Independent Market Operator

## Market Advisory Committee

# Agenda

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| **Meeting No.** | 36 |
| **Location:** | IMO Board Room<br>Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth |
| **Date:** | Wednesday 9 March 2011 |
| **Time:** | 2.00 – 5.00pm |

| Item | Subject | Responsible | Time |
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| **1.** | **WELCOME** | **Chair** | 2 min |
| **2.** | **MEETING APOLOGIES / ATTENDANCE** | **Chair** | 2 min |
| **3.** | **MINUTES OF PREVIOUS MEETING** (pg 3) | **Chair** | 10 min |
| **4.** | **ACTIONS ARISING** (pg 19) | **Chair** | 10 min |
| **5.** | **MARKET RULES** | | |
| | a) Market Rule Change Overview (pg 23) | **IMO** | 2 min |
| | b) PRC_2010_27: Ancillary Services Payment Equations (pg 37) | **IMO** | 40 min |
| | c) PRC_2011_02: Reassessment of Allowable Revenue during a Review Period (pg 97) | **ERA** | 20 min |
| **6.** | **MARKET PROCEDURES** | | |
| | a) Overview (pg 110) | **IMO** | 5 min |
| **7.** | **WORKING GROUPS** | | |
| | a) Overview (pg 115) | **IMO** | 2 min |
| | b) MRCPWG Update (pg 116) | **IMO** | 10 min |
| | c) RDIWG Update (pg 117) | **IMO** | 10 min |

| Item | Subject | Responsible | Time |
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| 8. | **MAC ANNUAL REVIEW WASH UP** (pg 120) | **IMO** | 15 min |
| 9. | **GENERAL BUSINESS**<br><br>a) RCM Review: Appointment of Consultant. | | |
| 10. | **NEXT MEETING: 13 April 2011 (2.00 – 5.00pm)** | | |

## Independent Market Operator

## Market Advisory Committee

# Minutes

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|---|---|
| **Meeting No.** | 35 |
| **Location** | IMO Board Room<br>Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth |
| **Date** | Wednesday 9 February 2011 |
| **Time** | Commencing at 2.00 pm |

| **Attendees** | **Class** | **Comment** |
|---|---|---|
| Allan Dawson | Chair | |
| Troy Forward | Compulsory – IMO | |
| Stephen MacLean | Compulsory – Customer | |
| Ken Brown | Compulsory – System Management | |
| Andrew Everett | Compulsory – Generator | |
| Peter Mattner | Compulsory – Network Operator | 2.07 – 4.28pm |
| Steve Gould | Discretionary – Customer | |
| Corey Dykstra | Discretionary – Customer | |
| Peter Huxtable | Discretionary – Contestable Customer Representative | |
| Andrew Sutherland | Discretionary – Generator | |
| Shane Cremin | Discretionary – Generator | |
| Chris Brown | Observer – ERA | |
| Nerea Ugarte | Minister's appointee | 2.00 – 4.23pm |
| Paul Biggs | Small Use Customer Representative | 2.00 – 2.30pm |
| **Also in attendance** | **From** | **Comment** |
| Pablo Campillos | EnerNOC | Presenter |
| Fiona Edmonds | IMO | Presenter |
| Jacinda Papps | IMO | Presenter |
| Jenny Laidlaw | IMO | Minutes |
| Shannon Turner | IMO | Observer |
| Courtney Roberts | IMO | Observer |
| Greg Ruthven | IMO | Observer (3.00 -4.28pm) |
| Michael Zammit | Energy Response | Observer |

| Item | Subject | Action |
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| **1.** | **WELCOME**<br>The Chair opened the meeting at 2.00 pm and welcomed members to the 35th meeting of the Market Advisory Committee (MAC).<br><br>The Chair noted the request from the Office of Energy (OoE) to amend the original agenda to discuss Statutory Reviews under the Electricity Corporations Act 2005 (Item 8 on the original agenda) earlier than previously indicated. An updated meeting agenda was tabled. | |
| **2.** | **MEETING APOLOGIES / ATTENDANCE**<br>The Chair noted that Mr Paul Biggs would only be able to attend the first part of the meeting and Ms Nerea Ugarte would need to leave the meeting by 4.15 pm. Ms Ugarte would also be acting as proxy for Mr Biggs after his departure.<br><br>The following other attendees were noted:<br>• Pablo Campillos (Presenter)<br>• Jacinda Papps (Presenter)<br>• Shannon Turner (Observer)<br>• Greg Ruthven (Observer)<br>• Fiona Edmonds (Presenter)<br>• Michael Zammit (Observer)<br>• Courtney Roberts(Observer) | |
| **3.** | **MINUTES OF PREVIOUS MEETING**<br>The minutes of MAC Meeting No. 34, held on 15 December 2010, were circulated prior to the meeting. The following amendments were agreed.<br><br>***Page 9: Section 5b: Limits to Early Entry Capacity Payments [PRC_2010_30]***<br><br>• "… recommended that external advice be sought on the change to inform~~ation~~ Alinta prior to formal submission."<br><br>***Page 11: Section 5c: System Restart Costs [PRC_2010_33]]***<br><br>• "Mr Andrew Everett noted that the Pre Rule Change Discussion Paper from Verve Energy proposes to remove a current anomaly in the Market Rules which would require Verve Energy to pay to provide System Restart services if the current Cost_LR value is zero and services are contracted to another party. Any costs for System Restart services provided by third party suppliers would be allocated to Market Customers through the Reconciliation Statement."<br><br>Subject to the agreed amendments, the MAC endorsed the minutes as a true and accurate record of the meeting.<br><br>*Action Point: The IMO to amend the minutes of Meeting No. 34 to reflect the points raised by the MAC and publish on the website as final.* | **IMO** |
| **4.** | **ACTIONS ARISING**<br>The actions arising were either complete or on the meeting agenda. The | |

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| | following exceptions were noted:<br><br>• **Item 88/89:** Mr Troy Forward noted that the IMO had provided the OoE with feedback on its draft report on gas contingency service options. Ms Ugarte noted that the OoE was taking the IMO's comments on the report into consideration. Mr Forward advised that when the OoE provides the IMO with a publically available report it will be circulated to MAC members.<br><br>• **Item 119:** To be undertaken in March 2011.<br><br>• **Item 130:** This will be considered closer to when the Statement of Opportunities (SOO) is prepared.<br><br>• **Item 149:** Mr Forward noted that the IMO had updated the Renewable Energy Generation Working Group (REGWG) Final Report in response to several concerns raised by MAC members. Mr Corey Dykstra had since contacted the IMO with a concern regarding the title of the report. Mr Dykstra suggested that the title be amended to "Renewable Energy Generation Working Group – Summary of Process and Outcomes". The Chair agreed to amend the title and publish the updated report.<br><br>*Action Point: The IMO to amend the title of the "REGWG Final Report" to "Renewable Energy Generation Working Group – Summary of Process and Outcomes" and re-publish the report on the IMO website.*<br><br>• **Item 167:** Mr Ken Brown advised that System Management were summarising the relevant findings of the Newton report on Spinning Reserve requirements and will try to send the results out in the next fortnight. Mr Brown noted that generally as the size of the largest generator increases the Spinning Reserve requirement may exceed 100 percent of the capacity of this generator. For example, the Spinning Reserve requirement to support a 750 MW unit could be 150 percent (1125 MW). There was some discussion about the impact of the size of the second largest unit on the Spinning Reserve requirement and about response time requirements.<br><br>• **Item 169:** Mr Dykstra requested that this item be removed from the list of action points, as the progression of PRC_2010_30 was not an action point but a matter subject to Alinta's discretion.<br><br>*Action Point: The IMO to remove Item 169 from the list of MAC action points.* | **IMO**<br><br>**IMO** |
| **4a** | **WORKED EXAMPLE OF DISPATCH OF PEAKER VERSUS DSM (ACTION POINT 121)**<br><br>Ms Jenny Laidlaw presented a worked example of the cost to the market of the dispatch of a peaking generator compared to a Demand Side | |

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| | Programme (DSP). A copy of the presentation is available on the IMO website[1].<br><br>The following points were raised:<br>• Mr Andrew Sutherland requested clarification that the costs (in excess of MCAP) of dispatching a generator following an increase in a Market Customer's consumption would be shared across all Market Customers during the Trading Month. Ms Laidlaw confirmed.<br><br>• Mr Dykstra clarified that where Market Customer 1 increases its consumption and a DSP is dispatched, the additional energy sold by Market Customer 2 (following the reduction in consumption of Load X) would be sold in the Balancing Market. Ms Laidlaw confirmed.<br><br>• Mr Dykstra noted that under both the scenario of a Market Customer increasing consumption and a Market Generator reducing generation, the cost to the market associated with the dispatch of a DSP is greater than if a peaker was dispatched. Ms Laidlaw confirmed that this would be the case assuming the same Pay as Bid prices.<br><br>• Ms Laidlaw noted that the dispatch of Load X could either benefit or disadvantage Market Customer 2 (the retailer for Load X), depending on its the contractual arrangements.<br><br>• Mr Sutherland queried whether the DSP has control over its Pay as Bid Price. Mr Pablo Campillos confirmed.<br><br>• The Chair noted that the question at hand is whether it should cost the market more for the dispatch of a DSP. Mr Shane Cremin noted that whether this is the case depends on the DSP's Pay as Bid Price. The Chair responded that assuming all else remains equal the cost to the market of dispatching DSPs is greater. Mr Michael Zammit commented that this seems counterintuitive.<br><br>• Mr Cremin noted that a peaker receives a Pay as Bid Price to allow for cost recovery when it is dispatched. Mr Cremin queried whether there was any necessary cost recovery for a DSP. Mr Stephen MacLean stated that a DSP's costs should be covered by its capacity payments.<br><br>• Mr Dykstra noted that there is no guarantee that the Pay as Bid price for a generator and a DSP would be the same. The Chair noted that if the Pay as Bid price limit for DSP was to be amended they would be more likely to be dispatched as they would move up the Dispatch Merit Order.<br><br>• Mr Zammit noted that it would be incorrect to assume the marginal cost for all DSPs to reduce consumption would all be the same. Mr Dykstra noted that a peaker has a high capital cost and a lower | |

[1] www.imowa.com.au/MAC_35

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| | SRMC, while a DSP has a lower capital cost and a higher SRMC. Mr MacLean noted that this was a reasonable assumption.<br><br>• Mr Sutherland noted that a Market Generator who is issued a Dispatch Instruction is also required to pay Market Fees and Spinning Reserve costs. This is not the case for a DSP.<br><br>• Mr Campillos noted that in the IMO's worked example where a DSP is dispatched it is Market Customer 2 that benefits from the Load's reduced consumption. Mr MacLean noted that Market Customer 2 however has no control over its Load also belonging to a DSP.<br><br>• The Chair suggested that the IMO look further into the requirement to pay a DSP to reduce consumption when issued a Dispatch Instruction, in particular whether the capacity payments made to DSPs are sufficient to compensate them for reduced consumption. Mr MacLean agreed that this should be further considered stating that this may otherwise be construed as being discriminatory towards DSPs.<br><br>*Action Point: The IMO to further consider the rationale for paying DSPs to reduce consumption following the issuance of a Dispatch Instruction by System Management and look to include in the MEP rule change process, if relevant.*<br><br>*Action Point: The IMO to provide MAC members with a copy of the IMO's worked example of the costs to the market of dispatching a peaker vs. a DSP.* | <br><br><br><br><br><br><br><br><br><br><br><br><br><br>**IMO**<br><br><br><br><br>**IMO** |
| **5** | **STATUTORY REVIEWS UNDER THE ELECTRICITY CORPORATIONS ACT 2005**<br><br>Ms Ugarte noted that the OoE wished the MAC to be aware of several statutory reviews of relevance to MAC members, to be undertaken during 2011. These reviews relate to:<br><br>• the restriction imposed on Verve Energy with regard to the supply of electricity;<br>• the prohibition on Synergy with regard to the generation of electricity; and<br>• the introduction of further (including full) retail contestability in the Western Australian electricity market.<br><br>Ms Ugarte noted that the OoE intended to conduct one on one discussions with key stakeholders, including MAC members, to ascertain their views on these issues. The OoE was preparing a detailed project plan for the reviews and would provide an update to the MAC at its next meeting.<br><br>The Chair queried whether the OoE wished the MAC to have any further role in the reviews. Ms Ugarte replied that the OoE did not require this at present. | |

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| | Mr Forward and Mr Stephen MacLean commended the OoE for the consultative and transparent approach it had adopted for the reviews. | |
| **6a** | **MARKET RULE CHANGE OVERVIEW**<br><br>The Chair noted the change to the number of issues listed in the rule change and issues log. Mr Forward explained that the IMO had reviewed the log as planned last year, removing old issues that did not warrant progression and rationalising issues that were being handled elsewhere. The aim of the review was to tidy the log so that it provides a clearer picture of the outstanding issues.<br><br>The Chair noted that the MAC did not usually see the rule change and issues log in full, and suggested that the full log be presented to the MAC at least once each year, starting from the next meeting.<br><br>*Action Point: The IMO to circulate the current rule change and issue log with the papers for the 9 March 2011 MAC meeting.*<br><br>Mr Dykstra noted an error in Appendix 1 of the Market Rule Change Overview, where some Rule Change Proposals were shown as having their first submission periods open when in fact they were closed. Mrs Jacinda Papps responded that there could be problems relating to the "point in time" nature of the report and that the IMO would review the reporting of this information for the next MAC meeting. Mrs Papps noted that the key dates were correctly reported on the IMO website. Mr Dykstra agreed that there was no need to issue an update to Appendix 1. | **IMO** |
| **6b** | **CAPACITY CREDIT REDUCTION [PRC_2010_28]**<br><br>Mr Forward noted that the Pre Rule Change Discussion Paper: Capacity Credit Reduction (PRC_2010_28) had been discussed previously at the MAC. MAC members had generally supported the proposal, but had asked the IMO to consider incorporating:<br><br>• an ability to draw down on Reserve Capacity Security prior to the end of the Capacity Year and diverting this to a Supplementary Reserve Capacity (SRC) fund; and<br><br>• potential adjustments to the capacity price as a result of reducing a Facility's Capacity Credits to zero.<br><br>Mr Forward asked Ms Fiona Edmonds to present the outcomes of the IMO's analysis of these issues.<br><br>**Issue 1:** Ms Edmonds presented the outcomes of the IMO's further assessment, noting that the cover paper for PRC_2010_28 included a diagram indicating the current and potential arrangements for forfeiting security and the resultant potential SRC exposure. Ms Edmonds clarified that the risk to the market of an SRC event being incurred can last for up to three Reserve Capacity Cycles, under the current arrangements, and that any monies drawn down by the IMO would not be paid out until this risk had lapsed or an SRC event had occurred.<br><br>Ms Edmonds contended that there is no clear rationale to distinguish between monies that would be distributed to the SRC fund following: | |

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| | • a reduction in a Facility's Capacity Credits to zero; or<br>• the Facility's failure to meet the 90 percent test by the end of the Capacity Year.<br><br>As such, Ms Edmonds considered that this concept should not be included in PRC_2010_28. Ms Edmonds recommended that the ability to draw down on security earlier in the case where a Facility's Capacity Credits have been reduced to zero should be further considered in conjunction with the development of an SRC fund by the Rules Development Implementation Working Group (RDIWG).<br><br>Ms Edmonds requested any comments from MAC members. The Chair noted that the scenario of a Market Participant not being able to meet its obligations for an entire capacity year had already eventuated.<br><br>**Issue 2:** Ms Edmonds noted that in its cover paper for PRC_2010_28 the IMO has listed a number of different situations under which the total number of Capacity Credits assigned in the market would change. (Ms Edmonds clarified that Forced Outages would impact on the amount of capacity available but not the number of Capacity Credits in the market.) Ms Edmonds noted the IMO's view that it is appropriate to consider the concept of adjusting the Reserve Capacity Price in response to all of these situations where there is an amendment to the number of Capacity Credits in the market, rather than only considering a reduction in a Facility's Capacity Credits to zero.<br><br>Ms Edmonds also noted that the cover paper contained a worked example of the financial impact of adjusting the capacity price to reflect a change in assigned Capacity Credits. In the example, the reduction of the Capacity Credits of a 40 MW Facility to zero for the 2010/11 Capacity Year resulted in a capacity price increase of approximately 1 percent. Ms Edmonds noted that generally Market Participants would have no ability to respond to these price signals. As such there appears to be little justification for introducing price adjustments, particularly given the associated implementation costs.<br><br>Ms Edmonds concluded that the IMO's recommendation is not to consider potential adjustments to the capacity price further at the stage.<br><br>Mr Andrew Sutherland queried whether the IMO would be able to reduce the Capacity Credits of a Market Generator that was supposed to be available in December but missed that deadline. Mr Forward and Ms Edmonds responded that under the Rule Change Proposal this would only be the case if there was a clear indication that the Facility would be unable to provide any capacity at all during the Capacity Year.<br><br>The Chair reiterated that the intent of the proposal was not to cancel Capacity Credits except when it was clear that no capacity would be provided for the entire upcoming Capacity Year. Mr MacLean considered that while this intent was stated explicitly in the paper, the drafting of the proposed new clause 4.20.8 was ambiguous about which Capacity Year | |

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| | was under consideration. Mr MacLean offered to send the IMO further details of the issue and his proposed solution.<br><br>*Action Point: Mr MacLean to email the IMO his comments on new clause 4.20.8 in the Pre Rule Change Discussion Paper PRC_2010_28: Capacity Credit Reduction.*<br><br>Mr Dykstra noted that he had some concerns regarding the proposed amendments. For example:<br>• the use of the word "will' in clause 4.20.8 suggested a very demanding test that could be difficult to meet; and<br>• clause 4.20.9(b) needed to be more specific about what information was required.<br><br>Mr Dykstra agreed to email his comments to the IMO.<br><br>*Action Point: Mr Dykstra to email the IMO his comments on PRC_2010_28: Capacity Credit Reduction.*<br><br>There was some discussion about how the proposal would apply where a Market Participant was late in making its capacity available but was meeting its financial obligations to the market. Ms Edmonds reiterated that the proposal only applied in situations where the IMO became aware, prior to the start of a Capacity Year, that a Facility would be unable to provide any capacity at all during that Capacity Year. It was agreed that the IMO should review the wording of the proposed amendments to ensure that they clearly reflected this requirement.<br><br>*Action Point: The IMO to review the proposed new clause 4.20.8 in PRC_2010_28: Capacity Credit Reduction to clarify that the IMO will only issue a Notice of Intention to Reduce Capacity Credits if it becomes aware, prior to the start of a Capacity Year, that a Facility will be unable to provide any capacity at all during that Capacity Year.*<br><br>The Chair queried whether MAC members had any other issues apart from those already raised. Members indicated that they had no further issues with the proposal, other than those already raised.<br><br>*Action Point: The IMO to update PRC_2010_28: Capacity Credit Reduction to reflect the feedback provided by MAC members and formally submit the proposal into the Rule Change Process.* | **Mr MacLean**<br><br>**Mr Dykstra**<br><br>**IMO**<br><br>**IMO** |
| **6c** | **DE-REGISTRATION OF RULE PARTICIPANTS WHO NO LONGER MEET REGISTRATION REQUIREMENTS [PRC_2010_31]**<br><br>Mrs Papps noted that there are currently only two ways to de-register a Rule Participant that has never actively participated in the market and no longer meets the requirements of its original registration:<br>• the Rule Participant can apply to the IMO to be de-registered (and pay the applicable fees); or<br>• the IMO can apply to the Electricity Review Board (ERB) for the | |

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| | Rule Participant to be de-registered.<br><br>Mrs Papps submitted that if the Rule Participant does not apply for de-registration and pay the de-registration fees then the IMO is faced with the costly and time-consuming process of going to the ERB to de-register the Rule Participant. The IMO considers that it should be able to de-register a Rule Participant in these circumstances without the need to apply to the ERB. Mrs Papps noted that the Pre Rule Change Discussion Paper PRC_2010_31 outlines a proposed process which allows the IMO to do so.<br><br>Mrs Papps explained that the process required the IMO to issue a Registration Correction Notice to the Rule Participant, allowing it 90 days to remedy the situation. If the situation was not remedied satisfactorily then the IMO would then issue a De-registration Notice. A Rule Participant that had been de-registered by the IMO would be able to apply to the ERB for a review of the decision. Mrs Papps submitted that this process still provided a significant level of governance over the IMO's actions.<br><br>The Chair noted that this situation has already occurred in the market. The IMO had issued cure notices to a company in liquidation, which did not wish to remain a Market Participant but was unable to pay the required de-registration fee. Mr Dykstra considered that de-registration fees were not cost-reflective and suggested removing them. Mrs Papps responded that this would not remove the problem completely as the IMO would still need to initiate the de-registration process in some cases.<br><br>*Action Point: When setting its Market Fees this financial year, the IMO to investigate removing the de-registration fee.* | **IMO** |
| | Mr Dykstra queried whether it really mattered if these Rule Participants were not de-registered. Mr Dykstra noted that a significant amount of paperwork was involved in the registration of a Rule Participant, and suggested that it could be useful to leave an inactive Rule Participant the option to retain its registration status.<br><br>Mrs Papps responded that the focus of the proposal was to deal with Rule Participants that no longer met the criteria for their registration (e.g. were no longer companies). Mr Dykstra then questioned whether in that case the criteria listed in the proposed new clauses 2.32.7B(b) and 2.32.7B(c) were really relevant. Mr Ken Brown noted that Perth Energy was registered as a Rule Participant for some time before it began to actively participate in the market. Mr Forward confirmed that the IMO's focus was on Rule Participants that no longer met the criteria for registration. There was general agreement among MAC members that this should be the only criterion for the IMO to issue a Registration Correction Notice to a Rule Participant.<br><br>The Chair queried whether MAC members had any other issues around PRC_2010_31. No further issues were raised.<br><br>*Action Point: The IMO to remove criteria (b) and (c) from the proposed* | **IMO** |

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| | *new clause 2.32.7B in the Pre Rule Change Discussion Paper: De-registration of Rule Participants who no longer meet registration requirements (PRC_2010_31), and then formally submit the proposal into the Rule Change Process.* | |
| **6d** | **PROFILE METHODOLOGY FOR THE RELEVANT DEMAND CALCULATION [PRC_2011_01]**<br><br>Mr Campillos gave a presentation to the MAC on the Pre Rule Change Discussion Paper: Profile Methodology for the Relevant Demand Calculation (PRC_2011_01). A copy of the presentation is available on the IMO's website. Mr Campillos noted that EnerNOC had recently bought DMT Energy, which was now trading under the EnerNOC name.<br><br>Mr Campillos noted that the aim of the paper was to offer a better means of estimating the capacity that a Demand Side Programme (DSP) would provide. Mr Campillos considered that both the current Relevant Demand (RD) calculation methodology and the methodology proposed in the Rule Change Proposal: Curtailable Loads and Demand Side Programmes (RC_2010_29) used a static baseline that is inherently unable to predict a DSP load. The use of a static baseline can reward end-users who have not actually curtailed their load ("incidental performance") and penalise customers who have actually curtailed their load but were operating above their static baselines.<br><br>Mr MacLean queried whether Mr Campillos meant that DSPs may not actually be able to provide their required capacity in some cases. Mr Campillos explained how this could occur. Mr Ken Brown agreed, noting that System Management is unable to determine the amount of capacity being provided by a DSP in real time. Mr Peter Huxtable noted that a DSP may also be operating above its RD, in which case it will provide additional capacity for which it will not be paid.<br><br>Mr Campillos described the benefits of moving to a dynamic profile measure, which would more accurately reflect the actual load level at any given time. There was some discussion about the use of different profile methodologies for system planning purposes versus operational purposes. The Chair noted that the proposal was not seeking to change the commitment required from DSPs but only the method of measurement.<br><br>Mr Campillos provided details of the proposed methodology for determining DSP profile baselines. Mr Huxtable noted that although the proposal suggested including only business days in the "High X of Y" day calculations, Water Corporation had been dispatched on a public holiday in the past. Mr Zammit considered that the profile baselines would be much more reflective of the actual loads than any static baselines.<br><br>Mr Sutherland queried whether the process would be applied to individual loads or to the DSP portfolio as a whole. Mr Campillos replied that profile baselines would be calculated for each load individually, but then summed over the portfolio to determine the overall performance of the DSP. | |

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| | Mr Sutherland considered that the proposal made a lot of sense when compared with the current static baseline methodologies. Mr Huxtable considered that while there appeared to be an assumption that the current Rule Change Proposal (RC_2010_29) would not work the MAC had no proof of this. Mr Sutherland explained that he meant it would have been beneficial to consider the dynamic profile baseline methodology as part of RC_2010_29.<br><br>Mr Dykstra considered that EnerNOC's proposal appeared to deal with a concern he had raised on several occasions, i.e. if System Management dispatches a peaker then it will know what result to expect, but if a DSP is dispatched then the result is less clear. Mr Dykstra noted that the proposal partially addressed this issue. Mr Brown noted that System Management would still lack visibility of the actual reduction in real time. Mr Dykstra replied that the proposal would however give more confidence that the market was only paying for capacity that was actually delivered.<br><br>Mr Campillos submitted that the proposed methodology provided a better alignment between the operational reality seen by System Management and the way in which the IMO calculates payments and assesses capacity. Mr Brown noted that it would be valuable to ensure that DSPs were only paid for the capacity delivered. Mr Brown was not overly concerned with DSPs while their capacity contribution was small, but noted the growth of DSM in the market, adding that System Management had no problem with EnerNOC's proposal.<br><br>Mr Zammit recommended some of the work in this area recently published by EnerNOC, and considered that the proposal promoted greater equity between generation and DSM. Energy Response had worked in various jurisdictions around the world and had found no two systems that used the same measurement approach for DSM. Mr Campillos agreed that no standard method for measuring DSM response existed, considering that EnerNOC had selected a "best practice" approach.<br><br>Mr Sutherland suggested that most MAC members appeared to agree on the merits of the proposal. Given that RC_2010_29 was halfway through the Rule Change Process and the proposed review of the Reserve Capacity Mechanism later this year will include consideration of DSM, Mr Sutherland queried what the next steps in the process should be. Mr Huxtable noted that investment would be needed to implement the proposal.<br><br>Mr MacLean noted that he had no difficulty with the basic concept of improving the accuracy of DSP baselines, but was concerned that the proposal could disconnect the measurement of the DSM capacity of a Load from its Individual Reserve Capacity Requirement (IRCR). This would allow a Load to reduce its IRCR without affecting its ability to sell DSM capacity. Mr MacLean considered that the two measurements should be related. There was some discussion about the various options for the determination of IRCRs and DSM capacity, and their relative advantages and disadvantages. | |

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| | Mr Forward suggested that it could be beneficial to work through some scenarios for a number of the options discussed. The IMO would need to consider the best action to take with regard to RC_2010_29. Mr Forward could see the merit in the operational aspects of EnerNOC's proposal but wanted to be sure that it would not have any adverse impacts. It was agreed that MAC members should provide their comments on the proposal to the IMO, and the IMO would work through these comments with Mr Campillos.<br><br>*Action Point: MAC members to provide their comments on the Pre Rule Change Discussion Paper: Methodology for the Relevant Demand Calculation (PRC_2011_01).*<br><br>*Action Point: The IMO to work with EnerNOC to consider and respond to the comments received from MAC members on the Pre Rule Change Discussion Paper: Methodology for the Relevant Demand Calculation (PRC_2011_01).* | **All**<br><br>**IMO** |
| **7a** | **MARKET PROCEDURE CHANGE OVERVIEW**<br><br>Mrs Papps noted an update to the entry for the LT PASA procedure in the overview of recent and upcoming procedure changes distributed in the MAC meeting papers. Mrs Papps advised that the MAC papers had been distributed on the day of the IMO Procedure Change and Development Working Group meeting. The "Next Step" for the proposed updates was listed as "Formal submission into the Procedure Change Process (subject to any working group comments)". It was requested at the working group meeting that the proposal be returned to the working group for further review before its formal submission into the Procedure Change Process.<br><br>The IMO noted the overview of recent and upcoming procedure changes. | |
| **8a** | **WORKING GROUP OVERVIEW**<br><br>Mr Forward noted that Mr Adam Lourey was replacing Mr Dykstra as Alinta's member of the IMO Procedure Change and Development Working Group.<br><br>Mr Cremin advised the MAC that Mr Tremayne Pirnie was replacing Mr Peter Ryan as Griffin Energy's member of the System Management Procedure Change and Development Working Group.<br><br>The MAC noted the Working Group overview.<br><br>*Action Point: The IMO to amend the membership details contained in the ToR for both the IMO and System Management Procedure Change and Development Working Groups and update the website accordingly.* | **IMO** |
| **8b** | **MRCPWG UPDATE**<br><br>Mr Forward provided MAC members with an update on the progress of the MRCPWG. The Chair noted that the ERA, in its recent determination on the Maximum Reserve Capacity Price (MRCP) for the 2013/14 Reserve Capacity Year, had made some comments about the Weighted | |

| Item | Subject | Action |
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| | Average Cost of Capital (WACC) used by the IMO in the calculation of the MRCP. The Chair queried whether the issue raised by the ERA would be resolved by the MRCPWG. Mr Forward confirmed that this would be the case.<br><br>Mr Dykstra noted the GFC had introduced sudden changes after a period of stability, and suggested that a degree of flexibility could be introduced into the procedure so that the IMO could adopt a different approach when the circumstances warranted this.<br><br>Mr Forward clarified that the WACC value determined by the IMO is used for a particular purpose, which may not always align with the purposes for which the ERA requires a WACC value. The ERA has determined that the IMO followed due process in preparing its MRCP proposal, but does not agree with the IMO's Debt Risk Premium and does not want to create any expectation that it will be used for any of the ERA's own regulatory purposes.<br><br>The MAC noted the overview of the MRCPWG. | |
| **8c** | **RDIWG UPDATE**<br><br>Mr Forward noted that most MAC members were also members of the RDIWG and so were aware of its progress. Mr Forward offered to provide a one on one progress update to any member on request.<br><br>Mr Dykstra queried when the pricing scenarios being developed by the IMO would be distributed to RDIWG members. The Chair replied that these would be circulated as soon as possible, and that the Market Evolution Program team had been reminded of the urgency of the work. Mr Forward noted that one scenario had been reviewed with System Management the previous day.<br><br>Mr Dykstra noted that participants had recently been approached with questions for a cost/benefit analysis. These were difficult to answer given the current lack of information. The Chair noted that a high level cost benefit analysis will be presented at the 22 February RDIWG meeting, with the aim for an updated paper to be presented at the 15 March 2011 RDIWG meeting. | |
| **9a** | **OPERATIONAL WORKLOAD AND THE MARKET EVOLUTION PROGRAM**<br><br>The Chair noted that comments had been made at the 1 February 2011 RDIWG meeting about workload for the coming year. The IMO had agreed to raise the issue at the February 2011 MAC meeting, as the people who had made the comments would be present and could be invited to speak on the issue. The Chair noted that the IMO was conscious of the need to handle both its Market Evolution Program (MEP) and business-as-usual obligations, and so had budgeted for these accordingly. However the IMO understood the concerns raised by some participants about their ability to deal with the increased workload. | |

| Item | Subject | Action |
|---|---|---|
| | Mr MacLean noted that Synergy had already increased its resources in expectation of the increase in workload generated by the MEP, and expected that other participants should also be taking similar action. Mr Ken Brown noted that System Management shared the concerns of other participants about the workload. The Chair advised that the IMO will try to manage the timeframes for submission periods, and where necessary will provide extensions to stagger the load on participants.<br><br>Mr Dykstra noted that a large number of Rule Change Proposals were submitted into the Rule Change Process in December 2010. Some of the Rule Change identifiers indicated that work on the proposals had started early in 2010. Mr Dykstra suggested that perhaps a more strategic approach could have been taken to how proposals are packaged and the timing of their progression. The Chair queried whether Mr Dykstra was concerned about the level or the prioritisation of the work. Mr Dykstra replied that he was concerned about both aspects.<br><br>Mr Forward considered that the scheduling of proposals was complex, as it was difficult to predict how long a proposal would need to work through the pre rule change process. It was unlikely that a series of complex proposals would emerge from the pre rule change process according to a perfect timetable. The Chair noted that the MAC frequently requests the IMO to undertake additional work in relation to a proposal, and while the IMO is happy to meet these requests they will have an impact on the timelines.<br><br>Mr Dykstra considered that the IMO was not obliged to progress all of the proposals submitted to it. Mr Forward asked if MAC members wished the IMO to exercise this option more frequently. The Chair considered that the IMO was never too busy to progress a proposal. Mr Andrew Everett agreed that a resources shortage was not a valid reason to not progress a proposal.<br><br>Mr Campillos queried whether Mr Dykstra was suggesting an increase in the combination of related changes into Rule Change Proposals. Mr Dykstra replied that he was unhappy with the current threshold for the acceptance of Rule Change Proposals by the IMO, considering that it should be stronger. Mr Dykstra considered that some recent proposals should not have been accepted by the IMO and that more work should have been done upfront.<br><br>Mr MacLean noted that in some cases when Synergy has reviewed a Rule Change Proposal it had found that the logic as expressed in the drafting did not work. Mr MacLean suggested that if the proposals were better prepared it would reduce the workload for participants. Mr Dykstra considered that he no longer has confidence that the drafting contained in a Rule Change Proposal will actually achieve the intent suggested in its title.<br><br>Mr Forward noted that he had discussed the criteria for the progression of Rule Change Proposals with Mr Dykstra in the past. Mr Dykstra asked why the IMO could not raise the bar for Rule Change Proposals. Mrs Papps submitted that the Market Rules offered little guidance on what the | |

| Item | Subject | Action |
|---|---|---|
| | IMO can use to decide to not progress a Rule Change Proposal. Mr Dykstra suggested that the IMO could make an administrative decision on the requirements.<br><br>Mr Forward noted that on many occasions participants had submitted proposals with drafting that did not achieve its intended effect. Mr Dykstra replied that he considered that the IMO was the "umpire" and was expected to be able to identify such errors. Mr Forward considered that the IMO's options were to increase resources (at the market's expense) or reduce the volume of work undertaken. If MAC members considered that more upfront analysis should be undertaken, then more resources could be allocated to support this.<br><br>Mr Dykstra considered that participants had limited time to read through the detail contained in Rule Change Proposals, and suggested an increase in the number of issues resulting from the progression of Rule Change Proposals. Mr Dykstra offered the example of the Rule Change Proposal: Changing the Window of Entry into the Reserve Capacity Mechanism (RC_2009_11), which had not been intended to allow early entry for DSPs. Mr Dykstra submitted that in some cases Rule Change Proposals were accepted without adequate analysis because they appeared to be "intuitively OK".<br><br>The Chair reiterated that if participants found themselves unable to meet a submission deadline for an important Rule Change Proposal then they should advise the IMO of the issue. The IMO will try to accommodate any reasonable requests from participants to extend submission periods in these cases, subject to the constraints of the Market Rules. Mr Forward noted that the IMO would need to consider these requests carefully to prevent them from being used to delay the Rule Change Process. The Chair agreed that a judicious approach would be required. | |
| **10** | **OTHER GENERAL BUSINESS**<br><br>Mr Sutherland noted that under the current network tariff structure some generators were forced to incur excess network usage charges (ENUC) in order to meet the requirements of a Reserve Capacity test.<br><br>Mr Sutherland noted that typically Market Participants requested a Declared Sent Out Capacity (DSOC) equal to their Certified Reserve Capacity. For example, a Scheduled Generator capable of generating 340 MW might have a DSOC and Certified Reserve Capacity of 330 MW. Depending on the temperature, the Generator may need to exceed their 330 MW DSOC limit in order to pass a Reserve Capacity test, incurring ENUC charges that apply for the full month. In this case the marginal cost of increasing from 330 MW to 331 MW could be around $1500 per MWh.<br><br>Mr Sutherland noted that a Scheduled Generator would almost never exceed their DSOC unless they were requested to do so by System Management.<br><br>The Chair queried what action Mr Sutherland wished the MAC and/or the IMO to take on the issue. Mr Sutherland suggested that ENUC penalties should only apply to the Trading Intervals during which the DSOC was | |

| Item | Subject | Action |
|---|---|---|
| | exceeded. Mr Peter Mattner noted that Western Power was currently working on the third access arrangement and that he would like to discuss the matter with Mr Sutherland off-line. Mr Forward suggested that the IMO could participate in these discussions.<br><br>*Action Point: Mr Sutherland to send an email to the IMO and Mr Peter Mattner summarising his issues around excess network usage charges incurred by Scheduled Generators during Reserve Capacity tests.*<br><br>*Action Point: The IMO to arrange a meeting between the IMO, Mr Mattner and Mr Sutherland to discuss the issues raised by Mr Sutherland around excess network usage charges incurred by Scheduled Generators during Reserve Capacity tests.* | **Mr Suther-land**<br><br>**IMO** |
| **12** | **NEXT MEETING**<br><br>Meeting No. 36 will be held on Wednesday 9 March 2011. | |
| **CLOSED:** The Chair declared the meeting closed at 4.28 pm. | | |

# Agenda item 4: 2010/11 MAC Action Points

**Legend:**

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

| # | Year | Action | Responsibility | Meeting arising | Status/Progress |
|---|---|---|---|---|---|
| 88 | 2010 | The Office of Energy to provide the IMO with a copy of its report on gas contingency service options for distribution to MAC members. | OoE | August | This report will be circulated once the Office of Energy provides an updated report. |
| 89 | 2010 | The IMO to distribute the report provided by the Office of Energy on gas contingency service options (action point 88) to MAC members. | IMO | August | See above. |
| 119 | 2010 | The IMO, in March 2011, to review with System Management whether there is an issue with the registration and dispatch of a large number of small Demand Side Programmes, and report back to the MAC. | IMO | September | |

| # | Year | Action | Responsibility | Meeting arising | Status/Progress |
|---|---|---|---|---|---|
| 130 | 2010 | The IMO to consider whether further information on new large loads should be included in the Statement of Opportunities (SOO). | IMO | October | The IMO will consider whether information on new large loads should be included in the SOO closer to the time when the SOO is prepared. |
| 167 | 2010 | System Management to distribute the results of Mr David Newton's work on Spinning Reserve requirements to MAC members | System Management | December | The IMO has requested this from System Management and will circulate once received. |
| 1 | 2011 | The IMO to amend the minutes of Meeting No. 34 to reflect the points raised by the MAC and publish on the website as final. | IMO | February | Completed. |
| 2 | 2011 | The IMO to amend the title of the "REGWG Final Report" to "Renewable Energy Generation Working Group – Summary of Process and Outcomes" and re-publish the report on the IMO website. | IMO | February | Completed. An updated final report published: www.imowa.com.au/REGWG |
| 3 | 2011 | The IMO to remove item 169 (Alinta to submit its "Limits to early entry capacity payments" rule change proposal") from the list of MAC action points. | IMO | February | Completed. |
| 4 | 2011 | The IMO to further consider the rationale for paying DSPs to reduce consumption following the issuance of a Dispatch Instruction by System Management. | IMO | February | This is included in the RCM Review Scope of Works:<br><br>*"The Consultant will consider the broader appropriateness of Dispatch Instruction Payments for all DSM facilities."* |
| 5 | 2011 | The IMO to provide MAC members with a copy of the IMO's worked example of the costs to the market of dispatching a peaker vs. a | IMO | February | Completed. Circulated to members on 18 February 2011. |

| # | Year | Action | Responsibility | Meeting arising | Status/Progress |
|---|---|---|---|---|---|
| | | DSP. | | | |
| 6 | 2011 | The IMO to circulate the current rule change and issue log with the papers for the 9 March 2011 MAC meeting. | IMO | February | Completed. Included in the meeting papers. |
| 7 | 2011 | Mr MacLean to email the IMO his comments on new clause 4.20.8 in the Pre Rule Change Discussion Paper PRC_2010_28: Capacity Credit Reduction. | Mr MacLean | February | Completed. |
| 8 | 2011 | The IMO to review the proposed new clause 4.20.8 in PRC_2010_28: Capacity Credit Reduction to clarify that the IMO will only issue a Notice of Intention to Reduce Capacity Credits if it becomes aware, prior to the start of a Capacity Year, that a Facility will be unable to provide any capacity at all during that Capacity Year. | IMO | February | Completed. |
| 9 | 2011 | Mr Dykstra to email the IMO his comments on PRC_2010_28: Capacity Credit Reduction. | Mr Dykstra | February | Completed. |
| 10 | 2011 | The IMO to update PRC_2010_28: Capacity Credit Reduction to reflect the feedback provided by MAC members and formally submit the proposal into the Rule Change Process. | IMO | February | Completed. Proposal published 1 March 2011. |
| 11 | 2011 | When setting its Market Fees this financial year, the IMO to investigate removing the de-registration fee. | IMO | February | This action point has been forwarded to the Market Operations team to action as part of setting the Market Fees for 2011. |
| 12 | 2011 | The IMO to remove criteria (b) and (c) from the proposed new clause 2.32.7B in the Pre Rule Change Discussion Paper: De-registration of Rule Participants who no longer meet registration requirements | IMO | February | Underway. |

| # | Year | Action | Responsibility | Meeting arising | Status/Progress |
|---|---|---|---|---|---|
| | | (PRC_2010_31), and then formally submit the proposal into the Rule Change Process. | | | |
| 13 | 2011 | MAC members to provide their comments on the Pre Rule Change Discussion Paper: Methodology for the Relevant Demand Calculation (PRC_2011_01) to the IMO. | MAC members | February | Completed. Email sent on 18 February 2011 requesting any comments by 2 March 2011. |
| 14 | 2011 | The IMO to work with EnerNOC to consider and respond to the comments received from MAC members on the Pre Rule Change Discussion Paper: Methodology for the Relevant Demand Calculation (PRC_2011_01). | IMO | February | Underway. The IMO is currently planning a workshop to discuss the two Relevant Demand methodologies. It is anticipated that this workshop will be held at the end of March. |
| 15 | 2011 | The IMO to amend the membership details contained in the ToR for both the IMO and System Management Procedure Change and Development Working Groups and update the website accordingly. | IMO | February | Completed. |
| 16 | 2011 | Mr Sutherland to send an email to the IMO and Mr Mattner summarising his issues around excess network usage charges incurred by Scheduled Generators during Reserve Capacity tests. | Mr Sutherland | February | Completed. Email sent on 18 Feb 2011. |
| 17 | 2011 | The IMO to arrange a meeting between the IMO, Mr Mattner and Mr Sutherland to discuss the issues raised by Mr Sutherland around excess network usage charges incurred by Scheduled Generators during Reserve Capacity tests. | IMO | February | Complete. Meeting scheduled for 1 March 2011 3.00pm. |

# Agenda Item 5a: Overview of Market Rule Changes

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

| Rule changes: Formally submitted (see appendix 1) | 2 March 2011 | |
|---|---|---|
| Fast track with Consultation Period open | 0 | |
| Standard Rule Changes with 1st Submission Period Open | 1 | |
| Fast Track Rule Changes with Consultation Period Closed (final report being prepared) | 0 | |
| Standard Rule Changes with 1st Submission Period Closed (draft report being prepared) | 8 | |
| Standard Rule Changes with 2nd Submission Period Open | 0 | |
| Standard Rule Changes with 2nd Submission Period Closed (final report being prepared) | 6 | |
| Rule Changes - Awaiting Minister's Approval and/or Commencement | 2 | |
| **Total Rule Changes Currently in Progress** | **17** | |
| | | |
| **Potential changes logged by the IMO- Not yet formally submitted (see appendix 2)** | **January** | **February** |
| High Priority (to be formally submitted in the next 3/6 months) | 0 | 0 |
| Medium Priority (may be submitted in the next 6/12 months) | 20 | 22<br>(+3/-1) |
| Low Priority (may be submitted in the next 12/18 months) | 17 | 20<br>(+5/-2) |
| **Potential Rule Changes (H, M and L)** | **37** | **42** |
| Minor and typographical (submitted in three batches per year) | 30 | 37<br>(+7) |
| **Total Potential Rule Changes** | **67** | **87** |

The changes in the rule change and issues log from January to February have arisen from:

| Priority | Issue |
|---|---|
| **High** | N/a |
| **Medium** | **In:**<br>• See IR128 in the issues log (appendix 2).<br>• See IR130 in the issues log (appendix 2).<br>• See IR131 in the issues log (appendix 2).<br><br>**Out:**<br>• See PRC_2011_02 on today's agenda: Reassessment of Allowable Revenue during a Review Period |
| **Low** | **In:**<br>• See IR132 in the issues log (appendix 2).<br>• See IR133 in the issues log (appendix 2).<br>• See IR134 in the issues log (appendix 2).<br>• See IR135 in the issues log (appendix 2).<br>• See IR136 in the issues log (appendix 2).<br>**Out:**<br>• Two minor amendments that have been assessed as not an issue/ or able to be resolved via other means. |

# APPENDIX 1: FORMALLY SUBMITTED RULE CHANGES

## Standard Rule Change with First Submission Period Open

| ID | Date submitted | Title | Submitter | Next Step | Date |
|---|---|---|---|---|---|
| **RC_2010_28** | 01/03/2011 | Capacity Credit Cancellation | IMO | Submission period ends | 13/04/2010 |

## Standard Rule Change with First Submission Period Closed

| ID | Date submitted | Title | Submitter | Next Step | Date |
|---|---|---|---|---|---|
| **RC_2010_08** | 15/04/2010 | Removal of DDAP uplift when less than facility minimum generation | Griffin Energy | Publish Draft Rule Change Report | 28/03/2011 |
| **RC_2010_12** | 17/11/2010 | Required Level and Reserve Capacity Security | IMO | Publish Draft Rule Change Report | 04/03/2010 |
| **RC_2010_14** | 06/12/2010 | Certification of Reserve Capacity | IMO | Publish Draft Rule Change Report | 04/03/2010 |
| **RC_2010_22** | 18/11/2010 | Partial Commissioning of Intermittent Generators | IMO | Publish Draft Rule Change Report | 04/03/2010 |
| **RC_2010_25** | 29/11/2010 | Calculation of the Capacity Value of Intermittent Generation - Methodology 1 (IMO) | IMO | Publish Draft Rule Change Report | 14/03/2011 |
| **RC_2010_29** | 02/02/2010 | Curtailable Loads and Demand Side Programmes | IMO | Publish Draft Rule | 11/03/2011 |

| ID | Date submitted | Title | Submitter | Next Step | Date |
|---|---|---|---|---|---|
| | | | | Change Report | |
| **RC_2010_33** | 17/12/2010 | Cost_LR | Verve Energy | Publish Draft Rule Change Report | 04/03/2010 |
| **RC_2010_37** | 30/11/2010 | Calculation of the Capacity Value of Intermittent Generation - Methodology 2 (Griffin Energy) | Griffin Energy | Publish Draft Rule Change Report | 14/03/2011 |

## Standard Rule Change with Second Submission Period Closed

| ID | Date submitted | Title | Submitter | Next Step | Date |
|---|---|---|---|---|---|
| **RC_2010_11** | 15/10/2010 | Removal of Network Control Services Expression of Interest and Tender Process from the Market Rules | IMO | Publish Final Rule Change Report | 11/03/2011 |
| **RC_2010_19** | 25/10/2010 | Settlement Cycle Timeline | IMO | Publish Final Rule Change Report | 23/03/2010 |
| **RC_2010_20** | 08/10/2010 | Market Fees | IMO | Publish Final Rule Change Report | 03/03/2011 |
| **RC_2010_21** | 15/10/2010 | Providing Price Related Standing Data to System Management | IMO | Publish Final Rule Change Report | 11/03/2011 |
| **RC_2010_24** | 03/08/2010 | Adjustment of Relevant Level for Intermittent Generation Capacity | Alinta | Publish Final Rule Change report | 01/04/2011 |
| **RC_2010_36** | 29/10/2010 | Acceptable Credit Criteria | Synergy | Publish Final Rule Change report | 21/03/2011 |

## Rule Changes Awaiting Commencement/Ministerial Approval

| ID | Date submitted | Title | Submitter | Next Step | Date |
|---|---|---|---|---|---|
| **RC_2010_06** | 27/04/2010 | Application of Spinning Reserve to Aggregated Facilities | Griffin Energy | Commencement | 01/04/2011 |
| **RC_2010_23** | 03/08/2010 | Consequential Outage – Relief from capacity refund and unauthorised deviation penalties | Alinta | Commencement | 01/05/2011 |

## APPENDIX 2: CURRENT RULE CHANGE AND ISSUES LOG

| Issue # | Priority | Date Raised | Who | Chapter | Clause | Topic Area | What is this issue? |
|---|---|---|---|---|---|---|---|
| IR 19 | L | 17/02/2006 | Brendan | 4 | Chapter 4 | RC Auction | The reserve capacity auction price is the price of the highest price offer cleared. But the rules fail to address what the price will be if there are no offers. The price should really be the maximum reserve capacity price. This is something we could address in the context of having the 85% factor on the price if no auction is held updated. (e.g. if no auction is held, or no capacity is scheduled in the auction, then price equals 85 % of the Maximum Reserve Capacity Price) |
| IR 20A | L | 17/02/2006 | Brendan | 4 | 4.21 | Special Price arrangements | The overlap between ST and LT SPA's in clauses 4.21 and 4.22 needs to be considered further. When the IMO accepts a high Reserve Capacity Offer price from a new facility in place of a lower RC offer price in the auction, that facility becomes eligible for a ST SPA (one year at the price of the higher offer) or a LT SPA (up to ten years at the auction clearing price). 4.21.1(c) states that a ST SPA cannot cover capacity already covered by a LT SPA – hence we are ok from a rules perspective but force a high cost provider to either take an ST SPA for one year and no LT SPA, or to take up LT SPA and accept that it cannot fully recover offer costs. Options include:<br>• clarify the existing situation in the rules (provider must choose one of the options), thus making the overlap work;<br>• allow both SPA's to be accepted with existing pricing methods, with the ST SPA to override LT SPA for first year, thus making the overlap work;<br>• allow LT SPA for such a facility at the Reserve Capacity Offer price for that facility, thus removing the overlap; or<br>• prevent the swap of auction offers with a new facility, thus removing the overlap. |
| IR 30 | M | ?? | Dora | Appendix | IRCR and notional | IRCR | Change the rules to clarify that all meters, including the notional meter, used for the IRCR calculations are not loss adjusted. |

| Issue # | Priority | Date Raised | Who | Chapter | Clause | Topic Area | What is this issue? |
|---|---|---|---|---|---|---|---|
| | | | | | meter | | |
| IR45 | L | 29/06/2009 | Robbie | 6 and 7 | 6.4.6, 7.2.3B, 7.2.3C | Timelines | The clauses 7.2.3B and 7.2.3C require System Management to provide information outlined in 7.2.1(a) and 7.2.3A during certain times of the day. If this is unable to be done by SM by the prescribed time, an alternative time needs to be arranged by the IMO for SM.<br><br>The issue here is that 6.4.6 allows a delay if the IMO or supporting infrastructure (interpreted to be System Management) fails to provide information. This delay is 2 hours and it lines up all the window start and end times to this 2 hour delay. The point made is that perhaps all of these timeframes should line up such that there is consistency in the timelines. |
| IR46 | M | 26/06/2009 | Allan/Board | 3 | 3.18.5D | Outage transparency | As part of RC_2009_05, the Board requested the IMO consider Full Transparency on outages. The IMO agreed to progress RC_2009_05 as it was as at the very minimum this allowed better coordination between SM and Western Power. The next action is to assess the Board request. |
| IR54 | M | 30/07/2009 | Fiona | 8 | 8.6.1 | Meter data submissions | Need to refer to Trading Day and KWh quantity - like in the Market Procedure currently. |
| IR56 | M | 28/08/2009 | Robbie | 8 | 8.3.5 | Metering timelines | Issue with metering timeliness. See metering data procedure |
| IR 68 | L | 16/12/2009 | Fiona | 2 & 7 | 7.6A.5 (b) | Disputes process | There is an inherent conflict between the disputes process outlined in clauses 2.18- 2.20 and the arbitration process required under 7.6A.5 (b). In particular, it is unclear if SM and the EGC can choose between which process they want to follow or whether they may go through the arbitration process and then reappeal under the disputes process. Some clarity is required as to what applies |
| IR 73 | M | 18/12/2009 | | 4 | 4.26.2 | Net STEM Shortfall calculations | 2 issues identified: Portfolios with multiple generators (solved with RC_2010_03) and facilities with outputs which exceed their Reserve Capacity Obligations. A detailed solution is needed for issue 2. (See RC_2010_03) for interim solution. |
| IR 74 | L | 19/01/2010 | Fiona | 7 | Section 7.5 | DMO | As the DMO is determined by the IMO based on price (as provided in Standing Data) it is possible that a unit which has not yet begun commissioning and therefore can not be considered reliable could be |

| Issue # | Priority | Date Raised | Who | Chapter | Clause | Topic Area | What is this issue? |
|---|---|---|---|---|---|---|---|
| | | | | | | | ranked highly up the DMO. Note that the determination of the DMO does not consider whether a unit is active, has undertaken commissioning |
| IR81 | L | 19/03/2010 | Ben | 4 | 4.25.13 | Reporting fuel levels | This rule is all about reporting fuel levels, however it only refers to alternative fuels, which only some facilities have, and it also refers to MPs failing to comply with 4.10.2 - which isn't an obligation so impossible to not comply with. |
| IR82 | M | 20/03/2010 | Ben | | 7.5.4 | | there is a rule somewhere that says that people need to put in fuel declarations in as part of STEM submissions - and a rule saying that if they change fuel types they MAY update the fuel declaration (and may not apply to Verve at all -ask Robbie) - so IMO can't tell what fuel they are running on. |
| IR84 | L | 23/03/2010 | Compliance Log discussion | 9 | 9.18.3 | Non STEM Settlement statements | The drafting in this section needs review. In particular subclause (c)ii(A) needs to be amended to Market Participant's and (c)v suggests that the Notional Wholesale Meter is a facility as currently drafted (this requires amendment) |
| IR85 | L | 23/03/2010 | Compliance Log discussion | Appendix 1 | Appendix 1 (I) (iii) | Standing data | It is unclear how the requirements under this clause for the IMO to keep standing data fit in with those requirements under chapter 6. There is potentially a duplication which could be deleted. |
| IR90 | M | 13/04/2010 | Barbara | 6 | 6.14.4(d)(ii) | Curtailed Demand | Clause 6.14 deals with the calculation of MCAP. The calculation includes the determination of Relevant Quantity. One of the inputs into Relevant Quantity is “the IMO’s estimate of the total MWh demand curtailed during that Trading Interval (if any). …” [Clause 6.14.4(d)(ii)]<br><br>The IMO has no information about curtailed demand and relies on information supplied under an informal arrangement with System Management. We would like to regularise this by changing the rule so that System Management is required to supply the information, and we are required to use the information supplied. |
| IR93 | L | 15/04/2010 | Griffin Energy | 3 | 3.21.7 | Reporting Forced Outages | The Market Rule (3.21.7 and associated obligations) presently requires Market Generators to lodge Forced outages in SMMITS within 15 business days of outage based on System Management SCADA. IMO does not use this information for settlements, but rather relies on Meter Data that in some cases takes 14 days to be made available. |

| Issue # | Priority | Date Raised | Who | Chapter | Clause | Topic Area | What is this issue? |
|---|---|---|---|---|---|---|---|
| | | | | | | | Therefore, the requirement to lodge outages in SMMITS appears to be a legacy issue that is no longer required. |
| IR95 | L | 30/04/2010 | Rules Walkthrough | 6 | 6.3A.2(d) | | Clause 6.3A.2(d) needs to be amended to also include facilities which run on non liquid fuel only. |
| IR97 | M | 13/05/2010 | IMO Board meeting | 7 | 7.11.7 | Compliances with directions under high risk state | This relates to the obligations of participants when SM issues directions during a High Risk Operating State or Emergency Operating State.<br>At present the rules say that participants must comply with those directions, even if SM has not told them that a High Risk Operating State or Emergency Operating State exists. SM has to advise them 'as soon as practicable" but the Board wants an express provision that says participants wont be found to be in breach of the rules if they weren't told a High Risk Operating State or Emergency Operating State existed and don't follow directions. |
| IR102 | M | 21/06/2010 | Ben Williams | 4 and appendix 3 | ?? | Committed Status | The System Capacity team is required to accept bilateral trade declarations from all "committed" Facilities - however we are not given the ability under the rules to deem a Facility to be committed and hence to deem it NOT committed. We do have some supporting ideas in the bilateral trades Market Procedure which seems to get us around this issue ()but is probably "ultra-vires" - sorry for spelling)- however it would be nice if we could firm up exactly the IMO's powers to be able to deem a Facility committed. |
| IR105 | M | 23/07/2010 | William Street | 10 | 10.5.1.(z) | | The IMO is required to publish near real time operating data (clause 10.5.1(z)). Two aspects of this (total generation and total Spinning Reserve) are provided in MW and the third aspect, Operational System Load Estimate, is provided in MWh. The IMO considers that all three aspects of this data should be published in the same format. |
| IR106 | M | 23/07/2010 | William Street | Appendix 5 | Appendix 5 - STEP 1 | Measurement of Peak trading intervals. | Step 1 of appendix 5 outlines the measurement process for the IRCR peak Trading Intervals. The IMO considers that the Market Rules need to be amended to either specify that this calculation will use total generation calculated in settlements (i.e. TT30GEN) or loss adjusted load (Total TPMLOAD).<br>There is an issue with how the systems calculate the 12 Peak trading intervals (And 4 peak monthly intervals) as the calculations are not consistent with the rules. |

| Issue # | Priority | Date Raised | Who | Chapter | Clause | Topic Area | What is this issue? |
|---|---|---|---|---|---|---|---|
| IR107 | L | 26/07/2010 | Fiona Edmonds | 4 | 4.25.3A | Reserve Capacity Testing | Clause 4.25.3A specifies that the IMO must not undertake a Reserve Capacity Test if a Facility is undergoing Opportunistic Maintenance, a Forced Outage or Consequential outage, among other things. However these events occur after the IMO has requested System Management to undertake the test and so therefore can not be taken into account by the IMO. |
| IR108 | M | 12/07/2010 | Fiona Edmonds | 3 | 3.21A.3 | Commissioning | Under the IMO's amended registration process, the IMO will register a facility on the date that they specify in clause 2.33.3(c)(vii) 1. As this will be the date that they commence operation in the market it will not be possible for SM to approve a commissioning test for this facility as it will no longer be yet to commence operation (they will be officially in the market at this point). SM will be precluded from approving commissioning tests for these units. |
| IR109 | L | 27/08/2010 | Fiona Edmonds | 4 | 4.27 | Reserve Capacity Performance Monitoring | The report prepared by the IMO on reserve capacity availability in the SWIS (when it drops below 80%) refers to capacity not made available. Currently it only takes into account Planned Outages (clause 4.27.3); however Opportunistic Maintenance, Consequential Outages and Forced Outages are not taken into account. Additionally Equipment Tests are not taken into account. The IMO needs to consider whether only incorporating Planned Outages is misrepresenting the causes of capacity not being made available. |
| IR110 | M | 27/08/2010 | Ben Williams | 4 | 4.13.11B (before Fiona's Rule Changes) | IRCR and RC Security | If at the end of the First Year of Capacity Credits (CCs) a Facility has failed to operate the Facility adequately the Market Participant forfeits the RC Security.<br><br>The IMO is therefore required to pay out the security to Market Customers in proportion to their IRCR after paying any SRC costs<br><br>There are a number of times which the IMO may decide to pay out the Security to MCs – each with different impacts on the amount of RC Security each would receive (due to monthly updates of IRCR proportions) and with implications on HOW it would be possible to pay for SRC |
| IR111 | M | 16/09/2010 | Greg Ruthven | 4 | 4.25.5 | RC Testing | A Market Participant can request a third test "once during the remaining |

| Issue # | Priority | Date Raised | Who | Chapter | Clause | Topic Area | What is this issue? |
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| | | | | | | | Reserve Capacity Cycle". This is unclear. The IMO considers that Market Participants should be allowed to request once in the remainder of the 6-month testing cycle or once for the remainder of the Capacity Year. |
| IR112 | M | 24/09/2010 | Greg Ruthven | 4 | 4.25.1 | RC Testing | A new Facility can come online and begin receiving Reserve Capacity payments between 1 August and 30 November (until 2011) or 1 June and 1 October (2012 onwards). The Reserve Capacity Testing provisions require that all generation facilities with obligations to be tested between 1 April to 30 September. Therefore the Market Rules currently require a new Facility that comes online in late September to be tested almost immediately. The IMO considers that this is impractical and an allowance could be made, such as a minimum period that a Facility is online during that period, before being required to be tested. |
| IR115 | M | 25/10/2010 | William Street | 3, 6 & 9 | | Commissioning | The Market Participant Registration project is recommending that Registration occurs after commissioning. The IMO would like to amend the rules to allow for energy payments to unregistered Facilities while commissioning. |
| IR120 | M | 1/11/2010 | IMO/REGWG | 4 | | Intermittent Generator Data | The REGWG requested that a Rule Change proposal be developed to publish aggregated Intermittent Generator data. See REGWG Minutes from 12 August 2010 meeting. |
| IR121 | L | 18/11/2010 | Barbara | 3 | 3.17.5 | | The Clause currently refers to "any other load facilities designated as significant by SM". It is unclear how SM would designate a facility as significant. |
| IR122 | L | 10/11/2010 | MAC | 2 | 2.24-2.25 | Market Fees | Concerns of MAC members around the exemption of Demand Side Management aggregators from Market Fees |
| IR125 | M | 23/11/2010 | John Nguyen | 2 | 2.27.2 | Loss Factors | The Market Rules and the Loss Factor Market Procedure are inconsistent in their treatment of deriving loss factors for Non-Dispatchable loads under 1000kVa peak consumption. Currently the Market Procedure is followed, which produces better loss factors than the Market Rules would. |
| IR126 | M | 14/12/2010 (date all LT PASA and | Various | 4 | 4.3.1d, 4.5.2A, 4.5.13(a)iv, | LT PASA and SOO | Old IR 17: Number of capacity credits which the IMO expects will be bilaterally traded in the EOI document is difficult to forecast, and impractical to do. We can report on the number of Capacity Credits |

| Issue # | Priority | Date Raised | Who | Chapter | Clause | Topic Area | What is this issue? |
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| | | SOO issues combined) | | | 4.5.12 and appendix 3 | | that were "intended to be Bilaterally Traded, from the Bilateral Trade Declaration process, but this would require different wording. Failure to comply will mean a rule breach. Possibly remove this requirement.<br><br>Old IR39: Circular with regards to intermittent loads reserve capacity margin. Will not become a problem again until 2010 year<br><br>Old IR 98: Market Rule states that the SOO "must include … for each Capacity Year of the Long Term PASA Study Horizon … the generation capacities of each probable generation project". The IMO is not able to publish information provided by participants in response to our request for information for the LT PASA as dictated by 4.5.7. Also, Expressions of Interest are given the confidentiality status of IMO Confidential. We should, however, include aggregate information from the Expressions of Interest.<br><br>Old IR104 According to Appendix 3, Facilities in Availability Class 4 must be available for at least 24 hours per year. This means that collectively Availability Class 4 can only be relied on to provide capacity for 0-24 hours per year, even though some of the individual Facilities in the Availability Class may be able to provide more than 24 hours. Clause 4.5.12(c)(i) specifies the capacity quantity associated with Availability Class 4. The clause refers to subtracting the quantity of capacity required for more 48 hours per year from the Reserve Capacity Target. However, since the intention is to determine the capacity that can be met by Availability Class 4 (0-24 hours), the clause should refer to subtracting the quantity of capacity required for more than 24 hours per year (not 48 hours) from the Reserve Capacity Target. Similar errors occur in clauses 4.5.12(c)(ii)(1) (should be 48 hours rather than 72 hours) and 4.5.12(c)(iii)(1) (should be 72 hours rather than 96 hours). |
| IR127 | L | 4/01/2011 | Monica Tedeschi | 4 | 4.27.10 and 4.27.10A | Progress Reports | Currently the rules state that only facilities which are yet to commence operation have to file progress reports. This excludes upgrades of Facilities. We believe that Facilities which are certified as an upgrade |

| Issue # | Priority | Date Raised | Who | Chapter | Clause | Topic Area | What is this issue? |
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| | | | | | | | should provide progress reports to inform the IMO of their progress as per all new facilities. |
| IR128 | M | 3/02/2011 | Jenny Laidlaw | 7 | 7.13.1(cA) and 9.3.4 | Verve Energy SCADA readings | Clause 9.3.4 defines the Metered Schedule for a Trading Interval for a Facility. Where the Facility does not have interval metering (i.e. some Verve Energy generation Facilities) the values are determined from SCADA data provided by System Management under clause 7.13.1(cA). However, clause 7.13.1(cA) defines this data as "a schedule of the MWh output of each generating system...” System Management sets any negative values to zero, with the result that the Metered Schedules are failing to measure any net consumption at the Facilities. |
| IR130 | M | 8/02/2011 | Monica Tedeschi | 7 | 7.5.4- 7.5.7 | Fuel Declarations | Market Participants who change their fuel on the day are meant to notify System Management and System Management must maintain a record of all notifications. If a Market Participant was cleared in STEM on liquid fuel but on the scheduling day it runs on non-liquid fuel it may have artificially inflated the price. Furthermore, the IMO on occasion receives notification from System Management of any changes to fuel declarations, thus the IMO has barely any visibility of changes in fuel on the scheduling day. |
| IR131 | M | 11/02/2011 | Monica Tedeschi | 4 | 4.23A.4 | Aggregation and Capacity Credits | Clause 4.23A.4 refers to the "original" application for CRC and what was "originally" held by the Registered Facilities. If you read this literally it would mean that the Capacity Credits, CRC and RCOQ's of an aggregated facility must equal what it was at the time of registration. This is a nonsensical outcome as Capacity Credits can change. |
| IR132 | L | 16/02/2011 | Greg Ruthven | 4 | 4.27.3-4.27.9 | Performance Monitoring | Two sets of actions are described for where the number of days with high outages in the past year exceeds 40 days or 80 days. Little consideration of overlap of these. For instance, if number of days exceeds 80, we will immediately apply an additional limit to Planned Outages for a Participant, while also requesting a fresh performance report for that participant. |
| IR133 | L | 16/02/2011 | Greg Ruthven | 4 | 4.27.3-4.27.9 | Performance Monitoring | Where the number of days in the last year with high outages exceeds 40, specific participants must tell the IMO its plan for Planned Outages. If the IMO considers that it is excessive, the IMO may limit their future Planned Outages for refund purposes and the participant may be |

| Issue # | Priority | Date Raised | Who | Chapter | Clause | Topic Area | What is this issue? |
|---|---|---|---|---|---|---|---|
| | | | | | | | penalised if they exceed this value. However, if:<br>• The IMO considers the outage plan is reasonable;<br>• The number of days never exceeds 80 in the future; and<br>• A participant exceeds the number of days of Planned Outage during the next 24 months,<br>the participant is not penalised in the same way. This provides an incentive to fabricate a performance report to avoid any future penalty. |
| IR134 | L | 18/02/2011 | Greg Ruthven | 4 | 4.13 | RC Security | A Market Participant may have two or more Demand Side Programmes commencing operation in the same year with Reserve Capacity Security applicable to all. In the event that the participant fails to fill both/all DSPs, they could assign loads to the first DSP and prove performance to get security back, then reassign loads to the other DSP to get that security back. This would be devalue the Reserve Capacity Security and defeats the intent of protecting against build risk. This is most likely to occur where one participant has more than one Facility commencing in the same year. |
| IR135 | L | 18/02/2011 | Greg Ruthven | 4 | 4.13 | RC Security | Similar to IR134.<br>A Market Participant with a new DSP and at least one existing DSP may fail to procure sufficient capacity to fill all programmes. This participant has incentive to fill new DSP first to get security back and leave existing DSP unfilled. Although the participant would be liable for refunds for the missing capacity, this subverts the intent of the RC security mechanism. |

# Agenda Item 5b: Ancillary Services Payment Equations (PRC_2010_27)

## 1. BACKGROUND

At the November 2010 MAC meeting, the IMO presented the Pre Rule Change Discussion Paper: Ancillary Services Payment Equations (PRC_2010_27). The paper was prepared by ROAM Consulting and based on recommendations contained in its final report to the IMO for the Renewable Energy Generation Working Group[1] (REGWG) Work Package 3: Assessment of FCS and Technical Rules.

During the meeting, MAC members discussed three issues raised in the paper on which decisions were required before the proposal could be progressed further. Since the November 2010 meeting the IMO has made a number of changes to the proposal, based on consideration of:

- the opinions offered by MAC members on the three issues raised in the paper, both at the November 2010 meeting and in the exchange of emails following the meeting;
- issues raised after the presentation of the paper at the November 2010 MAC meeting; and
- issues raised by the IMO's review of the Rule Change Proposal: Cost_LR (RC_2010_33).

The IMO's recommendations and actions around these issues are outlined in the following sections. An updated version of the Pre Rule Change Discussion Paper is attached.

## 2. ISSUES RAISED IN THE PRE RULE CHANGE DISCUSSION PAPER

***Issue 1: Clause 3.14.1 – Inclusion of unintended fluctuations of Scheduled Generators in Load Following Costs (attachment 1 to the original Pre Rule Change Discussion Paper)***

At the November 2010 meeting the MAC accepted the IMO's advice that the magnitude of uninstructed Scheduled Generator fluctuations would be costly to determine and probably small. The MAC agreed that the issue should not be pursued any further at this time. Accordingly, the IMO has removed the references to this issue from PRC_2010_27.

***Issue 2: Clause 3.13.1, 9.7.1 – Capacity Cost for Spinning Reserve (attachment 2 to the original Pre Rule Change Discussion Paper)***

During the discussion of this issue at the November 2010 MAC meeting, the IMO agreed to provide the MAC with an estimate of the financial impact on Market Participants of amending PRC_2010_27 to include a Capacity Cost for Spinning Reserve and therefore allocate the capacity payment to Scheduled Generators.

[1] Additional background to the REG WG can be found at: http://www.imowa.com.au/REGWG

An estimate of the financial impact, prepared by ROAM Consulting at the IMO's request, was distributed to MAC members at the December 2010 meeting. Following a discussion of the information provided, the MAC agreed to the IMO's suggestion to include further consideration of the potential re-allocation of capacity costs for Spinning Reserve in the 2013 Review of Ancillary Services requirements (required under clause 3.15 of the Market Rules). In view of this agreement the IMO has removed the references to this issue from PRC_2010_27.

***Issue 3: Full load, marginal generation payment for Load Following (attachment 3 to the original Pre Rule Change Discussion Paper)***

At the November 2010 meeting MAC members discussed the relative merits of the methodology proposed by ROAM Consulting for the allocation of Load Following costs ("Full Load, Marginal Generation") and the alternative proposed "Proportional Load and Generation" methodology. Under the Full Load, Marginal Generation methodology loads pay the full proportion of their Load Following requirement, while Intermittent Generators pay the additional increment required for their operation. Under the Proportional Load and Generation methodology, the Load Following requirements of loads and Intermittent Generators are assessed separately, and the costs of Load Following are distributed in direct proportion to the individual requirements of each group.

After some discussion of the methodologies, the Chair considered that while Verve Energy supported the Proportional Load and Generation methodology, in general MAC members appeared to be favouring the Full Load, Marginal Generation methodology out of the two methodologies proposed. Mr Andrew Everett offered to circulate some comments explaining Verve Energy's concerns to MAC members for discussion.

Following this meeting Mr Everett, Mr Chin Koay, Mr Corey Dykstra, Mr Stephen MacLean and Dr Steve Gould all sent emails to MAC members outlining their views on the issues around the choice of methodology for the allocation of Load Following costs.

After consideration of all the views expressed the IMO recommends the adoption of the Full Load, Marginal Generation methodology. The IMO considers that the current methodology is in conflict with the principle of "causer pays" and creates a significant cross-subsidy from loads to Intermittent Generators. The IMO agrees with ROAM Consulting that the Full Load, Marginal Generation methodology ensures that the cost allocation to loads for Load Following is unaffected by the extent of Intermittent Generation operating in the SWIS. Under the Proportional Load and Generation methodology, loads would receive a "windfall gain" at the expense of Intermittent Generators, as this methodology ignores the extent to which fluctuations of Intermittent Generators cancel out fluctuations in load. The Full Load, Marginal Generation methodology ensures that Intermittent Generators only pay for the additional Load Following costs that they impose on the SWIS.

## 3. ISSUES RAISED AFTER THE PRESENTATION OF PRC_2010_27

Following the presentation of the Pre Rule Change Discussion Paper at the November 2010 MAC meeting, the IMO discussed a number of issues relating to the proposal with representatives from ROAM Consulting, System Management, Verve Energy, IMO Market Operations and the ERA. A summary of these issues and any recommendations or actions taken is provided below.

***Source, granularity and timing of parameters GTR, FKR and FKR_Loads***

The original paper did not fully explain the source, granularity (e.g. per Trading Interval, Trading Month, Financial Year, etc) or timing (i.e. when the values are to be provided/calculated) of the GTR, FKR and FKR_Loads parameters used in the proposed settlement equations. The IMO has updated PRC_2010_27 to include details of its proposed approach for these parameters, developed after discussions with ROAM Consulting and various internal and external stakeholders, including System Management, Verve Energy, the ERA and Market Operations.

***Impact of full provision of Load Following or Spinning Reserve Service under contract***

During an internal review of the proposal, the IMO identified that the proposed margin value calculations are dependent on the assumption that, for the purposed of modelling:

- the forecast quantity of Load Following Service to be provided under Ancillary Service Contracts (ASCs) never exceeds the total Load Following requirement; and
- the forecast quantity of Spinning Reserve Service to be provided under ASCs never exceeds the total Spinning Reserve requirement.

The IMO considers that this assumption is reasonable, given the issues that exist around the provision of these services through ASCs. PRC_2010_27 has been updated to clarify this assumption and to remove the unnecessary "max(0, xxxx)" terms from the modelling calculations.

***Initial values for Margin_FKR_Peak, Margin_FKR_Off-Peak, Margin_GTR_Peak and Margin_GTR_Off-Peak***

The original version of PRC_2010_27 proposed to use the "current" values of the existing parameters Margin_Peak and Margin_Off-Peak as the initial values for the new parameters Margin_FKR_Peak, Margin_FKR_Off-Peak, Margin_GTR_Peak and Margin_GTR_Off-Peak. To correctly calibrate the current values for the new format equations in clause 9.9.2 (in which the 0.5 MW to MWh conversion factor has been removed), the IMO proposes to use the following initial values for these parameters:

- Margin_Peak * 0.5 for Margin_FKR_Peak and Margin_GTR_Peak; and
- Margin_Off-Peak * 0.5 for Margin_FKR_Off-Peak and Margin_GTR_Off-Peak.

***Load Following cost allocation for solar Intermittent Generators***

Verve Energy suggested that the Load Following cost allocation calculations should be split into separate calculations for Peak and Off-Peak Trading Intervals, and that solar Intermittent Generators should be exempt from any Load Following costs associated with Off-Peak Trading Intervals.

The IMO has not included Verve Energy's suggestion in PRC_2010_27, as it considers that the additional complexity associated with this change is not warranted at this time by the available information on the relative variability of solar Intermittent Generators.

***Enhancements proposed by the ERA***

The ERA suggested the following enhancements:

- the inclusion of a requirement for the IMO to undertake a public consultation process on the assumptions and methodology used to develop the IMO's annual margin value proposal for the ERA; and
- the correction of inconsistencies in the naming of Ancillary Services throughout the Market Rules, e.g. "System Restart" versus "System Restart Service".

The IMO has updated PRC_2010_27 to incorporate these enhancements.

***Minor Drafting Changes***

The IMO has updated the proposed drafting in PRC_2010_27 to further clarify the definitions of various terms and parameters and to correct a number of minor typographical and cross-referencing errors.

## 4. RC_2010_33: COST_LR

PRC_2010_27 affects several clauses to which amendments have been proposed in the Rule Change Proposal: Cost_LR (RC_2010_33) and in the Draft Rule Change Report for that proposal. In addition, two new clauses (9.9.3A and 9.9.3B) have been proposed as part of RC_2010_33, which will require amendments to reflect the renaming of Load Following and Spinning Reserve to Frequency Keeping and Generator Trip Reserve.

The IMO has updated PRC_2010_27 to incorporate the relevant changes from the Draft Rule Change Report for RC_2010_33. Comments have been included to indicate those amendments proposed under RC_2010_33. Note that some of the additional minor and typographical amendments proposed in the Draft Rule Change Report for RC_2010_33 were originally proposed as part of PRC_2010_27.

## 5. INDEPENDENT REVIEW OF EQUATIONS CONTAINED IN PRC_2010_27

As PRC_2010_27 contains a large number of equations, the IMO is commissioning an independent review of the drafting to ensure that the equations make mathematical sense and achieve what is intended.

## 6. RECOMMENDATIONS

The IMO recommends that the MAC:

- **Discuss** the Ancillary Services Payment Equations Pre Rule Change paper.

Independent Market Operator

# Agenda item 5b, appendix 1:

# Wholesale Electricity Market
# Pre Rule Change Discussion Paper

**Change Proposal No:** PRC_2010_27
**Received date:**

**Change requested by:**

| | |
|---|---|
| **Name:** | Troy Forward |
| **Phone:** | (08) 9254 4304 |
| **Fax:** | (08) 9254 4399 |
| **Email:** | Troy.forward@imowa.com.au |
| **Organisation:** | Independent Market Operator |
| **Address:** | Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth |
| **Date submitted:** | TBA |
| **Urgency:** | Standard Rule Change Process |
| **Change Proposal title:** | Ancillary Services Payment Equations |
| **Market Rules affected:** | 2.30A, 2.30A.1, 2.30A.2, 2.30A.3, 2.30A.4, 2.30A.5, 2.30A.6, 3.4.1, 3.9.1, 3.9.2, 3.9.3, 3.10.1, 3.10.1A (new), 3.10.2, 3.10.2A (new), 3.10.5, 3.11.4, 3.11.8, 3.11.8A, 3.11.8B, 3.13.1, 3.13.3, 3.13.3A, 3.13.3B, 3.13.3C, 3.13.3D (new), 3.14.1, 3.14.2, 3.14.3, 3.18.11A, 3.22.1, 3.22.1A (new), 3.22.2, 3.22.3, 3.22.4 (new), 3.22.5 (new), 3.22.6 (new), 4.5.12, 6.3A.2, 6.17.6, 7.2.3A, 9.7.1, 9.9.1, 9.9.1A, 9.9.2, 9.9.3, 9.9.3A (new), 9.9.3B (new), 9.9.4, 10.5.1, the Glossary, Appendix 1 and Appendix 2. |

## Introduction

Clause 2.5.1 of the Wholesale Electricity Market Rules (Market Rules) provides that any person (including the Independent Market Operator (IMO)) may make a Rule Change Proposal by submitting a completed Rule Change Proposal form to the IMO.

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

> **Independent Market Operator**
> Attn: General Manager, Development
> 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 proposal must explain how it will enable the Market Rules to better contribute to the achievement of the wholesale electricity market objectives. The objectives of the market are:

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

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

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

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

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

## Details of the proposed Market Rule Change

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

**BACKGROUND**

Ancillary Services are used to support the safe, secure and reliable production of electricity on the South West interconnected system (SWIS) by ensuring the system can adequately respond to real time changes in load and generation under a range of scenarios. Ancillary Services are used to control key technical characteristics of the power system such as frequency and voltage. Specifically, Ancillary Services:

- help maintain Power System Reliability (the ability of the SWIS to deliver energy within reliability standards);
- help maintain Power System Security (the ability of the SWIS to withstand sudden disturbances including restoration in the case of blackout);
- ensure that electricity supplies are of acceptable quality; and
- facilitate orderly trading in electricity.

Ancillary Services are required to support the Wholesale Electricity Market (WEM) but are not traded as part of the WEM. The Market Rules require that System Management is procure adequate quantities of these services, either from Verve Energy resources (the default option) or on a contestable basis from independent providers (if they provide a least cost option to Verve Energy's Facilities).

## Definition of Ancillary Services

The Market Rules identify the following as Ancillary Services in the WEM:

- Load Following Service;
- Spinning Reserve Service;
- Load Rejection Reserve Service;
- System Restart Service; and
- Dispatch Support Service.

This Rule Change Proposal addresses the first two services.

The Load Following requirement is described in the Market Rules (clause 3.10.1) as arising from:

- short term fluctuations in load;
- short term fluctuations in the output of Non-Scheduled Generators (mainly Intermittent Generators); and
- uninstructed output fluctuations from Scheduled Generators.

Analysis has indicated that the uninstructed output fluctuations from Scheduled Generators are likely to be small in comparison with Load and Intermittent Generator fluctuations.

The Spinning Reserve requirement is specified in the Market Rules (clause 3.10.2) to meet:

- generator trips; and
- expected maximum ramping up and ramping down of Loads over a 15 minute period.

The generator trip requirement dominates the specification for Spinning Reserve.

As a synchronised Scheduled Generator can meet the requirements for both Load Following Service and Spinning Reserve Service, these requirements are combined such that capacity providing Load Following is counted as also meeting the Spinning Reserve requirement (clause 3.10.2(b)). Currently, the Spinning Reserve requirement exceeds the Load Following requirement, and Interruptible Loads and slower-response thermal units are used to meet part of the Spinning Reserve requirement. These two supplies are not suitable for Load Following Service.

## Existing Calculation of Load Following Service Costs

The total cost of the Load Following Service, as defined in the Market Rules, is composed of a capacity cost and an availability cost (clause 3.13.1). This can be summarised as:

$$\text{Total Cost}_{\text{LF}} = \text{Capacity Cost}_{\text{LF}} + \text{Availability Cost}_{\text{LF}}$$

**Equation 1**

where the capacity cost is calculated as the Reserve Capacity Price, multiplied by the Load Following requirement determined[1] to be needed in that Trading Month:

$$\text{Capacity Cost}_{\text{LF}} = \text{Reserve Capacity Price} \times \text{LF Requirement}$$

**Equation 2**

The Reserve Capacity Price is determined via the Reserve Capacity Auction, or if no auction is run it is 85 percent of the Maximum Reserve Capacity Price reduced by an excess capacity adjustment.

The availability cost of providing Load Following Service is defined in clause 9.9.2 of the Market Rules. It is calculated as the total availability cost for Load Following Service and Spinning Reserve Service, minus the availability cost for providing Spinning Reserve Service.

$$\text{Availability Cost}_{\text{LF}} = \text{Total Availability Cost} - \text{Availability Cost}_{\text{SR}}$$

**Equation 3**

The total availability cost is given by:

$$\begin{aligned}\text{Total Availability Cost} &= 0.5 \times \left[\text{M}_{p} \times \sum_{t=p} \text{MCAP} \times \left(\text{SR Requirement}_{p} - \text{SR provided}_{\text{contracts}}\right)\right] \\ +0.5 \times &\left[\text{M}_{op} \times \sum_{t=op} \text{MCAP} \times \left(\text{SR Requirement}_{op} - \text{SR provided}_{\text{contracts}}\right)\right] + \text{Contracts}_{\text{SR}} \\ &+ \text{Contracts}_{\text{LF}}\end{aligned}$$

**Equation 4**

Where:

| | | |
|---|---|---|
| t | = | Time (applying in each Trading Interval) |
| p | = | Applying to Peak Trading Intervals |
| op | = | Applying to Off-Peak Trading Intervals |
| $M_{p(op)}$ | = | Reserve availability payment margin applying for Peak (Off-Peak) Trading Intervals. This reflects the margin applied to MCAP which is paid to Verve Energy for being available to provide Load Following Service and Spinning Reserve Service during Peak (Off-Peak) Trading Intervals. |
| MCAP | = | Marginal Cost Administered Price, $/MWh calculated two Business Days after the relevant Trading Day (defined in each Trading Interval t). |

[1] As determined annually by System Management in accordance with clause 3.11 of the Market Rules

| | | |
|---|---|---|
| SR Requirement$_{p(op)}$ | = | Capacity necessary for Spinning Reserve in Peak (Off-Peak) Trading Intervals. |
| SR provided$_{contracts}$ | = | Quantity of Spinning Reserve provided by all contracted Ancillary Service providers in the relevant Trading Interval. Does not include Spinning Reserve provided by Verve Energy plant. |
| Contracts$_{SR}$ | = | Sum of all payments under Ancillary Service Contracts for Spinning Reserve Service. |
| Contracts$_{LF}$ | = | Sum of all payments under Ancillary Service Contracts for Load Following Service. |

In the limiting case where there are no contracts (all Spinning Reserve and Load Following Service is provided by Verve Energy):

$$\text{Total Availability Cost} = 0.5 \times \left[\mathrm{M}_p \times \sum_{t=p} \mathrm{MCAP} \times \left(\text{SR Requirement}_p\right)\right] + 0.5 \times \left[\mathrm{M}_{op} \times \sum_{t=op} \mathrm{MCAP} \times \left(\text{SR Requirement}_{op}\right)\right]$$

**Equation 5**

The availability cost of Spinning Reserve Service is given by:

$$\text{Availability Cost}_{\mathrm{SR}} =$$

$$0.5 \times \left[M_p \times \sum_{t=p} \mathrm{MCAP} \times \left(\text{SR Requirement}_p - \text{SR provided}_{\text{contracts}} - 0.5 \times \text{LF Requirement}\right)\right]$$

$$+ 0.5 \times \left[M_{op} \times \sum_{t=op} \mathrm{MCAP} \times \left(\text{SR Requirement}_{op} - \text{SR provided}_{\text{contracts}} - 0.5 \times \text{LF Requirement}\right)\right] + \text{Contracts}_{SR}$$

**Equation 6**

By subtraction, the availability cost of Load Following Service is therefore given by:

$$\text{Availability cost}_{LF} = 0.5 \times \left[ M_p \times \sum_{t=p} \text{MCAP} \times (0.5 \times \text{LF Requirement}) \right] + 0.5 \times \left[ M_{op} \times \sum_{t=op} \text{MCAP} \times (0.5 \times \text{LF Requirement}) \right] + \text{Contracts}_{LF}$$

**Equation 7**

$M_p$ and $M_{op}$ (Margin_Peak and Margin_Off-Peak) are re-calibrated regularly via a simulation process to calculate the cost to Verve Energy of providing the combined Spinning Reserve and Load Following Service (outlined in clause 3.13.3A).

The intention of this methodology appears to be to assume that over a small range the availability cost of Load Following Service will be directly proportional to MCAP (the system price in $/MWh) and the size of the Load Following requirement (in MW). The Margin_Peak and Margin_Off-Peak values are used to calibrate the cost to the correct range, which is then adjusted for minor differences in MCAP or the size of the Load Following requirement.

The Spinning Reserve Service is treated similarly, with the assumption that over a small range the availability cost of Spinning Reserve Service will be directly proportional to MCAP and the size of the Spinning Reserve requirement.

This methodology allows for a forecast of the cost (used to calibrate Margin_Peak and Margin_Off-Peak) to be adjusted for minor differences in the price outcome, or the size of the Load Following and Spinning Reserve requirements, where in the actual operation of the market these may differ from the assumptions used in the original simulation.

**Recovery of costs for Load Following Service**

In recovering the cost for Load Following Service, Loads and Intermittent Generators carry a proportional share on an energy consumed and energy sent out basis of the total Load Following requirement (defined in clause 3.14.1). Since Loads consume a much larger quantity of energy than Intermittent Generators produce this means that the majority of the Load Following Service cost is borne by Loads.

**MAJOR ISSUES**

The existing design of the Market Rules exhibits the following flaws:

| Clause | Issue | Proposed solution |
|---|---|---|
| 9.9.2 | **Load Following requirement exceeding Spinning Reserve requirement -** The existing equations do not allow for the situation where the Load Following requirement exceeds the Spinning Reserve requirement, which is likely to occur | Clause 9.9.2 has been re-drafted to address this issue. The proposed formulation of this equation will transition appropriately as the Load |

| Clause | Issue | Proposed solution |
|---|---|---|
| | within the next few years due to the entry of several new wind farms.<br><br>Under the existing methodology half of the cost of the Load Following Service is paid for by Market Participants liable for the cost of Spinning Reserve Service. This is not a fair or equitable distribution of costs, especially in the case where the Load Following requirement exceeds the Spinning Reserve requirement. | Following requirement increases and eventually exceeds the Spinning Reserve requirement. |
| 9.9.2 | **Size of Load Following requirement** - The total availability cost defined in the Market Rules for the combined Spinning Reserve and Load Following Services does not refer to the size of the Load Following requirement. This means that as the size of the Load Following requirement increases (and the actual cost of providing the service increases) the total availability cost recovered from Market Participants (and paid to Verve Energy for providing this service) does not increase. | Clause 9.9.2 has been re-drafted to address this issue. |
| 9.9.2 | **Load Following from Contracts -** The expression to calculate the total availability cost does not include a term accounting for any Load Following/Spinning Reserve capacity provided through Ancillary Service Contracts for Load Following Service. For example, if an Ancillary Service Contract for 20 MW of Load Following Service existed, then Verve Energy would not need to provide this 20 MW of capacity and so its availability payment should be reduced. However, while the current equations would increase the total availability cost by the amount paid under the Ancillary Service Contract, the amount to be paid to Verve Energy would be unchanged, as it would still be paid for the same MW capacity amount. | Clause 9.9.2 has been re-drafted to address this issue. |
| 9.9.2, 3.13.3, 3.13.3A, 3.13.3D | **Marginal cost of Load Following and Spinning Reserve -** The equations for determining the cost of providing the Spinning Reserve and Load Following Services assume that the marginal cost of providing these services (Load Following and Spinning Reserve) is the same (the same calibration factors, Margin_Peak and Margin_Off-Peak are applied to both). Dispatch modelling indicates that this is likely to be a poor approximation[2], and is likely to lead to the costs of these services being distributed unfairly between | Clauses 9.9.2, 3.13.3 and 3.13.3A have been re-drafted to address this issue. Individual Margin_Peak and Margin_Off-Peak values have been defined for Load Following and Spinning Reserve. New clause 3.13.3D has been developed to define these terms accurately, including the |

[2] ROAM Consulting report to the Independent Market Operator, "Assessment of FCS and Technical Rules", July 2010.

| Clause | Issue | Proposed solution |
|---|---|---|
| | Market Participants. | process for their calibration. |
| 9.9.2, 3.13.3, 3.13.3A, 3.13.3D | **Cost of Load Following split equally between Market Participants liable for the costs of Load Following Service and Spinning Reserve Service** - The existing equations split the cost of providing the Load Following Service equally between Market Participants liable for the costs of Load Following Service and Market Participants liable for the costs of Spinning Reserve Service. This is not a fair distribution of costs, particularly in the case where the two services have different marginal costs. | Clause 9.9.2 has been re-drafted to address this issue. The costs of each service are calculated and calibrated separately using individual Margin_Peak and Margin_Off-Peak values (defined in clauses 3.13.3, 3.13.3A and 3.13.3D).<br><br>New parameters have been defined to accurately calibrate the cost "saving" that is derived from the dual use of Load Following plant for Spinning Reserve Service (Savings_Cal_Peak and Savings_Cal_Off-Peak), and to allocate this cost saving to Market Participants liable for Load Following and Spinning Reserve Services (Savings_Alloc_Peak and Savings_Alloc_Off-Peak). These are defined in clauses 3.13.3, 3.13.3A and 3.13.3D. |
| 3.14.1 | **Distribution of Load Following Service costs between Intermittent Generators and Loads** - As consistently identified by System Management[3] and supported by findings by ROAM Consulting[4], Intermittent Generators contribute more to the Load Following requirement than do Loads. In 2007/08 the fluctuations caused by Loads alone was -28/+24 MW, and for the Intermittent Generators alone was -58/+59 MW. In 2008/09 the fluctuations caused by Loads alone was -35/+36 MW and for the Intermittent Generators alone was -48/+53 MW. However, the methodology for sharing the cost of the Load Following Service in the existing rules attributes the majority of the cost of the Load Following Service to Loads. | Clause 3.14.1 has been re-drafted to address this issue. The distribution of costs between Intermittent Generators (in aggregate) and Loads (in aggregate) has been redefined in terms of their respective Load Following requirements. |

[3] Western Power, Ancillary Service Report prepared under clause 3.11.11 of the Market Rules by System Management, 2008, 2009.

[4] ROAM Consulting report to the Independent Market Operator, "Assessment of FCS and Technical Rules", July 2010.

## MINOR ISSUES

| Clause | Issue | Proposed solution |
|---|---|---|
| General | As the proportion of intermittent generation in the Market increases, the Load Following Service will increasingly be related to the fluctuations in the output of Intermittent Generators (rather than fluctuations in the load). Referring to this service by the name "Load Following" is therefore misleading. | The name "Load Following" has been changed to "Frequency Keeping". This is also reflected in the terms used as abbreviations in equations, with the abbreviation "FKR" replacing the abbreviation “LF”. |
| General | The standard for the Spinning Reserve Service is defined as being sufficient to cover generator trips, and also to cover the maximum load ramp expected over a period of 15 minutes. However, the Spinning Reserve requirement is dominated by the generator trip condition, and the maximum load ramp is very likely to be covered by the Load Following Service definition in the existing rules (clause 3.10.1). Additionally, Loads do not contribute to the payment for the Spinning Reserve Service (but do contribute to the payment for the Load Following Service). | The name "Spinning Reserve" has been changed into "Generator Trip Reserve". Clause 3.10.2 has been adjusted such that the Generator Trip Reserve Service covers only generator trips, with the load ramping over 15 minutes being covered by the combination of the Load Following Service and the Spinning Reserve Service (now covered in clause 3.10.2A). |
| General | There are inconsistencies in the naming of Ancillary Services throughout the Market Rules, e.g. “System Restart” vs “System Restart Service”. | This has been corrected, so that all service names include the word “Service”. |
| General | A number of terms are defined for use in equations by misleading names.<br>• Capacity_LF is the capacity cost of Load Following Service (rather than the capacity of Load Following required)<br>• Capacity_R_Peak and Capacity R_Off-Peak are the capacity of Spinning Reserve required in Peak and Off-Peak Trading Intervals respectively (rather than the capacity cost of Spinning Reserve Service)<br>• Reserve_Cost_Share refers specifically to the cost share of the Spinning Reserve Service (and does not include the Load Following Service). | • Capacity_LF has been changed to Capacity_Cost_FKR.<br>• Capacity_R_Peak and Capacity_R_Off-Peak have been replaced by GTR_Peak and GTR_Off-Peak.<br>• Reserve_Cost_Share has been changed to GTR_Cost_Share. |
| 3.10.1 | The relationship between the Minimum Frequency Keeping Capacity and the Load Following requirement is unclear. | This has been made more explicit in clause 3.10.1 and the proposed new clause 3.10.1A. |
| 3.13.3A | The ERA has requested that the IMO undertake a public consultation process on the assumptions and methodology used to | Clause 3.13.3A has been re-drafted to include this requirement. |

| Clause | Issue | Proposed solution |
|---|---|---|
| | develop the IMO's annual margin value proposal for the ERA. | |
| 3.13.3D | The methodology for calibrating Margin_Peak and Margin_Off-Peak is poorly defined in the Rules. This is an important procedure that determines the magnitude of payments for Load Following Service and Spinning Reserve Service. | The calibration procedure for the margin values is now outlined in more detail in the new clause 3.13.3D. |
| 3.22.2, 3.22.3, 9.9.1, 9.9.1A, 9.9.2, 9.9.3, 9.9.3A, 9.9.3B, 9.9.4, Glossary | This Rule Change Proposal affects several clauses to which amendments have been proposed in the Rule Change Proposal: Cost_LR (RC_2010_33)[5] and in the Draft Rule Change Report for that proposal. In addition, two new clauses (9.9.3A and 9.9.3B) have been proposed as part of RC_2010_33, which will require amendments to reflect the renaming of Load Following and Spinning Reserve to Frequency Keeping and Generator Trip Reserve. | The proposed amendments incorporate the relevant changes from the Draft Rule Change Report for RC_2010_33. Comments have been used to indicate those amendments proposed under RC_2010_33. |
| 9.9.2 | Owing to the calibration of the Margin_Peak and Margin_Off-Peak values the factor of 0.5 multiplied by the Margin_Peak and Margin_Off-Peak values in the clause 9.9.2 calculations is superfluous. | The factor of 0.5 has been removed from clause 9.9.2. |

[5] See: http://www.imowa.com.au/RC_2010_33

## PROPOSED CHANGES TO AVAILABILITY COST CALCULATIONS

This section outlines the theory behind the proposed amendments to clauses 9.9.2, 3.13.3, 3.13.3A and the new clause 3.13.3D.

### Calibration of the Margins

The margins and factors used in the calculation of availability costs of Spinning Reserve Service and Load Following Service need to be re-calibrated regularly. The following process is proposed.

Consider a single period t, and for the purposes of illustration let t be a Peak Trading Interval. We seek to write an expression for the availability cost to Verve Energy of providing only the Load Following Service in Trading Interval t (in excess of Load Following Service provided by Ancillary Service Contracts, and not providing any Spinning Reserve Service).

As in the existing methodology, over a small range the availability cost of Load Following to Verve Energy in the Trading Interval t is assumed to scale linearly with MCAP (in $/MWh) and the Load Following requirement (in MW), with the constant of proportionality ($\text{Margin_LF}_p$) giving the correct scaling of the total cost (this factor is to be determined through a calibration process outlined below).

Therefore, the availability cost to the Verve Energy ("EGC" in the following equations) of providing only the Load Following Service in Trading Interval t can be expressed as:

$$\begin{aligned}\text{Availability\_Cost\_LF\_EGC}(t) &= \text{Margin\_LF}_p \times MCAP_{\text{LF}}(t) \\ &\times \left(\text{LF Requirement} - \text{LF provided contracts}_p(t)\right)\end{aligned}$$

**Equation 8**

Consequently, the total availability cost to Verve Energy of providing the Load Following Service in Peak Trading Intervals would be given by the sum of Equation 8 over all Peak Trading Intervals:

$$\begin{aligned}\text{Availability\_Cost\_LF\_EGC}_p &= \text{Margin\_LF}_p \\ &\times \sum_{t=p}\left[MCAP_{\text{LF}}(t) \times \left(\text{LF Requirement} - \text{LF provided contracts}_p(t)\right)\right]\end{aligned}$$

**Equation 9**

The same will be true for Off-Peak Trading Intervals, so the notation below can be applied to refer to the relevant case as required:

$$\begin{aligned}\text{Availability\_Cost\_LF\_EGC}_{p(op)} &= \text{Margin\_LF}_{p(op)} \\ &\times \sum_{t=p(op)}\left[MCAP_{\text{LF}}(t)\right. \\ &\times \left.\left(\text{LF Requirement} - \text{LF provided contracts}_{p(op)}(t)\right)\right]\end{aligned}$$

**Equation 10**

The margin for Load Following Service for Peak and Off-Peak Trading Intervals can therefore be calculated as a rearrangement of this equation:

$$\text{Margin\_LF}_{p(op)} = \frac{\text{Availability\_Cost\_LF\_EGC}_{p(op)}}{\sum_{t=p(op)}\left[MCAP_{\text{LF}}(t) \times \left(\text{LF Requirement} - \text{LF provided contracts}_{p(op)}(t)\right)\right]}$$

**Equation 11**

where the availability cost of Load Following Service to Verve Energy has been forecast via an appropriate method (such as dispatch modelling).

Similarly for Spinning Reserve Service, the availability cost of Spinning Reserve Service to Verve Energy is assumed to scale linearly with MCAP and the Spinning Reserve requirement, with the constant of proportionality ($\text{Margin\_SR}_{p(op)}$) to be determined. Therefore, if only Spinning Reserve Service was being provided by Verve Energy the total availability cost to Verve Energy of providing the Spinning Reserve Service would be given by:

$$\text{Availability\_Cost\_SR\_EGC}_{p(op)} = \text{Margin\_SR}_{p(op)} \times \sum_{t=p(op)}\left[MCAP_{\text{SR}}(t) \times \left(\text{SR Requirement}_{p(op)} - \text{SR provided contracts}_{p(op)}(t)\right)\right]$$

**Equation 12**

(Note that the Spinning Reserve requirement is assumed to differ between Peak and Off-Peak Trading Intervals.) The margin for Spinning Reserve Service for Peak and Off-Peak Trading Intervals can therefore be calculated as a rearrangement of this equation:

$$\text{Margin\_SR}_{p(op)} = \frac{\text{Availability\_Cost\_SR\_EGC}_{p(op)}}{\sum_{t=p(op)}\left[MCAP_{\text{SR}}(t) \times \left(\text{SR Requirement}_{p(op)} - \text{SR provided contracts}_{p(op)}(t)\right)\right]}$$

**Equation 13**

where the availability cost of Load Following Service to Verve Energy has been forecast via an appropriate method (such as dispatch modelling).

**Quantifying the magnitude of the saving**

There will be a "cost saving" obtained through the dual use of Load Following plant to simultaneously provide Spinning Reserve Service. It is important to accurately quantify this saving so that it can be distributed to Market Participants in an equitable manner.

In the case where the Load Following capacity provided by Verve Energy is larger than the Spinning Reserve capacity provided by Verve Energy, the "cost saving" will be equal to the availability cost of Spinning Reserve Service (to Verve Energy), since this service can be entirely provided by Load Following plant.

In the case where the Spinning Reserve capacity provided by Verve Energy is larger than the Load Following capacity provided by Verve Energy, the saving can be quantified in the following way. By operating an additional 1 MW of Load Following capacity, the operation of 1 MW of Spinning Reserve plant can be avoided, increasing the magnitude of the saving. Therefore, following the existing methodology, over a small range the total saving is assumed to be directly proportional to MCAP, $\text{Margin\_SR}_{p(op)}$ and the Load Following requirement, and is calibrated by the factor $\text{Savings\_Cal}_{p(op)}$ (equivalent in nature to Margin_Peak and Margin_Off-Peak). The total saving can therefore be expressed as:

$$\begin{aligned}\text{Savings}_{p(op)} = {} & \text{Savings\_Cal}_{p(op)} \times \text{Margin\_SR}_{p(op)} \\ & \times \sum_{t=p(op)} \Big[ MCAP_{\text{TOT}}(t) \\ & \times \big(\text{LF Requirement} - \text{LF provided contracts}_{p(op)}(t)\big)\Big]\end{aligned}$$

**Equation 14**

The magnitude of the saving is assumed to scale linearly with MCAP, $\text{Margin\_SR}_{p(op)}$ and the Load Following requirement because:

- If MCAP increases, the saving increases proportionally (since the costs of providing each service alone are assumed to increase in proportion to MCAP, as does the cost of providing both services together. This means that the difference between these values also scales by the same factor).
- If the Load Following requirement increases by 1 MW, 1 MW less of Spinning Reserve is required. This produces a saving that is proportional to $\text{Margin\_SR}_{p(op)}$, since $\text{Margin\_SR}_{p(op)}$ gives a measure of the marginal cost of Spinning Reserve.

This assumption of linear scaling in these factors is likely to only be valid over a relatively small range, which makes regular re-calibration of all these factors essential (as was required in the existing equations for Margin_Peak and Margin_Off-Peak).

The cost saving obtained through dual use of Load Following plant to provide Spinning Reserve Service can also be expressed as:

$$\begin{aligned}\text{Savings}_{p(op)} = {} & \big(\text{Availability\_Cost\_LF\_EGC}_{p(op)} + \text{Availability\_Cost\_SR\_EGC}_{p(op)}\big) \\ & - \text{Availability\_Cost\_Total\_EGC}_{p(op)}\end{aligned}$$

**Equation 15**

Where $\text{Availability\_Cost\_Total\_EGC}_{p(op)}$ is the cost to Verve Energy of providing both the Load Following Service and the Spinning Reserve Service simultaneously (forecast via dispatch simulation, for example). Combining Equation 14 and Equation 15,, $\text{Savings\_Cal}_{p(op)}$ is therefore determined as follows:

$$\text{Savings\_Cal}_{p(op)} = \frac{\big(\text{Availability\_Cost\_LF\_EGC}_{p(op)} + \text{Availability\_Cost\_SR\_EGC}_{p(op)}\big) - \text{Availability\_Cost\_Total\_EGC}_{p(op)}}{\text{Margin\_SR}_{p(op)} \times \sum_{t=p(op)} \big[MCAP_{\text{TOT}}(t) \times \big(\text{LF Requirement} - \text{LF provided contracts}_{p(op)}(t)\big)\big]}$$

**Equation 16**

## Allocating the saving between Load Following and Spinning Reserve

Once the magnitude of the saving is determined (through the use of $\text{Savings\_Cal}_{p(op)}$), it must be allocated in an equitable and fair manner to Market Participants. It is proposed that the factor $\text{Savings\_Alloc}_{p(op)}$ is defined and used for this purpose.

It is proposed that the saving is allocated based upon the relative magnitude of the total costs to Verve Energy of providing the Load Following and Spinning Reserve Services. If providing Load Following Service has a much higher total cost than providing Spinning Reserve Service (either due to a larger Load Following capacity, or a higher per MW cost) then a larger proportion of the saving will be allocated to parties liable for the Load Following Service. Similarly if the total cost of providing the Spinning Reserve Service is larger than the total cost of providing the Load Following Service then a larger proportion of the saving will be allocated to the Market Participants liable for the costs of the Spinning Reserve Service. This allocation is considered more equitable than a 50 percent allocation, since it is proportionate to the relative costs of the two services.

To allocate the savings in this way, $\text{Savings\_Alloc}_{p(op)}$ is defined as the proportion of the saving that is allocated to Market Participants liable for Load Following Service, and is calculated in this way:

$$\text{Savings\_Alloc}_{p(op)} = \frac{\text{Availability\_Cost\_LF\_EGC}_{p(op)}}{\text{Availability\_Cost\_LF\_EGC}_{p(op)} + \text{Availability\_Cost\_SR\_EGC}_{p(op)}}$$

**Equation 17**

Participants liable for Spinning Reserve Service receive the remaining proportion of the saving (1 - $\text{Savings\_Alloc}_{p(op)}$). If $\text{Savings\_Alloc}_{p(op)} = 0$ the full saving goes to Market Participants liable for the costs of Spinning Reserve Service, and Market Participants liable for the costs of Load Following Service pay the full proportion of their costs. If $\text{Savings\_Alloc}_{p(op)} = 1$, the full saving goes to Market Participants liable for the costs of Load Following Service, and Market Participants liable for the costs of Spinning Reserve Service pay the full proportion of their costs.

Importantly, via this methodology neither group of Market Participants (those liable for Spinning Reserve Service or those liable for Load Following Service) can be required to pay for the other service (as can occur under the existing methodology). Instead, they share the saving that comes from dual use of plant to provide both services simultaneously. This is an important correction from the previous methodology.

## Calculating Availability Payments

With the margins and other factors defined and calculated through the calibration process, the availability payments to Verve Energy for Spinning Reserve Service and Load Following Service can be determined.

As in the existing methodology, the total availability payment is the sum of payments for Load Following Service and Spinning Reserve Service. Splitting these into Peak and Off-Peak components yields the equation below.

$$\text{Total Availability payment} = \text{Availability payment\_LF\_EGC}_{\text{p}} + \text{Availability payment\_LF\_EGC}_{\text{op}} + \text{Availability payment\_SR\_EGC}_{\text{p}} + \text{Availability payment\_SR\_EGC}_{\text{op}} + \text{Contracts}_{\text{LF}} + \text{Contracts}_{SR}$$

**Equation 18**

where:

| | | |
|---|---|---|
| Availability payment_LF_$EGC_{p(op)}$ | = | Payment to Verve Energy for Load Following Service in Peak (Off-Peak) periods by parties liable for costs of Load Following Service. |
| Availability payment_SR_$EGC_{p(op)}$ | = | Payment to Verve Energy for Spinning Reserve Service in Peak (Off-Peak) periods by parties liable for costs of Spinning Reserve Service. |
| $Contracts_{LF}$ | = | Total payments under Ancillary Service Contracts for Load Following Service. |
| $Contracts_{SR}$ | = | Total payments under Ancillary Service Contracts for Spinning Reserve Service. |

The appropriate equations to calculate each of these components are outlined below, for the case where the Spinning Reserve requirement exceeds the Load Following requirement and vice versa. Note that it is possible for the Spinning Reserve requirement to exceed the Load Following requirement in some periods, but be lower in other periods. In this case, the appropriate calculation should be used for each Trading Interval as required. This is included in the proposed amendments through the use of multiple terms with a sum that does not apply if the alternative form of the equation (included in a different term) is required.

**Cases for consideration**

Four different categories of Trading Intervals must be considered for the calculation of availability payments for Spinning Reserve Service and Load Following Service to Verve Energy:

- ***Category 1*** - Peak Trading Intervals, where the Spinning Reserve capacity provided by Verve Energy exceeds the Load Following capacity provided by Verve Energy;
- ***Category 2*** - Off-Peak Trading Intervals, where the Spinning Reserve capacity provided by Verve Energy exceeds the Load Following capacity provided by Verve Energy;
- ***Category 3 -*** Peak Trading Intervals, where the Load Following capacity provided by Verve Energy exceeds or equals the Spinning Reserve capacity provided by Verve Energy; and
- ***Category 4*** - Off-Peak Trading Intervals, where the Load Following capacity provided by Verve Energy exceeds or equals the Spinning Reserve capacity provided by Verve Energy.

Note that each Trading Interval falls into one of these categories uniquely. In the proposed methodology the availability payment for each category is calculated and summed to give the total availability payment for the relevant service (Spinning Reserve or Load Following) to

Verve Energy. Payments under contracts (to Rule Participants other than Verve Energy) are then added to give the total availability payments for each service.

The following sections outline the methodology for calculating the availability payments to Verve Energy within each of these categories.

**Categories 1 and 2 - Spinning Reserve capacity provided by Verve Energy exceeds Load Following capacity provided by Verve Energy**

The availability payment for Load Following Service in Peak (or Off-Peak) Trading Intervals when the Spinning Reserve capacity provided by Verve Energy exceeds the Load Following capacity provided by Verve Energy is given by the total cost of providing the Load Following Service in the absence of the Spinning Reserve Service (discussed earlier and shown in Equation 10) minus a proportion of the saving obtained through the dual use of plant to provide both services:

$$\text{Availability payment\_LF\_EGC}_{p(op)} = \text{Margin\_LF}_{p(op)} \times \sum_{t=p(op)} \left[MCAP(t) \times \left(\text{LF Requirement} - \text{LF provided contracts}_{p(op)}(t)\right)\right] - \text{Savings\_LF}_{p(op)}$$

**Equation 19**

The magnitude of the saving allocated to Market Participants liable for Load Following Service is given by Savings_Alloc$_{p(op)}$ multiplied by the total saving (given in Equation 14):

$$\text{Savings\_LF}_{p(op)} = \text{Savings\_Alloc}_{p(op)} \times \text{Savings\_Cal}_{p(op)} \times \text{Margin\_SR}_{p(op)} \times \sum_{t=p(op)} \left[MCAP(t) \times \left(\text{LF Requirement} - \text{LF provided contracts}_{p(op)}(t)\right)\right]$$

**Equation 20**

Combining Equation 19 and Equation 20 gives the expression for the availability payments to Verve Energy for Load Following Service:

$$\text{Availability payment\_LF\_EGC}_{p(op)} = \left(\text{Margin\_LF}_{p(op)} - \text{Savings\_Alloc}_{p(op)} \times \text{Savings\_Cal}_{p(op)} \times \text{Margin\_SR}_{p(op)}\right) \times \sum_{t=p(op)} \left[MCAP(t) \times \left(\text{LF Requirement} - \text{LF provided contracts}_{p(op)}(t)\right)\right]$$

**Equation 21**

The availability payment to Verve Energy for Spinning Reserve Service in Peak (or Off-Peak) Trading Intervals is given by the total cost of providing the Spinning Reserve Service in the absence of the Load Following Service (given in Equation 12) minus a proportion of the saving obtained through the dual use of plant to provide both services:

$$
\begin{aligned}
\text{Availability payment\_SR\_EGC}_{p(op)} &\\
&= \text{Margin\_SR}_{p(op)} \\
&\times \sum_{t=p(op)} \Big[MCAP(t) \\
&\times \left(\text{SR Requirement}_{p(op)} - \text{SR provided contracts}_{p(op)}(t)\right)\Big] \\
&- \text{Savings\_SR}_{p(op)}
\end{aligned}
$$

**Equation 22**

The magnitude of the saving allocated to Market Participants liable for the Spinning Reserve Service is given by (1 - $\text{Savings\_Alloc}_{p(op)}$) multiplied by the total saving (given in Equation 14):

$$
\begin{aligned}
\text{Savings\_SR}_{p(op)} &\\
&= (1 - \text{Savings\_Alloc}_{p(op)}) \times \text{Savings\_Cal}_{p(op)} \times \text{Margin\_SR}_{p(op)} \\
&\times \sum_{t=p(op)} \left[MCAP(\text{t}) \times \left(\text{LF Requirement} - \text{LF provided contracts}_{p(op)}(t)\right)\right]
\end{aligned}
$$

**Equation 23**

Combining the two previous equations gives the expression for the availability payments to Verve Energy for Spinning Reserve Service:

$$
\begin{aligned}
\text{Availability payment\_SR\_EGC}_{p(op)} &\\
&= \text{Margin\_SR}_{p(op)} \\
&\times \sum_{t=p(op)} \Big[MCAP(t) \\
&\times \Big[\text{SR Requirement}_{p(op)} - \text{SR provided contracts}_{p(op)}(t) \\
&- \text{Savings\_Cal}_{p(op)} \times (1 - \text{Savings\_Alloc}_{p(op)}) \\
&\times \left(\text{LF Requirement} - \text{LF provided contracts}_{p(op)}(t)\right)\Big]\Big]
\end{aligned}
$$

**Equation 24**

**Categories 3 and 4 - Load Following capacity provided by Verve Energy exceeds or equals Spinning Reserve capacity provided by Verve Energy**

If the Load Following capacity provided by Verve Energy exceeds the Spinning Reserve capacity provided by Verve Energy then the following equations should be applied.

As in the previous case, the availability payment for Load Following Service in Peak (or Off-Peak) Trading Intervals is given by the total cost of providing the Load Following Service in the absence of the Spinning Reserve Service (given in Equation 10), minus a proportion of the saving obtained through the dual use of plant to provide both services:

$$\begin{aligned}\text{Availability payment\_LF\_EGC}_{p(op)} &= \text{Margin\_LF}_{p(op)} \\ &\times \sum_{t=p(op)} \left[MCAP(t) \times \left(\text{LF Requirement} - \text{LF provided contracts}_{p(op)}(t)\right)\right] \\ &- \text{Savings\_LF}_{p(op)}\end{aligned}$$

**Equation 25**

The magnitude of the saving allocated to Market Participants liable for Load Following Service is given by $\text{Savings\_Alloc}_{p(op)}$ multiplied by the total saving. In this case, because the Load Following requirement exceeds the Spinning Reserve requirement the total saving is equivalent to the total availability cost of the Spinning Reserve Service (if it were being provided in the absence of the Load Following Service):

$$\text{Savings\_LF}_{p(op)} = \text{Savings\_Alloc}_{p(op)} \times \text{Availability\_Cost\_SR\_EGC}_{p(op)}$$

**Equation 26**

As in Equation 12, the total availability cost of Spinning Reserve Service is given by:

$$\begin{aligned}\text{Availability\_Cost\_SR\_EGC}_{p(op)} &= \text{Margin\_SR}_{p(op)} \\ &\times \sum_{t=p(op)} \left[MCAP_{\text{SR}}(t) \right.\\ &\left.\times \left(\text{SR Requirement}_{p(op)} - \text{SR provided contracts}_{p(op)}(t)\right)\right]\end{aligned}$$

**Equation 27**

In this case the payments under contracts for Spinning Reserve Service should be zero, since no Spinning Reserve service is explicitly required (it is provided entirely by the Load Following Service). This term is left in these equations for completeness, and to account for the situation where previous contracts may exist for the Spinning Reserve Service even though it is no longer required.

Combining Equation 26 and Equation 27 gives:

$$\begin{aligned}\text{Savings\_LF}_{p(op)} &\\ &= \text{Savings\_Alloc}_{p(op)} \times \text{Margin\_SR}_{p(op)} \\ &\times \sum_{t=p(op)} \left[MCAP(t) \right.\\ &\left.\times \left(\text{SR Requirement}_{p(op)} - \text{SR provided contracts}_{p(op)}(t)\right)\right]\end{aligned}$$

**Equation 28**

Combining this with Equation 25 gives the expression for the total availability payment for Load Following Service:

$$\begin{aligned}
&\text{Availability payment_LF_EGC}_{p(op)} \\
&\qquad = \text{Margin_LF}_{p(op)} \\
&\qquad \times \sum_{t=p(op)} \Bigg[ MCAP(t) \\
&\qquad \times \Bigg( \text{LF Requirement} - \text{LF provided contracts}_{p(op)}(t) \\
&\qquad - \text{Savings_Alloc}_{p(op)} \times \frac{\text{Margin_SR}_{p(op)}}{\text{Margin_LF}_{p(op)}} \\
&\qquad \times \left(\text{SR Requirement}_{p(op)} - \text{SR provided contracts}_{p(op)}(t)\right)\Bigg)\Bigg]
\end{aligned}$$

**Equation 29**

The availability payment to Verve Energy for Spinning Reserve Service in Peak (or Off-Peak) Trading Intervals is given by the total cost of providing the Spinning Reserve Service in the absence of the Load Following Service (Equation 12), minus a proportion of the saving obtained through the dual use of plant to provide both services:

$$\begin{aligned}
&\text{Availability_payment_SR_EGC}_{p(op)} = \text{Margin_SR}_{p(op)} \\
&\qquad \times \sum_{t=p(op)} \Big[ MCAP_{\text{SR}}(t) \\
&\qquad \times \left(\text{SR Requirement}_{p(op)} - \text{SR provided contracts}_{p(op)}(t)\right)\Big] \\
&\qquad - \text{Savings_SR}_{p(op)}
\end{aligned}$$

**Equation 30**

The magnitude of the saving allocated to Market Participants liable for Spinning Reserve Service is given by (1 - $\text{Savings\_Alloc}_{p(op)}$) multiplied by the total saving. In this case, because the Load Following requirement exceeds the Spinning Reserve requirement the total saving is equivalent to the total availability cost of the Spinning Reserve Service (if it were being provided in the absence of the Load Following Service):

$$\text{Savings\_SR}_{p(op)} = \left(1 - \text{Savings\_Alloc}_{p(op)}\right) \times \text{Availability\_Cost\_SR\_EGC}_{p(op)}$$

**Equation 31**

As in Equation 12, the total availability cost of Spinning Reserve Service is given by:

$$\begin{aligned}
&\text{Availability_Cost_SR_EGC}_{p(op)} = \text{Margin_SR}_{p(op)} \\
&\qquad \times \sum_{t=p(op)} \Big[ MCAP_{\text{SR}}(t) \\
&\qquad \times \left(\text{SR Requirement}_{p(op)} - \text{SR provided contracts}_{p(op)}(t)\right)\Big]
\end{aligned}$$

**Equation 32**

Combining Equation 30, Equation 31 and Equation 32 gives:

$$\text{Availability payment\_SR\_EGC}_{p(op)} = \text{Savings\_Alloc}_{p(op)} \times \text{Margin\_SR}_{p(op)} \times \sum_{t=p(op)} \left[MCAP(t) \times \left(\text{SR Requirement}_{p(op)} - \text{SR provided contracts}_{p(op)}(t)\right)\right]$$

**Equation 33**

**Implementation of these equations in the Market Rules**

These equations are implemented in the revised clause 9.9.2. For Spinning Reserve Service (clause 9.9.2(b)) the following components are defined and summed sequentially:

$$\begin{aligned}\text{Total Availability payment\_SR} = {} & \text{Availability payment\_SR\_EGC}_{\mathrm{p}} \text{ (if FKR} < \text{GTR)} \\ & + \text{Availability payment\_SR\_EGC}_{\mathrm{op}} \text{(if FKR} < \text{GTR)} \\ & + \text{Availability payment\_SR\_EGC}_{\mathrm{p}} \text{ (if GTR} \leq \text{FKR)} \\ & + \text{Availability payment\_SR\_EGC}_{\mathrm{op}} \text{ (if GTR} \leq \text{FKR)} \\ & + \text{Contracts}_{SR}\end{aligned}$$

**Equation 34**

FKR is the Frequency Keeping requirement (formerly the Load Following requirement) and GTR is the Generator Trip Reserve requirement (formerly the Spinning Reserve requirement). Each term is multiplied by GTR_Share(p,t) (formerly Reserve_Share(p,t)) when the sum over time is executed, which defines the proportion of the Spinning Reserve Service availability cost paid by each Market Participant p.

For Load Following Service (clause 9.9.2(d)) the terms are similarly defined and summed sequentially:

$$\begin{aligned}\text{Total Availability payment\_LF} = {} & \text{Availability payment\_LF\_EGC}_{\mathrm{p}} \text{ (if FKR} < GTR\text{)} \\ & + \text{Availability payment\_LF\_EGC}_{\mathrm{op}} \text{(if FKR} < \text{GTR)} \\ & + \text{Availability payment\_LF\_EGC}_{\mathrm{p}} \text{ (if GTR} \leq \text{FKR)} \\ & + \text{Availability payment\_LF\_EGC}_{\mathrm{op}} \text{ (if GTR} \leq \text{FKR)} \\ & + \text{Contracts}_{LF}\end{aligned}$$

**Equation 35**

The total availability payment for Load Following is then multiplied by FKR_Share(p,m) (formerly Load_Following_Share(p,m)) to determine the proportion of the Load Following availability cost paid by each Market Participant p. FKR_Share(p,m) is defined in clause 3.14.1.

**Impact of full provision of Load Following or Spinning Reserve Service under contract**

The methodology outlined above depends on the assumption that for the purposes of modelling:

- the forecast quantity of Load Following to be provided under Ancillary Service Contracts never exceeds the total Load Following requirement; and
- the forecast quantity of Spinning Reserve to be provided under Ancillary Service Contracts never exceeds the total Spinning Reserve requirement.

The IMO considers that this assumption is reasonable, given the issues that exist around the provision of these services through Ancillary Service Contracts. It is expected that further changes to the Market Rules will be needed before there is any significant increase in the proportion of these services provided by Independent Power Producers. However, for the sake of completeness the proposed availability cost equations in clause 9.9.2 include terms that prevent the calculation of negative availability costs in situations where the Load Following or Spinning Reserve requirement is met completely by contracts.

**LOAD FOLLOWING COST ALLOCATION**

The IMO proposes a "Full Load, Marginal Generation" methodology for the allocation of Load Following costs between Loads and Intermittent Generators. Under this methodology Loads are charged the full cost of their variability, while Intermittent Generators are only charged for the marginal increase in Load Following costs due to their operation. Within each of the two groups, the total absolute values of Metered Schedules are still used to determine the proportion of costs allocated to individual Facilities.

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## 2. Explain the reason for the degree of urgency:

It is proposed that this Rule Change Proposal be progressed through the Standard Rule Change Process.

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

### 2.30A Exemption from Funding ~~Spinning~~ Generator Trip Reserve

2.30A.1. When registering an Intermittent Generator as a Non-Scheduled Generator, a Rule Participant, or an applicant for rule participation, may apply to the IMO for that Intermittent Generator to be exempted from funding ~~Spinning~~ Generator Trip Reserve cost.

2.30A.2. Where an application is received in accordance with clause 2.30A.1, the IMO must exempt the Intermittent Generator from funding ~~Spinning~~ Generator Trip Reserve costs where the applicant demonstrates to the satisfaction of the IMO that the shut down of the facility is a gradual process not exceeding a maximum ramp down rate equal to the installed capacity divided by 15MW/minute.

2.30A.3. The IMO must consult with System Management when assessing an application for exemption from funding ~~Spinning~~ Generator Trip Reserve costs.

2.30A.4. If the IMO approves the application for exempting an Intermittent Generator from funding ~~Spinning~~ Generator Trip Reserve costs then that facility must be excluded from the set of applicable facilities described in Appendix 2.

2.30A.5. Where the IMO considers, after consultation with System Management, that a change in the nature of an Intermittent Generator means that it should no longer be exempted from funding ~~Spinning~~ Generator Trip Reserve costs, it must:

(a) inform the relevant Market Participant of the first Trading Month from which the facility will cease to be exempted; and

(b) include that facility in the list of applicable facilities described in Appendix 2 from the commencement of that Trading Month.

2.30A.6. The IMO must document the ~~Spinning~~ Generator Trip Reserve costs exemption process in the Registration Procedure, and:

(a) applicants for exemption from ~~Spinning~~ Generator Trip Reserve costs must follow that documented Market Procedure; and

(b) the IMO and System Management must follow that documented Market Procedure when processing applications for exemption from ~~Spinning~~ Generator Trip Reserve cost funding.

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

(a) there is a violation of the ~~Spinning Reserve~~ Generator Trip Reserve and Frequency Keeping requirements determined in accordance with clause 3.11;

(b) insufficient ~~Load Following~~ Frequency Keeping range is available to meet the requirements determined in accordance with clause 3.11;

…

3.9.1. ~~Load Following~~ Frequency Keeping Service is the service of frequently adjusting:

(a) the output of one or more Scheduled Generators;

(b) the output of one or more Non-Scheduled Generators; or

(c) the consumption of one or more Loads

within a Trading Interval so as to match total system generation to total system load in real time in order to correct any SWIS frequency variations.

3.9.2. ~~Spinning~~ Generator Trip 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 Registered Facilities; and

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

(c) [Blank]

3.9.3. ~~Spinning~~ Generator Trip Reserve response is measured over three time periods following a contingency event. A provider of ~~Spinning~~ Generator Trip Reserve Service must be able to ensure the relevant Facility can:

…

3.10.1. The standard for ~~Load Following~~ Frequency Keeping Service is a ~~level~~ MW capacity range which is sufficient to encompass:

(a) +30/-30 MW; and ~~provide Minimum Frequency Keeping Capacity, where the Minimum Frequency Keeping Capacity is the greater of:~~

~~i. 30 MW; and~~

~~ii. the capacity sufficient to cover 99.9% of the short term fluctuations in load and output of Non-Scheduled Generators and uninstructed output fluctuations from Scheduled Generators, measured as the variance of 1 minute average readings around a thirty minute rolling average.~~

(b) ~~[Blank]~~ the capacity sufficient to cover 99.9% of the short term fluctuations in load and output of Non-Scheduled Generators and uninstructed output fluctuations from Scheduled Generators, measured as the variance of 1 minute average readings around a thirty minute rolling average.

3.10.1A. The Minimum Frequency Keeping Capacity is the upper limit of the range defined in clause 3.10.1.

3.10.2. The standard for ~~Spinning~~ Generator Trip Reserve Service is a level which satisfies the following principles:

(a) the level must be sufficient to cover ~~the greater of~~:

i. 70% of the total output, including Parasitic Load, of the generation unit synchronised to the SWIS with the highest total output at that time; ~~and~~

ii. ~~the maximum load ramp expected over a period of 15 minutes;~~[Blank]

(b) the level must include capacity utilised to meet the ~~Load Following~~ Frequency Keeping Service standard under clause 3.10.1, so that the capacity provided to meet the ~~Load Following~~ Frequency Keeping requirement is counted as providing part of the ~~Spinning~~ Generator Trip Reserve requirement;

(c) the level may be relaxed by up to 12% by System Management where it expects that the shortfall will be for a period of less than 30 minutes; and

(d) the level may be relaxed following activation of ~~Spinning Reserve~~ Generator Trip Reserve and may be relaxed by up to 100% if all reserves are exhausted and to maintain reserves would require involuntary load shedding. In such situations the levels must be fully restored as soon as practicable.

3.10.2A. The combined Generator Trip Reserve and Frequency Keeping requirement must be a level which is sufficient to cover the maximum load ramp expected over a period of 15 minutes.

3.10.5. The level of ~~Load Following~~ Frequency Keeping Service, ~~Spinning~~ Generator Trip Reserve Service and Load Rejection Reserve Service may be reduced:

(a) following relevant contingencies; or

(b) where System Management cannot meet the standard without shedding load, providing that System Management considers that reducing the level is not inconsistent with maintaining Power System Security.

3.11.4. System Management must determine the Ancillary Service Requirements in accordance with clause 3.11.1 and 3.11.5 for the:

(a) ~~Load Following~~ Frequency Keeping Service;

(b) ~~Spinning~~ Generator Trip Reserve Service;

(c) [Blank]

(d) Load Rejection Reserve Service;

(e) each Dispatch Support Service; and

(f) System Restart Service.

3.11.8. System Management may enter into an Ancillary Service Contract with a Rule Participant other than the Electricity Generation Corporation, for ~~Spinning~~ Generator Trip Reserve and ~~Load Following~~ Frequency Keeping Ancillary Services, where:

…

3.11.8A. System Management may enter into an Ancillary Service Contract with a Rule Participant for Load Rejection Reserve Service, System Restart Service and Dispatch Support Service~~Ancillary Services~~.

3.11.8B. System Management must obtain the approval of the Economic Regulation Authority before entering into an Ancillary Service Contract for Dispatch Support Service~~Ancillary Services~~.

3.13.1. The total payments by the IMO on behalf of System Management for Ancillary Services in accordance with Chapter 9 comprise:

(a) [Blank]

(aA) for ~~Load Following~~ Frequency Keeping Service for each Trading Month:

i. a capacity payment ~~Capacity_LF~~ Capacity_Cost_FKR calculated as~~;~~:

1. the Monthly Reserve Capacity Price in that Trading Month;

2. multiplied by ~~LFR~~FKR, the maximum MW capacity ~~necessary to meet the Ancillary Service Requirement for Load Following in that month~~requirement for Frequency Keeping Service in that Trading Month, as specified in clause 3.22.1A(c); and

ii. an availability payment Availiability_Cost_FKR~~LF(m)~~ calculated in accordance with clause 9.9.2(d) for that Trading Month;

(b) an amount ~~Availability_Cost_R(m)~~ Availability_Cost_GTR for ~~Spinning Reserve~~Generator Trip Reserve Service for each Trading Month, which is calculated in accordance with clause 9.9.2(c) for that Trading Month; and

(c) Cost_LRD, the monthly amount for Load Rejection Reserve Service and System Restart Service, determined in accordance with the process described in ~~clause~~ clauses 3.13.3B and 3.13.3C; and Dispatch Support Service~~service~~ determined in accordance with clause 3.11.8B.

| |
|---|
| Initially, Margin_FKR_Peak and Margin_GTR_Peak will be set to the value of the replaced parameter Margin_Peak determined by the ERA for the relevant Financial Year, multiplied by 0.5 (to account for the removal of this conversion factor from the Settlement calculations in clause 9.9.2). Similarly, Margin_FKR_Off-Peak and Margin_GTR_Off-Peak will set to the Margin_Off-Peak value for the relevant Financial Year, multiplied by 0.5. |

3.13.3. The parameters ~~Margin_Peak and Margin_Off-Peak~~ Margin_FKR_Peak, Margin_FKR_Off-Peak, Margin_GTR_Peak, Margin_GTR_Off-Peak, Savings_Alloc_Peak, Savings_Alloc_Off-Peak, Savings_Cal_Peak and Savings_Cal_Off_Peak to be used in the settlement calculation described in clause 9.9.2 are:

(a) where the Economic Regulation Authority has not completed its first assessment in accordance with clause 3.13.3A:

i. ~~15 % for Margin_Peak; and~~xx for Margin_FKR_Peak;

ii. ~~12% for Margin_Off-Peak; and~~yy for Margin_FKR_Off-Peak;

iii. xx for Margin_GTR_Peak;

iv. yy for Margin_GTR_Off-Peak;

v. 0.5 for Savings_Alloc_Peak;

vi. 0.5 for Savings_Alloc_Off-Peak;

vii. 1.0 for Savings_Cal_Peak; and

viii. 1.0 for Savings_Cal_Off-Peak; and

(b) determined by the Economic Regulation Authority, where the Economic Regulation Authority has completed its first assessment in accordance with clause 3.13.3A.

3.13.3A. 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~~ Margin_FKR_Peak, Margin_FKR_Off-Peak, Margin_GTR_Peak, Margin_GTR_Off-Peak, Savings_Alloc_Peak, Savings_Alloc_Off-Peak, Savings_Cal_Peak and Savings_Cal_Off-Peak, taking into account the Wholesale Market Objectives and in accordance with the following process.~~:~~

(a) ~~by 30 November prior to the start of the Financial Year, the IMO must submit a proposal for the Financial Year to the Economic Regulation Authority~~Each year the IMO must develop a proposal for the parameter values for the following Financial Year, in accordance with clause 3.13.3D. The proposal must take account of:

i. ~~for the reserve availability payment margin applying for Peak Trading Intervals, Margin_Peak, the IMO must take account of:~~ the margin the Electricity Generation Corporation could reasonably have been expected to earn on energy sales forgone due to the supply of Generator Trip Reserve Service and Frequency Keeping Service; and

~~1. the margin the Electricity Generation Corporation could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve during Peak Trading Intervals;~~

~~2. the loss in efficiency of the Electricity Generation Corporation Registered Facilities 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;~~

ii. ~~for the reserve availability payment margin applying for Off-Peak Trading Intervals, Margin_Off-Peak, the IMO must take account of:~~ the loss in efficiency of the Electricity Generation Corporation Registered Facilities that System Management has scheduled to provide Generator Trip Reserve Service and Frequency Keeping Service that could reasonably be expected due to the scheduling of those services.

~~1. the margin the Electricity Generation Corporation could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve during Off-Peak Trading Intervals;~~

~~2. the loss in efficiency of the Electricity Generation Corporation Registered Facilities 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;~~

(b) ~~the Economic Regulation Authority must undertake a public consultation process, which must include publishing an issues paper and issuing an invitation for public submissions.~~The IMO must prepare a report describing the assumptions (excluding any market related information assigned to a Confidentiality Class other than Public) and the methodology it proposes to adopt in developing its proposal. The IMO must publish this report and issue an invitation for submissions on the Market Web Site.

(c) The IMO must consider the submissions received on the report described in clause 3.13.3A(b) when developing its proposal under clause 3.13.3A(a).

(d) The IMO must submit the proposal described in clause 3.13.3A(a) for a Financial Year to the Economic Regulation Authority by 30 November prior to the start of that Financial Year.

(e) The Economic Regulation Authority must undertake a public consultation process, which must include publishing an issues paper and issuing an invitation for public submissions.

3.13.3B. For each Review Period, by 31 March of the year in which the Review Period commences, the Economic Regulation Authority must determine values for Cost_LR, taking into account the Wholesale Market Objectives and in accordance with the following:

(a) by 30 November of the year prior to the start of the Review Period, System Management must submit a proposal for the Cost_LR parameter for the Review Period to the Economic Regulation Authority. Cost_LR must cover the costs for providing the Load Rejection Reserve Service and System Restart ~~Ancillary~~ Services and Dispatch Support ~~Ancillary~~ Services except those provided through clause 3.11.8B;

…

3.13.3C. For any year within a Review Period if System Management determines Cost_LR for the following ~~financial year~~ Financial Year to be materially different than the costs provided under clause 3.13.3B, then the Economic Regulation Authority must determine the revised values for Cost_LR, taking into account the Wholesale Market Objectives and in accordance with the following:

(a) by 30 November of the year prior to the start of the relevant ~~financial year~~Financial Year, System Management must submit an updated proposal for the Cost_LR parameter to the Economic Regulation Authority. Cost_LR must cover the costs for providing the Load Rejection Reserve Service and System Restart ~~Ancillary~~ Services and Dispatch Support ~~Ancillary~~ Services except those provided through clause 3.11.8B;

…

3.13.3D. The parameters Margin FKR_Peak, Margin_FKR_Off-Peak, Margin_GTR_Peak, Margin_GTR_Off-Peak, Savings_Alloc_Peak, Savings_Alloc_Off-Peak, Savings_Cal_Peak and Savings_Cal_Off-Peak are defined for a Financial Year as follows:

(a) Margin_FKR_Peak = ACFKR_Peak /
(Sum(tϵPeak,MCAP_FKR(t)
× (FKR(m) - Sum(cϵCAS_FKR,ASP_FKRQ(c,t)))))

(b) Margin_FKR_Off-Peak = ACFKR_Off-Peak / (Sum(tϵOff-Peak,MCAP_FKR(t) × (FKR(m) - Sum(cϵCAS_FKR,ASP_FKRQ(c,t)))))

(c) Margin_GTR_Peak = ACGTR_Peak / (Sum(tϵPeak,MCAP_GTR(t) ×(GTR_Peak(m) - Sum(cϵCAS_GTR,ASP_GTRQ(c,t)))))

(d) Margin_GTR_Off-Peak = ACGTR_Off-Peak / (Sum(tϵOff-Peak,MCAP_GTR(t) × (GTR_Off-Peak(m) - Sum(cϵCAS_GTR,ASP_GTRQ(c,t)))))

(e) Savings_Alloc_Peak = ACFKR_Peak / (ACFKR_Peak + ACGTR_Peak)

(f) Savings_Alloc_Off-Peak = ACFKR_Off-Peak / (ACFKR_Off-Peak + ACGTR_Off-Peak)

(g) Savings_Cal_Peak = (ACFKR_Peak + ACGTR_Peak - ACTOT_Peak)/(Margin_GTR_Peak × Sum(tϵPeak,MCAP_TOT(t) × (FKR(m) -Sum(cϵCAS_FKR,ASP_FKRQ(c,t)))))

(h) Savings_Cal_Off-Peak = (ACFKR_Off-Peak + ACGTR_Off-Peak - ACTOT_Off-Peak)/(Margin_GTR_Off-Peak × Sum(tϵOff-Peak,MCAP_TOT(t) × (FKR(m) - Sum(cϵCAS_FKR,ASP_FKRQ(c,t)))))

Where:

t denotes a Trading Interval in the Financial Year;

for any Trading Interval t, m denotes the Trading Month containing Trading Interval t;

Peak is the set of Peak Trading Intervals in the Financial Year;

Off-Peak is the set of Off-Peak Trading Intervals in the Financial Year;

c denotes a Contracted Ancillary Service;

CAS_FKR is the set of Contracted Frequency Keeping Services expected by the IMO to be provided during the Financial Year;

CAS_GTR is the set of Contracted Generator Trip Reserve Services expected by the IMO to be provided during the Financial Year;

MCAP_TOT(t) is the greater of zero and the IMO's forecast of the Marginal Cost Administered Price for Trading Interval t, in a scenario where the Electricity Generation Corporation provides both Frequency Keeping Service and Generator Trip Reserve Service (in excess of the services assumed to be provided by contracts under clause 3.11.8);

MCAP_FKR(t) is the greater of zero and the IMO's forecast of the Marginal Cost Administered Price for Trading Interval t, in a scenario where the Electricity Generation Corporation provides Frequency Keeping Service (in excess of the service provided by contracts under clause 3.11.8) but the Generator Trip Reserve Service is only provided by contracts under clause 3.11.8;

MCAP_GTR(t) is the greater of zero and the IMO's forecast of the Marginal Cost Administered Price for Trading Interval t, in a scenario where the Electricity Generation Corporation provides Generator Trip Reserve Service (in excess of the service provided by contracts under clause 3.11.8), but the Frequency Keeping Service is only provided by contracts under clause 3.11.8;

ACFKR_Peak is the IMO's forecast of the total availability cost to the Electricity Generation Corporation of providing Frequency Keeping Service during Peak Trading Intervals in the Financial Year (in excess of the services provided by contracts under clause 3.11.8), when the Generator Trip Reserve Service is only provided by contracts under clause 3.11.8;

ACFKR_Off-Peak is the IMO's forecast of the total availability cost to the Electricity Generation Corporation of providing Frequency Keeping Service during Off-Peak Trading Intervals in the Financial Year (in excess of the services provided by contracts under clause 3.11.8), when the Generator Trip Reserve Service is only provided by contracts under clause 3.11.8;

ACGTR_Peak is the IMO's forecast of the total availability cost to the Electricity Generation Corporation of providing Generator Trip Reserve Service during Peak Trading Intervals in the Financial Year (in excess of the services provided by contracts under clause 3.11.8), when the Frequency Keeping Service is only provided by contracts under clause 3.11.8;

ACGTR_Off-Peak is the IMO's forecast of the total availability cost to the Electricity Generation Corporation of providing Generator Trip Reserve Service during Off-Peak Trading Intervals in the Financial Year (in excess of the services provided by contracts under clause 3.11.8), when the Frequency Keeping Service is only provided by contracts under clause 3.11.8;

ACTOT_Peak is the IMO's forecast of the total availability cost to the Electricity Generation Corporation of simultaneously providing Frequency Keeping Service and Generator Trip Reserve Service (in excess of the services provided by contract under clause 3.11.8) during Peak Trading Intervals in the Financial Year;

ACTOT_Off-Peak is the IMO's forecast of the total availability cost to the Electricity Generation Corporation of simultaneously providing Frequency Keeping Service and Generator Trip Reserve Service (in excess of the services provided by contract under clause 3.11.8) during Off-Peak Trading Intervals in the Financial Year;

ASP_FKRQ(c,t) is the IMO's forecast of the quantity of Frequency Keeping Service provided by Contracted Ancillary Service c in Trading Interval t, expressed as a MW capacity;

ASP_GTRQ(c,t) is the IMO's forecast of the quantity of Generator Trip Reserve Service provided by Contracted Ancillary Service c in Trading Interval t, expressed as a MW capacity;

GTR_Peak(m) is the IMO's forecast of the maximum MW capacity necessary to meet the requirement for Generator Trip Reserve Service in Peak Trading Intervals during Trading Month m;

GTR_Off-Peak(m) is the IMO's forecast of the maximum MW capacity necessary to meet the requirement for Generator Trip Reserve Service in Off-Peak Trading Intervals during Trading Month m;

FKR(m) is the IMO's forecast of the maximum MW capacity necessary to meet the requirement for Frequency Keeping Service during Trading Month m;

Margin_GTR_Peak is the reserve availability payment margin applying for Generator Trip Reserve Service for Peak Trading Intervals in the Financial Year;

Margin_FKR_Peak is the reserve availability payment margin applying for Frequency Keeping Service for Peak Trading Intervals in the Financial Year;

Margin_GTR_Off-Peak is the reserve availability payment margin applying for Generator Trip Reserve Service for Off-Peak Trading Intervals in the Financial Year;

Margin_FKR_Off-Peak is the reserve availability payment margin applying for Frequency Keeping Service for Off-Peak Trading Intervals in the Financial Year;

Savings_Alloc_Peak is the allocation factor for cost savings from dual use of plant providing Frequency Keeping Service to simultaneously provide Generator Trip Reserve Service, applying for Peak Trading Intervals in the Financial Year;

Savings_Alloc_Off-Peak is the allocation factor for cost savings from dual use of plant providing Frequency Keeping Service to simultaneously provide Generator Trip Reserve Service, applying for Off-Peak Trading Intervals in the Financial Year;

Savings_Cal_Peak is the calibration factor for cost savings from dual use of plant providing Frequency Keeping Service to simultaneously provide Generator Trip Reserve Service, applying for Peak Trading Intervals in the Financial Year; and

Savings_Cal_Off-Peak is the calibration factor for cost savings from dual use of plant providing Frequency Keeping Service to simultaneously provide Generator Trip Reserve Service, applying for Off-Peak Trading Intervals in the Financial Year.

3.14.1. Market Participant p's share of the ~~Load Following~~ Frequency Keeping Service payment cost in each Trading Month m is ~~Load_Following~~ FKR_Share(p,m) which ~~equals~~ is given by:

FKR_Share(p,m) =

MS_Loads(p,m) / MS_Loads_Total(m) × FKR_Loads(m) / FKR(m)

+ MS_IG(p,m) / MS_IG_Total(m) × (FKR(m) - FKR_Loads(m)) / FKR(m)

Where:

MS_Loads(p,m) is the absolute value of the sum of the Metered Schedules for the Non-Dispatchable Loads, Interruptible Loads, and Curtailable Loads registered by the Market Participant p for all Trading Intervals during Trading Month m;

MS_Loads_Total(m) is the absolute value of the sum of the Metered Schedules for the Non-Dispatchable Loads, Interruptible Loads, and Curtailable Loads registered by all Market Participants for all Trading Intervals during Trading Month m;

MS_IG(p,m) is the sum of the Metered Schedules for Intermittent Generators registered by Market Participant p, except those Intermittent Generators exempted under clause 2.30D.2, for all Trading Intervals during Trading Month m;

MS_IG_total(m) is the sum of the Metered Schedules for Intermittent Generators registered by all Market Participants, except those Intermittent Generators exempted under clause 2.30D.3, for all Trading Intervals during Trading Month m;

FKR(m) is the maximum MW capacity requirement for Frequency Keeping Service in Trading Month m as determined in accordance with clause 3.22.1A(c); and

FKR_Loads(m) is the estimated maximum MW capacity requirement to cover short term fluctuations in load in Trading Month m as advised in accordance with clause 3.22.4.

~~(a) the Market Participant's contributing quantity; divided by~~

~~(b) the total contributing quantity of all Market Participants,~~

~~where a Market Participant's contributing quantity for Trading Month m is the sum of:~~

~~i. the absolute value of the sum of the Metered Schedules for the Non-Dispatchable Loads, Interruptible Loads, Curtailable Loads registered by the Market Participant for all Trading Intervals during Trading Month m; and~~

~~ii. the sum of the Metered Schedules for Non-Scheduled Generators registered by the Market Participant for all Trading Intervals during Trading Month m.~~

~~iii. [Blank]~~

3.14.2. Market Participant p's share of the ~~Spinning Reserve service~~ Generator Trip Reserve Service payment costs in each Trading Interval t is ~~Reserve_Share(p,t)~~ GTR_Share(p,t) which equals the amount determined in Appendix 2.

3.14.3. Market Participant p's share of the Load Rejection Reserve Service, System Restart Service and~~,~~ Dispatch Support Service~~services~~ payment costs in each Trading Month m is Consumption_Share(p,m) determined in accordance with clause 9.3.7.

3.18.11A. The Ready Reserve Standard requires that the available generation and demand-side capacity at any time satisfies the following principles:

(a) Subject to (c), the additional energy available within fifteen minutes must be sufficient to cover:

i. 30% of the total output, including Parasitic Load, of the generation unit synchronized to the SWIS with the highest total output at that time;

ii. plus the Minimum Frequency Keeping Capacity as defined in clause ~~3.10.1(a)~~3.10.1A.

(b) Subject to (c), and in addition to the additional energy described in (a), the additional energy available within four hours must be sufficient to cover:

i. 70% of the total output, including Parasitic Load, of the generation unit synchronized to the SWIS with the second highest total output at that time;

ii. less the Minimum Frequency Keeping Capacity as defined in clause ~~3.10.1(a)~~3.10.1A.

(c) …

3.22.1. The IMO must provide the following information to the Settlement System for each Trading Month:

(a) ~~Capacity_LF~~ Capacity_Cost_FKR as described in clause 3.13.1(aA);

(b) [Blank]

(c) ~~Margin_Peak as described in clause 3.13.3A;~~[Blank]

(cA) Margin_FKR_Peak as defined in clause 3.13.3;

(cB) Margin_GTR_Peak as defined in clause 3.13.3;

(cC) Savings_Alloc_Peak as defined in clause 3.13.3;

(cD) Savings_Cal_Peak as defined in clause 3.13.3;

(d) ~~Margin_Off-Peak as described in clause 3.13.3A;~~[Blank]

(dA) Margin_FKR_Off-Peak as defined in clause 3.13.3;

(dB) Margin_GTR_Off-Peak as defined in clause 3.13.3;

(dC) Savings_Alloc_Off-Peak as defined in clause 3.13.3;

(dD) Savings_Cal_Off-Peak as defined in clause 3.13.3;

(e) ~~Capacity_R_Peak, the requirement for Spinning Reserve for Peak Trading Intervals assumed in forming Margin_Peak;~~GTR_Peak as defined in clause 3.22.1A(a);

(f) ~~Capacity_R_Off-Peak, the requirement for Spinning Reserve for Off-Peak Trading Intervals assumed in forming Margin_Off-Peak;~~GTR_Off-Peak as defined in clause 3.22.1A(b);

(fA) ~~LFR as described in clause 3.13.1(aA)(i)(2);~~FKR as defined in clause 3.22.1A(c);

(g) Cost_LRD as the sum of:

i. Cost_LR (as described in ~~clause~~ clauses 3.13.3B and 3.13.3C) divided by 12 as a monthly amount; and

ii. the monthly amount for Dispatch Support ~~service~~ Service as advised in accordance with clause 3.22.3(b); and

(h) the compensation due to changed outage plans to be paid to a Market Participant for that Trading Month as determined in accordance with clause 3.19.12(e).

3.22.1A. The parameters GTR_Peak(m), GTR_Off-Peak(m) and FKR(m) for Trading Month m are defined as follows:

(a) GTR_Peak(m) = Max(t∈Peak, Sum(i∈I, GTR_Req_MWh(i,t))) * 2;

(b) GTR_Off-Peak(m) = Max(t∈Off-Peak, Sum(i∈I, GTR_Req_MWh(i,t))) * 2; and

(c) FKR(m) = Max(t∈T, Sum(i∈I, FKR_Req_MWh(i,t))) * 2,

where

i denotes a Rule Participant;

I is the set of Rule Participants that are providers of Generator Trip Reserve Service or Frequency Keeping Service;

t denotes a Trading Interval;

T is the set of Trading Intervals in Trading Month m;

Peak is the set of Peak Trading Intervals in Trading Month m;

Off-Peak is the set of Off-Peak Trading Intervals in Trading Month m;

GTR_Req_MWh(i,t) is the value determined by System Management for Rule Participant i and Trading Interval t in accordance with clause 7.2.3A(a) and provided to the IMO in accordance with clauses 7.2.3B or 7.2.3C; and

FKR_Req_MWh(i,t) is the value determined by System Management for Rule Participant i and Trading Interval t in accordance with clause 7.2.3A(aA) and provided to the IMO in accordance with clauses 7.2.3B or 7.2.3C.

| |
|---|
| The amendments to clause 3.22.2 are to ensure consistency with RC_2010_33. |

3.22.2. When System Management has entered into an Ancillary Service Contract with a Rule Participant, System Management must as soon as practicable and not less than 20 Business Days prior to the Ancillary Service Contract taking effect, provide the IMO with:

(a) the identity of the Rule Participant~~,~~; and

(b) for each Contracted Ancillary Service ~~the Ancillary Service contracted~~ to be provided by the Rule Participant under the Ancillary Service Contract:~~,~~

i. a unique identifier for the Contracted Ancillary Service;

ii. the type of Ancillary Service where this can be one of:

1. Spinning Reserve Service;

2. Load Following Service;

3. Load Rejection Reserve Service;

4. System Restart Service; or

5. Dispatch Support Service; and

iii. the form of settlement data that System Management will provide to the IMO for the Contracted Ancillary Service provided by the Rule Participant, where this data must be one of the formats allowed by clause 3.22.3.

~~(c) a unique identifier for the Ancillary Service Contract;~~

~~(d) the form of settlement data that System Management will provide to the IMO for the Contracted Ancillary Service provided by the Rule Participant, where this data must be one of the formats allowed by clause 3.22.3.~~

| |
|---|
| The amendments to clause 3.22.3 are to ensure consistency with RC_2010_33 and to replace the names “Load Following” and “Spinning Reserve” with “Frequency Keeping” and “Generator Trip Reserve”. |

3.22.3. System Management must provide the following information to the IMO for each Rule Participant holding an Ancillary Service Contract for a Trading Month by the date specified in clause 9.16.2(a):

(a) the identity of the Rule Participant;

(b) for each Contracted Ancillary Service provided under an Ancillary Service Contract held by the Rule Participant:

i. the type of Ancillary Service where this can be one of:

1. ~~Spinning~~ Generator Trip Reserve Service;

2. ~~Load Following~~Frequency Keeping Service;

3. Load Rejection Reserve Service;

4. System Restart Service; or

5. Dispatch Support Service;

ii. for each Trading Interval of the Trading Month the quantity of Ancillary Service to a precision of 0.001 units ~~(where no specific unit of measure will be assumed).~~, where the unit of measure is:

1. MWh for Generator Trip Reserve Service;

2. MWh for Frequency Keeping Service;

3. MWh for Load Rejection Reserve Service;

4. as determined by System Management for System Restart Service; or

5. as determined by System Management for Dispatch Support Service; and

iii. either:

1. a total monthly payment for the Ancillary Service in dollars and whole cents; or

2. a price in dollars and whole cents per unit of the quantity described in (ii) per Trading Interval.

3.22.4. For each Trading Month, by the date specified in clause 9.16.2(a), System Management must provide to the IMO FKR_Loads, System Management's estimate of the maximum MW capacity requirement for Frequency Keeping Service that it would have determined for the Trading Month by considering short term fluctuations in load only and excluding any short term fluctuations in output of Non-Scheduled Generators and uninstructed output fluctuations from Scheduled Generators.

3.22.5. System Management must document in the Power System Operation Procedure the procedure to be followed, and must follow that documented procedure, when determining FKR_Loads in accordance with clause 3.22.4.

3.22.6. The IMO must publish the value of FKR_Loads provided by System Management under clause 3.22.4 on the Market Web Site as soon as practicable after the date specified in clause 9.16.2(a) for each Trading Month.

4.5.12. An Availability Curve for a Capacity Year is to contain the following information:

(a) the forecast capacity, in MW, required for more than 24 hours per year, 48 hours per year, 72 hours per year and 96 hours per year;

(b) the minimum capacity required to be provided by generation capacity if Power System Security and Power System Reliability is to be maintained. This minimum capacity is to be set at a level such that if:

i all Demand Side Management capacity (excluding Interruptible Load used to provide ~~Spinning~~ Generator Trip Reserve to the extent that it is anticipated to provide Certified Reserve Capacity), were activated during the Capacity Year so as to minimise the peak demand during that year; and ii the Planning Criterion and the criteria for evaluating Outage Plans set out in clause 3.18.11 were to be applied to the load scenario defined by (i), then

it would be possible to satisfy the Planning Criterion and the criteria for evaluating Outage Plans set out in clause 3.18.11, as applied in paragraph (ii), using, to the extent that the capacity is anticipated to provide Certified Reserve Capacity, the anticipated installed generating capacity, the anticipated Interruptible Load capacity available as ~~Spinning~~ Generator Trip Reserve and, to the extent that further generation capacity would be required, an appropriate mix of generation capacity to make up that shortfall; and

…

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 clauses 7.2.3B or 7.2.3C (being the maximum of the relevant quantities for the Trading Interval determined under clauses 7.2.3A(a) and 7.2.3A(aA));

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

…

(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 (being the maximum of the relevant quantities for the Trading Interval determined under clauses 7.2.3A(a) and 7.2.3A(aA)); and

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

as provided to the IMO by the System Management in accordance with clauses 7.2.3B or 7.2.3C.

6.17.6. The Dispatch Instruction Payment, DIP(p,d,t), for Market Participant p and Trading Interval t of Trading Day d equals the sum of:

…

(b) the sum over all Scheduled Generators and Dispatchable Loads registered by the Market Participant of the following amounts for Trading Interval t:

…

ii. if neither paragraph (i) nor (iA) applies, the amount for the Registered Facility is the product of:

…

2. the price defined as:

i. the contracted price, if the Dispatch Instruction is for the purposes of an Ancillary ~~Services~~ Service Contract for System Restart Service, Dispatch Support Service or Load Rejection Reserve Service;

ii. zero, if the Dispatch Instruction is for the purposes of an Ancillary ~~Services~~ Service Contract other than for System Restart Service, Dispatch Support Service or Load Rejection Reserve Service; or

iii. the applicable price as defined by clause 6.17.7 less MCAP for Trading Interval t.

…

7.2.3A. By 8:30 AM on the Scheduling Day, System Management must determine for each ~~Market~~ Rule Participant that is a provider of Ancillary Services:

(a) an estimate of the Loss Factor adjusted MWh of energy that could potentially be called upon by System Management after 1:00 PM on the Scheduling Day to meet ~~Ancillary~~ Generator Trip Reserve Service requirements for each Trading Interval of the Trading Day where these estimates must reflect the Ancillary Service standards described in clause 3.10; ~~and~~

(aA) an estimate of the Loss Factor adjusted MWh of energy that could potentially be called upon by System Management after 1:00 PM on the Scheduling Day to meet Frequency Keeping Service requirements for each Trading Interval of the Trading Day where these estimates must reflect the Ancillary Service standards described in clause 3.10; and

(b) a list of Facilities that it might reasonably expect to call upon to provide the energy described in (a) and (aA).

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

RCSA(p,m) =

Monthly Reserve Capacity Price(m) × (CC_NSPA(p,m)
– Sum(q∈ P,CC_ANSPA(p,q,m)))
+ Sum(a ∈ A, Monthly Special Price(p,m,a) × (CC_SPA(p,m,a)
– Sum(q∈ P,CC_ASPA(p,q,m,a))))
- Capacity Cost Refund(p,m)
- Intermittent Load Refund(p,m)
+ Supplementary Capacity Payment(p,m)
- Targeted Reserve Capacity Cost(m) × Shortfall Share(p,m)
- Shared Reserve Capacity Cost(m) × Capacity Share(p,m)
+ ~~Capacity_LF~~Capacity_Cost_FKR(m) × Capacity Share(p,m)

Where

...

~~Capacity_LF~~Capacity_Cost_FKR(m) is the total ~~Load Following service~~ Frequency Keeping Service capacity payment cost for Trading Month m as specified by IMO under clause 3.22.1(a).

| |
|---|
| The amendments to clause 9.9.1 are to ensure consistency with RC_2010_33 and to update the parameter names relating to Load Following and Spinning Reserve. |

9.9.1. The Ancillary Service settlement amount for Market Participant p for Trading Month m is:

~~ASSA(p,m) = Electricity Generation Corporation AS Provider Payment(p,m)~~
~~+ d(p,i) × ASP_Payment(i,m)~~
~~- Load_Following_Share(p,m)~~
~~× (Capacity_LF(m) + Availability_Cost_LF(m))~~

~~- Reserve_Cost_Share(p,m)~~
~~- Consumption_Share(p,m) × Cost_LRD(m)~~

ASSA(p,m) = Electricity Generation Corporation AS Provider Payment(p,m)
+ ASP_Payment(p,m)
- FKR_Share(p,m)
× (Capacity_Cost_FKR(m) + Availability_Cost_FKR(m))
- GTR_Cost_Share(p,m)
- Consumption_Share(p,m) × Cost_LRD(m)

Where:

the Electricity Generation Corporation AS Provider Payment(p,m) =
0 if Market Participant p is not the Electricity Generation Corporation and (Availability_Cost_GTR(m) + Availability_Cost_FKR~~LF~~(m) + Cost_LRD(m)) - ~~Sum(i∈I, ASP_Payment(i,m))~~ ASP_Balance_Payment(m) otherwise~~.~~;

~~d(p,i) is 1 if ASP i corresponds to Market Participant p and zero otherwise;~~

ASP_Payment(~~i~~p,m) is the total payment to Market Participant p for Contracted Ancillary Services in Trading Month m, determined in accordance with clause 9.9.3;

ASP_Balance_Payment(m) is the amount determined in accordance with clause 9.9.3A for Trading Month m;

~~Load_Following_Share(p,m)~~ FKR_Share(p,m) is the share of the ~~Cost_LF(m)~~ total cost of the Frequency Keeping Service allocated to Market Participant p in Trading Month m, where this is to be determined by the IMO using the methodology described in clause 3.14.1;

~~Reserve_Cost_Share(p,m)~~ GTR_Cost_Share(p,m) is defined in clause 9.9.2(b);

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;

~~Capacity_LF(m)~~ Capacity_Cost_FKR(m) is the total ~~Load Following service~~ Frequency Keeping Service capacity payment cost for Trading Month m as specified by the IMO under clause 3.22.1(a);

~~Availability_Cost_R(m)~~ Availability_Cost_GTR(m) is the total ~~Spinning~~ Generator Trip Reserve Service availability payment cost~~s, excluding Load Following costs,~~ for Trading Month m, as calculated under clause 9.9.2(c);

~~Availability_Cost_LF(m)~~Availability_Cost_FKR(m) is the ~~Load Following~~ total Frequency Keeping Service availability payment cost~~s~~ for Trading Month m, as calculated under clause 9.9.2(d); and

Cost_LRD(m) is the total Load Rejection Reserve Service, System Restart Service~~,~~ and Dispatch Support Service ~~services~~ payment cost~~s~~ for Trading Month m as specified by the IMO under clause 3.22.1(g).

| |
|---|
| The amendments to clause 9.9.1A are to ensure consistency with RC_2010_33. |

9.9.1A. The Ancillary Service settlement amount for Trading Month m for Rule Participant ~~k~~ i where Rule ~~Partiant k~~ Participant i is not a Market Participant is ~~d(k,i) × ASP_Payment(i,m) where d(k,i) = 1 if ASP i corresponds to Rule Participant k and zero otherwise and ASP_Payment(i,m) is~~ ASP_Payment(i,m), determined in accordance with clause 9.9.3.

| |
|---|
| The amendments to clause 9.9.2 include changes to ensure consistency with RC_2010_33 (apart from the additional changes required to implement the new calculation methodology). |

9.9.2. The following terms ~~related~~ relate to Ancillary Service availability costs:

(a) ~~the total availability cost for Trading Month m:~~

~~Availability_Cost(m) =~~
~~0.5 × (Margin_Peak(m) × Sum(d∈D,t∈Peak,MCAP(d,t)~~
~~× (Capacity_R_Peak(m) – Sum(i∈I,ASP_SRQ(i,t)))))~~
~~+ 0.5 × (Margin_Off-Peak(m) × Sum(d∈D,t∈Off-Peak,MCAP(d,t)~~
~~× (Capacity_R_Off-Peak(m) – Sum(i∈I,ASP_SRQ(i,t)))))~~
~~+ Sum(i∈I,ASP_SRPayment(i,m))~~
~~+ Sum(i∈I,ASP_LFPayment(i,m))~~[Blank]

(b) ~~the Spinning Reserve Cost Share for Market Participant p, which is a Market Generator, for Trading Month m:~~

~~Reserve_Cost_Share(p,m) =~~
~~0.5 × (Margin_Peak(m) × Sum(d∈D,t∈Peak,MCAP(d,t)~~
~~× Reserve_Share(p,t)~~
~~× (Capacity_R_Peak(m) – Sum(i∈I,ASP_SRQ(i,t))~~) ~~- 0.5 LFR(m))))~~
~~+ 0.5 × (Margin_Off-Peak(m) × Sum(d∈D,t∈Off-Peak,MCAP(d,t)~~
~~× Reserve_Share(p,t)~~
~~× (Capacity_R_Off-Peak(m) – Sum(i∈I,ASP_SRQ(i,t))~~
~~- 0.5 × LFR(m))))~~
~~+ Sum(t∈Peak and Off_Peak, Reserve_Share(p,t)~~
~~× Sum(i∈I,ASP_SRPayment(i,m) / TITM))~~

the Generator Trip Reserve cost share for Market Participant p, which is a Market Generator, for Trading Month m is given by:

GTR_Cost_Share(p,m) =
Margin_GTR_Peak(m)
× Sum(t∈Peak_FKR_LT_GTR, MCAP(t)

× GTR_Share(p,t)
× (max(0,GTR_Peak(m) – Sum(c∈CAS_GTR,ASP_GTRQ(c,t)))
- Savings_Cal_Peak(m) × (1 - Savings_Alloc_Peak(m))
× max(0,FKR(m) - Sum(cϵCAS_FKR,ASP_FKRQ(c,t)))))

+ Margin_GTR_Off-Peak(m)
× Sum(t∈Off-Peak_FKR_LT_GTR, MCAP(t)
× GTR_Share(p,t)
× (max(0,GTR_Off-Peak(m) – Sum(c∈CAS_GTR,ASP_GTRQ(c,t)))
- Savings_Cal_Off-Peak(m) × (1 - Savings_Alloc_Off-Peak(m))
× max(0,FKR(m) - Sum(cϵCAS_FKR,ASP_FKRQ(c,t)))))

+ Margin_GTR_Peak(m) × Savings_Alloc_Peak(m)
× Sum(t∈Peak_GTR_LE_FKR, MCAP(t)
× GTR_Share(p,t)
× max(0,GTR_Peak(m) - Sum(c∈CAS_GTR,ASP_GTRQ(c,t))))

+ Margin_GTR_Off-Peak(m) × Savings_Alloc_Off-Peak(m)
× Sum(t∈Off-Peak_GTR_LE_FKR, MCAP(t)
× GTR_Share(p,t)
× max(0,GTR_Off-Peak(m) - Sum(c∈CAS_GTR,ASP_GTRQ(c,t))))

+ Sum(t∈T, GTR_Share(p,t)
× Sum(c∈CAS_GTR,ASP_GTRPayment(c,m) / TITM))

(c) the total ~~Spinning~~ Generator Trip Reserve ~~Availability Cost~~ availability cost for Trading Month m:

~~Availability_Cost_R(m) =~~
~~Sum(p∈P, Reserve_Cost_Share(p,m))~~

Availability_Cost_GTR(m) =
Sum(p∈P, GTR_Cost_Share(p,m))

(d) the total ~~Load Following~~ Frequency Keeping ~~Availability Cost~~ availability cost for Trading Month m:

~~Availability_Cost_LF(m) =~~
~~Availability_Cost(m) - Availability_Cost_R(m)~~

Availability_Cost_FKR(m) =
(Margin_FKR_Peak(m)
- Savings_Cal_Peak(m) × Savings_Alloc_Peak(m)
× Margin_GTR_Peak(m))
× Sum(tϵPeak_FKR_LT_GTR, MCAP(t)
× max(0,FKR(m) – Sum(c∈CAS_FKR,ASP_FKRQ(c,t))))

+ (Margin_FKR_Off-Peak(m)
- Savings_Cal_Off-Peak(m) × Savings_Alloc_Off-Peak(m)
× Margin_GTR_Off-Peak(m))
× Sum(tϵOff-Peak_FKR_LT_GTR, MCAP(t)
× max(0,FKR(m) – Sum(c∈CAS_FKR,ASP_FKRQ(c,t))))

+ Margin_FKR_Peak(m)
× Sum(tϵPeak_GTR_LE_FKR, MCAP(t)
× (max(0,FKR(m) – Sum(c∈CAS_FKR,ASP_FKRQ(c,t)))
- Savings_Alloc_Peak(m)
× Margin_GTR_Peak(m) / Margin_FKR_Peak(m)
× max(0,GTR_Peak(m) - Sum(c∈CAS_GTR,ASP_GTRQ(c,t)))))

+ Margin_FKR_Off-Peak(m)
× Sum(tϵOff-Peak_GTR_LE_FKR, MCAP(t)
× (max(0,FKR(m) – Sum(c∈CAS_FKR,ASP_FKRQ(c,t)))
- Savings_Alloc_Off-Peak(m)
× Margin_GTR_Off-Peak(m) / Margin_FKR_Off-Peak(m)
× max(0,GTR_Off-Peak(m) - Sum(c∈CAS_GTR,ASP_GTRQ(c,t)))))

+ Sum(c∈CAS_FKR,ASP_FKRPayment(c,m))

Where

t denotes a Trading Interval in Trading Month m;

T is the set of all Trading Intervals in Trading Month m;

c denotes a Contracted Ancillary Service;

CAS_GTR is the set of Contracted Generator Trip Reserve Services;

CAS_FKR is the set of Contracted Frequency Keeping Services;

P is the set of all Market Generators;

~~ASP_SRQ(i,t)~~ ASP_GTRQ(c,t) is the quantity provided by System Management in accordance with clause 3.22.3(b)(ii) for Contracted Generator Trip Reserve Service c ~~of Spinning Reserve provided by Ancillary Service Provider i~~ in Trading Interval t multiplied by 2, in units of MW ~~(this being one of the quantities referred to in clause 9.9.3)~~;

ASP_FKRQ(c,t) is the quantity provided by System Management in accordance with clause 3.22.3(b)(ii) for Contracted Frequency Keeping Service c in Trading Interval t multiplied by 2, in units of MW;

~~ASP_SRPayment(i,m)~~ASP_GTRPayment(c,m) is defined in clause ~~9.9.3~~9.9.4;

~~ASP_LFPayment(i,m)~~ ASP_FKRPayment(c,m) is defined in clause ~~9.9.3~~9.9.4;

TITM is the number of Trading Intervals in ~~the~~ Trading Month m (excluding any Trading Intervals prior to Energy Market Commencement);

~~Reserve_Share(p,t)~~ GTR_Share(p,t) is the share of the ~~Spinning~~ Generator Trip Reserve ~~service~~ Service payment costs allocated to Market Participant p in Trading Interval t, where this is to be determined by the IMO using the methodology described in clause 3.14.2;

~~Margin_Peak(m) is the reserve availability payment margin applying for Peak Trading Intervals for Trading Month m as specified by the IMO under clause 3.22.1(c);~~

~~Margin_Off-Peak(m) is the reserve availability payment margin applying for Off-Peak Trading Intervals for Trading Month m as specified by the IMO under clause 3.22.1(d);~~

Margin_FKR_Peak(m) is the reserve availability payment margin applying for Frequency Keeping Service for Peak Trading Intervals for Trading Month m as specified by the IMO under clause 3.22.1(cA);

Margin_GTR_Peak(m) is the reserve availability payment margin applying for Generator Trip Reserve for Peak Trading Intervals for Trading Month m as specified by the IMO under clause 3.22.1(cB);

Savings_Alloc_Peak(m) is the allocation factor for cost savings from dual use of plant providing Frequency Keeping Service to simultaneously provide Generator Trip Reserve Service, applying for Peak Trading Intervals in Trading Month m as specified by the IMO under clause 3.22.1(cC);

Savings_Cal_Peak(m) is the calibration factor for cost savings from dual use of plant providing Frequency Keeping Service to simultaneously provide Generator Trip Reserve Service, applying for Peak Trading Intervals in Trading Month m as specified by the IMO under clause 3.22.1(cD);

Margin_FKR_Off-Peak(m) is the reserve availability payment margin applying for Frequency Keeping Service for Off-Peak Trading Intervals for Trading Month m as specified by the IMO under clause 3.22.1(dA);

Margin_GTR_Off-Peak(m) is the reserve availability payment margin applying for Generator Trip Reserve for Off-Peak Trading Intervals for Trading Month m as specified by the IMO under clause 3.22.1(dB);

Savings_Alloc_Off-Peak(m) is the allocation factor for cost savings from dual use of plant providing Frequency Keeping Service to simultaneously provide Generator Trip Reserve Service, applying for Off-Peak Trading Intervals in Trading Month m as specified by the IMO under clause 3.22.1(dC);

Savings_Cal_Off-Peak(m) is the calibration factor for cost savings from dual use of plant providing Frequency Keeping Service to simultaneously provide Generator Trip Reserve Service, applying for Off-Peak Trading Intervals in Trading Month m as specified by the IMO under clause 3.22.1(dD);

~~Capacity_R_Peak(m) is the capacity necessary to cover the Ancillary Services Requirement for Spinning Reserve for Peak Trading Intervals for Trading Month m as specified by the IMO under clause 3.22.1(e);~~

~~Capacity_R_Off-Peak(m) is the capacity necessary to cover the Ancillary Services Requirement for Spinning Reserve for Off-Peak Trading Intervals for Trading Month m as specified by the IMO under clause 3.22.1(f);~~

GTR_Peak(m) is the requirement for Generator Trip Reserve in Peak Trading Intervals in Trading Month m, as specified by the IMO under clause 3.22.1(e);

GTR_Off-Peak(m) is the requirement for Generator Trip Reserve in Off-Peak Trading Intervals in Trading Month m, as specified by the IMO under clause 3.22.1(f);

~~LFR(m) is the capacity necessary to cover the Ancillary Services Requirement for Load Following for Trading Month m as specified by the IMO under clause 3.22.1(fA);~~

FKR(m) is the requirement for Frequency Keeping Service in Trading Month m, as specified by the IMO under clause 3.22.1(fA);

~~MCAP(d,t) has the meaning given in clause 9.8.1and=0 if MCAP (d,t)<0;~~MCAP(t) is the greater of zero and the Marginal Cost Administered Price for Trading Interval t calculated in accordance with clause 6.14.2;

~~Peak denotes the set of Trading Intervals occurring during Peak Trading Intervals, where “t” refers to a Trading Interval during a Trading Day;~~

~~Off-Peak denotes the set of Trading Intervals occurring during Off-Peak Trading Intervals, where "t" refers to a Trading Interval during a Trading Day; and~~

~~D denotes the set of Trading Days within Trading Month m, where "d" is used to refer to a member of that set;~~

Peak_FKR_LT_GTR is the set of Peak Trading Intervals within Trading Month m where (FKR(m) - Sum(c∈CAS_FKR,ASP_FKRQ(c,t))) < (GTR_Peak(m) - Sum(c∈CAS_GTR,ASP_GTRQ(c,t)));

Off-Peak_FKR_LT_GTR is the set of Off-Peak Trading Intervals within Trading Month m where (FKR(m) - Sum(c∈CAS_FKR,ASP_FKRQ(c,t))) < (GTR_Off-Peak(m) - Sum(c∈CAS_GTR,ASP_GTRQ(c,t)));

Peak_GTR_LE_FKR is the set of Peak Trading Intervals within Trading Month m where (GTR_Peak(m) - Sum(c∈CAS_GTR,ASP_GTRQ(c,t))) ≤ (FKR(m) - Sum(c∈CAS_FKR,ASP_FKRQ(c,t))); and

Off-Peak_GTR_LE_FKR is the set of Off-Peak Trading Intervals within Trading Month m where (GTR_Off-Peak(m) - Sum(c∈CAS_GTR,ASP_GTRQ(c,t))) ≤ (FKR(m) - Sum(c∈CAS_FKR,ASP_FKRQ(c,t))).

| |
|---|
| The amendments to clause 9.9.3 are to ensure consistency with RC_2010_33 and to update the names relating to Load Following and Spinning Reserve. |

9.9.3. The value of ASP_Payment(i,m) for ~~Ancillary Service Provider~~ Rule Participant i in Trading Month m is the sum of:

(a) the sum over all ~~Ancillary Service Contracts for Spinning Reserve~~ Contracted Generator Trip Reserve Services c provided by Rule Participant i of ASP_GTRPayment(c,m)~~ASP_SRPayment(i,m), the payment under that contract~~;

(b) the sum over all ~~Ancillary Service Contracts for Load Following~~ Contracted Frequency Keeping Services c provided by Rule Participant i of ASP_FKRPayment(c,m)~~ASP_LFPayment(i,m), the payment under that contract~~;

(c) the sum over all ~~Ancillary Service Contracts for Load Rejection Reserve~~ Contracted Load Rejection Reserve Services c provided by Rule Participant i of ASP_LRPayment(~~i~~c,m)~~, the payment under that contract~~;

(d) the sum over all ~~Ancillary Service Contracts for System Restart~~ Contracted System Restart Services c provided by Rule Participant i of ASP_BSPayment(~~i~~c,m)~~, the payment under that contract~~; and

(e) the sum over all ~~Ancillary Service Contracts for Dispatch Support~~ Contracted Dispatch Support Services c provided by Rule Participant i of ASP_DSPayment(~~i~~c,m)~~, the payment under that contract~~

where each of the terms ~~ASP_SRPayment(i,m), ASP_LFPayment(i,m),~~ ASP_GTRPayment(c,m), ASP_FKRPayment(c,m), ASP_LRPayment(~~i~~c,m), ASP_BSPayment(~~i~~c,m) and ASP_DSPayment(~~i~~c,m) is determined in accordance with clause 9.9.4.

New clauses 9.9.3A and 9.9.3B are included to ensure consistency with RC_2010_33 – the names relating to Load Following and Spinning Reserve have been updated.

9.9.3A. The value of ASP_Balance_Payment(m) for Trading Month m is:

ASP_Balance_Payment(m) =
Sum(c∈CAS_GTR, ASP_GTRPayment(c,m)) +
Sum(c∈CAS_FKR, ASP_FKRPayment(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))

where

c denotes a Contracted Ancillary Service;

CAS_GTR is the set of Contracted Generator Trip Reserve Services;

CAS_FKR is the set of Contracted Frequency Keeping Services;

CAS_LR is the set of Contracted Load Rejection Reserve Services;

CAS_BS is the set of Contracted System Restart Services;

CAS_DS is the set of Contracted Dispatch Support Services;

Cost_LR(m) is the amount specified by the IMO for Trading Month m under clause 3.22.1(g)(i) for Load Rejection Reserve Service and System Restart Service, and Dispatch Support Services except those provided through clause 3.11.8B, and

each of the terms ASP_GTRPayment(c,m), ASP_FKRPayment(c,m), ASP_LRPayment(c,m), ASP_BSPayment(c,m) and ASP_DSPayment(c,m) is determined in accordance with clause 9.9.4.

9.9.3B. The value of Cost_LR_Shortfall(m) for Trading Month m is:

Cost_LR_Shortfall(m) =
Max(0, Sum(c∈CAS_LR, ASP_LRPayment(c,m))

+ Sum(c∈CAS_BS, ASP_BSPayment(c,m))
- Cost_LR(m))

where

c denotes a Contracted Ancillary Service;

CAS_LR is the set of Contracted Load Rejection Reserve Services;

CAS_BS is the set of Contracted System Restart Services;

Cost_LR(m) is the amount specified by the IMO for Trading Month m under clause 3.22.1(g)(i) for Load Rejection Reserve Service and System Restart Service, and Dispatch Support Services except those provided through clause 3.11.8B, and

each of the terms ASP_LRPayment(c,m) and ASP_BSPayment(c,m) is determined in accordance with clause 9.9.4.

| |
|---|
| The amendments to clause 9.9.4 are to ensure consistency with RC_2010_33 and to update the names relating to Load Following and Spinning Reserve. |

9.9.4. For each ~~Ancillary Service Provider i and each Ancillary Service Contract~~ Contracted Ancillary Service c, the payment~~s ASP_SRPayment(i,m), ASP_LFPayment(i,m),~~ ASP_GTRPayment(c,m) for Generator Trip Reserve Service, ASP_FKRPayment(c,m) for Frequency Keeping Service, ASP_LRPayment(~~i~~c,m) for Load Rejection Reserve Service, ASP_BSPayment(~~i~~c,m) for System Restart Service or ~~and~~ ASP_DSPayment(~~i~~c,m) for Dispatch Support Service, as applicable, ~~are~~ for Trading Month m is:

(a) the applicable monthly dollar value specified by System Management for that Trading Month in accordance with clause 3.22.3(b)(iii)(1); or~~, if no such value is specified,~~

(b) where no value is specified under clause 9.9.4(a), the product of the applicable price specified in clause 3.22.3(b)(iii)(2) for that Trading Month and the sum over Trading Intervals in that Trading Month of the applicable quantities specified in clause 3.22.3(b)(ii).

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:

…

(y) as soon as practicable after a Trading Interval:

i. the total generation in that Trading Interval;

ii. the total ~~Spinning~~ Generator Trip Reserve in that Trading Interval;

iii. an initial value of the Operational System Load Estimate, taken directly from System Management's EMS/SCADA system.

where these values are to be available from the IMO Web Site for each Trading Interval in the previous 12 calendar months;

(z) as soon as practicable after real-time:

i. the total generation;

ii. the total ~~Spinning~~ Generator Trip Reserve;

iii. an initial value of the Operational System Load Estimate, taken directly from System Management's EMS/SCADA system;

where these values are not required to be maintained on the IMO Web Site after their initial publication;

…

**Glossary**

**Contracted Ancillary Service:** an Ancillary Service provided by a Rule Participant under an Ancillary Service Contract.

**Contracted Dispatch Support Service:** a Dispatch Support Service provided by a Rule Participant under an Ancillary Service Contract.

**Contracted Frequency Keeping Service:** a Frequency Keeping Service provided by a Rule Participant under an Ancillary Service Contract.

**Contracted Generator Trip Reserve Service:** a Generator Trip Reserve Service provided by a Rule Participant under an Ancillary Service Contract.

**Contracted Load Rejection Reserve Service:** a Load Rejection Reserve Service provided by a Rule Participant under an Ancillary Service Contract.

**Contracted System Restart Service:** a System Restart Service provided by a Rule Participant under an Ancillary Service Contract.

**Dispatch Support Service**: Has the meaning given in clause 3.9.9.

**Frequency Keeping:** The frequent adjustment of the output of one or more generators or the consumption of one or more loads within a Trading Interval, so as to match total system generation to total system load in real time in order to correct any SWIS frequency variations.

**Frequency Keeping Service**: Has the meaning given in clause 3.9.1.

**Generator Trip 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.

**Generator Trip Reserve Service:** Has the meaning given in clause 3.9.2.

~~**Load Following Service**: Has the meaning given in clause 3.9.1.~~

**Minimum Frequency Keeping Capacity**: Has the meaning given in clause ~~3.10.1(a)~~3.10.1A.

~~**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.~~

**System Restart Service**: ~~The Ancillary Service described~~Has the meaning given in clause 3.9.8.

# 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 for Facility Registration, and which is to be updated by Rule Participants as necessary, is described by clauses (a) to (j).

Standing Data not required to be provided as a pre-condition for Facility Registration but that which is required to be maintained by the IMO includes the data described in clauses (k) onwards.

…

(b) for a Scheduled Generator:

…

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~~Frequency Keeping Service;

2. ~~Spinning Reserve~~Generator Trip Reserve Service;

3. [Blank]; and

4. Load Rejection Reserve Service;

…

(g) for an Interruptible Load:

i. the Market Customer's nominated maximum consumption quantity, in units of MWh per Trading Interval;

ii. evidence that the communication and control systems required by clause 2.36 are in place and operational;

iii. real-time telemetry capabilities;

iv. the maximum amount of load that can be interrupted;

v. the maximum duration of any single interruption;

vi. the capability to provide each of the following Ancillary Services as a function of consumption:

1. ~~Spinning~~ Generator Trip Reserve Service~~.~~; and

1A. Frequency Keeping Service;

2. [Blank]

…

(i) for a Dispatchable Load:

…

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~~Frequency Keeping Service;

2. ~~Spinning Reserve~~Generator Trip Reserve Service;

3. [Blank]; and

4. Load Rejection Reserve Service;

…

(m) For each Intermittent Facility, whether it is exempted from funding ~~Spinning~~ Generator Trip Reserve costs.

# Appendix 2: ~~Spinning~~ Generator Trip Reserve Cost Allocation

This Appendix determines the value of ~~Reserve_Share(p,t)~~ GTR_Share(p,t) of the ~~Spinning~~ Generator Trip Reserve ~~service~~ Service payment costs in Trading Interval t to be borne by Market Participant p.

In this Appendix the relevant Market Participant p is the Market Participant to whom a facility is registered, with the exception that in the case of unregistered generation systems serving Intermittent Loads, the relevant Market Participant p is the Market Participant to whom the Intermittent Load is registered.~~.~~

The calculations in this Appendix are based on data for a set of applicable facilities (indexed by f) where this set comprises all Scheduled Generators and all Non-Scheduled Generators registered during Trading Interval t, except those Intermittent Generators exempted under clause 2.30A.2. This set also includes all unregistered generation systems serving Intermittent Loads.

For the purpose of determining the ~~Reserve_Share(p,t)~~ GTR_Share(p,t) values, each applicable facility f has an applicable capacity associated with it for Trading Interval t.

- If facility f is an Intermittent Generator with an interval meter then this is double the MWh average interval meter reading for the Trading Month containing Trading Interval t.
- If facility f is a Scheduled Generator with an interval meter then this is double the MWh interval meter reading for Trading Interval t.
- If facility f is an Electricity Generation Corporation Intermittent Generator without an interval meter then this is double the average monthly MWh sent out generation of that facility based on SCADA data over the Trading Month containing Trading Interval t.
- If facility f is an Electricity Generation Corporation Scheduled Generator without an interval meter or an unmetered generation system serving Intermittent Load then this is double the MWh sent out generation of that facility based on SCADA data for Trading Interval t.

The methodology makes use of the data in Table 1.

| Block Number | Block Range (MW) | Block Size (MW) |
|---|---|---|
| 1 | > 200 | 100 |
| 2 | >125 and ≤ 200 | 75 |
| 3 | >65 and ≤ 125 | 60 |
| 4 | >45 and ≤ 65 | 20 |

| | | |
|---|---|---|
| 5 | >10 and ≤ 45 | 35 |

**Table 1: Data ~~for~~ to Determine ~~Reserve_Share(p,t)~~GTR_Share(p,t)**

For each Block, indicated by block number b, in Table 1, the Reserve Block Share is:

If Sum(f(i≤)) > 0

RBS(b) = [Block Size(b) / Sum(i, Block Size(i))] / Sum(f(i≤), TIS(f))

If Sum(f(i≤)) = 0

RBS(b) = 0

Where

Block Size(i) is the size of the Block with block number i listed in Table 1.

f(i≤) is the subset of applicable facilities that had applicable capacities for Trading Interval t lying within the block range of any Block with a block number value of b or less.

TIS(f) is 1 if the applicable facility f was synchronised to the SWIS during Trading Interval t, and is zero otherwise.

For each Block b in Table 1, the Reserve Generator Share is:

RGS(b) = Sum(i≥, RBS(i))

Where

i≥ is the set of Blocks listed in Table 1 that have a block number i greater than or equal to b.

For each Market Participant p, its unadjusted share of the ~~Spinning~~ Generator Trip Reserve ~~service~~ Service payment costs for the Trading Interval is:

USHARE(p) = Sum(f(p), RGS(b(f)) × TIS(f))

Where

f(p) is the set of applicable facilities for the Market Participant p that have applicable capacities within one of the block ranges listed in Table 1.

b(f) is the block number of the Block in Table 1 that has a block range that corresponds to the applicable capacity of the applicable facility f.

TIS(f) is 1 if the applicable facility f was synchronised to the SWIS during Trading Interval t, and is zero otherwise.

For each Market Participant p, its adjusted share of the ~~Spinning~~ Generator Trip Reserve ~~services~~ Service payment costs for Trading Interval t is:

~~Reserve_Share(p,t)~~ GTR_Share(p,t) = USHARE(p) / sum(q, USHARE(q))

Where

q is the index of the set of all Market Participants.

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

The IMO considers the changes proposed will have the following impact on the Wholesale Market Objectives:

| Impact | Market Objectives |
|---|---|
| Allow the Market Rules to better address the objective. | a, c |
| Consistent with objective. | b, d, e |
| Inconsistent with objective. | |

The proposed amendments will provide more accurate pricing of Load Following and Spinning Reserve Services, particularly where the Load Following requirement is partially met by contracts or exceeds the Spinning Reserve requirement. The amendments will also ensure a more accurate allocation of the costs of Load Following and Spinning Reserve Services to those who cause them, through a more accurate division of availability costs between Load Following Service and Spinning Reserve Service (which are funded by different groups) and through the adoption of the "Full Load, Marginal Generation" methodology for the allocation of Load Following Service costs. The IMO considers that these improvements better promote the economically efficient production and supply of electricity and electricity related services in the SWIS (Wholesale Market Objective (a)).

The IMO also considers that the more equitable allocation of Load Following Service and Spinning Reserve Service costs on a "causer pays" basis will assist in avoiding discrimination against particular generator types, better promoting Wholesale Market Objective (c).

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

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

**Costs:**

- The IMO will have IT costs associated with this proposal. These costs will be quantified during the first submission period.
- The IMO will be required to update its internal operating procedures.
- The IMO may need to update some of its Market Procedures, including the Facility Registration, de-Registration and Facility Transfer Procedure, the Settlement Procedure, the Information Confidentiality Procedure and the Reserve Capacity Procedure for Undertaking the LT PASA and conducting a review of the Planning Criterion.

- The complexity of the IMO's annual review of margin values is expected to increase, with the number of parameters rising from two (Margin_Peak and Margin_Off-Peak) to eight (Margin_FKR_Peak, Margin_FKR_Off-Peak, Margin_GTR_Peak, Margin_GTR_Off-Peak, Savings_Alloc_Peak, Savings_Alloc_Off-Peak, Savings_Cal_Peak and Savings_Cal_Off-Peak). This is likely to involve a substantial increase in the review costs (currently around $30,000 per annum). These costs will be quantified during the first submission period.
- The increased complexity of the annual review and the requirement to undertake a public consultation process on the review assumptions and methodology may require additional IMO resources. These additional resource requirements will be quantified during the first submission period.
- The ERA may incur additional costs in its review and approval process of the additional variables, listed above. The IMO will work with the ERA during the first submission period to quantify these costs.
- System Management will need to update some of its Power System Operation Procedures, including the Ancillary Services Procedure, the Dispatch Procedure, the Security Procedure, the Operational Data Points for Generating Plant Procedure and the Glossary of Terms.
- System Management may incur additional costs around the provision of the parameters GTR_Peak, GTR_Off-Peak, FKR and FKR_Loads each Trading Month. The IMO will work with System Management during the first submission period to quantify these costs.
- Market Participants may require minor changes to IT systems and internal procedures.

**Benefits:**

- The Rule Change Proposal corrects a number of manifest errors in the Market Rules, which would lead to perverse outcomes if the Load Following requirement was partially met by contracts or exceeded the Spinning Reserve requirement.
- The Rule Change Proposal will provide more accurate pricing signals to generators and Loads that are more reflective of the actual costs of the Ancillary Services (Load Following and Spinning Reserve) that they require.
- The Rule Change Proposal will enhance the economic efficiency of the market, preventing investment in projects that may have large externalities that are not accounted for under the existing payment structure.
- The Rule Change Proposal may also facilitate investment in projects that are economically viable, but under the existing Ancillary Services payment structure are liable for excessive costs that are not related to their operation.

# Agenda Item 5c: Reassessment of Allowable Revenue during a Review Period (PRC_2011_02)

## 1. BACKGROUND

In its Pre Rule Change Discussion Paper, the Economic Regulation Authority (ERA) seeks to address three issues of concern around the operation of clauses 2.22.8, 2.22.13 and 2.23.8 of the Wholesale Electricity Market Rules (Market Rules). These clauses provide for a reassessment of Allowable Revenue for the IMO and System Management during a Review Period where an amount of un-forecast expenditure is proposed to be incurred.

### *1.1 Inconsistencies in the treatment of proposed capital expenditures*

In their current form, the way in which clauses 2.22.8, 2.22.13 and 2.23.8 apply to proposed capital expenditures of the IMO and System Management can result in inconsistencies, depending on the timing of the expenditure and the period over which the cost is to be depreciated or amortised, in:

- whether a project of a given total cost meets the criteria for a Declared Market Project (clause 2.22.13); and
- whether a reassessment of approved Allowable Revenue by the ERA is triggered.

As a result of these inconsistencies, capital expenditures made by the IMO and System Management that involve material increases in the market fees charged to Market Participants may or may not be subject to review by the ERA. The ERA has proposed amendments to clauses 2.22.8, 2.22.13 and 2.23.8 to ensure a more consistent approach to the consideration of proposed capital expenditures.

### *1.2 Incremental revenue threshold for declaration of Declared Market Projects and reassessment of approved Allowable Revenue*

Currently the threshold value of incremental revenue, which acts as a trigger for the declaration of a Declared Market Project (under clause 2.22.13) or the reassessment of approved Allowable Revenue (under clauses 2.22.8 and 2.23.8), is 15 percent of the Allowable Revenue approved by the ERA. The ERA considers that this threshold is too high, creating the potential for material increases in fees to occur without review by the ERA of whether the additional expenditure meets the criteria specified in clauses 2.22.12(b) or 2.23.12(b). The ERA has proposed a reduced threshold of 10 percent of approved Allowable Revenue, but considers that the views of stakeholders should be sought as to the appropriate level as part of the rule change process.

### *1.3 Mechanism for the IMO or System Management to request the ERA to review a budget proposal*

The Market Rules do not allow for the IMO or System Management to request that the ERA review a budget proposal that does not automatically trigger such a review under clauses 2.22.8, 2.22.13 and 2.23.8. As a result, no mechanism is currently available to resolve uncertainty over whether the budget proposal satisfies the criteria in clauses 2.22.12(b) or

2.23.12(b), and there is a risk that the ERA may not approve the associated Allowable Revenue for the next Review Period. The ERA has proposed two new clauses (2.22.15 and 2.23.13) to provide such a mechanism.

## 2. RECOMMENDATIONS

The IMO recommends that the MAC:

- **Discuss** the Pre Rule Change Discussion Paper.

# Agenda item 5c, appendix 1

# Wholesale Electricity Market
# Pre Rule Change Proposal

**Change Proposal No:** **PRC_2011_02**
**Received date:** *[to be filled in by the IMO]*

**Change requested by:**

| | |
|---|---|
| **Name:** | Chris Brown |
| **Phone:** | 08 9213 1992 |
| **Fax:** | |
| **Email:** | chris.brown@erawa.com.au |
| **Organisation:** | Economic Regulation Authority |
| **Address:** | |
| **Date submitted:** | *TBA* |
| **Urgency:** | *2* |
| **Change Proposal title:** | Reassessment of Allowable Revenue during a Review Period |
| **Market Rule(s) affected:** | Clauses 2.22.8, 2.22.13, 2,22,15 (new), 2.23.8 and 2.23.13 (new) |

## Introduction

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

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

**Independent Market Operator**
Attn: Manager Market Development and System 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 Market Rule Change

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

The Economic Regulation Authority (**ERA**) has three concerns over the operation of clauses 2.22.8, 2.22.13 and 2.23.8 of the *Wholesale Electricity Market Rules* (**Market Rules**), which provide for a reassessment of Allowable Revenue for the Independent Market Operator (**IMO**) and System Management during a Review Period where an amount of un-forecast expenditure is proposed to be incurred.

First, in their current form, the way in which clauses 2.22.8, 2.22.13 and 2.23.8 of the Market Rules apply to proposed capital expenditures of the IMO and System Management can result in inconsistencies, depending on the timing of the expenditure and the period over which the cost is to be depreciated or amortised, in:

- whether a project of a given total cost meets the criteria for a Declared Market Project (clause 2.22.13); and
- whether a reassessment of approved Allowable Revenue by the ERA is triggered.

As a result of these inconsistencies, capital expenditures made by the IMO and System Management that involve material increases in the market fees[1] charged to Market Participants may or may not be subject to review by the ERA.

Secondly, the existing threshold value of incremental revenue that acts as a trigger for the declaration of a Declared Market Project (under 2.22.13) and the reassessment of approved Allowable Revenue (under 2.22.8 and 2.23.8) is too high. This creates the potential for material increases in fees to occur without review by the ERA of whether the additional

[1] Market fees in this context can include IMO ‘Market Fees’ (IMO) and/or System Management ‘System Operation Fees’.

expenditure meets the criteria specified in clauses 2.22.12(b) or 2.23.12(b) of the Market Rules.

Thirdly, the Market Rules do not allow for the IMO or System Management to request that the ERA review a budget proposal that does not automatically trigger such a review under clauses 2.22.8, 2.22.13 and 2.23.8. As a result no mechanism is currently available to resolve uncertainty over whether the budget proposal satisfies the criteria in clause 2.22.12(b) or 2.23.12(b), and there is a risk that the ERA may not approve the associated Allowable Revenue for the next Review Period.

**The purpose and operation of the Market Rules for which changes are being proposed**

Under the Market Rules, the IMO and System Management submit proposed expenses for the forthcoming three-year Review Period, including capital expenditures, for the purposes of allowing the ERA to determine their respective approved Allowable Revenue. Allowable Revenue is recovered from Market Participants through Market Fees (IMO) or System Operation Fees (System Management).

The Market Rules recognise that budget proposals involving expenditure that was not anticipated by the IMO or System Management at the time that proposed expenses were submitted to the ERA as part of the Revenue Determination process may need to be incurred during a Review Period.

Two provisions in the Market Rules can be used to recover such expenditures through the fess payable by Market Participants.

- Clauses 2.22.7 and 2.23.7 require the IMO or System Management to increase (decrease) revenue from Market Fees or System Operation Fees in the current year's budget when their expenditure in the previous Financial Year was greater than (less than) revenue in that year.
- Clauses 2.22.8 and 2.23.8 provide for the ERA to reassess Allowable Revenue if, taking into account adjustments under 2.22.7 or 2.23.7, revenue recovery for the whole of the Review Period is likely to be greater than 15 per cent of approved Allowable Revenue for the Review Period.

Clauses 2.22.8 and 2.23.8 ensure that expenditure proposals involving a significant departure from approved Allowable Revenue for the Review Period, or a series of expenditure proposals that in aggregate constitute a significant departure from approved Allowable Revenue, are subject to appropriate scrutiny by the ERA. Expenditure proposals are approved only when the ERA considers that the underlying expenditures meet the criteria specified in clauses 2.22.12(b) or 2.23.12(b).

Clause 2.22.13 provides for the IMO to determine that particular capital projects are Declared Market Projects. A Declared Market Project must involve:

- a major change to a function of the IMO or System Management under these Market Rules; or
- a major change to any of the computer software or systems that the IMO or System Management uses in the performance of any of its functions under these Market Rules; and
- an estimated cost to implement the changes would cause either the IMO's budget or System Management's budgets during the current Review Period to exceed their respective approved Allowable Revenue by greater than 15 per cent.

Clause 2.22.14 requires the IMO to receive ERA approval for the incremental Allowable Revenue associated with a Declared Market Project prior to commencing that project.

Declared Market Projects represent significant changes to the operation of the IMO or System Management in the Wholesale Electricity Market (**WEM**), with potential consequences for Market Participants that include the additional fees required to recover the cost of the project, adjustment costs and changes to the competitiveness of the WEM. It is therefore appropriate that the ERA considers the merits of a Declared Market Project, applying the criteria specified in clauses 2.22.12(b) or 2.23.12(b).[2]

**Issue 1 - Inconsistencies in the treatment of capital expenditures**

The ERA is concerned that, under the current Market Rules, a budget proposal involving capital expenditure that will result in the IMO or System Management recovering Allowable Revenue in excess of 15 per cent of approved Allowable Revenue for the current Review Period may or may not trigger an assessment of that expenditure by the ERA depending on the timing of the expenditure and the period over which the expenditure is to be depreciated or amortised. These two dependencies are illustrated in Table 1 and Table 2, respectively.

Table 1 illustrates how, for the same capital project, the year in which the project occurs can determine the outcome of the threshold test under either clauses 2.22.8 (for the IMO) or 2.23.8 (for System Management) of the Market Rules.

**Table 1. Impact of a capital expenditure – expenditure in different years of a Review Period**

| | *Current Review Period* | | | | *Next Review Period* | | | |
|---|---|---|---|---|---|---|---|---|
| | Year 1 $m | Year 2 $m | Year 3 $m | **Total $m** | Year 1 $m | Year 2 $m | Year 3 $m | **Total $m** |
| **Approved Allowable Revenue** | 25 | 25 | 25 | **75** | 25 | 25 | 25 | **75** |
| **Capital project – incremental revenue** | | | | | | | | |
| **Scenario 1** | 5 | 5 | 5 | **15** | | | | |
| **Scenario 2** | | 5 | 5 | **10** | 5 | | | **5** |

Under scenario one, the capital project has a cost (expressed as three years of amortisation allowances) of $15 million, equivalent to 20 per cent of previously approved Allowable Revenue for the current Review Period of $75 million. The project cost is written off by depreciation over three years.[3] The depreciation allowances are recovered through an

[2] Clause 2.22.12(b) states "the [IMO] Allowable Revenue must include only costs which would be incurred by a prudent provider of the services described in clause 2.22.1, acting efficiently, seeking to achieve the lowest practicably sustainable cost of delivering the services described in clause 2.22.1 in accordance with these Market Rules, while effectively promoting the Wholesale Market Objectives.". Clause 2.23.12(b) states "the [System Management] Allowable Revenue must include only costs which would be incurred by a prudent provider of the services described in clause 2.23.1, acting efficiently, in accordance with good electricity industry practice, seeking to achieve the lowest practicably sustainable cost of delivering the services described in clause 2.23.1 in accordance with these Market Rules, while effectively promoting the Wholesale Market Objectives..."

[3] The IMO's and System Management's capital projects predominantly consist of systems enhancements and computer equipment for which a three-year depreciation schedule is consistent with generally accepted accounting standards.

increase in revenue generated by fees of $15 million levied on Market Participants over the current Review Period. As revenue raised over the current Review Period is now expected to be greater than 15 per cent of approved Allowable Revenue, a review of the proposed expenditure by the ERA is triggered (under clauses 2.22.8 or 2.23.8, or under 2.22.14 if the project meets the necessary criteria for a Declared Market Project under 2.22.13).

Under scenario two, the project is undertaken in the second year of the current Review Period but is otherwise identical to the project in scenario one. As the additional revenue that will be raised in the current review period is expected to be less than 15 per cent of approved Allowable Revenue, the Market Rules do not trigger a review of the proposed expenditure by the ERA.

The ERA's view is that this outcome is an anomaly and that the year of the Review Period in which a capital expenditure is incurred should have no bearing on whether expenditure triggers a reassessment of Allowable Revenue by the ERA.

As part of the Allowable Revenue determination for the next Review Period, the ERA will review the proposed depreciation allowance in the first year of that triennium and could elect not to approve this expense. However, this would not be a satisfactory outcome as, if the cost were determined to not satisfy the criteria of the Market Rules, a substantial part of the cost would already have been met by Market Participants through market Fees.

Table 2 shows how the length of time over which a capital expenditure is depreciated, or in the case of an intangible asset, amortised, can partly determine the outcome of the threshold test.

**Table 2. Impact of a capital expenditure – different depreciation/amortisation periods**

| | ***Current Review Period*** | | | | ***Next Review Period*** | | | |
|---|---|---|---|---|---|---|---|---|
| | Year 1 | Year 2 | Year 3 | **Total** | Year 1 | Year 2 | Year 3 | **Total** |
| | $m | $m | $m | **$m** | $m | $m | $m | **$m** |
| **Approved Allowable Revenue** | 25 | 25 | 25 | **75** | 25 | 25 | 25 | **75** |
| **Capital project – incremental revenue** | | | | | | | | |
| **Scenario 1** | 5 | 5 | 5 | **15** | | | | |
| **Scenario 2** | 3 | 3 | 3 | **9** | 3 | 3 | | **6** |

Under scenario two the capital expenditure is depreciated over five years, rather than the three years under scenario one. The longer time period under scenario two would be appropriate under the Market Rules as long as it is consistent with generally accepted accounting principles for the depreciation or amortisation of the type of asset being acquired.[4]

The capital expenditures under both scenarios are of the same amount. However, the longer time period for depreciation under scenario two means that the additional revenue required during the current Review Period is equivalent to only 12 per cent of approved Allowable Revenue. A reassessment of Allowable Revenue by the ERA, or an assessment of the project by the ERA under the rules for Declared Market Projects would not be triggered under this scenario.

[4] As required under clauses 2.22.12 (a) ii. and 2.23.12 (a) ii of the Market Rules.

The ERA seeks to address these inconsistencies in the treatment of capital expenditures through redrafting clauses 2.22.8, 2.22.13 and 2.23.8 of the Market Rules.

In seeking to rectify these inconsistencies in clauses 2.22.8 (for the IMO) and 2.23.8 (for System Management) of the Market Rules, the ERA has sought to preserve the primary intent of these clauses. In particular, the ERA has sought to ensure that the redrafted clauses will continue to trigger a reassessment of Allowable Revenue when:

- a single budget proposal will result in revenue exceeding the threshold in the Market Rules; or
- the combined revenue associated with more than one budget proposal exceeds the threshold in the Market Rules.

To achieve this outcome the proposed changes to the relevant clauses differentiate between the concepts of capital expenditure and recurring expenditure. In the interest of consistency the ERA has also applied these concepts in the proposed redrafting of clause 2.22.13 of the Market Rules (i.e. regarding the IMO proposing a Declared Market Project).

A capital expenditure refers to expenditure where the benefits are spread across several accounting periods such as the acquisition of new assets and improvements or extensions to existing assets. This term capital expenditure appears in clauses 2.22.12(a)(ii) and 2.23.12(a)(ii) of the Market Rules.

Recurring expenditure requirements consists of expenditure incurred in only one accounting period where the benefit of that expenditure is enjoyed only in that period. It includes depreciation and amortisation expenses that recoup capital expenditures made in previous periods. Recurring expenditure is analogous to the concept of ‘recurring expenditure requirements and payments’ in clauses 2.22.12(a)(i) and 2.23.12(a)(i) of the Market Rules.

The proposed revised clauses 2.22.8 and 2.23.8 of the Market Rules have been drafted to ensure that it is the capital expenditure that is taken into account in the threshold test, rather than the resulting depreciation (or amortisation) expenses. This eliminates any influence of the timing of the capital expenditure within a Review Period or the time over which that expenditure is depreciated or amortised.

To avoid double counting in the application of the threshold test, the redrafted rules exclude any depreciation or amortisation expenses that will be incurred during the Review Period. These redrafted clauses of the Market Rules also seek to ensure that decisions to capitalise or not capitalise particular expenditures associated with a project cannot influence whether a reassessment of Allowable Revenue is triggered.

The proposed treatment of capital expenditure partly reflects the arrangements set out in clause 6A.7.1 of the *National Electricity Rules* for the reopening of a revenue determination for the capital expenditure of a transmission network service provider. Among other requirements, this clause includes a threshold test that ‘the total of the un-forecast capital expenditure required in the regulatory control period must exceed five per cent of the value of the regulatory asset base of the transmission network service provider in the first year of the relevant regulatory control period’.

**Issue 2 - The level of the threshold exceeds the appropriate level for the triggering of a reassessment of Allowable Revenue by the ERA.**

In the ERA’s opinion, the 15 per cent threshold specified in clauses 2.22.8, 2.22.13 and 2.23.8 prevents the appropriate degree of scrutiny of proposed changes to the IMO’s and System Management’s costs within a Review Period. Given the current level of the threshold, Market Participants could not be confident that material increases in the market fees they are required to pay reflect costs that meet the principles outlined in clauses 2.22.12(b) and 2.23.12(b) of the Market Rules.

Table 3 shows the dollar value of the 15 per cent threshold under the approved Allowable Revenue for the IMO and System Management for the first and second Review Periods.

**Table 3. IMO and System Management Allowable Revenue and reassessment threshold triggers**

| | IMO | | System Management | |
|---|---|---|---|---|
| | 1st Review Period | 2nd Review Period | 1st Review Period | 2nd Review Period |
| | $m | $m | $m | $m |
| Approved Allowable Revenue | 29.7 | 33.9 | 14.4 | 21.2 |
| 15 per cent threshold | 4.5 | 5.1 | 2.2 | 3.2 |

The ERA observes that the IMO and System Management were able to manage the variation between actual and approved expenditure to within five per cent of approved Allowable Revenue in the first Review Period. This is in spite of the uncertainty in projected costs submitted to the ERA as part of the assessment of Allowable Revenue for the First Review Period.

The ERA accepts that the appropriate level of the threshold is largely a matter of judgement as to the necessary balance between:

- providing the IMO and System Management with the flexibility to respond to changing circumstances (e.g. cost increases or need for additional expenditure) during a Review Period; and
- providing for accountability of the IMO and System Management to ensure that Allowable Revenue includes only those costs that would be incurred by a prudent provider acting efficiently, seeking to achieve the lowest practicably sustainable cost of delivering the required services, while effectively promoting the wholesale market objectives.

The ERA proposes that the threshold increase in revenue for a Review Period should be reduced to ten per cent of approved Allowable Revenue for the Review Period. However, the ERA also considers that the views of stakeholders should be sought as to the appropriate level as part of the rule change process.

**Issue 3 - The need for a rule providing for a power to request the ERA to review a budget proposal for capital expenditure**

The ERA considers that the assessment of proposed capital expenditure against the provisions of clauses 2.22.12(b) and 2.23.12(b) often involves an element of judgement. As a result, in circumstances where the Market Rules do not create the requirement for the ERA to assess a proposed capital expenditure, the IMO or System Management may elect to delay a project due to the risk that the ERA may not approve the Allowable Revenue recovering depreciation or amortisation expenses in the next Review Period. Capital projects that are consistent with the attainment of the Market Objectives may be delayed as a result.

The inclusion of a clause in the Market Rules allowing the IMO or System Management to request that the ERA review a proposed capita project has a precedent. Section 80 of Part 9 of the *National Gas Rules* provides for the Australian Energy Regulator to make an advance determination with regard to future capital expenditure at the request of a service provider.

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## 2. Explain the reason for the degree of urgency:

The proposed rule changes are considered to be of a moderate level of urgency given that the issues with the existing rules prompting these changes do not put at risk the safe, effective and reliable operation of the WEM. The proposed rule changes cannot reasonably be considered to be of a high level of urgency for this reason.

However, proposals for previously un-forecast capital expenditure may result in either the IMO or System Management incurring depreciation and/or amortisation expenses over a period of time that exceed 15 per cent of allowable revenue in the Review Period in which the capital item is purchased could occur at any time during the current Review Period. In the absence of the proposed rule changes the costs of these capital expenditures may be recovered from Market Participants without the appropriate scrutiny of expenditure by the ERA. The ERA's view is that the potential for this to occur means that the proposed rule changes should not be considered to be of a low level of urgency.

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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)

2.22.8. Where, taking into account any adjustment under clause 2.22.7, the budget proposal is likely to:

(a) result in revenue recovery, over the ~~relevant~~ current Review Period, ~~more than 15%~~ at least 10% greater than the Allowable Revenue determined by the Economic Regulation Authority~~,~~; or

(b) result in a sum of capital expenditures and recurring expenditures such that if:

i. depreciation and amortisation expenses in the current Review Period recovering the capital expenditures are subtracted from recurring expenditures; and

ii. the capital expenditures were to be fully recovered in the current Review Period;

then revenue recovery would be at least 10% greater than the Allowable Revenue determined by the Economic Regulation Authority,

the IMO must apply to the Economic Regulation Authority to reassess the Allowable Revenue. The IMO must endeavour to make such an application in sufficient time to allow its budget proposal to be approved under clause 2.22.9 before the commencement of the Financial Year 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 this clause 2.22.8. Clause 2.22.3(b) applies in the case of an application under this clause 2.22.8.

…

2.22.13. Subject to clause 2.22.14, the IMO may declare a project to be a Declared Market Project if:

(a) the project involves:

i. a major change to a function of the IMO or System Management under these Market Rules; or

ii. a major change to any of the computer software or systems that the IMO or System Management uses in the performance of any of its functions under these Market Rules; and

(b) the IMO estimates~~ that the cost~~ a sum of capital expenditures and recurring expenditures required by the IMO or System Management to implement the changes such that if:

i. depreciation and amortisation expenses in the current Review Period recovering the capital expenditures of the Declared Market Project are subtracted from recurring expenditures; and

ii. the capital expenditures of the Declared Market Project were to be fully recovered in the current Review Period;

would cause either the IMO's budget or System Management's budget~~s~~ during the current Review period to exceed their respective approved Allowable Revenue by ~~more than 15%.~~ at least 10%.

…

2.22.15 During a Review Period, the IMO may seek the approval of an adjustment of its approved Allowable Revenue for that Review Period from the Economic Regulation Authority for each of the services described in clause 2.22.1 in accordance with the following:

(a) the Economic Regulation Authority may, on application by the IMO under clause 2.22.15, make a determination to the effect that, if capital expenditure is made in accordance with a proposal made by the IMO and specified in the determination, then approved Allowable Revenue for the relevant Review Period is increased by an amount equal to the associated depreciation or amortisation expenses over the Review Period;

(b) any proposal under clause 2.22.15 must include only costs which would be incurred by a prudent provider of the services described in clause 2.22.1, acting efficiently, seeking to achieve the lowest practicably sustainable cost of delivering the services described in clause 2.22.1 in accordance with these Market Rules, while effectively promoting the Wholesale Market Objectives;

(c) the Economic Regulation Authority may, but is not required to, engage in public consultation before making a determination under clause 2.22.15; and

(d) a determination under clause 2.22.15 is binding on the Economic Regulation Authority, but a decision not to make such a determination creates no presumption that future expenditure will not meet the relevant criteria under clause 2.22.15(b).

…

2.23.8. Where, taking into account any adjustment under clause 2.23.7, the budget proposal is likely to:

(a) result in revenue recovery, over the relevant Review Period, ~~more than 15%~~ at least 10% greater than the Allowable Revenue determined by the Economic Regulation Authority; or

(b) result in a sum of capital expenditures and recurring expenditures such that if:

i. depreciation and amortisation expenses in the current Review Period recovering the capital expenditures are subtracted from recurring expenditures; and

ii. the capital expenditures were to be fully recovered in the current Review Period;

then revenue recovery would be at least 10% greater than the Allowable Revenue determined by the Economic Regulation Authority,

System Management must apply to the Economic Regulation Authority to reassess the Allowable Revenue. System Management must endeavour to make such an application in sufficient time to meet its obligation under clause 2.23.9. The Economic Regulation Authority may amend a determination under clause 2.23.3(c) if System Management makes an application under this clause 2.23.8. Clause 2.23.3(b) applies in the case of an application under this clause 2.23.8.

…

2.23.13 During a Review Period, System Management may seek the approval of an adjustment of its approved Allowable Revenue for that Review Period from the Economic Regulation Authority for each of the services described in clause 2.23.1 in accordance with the following:

(a) the Economic Regulation Authority may, on application by System Management under clause 2.23.13, make a determination to the effect that, if capital expenditure is made in accordance with a proposal made by System Management and specified in the determination, then approved Allowable Revenue for the relevant Review Period is increased by an amount equal to the associated depreciation or amortisation expenses over the Review Period;

(b) any proposal under clause 2.23.13 must include only costs which would be incurred by a prudent provider of the services described in clause 2.23.1, acting efficiently, in accordance with good electricity industry practice, seeking to achieve the lowest practicably sustainable cost of delivering the services described in clause 2.23.1 in accordance with these Market Rules, while effectively promoting the Wholesale Market Objectives;

(c) the Economic Regulation Authority may, but is not required to, engage in public consultation before making a determination under clause 2.22.13; and

(d) a determination under clause 2.23.13 is binding on the Economic Regulation Authority, but a decision not to make such a determination creates no presumption that future expenditure will not meet the relevant criteria under clause 2.23.13(b).

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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 objectives of the market defined in section 1.2.1 of the Market Rules are:

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

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

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

d) to minimise the long-term cost of electricity supplied to consumers 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.

The ERA's view is that the proposed rule changes will:

- promote the economically efficient production and supply of electricity and electricity related services in the South West interconnected system by helping to ensure that proposed significant capital expenditures of the IMO and System Management during a Review Period are assessed by the ERA in the same manner as capital expenditures that are part of proposed costs for the three-yearly Allowable Revenue Determination.
- contribute to the minimisation of the long-term cost of electricity supplied to consumers from the SWIS by increasing the level of scrutiny of costs incurred by the IMO and System Management that are ultimately passed on to consumers by Market Participants.

The ERA is of the view that the proposed changes will not reduce the extent to which the Market Rules address the other objectives of the WEM.

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

The ERA notes that the costs and benefits of the changes being proposed are difficult to quantify.

The only direct cost resulting from these changes are the costs associated with the preparation of a proposal by the IMO or System Management and the ERA's assessment of those proposals.

In practice, the information that the ERA requires to make an assessment of a proposed expenditure is the same information that should be prepared to inform Board or senior management consideration of such proposals. On this basis, we would not anticipate that the proposed rule changes would add materially to the costs incurred by the IMO or System Management.

Overall, we consider that the additional direct costs would be no more than a few tens of thousands of dollars for the most complex capital expenditure proposals. The bulk of these costs would be incurred by the ERA.

# Agenda Item 6a: Overview of Recent and Upcoming IMO and System Management Procedure Change Proposals

**Legend:**

| | |
|---|---|
| **Shaded** | Shaded rows indicate procedure changes that have been completed since the last MAC meeting. |
| **Unshaded** | Unshaded rows are procedure changes still being progressed. |

| Change ID | Title | Brief overview of changes | Status | Next Step(s) | Date |
|---|---|---|---|---|---|
| **IMO Procedure Change Proposals** | | | | | |
| PC_2010_03 | Monitoring Protocol | The proposed updates are to:<br>• Allow the IMO to disclose the identity of System Management as a participant that notifies us of alleged breaches; and<br>• Update to conform to recently adopted style changes. | • Final Report being prepared | • Final Report to be published | TBA |
| PC_2010_05 | Reserve Capacity Performance Monitoring | The proposed updates are to:<br>• Include the changes to the Amending Rules arising from RC_2010_11, RC_2009_19 and RC_2010_02;<br>• Update to conform to recently adopted style changes. | • Final Report being prepared | • Final Report to be published | March 2011 |

| Change ID | Title | Brief overview of changes | Status | Next Step(s) | Date |
|---|---|---|---|---|---|
| PC_2010_08 | Supplementary Reserve Capacity (SRC) | The proposed new Market Procedure describes the process that the IMO and System Management will follow in:<br>• acquiring Eligible Services,<br>• entering into SRC Contracts;<br>• determining the maximum contract value per hour of availability for any contract; and<br>• Details the information that is required to be exchanged.<br>This Market Procedure needs to be published (as required by the Market Rules) and will be revised following any rule changes (if applicable). | • Final Report being prepared | • Final Report to be published | March 2011 |
| TBD | Data and IT Interface Requirements | The proposed updates are to:<br>• Reflect the IMO's new format arising from its Market Procedures project;<br>• Include some minor and typographical amendments to improve the integrity of the Market Procedure;<br>• Remove the minimum workstation requirements, specifically outlining just the recommended workstation requirements;<br>• Clarify the internet explorer requirements for different versions of the Market Participant Interface; and<br>• Update the IMO's Access Security section. | • Presented at the 2 February 2011 working group meeting. | • Formal submission into the Procedure Change Process (subject to any working group comments) | March 2011 |
| TBD | Prudential Requirements | The proposed updates are to:<br>• Reflect the IMO's new format arising from its Market Procedures project;<br>• Include some minor and typographical amendments to improve the integrity of the | • Presented at the 2 February 2011 working group meeting. | • Formal submission into the Procedure Change Process (subject to any working group comments) | March 2011 |

| Change ID | Title | Brief overview of changes | Status | Next Step(s) | Date |
|---|---|---|---|---|---|
| | | Market Procedure;<br>• Include amendments required as a result of two Rule Change Proposals:<br>o RC_2010_11[1] Removal of Network Control Services (NCS) Expression of Interest and Tender Process from the Market Rules; and<br>o RC_2010_36[2] Acceptable Credit Criteria;<br>The IMO would like to note that the remainder of the Market Procedure is out of scope for the purposes of this Procedure Change Proposal, as the IMO is currently undertaking a more detailed process review regarding Prudential requirements. Any amendments resulting from this review will be presented to the Working Group. | | | |
| TBD | Undertaking the LT PASA and conducting a review of the Planning Criterion | The proposed updates are to:<br>• Reflect the IMO's new format arising from its Market Procedures project;<br>• Include some minor and typographical amendments to improve the integrity of the Market Procedure, including re-ordering some sections; and<br>• Include both reviews required under clause 4.5.15 of the Market Rules (Planning Criterion and forecasting processes). | • Updating procedure as a result of 2 February 2011 working group meeting. | • Updated procedure to be presented at the next working group meeting, provisionally scheduled for 23 March 2011. | March 2011 |

[1] Refer to www.imowa.com.au/RC_2010_11
[2] Refer to www.imowa.com.au/RC_2010_36

| Change ID | Title | Brief overview of changes | Status | Next Step(s) | Date |
|---|---|---|---|---|---|
| TBD | Procurement of Network Control Services | RC_2010_11[3] (Removal of NCS Expression of Interest and Tender Process from the Market Rules) removes the NCS expression of interest, tender and contracting processes from the Market Rules to allow a Network Operator to undertake these processes under the regulatory oversight of the Economic Regulation Authority. As this Rule Change Proposal removes the heads of power (and the requirement) for the Market Procedure the IMO proposes to revoke the Market Procedure in its entirety. | • Presented at the 2 February 2011 working group meeting. | • Formal submission into the Procedure Change Process | March 2011 |
| **System Management Procedure Change Proposals** | | | | | |
| TBD | Monitoring and Reporting Protocol | The proposed updates are to provide further details around how System management will determine and review the annual Tolerance Range and any Facility Tolerance Ranges to apply for the purposes of clause 7.10.1 and 3.21 of the Market Rules.<br><br>The proposed updates will ensure consistency with the requirements of RC_2009_22 and in particular the new clause 2.13.6K. | • Discussed at Working Group Meeting (28 October 2010) | • System Management to submit into the Procedure Change Process. | March 2011 |
| TBD | Dispatch | The proposed updates are to allow for discretion to be exercised in requesting daily dispatch profiles from Market participants with facilities smaller than 30 MW. | • Discussed at Working Group Meeting (28 October 2010) | • System Management to submit into the Procedure Change Process | March 2011 |
| PPCL0016 | Commissioning and Testing | The proposed update is to amend the procedure to reflect the commenced RC_2010_37 ‘Equipment Tests’. | • Submissions closed 13 January 2011.<br>• Final Report being prepared by System | • Final Report to be provided to the IMO for approval | March 2011 |

[3] Refer to www.imowa.com.au/RC_2010_11

| Change ID | Title | Brief overview of changes | Status | Next Step(s) | Date |
|---|---|---|---|---|---|
| | | | Management | | |
| PPCL0017 | Facility Outages | The proposed update is to amend the procedure to reflect the commenced RC_2010_05 'Confidentiality of Accepted Outages by System Management'. | • Submissions closed 13 January 2011.<br>• Final Report being prepared by System Management | • Final Report to be provided to the IMO for approval | March 2011 |

# Agenda Item 7a: Working Group Overview

## 1. WORKING GROUP OVERVIEW

| Working Group (WG) | Status | Date commenced | Date concluded | Latest meeting date | Next scheduled meeting date |
|---|---|---|---|---|---|
| Reserve Capacity 2007 WG | Closed | Feb 07 | May 07 | - | - |
| NTDL WG | Closed | Oct 07 | Nov 07 | - | - |
| Energy Limits WG | Closed | Dec 07 | Jan 08 | - | - |
| DSM WG | Closed | Jan 08 | May 08 | - | - |
| SRC WG | Closed | Jun 08 | Sept 08 | - | - |
| Reserve Capacity 2008/09 WG | Closed | Dec 08 | Jan 09 | - | - |
| Renewable Energy Generation WG | Closed | Mar 08 | Nov 10 | - | - |
| System Management Procedures WG | Active | Jul 07 | Ongoing | 28/10/2010 | TBA |
| IMO Procedures WG | Active | Dec 07 | Ongoing | 02/02/2011 | 23/03/2011 |
| Maximum Reserve Capacity Price WG | Active | May 10 | Ongoing | 17/02/2011 | 24/02/2011 |
| Rules Development Implementation WG | Active | Aug 10 | Ongoing | 22/02/2011 | 15/03/2011 |

# Agenda Item 7b: MRCPWG Update

## 1. RECENT PROGRESS

The Maximum Reserve Capacity Price Working Group (MRCPWG) last met on 17 February 2011. The IMO has scheduled the next Working Group for 24 March 2011.

At the February meeting, the MRCPWG endorsed the updated draft report from Pricewaterhouse Coopers (PwC) on the methodology for determining the Weighted Average Cost of Capital (WACC). The final report will be published on the IMO website following the completion of PwC's internal quality assurance process. The IMO also presented to the MRCPWG a list of recommendations, with the MRCPWG agreeing for the IMO to incorporate these recommendations into the initial draft Market Procedure for consideration at the next meeting.

The MRCPWG also reviewed the research report from Sinclair Knight Merz (SKM) that presented options for determining the deep connection costs. SKM explained the workings of its preferred methodology for determining connection costs and estimated that it would result in a 70% reduction in the transmission connection cost component when compared with that determined for the 2011 Maximum Reserve Capacity Price (MRCP). SKM was asked to further consider data validity and availability, including robustness of the methodology when data is limited, prior to the next meeting.

In light of discussion surrounding the margin M (covering legal, financing, insurance, approvals and other costs) and cost escalation factors, the MRCPWG considered it reasonable that the IMO appoint an engineering consultant to provide independent advice on methods for determination of these factors. The IMO aims to provide this information at the next meeting.

For the March meeting, the IMO will be developing an initial draft Market Procedure that incorporates all of the elements of the MRCP agreed previously by the MRCPWG.

## 2. UPCOMING MRCPWG MEETINGS

The table below details the IMO's current expectation of the agendas for upcoming MRCPWG meetings.

| Meeting # | Date | Likely Agenda Items |
|---|---|---|
| 8 | March | SKM Final Report (Deep Connection Costs)<br>Initial draft Market Procedure amendments |
| 9 | April | Final Market Procedure amendments<br>Discussion of use of MRCP within Market Rules |

## 3. RECOMMENDATION

It is recommended that the MAC:

- **note** this update.

# Agenda Item 7c: RDIWG Update

## 1. UPDATE

The Rules Development Implementation Working Group (RDIWG) last met on 22 February 2011.

At this meeting the following was discussed:

- Balancing market design details and scenarios;
- Initial work on the cost benefit analysis for the Balancing proposal;
- Timelines and milestones for the Balancing market and related work under the Market Evolution Program (MEP); and
- Reserve Capacity Refunds proposed new methodology and funding pool.

## 2. BALANCING MARKET DESIGN

The IMO presented an update on the proposed design for the Balancing market, each of the stages with additional amendments to what was presented at the 2 February 2011 RDIWG meeting were discussed. A scenario, stepping through each stage of the proposed design was then presented. A number of issues were identified for further discussion and members requested some further scenarios.

The Acting Chair the requested each member's overall thoughts on the Balancing work and progress to date. Sentiments included:

- concern around the complexity, the ambitious timeframes, whether the benefits would outweigh the costs and whether there were simpler ways of achieving the outcomes sought;
- concern that the benefits would be largely captured by Market Generators but Market Customers were bearing substantial proportion of the cost;
- support for a competitive balancing outcome, concern about the potential costs versus benefits and the timeframes but acknowledgement that the overnight load issue had kicked off the work (and would start to be solved by it);
- acknowledgement of the need to think about the longer term, that there was a need to make competitive balancing work, that the work had to continue and be made consistent with broader strategic work streams (e.g. around the Verve/Synergy generator/retailer only constraints)
- generally positive support for the proposal although some detail needed to be worked through (e.g. around gate closure/windows) and that the work needed to continue;
- acknowledgement that the proposal seemed complex but had to be, that it would lead to more transparency and complexity but needed to be pushed forward;
- acknowledgement that this was work asked for by the industry but concern that the work may have lost its way and that it was too early to make decisions;

- interest in gaining an understanding of the level of competition that will result from the hybrid design and proposed changes;
- support for the direction of the work but could do with another industry workshop to help people understand it;
- optimism about the proposal, that it had nearly arrived at a workable solution, that it was well considered and could be made to work; and
- supportive of the work, noting some concern of the resourcing implications for Verve and System Management, comment that the proposal was looking “pretty close”.

The IMO will review the feedback on the Balancing work and present the outcome, as well as the further scenarios and the full cost benefit analysis, at the 15 March 2011 RDIWG meeting.

Subject to the RDIWG’s consideration of these issues, the IMO anticipates presenting a paper to the RDIWG and is hoping to seek the RDIWG’s endorsement of the proposal and recommending to the MAC that work on development of rule and system changes commences at the following RDIWG meeting on 4 April 2011.

## 3. TIMELINES AND MILESTONES

The proposed timelines and milestones for the MEP, as requested by the IMO Board, were presented to the RDIWG. Concern was expressed about the tightness of the timeframes and the ability of Market Participants to deliver change in the times required. The Program Manager outlined the costs of the program and the risks (and associated cost) of delays. Market Participants were asked to come back with comments on the timelines so they could be presented to the IMO Board for consideration.

## 4. RESERVE CAPACITY REFUNDS

The RDIWG was presented with a paper setting out a methodology for determining a more dynamic refund rate – as well as the creation of a funding pool into which refunds would be paid for the purposes of funding Supplementary Reserve Capacity (SRC), when required.

Opinion was divided on the proposal, at one end of the scale it was noted that it presented significant additional risk to participants. However, the contra opinion was that the proposal does not sufficiently reflect the concept of scarcity.

The new proposal for the SRC fund was also discussed, the following points were raised:

- Would Market Customers be able to opt in or out?
- Should refunds be distributed to Market Customers in their entirety if SRC is not called?
- Should generators be entitled to a proportion of the refunds back if, for example, they attain a better that 3% Forced Outage rate?
- Is the current allocation methodology (via IRCR) correct?

RDIWG members were asked to provide comment on the paper so that the IMO could bring it back for further consideration at the 5 April 2011 RDIWG meeting.

## 5. RECOMMENDATIONS

It is recommended that the MAC:

- **Note** this update.

# Agenda Item 8: MAC Annual Review Wash-up

## 1. BACKGROUND

Each year the IMO is required to review the composition of the Market Advisory Committee (MAC).

## 2. INITIAL MAC COMPOSITION REVIEW

As part of the nominations and appointment process (set out in the MAC Appointment Guidelines[1]) the IMO:

- Reviews the composition of the MAC (against the requirements outlined in clause 2.3.5 of the Market Rules) and identifies those members whose tenures are lapsing;
- Undertakes a review of the performance of MAC members during the year, including whether members and observers have:
    - been prepared for all MAC meetings;
    - read all the papers;
    - actively contributed to the discussions; and
    - not used their position or information gained improperly to gain an advantage for themselves or anyone else, or cause detriment to the IMO or the market;
- Assesses whether there may be a need to remove a member in accordance with clause 2.3.11 of the Market Rules; and
- Undertakes an assessment of the IMO's performance in its role as the MAC Secretariat (outlined in the MAC Constitution).

A report outlining the IMO's findings is attached as appendix 1 to this paper.

## 2. NOMINATIONS PROCESS

For the 2011 calendar year, three Discretionary Class member positions were up for renewal:

- Corey Dykstra representing Market Customers;
- Shane Cremin representing Market Generators; and
- Peter Huxtable representing Contestable Customers.

[1] Available: www.imowa.com.au/market-advisory-committee

There is no limit to renominations to be on the MAC, therefore, those MAC members whose positions are expiring were able to reapply.

On 18 May 2010 Perth Energy submitted a Rule Change Proposal regarding amendments to clause 2.3.5 of the Wholesale Electricity Market Rules (Market Rules). This rule change sought to amend the membership of the MAC to allow an extra two positions for Discretionary Class members. This rule change was progressed through the Standard Rule Change Process and commenced on 1 November 2010. Therefore this year the IMO has three - five Discretionary Class positions up for renewal:

- 1 - 2 vacancies representing Market Customer
- 1 - 2 vacancies representing Market Generator; and
- 1 vacancy representing Contestable Customers.

### 2.1 Nominations Received by the IMO

The following nominations were received by the IMO.

| # | Nominee | Member |
|---|---|---|
| **Discretionary Class** | | |
| 01 | Corey Dykstra | Market Customer and Market Generator |
| 02 | Timothy Edwards | Market Customer |
| 03 | Pablo Campillos | Market Customer |
| 04 | Michael Zammit | Market Customer |
| 05 | Shane Cremin | Market Generator |
| 06 | Ben Tan | Market Generator |
| 07 | Peter Huxtable | Contestable Customer |
| 08 | Jim Brosnan | Contestable Customer |

### 2.2 Evaluation Panel Assessment

The nominations received were checked for completeness and compliance with the pre-qualification and compliance criteria set out by the IMO in the request for nominations and established in the Market Rules, MAC Constitution and Appointment Guidelines.

A consensus score for each criterion was determined by the Evaluation Panel[2] using the nomination evaluation rating scale. The score for each criterion was then weighted. The four qualitative criteria and their respective weights are:

- Demonstrated skills, experience and knowledge of energy sector issues - 20% weighting;
- Demonstrated skills and knowledge of the Wholesale Electricity Market - 30% weighting;

2 A team made up of members from across the organisation, including Market Development, System Capacity, Legal and Compliance and Market Operations.

- Demonstrated ability to contribute actively to the MAC – 30% weighting; and
- Relevant background - 20% weighting.

The Evaluation Panel undertook a further assessment process which included reviewing the relevant qualifications and years of experience of these nominees to determine the best possible composition for the MAC (taking into account the relevant skills and experiences of the compulsory members).

### 2.3 Evaluation Panel initial proposal to MAC Chair

The Evaluation Panel initially proposed the following new/reappointed members to the MAC Chair for further discussion and review:

| Discretionary Class: Market Customers |
|---|
| Corey Dykstra |
| Michael Zammit |
| **Discretionary Class: Market Generators** |
| Shane Cremin |
| Ben Tan |
| **Discretionary Class: Contestable Customers** |
| Peter Huxtable |

The Chair was also provided with details of the qualitative assessment of each nominee and details of the Evaluation Panel's discussion around how each Discretionary Class nominee could contribute to the overall success of the MAC.

### 4.4 Review by MAC Chair and IMO Board

The MAC Chair and the IMO Board agreed with the Evaluation Panel's recommendations.

## 3. KEY LEARNINGS

As part of the review the Evaluation Panel noted a concern that the qualitative criteria and weighting (outlined in section 2.3 above) biased the results towards the re-appointment of members rather than the appointment of new members. As a result the IMO is considered an amendment to the qualitative criteria. The proposal is outlined below:

- Demonstrated skills, experience and knowledge of energy sector issues - 35% weighting;
- Demonstrated skills and knowledge of the Wholesale Electricity Market - 35% weighting;
- Demonstrated ability to contribute actively to the MAC (or other similar committee) – 10% weighting; and
- Relevant background - 20% weighting.

## 4. RECOMMENDATION

It is recommended that the MAC:

- **discuss** this update, specifically the proposed amendments to the qualitative criteria.

# "2011 MAC COMPOSITION" REVIEW REPORT

Title: 2011 MAC Composition Review Report

Agency: Independent Market Operator

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# 1 OVERVIEW

## 1.1 BACKGROUND

The IMO must annually review the composition of MAC and may remove and appoint members following the review **[MR 2.3.9]**.

The composition of MAC may also change from time to time as members resign or are removed by the IMO.

The IMO may remove a member of MAC only if:

(a) the person becomes an undischarged bankrupt;

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

(c) an event specified for this purpose in the constitution for the MAC occurs;

(d) in the IMO's opinion the person no longer represents the person or class of persons that they were appointed to represent in accordance with clause 2.3.5 **[MR 2.3.11]**; or

(e) the member breaches any part of the constitution of the MAC (appendix 2, MAC Constitution), for example- not being prepared for meetings or poor attendance records..

The IMO must have undertaken its appointment process before 1 March of each year.

## 1.2 PURPOSE OF THIS REPORT

The purpose of this report is to:

1. Review the composition of the MAC against the requirements outlined in clause 2.3.5 of the Market Rules;

2. Undertake the review of the performance of MAC members during the year, including whether members and observers have:

    a. been prepared for all MAC meetings;
    b. read all the papers;
    c. actively contributed to the discussions; and
    d. not used their position or information gained improperly to gain an advantage for themselves or anyone else, or cause detriment to the IMO or the market; and

3. Assess whether there may be a need to remove a member in accordance with clause 2.3.11 of the Market Rules.

## 2 REVIEW OF 2011 MAC COMPOSITION

### 2.1 MAC COMPOSTION REQUIREMENTS

Throughout the year of 2010 the IMO had two members resign from the MAC:

- Wendy Ng from Verve Energy was replaced by Andrew Everett, as approved by the Chair and notified at the September MAC; and
- Tony Perrin was replaced by Paul Biggs (Michael Kerr was appointed as a transitional member until Paul Biggs was appointed) and Nerea Ugarte, as approved by the Chair and notified at the November MAC.

Both these membership classes were classified as compulsory and hold a tenure of 2 years. As these positions have been appointed replacements, they are no longer vacant.

### 2.2 TENURE LAPSES

For the 2011 year the following discretionary class positions are up for renewal:

- Corey Dykstra – Market Customer;
- Shane Cremin – Market Generator; and
- Peter Huxtable – Contestable Customers.

There is no limit to renominations to be on the MAC, therefore, those MAC members whose positions are expiring can reapply.

On 18 May 2010 Perth Energy submitted a Rule Change Proposal regarding amendments to clause 2.3.5 of the Wholesale Electricity Market Rules (Market Rules).

This rule change sought to amend the membership of the Market Advisory Committee (MAC) to allow an extra two positions for Discretionary Class members. This rule change was progressed through the Standard Rule Change Process, approved and commenced on 1 November 2010.

Therefore this year the IMO has three - five discretionary positions up for renewal:

| Vacancies | Member | Tenure |
|---|---|---|
| 1 - 2 | Market Customer | 2 years |
| 1 - 2 | Market Generator | 2 years |
| 1 | Contestable Customers | 2 years |

## 3 REVIEW OF MEMBER'S PERFORMANCE

### 3.1 ATTENDANCE

Clause 3.10 of the MAC Constitution requires that each member make him or herself reasonably available for all meetings. Members who have not been reasonably available may be removed by the IMO under clause 4.6 of the Constitution.

A review was undertaken on the attendance of members at each of the 12 meetings for 2010 (outlined in the table below). This review showed no trends in absences from members.

| Member | # meetings | Attend | Proxy | Not attend |
|---|---|---|---|---|
| **Compulsory - Note - Proxies for compulsory members are counted towards attendance** | | | | |
| Allan Dawson | 12 | 12 | 0 | n/a |
| Ken Brown | 12 | 9 | 3 | n/a |
| Peter Mattner | 12 | 8 | 4 | n/a |
| Stephen MacLean | 12 | 9 | 3 | n/a |
| Troy Forward | 12 | 12 | 0 | n/a |
| Wendy Ng | 8 | 7 | 1 | n/a |
| Andrew Everett | 4 | 4 | 0 | n/a |
| **Discretionary - Note - Proxies for discretionary members are not counted towards attendance** | | | | |
| Corey Dykstra | 12 | 10 | n/a | 2 |
| Ky Cao | 2 | 1 | n/a | 1 |
| Shane Cremin | 12 | 12 | n/a | 0 |
| Steve Gould | 12 | 12 | n/a | 0 |
| Andrew Sutherland | 10 | 10 | n/a | 0 |
| Peter Huxtable | 12 | 12 | n/a | 1 |
| **Observers** | | | | |
| Chris Brown | 12 | 8 | 4 | n/a |
| Anne Hill | 2 | 1 | 1 | n/a |
| Tony Perrin | 8 | 8 | 0 | n/a |
| Nerea Ugarte | 2 | 2 | 0 | n/a |
| Michael Kerr | 1 | 1 | 0 | n/a |
| Paul Biggs | 1 | 1 | 0 | n/a |

In addition to the attendance of members, over the 12 meetings for 2010 there was an average of 2.5 observers (excluding IMO staff and consultants) per meeting

### 3.2 PERFORMANCE

Clause 3.11 of the MAC constitution requires that members:

a. be prepared for all MAC meetings, read all the papers and actively contribute to the discussions; and

b. not use their position or information gained improperly to gain an advantage for themselves or anyone else, or cause detriment to the IMO or the market; and

Over the 2010 year all members have mostly been prepared for each monthly MAC meeting by reading meeting papers issued one week prior. However, on two occasions one member did notify the MAC that he was unable to read through all the papers in detail due to his current workload and the large agenda. However, in noting this, the IMO does not recommend the removal of this member from the MAC, or from applying for membership for the 2011 year.

All members have actively contributed to each MAC and there is no evidence that members have used their position or the information raised in the meetings to advantage themselves or anyone else.

The MAC appointment guidelines require that members act in the best interests of the Wholesale Electricity Market and note that Discretionary Class members are individuals that represent a class of participants. Discretionary Class members are expected to act in a way that properly reflects the interests of the group that they have been chosen to represent.

As such, it should be noted that there have been a number of instances where members have represented their own entities commercial interests and not the interests of the class that they are appointed in. The IMO recommends that when the 2011 MAC is appointed, each member is reminded of his/her responsibility in representing the interests of the group that they have been chosen to represent.

## 4 IMO PERFORMANCE

The MAC Constitution requires that the IMO (in its role as the MAC Secretariat):

a. compile the meeting papers and send them by email to all members and observers of the MAC at least five days before each meeting (subject to any approved late papers approved by the Chair);

b. prepare the minutes of each meeting and send them by email to all members and observers of the MAC within ten Business Days of the meeting.

The IMO sent late papers to 2 of the twelve MAC meetings (with the approval of the Chair). All meeting minutes were circulated within ten Business Days of the meeting.

## 5 REMOVAL OF MEMBER(S) (MR 2.3.11)

The IMO may remove a member of if (clause 2.3.11 and Appendix 2 of the MAC Constitution):

- the person becomes an undischarged bankrupt;
- the person becomes of unsound mind or his or her estate is liable to be dealt with in any way under law relating to mental health;
- an event specified for this purpose in the constitution for the MAC occurs; or
- in the IMO's opinion the person no longer represents the person or class of persons that they were appointed to represent in accordance with clause 2.3.5; or
- the member breaches any part of the constitution of the MAC.

No members were required to be removed from the MAC in accordance the above requirements.

## 6 RECOMMENDATION

It is recommended that:

- No members be removed from the MAC membership on the basis of attendance and performance;

- all members whose tenures are expiring be allowed to reapply for 2011 MAC membership; and

- that once the 2011 MAC is appointed, the Chair reminds each member of his/her responsibility in representing the interests of the group that they have been chosen to represent.

## 6 APPROVAL BY THE CHAIR

Allan Dawson ______________________ 2/1/2011