and which has been notified to the IMO under clause 7B.4.2.~~

Upwards LFAS Enablement: Means, for a Trading Interval and an LFAS Facility, the ~~capacity~~ total quantity~~, or that part of the capacity, in MW, in an LFAS Upwards Price-~~

~~Quantity Pair selected under clause 7B.3.4(b) which is~~ associated with that LFAS Facility ~~or with the Balancing Portfolio, as applicable~~ in the Upwards LFAS Enablement Schedule for that Trading Interval.

Upwards LFAS Enablement Schedule: Means, for a Trading Interval, the Forecast Upwards LFAS Enablement Schedule for that Trading Interval most recently provided by the IMO to System Management under clause 7B.3.1(b) between LFAS Gate Closure for that Trading Interval and the point in time 15 minutes after LFAS Gate Closure for that Trading Interval.

Upwards LFAS Merit Order: Means, for a Trading Interval, the Forecast Upwards LFAS Merit Order for that Trading Interval used by the IMO under clause 7B.3.3(a) to determine the Upwards LFAS Enablement Schedule.

Upwards LFAS Price: Means, for a Trading Interval, the ~~price~~ Forecast Upwards LFAS Price for that Trading Interval determined by the IMO under clause ~~7B.3.9 or~~ 7B.3.4(a) from the Upwards LFAS Enablement Schedule, subject to clause 7B.3.12, and published under clause 7B.3.11.

Upwards LFAS Price-Quantity Pair: Means for an LFAS Facility:

(a) the specified non-Loss Factor adjusted capacity, in MW, by which a Market Participant is prepared to have its LFAS Facility activated upwards within a Trading Interval;

(b) the non-Loss Factor Adjusted Price, in $/MW, the Market Participant wants to be paid to have that capacity available within that Trading Interval.

Upwards LFAS Quantity: Means ~~the capacity, in MW, of upwards Load Following Service required by System Management for a Trading Interval.~~, for a Trading Interval, the Forecast Upwards LFAS Quantity for that Trading Interval used by the IMO under clause 7B.3.3(a) to determine the Upwards LFAS Enablement Schedule.

...

Appendix 1: Standing Data

...

(i) ~~for a Dispatchable Load:~~[Blank]

~~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.~~

...

Appendix 3: Reserve Capacity Auction & Trade Methodology

...

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

...

Wholesale Electricity Market
Rule Change Proposal

Rule Change Proposal ID: RC_2014_07
Date received: TBC

Change requested by:

Name:	Kate Ryan
Phone:	9254 4357
Fax:	9254 4399
Email:	kate.ryan@imowa.com.au
Organisation:	IMO
Address:	Level 17, 197 St Georges Terrace, Perth 6000

Date submitted:	TBC
Urgency:	Medium
Rule Change Proposal title:	Omnibus Rule Change
Clauses affected:	Clauses 2.12.1, 2.12.2, 2.12.3, 2.12.4, 2.12.5, 2.13.15, 2.13.16, 2.13.21, 2.16.9FA, 2.22.8B, 2.23.1, 2.23.4, 2.23.9, 2.24.6, 2.30A.6, 2.31.23, 2.33.2, 2.33.5, 2.34.14, 2.38.4, 3.2.5 ,3.5.1, 3.11.8A, 3.16.4, 3.16.9, 3.21B.8, 3.22.1, 4.5.1, 4.5.2, 4.7.1, 4.13.11B, 4.27.1, 4.27.2, 4.27.10, 4.27.10A, 4.29.3, 5.1, 5.1.1, 5.1.2, 5.1.3, 5.1.4, 5.2.1, 5.2.2, 5.2.3, 5.2.4, 5.2.5, 5.2.6, 5.2.7, 5.3.1, 5.3.2, 5.3.3, 5.3.4, 5.3.5, 5.3.6, 5.3.7, 5.3.8, 5.3.9, 5.4.1, 5.4.2, 5.4.3, 5.4.4, 5.4.5, 5.4.6, 5.4.7, 5.4.8, 5.4.9, 5.4.10, 5.4.11, 5.4.12, 5.4.13, 5.4.14, 5.5.1, 5.5.2, 5.5.3, 5.5.4, 5.6.1, 5.6.2, 5.6.3, 5.8.1, 5.8.2, 5.8.3, 5.8.4, 5.8.5, 5.8.6, 5.8.7, 5.8.8, 6.2.4C, 7.13.1, 8.6.1, 9.2.1, 9.3.2, 9.4.7, 9.9.3A, 9.12.1, 9.12.2, 9.14.2, 9.20.1, the Glossary and Appendices 1 and 5.

Introduction

Clause 2.5.1 of the Wholesale Electricity Market (WEM) Rules (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 IMO.

This Rule 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 IMO will assess the proposal and, within five Business Days of receiving this Rule Change Proposal form, will notify the submitter 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:

As part of its ongoing review of the Market Rules, the IMO has identified a number of minor, administrative and typographical errors. The proposed amendments to address these errors in this Rule Change Proposal seek to correct language and punctuation, update and delete redundant references and titles, and correct a number of incorrect clauses in the Market Rules. A number of amendments have also been proposed to remove unnecessary ambiguity from specific clauses of the Market Rules.

None of these proposed amendments seek to change the operation or the intended meaning of the Market Rules. The IMO considers that these proposed amendments will improve the clarity and integrity of the Market Rules.

The IMO has also identified clauses 3.16.9, 4.27.1, 4.27.2, 7.13.1(cB) and 9.20.1 of the Market Rules as outlining certain activities that may be impractical to undertake in the manner required by the current drafting. The IMO proposes minor amendments to these clauses to reflect current practice, which is reasonable and practicable. The IMO considers that these proposed amendments will ensure that the activities continue to be undertaken in a timely manner but improve the practicality of complying with the associated obligations.

The following table provides a summary of the proposed amendments. The IMO considers that the majority of proposed amendments are minor, administrative and typographical errors and meet the requirements of clause 2.5.9 of the Market Rules. However, the proposed amendments to clauses 3.16.9, 4.27.1, 4.27.2, 7.13.1(cB), 9.4.7 and 9.20.1 of the Market Rules, while they are minor changes, designed to improve the practicality of operation activities, they do not meet the requirements of clause 2.5.9 of the Market Rules. Therefore, the IMO proposes to progress this Rule Change Proposal under the Standard Rule Change Process.

Clause	Explanation of proposed amendments
2.12.1-2.12.5 4.13.11B 4.27.10A 5.1.3 5.1.4 5.2.1-5.2.7 5.3.1-5.3.9 5.4.1-5.4.14 5.5.1-5.5.4 5.6.1-5.6.3 5.8.1-5.8.8 6.2.4C 9.12.1 9.12.2 9.14.2	These clauses are blank and are proposed to be deleted to streamline the Market Rules without affecting the sequence of the remaining clauses.
2.13.15 2.13.16(a)	Clauses 2.13.15 and 2.13.16(a) reference “Regulations” which are defined as any regulations made under the *Electricity Industry Act 2004*, including the IMO Regulations and WEM Regulations. To improve the clarity of both clauses, “Regulations” should be replaced with “WEM Regulations” to ensure the appropriate Regulations, which contain the civil penalty provisions, are referenced.
2.13.21(a)	Clause 2.13.21(a) contains unnecessary extra spaces and should be amended by deleting the additional spaces prior to “The” and “:”.
2.16.9FA 2.24.6	Clauses 2.16.9FA and 2.24.6 incorrectly refer to the Economic Regulation Authority as Economic Regulatory Authority. The clauses require “Regulatory” to be replaced with “Regulation”. Clause 2.16.9FA also requires a “.” after the clause number to be consistent with the drafting style.
2.22.8B	Clause 2.22.8B is grammatically incorrect and requires the correction of the word “in” to “to” following “Financial Year”.
2.23.1	Clause 2.23.1 is inconsistent with the current drafting style and should be amended to delete the unnecessary bulleting of the paragraph.

Clause	Explanation of proposed amendments
2.23.4	Clause 2.23.4 incorrectly cross-references clause 2.33.1 instead of clause 2.23.2. Clause 2.33.1 relates to the information that the IMO must prescribe in a Rule Participant registration form which is not relevant to the Allowable Revenue process. Clause 2.23.4 must be amended to correct this adminsitrative error by deleting the reference "2.33.1" and inserting "2.23.2" which correctly states the requirement for the Shareholding Minister to determine the budget of System Management.
2.23.9	Clause 2.23.9 relates to System Management's budget proposal. Therefore, the occurrence of "System Management's budget" should be amended to "System Management's budget proposal" so as to correctly refer to its proposed form. Additionally, the unnecessary spaces at the start of the second sentence and following "approved" also need to be deleted.
2.30A.6 2.31.23	Clauses 2.30A.6 and 2.31.23 capitalise a non-defined term "Registration Procedure". The reference in clause 2.30A.6 needs to be replaced with "Market Procedure referred to in clause 2.31.23" to ensure that the correct Market Procedure is referenced in this clause. Clause 2.30A.6 also requires a "." after the clause number to be consistent with the drafting style. The reference in clause 2.31.23 "the Registration Procedure" needs to be replaced with "a Market Procedure". Additionally, the extra space before "transfer process" needs to be removed.
2.33.2	Clause 2.33.2 is grammatically incorrect and requires the correction of the word "prescribed" to "prescribe".
2.33.5	Clause 2.33.5 uses passive language and is inconsistent with the drafting style of other similar clauses in this section and therefore should be revised to "The IMO must prescribe a Facility transfer form that requires an applicant for transfer of a Facility to provide the following". This correction will ensure that the obligation is actively placed on the relevant entity, in this case, the IMO. Further, the readability of clause 2.33.5(f) could be improved by rewording "evidence to the satisfaction of IMO" to "evidence to the IMO's satisfaction".

Clause	Explanation of proposed amendments
2.34.14	Clause 2.34.14(a) requires the IMO to commence using revised Standing Data related to Standing STEM, Bilateral and Resource Plan Submissions, Consumption Increase and Decrease Prices and Standing Data changes stemming from an application made under clause 6.6.9, by 8:00 AM on the Scheduling Day following the IMO's acceptance of that revised Standing Data. This can lead to situations where the IMO and the Rule Participant are non-compliant with other Market Rules. For example, clause 6.20.3(b) requires the Alternative Maximum STEM Price to commence on the first day of the month. The current drafting of this clause would require the Market Participant to work back from the required commencement date for correct Consumption Increase and Decrease Prices to apply on the correct date. The IMO considers that this is impractical and has removed them from the list in sub-clause (a). Consumption Increase and Decrease Prices need to be commenced on a specific date and therefore also cannot be covered under sub-clause (b) (to be renumbered to (c)). Under clause 2.34.3(c) a Rule Participant seeking to revise its Standing Data (other than that changed in accordance with the processes under clauses 6.2A, 6.3C or 6.5C) must provide the IMO with the proposed date from which the revision will take effect. The IMO therefore proposes to insert a new sub-clause 2.34.14(b) containing the ability for the IMO to commence using this Standing Data no sooner than 8:00 AM on the date proposed by the Rule Participant or as soon as practicable thereafter. Furthermore, the numbering of sub-clause 2.34.14(a) will be simplified to improve readability.
2.38.4(a)(iv)	Clause 2.38.4(a)(iv) is grammatically incorrect and requires the correction of the word "to" to "of" following "unsubordinated obligations".
3.2.5 Glossary "Technical Code"	Clause 3.2.5(e) and the Glossary contain the term "Technical Code" which needs to be replaced with "Technical Rules" to reflect the correct name of the document in accordance with the Access Code. The definition in the Glossary needs to also be corrected to: "The rules established under the Access Code to detail the technical requirements to be met by Western Power on the transmission and distribution systems and by users who connect facilities to those systems." Also note the Glossary will need to be re-ordered to insert this term after "Technical Envelope" to ensure the Glossary remains in alphabetical order. Clause 3.2.5 also contains an extra space at the start of the sentence "In establishing" which will be removed.
3.5.1(eA)	Clause 3.5.1(eA) contains a typographical error. The word "personal" needs to be amended to "personnel".
3.11.8A	The IMO proposes to clarify clause 3.11.8A by adding the phrase "the provision of a" following "for" to ensure that the clause appropriately relates to the provision of a Load Rejection Reserve, System Restart or Dispatch Support service.

Clause	Explanation of proposed amendments
3.16.4 3.16.9	Clauses 3.16.4 and 3.16.9 capitalise a non-defined term "Medium Term Planning" and the capitalisation of the words "Medium", "Term" and "Planning" needs to be removed.
3.16.9	Clause 3.16.9 states "By the 15th day of each month, System Management must provide to the IMO and the IMO must publish the following information" irrespective of the 15th day being a Business Day. To improve practicality, the above clause will be amended to "On the first Business Day falling on or following the 15th day of each month". Due to the fact that the information provided by System Management covers a 3 year period, a maximum delay of two days will not have an impact on the end-users of the information. Also the term "as a result of its" should be replaced with "as a result of System Management's" to improve clarity of who produces the Medium Term PASA.
3.21B.8	Clause 3.21B.8 is grammatically incorrect and requires correcting "granting" to "to grant" and amend the term "is accordance with this clause 3.21B" to "in accordance with this clause 3.21B". The IMO also proposes to clarify what System Management is granting permission for by adding "for re-synchronisation".
3.22.1 4.29.3 9.3.2	The term "provide the following information to" in clauses 3.22.1 and 4.29.3 should be amended to "update the following information in". This amendment improves clarity and emphasises that a settlement system is not an active party. Also the capitalisation of the non-defined term "Settlement System" in clause 3.22.1 needs to be removed. Furthermore the non-defined term "Settlement Systems" in clause 4.29.3 should be replaced with "settlement system". The term "provide to the Settlement System" in clause 9.3.2 is incorrect and is proposed to be replaced with "provide the IMO with" to reflect the current practice that the IMO receives and loads the data into the settlement system.
4.5.1 4.5.2	Clauses 4.5.1 and 4.5.2 capitalise a non-defined term "Long Term PASA Study". This needs to be amended to the correct term "Long Term PASA" as defined in the Glossary.
4.7.1	Clause 4.7.1 is inconsistent with the drafting style of other blank clauses in the Market Rules and therefore should be amended from "[BLANK]" to "[Blank]".

Clause	Explanation of proposed amendments
4.27.1 4.27.2	Clause 4.27.1 requires the IMO to monitor the total availability of capacity in the SWIS on a daily basis. This is followed by clauses 4.27.2 and 4.27.3 where the IMO is required to perform certain actions on a monthly basis using the information collected through the monitoring activities. For the purposes of the practical implementation of clause 4.27.1, the IMO's daily monitoring activities are automated in the market software, the results of which are produced in the monthly report as required under clause 4.27.2. The IMO notes that the automated monitoring processes do not (and are not required to) result in a daily report. The IMO therefore considers that the obligation outlined in clause 4.27.1 is redundant as the daily monitoring activities are required to culminate in the monthly report under clause 4.27.2. The IMO considers that the practicality of complying with clause 4.27.1 should be improved by amending clause 4.27.1 to remove the daily monitoring requirement from 4.27.1 and introduce the obligation in 4.27.2 for the IMO to monitor the total available capacity in the SWIS and produce the report required under clause 4.27.2 on a monthly basis.
4.27.10(a)	Clause 4.27.10(a) is grammatically incorrect and requires amending the word "Credit" to its plural form "Credits" in the term "Capacity Credit".
5.1 5.1.1 5.1.2 Glossary "Network Control Service"	The IMO considers that definitions should be part of the Glossary, the IMO therefore proposes to delete clause 5.1.1 which defines the term "Network Control Service" and clause 5.1.2 which defines the term "Network Control Service Contract". These do not need to be retained as blank clauses as their removal will not affect the numbering in the Market Rules. The heading for section 5.1 will need to be changed to "[Blank]" as there will no longer be content in this section. The term "Network Control Service Contract" is already included in the Glossary. The IMO proposes to include the definition for Network Control Service as follows: "A service provided by generation or demand side management that can be a substitute for transmission or distribution network upgrades."
7.13.1(cB)	To better reflect the data being provided by System Management to the IMO, the IMO proposes to amend clause 7.13.1(cB) as follows: "for each generating system monitored by System Management's SCADA system, the ambient temperature at the site measured at five minute intervals."
8.6.1(e)	Clause 8.6.1(e) has inappropriate formatting for the word "M**eter**". The M in "Meter" needs to be bolded consistent with the rest of the word.

Clause	Explanation of proposed amendments
9.2.1	The reference in clause 9.2.1 to “the Settlement Procedure” is not a defined term and needs to be replaced with “a Market Procedure”.
9.4.7	Clause 9.4.7 requires the IMO to acknowledge resubmitted Capacity Credit Allocation Submissions within 30 minutes of receipt, by telephone. This process is automated through the Market Participant Interface and therefore Market Participants are issued an automated notice of receipt or failure, at which point the Market Participant may resubmit. Where a Market Participant contacts the IMO to make alternative arrangements, it is usual that the IMO would provide a response by email. The IMO therefore proposes to change the obligation in clause 9.4.7 to remove “by telephone”.
9.9.3A	Clause 9.9.3A contains an unnecessary comma at the end of the term “ASP_BSPayment(c,m))),” which needs to be deleted.
9.20.1	Clause 9.20.1 provides the options of mail, facsimile, email or electronic submission for the lodgement of a Notice of Disagreement. The Market Rules should be principles based, with specific details to be provided in the relevant Market Procedure. The IMO therefore proposes to replace the different methods with a reference to the Market Procedure: Settlement which contains information about how to lodge a Notice of Disagreement.
Glossary “Derogation”	The term “Derogation” is not used within the Market Rules and only exists in the Glossary. This defined term is redundant and is proposed to be removed from the Market Rules.
Glossary “Shareholding Minister”	The definition of Shareholding Minster includes a reference to the “Electricity Corporation Act” in which the word “Corporation” is incorrect and needs to be amended to “Corporations”. In addition, at the start of the sentence there is an extra space which should be deleted.
Appendix 1 (b)(i) (e)(i) (g)(ii) (i)(ii)	Appendix 1(b)(i), (e)(i), (g)(ii) and (i)(ii) refer to communication and control systems with the incorrect reference to clause 2.36. Clause 2.36 refers to market system requirements. The reference to clause 2.36 in these clauses needs to be replaced with clause 2.35 which will correct the reference to communication and control system requirements.
Appendix 1 (b)(ii) (b)(xv) (e)(ii)	Appendix 1(b)(ii), (b)(xv) and (e)(ii) contain a typographical error “name plate” and should be replaced with the correct spelling “nameplate”.

Clause	Explanation of proposed amendments
Appendix 5	Step 9 of Appendix 5 contains two unnecessary end brackes "))" within the equation for X(i) which need to be removed.

2. Explain the reason for the degree of urgency:

Most of the proposed amendments in this Rule Change Proposal correct minor, administrative and typographical errors. These proposed amendments will improve the integrity of the Market Rules and do not seek to amend the operation or intended meaning of the Market Rules. The IMO considers that these proposed amendments meet the requirements set out in clause 2.5.9(a) and (b) of the Market Rules to apply the Fast Track Rule Change Process.

However, the proposed amendments to clauses 3.16.9, 4.27.1, 4.27.2, 7.13.1(cB), 9.4.7 and 9.20.1 do not meet the requirements set out in clause 2.5.9 of the Market Rules. Therefore, the IMO proposes to progress this Rule Change Proposal under the Standard Rule Change Process described in section 2.7 of the Market Rules.

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)*

~~2.12.1. [Blank]~~

~~2.12.2. [Blank]~~

~~2.12.3. [Blank]~~

~~2.12.4. [Blank]~~

~~2.12.5. [Blank]~~

...

2.13.15. Where the alleged breach relates to a Category A Market Rule (as determined in accordance with the <u>WEM</u> Regulations) and the IMO is not the Rule Participant that is alleged to have breached the Market Rules, the IMO must make a decision as to whether a breach has occurred.

2.13.16. The IMO may:

(a) decide a breach has taken place in which case the IMO may issue a penalty notice in accordance with the <u>WEM</u> Regulations; or

...

…

2.13.21. Following the investigation referred to in clause 2.13.19, where the person referred to in clause 2.13.1 reasonably believes a breach of the Market Rules or Market Procedures has taken place it:

(a) may issue a warning to the IMO to rectify the alleged breach. The warning must:

…

…

...

2.16.9FA. Subject to clause 2.16.9FB, the Economic Regulation Authority may extend the timeframe for an investigation under clause 2.16.9E for a period of up to six months, to the nearest Business Day following that six month extension period. Where the Economic ~~Regulatory~~Regulation Authority makes such an extension it must notify the IMO and the IMO must publish a notice of the extension on the Market Web Site within one Business Day of receiving the notification. The Economic Regulation Authority may extend the timeframe for an investigation more than once.

…

2.22.8B. The IMO must endeavour to make an application under clauses 2.22.8 or 2.22.8A in sufficient time to allow its budget proposal to be approved under clause 2.22.9 before the commencement of the Financial Year ~~in~~to which it relates. The Economic Regulation Authority may amend a determination under clause 2.22.3(c) if the IMO makes an application under clauses 2.22.8 or 2.22.8A. Clause 2.22.3(b) applies in the case of an application made under clauses 2.22.8 or 2.22.8A.

…

2.23.1. For the purposes of this clause 2.23, the services provided by System Management are~~:~~ system operation services, including all of System Management's functions and obligations under these Market Rules.

~~(a) system operation services, including all of System Management's functions and obligations under these Market Rules.~~

…

2.23.4. Where the Economic Regulation Authority does not make a determination by the date specified in clause 2.23.3(c), the Allowable Revenue and Forecast Capital Expenditure from the previous Review Period, or the budget determined by the Shareholding Minister under clause 2.~~33.1~~23.2, as applicable, will continue to apply until the Economic Regulation Authority makes a determination.

…

2.23.9. System Management must provide a copy of its budget proposal to the IMO by 30 April each year. The IMO must review the budget proposal and submit a report containing advice on whether System Management's budget proposal is consistent with the Allowable Revenue and Forecast Capital Expenditure approved by the

Economic Regulation Authority, including the reasons why, to the Minister by 31 May.

…

2.24.6. By the date which is five Business Days prior to 30 June each year, the Economic Regulation Authority must notify the IMO of the dollar amount that the Economic ~~Regulatory~~Regulation Authority may recover under clause 2.24.5.

…

2.30A.6. The IMO must document the Spinning Reserve costs exemption process in the ~~Registration~~ Market Procedure referred to in clause 2.31.23, and:

…

…

2.31.23. The IMO must document the registration, de-registration and transfer process in ~~the Registration~~ a Market Procedure, and:

…

…

2.33.2. The IMO must prescribe~~d~~ a Rule Participant de-registration form that requires an applicant for de-registration as a Rule Participant to provide the following:

…

...

2.33.5. The IMO must prescribe a Facility transfer form ~~prescribed by IMO must~~that requires ~~that~~ an applicant for transfer of a Facility to provide the following:

…

(f) evidence to the ~~satisfaction of~~ IMO's satisfaction that the party making the application has assumed the Reserve Capacity Obligations associated with the Facility, and agrees to any Short Term Special Price Arrangements or Long Term Special Price Arrangements associated with the Facility;

…

...

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~~ii. Standing Bilateral Submissions;

~~iB~~iii. Standing Resource Plan Submissions; and

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

~~iii~~iv. 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) no sooner than 8:00 AM on the date proposed by the Rule Participant or as soon as practicable thereafter in the case of Consumption Increase Prices and Consumption Decrease Prices; and

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

...

2.38.4. The Credit Support for a Market Participant must be:

(a) an obligation in writing that:

…

iv. constitutes valid and binding unsubordinated obligations ~~to~~ of the Credit Support provider to pay to the IMO amounts in accordance with its terms which relate to the relevant Market Participant's obligations under the Market Rules; and

...

…

...

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:

...

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

…

3.5.1. The SWIS is in an Emergency Operating State when System Management considers that any of the following circumstances exist, or are likely to exist within the next fifteen minutes, or are likely to exist after fifteen minutes; and actions other than those allowed under the Normal Operating State or High-risk Operating State must be implemented immediately by System Management so as to moderate or avoid the circumstance:

...

(eA) operation under a Normal Operating State or a High-Risk Operating State would pose a significant risk to the physical safety of the public or field personne~~a~~l;

…

…

3.11.8A. System Management may enter into an Ancillary Service Contract with a Rule Participant for the provision of a Load Rejection Reserve Service, System Restart Service or Dispatch Support Service.

…

3.16.4. Unless otherwise directed by System Management, Rule Participants must provide the following data to System Management in respect of each week in the m~~M~~edium t~~T~~erm p~~P~~lanning horizon described in clause 3.16.2 by the time specified in the Power System Operation Procedure:

...

...

3.16.9. ~~By~~ On the first Business Day falling on or following the 15th day of each month, System Management must provide to the IMO and the IMO must publish the following information developed as a result of ~~its~~ System Management's Medium Term PASA study for each week in the m~~M~~edium t~~T~~erm p~~P~~lanning horizon described in clause 3.16.2:

…

...

3.21B.8. System Management must document the procedure it follows to grant~~ing~~ permission for re-synchronisation in~~is~~ accordance with this clause 3.21B in the Power System Operation Procedure and System Management and Market Participants must follow that documented Market Procedure.

…

3.22.1. The IMO must ~~provide~~ update the following information ~~to~~ in the s~~S~~ettlement s~~S~~ystem for each Trading Month:

…

4.5.1. The Long Term PASA ~~Study~~ must be performed annually by the IMO and considers each of the years in the Long Term PASA Study Horizon.

4.5.2. The Long Term PASA ~~Study~~ must take into account:

...

...

4.7.1. [Blank~~LANK~~]

...

~~4.13.11B [Blank]~~

...

4.27.1. ~~The IMO must monitor the total availability of capacity in the SWIS on a daily basis.~~ The total available capacity should equal:

(a) the total Capacity Credits held by Market Participants on that day; less

(b) the maximum amount of capacity unavailable at any time due to Planned Outages.

4.27.2. The IMO must monitor the total availability of capacity in the SWIS and, ~~B~~by the twenty fifth day of each month, the IMO must assess the number of days in the preceding 12 calendar months where the total available capacity in the SWIS dropped below 80% (during the Hot Season), and 70% (in either the Intermediate Season or Cold Season), of the total Capacity Credits held by Market Participants for more than six hours on the day.

...

4.27.10. Market Participants holding Capacity Credits for Facilities that are yet to commence operation must file a report on progress with the IMO:

(a) at least once every three months from the date the Capacity Credits are confirmed under clause 4.20.5A; and

…

~~4.27.10A. [Blank]~~

...

4.29.3. The IMO must prepare and ~~provide~~ update the following information ~~to~~ in the s~~S~~ettlement s~~S~~ystem~~s~~ in time for settlement of Trading Month m:

…

…

5.1. ~~Definitions~~[Blank]

~~5.1.1. A Network Control Service is a service provided by generation or demand side management that can be a substitute for transmission or distribution network upgrades.~~

~~5.1.2. A Network Control Service Contract is a contract between a Network Operator and a Market Participant for the Market Participant to provide a Network Control Service.~~

~~5.1.3. [Blank]~~

~~5.1.4. [Blank]~~

...

~~5.2.1. [Blank]~~

~~5.2.2. [Blank]~~

~~5.2.3. [Blank]~~

~~5.2.4. [Blank]~~

~~5.2.5. [Blank]~~

~~5.2.6. [Blank]~~

~~5.2.7. [Blank]~~

...

~~5.3.1. [Blank]~~

~~5.3.2. [Blank]~~

~~5.3.3. [Blank]~~

~~5.3.4. [Blank]~~

~~5.3.5. [Blank]~~

~~5.3.6. [Blank]~~

~~5.3.7. [Blank]~~

~~5.3.8. [Blank]~~

~~5.3.9. [Blank]~~

...

~~5.4.1. [Blank]~~

~~5.4.2. [Blank]~~

~~5.4.3. [Blank]~~

~~5.4.4. [Blank]~~

~~5.4.5. [Blank]~~

~~5.4.6. [Blank]~~

~~5.4.7. [Blank]~~

~~5.4.8. [Blank]~~

~~5.4.9. [Blank]~~

~~5.4.10. [Blank]~~

~~5.4.11. [Blank]~~

~~5.4.12. [Blank]~~

~~5.4.13. [Blank]~~

~~5.4.14. [Blank]~~

...

~~5.5.1. [Blank]~~

~~5.5.2. [Blank]~~

~~5.5.3. [Blank]~~

~~5.5.4. [Blank]~~

...

~~5.6.1. [Blank]~~

~~5.6.2. [Blank]~~

~~5.6.3. [Blank]~~

...

~~5.8.1. [Blank]~~

~~5.8.2. [Blank]~~

~~5.8.3. [Blank]~~

~~5.8.4. [Blank]~~

~~5.8.5. [Blank]~~

~~5.8.6. [Blank]~~

~~5.8.7. [Blank]~~

~~5.8.8. [Blank]~~

...

~~6.2.4C. [Blank]~~

...

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:

…

(cB) for each generating system monitored by System Management's SCADA system, the ~~maximum daily~~ ambient temperature at the site ~~of each generating system monitored by System Management's SCADA system for the Trading Day~~ measured at ~~5~~five minute intervals;

…

…

8.6.1. A Meter Data Submission must comprise:

…

(e) meter adjustments that stem from actual meter data becoming available or from the resolution of a dispute concerning meter data ("**M~~M~~eter Dispute**") in accordance with the dispute resolution process in the applicable Metering Protocol, including:

…

…

...

9.2.1. The IMO must document the settlement process, including the application of taxes and interest, in ~~the Settlement Procedure~~ a Market Procedure, and the IMO and Market Participants must follow that documented Market Procedure.

…

9.3.2. Metering Data Agents must provide ~~to the Settlement System,~~ the IMO with settlement ready metering data in accordance with Chapter 8.

…

9.4.7. The IMO must confirm receipt~~, by telephone,~~ of a Capacity Credit Allocation Submission from a Market Participant made in accordance with clause 9.4.6 within 30 minutes of receiving the submission, indicating the matters referred to in paragraphs 9.4.5(a) and (b).

…

9.9.3A. The value of ASP_Balance_Payment(m) for Trading Month m is:

ASP_Balance_Payment(m) =
Sum(c∈CAS_SR, ASP_SRPayment(c,m)) +
Min(Cost_LR(m), Sum(c∈CAS_LR, ASP_LRPayment(c,m))
+ Sum(c∈CAS_BS, ASP_BSPayment(c,m)))~~,~~ +
Sum(c∈CAS_DS, ASP_DSPayment(c,m))

…

…

~~9.12.1. [Blank]~~

~~9.12.2. [Blank]~~

...

~~9.14.2. [Blank]~~

...

9.20.1. A Notice of Disagreement must be submitted to the IMO in accordance with the Market Procedure referred to in clause 9.2.1.~~writing and may be mailed, sent by facsimile, e-mailed or submitted electronically to the IMO.~~

…

11 Glossary

...

~~**Derogation**: An exemption or modification to the Market Rules applicable to one or more Rule Participants set out in Chapter 11 of these Market Rules.~~

…

Network Control Service:~~Has the meaning given in clause 5.1.1.~~ A service provided by generation or demand side management that can be a substitute for transmission or distribution network upgrades.

Network Control Service Contract: A contract between a Network Operator and a Market Participant to provide a Network Control Service.

[Note: this definition has been included to provide context to other proposed amendments and is not proposed to be amended itself]

…

Shareholding Minister: —The Minister responsible for administering the Electricity Corporations Act.

…

Technical ~~Code~~Rules: The rules established under the Access Code to detail the technical requirements to be met by Western Power on the transmission and distribution system and by users who connect facilities to those systems.~~A code prescribing technical rules and requirements for access arrangements, established under the Access Code.~~

[Note: this definition will need to be re-ordered to ensure that the Glossary remains in alphabetical order]

...

Appendix 1: Standing Data

...

(b) for a Scheduled Generator:

i. evidence that the communication and control systems required by clause 2.3~~6~~5 are in place and operational;

ii. the nameplate~~name plate~~ capacity of the generator, expressed in MW;

…

xv. any output range between minimum dispatchable loading level and nameplate~~name plate~~ capacity in which the facility is incapable of stable or safe operation;

…

(e) for a Non Scheduled Generator:

i. evidence that the communication and control systems required by clause 2.3~~6~~5 are in place and operational;

ii. the nameplate~~name plate~~ capacity of the generator, expressed in MW;

…

(g) for an Interruptible Load:

...

ii. evidence that the communication and control systems required by clause 2.3~~6~~5 are in place and operational;

…

(i) for a Dispatchable Load:

ii. evidence that the communication and control systems required by clause 2.3~~6~~5 are in place and operational;

…

…

...

Appendix 5: The Individual Reserve Capacity Requirements

…

…

STEP 9: For each Market Customer, i, calculate

X(i) = Sum(i, ILRCR(i) + NTDLRCR(i) + TDLRCR(i))~~)~~ + Sum(u, NMNTCR(u) × d(u,i)) + Sum(v, NMTDCR(v) × d(v,i))

…

---

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

The proposed amendments will lower the long-term cost of electricity supply by improving the practicality of the administrative processes associated with the WEM. Additionally, the removal of typographical errors will improve the integrity of, and reduce the effort required to administer the Market Rules. Therefore, the IMO considers that the proposed amendments will better achieve Wholesale Market Objectives (a) and (d).

The proposed amendments also seek to make minor, administrative changes and correct typographical errors in the Market Rules. As such, the IMO considers that the proposed changes do not impact the operation of the WEM but seek to provide clarity and consistency in the drafting of the Market Rules. The IMO therefore considers the amendments in this Rule Change Proposal are consistent with the Wholesale Market Objectives.

---

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

Costs:

No costs associated with implementing these proposed changes have been identified.

Benefits:

The proposed changes to remove minor, administrative and typographical errors will improve the clarity of the Market Rules and ensure that the market functions as intended.

Amendments to Market Rules related to administrative processes will improve the practicality of the implementation of the Market Rules without changing the initial intention.

---

6. Provide any identifiable issues with respect to the practicality of implementation:

The IMO notes that clauses 2.12.1, 2.12.2, 2.12.3, 2.12.4, 2.12.5, 2.13.15, 2.13.16(a), 2.13.21(a), 2.16.9FA, 2.22.8B, 2.23.1, 2.23.4, 2.23.9 and 2.24.6 of the Market Rules that are proposed to be amended are Protected Provisions under clause 2.8.13 of the Market Rules. In accordance with clause 2.8.3 of the Market Rules, the proposed Amending Rules in this Rule Change Proposal will therefore require to be approved by the Minister.

The IMO also notes that clauses 3.16.4 and 9.3.2 of the Market Rules are Category B civil penalties under the *Electricity Industry (Wholesale Electricity Market) Regulations 2004*. The IMO notes that the proposed amendments do not intend to alter the meaning and operation of these clauses and therefore remain appropriate.

The IMO will engage with the Public Utilities Office to progress this Rule Change Proposal.

This Rule Change Proposal aligns the Market Rules with current practice and therefore will not require any system changes.

INDEPENDENT MARKET OPERATOR

Wholesale Electricity Market
Rule Change Proposal

Rule Change Proposal ID: RC_2014_10
Date received: TBA

Change requested by:

Name:	Kate Ryan
Phone:	9254 4357
Fax:	9254 4399
Email:	kate.ryan@imowa.com.au
Organisation:	IMO
Address:	Level 17, 197 St Georges Terrace, Perth 6000
Date submitted:	TBA
Urgency:	Medium
Rule Change Proposal title:	Provision of Network Information to System Management
Clause(s) affected:	Clauses 2.28.2, 2.28.3, 2.28.4, 2.29.3, 2.29.3A (new), 2.29.3B (new), the Glossary and Appendix 1.

Introduction

Clause 2.5.1 of the Wholesale Electricity Market Rules (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 IMO.

This Rule 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 IMO will assess the proposal and, within five 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 Rule Change Proposal:

The flow of Network information

Currently, the Market Rules require a Network Operator to register any transmission system or distribution system owned, operated or controlled by that Network Operator as a Network, where that transmission or distribution system forms part of the South West interconnected system (SWIS), or is electrically connected to that system.

As a pre-condition of Facility registration, a Network Operator is required to provide the Standing Data described in Appendix 1(a) of the Market Rules. In accordance with clause 2.34.1(b) of the Market Rules, the IMO is required to provide this Standing Data to System Management. The Standing Data for a Network is dynamic and is used by System Management to set the limits in each Trading Interval for the operation of the SWIS in each SWIS Operating State to maintain Power System Security and Reliability.

In practice, Western Power is the only registered Network Operator and its transmission system and distribution systems are not registered in the WEM. The IMO therefore does not hold Standing Data for any networks and does not any provide any Standing Data with respect to Networks to System Management. Instead, Western Power provides System Management with access to all the information required in Appendix 1(a) of the Market Rules through Western Power's Supervisory Control and Data Acquisition (SCADA) systems (though it is not required to do so under the Market Rules).

If Network Operators were to provide the IMO with this information, and the IMO were to pass this information on to System Management as required under the Market Rules, Network Operators, the IMO and System Management would incur significant operational costs to manage this dynamic information flow. These costs would exceed the costs incurred by System Management and Western Power under the current practice whereby Western Power provides System Management with direct access to its SCADA systems. Furthermore, this information is not required by the IMO to carry out its current market functions and so can be provided directly to System Management.

The IMO considers that the current practice, whereby a Network Operator provides System Management with access to all the information required under Appendix 1(a), should be reflected in the Market Rules to ensure that the current effective and efficient transfer process is captured in the Market Rules and remove an unworkable pre-condition to registration of Networks in the SWIS.

The IMO notes that access to the required network information may be provided to System Management either directly by the relevant Network Operator or indirectly through another party. This reflects current practice, as some of the private network operators provide data access to System Management via Western Power's SCADA systems. It should be noted however, that in such cases, the obligation to provide the network information to System Management, by whatever means, remains with the relevant Network Operator and not with the third party.

Proposed solution:

The IMO proposes to delete Appendix 1(a) of the Market Rules. This will effectively remove the requirement for a Network Operator to provide this data to the IMO as a pre-condition of Facility registration for a Network.

The IMO also proposes to introduce two new clauses into the Market Rules:

- a new clause 2.29.3A of the Market Rules to require System Management to document in a Power System Operation Procedure (PSOP) the process relating to how the network information is technically transferred between Network Operators and System Management; and

- a new clause 2.29.3B of the Market Rules to require a Network Operator to, in accordance with the PSOP, provide System Management with access, at all times, to the necessary information (to be moved from Appendix 1(a) of the Market Rules) for any Network operated by that Network Operator.

The definition of a Network

Currently, the definition in the Market Rules for a 'Network' is any transmission system or distribution system registered as a Network under clause 2.29.3 of the Market Rules. The IMO proposes to amend this definition to better clarify what constitutes a Network, to provide greater certainty to parties in relation to their obligations to register as a Network Operator and to register a Network Facility.

The IMO proposes to amend the definition of a 'Network' to be consistent with the definition in the Electricity Networks Access Code 2004. This definition includes any electrical equipment in the distribution or transmission system that transfers electricity between the relevant points of connection for a transmission or distribution system within the SWIS, which is registered under clause 2.29.3 of the Market Rules. In particular, the reference to 'relevant points of connection' will ensure that privately owned equipment behind a connection point is not included.

It should be noted that the proposed definition of a 'Network' includes any electrical equipment that transfers electricity between relevant points of connectionwithin the SWIS, even where the electrical equipment transfers electricity to a Facility, which is temporarily not electrically connected to the SWIS[1].

The IMO notes that, under clause 2.29.9 of the Market Rules, the IMO has the ability to provide an exemption from the requirement to register its Facility as a Network under clause 2.29.3 of the Market Rules.

The IMO has also taken the opportunity to amend clauses 2.28.2, 2.28.3, 2.28.4 and 2.29.3 of the Market Rules to align the wording of these clauses with the amended term 'Network'. The previous wording of these clauses had linked obligations to register as a Network Operator or a Network Facility, on the basis of operating, owning or controlling a transmission system or distribution system connected to the SWIS. The amended wording of these clauses retains these concepts but also links to registration obligations.

Proposed solution:

The IMO proposes to amend the definition of 'Network' in the Glossary of the Market Rules.

The IMO proposes to expressly link the criteria under which a person may, but is not required to, register as a Network Operator applies to the IMO's determination under clause 2.28.16 of the Market Rules.

The IMO also proposes to amend clauses 2.28.2, 2.28.3, 2.28.4 and 2.29.3 of the Market Rules to align the wording of these clauses with the proposed definition of a 'Network'.

Protected Provisions, Reviewable Decisions and civil penalty provisions

The IMO notes that clauses 2.28.2, 2.28.3, 2.28.4 of the Market Rules are Protected Provisions under clause 2.8.13. Therefore, under clause 2.8.3 of the Market Rules, the proposed Amending Rules in this Rule Change Proposal must be approved by the Minister.

The proposed amendments in this Rule Change Proposal do not amend any clauses which are Reviewable Decisions or civil penalty provisions but do cross-reference, and are cross-referenced by, clauses that are Reviewable Decisions and civil penalty provisions. The IMO notes that the proposed amendments do not change these meaning or effect of these cross-referenced clauses.

[1] Please refer to the Agenda item 4 in the MAC Meeting No. 27 Papers available at: http://www.imowa.com.au/interpretation on what constitutes a connection to the SWIS.

2. Explain the reason for the degree of urgency:

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

The IMO considers the proposed amendments will benefit the market, by clarifying the obligations of Network Operators and facilitating registration, and involve minimal costs and therefore should be progressed prior to the completion of the State Government's Electricity Market Review.

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

2.28.2. Subject to clauses 2.28.3 and 2.28.16, a person who owns, controls or operates <u>electrical equipment that is used in order to transfer electricity within the SWIS, and between the relevant points of connection for a distribution system or transmission system</u> ~~a transmission system or distribution system which forms part of the South West Interconnected System, or is electrically connected to that system~~, must register as a Rule Participant in the Network Operator class.

2.28.3. <u>For the purposes of clause 2.28.16, a</u>~~A~~ person that owns, controls or operates <u>electrical equipment that is used in order to transfer electricity within the SWIS, and between the relevant points of connection for a distribution system or transmission system</u> ~~a transmission system or distribution system~~ may, but is not required to, register as a Rule Participant in the Network Operator class where both the following are satisfied:

(a) System Management informs the IMO that it has determined that it does not require information about the relevant network to maintain Power System Security and Power System Reliability; and

(b) no Market Participant Registered Facilities are directly connected to the transmission system or distribution system.

2.28.4. A person who intends to own, control or operate <u>electrical equipment that will be used in order to transfer electricity within the SWIS, and between the relevant points of connection for a distribution system or transmission system</u> ~~a transmission system or distribution system which will form part of the South West Interconnected System, or will be electrically connected to that system~~, may register as a Rule Participant in the Network Operator class.

…

2.29.3. Subject to clause 2.29.9, a Network Operator must register <u>the electrical equipment that is used in order to transfer electricity within the SWIS, and between the relevant points of connection for a distribution system or transmission system</u> ~~any transmission system or distribution system~~ owned, operated or controlled by that Network Operator as a Network~~, where that transmission or distribution system forms part of the South West Interconnected System, or is electrically connected to that system~~.

…

2.29.3A. System Management must document in a Power System Operation Procedure the procedure to be followed relating to the provision of Network information between Network Operators and System Management. System Management and Network Operators must comply with that documented Market Procedure in respect to the provision of network information.

2.29.3B. In accordance with the Power System Operation Procedure referred to in clause 2.29.3A, for any Network, the relevant Network Operator must provide System Management with access, at all times, to the following information:

(a) positive, negative and zero sequence network impedances for the network elements;

(b) information on the network topology;

(c) information on transmission circuit limits;

(d) information on security constraints;

(e) overload ratings, including details of how long overload ratings can be maintained; and

(f) the short circuit capability of facility equipment.

…

11 Glossary

Network: The electrical equipment that is used in order to transfer electricity within the SWIS, and between the relevant points of connection for a distribution system or transmission system~~A transmission system or distribution System~~ registered ~~as a Network~~ under clause 2.29.3.

…

Appendix 1: Standing Data

This Appendix describes the Standing Data to be maintained by the IMO for use by the IMO in market processes and by System Management in dispatch processes.

Standing Data required to be provided as a pre-condition of Facility Registration and which Rule Participants are to update as necessary, is described in clauses (a) to (i).

Standing Data not required to be provided as a pre-condition of Facility Registration but which the IMO is required to maintain, and which Rule Participants are to update as necessary, includes the data described in clauses (j) to (m).

(a) [blank]~~for a Network:~~

~~i. positive, negative and zero sequence network impedances for the network elements;~~

~~ii. information on the network topology;~~

~~iii. information on transmission circuit limits;~~

~~iv. information on security constraints;~~

~~v. overload ratings, including details of how long overload ratings can be maintained; and~~

~~vi. the short circuit capability of facility equipment.~~

…

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4. Describe how Rule Change Proposal 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) and (d) and are consistent with the other Wholesale Market Objectives. The IMO's assessment is presented below:

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

The proposed amendments align the Market Rules with current operations and better define what constitutes a Network. These changes enhance economic efficiency by:

- clarifying and providing greater certainty to Network Operators of their obligations under the Market Rules;
- ensuring that the Market Rules provide System Management with access, at all times, to the dynamic Network information being captured in the relevant SCADA systems; and
- providing a more practicable solution to the manual process currently contemplated in the Market Rules in regard to the transfer of Network information.

The proposed amendments also support the safe and reliable supply of electricity, by ensuring that the Market Rules provide for System Management to have direct access to the dynamic Network information relevant to each Trading Interval, rather than indirect and static information provided through the IMO as currently contemplated by the Market Rules.

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

The IMO also considers that the proposed changes to clarify definitions and obligations in the Market Rules will provide for more transparent and accurate Market Rules and therefore reducing the time and effort of compliance, reducing the cost of administering the WEM.

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

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

<u>Costs</u>

There will be minor costs associated with the documentation of the process relating to the provision of network information between Network Operators and System Management in a PSOP. However, the IMO understands that the costs associated with this are able to be accommodated within System Management's existing budget.

The IMO anticipates minor system costs associated with removing the Standing Data fields for Network Facilities from the Market Participant Interface (MPI). However, as these changes are not necessary prior to commencement, the IMO will schedule this work with other activities related to registration to minimise the cost of these changes.

<u>Benefits</u>

The proposed amendments ensure that the Market Rules provide System Management with access at all times to the dynamic Network information being captured in a Network Operator's SCADA systems. The proposed amendments reduce the manual effort currently proposed in the Market Rules in regard to the transfer of Network information, and align the Market Rules with current operations. The proposed amendments also remove a practical impediment to registration of Networks in the SWIS.

In addition, the IMO has taken the opportunity to clarify some related clauses of the Market Rules to provide greater clarity and certainty to Network Operators of their obligations under the Market Rules.

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6. Provide any identifiable issues with respect to the practicality of implementation:

The IMO will assist System Management detail the requirements for the provision of Network information in a PSOP. The IMO expects that the requirements in the PSOP will be similar to those in the Market Procedure: IMS Interface.

The IMO will make system changes to the MPI to remove the Standing Data fields for Network Facilities. However, practically this will not need to occur prior to the commencement of this Rule Change Proposal. The IMO will therefore coordinate the timing of these changes with other changes that it needs to make to its systems to minimise the cost and impact of the necessary changes.

The IMO notes that the process for exemption from registering as a Rule Participant in the Market Procedure: Rule Participant Registration and De-Registration does not explicitly cover Network Operators. The IMO proposes to clarify this process in the Market Procedure together with other proposed amendments to streamline and clarify the procedure.

The IMO will assess for each of the relevant parties and transmission and distribution systems, whether an exemption from registering as a Network Operator is appropriate, and where appropriate, will work with the relevant parties to progress the operational process of registration or exemption in the Market Rules.

As clauses 2.28.2, 2.28.3, 2.28.4 of the Market Rules are Protected Provisions, the proposed Amending Rules in this Rule Change Proposal will require Ministerial approval. The IMO will engage with the Public Utilities Office to progress the proposed amendments.

Discussion paper: constrained network access for new generators

1 Introduction

This is a discussion paper to consider constrained network access for new generators.

An unconstrained network is one in which all generators are able to supply electricity onto the network without limitation. While the Wholesale Electricity Market (**WEM**) treats the dispatch of generators as unconstrained, the South West Interconnected Network is in fact already constrained, with a significant amount of generation built since market commencement connected on a quasi-constrained basis[1].

The Western Power Network (**WPN**) has now reached its practical security limits in many sections of the network, and cannot accommodate further quasi-constrained connections by utilising post contingent run-back schemes. While there are areas within the WPN that can still accommodate new generation on an unconstrained basis, Western Power is currently attempting to facilitate the connection of several generators in two constrained regions (known as Competing Access Groups or **CAG**s). These applicants require connection by April 2017, with information concerning how curtailment might occur by February 2015.

Under clause 2.7 the Electricity Networks Access Code 2004 (**Access Code**), Western Power must make all reasonable endeavours to accommodate an applicant's requirement to obtain services. These applicants are either unwilling or unable to pay for the network augmentation required to provide them with unconstrained network access, and therefore Western Power must investigate constrained access.

Western Power believes that the concepts proposed in this paper represent a viable (albeit interim) step in the development of the WEM. Our proposed solution to the current connection and curtailment dilemma will improve market objectives (as indicated in section 5) and ensure that Western Power is able to meet its obligations under the Access Code.

2 Options

Western Power has investigated a number of options to address the issue of constraining dispatch and providing these generators with their requested non-firm access.

2.1 Constrained Dispatch

This option would see the WEM evolving to a market design where all generators are constrained, such as the National Electricity Market (NEM).

The EMR is currently considering whether the WEM should move to a constrained model. The ERA supports this review[2] and notes that a number of submissions to the EMR Panel provide useful discussion and suggestions in relation to this matter.

However, any transition to a fully constrained network access is limited by legislation, and as such would not meet the timeframe of Western Power to advise applicants of curtailment methodology (February 2015).

2.2 Partially Constrained Dispatch with Re-bidding

Partially constrained dispatch prevents a constraint from occurring by constraining dispatch of selected curtailable generators before the interval in question. This methodology is in

[1] Using post-contingent run-back schemes.
[2] Discussion Paper: 2014 Wholesale Electricity Market Report to the Minister for Energy, November 2014

effect a constrained dispatch model but unlike the constrained dispatch option, would be applied only to new generators.

Like the constrained dispatch option however, the implementation of this model is complex, and would require significant modification to the WEM Rules with regard to the dispatch engine and generator bidding “windows”. It is not likely to meet the timeframe of applicants (April 2017).

2.3 Partially Constrained Network Access

In this option System Management would develop systems to constrain new generation on a least cost basis, with Western Power providing constraint equations and information on the state of the network. It can be considered a “cut-down” version of Option 2.2 because the need to change “bidding windows” is eliminated, and the current timeframes for last bid submission by generators are retained.

As such, the timing, funding, operation, and information provision of the following high-level implementation options are being considered:

1. Constrained access based on a system operated by System Management, funded by Western Power and utilising a Network Control Service (NCS) contract[3]; or
2. A WEM Rules solution funded by the market and operated by System Management.

While there are many potential options for the implementation of a least cost approach, Western Power considers options involving cost data being provided to System Management or the IMO may be effective and achievable within the time restrictions imposed by applicants, although further detailed investigation is required.

2.4 Quantum Curtailment

Should all of the above options be deemed unfeasible, Western Power will be required to consider any other alternative for connecting these new applicants, including curtailment by quantum of impact of the constraint. This would essentially constrain new generators without bid information based on the location of the generator in regards to the constraint.

This option would use a NCS to over-ride the Balancing Merit Order and, while it may result in a lower cost of electricity compared to the status quo, it will not meet the WEM Objectives to the same degree as Partially Constrained Network Access.

2.5 Preferred Solution

While the preferred solution is Constrained Dispatch, and Western Power and the IMO propose to advise Government and request a policy decision, this requires legislative change and is not likely to be able to be implemented prior to the indicative start date for proposed new generators in the CAGs (April 2017).

The next best solution, to meet the connecting customers’ timelines, is Partially Constrained Network Access. We believe that this solution can be implemented within Western Power’s time constraints under the Access Code, and reflects the options proposed by the EMR and recommendations from the Economic Regulation Authority (ERA). Ideally, a partially constrained market design would also allow a transition path to a fully constrained market design should the government decide on such an outcome as part of the EMR, although this will depend on the feasibility of design options to achieve this.

Allowing new generators to connect to the Western Power Network without expensive network augmentation will mean that additional generation facilities can connect quickly and easily, at the lowest possible cost. As these facilities can only generate when their operating costs are lower than the existing generation fleet, the total cost of electricity to customers will

[3] A Network Control Service (NCS) is defined in WEM Rule 5.1.1 as a service provided by generation or demand side management that can be a substitute for transmission or distribution network upgrades, and is a contract between the Network Operator and a Market Participant – in this case the new generators would provide curtailment to avoid network upgrades.

reduce. This will improve outcomes of the WEM Objectives and the Access Code as indicated in section 5.

We provided an example of the dispatch under a partially constrained network solution dispatch at Appendix B. This example demonstrates that generators with existing firm access are not disadvantaged by the implementation of this solution.

3 Timing and need

Western Power is required by the Access Code to use all reasonable endeavours to connect applicants in their preferred form of network access, and to meet their time frame.

Western Power is currently attempting to facilitate the connection of several generators in CAGs in two constrained regions. As noted above these applicants require connection by April 2017, with information concerning how curtailment might occur by February 2015.

Given the prohibitive cost of unconstrained access to the network, these applicants have requested access on a constrained basis. Where previous generators have been connected on a virtually unconstrained basis using post-contingent run-back schemes, the network can no longer accommodate this.

For any of the options outlined above, there are three time horizons that require consideration:

1. Application Development (including testing and implementation) of an initial solution within the timeframes required by applicants. These timeframes are:

    a. Initial development of options by January 2015;
    b. Preliminary Access Offers in February 2015;
    c. Final Access Offers in August 2015, with an in-service date of April 2017;

2. Development of a market solution extensible to all generators. This may be able to be done in parallel with the above and would extend operation of constraints to include general network contingency events to cover limitations arising from existing arrangements and planning criteria – that is, network issues that would impact the market significantly would then give rise to constraint equations, some involving generators required to be constrained on (such as for Muja transformer failure);

3. Extension of the constrained access approach to all generators (including legacy generators). This would follow legislative changes under the Electricity Industry Act to enact a policy decision to transition to a fully constrained network model for all generators.

4 Market Rule Impacts

A number of WEM Rules and systems are impacted by our preferred concept of Partially Constrained Network Access. An initial list is provided below.

Issue	Rule issue	IT system issue	Required for Partially Constrained Network Access		Required for Constrained Dispatch
			Implementation Option 1 (NCS)	Implementation Option 2 (WEM Rules solution)	
Create and use constraint equations	X	X	X	X	X
System Management needs ability to vary balancing merit order to resolve constraints by curtailing generators	X	X	X	X	X

Issue	Rule issue	IT system issue	Required for Partially Constrained Network Access		Required for Constrained Dispatch
			Implementation Option 1 (NCS)	Implementation Option 2 (WEM Rules solution)	
Constrained generators must not receive constrained off payments	X	X	X	X	X
System Management or IMO needs cost information to identify least cost outcome for constraining generators	X	X		X	X
Participants need to be able to re-bid to take into account impact of constraints	X	X			X

We have undertaken an initial (high-level) assessment of the impact of the status quo, constrained dispatch and partially constrained network access (in any form, least cost or otherwise) against the WEM and Access Code objectives. This is contained at Appendix A: Impact on Objectives. This assessment illustrates that whilst Constrained Dispatch is optimal in meeting objectives, the partially constrained access option being proposed improves upon the status quo.

Conclusion

Identifying the costs, risks and implementation options of the preferred approach will be an intensive process. We are seeking feedback from the Market Advisory Committee on how such a transformation should be considered.

5 Appendix A: Impact on Objectives

Objective		Current Unconstrained Network	Partially Constrained Network Access	Constrained Dispatch
WEM	(a) Promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;	No longer met by introduction of constraints. At this point in the network, connection of unconstrained generation is prohibitive in some areas, without substantial (likely inefficient) augmentation costs.	Allows introduction of new low cost generators without compromising reliability or safety. However, doesn't ensure dispatch of least cost generation each trading interval and may not provide information to new and existing generators about the constraint in order for them to respond accordingly.	Would maximise outcome
WEM	(b) Encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;	Unconstrained access is a barrier to entry, but enables competition of connected generators on an equal footing (aside from existing runback schemes etc.).	Facilities low cost entry for new generators. If information about constraints is not available, may limit competition by all generators.	Would maximise outcome
WEM	(c) Avoid discrimination in that market against particular energy options and technologies,	Given that renewable generation is often intermittent, and is therefore most conducive to constrained access, unconstrained access is a barrier to further renewable generation.	Would promote connection of renewable generation, and allow unhindered operation for large portion of year.	Would maximise outcome
WEM	(d) Minimise the long-term cost of electricity supplied to customers from the South West interconnected system;	Unconstrained access is a barrier to further cost reductions. Also compromises least cost dispatch.	Has the potential to reduce the long-term cost of electricity compared to the status quo by allowing connection of new generation at minimal cost.	Would maximise outcome
WEM	(e) Encourage the taking of measures to manage the amount of electricity used and when it is used	N/A	N/A	N/A
Access Code	Promote the economically efficient investment in and operation of and use of, networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the	Unconstrained access is a barrier to economically efficient investment.	Would promote economically efficient investment for new generators. However, doesn't ensure dispatch	No improvement over partially constrained network access

	networks		of least cost generation each trading interval and may not provide information to new and existing generators about the constraint in order for them to respond accordingly. Also requires inefficient investment in market systems to implement.	
Cost / benefit	Able to be implemented without government legislative change?	No change	Yes	No
Cost / benefit	Able to be implemented without WEM Rule changes and market system changes?	No change	No	No
Cost / benefit	Able to be implemented without Access Code changes and market system changes?	No change	Yes	No
Timing	Able to be implemented in timeframes required by new applicants?	N/A	Potentially	No

6 Appendix B – Sample Dispatch

A sample model of partially constrained dispatch will be provided.

7 Appendix C – Background information

7.1 History

Western Power's obligation under the Access Code towards new applicants is to use all reasonable endeavours to provide their preferred form of network access to meet their time frame – in this case connection by April 2017. Given the Minister for Energy's rejection of changes to certain WEM Rules in May 2014, on the basis that the costs to implement the amendments may not be recovered in light of possible reforms emanating from the Electricity Market Review, Western Power has been endeavouring to fulfil applicant preferences without attempting to vary the regime. With Western Power's obligation to use all reasonable endeavours in mind, this has given rise to the various proposals of a Network Constraint Tool (NCT).

The most recent model of the NCT considered involved a tool funded by Western Power, but operated by System Management. Given that neither Western Power nor System Management had access to cost data, this model used a Network Control Service under the WEM Rules to constrain the relevant generators on a coefficient basis in an attempt to minimise the amount of generation constrained on, and thereby attempting to minimise the overall cost to the WEM. While Western Power recognised that this would not always result in a least cost outcome on an individual interval basis, given the limitations on Western Power's abilities discussed above, this was the model that fulfilled obligations imposed by the Access Code.

During consultations regarding the proposed NCT, Western Power has received feedback from several stakeholders, including the IMO, that constraining facilities on a least cost basis is preferable. Western Power supports this proposal, while recent engagement with the Public Utilities Office has indicated that a least cost model involving the provision of cost data to System Management (as was the case during earlier versions of the WEM Rules) may be acceptable to the Minister.

To recap, Western Power supports the move towards a fully constrained network regime, however Western Power is currently obliged to offer unconstrained access where so requested.

7.2 Access to the network

Under clause 2.7 the Electricity Networks Access Code 2004, Western Power must make all reasonable endeavours to accommodate an applicant's requirement to obtain services. While Western Power provides reference services, which are approved by the Economic Regulation Authority, any applicant can negotiate access.

The reference services for generation access provide unconstrained access to the Western Power Network. A requirement to obtain this service is that the connection and the network meet the requirements of the Technical Rules, and this is generally funded by the applicant. In parts of the network where there is little to no spare capacity, this is prohibitive.

Over the last decade, new generators seeking to connect to the network have generally not been prepared to fund the cost of augmentations for the deep network connections that are needed to maintain unconstrained access. Consequently, Western Power has permitted generators to connect to the network on a constrained basis through the implementation of run-back schemes (around 25 of which are currently in place in the South West Interconnected System) or through other forms of non-firm connection.

These arrangements are very similar to the way in which generators connect in the NEM and in other markets such as New Zealand. In both cases, generators are permitted to connect on the basis of their own assessment of the extent to which likely future network congestion might affect their ability to either be dispatched in merit order or the price at which they will be dispatched.

Existing runback schemes in the South West Interconnected System (**SWIS**) do not affect the dispatch of generators who are not party to those schemes. Generators with constrained access are turned down if an event referred to in their connection agreement occurs, whereas generators with unconstrained access are not turned down under the same circumstances.

7.3 The Western Power Network

Western Power is the only registered network operator in the SWIS. However, other licensed transmission and distribution networks exist that comprise part of the SWIS.

The Electricity Network Access Code 2004 does not require unconstrained access; however the network is planned, designed and built to allow unconstrained natural load growth. In 2006, there was sufficient capacity in the Western Power Network to generally meet reliability standards required by the Technical Rules and to provide unconstrained network access to connected generators. However, as the SWIS has grown it is becoming more difficult and expensive to provide unconstrained access, and so quasi-constrained connections using post-contingent run-back schemes have been the norm.

At present, the WPN is nearing operational limits of post-contingent run-back schemes. In certain areas, connection of further post-contingent run-back schemes could create a risk of cascading network failures.

The EMR seems to be moving towards fully constrained access. However there are many legacy issues such as existing contracts that will need to be resolved prior to such an outcome occurring. As such, Western Power considers that a fully constrained network access for all generators can only be achieved through a change in government policy, perhaps as part of the EMR. There are however a set of interim solutions that could potentially facilitate a partially constrained network or aid the transition to a fully constrained network.

7.4 Current applicants

Western Power is required by the Access Code to use all reasonable endeavours to provide new applicants their preferred form of network access to meet their time frame. Western Power is currently attempting to facilitate the connection of several generators in two constrained regions (known as CAGs). These applicants require connection by April 2017.

As part of the application process, Western Power must provide preliminary information (known as Preliminary Access Offers or PAO) to applicants by February 2015. In order for the applicants to determine financial viability, this information must indicate the type of service to be provided, as well as the details of access, as well as any potential contributions that must be made for shared network augmentation. In order to progress, the applicants must then make a financial contribution towards augmentation of the shared network. For acceptance of the PAO, Western Power then proceeds to finalise the access offer, including detailed scoping and estimation of any shared works. Final Access Offers (AOs) are to be developed by August 2015. Following acceptance of the AO, and provision of required contributions, Western Power will commence development and construction of any required shared works.

If an applicant decides against proceeding, either at the PAO or AO stage, their application is then withdrawn. If sufficient applicants withdraw then the CAG will be closed. However, Western Power must proceed to develop access offers in spite of this uncertainty.

7.5 Future Policy

The ERA has for several years, in its annual Wholesale Electricity Market Report to the Minister for Energy,[4] indicated that while an unconstrained network approach facilitates simpler operation of the power system and the wholesale market, it does not serve the WEM Objectives for the following reasons:

- It does not promote the economically efficient supply of electricity because it is likely to cause investment in assets that may have a low utilisation;
- It creates a barrier to competition, as new entrant generators must pay a proportion of the costs of the next network augmentation; and,
- It is not clear that it minimises the long term cost of supply, in the sense that the requirement may provide more reliability than customers are willing to pay for through increased electricity prices.

Concerns have also been expressed that the unconstrained access approach could lead to inefficiencies in the way generators are selected to run to meet demand and in the connection of new generation to the network. There is also a concern as to whether "unconstrained access" could lead to over-investment in transmission in the SWIS.

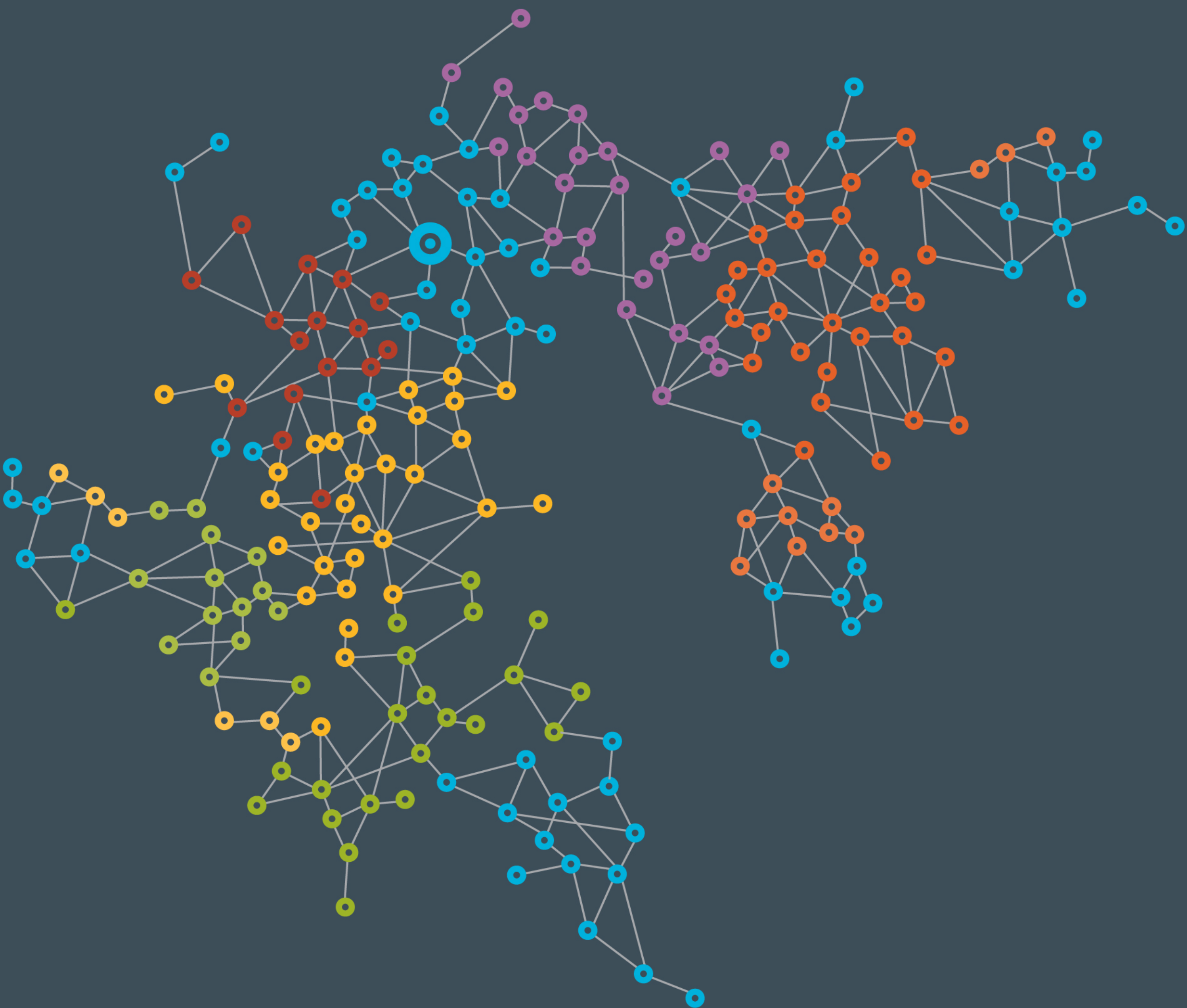
At present the dispatch process does not constrain generators based on generators' costs or bid prices but on the provisions of their respective connection agreements. Therefore, generators who connected when network capability was less scarce effectively have dispatch priority over more recently connected generators whose access is subject to runback schemes. This will often not be consistent with economic efficiency because providing certain generators with dispatch priority over others irrespective of their relative operating costs will in general not minimise the resource cost of dispatch. In other words it will lower the static or short term efficiency of the WEM as a whole.

[4] See, for example: Economic Regulation Authority, 2010 Wholesale Electricity Market Report to the Minister for Energy, June 2011, pp. 25.

INDEPENDENT MARKET OPERATOR

Market Rules Evolution Plan: 2013-2016 December 2014 Update

3 December 2014



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1. Introduction

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

The current 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 current 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 2012-2013 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.

2. October 2013 Update

The IMO provided an update to MAC members on the status of the MREP at the 9 October 2013 MAC meeting[2]. Several significant issues had emerged since the MREP was finalised in November 2012, and the IMO sought the views of MAC members on the relative priority of these issues compared with the issues listed in the MREP. The IMO also sought the views of MAC members on whether the priority of some MREP issues was still appropriate given recent developments.

Following a discussion of the issues there was general agreement from MAC members that:

- the IMO should undertake as a priority any work required to support the upcoming merger of Verve Energy and Synergy – this work was expected to comprise two phases, an initial fast track Rule Change Proposal to address administrative issues, followed by consideration (once more information was available) of more substantive issues, such as market power mitigation and how the new entity would operate in the market;
- the high priority of Issue 1 (Additional Improvements to the Balancing Mechanism) should be retained;
- Issue 2 (the development of an Emissions Intensity Index) was no longer a high priority;
- the high priority of Issue 3 (Transition to Half Hour Balancing Gate Closure) should be retained and the scope of the issue expanded to include the reduction of LFAS Gate Closure timeframes;
- transition to a 10 minute (or shorter) dispatch cycle should be considered by the IMO in conjunction with the outcomes of the 2014 Ancillary Service Standards and Requirements Study, to ensure consistency in the definitions of dispatch and the LFAS standard - the IMO also noted its intention to consider the outcomes of this study before proceeding with the introduction of a Spinning Reserve market (Issue 4);
- Issue 16 (Calculation of Loss Factors) was no longer required, given the confirmation that Western Power no longer had concerns with the processes used to determine Loss Factors;

[1] Available at: http://www.imowa.com.au/market_rules_evolution_plan
[2] See: http://www.imowa.com.au/mac_65.

- the dot point “Link between Balancing Submissions and Facility limit so that a Balancing Submission may contain more capacity than the Facility limit but not less” was not required in the issue description for Issue 1; and
- the IMO should progress a Rule Change Proposal to remove early capacity payments for all Facilities where there was an excess of capacity in the market – this work should proceed as soon as practicable, but was of a lower priority than the work associated with the Verve Energy/Synergy merger and Issues 1 and 3.

MAC members also supported the IMO’s proposal to split Issue 1 into two components. This was because the first component, the removal of Resource Plans, could be progressed relatively quickly, while changes to the Bilateral Submission and Short Term Energy Market (STEM) processes would require more consideration and were likely to be impacted by the Synergy/Verve Energy merger.

3. Developments since October 2013

3.1. Merger of Synergy and Verve Energy

The merger of Synergy and Verve Energy to form the Electricity Generation and Retail Corporation (trading as Synergy) took effect on 1 January 2014. To support the merger, transitional Amending Rules for the Rule Change Proposal: Market Rule changes arising due to the merger of the Electricity Retail Corporation and Electricity Generation Corporation (RC_2013_18)[3] commenced on 30 December 2013, with the remaining Amending Rules for the proposal commencing on 1 January 2014.

The IMO monitors Synergy’s bidding behaviour on an ongoing basis, and awaits with interest the outcomes of the Economic Regulation Authority’s (ERA’s) first annual review of the operation of the Synergy regulatory regime[4]. However to date the IMO has not identified any issues relating to the merger that it considers require the progression of a further Rule Change Proposal.

3.2. Electricity Market Review

On 6 March 2014 the Minister for Energy launched the State Government’s Electricity Market Review (EMR). The EMR is examining the structures of the electricity generation, wholesale and retail sectors within the South West interconnected system (SWIS) and the incentives for industry participants to make efficient investments and minimise costs.

As the EMR is considering options for the future evolution of the Wholesale Electricity Market (WEM) its progress has dominated market development activities during 2014. In particular, on 19 May 2014 the Minister for Energy notified the IMO of his decision to not approve two Rule Change Proposals, Incentives to Improve Availability of Scheduled Generators (RC_2013_09) and Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10)[5]. The Minister advised that in making his assessment he had “taken into account that the costs to implement the amendments may not be recovered in light of possible reforms emanating from the Electricity Market Review”.

Given the context of the EMR and the reasons provided by the Minister for his rejection of the two

[3] See http://www.imowa.com.au/RC_2013_18.
[4] Required under the *Electricity Corporations (Electricity Generation and Retail Corporation) Regulations 2013*.
[5] See http://www.imowa.com.au/RC_2013_09 and http://www.imowa.com.au/RC_2013_10

Rule Change Proposals, the IMO revised its 2014-15 work plan to avoid any changes that were likely to have large implementation costs. This has severely limited the progression of any significant changes to address MREP issues.

It should be noted that several MREP issues have been raised for consideration during the course of the EMR, either in the Discussion Paper published for public consultation on 13 August 2014 or in submissions provided by stakeholders on the Discussion Paper; including:

- review of the STEM (Issue 1);
- reduction of gate closure times (Issue 3);
- increased competition in Ancillary Services (Issue 4);
- the treatment of potential new large block loads (Issue 7); and
- participation of DSM in Balancing (Issue 17).

Also under consideration is the adoption of a constrained network access model, which was excluded from the scope of the 2013-2016 MREP due to its dependence on State energy policy.

3.3. Improvements to the Energy Market

On 11 December 2013 Mr Jim Truesdale presented a discussion paper to the MAC titled "Enhancements to the Energy and LFAS Markets"[6]. The paper discussed options to address several issues, including:

- the removal of Resource Plans and options for changes to the current arrangements for Bilateral Submissions and the STEM (Issue 1);
- reduction of gate closure times for the Balancing and LFAS Markets (Issue 3); and
- the participation of Verve Energy in the Balancing and LFAS Markets on an individual facility basis.

Following the December 2013 meeting the IMO developed a Pre Rule Change Proposal: Improvements to the Energy Market (PRC_2014_01). PRC_2014_01 proposed the removal of Resource Plans and the reduction of Balancing and LFAS gate closure times, as well as several other changes to address outstanding issues in related areas of the Market Rules.

PRC_2014_01 was presented at the 19 March 2014[7] and 14 May 2014[8] MAC meetings, with the IMO noting at the latter meeting its intention to submit the proposal into the formal rule change process. However, following the Minister's decision on RC_2013_09 and RC_2013_10 the IMO decided to delay the proposed gate closure changes in PRC_2014_01 due to their potentially large implementation costs. The IMO has developed a revised proposal (PRC_2014_06: Removal of Resource Plans and Dispatchable Loads), which excludes any changes to gate closure times, for discussion at the December 2014 MAC meeting.

During 2014 the IMO conducted some preliminary investigations into the implications of Synergy moving to facility based bidding and dispatch. The IMO however considers that further progress on this option is now dependent on the outcomes of the EMR, as is further progress of options for replacement of the current STEM and Bilateral Submission arrangements.

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[6] See http://www.imowa.com.au/mac_67.
[7] See http://www.imowa.com.au/MAC_69.
[8] See http://www.imowa.com.au/MAC_71.

3.4. 2014 Ancillary Service Standards and Requirements Study

On 6 November 2014 the IMO published the Final Report for the 2014 Ancillary Service Standards and Requirements Study (AS Study)[9]. The AS Study was undertaken in accordance with clause 3.15.1 of the Market Rules, which requires the IMO, with the assistance of System Management, to carry out a study on the Ancillary Service Standards and the basis for setting the Ancillary Service Requirements for the SWIS at least once in every five year period.

The IMO engaged ROAM Consulting, an independent consultant, to assist the IMO in undertaking the AS Study. During the course of the AS Study ROAM Consulting was acquired by Ernst & Young (EY) and the group now operates under the EY name.

EY made a total of 21 recommendations in its Final Report, although uncertainty about the outcomes of the EMR has made it difficult to develop detailed solutions for some of the issues identified. The IMO expects that further work on the definition of Ancillary Service Standards and Requirements will be needed during 2015, once the EMR recommendations are known and the path for the ongoing evolution of the WEM is clearer.

The IMO notes two points specifically relating to previous MREP discussions:

- EY's recommendations included moving to a ten or five minute dispatch cycle, consistent with the suggestion discussed at the October 2013 MAC meeting; and
- based on the outcome of discussions with EY, System Management and Synergy, the IMO considers that the most efficient approach to implementing a Spinning Reserve market (Issue 4) would be to do so as part of a larger package of work that includes the co-optimisation of energy and Ancillary Service dispatch in the SWIS.

3.5. Other developments

On 10 January 2014 the IMO submitted the Rule Change Proposal: Limit to Early Entry Capacity Payments (RC_2013_21)[10]. The proposal sought to limit early entry capacity payments for all new Facilities in periods of excess capacity. The second submission period for the proposal closed on 24 April 2014; however the IMO has extended the timeframe for the publication of the Final Rule Change Report until 31 December 2014, to allow the IMO to consider the outcomes of the EMR and any potential impacts on the Rule Change Proposal.

At the 13 November 2013 MAC meeting, Mr Andrew Stevens presented a concept paper developed by Bluewaters Power titled "Market Fees – Payable based on Energy and Capacity" (CP_2013_13)[11]. The concept paper, which addresses Issue 12 (Market Fees), proposed that market costs (i.e. Market Fees, System Operation Fees and Regulator Fees) be recovered on a capacity as well as an energy basis. During the discussion the IMO agreed to conduct further analysis to determine the impact of the proposed allocation method on the Reserve Capacity Mechanism. On 31 January 2014 the IMO advised MAC members that based on its analysis for 2013-14 the proposed change would be expected to increase the Maximum Reserve Capacity Price by $715.

Mr Stevens also presented a Pre Rule Change Proposal: Adjustment of Spinning Reserve Block

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[9] See http://www.imowa.com.au/2014_AS_Study.
[10] See http://www.imowa.com.au/RC_2013_21.
[11] See http://www.imowa.com.au/MAC_66.

Sizes (PRC_2013_14) to the 19 March 2014 MAC meeting[12]. PRC_2013_14 proposed two options for changes to the block sizes and boundaries used for Spinning Reserve cost allocation, to address Issue 8 (Review of Spinning Reserve calculation and cost allocation). Following this meeting the IMO prepared a comparison of the two options outlined in PRC_2013_14 against the application of a full runway methodology and the status quo, presenting its results to the MAC at the 14 May 2014 meeting[13].

To date Bluewaters Power has not formally submitted either proposal.

4. Current Status

The table in Appendix 1 of this paper provides a summary of the issues listed in the MREP and their current status. The issues are listed in the priority order determined by the MAC in the August 2012 ballot. Shaded items are either completed or else have been deemed by the MAC to no longer be required.

5. Recommendations

The IMO recommends that the MAC:

- notes the update to the status of the issues listed in the MREP; and
- notes that the IMO intends to undertake a further review of the MREP once the outcomes of the EMR become available.

[12] See http://www.imowa.com.au/MAC_69.
[13] See http://www.imowa.com.au/MAC_71.

Appendix 1. Market Rules Evolution Plan: 2013-2016 Issue list

A summary of the issues in the current MREP is provided in the following table.

Rank	Issue	Explanation (from MREP)	Source	Status
1	Additional Improvements to the Balancing Mechanism	• Remove requirement to submit Resource Plans; • Investigate removal of STEM submissions requirement, or allow multiple STEM windows catering for multiple STEM transactions within the Trading Day, aligned to the balancing windows; • Investigate closer to real time bilateral nominations/updates/adjustments; • Link between Balancing Submissions and Facility limit so that a Balancing Submission may contain more capacity than the Facility limit but not less; and • Timing of submissions: consider starting at 9:00am or 10:00am instead of 8:00am.	Multiple Stakeholders	The Pre Rule Change Proposal: Removal of Resource Plans and Dispatchable Loads (PRC_2014_06) will be presented at the December 2014 MAC meeting. Other components are waiting on the outcomes of the EMR. For further details please see section 3.3 of this report.
2	Emissions Intensity Index (EII)	Amendments to the Market Rules have been proposed to formalise the provision of emissions data by Market Participants to the IMO and the publication by the IMO of an Emissions Intensity Index for the WEM.	IMO	At the October 2013 MAC meeting members agreed that this issue was no longer a high priority.
3	Transition to half hour gate closure	It has been suggested that a half hour gate closure would lead to more efficient market outcomes.	ERM Power	At the October 2013 MAC meeting members agreed that the scope of this issue should be expanded to include the reduction of LFAS Gate Closure timeframes. The issue is currently waiting on the outcomes of the EMR. For further details please see section 3.3 of this report.
4	Introducing Market in Spinning Reserve	Suggestions have been expressed at MAC that the introduction of a Spinning Reserve Market will increase competition in the WEM.	Multiple Stakeholders	Outstanding

Rank	Issue	Explanation (from MREP)	Source	Status
5	Settlement simplification	A number of participants have commented that the complexity in the Market Rules around market settlements may benefit from simplification.	MREP 2009-2013	Outstanding
6	Market Rule Change Process	Under the current Market Rules, a Standard Rule Change Process takes a considerable time to complete. A number of Market Participants have commented on this process in various forums over the years. While it is appropriate that the rule change process proceeds in an efficient and timely manner, it should also provide sufficient time for consultation and analysis. Further, some rule changes would be more complex while others would be simpler and a single timeline may not always deliver efficient outcomes. The IMO considers that the efficiency of the market rule change processes should be examined with the objective to streamline the existing prescribed timelines. Any changes to the processes and timelines should provide sufficient flexibility to allow the IMO Board to consider proposed rule changes in session.	MREP 2009-2013	Outstanding
7	New Loads	The non-arrival of new loads (allowed for in the Statement of Opportunities) places a capacity cost onto existing loads as the capacity credited for the new load which did not arrive is paid for by the existing loads. Capacity could be linked to proposed large loads, requiring a security deposit from large loads, or requiring large loads to act as a Demand Side Programme (DSP), with no rights to reliable supply; where, if the opposite occurs and a large load arrives unexpectedly and this results in an supplementary reserve capacity auction, then that load should bear the supplementary reserve capacity cost as targeted capacity.	Synergy	Outstanding
8	Review of Spinning Reserve calculation and cost application	The design of the Balancing market, with intra-interval dispatch instructions, in combination with the current Spinning Reserve cost regime (a fixed charge per block) appears at odds with creating an efficient market. Suggestion to review the Spinning Reserve regime with a view to making it more granular to combat regular per-interval fixed costs.	Griffin	A Pre Rule Change Proposal developed by Bluewaters Power was presented at the March 2014 MAC meeting. Additional IMO analysis results were presented at the May 2014 meeting. For further details please see section 3.5 of this report.

Rank	Issue	Explanation (from MREP)	Source	Status
9	Feedback on Synergy's actual demand	Earlier feedback on Synergy's actual demand rather than wait for the non-STEM publication. This may morph into changing the settlement timeframe such that settlement occurs more frequently. Such a change has the benefit of reducing the level of participants' prudential requirements.	Synergy	Outstanding
10	LoadWatch Data Publication	The IMO considers an obligation should be included in the Market Rules for System Management to deliver LoadWatch data to the IMO each Monday prior to noon. The required data would include forecast min and max temperature, and forecast system load, for weekdays. The obligation on the IMO would be to publish the LoadWatch report each Monday.	IMO & ERA	Completed. The Amending Rules for the Rule Change Proposal: LoadWatch, EOI and RDQ Provision (RC_2013_05) commenced on 2 September 2013.
11	Remove some of the uncertainty around Non Temperature Dependent Loads (NTDLs)	Given NTDLs have a much lower capacity ratio than Temperature Dependant Loads (TDLs), if a new NTDL is created in the Capacity Year this changes the TDL ratio for all customers. This ratio variation could be minimised by confirming NTDL status for a Capacity Year in Year 1 of the Reserve Capacity Cycle. A simplification would be to disallow changes from TDL to NTDL within a Capacity Year, allowing these changes only in a future Capacity Year.	Synergy	Outstanding
12	Market Fees	Concerns have been expressed by MAC members around the exemption of Demand Side Aggregators from Market Fees. The IMO notes that there may be benefit in a wider review around Market Fees including allocation of fees to non-energy producing capacity facilities (e.g. peaking capacity).	Multiple Stakeholders	A concept paper developed by Bluewaters Power was presented at the November 2013 MAC meeting. For further details please see section 3.5 of this report.
13	Reviews	The IMO undertakes a number of reviews (e.g. Energy Price Limits, Margin Values) which require input assumptions for modelling, e.g. fuel costs, heat rates, operating and maintenance costs, etc. Currently the IMO is unable to request confidential operational data from Market Participants for use in these reviews. The Market Rules could be enhanced so that the powers of the IMO to request actual operational data from Market Participants are extended to allow the request of relevant data (on a confidential basis), to provide more accurate inputs to the modelling processes.	IMO & ERA	Outstanding

Rank	Issue	Explanation (from MREP)	Source	Status
14	Intermittent Loads	A number of issues have been identified with respect to the provisions of the Market Rules related to Intermittent Load refunds. This was identified in the original Market Rules Evolution Plan. This noted that the Market Rules relating to the Intermittent Load maximum nominated Reserve Capacity Requirements be reviewed to ensure that the Market Rules cannot be misconstrued as allowing participants to completely avoid Individual Reserve Capacity Requirement (IRCR) charges for Intermittent Loads by setting the requirements to either 0 or a number lower than the actual requirement of the loads in the event of a generator failure.	MREP 2009-2013	Outstanding
15	Capacity Lead time for Demand Side Programmes	It has been noted that the two year lead time for certification could be a significant impediment for generation with shorter lead times, especially smaller generation and Demand Side Management (DSM). Shorter lead times for capacity certification would facilitate smaller generation and DSM more readily. In respect of DSM, a shorter lead time may mean that DSM could be made available spontaneously.	Premier Power	Outstanding
16	Calculation of Loss Factors	By June each year each Network Operator must calculate and provide to the IMO Loss Factors for each connection point in their Network. It has been noted that this is an often time consuming and expensive process to undertake. It has been suggested that this process could be streamlined to make it more efficient while not losing the integrity of the process.	MREP 2009-2013	At the October 2013 MAC meeting members agreed that this issue was no longer required.
17	Participation of DSM in Balancing	The Reserve Capacity Mechanism Working Group (RCMWG) has explored the concept of DSM participation in Balancing and it has been proposed to include this on the next MREP for consideration.	RCMWG	Outstanding
18	Treatment of new small generators	Section 4.28B of the Market Rules outlines the Reserve Capacity rules for the treatment of new small generators. The section is applicable to Registered Facilities to which the following conditions apply: • the Facility is a Non-Scheduled Generator and has commenced operation; and • the Facility has a nameplate capacity not exceeding 1 MW. It has been suggested that the threshold for this section be increased from the 1 MW nameplate capacity.	MREP 2009-2013	Outstanding

INDEPENDENT MARKET OPERATOR

Agenda item 9.1: Overview of Procedure Change Proposals

3 December 2014

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

ID	Summary of changes	Status	Next steps	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.	Submissions closed on 16 July 2013.	The IMO is currently preparing the Procedure Change Report.	TBC

ID	Summary of changes	Status	Next steps	Date
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).	The IMO published a call for further consultation on 30 October 2014.	Submissions close.	27 November 2014
PC_2013_06: Certification of Reserve Capacity	The proposed updates are to: • reflect the IMO's new format; • improve the integrity of the Market Procedure; and • reflect the treatment of Facilities that share a Declared Sent Out Capacity as a result of RC_2012_20.	The Procedure Change Report is being prepared by the IMO in light of the rejection of RC_2013_09 and RC_2013_10 by the Minister.	Procedure Change Report published.	December 2014
PC_2013_09: Reserve Capacity Performance Monitoring	The proposed updates are to: • reflect the IMO's new format; • reflect the amendments to Certification of Reserve Capacity in RC_2010_14; and • clarify the process for Performance Reports and Progress Reports.	The Procedure Change Report is being prepared by the IMO in light of the rejection of RC_2013_09 and RC_2013_10 by the Minister.	Procedure Change Report published.	December 2014

ID	Summary of changes	Status	Next steps	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.	The Market Procedure was updated following the discussion at the 6 February 2014 IMOPWG. The IMO will make further changes related to RC_2014_06 before progressing this proposal through the IMOPWG.	Updated Market Procedure to be circulated to the IMOPWG for comment.	TBA
PC_2014_03: Market Procedure for Determining the Benchmark Reserve Capacity Price	The proposed updates are to: • rename the Maximum Reserve Capacity Price (MRCP) in the Market Rules as the Benchmark Reserve Capacity Price; and • make other minor editorial improvements to the Market Procedure.	PC_2014_03 was tabled at the 1 May 2014 IMO Procedures Working Group.	The IMO will align the formal submission of PC_2014_03 with RC_2013_20 which has been extended until 31/12/2014.	TBA
System Management Procedure Change Proposals				
n/a				

Agenda item 10.1: Working Group overview and membership updates

3 December 2014

Working Group	Status	Date commenced	Date concluded	Last meeting	Next meeting
System Management Procedure Change and Development Working Group	Active	July 2007	Ongoing	14 August 2013	TBA
IMO Procedure Change and Development Working Group	Active	December 2007	Ongoing	1 May 2014	TBA

1. Membership updates

The IMO has received a request to change Synergy's representation on the IMO Procedure Change and Development Working Group to:

- remove Jacinda Papps as the Synergy representative; and
- add Brad Huppatz as the new Synergy representative.

2. Recommendation

The IMO recommends that MAC members:

- **note** the membership update.

Agenda item 11.1: 2014 year in review

3 December 2014

Event	2014
MAC and Working Group meetings	
• MAC meetings	6
• IMO Procedure Change and Development Working Group	2
• System Management Procedure Change and Development Working Group	0
Rule Change Proposals developed and underway	20
• Commenced	5
• Rejected or not progressed	2
• Underway	13
Procedure Change Proposals commenced (IMO/SM)	3/3
Stakeholder workshops (e.g. Rule Change Proposals, Procedure Change Proposals, Reviews)	1
RulesWatch issued	46

Significant work in 2014:

- Rule and system changes to support the merger of Verve and Synergy.
- Finalisation of Prudential Requirements (RC_2012_23) and commencement of the Amending Rules
- Finalisation of rule change process for Incentives to Improve Availability of Scheduled Generators (RC_2013_09) – rejected by the Minister due to the Electricity Market Review (EMR)*
- Finalisation of rule change process for Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10) – rejected by the Minister due to the EMR*
- Changes to the Reserve Capacity Price and the Dynamic Reserve Capacity Refunds Regime (RC_2013_20) – Final Rule Change Report deferred pending outcomes of the EMR*
- Reduced Frequency of Determining Energy Price Limits and the Maximum Reserve Capacity Price (RC_2014_05)

- Deferral of the 2014 Reserve Capacity Cycle (including Rule Change Proposal: Specific Transition Provisions for the 2014 Reserve Capacity Cycle (RC_2014_04))
- Relevant Level Methodology Review
- 5-Yearly Review of Ancillary Service Standards and Requirements
- Briefings on the Muja Transformer Failure
- Significant engagement with the Electricity Market Review
- Complete review of IMO internal procedures in preparation for 2014 Market Audit
- New website data visualisations and restructure of IMO website

* Note: the Rule Change Proposals that have either been rejected or deferred as a result of the EMR may be re-initiated or continued once the outcomes of the EMR are known.

Agenda item 11.2: Proposed MAC meeting dates for 2015

3 December 2014

Proposed meeting schedule

The IMO proposes to hold MAC meeting every six weeks.

The meeting time, subject to change on occasion, is 2:00 PM to 5:00 PM.

Table 1: Proposed MAC meeting schedule

Month	Meeting No.	Date
January	n/a	No meeting
February	78	12 February 2015*
March	79	18 March 2015
April	n/a	No meeting
May	80	6 May 2015
June	81	17 June 2015
July	82	29 July 2014
August	n/a	No meeting
September	83	9 September 2015
October	84	21 October 2015
November	n/a	No meeting
December	85	2 December 2015

**MAC Meeting 78 (12 February 2015) falls on a Thursday.*

Note the frequency of meetings and any Working Groups will be revisited if required once the outcomes of the Electricity Market Review are known.