Independent Market Operator

Market Advisory Committee

Agenda

Meeting No.	33
Location:	IMO Board Room Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Wednesday 10 November 2010
Time:	12.00 – 5.00pm

Item	Subject	Responsible	Time
1.	**WELCOME**	**Chair**	5 min
2.	**MEETING APOLOGIES / ATTENDANCE**	**Chair**	
3.	**MINUTES OF PREVIOUS MEETING**	**Chair**	15 min
4.	**ACTIONS ARISING**	**Chair**	
5.	**RATIONALISATION OF THE INFORMATION CONFIDENTIALITY STATUS CLASSES IN THE WEM**	**LECG**	30 min
6.	**WORKING GROUPS**		
	a) Overview and membership updates	**IMO**	5 min
	b) Maximum Reserve Capacity Price Working Group Update	**IMO**	10 min
	c) Renewable Energy Generation Working Group: FINAL REPORT	**IMO**	10 min
	d) Rules Development Implementation Working Group Update (Verbal Update following 2 November 2010 Meeting)	**IMO**	10 min
7.	**MARKET RULES**		
	a) Market Rule Change Overview	**IMO**	5 min

Item	Subject	Responsible	Time
	b) PRC_2010_22: Partial Commissioning for Intermittent Generators	**IMO**	30 min
	c) PRC_2010_25: Calculation of the Capacity Value of Intermittent Generation (Work Package 2)	**IMO**	60 min
	d) PRC_2010_27: Ancillary Services Payment Equations (Work Package 3)	**IMO**	45 min
	e) PRC_2010_29: Curtailable Loads and Demand Side Programmes	**IMO**	60 min
	f) PRC_2010_30: Limits to early entry capacity – *Assessment of proposal against the Wholesale Market Objectives*	**Alinta/IMO**	20 min
	g) RC_2010_36: Acceptable Credit Criteria	**Synergy**	15 min
8.	**MARKET PROCEDURES**		
	a) Overview	**IMO**	5 min
9.	**MAC MEMBERSHIP REVIEW: 2011 PROCESS**	**IMO**	5 min
10.	**GENERAL BUSINESS**		
11.	**NEXT MEETING: 8 December 2010**		

Independent Market Operator

Market Advisory Committee

Minutes

Meeting No.	32
Location:	IMO Board Room Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Wednesday 13 October 2010
Time:	Commencing at 9.00 pm

Attendees	**Class**	**Comment**
Allan Dawson	Chair	
Troy Forward	Compulsory – IMO	
John Rhodes	Compulsory – Customer	Proxy
Phil Kelloway	Compulsory – System Management	Proxy
Andrew Everett	Compulsory – Generator	
Peter Mattner	Compulsory – Network Operator	(9.25 - 10.50am)
Steve Gould	Discretionary – Customer	
Peter Huxtable	Discretionary – Contestable Customer Representative	
Andrew Sutherland	Discretionary – Generator	
Shane Cremin	Discretionary – Generator	
Rob Pullella	Observer – ERA	Proxy
Tony Perrin	Minister's appointee/ Small Use Customers	(9.00 - 12.10pm)
Apologies	**Class**	**Comment**
Corey Dykstra	Discretionary – Customer	
Ken Brown	Compulsory – System Management	
Chris Brown	Observer - ERA	
Stephen MacLean	Compulsory – Customer	
Also in attendance	**From**	**Comment**
Fiona Edmonds	IMO	Minutes
Jenny Laidlaw	IMO	Presenter
Greg Ruthven	IMO	Presenter
Bruce Cossill	IMO	Presenter (10.30-11.00am)
Ben Connor	Marchment Hill Consulting	Presenter (11.50 – 12.10pm)
Jacinda Papps	IMO	Observer
Courtney Roberts	IMO	Observer
Shannon Turner	IMO	Observer
Kris Ellery	IMO	Observer (10.30-11.00am)
Rob Rohrlach	Energy Response	Observer (9.00 – 10.00am)
Pablo Campillos	DMT Energy	Observer (9.00 – 10.50am)

Item	Subject	Action
1.	**WELCOME:** The Chair opened the meeting at 9.00am and welcomed members to the 32nd meeting of the Market Advisory Committee (MAC).	
2.	**MEETING APOLOGIES / ATTENDANCE** Apologies were received from: • Ken Brown • Stephen MacLean • Corey Dykstra • Chris Brown The following other attendees were noted: • Greg Ruthven (Presenter) • Jenny Laidlaw (Presenter) • Bruce Cossill (Presenter) • Ben Connor (Presenter) • Jacinda Papps (Observer) • Courtney Roberts(Observer) • Shannon Turner (Observer) • Kris Ellery (Observer) • Pablo Campillos (Observer) • Rob Rohrlach (Observer)	
3	**MINUTES OF PREVIOUS MEETING** The minutes of MAC Meeting No. 31, held on 8 September 2010, were circulated prior to the meeting. The following amendments were agreed: *Page 6: Section 4: Actions Arising [Item 90]* • "…such as inclusion of a heads of power for NCS in the upcoming ~~Electrical Amendments Bill~~ Electricity Legislation Amendment Bill…" *Page 9: Section 5c: Certification of Reserve Capacity [PRC_2010_14]* • "The Chair suggested that the IMO look at the option of publishing the SOO earlier in the Reserve Capacity timeline. Dr Gould suggested that the SOO could also be published later in the timeline, for example in October. Dr Gould considered that a later publication date for the SOO would give generators more time to consider its contents relative to the recently concluded certification process for the following year. Mr Ken Brown noted that any change to the SOO publication date would need to be considered carefully, as the SOO was used by many industry members, including Western Power. Mr Cremin and Mr Sutherland agreed that currently the SOO was published too late to be useful to generators. ~~There was some discussion about the usage of the SOO and the optimum time for its publication.~~ The Chair advised…" Subject to the agreed amendments, the MAC endorsed the minutes as a true and accurate record of the meeting. *Action Point: The IMO to amend the minutes of Meeting No. 31 to reflect the points raised by the MAC and publish on the website as final.*	**IMO**
4	**ACTIONS ARISING** The actions arising were either complete or on the meeting agenda. The MAC noted the current status/progress report on each of the action points.	

Item	Subject	Action
5a	**MARKET RULE CHANGE OVERVIEW** The MAC noted the Market Rule Change Overview and specifically discussed two issues. *Use of forecasts in assessment of Supplementary Reserve Capacity (SRC)* Mr Troy Forward noted that the Market Rules require the IMO's determination of Supplementary Reserve Capacity (SRC) requirements to be based on the forecast information determined two years prior. Mr Forward noted that updated forecasts are not able to be taken into account by the IMO under the current Market Rules. The IMO will be proposing a Fast Track Rule Change Proposal regarding this issue. *Rule Change Proposal: Adjustment of Relevant Level for Intermittent Generators [RC_2010_24]* Mr Forward noted that the IMO had received a Rule Change Proposal from Alinta which seeks to adjust the calculation of the Relevant Level for Intermittent Generators (RC_2010_24). Mrs Jacinda Papps noted that the proposal includes some overlap with the potential outcomes of the Work Package 2 work that had been undertaken by the REGWG. The following additional points were raised: • Mrs Papps noted that any Amending Rules resulting from RC_2010_24 would provisionally commence on 1 April 2011. These Amending Rules would be likely superseded by any Amending Rules resulting from a future Rule Change Proposal regarding the valuation methodology for Intermittent Generators (Work Package 2). Mrs Papps noted the IMO intended to shortly progress with its proposal for a valuation methodology. • Mrs Papps noted that RC_2010_24 had been discussed at the REGWG meeting on 2 September 2010. During the meeting the REGWG noted the impacts of Alinta's changes on any of the methodologies under consideration for the determination of the Capacity Credit allocation levels for Intermittent Generators. No REGWG members raised any issues, though Verve Energy noted that any methodology should take into account curtailment of Verve Energy wind farms. • Mrs Papps noted that the IMO's assessment of RC_2010_24 indicates that it is consistent with the Wholesale Market Objectives and was supported by all submissions received during the first consultation period, albeit with some minor suggested amendments. Mrs Papps noted that the MAC had not discussed the proposed changes previously and requested the MAC consider the system costs of implementation of the proposed changes ($50,000) given the likely replacement by any Work Package 2 Rule Change Proposal. • The Chair noted that the IMO does not object with the principles being implemented by the Rule Change Proposal; however, it does not want to subject the Market to potentially bearing the costs of two system changes within quick succession of each other. • Mr Shane Cremin noted that there was no agreement at the REGWG regarding a methodology to put forward for Work Package 2. Mr Cremin	

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	noted that any Amending Rules resulting from RC_2010_24 would need to commence for the 2011 certification process. • The Chair noted that the IMO would be comfortable reflecting the amendments proposed by Alinta in a Rule Change Proposal regarding the valuation methodology for Intermittent Generators. However, the Chair noted that if any future Rule Change Proposal regarding the valuation methodology for Intermittent Generators was not accepted that this would mean that Alinta's proposed changes would then not be made. Mrs Papps pointed out that Alinta was not represented at the MAC for this discussion. • The MAC advised that it would be appropriate that RC_2010_24 be extended until the latest possible time where, if the REGWG Work Package 2 Rule Change Proposal is not likely to be approved and operational in time for the 2011 Relevant Level calculation, this proposal could progress and the system changes be completed in time. The MAC agreed to reconfirm this advice at the next MAC meeting, when Alinta was able to be present. *Action Point: The IMO to extend RC_2010_24: Adjustment of the Relevant Level for Intermittent Generators until the latest possible time where, if the REGWG Work Package 2 Rule Change Proposal is not likely to be approved and operational in time, this proposal could be completed in time for the 2011 Relevant Level calculation.* *Action Point: The MAC to reconfirm its advice to the IMO to extend RC_2010_24 at the November MAC meeting.*	**IMO** **IMO**
5b	**REMOVAL OF NCS PROCUREMENT FROM THE MARKET RULES [PRC_2010_11]** Ms Jenny Laidlaw noted that the IMO had presented the Pre Rule Change Discussion Paper: Removal of Network Control Services (NCS) expression of interest and tender process from the Market Rules (PRC_2010_11) to the MAC at the August 2010 meeting. During the August meeting a number of issues for further consideration were raised. The paper to the MAC outlines the progress against each of the action points and presents an updated Pre Rule Discussion Paper. • *<u>Action Point 90:</u>* Mr Tony Perrin noted that the OoE had met with Western Power to discuss the concerns relating to the future provision of NCS. During the meeting Western Power expressed its legal position as being prohibited from under the Electricity Corporations Act to contract for NCS. Mr Perrin noted that the OoE had some concerns with this position which it would be continuing to work with Western Power to address. In the meantime the OoE has initiated the regulatory process for the necessary legislative amendments to provide the required heads of power. Mr Perrin noted that this would be an eight to ten month process, which is already underway. The Electricity Industry Amendments Act is currently with the Minister's office for consideration. Mr Perrin noted that the OoE is currently preparing an issues paper to aide consultation with stakeholders. This consultation is scheduled to be undertaken early next year.	

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	Mr Forward questioned what would happen if significant issues were raised during the regulatory process. Mr Forward suggested there may be merit in delaying the Rule Change Process, given that the necessary amendments to the Act and Regulations may not eventuate. Mr Perrin noted that the OoE will continue to seek legal advice on any potential issues. Mr Perrin noted that the OoE would continue to proceed with regulatory process in any event and recommended that the rule change is progressed. Mr Peter Mattner thought it was agreed that the IMO would formally submit the Rule Change Proposal but delay implementation until there is certainty over the heads of power. Mr Rob Pullella questioned whether the proposed amendments would have any impact if they were not in place when procurement of NCS needs to be undertaken by Western Power. Mr Forward noted that there would be issues with the way the energy flows and payments would work in the Market Rules.	
	Action Item: The OoE and Western Power to provide bi-monthly updates to the MAC on status of any regulatory changes relating to NCS procurement.	**OoE/WP**
	• *<u>Action Point 91:</u>* The Chair questioned whether there was a requirement for a Market Participant awarded a NCS contract to include on-site metering. Mr Andrew Sutherland noted that if not there would be an impact on settlement. It was agreed that there should be a requirement in NCS contracts to ensure appropriate metering for settlement.	
	Action Item: The MAC Chair to write to Western Power to request it to include a requirement for appropriate metering for settlement in any NCS contracts.	**MAC Chair**
	• *<u>Action Point 92:</u>* Mr Kelloway noted that System Management was unsure how the merit order for NCS and pay as bid would work, noting that this required further consideration. Mr Kelloway suspected that an NCS would be dispatched ahead of pay as bid. Ms Laidlaw suggested that payment details for NCS contracts could be provided to System Management. Mr Kelloway agreed that would be reasonable, though noting that this in itself would not constitute a merit order. The Chair questioned how System Management would use price details in circumstances where they do not have prices for any other facilities. Mr Forward noted that this would depend on the reasons for dispatching the facility.	
	Action Point: The IMO and System Management to discuss whether any additional amendments to the Market Rules are required to ensure that NCS is included in the Dispatch Merit Order.	**IMO/SM**
	• *<u>Potential for double payments for NCS instructions.</u>* Ms Laidlaw noted that the IMO had not proposed any additional amendments to clause 6.17.6 for NCS instructions to Non-Scheduled Generators to decrease output. Mr Kelloway noted that this issue was not high priority currently. It was agreed that this issue could be retained on the IMO's issue log for future review.	
	Action Point: The IMO to include future amendments to support NCS	**IMO**

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	instructions to Non-Scheduled Generators to decrease output on its potential rule change log, pending further consideration by the IMO. Mr Pablo Campillos questioned whether proposed clause. 6.17.6 would mean that any facility providing NCS which reduces load or increases generation would be paid zero by the market. Ms Laidlaw noted that payment for this would need to be included in the NCS contract. Additionally, Mr Campillos questioned whether the intent behind the proposed new clauses 5.3A.2, 5.3A.3 and 5.3A.4 would be to provide any change in the contract details to System Management. Ms Papps noted that the information exchange would only be that information needed for the purposes of dispatch. *Action Point: The IMO to progress the Rule Change Proposal: Removal of NCS procurement from the Market Rules (RC_2010_11) into the formal rule change process, subject to any implementation date being tied to the outcomes of the OoE's regulatory changes.*	 **IMO**
5c	**UPDATES TO CERTIFICATION OF RESERVE CAPACITY [PRC_2010_14]** Mr Forward noted that the Pre Rule Change Discussion Paper (PRC_2010_14) has been discussed at the September MAC meeting. During the meeting the MAC requested that the IMO consult with industry around the content and preferred timing of the Statement of Opportunities (SOO). Following this consultation the IMO proposes to bring the SOO publication deadline forward to 17 June (currently 1 July). Mr Forward noted that one of the considerations taken into account is the quality of the load forecasts available for inclusion in the SOO. Mr Ruthven noted that load forecasters had indicated to the IMO that providing this information earlier would essentially result in the job being undertaken twice. The Chair noted that historically the IMO has seen the timeframes specified in the Market Rules as being the last possible date. The System Capacity team will continue to aim to publish the SOO as early as possible. The following points were raised by MAC members: • Mr Sutherland questioned the value of the SOO, stating that there is a very short timeframe between the availability of the SOO (and identification of a potential opportunity) and the timeframes for discussion with Western Power regarding network access. The Chair noted that thermal developers are not the entire spectrum of capacity providers, with DSM being able to develop their projects under much shorter timeframes. Mr Perrin noted that the SOO is a risk management tool for a developer to confirm business plans and not necessarily a driver for investment. The Chair noted that the SOO can equally send signals to developers that the capacity is no longer required in the WEM. • Mr Kelloway questioned the relationship between IMO's proposal to state the required level of operation for a dual fuel facility and the work previously undertaken by McLennan Magasanik & Associates (MMA). Mr Forward confirmed that the proposal was consistent with the 14 hour fuel availability requirement for Peak Trading Intervals on Business Days. • Mr Peter Huxtable questioned the IMO's view on the request from	

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	participants for details of new large loads to be included in the load forecasts. Mr Forward noted that the IMO could seek legal advice on releasing this information. Mr Forward stated that it might be useful to list some of the details of large proposed loads, but noted that the SOO should not make a judgement on the likelihood of the plans going forward. The Chair noted that the IMO advocates increased transparency and agreed that the IMO could list the projects being taken into consideration but not the exact MW quantities. Mr Cremin noted that this would be inconsistent with the treatment of generation, as the SOO does not explicitly list the proposed generation projects. *Action Point: The IMO to consider whether further information on new large loads should be included in the Statement of Opportunities.* • Mr Rhodes questioned the ability for the IMO to reject an expert report proposed under clause 4.11.3A. Mr Rhodes agreed that while it might be a case for the IMO to take a view, he questioned how this would be demonstrated. Mr Ruthven noted that the basis that a Facility was certified (3 year average) could potentially differ considerably in reality. Mr Rhodes expressed concern that the amendments would create a broad ability for the IMO to reject the expert report. Mr Forward suggested that the IMO could provide greater clarification of the circumstances under which it would reject a report in the Reserve Capacity Procedure, including a notification and opportunity for a Market Participant to respond. The Chair noted that a decision by the IMO to reject an expert report should be a Reviewable Decision. • Mr Rhodes also noted that the amendment to clause 4.11.1(a) would create an objective test by the IMO as to whether a Non-Scheduled Generator can be dispatched by System Management. Mr Kelloway noted that these facilities can be generally dispatched downwards but not upwards, however there are exceptions to these such as small wind turbines which are not dispatchable downwards but can be turned off. Mr Forward noted that the IMO's reasonable expectation of non-dispatchable generators availability is zero. The Chair noted that the IMO would request System Management to confirm whether it is dispatchable. Mr Rhodes noted that the Amending Rules need to be clear as to whether the facility can be dispatchable upwards or downwards. Mr Forward noted that concept relates to generators who can be scheduled upwards and suggested clause 4.11.1(a) be amended to refer to scheduled generators. The MAC accepted the principles being proposed by PRC_2010_14, subject to the agreed amendments to the drafting. *Action Point: The IMO to progress the Rule Change Proposal: Certification of Reserve Capacity (RC_2010_14) into the formal rule change process, subject to the agreed amendments to the drafting.*	**IMO** **IMO**
5d	**SETTLEMENT CYCLE TIMELINES [PRC_2010_19]** Mr Bruce Cossill noted that the Pre Rule Change Discussion Paper: (PRC_2010_19) proposes to amend the number of Settlement Statements to be reviewed in any single Adjustment Process to nine (currently 12). Mr Cossill noted that since market start the IMO has applied nine months worth of adjustments over a 12 month period. If the IMO were to apply the fourth	

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	adjustment, prescribed currently in the Market Rules, this would add little value to accuracy either in metering data or settlement statements. The IMO does not consider this additional adjustment would be warranted on basis of very small amendments. The IMO had also received feedback from Market Participants that a shorter process would be preferable. The Chair questioned whether it is necessary to have three adjustment runs and requested the MAC's comments on whether two adjustments would be appropriate. In response, Mr John Rhodes noted that the settlements team at Synergy had considered that three runs were sufficient, with an additional run being superfluous. Mr Sutherland agreed that no reason to undertake a fourth adjustment but noted that NewGen would be hesitant for the number of adjustments to be reduced to two. The following additional points were raised by members: • Mr Sutherland noted that previously NewGen had received invoices from the IMO that had been materially incorrect and that there did not appear to have been logic checked by the IMO. Mr Sutherland questioned whether the IMO reviews the adjustments to ensure that any final adjustment is not a significant amount. Mr Cossill noted that any major changes are reviewed and that the IMO ensures that these are explainable. The Chair noted that the IMO's system for settlement had up until two months ago, taken almost 50 hours to complete a run, this has now been reduced to four hours. The Chair contended that Market Participants should notice a difference in the IMO reviewing the statements more thoroughly from now onwards. • The Chair also noted that the IMO had, until six months ago, modified meter readings that were obviously incorrect. This practice however led to Market Participants raising concerns that the meter database and the IMO values were different. On further review of the relevant Market Rules the IMO has determined that it should not amend incorrect meter readings. The IMO is currently actively working with Western Power to correct and review potential issues identified by the IMO with information contained in the meter database. • Mr Sutherland noted that Market Participants need to be certain that the statements are converging prior to agreeing with a reduction in the number of adjustments being undertaken by the IMO. • Mr Sutherland suggested considering whether an interim invoice for Market Participants to review could be issued prior to the first settlement statement. Mr Cossill noted that the IMO is currently considering this but noted that they are highly reliant on the provision of metering data and the timing associated with this. The Chair noted that his preference would be to see the settlement timeframes to be shortened. • The Chair noted that the biggest issues for settlement are around the entry of new participants and the accuracy of their meter data. Mr Pullella questioned whether it is possible for Market Participants to interact with Western Power to check their metering data. Dr Gould agreed that this is possible, noting that LGP currently uses this process to estimate its exact output and consequent settlement values. *Action Point: The IMO to consider whether it is possible to provide provisional settlement statements to Market Participants prior to the first*	**IMO**

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	settlement statements being provided.	
5e	**PROVIDING PRICE RELATED STANDING DATA TO SYSTEM MANAGEMENT [PRC_2010_21]** Mr Forward noted that currently the Market Rules require the IMO to provide Standing Data, including price related data, to System Management. The IMO considers this is inappropriate and inconsistent with the changes arising from System Management's Rule Change Proposal: Standing Data Compliance Monitoring (RC_2008_04) which commenced 24 June 2008. As a result the IMO proposes to amend the Market Rules to ensure that price related Standing Data is not provided to System Management. In response, Mr Kelloway noted that, in light of recent discussions in the RDIWG, System Management is no longer certain that it is appropriate that price related information is not provided to it. The Chair noted that typically in markets where the system operator is separate from a market operator, the market operator looks at the pricing related issues and presents a Dispatch Merit Order for the system operator. The system operator then only has regard to system security issues. Mr Kelloway questioned the need for the change and the value of precluding System Management from being provided this information. Mr Kelloway stated that at this stage System Management does not use any pricing related information but the recent discussions of RDIWG have indicated that System Management's role may change and that the proposed amendments under PRC_2010_21 would not facilitate this evolution in System Management's role. Mr Forward noted that the IMO does not currently provide System Management with price related Standing Data which is a compliance breach. Additionally, Mrs Papps noted that under the current Market Rules some clauses clearly preclude the discussion of price related information with System Management (as implemented following RC_2008_04). Mrs Papps noted that if System Management did want to be provided with price related information then the IMO would need to revert the changes implemented under RC_2008_04 to enable the IMO to provide this information to System Management. The Chair noted that the proposed changes would reflect current operational practice. Mr Kelloway agreed that the proposed changes should be progressed, noting that if in the future System Management needs this information to be provided to it further changes to the Market Rules will be required. The MAC agreed to progress the Rule Change Proposal, noting that it is dependent on the outcomes of the RDIWG, subsequent changes to provide System Management with this information may be required. *Action Point: The IMO to progress the Rule Change Proposal: Providing Price Related Standing Data to System Management (RC_2010_21) into the formal process.*	**IMO**
5f	**CONSEQUENTIAL OUTAGE – RELIEF FROM CAPACITY REFUND AND UNAUTHORISED DEVIATION PENALTIES [RC_2010_23]**	

Item	Subject	Action
	Mr Forward noted that Alinta's Rule Change Proposal (RC_2010_23) seeks relief from Capacity Cost Refunds, UDAP and DDAP where a Facility suffers a Consequential Outage. RC_2010_23 had initially been progressed via the Fast Track Rule Change Process, however due to the complexity of the solutions its timelines had been extended twice and so the proposal had reverted to the Standard Rule Change Process. Mr Forward noted that the IMO and System Management had been working closely to determine a solution to the following issues: • Impact of partial Consequential Outages – and how to estimate the impact on a Facility's output in these situations; • Limitation of gaming potential; and • Strengthening the governance arrangements in relation to Consequential Outage submissions. Ms Laidlaw noted that since market start to July 2010, 2017 ex-post Consequential Outages had been recorded. Of this 1254 were experienced by Independent Power Producers and 763 by Verve Energy. During this period, excluding Verve Energy outages, there were 5 distinct events which had occurred. For these events the total DDAP payments were approximately $19,000 and the Capacity Refunds approximately $20,000. Of the total amount (DDAP payments plus Capacity Refunds) approximately $26,000 could be attributed to one event, which also involved a Planned Outage. Mr Kelloway noted that System Management would require adequate time to investigate incidences of Consequential Outages (both full and partial). Mr Forward noted that the IMO did not want to make any Amending Rules any more complex than required as these events are currently infrequent. Mr Forward noted that System Management's suggested approach of implementing a simple mechanism with provision for a review at a later date. Mr Kelloway noted that a considerable increase in the amount of reporting could result from RC_2010_23 and that undertaking a review at a later date would uncover this. Mr Kelloway also noted that appointing an expert in the field to provide oversight of the process would involve a cost to the market. Mr Forward noted that the proposal is for a company representative to sign off on the occurrence and extent of a Consequential Outage. Ms Laidlaw confirmed that it would be an authorised officer of the company. *Action Point: The IMO to update the drafting of RC_2010_23 to clarify that an authorised officer of the company would be required to affirm that a Consequential Outage had occurred and provide relevant details to the best of its knowledge of the events which resulted in the Consequential Outage.* Ms Laidlaw noted the two following estimated IT costs: • Original Alinta proposal: approx $19,000; and • Alternative (including partial Consequential Outages): approx $47,000. Ms Laidlaw also noted that the alternative proposal would also involve System Management IT costs.	

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	The following additional points were raised: • Dr Steve Gould noted that if System Management were to require an expert review of each alleged partial Consequential Outage there could be significant costs to the market that would be likely negate the benefits of the proposed changes. Mr Forward noted that it was for these reasons he considered there would be value in undertaking an annual review. Additionally, Dr Gould noted that it is a criminal offense for an officer of the company to make a false declaration. • Mr Forward requested that the MAC be provided with summary statistics after six months of implementation so that a view on the impacts on market behaviour of the more simplistic change could be considered. • Mr Forward questioned whether full relief or partial relief from refunds and unauthorised deviation penalties should be granted, stating that his preference was for these to be granted at a level nominated by the Facility. Ms Laidlaw noted that this would be consistent with implementing a more complex option. Mr Andrew Sutherland questioned where the complexity with this option would occur. In response, Ms Laidlaw noted that currently a scheduled generator nominates an amount of reduction from it maximum achievable output (similar to if a Planned Outage). System Management then takes the figure and removes any quantity that would fall above the Facility's RCOQ. This amended value is then provided through to the IMO. The IMO as such can not reconstruct the value of capacity provided and so would need a different figure which excludes the adjustment to be provided. Ms Laidlaw also noted that this methodology also does not consider Dispatchable Loads. • Mr Forward suggested it might be more appropriate if the officer of the company made the adjustment. Ms Laidlaw agreed that this would simplify System Management's assessment but questioned how hard it would be for Market Participants to determine the appropriate figure. The Chair questioned whether there would be a reduction in the IMO's system costs if this process were to be adopted. • Mr Cremin suggested that the information requirements for provision of the required information in these instances could be specified in a Market Procedure, including details of the form that a Market Participant would need to fill in. Mr Forward agreed with this suggestion. • Mr Sutherland suggested that in these incidences the facility's DSQ could simply be equated to its MSQ. Ms Laidlaw noted that this was Alinta's original proposal but that it would create a loop hole for an aggregated facility where for example one facility is on Consequential Outage for six months and the other facility is relieved from deviation penalties and capacity refunds ex-post during this time as a result. Dr Gould noted that undertaking a review after 6 months would allow the MAC to consider these situations. The MAC agreed that it would be appropriate to adopt the simple approach subject to a review being undertaken after implementation to consider the impacts on market behaviour. *Action Point: The IMO to progress the simple solution to the Rule Change*	

Item	Subject	Action
	Proposal: Consequential Outage- Relief from Capacity Refunds and Unauthorised Deviation Penalties (RC_2010_23), subject to a annual review of Consequential Outages by System Management being included in the Amending Rules and details of the information requirements being provided in a Market Procedure.	**IMO**
5g	**CAPACITY CREDIT REDUCTION [PRC_2010_28]** Mr Forward noted the Pre Rule Change Discussion Paper (PRC_2010_28) would allow the IMO to reduce a Market Participant's Capacity Credits to zero in the case where the IMO does not consider it would be able to make its capacity available for the entire year. Mr Forward noted that the proposal would include a notification and appeal process, with the IMO's decision also being a Reviewable Decision. Mr Forward noted that an incidence where a Market Participant does not build its facility and so fails to provide its capacity to the WEM can have repercussions for a number of years. The Chair noted that there is a significant burden placed on all Market Participants in these instances where short-pay arrangements are required. The following points were noted: • Dr Gould noted that a large facility being unavailable may have significant impacts on all Market Participants. • Mr Sutherland questioned whether it would be possible for the IMO to reduce a Facility's Capacity Credits half way through the year option or make a decision to partially reduce. Mr Forward noted that there may be a net outflow to the market if the IMO were to reduce a Facility's Capacity Credits to zero part way through the year. • Mr Sutherland questioned whether if a DSM programme amends its certification level by 1 MW it is required to provide the IMO additional security. Mr Forward confirmed this was the case as there would be a delivery risk to the market. The IMO wants to limit exposure to the market associated with these circumstances. The Chair noted that a Market Customer would also receive a share of any security which is forfeited by a Market Participant. • Mr Rhodes questioned whether the reduction of Capacity Credits would impact on the IRCR calculations. Similarly, Mr Sutherland questioned the likely impact on the capacity price. Mr Forward noted that the impact should but similar to the early entry of Capacity Credits. The IRCR calculation would be responsive to these cases however any amendment to the capacity price would be a significant structural amendment. Mr Sutherland noted that in these cases the capacity price would be lower than what it would have otherwise been if participant not been included in the original calculation. Additionally, Mr Sutherland noted that a participant's security deposit does not get distributed to Market Generators. Mr Forward noted that it may be reasonable to adjust the capacity price in these instances. The MAC agreed that it supports the idea in principle but requested the IMO to consider the appropriateness of price adjustments and ratio changes.	

Item	Subject	Action
	Mr Forward also noted that the IMO's ability to draw down on security in these circumstances would be at the end of the year (current provisions in the Market Rules). The alternative would be for the IMO to be able to draw down on security immediately. Dr Gould suggested that there may be merit in diverting this security to a SRC fund. The Chair agreed that this should be further considered. *Action Point: The IMO to consider incorporating:* • *an ability to draw down of Reserve Capacity Security prior to the end of the Capacity Year and diverting this to a SRC fund; and* • *potential adjustments to the capacity price as a result of reducing a Market Participants Capacity Credits to zero,* *and update the Pre Rule Change Discussion Paper: Capacity Credit Reduction (PRC_2010_28) accordingly.* *Action Point: The IMO to present an updated version of the Pre Rule Change Discussion Paper: Capacity Credit Reduction (PRC_2010_28) to the MAC for further discussion at the December 2010 MAC meeting.*	**IMO** **IMO**
5h	**LIMITS TO EARLY ENTRY CAPACITY PAYMENTS [PRC_2010_30]** The Chair noted that Alinta's Pre Rule Change Discussion Paper (PRC_2010_30) would preclude any newly accredited Facility's that are not Scheduled or Non-Scheduled Generators from being able to receive Capacity Credit payments prior to the close of the Reserve Capacity window in the year that the Reserve Capacity Obligations first apply. The Chair noted that he had discussed this with Mr Corey Dykstra who had expressed concern that the previous Rule Change Proposal: Early Certified Reserve Capacity (RC_2009_10) had been intended to incentivise the early entry of Market Generators and so reduce the risk to the market of a facility entering the market late. However the Amending Rules resulting from RC_2009_10 apply to all types of capacity providers. Mr Dykstra had expressed concern with the financial consequences of this outcome to the market. Mr Forward noted that he had received some correspondence from EnerNOC stating that they were planning on entering the market based on the existing Market Rules, which includes the opportunity to be provided early entry payments. Mr Forward noted that they were concerned that the proposed amendments would take immediate effect. Mr Forward had agreed to represent EnerNOC's concerns about the assumption that there is no commissioning associated with DSM programmes. In response Mr Rhodes noted that this should be part of their business plan preparation, for example installing telecommunications equipment and testing of equipment. *Action Point: The IMO to distribute the comments received from EnerNOC on the Pre Rule Change Discussion Paper: Limits to Early Entry Capacity payments (PRC_2010_30) to MAC members.* The following points were also raised: • Mr Cremin noted that the original Market Rules had specified arbitrary dates for the window of entry, which were later amended due to empirical evidence. During its consideration of RC_2009_10, the MAC	 **IMO**

Item	Subject	Action
	had had a large amount of discussion as to whether Market Customers should pay for the additional capacity. The MAC had determined that the proposal was appropriate. Mr Cremin noted that there is a question over where to draw the line, suggesting that it makes sense to delineate between generation capacity and DSM. • Mr Forward noted that the IMO would need to consider whether the proposed amendments would be consistent with the Wholesale Market Objectives and in particular Market Objective (c) – avoiding discrimination against particular energy options and technologies. The Chair noted concern with singling out one specific type of capacity provider. Mr Pullella noted that a balance between economic efficiency (Market Objective (a)) and discrimination (Market Objective (c)) would need to be struck. • Mr Perrin noted that the value proposition needs to be demonstrated from the perspective of small use customers and that this should be presented to the MAC prior to its further consideration. Mr Kelloway also noted that the usability of the capacity at that time of year is also questionable. In response, it was noted that Varanus Island occurred in July and DSM may well have been used then, had it been available. • Mr Huxtable noted that the proposed amendments would shift the capacity year for DSM to 1 December. Mr Huxtable considered that it was an ambient argument that DSM should not receive Capacity Credits till later in the year. Mr Forward noted that the Reserve Capacity Year is from 1 October to 1 October. A concession had been made under RC_2009_10 in interests of reliability of supply to encourage earlier entry of thermal plant. The MAC supported aligning the proposal with the 1 October Reserve Capacity Year rather than the close of the window of entry. Mr Forward stated that in his view the question is really around whether non-generation plant should have early access to income stream for purposes of commissioning. • Mr Rob Rohrlach noted that Energy Response was opposed to the proposed amendments, stating that it is not appropriate to create differences between the treatment of generation and DSM under the Market Rules. Mr Rohrlach noted that the Market Rules currently treat DSM as a valid and valuable alternative to generation, and that this principle should be retained. The Chair agreed however noting that DSM has a shorter duration of availability (24 hours). Mr Cremin noted that Intermittent Generation is already distinguished from other types of generation in its treatment. This creates a precedent that not all capacity had an equal value to the market and therefore should not be treated evenly. • Mr Rohrlach noted that Energy Response has already signed contracts for next year from 1 August based on the Market Rules as they currently stand. The Chair noted that immediate implementation of any proposed amendments would require further consideration. • Mr Rohrlach considered that Alinta's assessment of the proposed amendments against the Market Objectives was questionable. • Mr Pablo Campillos noted that the proposal: o Discriminates between capacity options and technologies that reduce overall greenhouse gas emissions and therefore breaches	

Item	Subject	Action
	Market Objective (c); o Ignores that the enabling of DSM at many end-user sites does involve costly and time-consuming retrofits of existing facilities, often requiring the engagement of Western Power and the associated variability underlying their provision of network costs and timelines. While acknowledging that these costs and variability's may not, in actual quantity, match those that might be associated with traditional generation, they are significant and impact the likelihood and timing of DSM provision at the relevant sites; o Does not recognise that the early entry of DSM programs can support Market objective (e) by helping reduce the amount of electricity used by small and large consumers alike; and o Were it to be implemented prior to the next capacity cycle (2013/14), would seriously impact the commercial arrangements made by current DSM program operators with end-use capacity providers. • Mr Campillos noted that one of the fundamental principles of Alinta's proposed amendments relates to the immediate availability of DSM. Mr Kelloway noted that from a security point of view if it was demonstrable that there was a significant increase in availability then this should be further considered. Mr Kelloway stated that if System Management could call a DSM provider similarly to a generator then they should be treated the same; however this is not currently the case. Mr Kelloway however noted that System Management have had very little experience with dispatching DSM. • Mr Sutherland noted that capacity payments are currently based on the Maximum Reserve Capacity Price. Mr Sutherland questioned if a DSM programme enters the market early whether market will not be paying a large amount for this capacity or whether it will equate to a wealth transfer. Mr Forward clarified that the past year's price would not be diluted by the early entry of a Market Participant. The impact of the entry of that participant would not be reflected in the capacity price until the next year. Mr Rhodes noted that this adds to the market cost. • The Chair explained that commencement of any Amending Rules in 2013/14 would be unlikely and that the IMO would need to strike a balance between immediate implementation and delaying implementation for too long. The Chair noted that DSM providers can more easily finalise their portfolio towards the end of the process than generators. Mr Campillos noted that DSM providers would have identified DSM programme quantities but not necessarily the NMIs but that this does not change the fact they have provided security and will be looking for commencement in next cycle. The Chair noted that all Market Participants should be factoring in risks associated with changes to the Market Rules in contracting arrangements. • Mr Cremin noted that further consideration of the regulatory risk created by such an amendment to the Market Rules would be required. Mr Cremin noted that previously Alinta had argued that changes should not be implemented that would impact on their existing DSM programmes. • The Chair noted that the fundamental hurdle for the proposed amendments is whether they are on balance consistent with the Market Objectives in particular the objective to avoid discrimination in the market against particular energy options and technologies. The Chair	

Item	Subject	Action
	agreed that the IMO would further consider this as well as determining the costs to the market associated with the early entry of DSM programmes. • Mr Kelloway noted that System Management would appreciate an opportunity to discuss the availability and the ability to dispatch DSM. The Chair noted that there was support from MAC for the proposal to proceed but the IMO needs to ensure whether the proposal is on the whole consistent with the Market Objectives. The Chair noted that the outcomes of the IMO's further assessment will be presented at November MAC meeting. *Action Point: The IMO to assess the Pre Rule Change Discussion Paper Limits to early entry capacity payments (PRC_2010_30) against the Market Objective and report back to the November MAC meeting.*	**IMO**
6a	**MARKET PROCEDURE CHANGE OVERVIEW** The MAC noted the overview of recent and upcoming procedure changes.	
7a	**WORKING GROUP OVERVIEW** The MAC noted the Working Group overview and agreed to the proposed amendments to the System Management Procedure Change and Development Working Group's membership.	
7b	**REGWG UPDATE** Mr Ruthven noted that the IMO was preparing the final report for the REGWG. The Chair noted that Pre Rule Change Discussion Papers for both Work Package 2 and Work Package 3 will be presented at the November MAC meeting.	
7c	**MRCPWG UPDATE** Mr Forward noted that the MRCPWG had now resolved approximately 80 percent of the procedural based questions that had been identified. The IMO is currently undertaking a tender to process to appoint Consultants to review network transmission pricing and the determination of the WACC.	
7d	**RDIWG UPDATE** The Chair noted that the RDIWG was progressing well and is moving from the exploration period into the solution period. The MAC noted the update.	
8a	**MAC DISCRETIONARY MEMBERSHIP** Mr Forward noted that following the 2010 review of the composition of the MAC, a Market Participant had raised concerns with the method for selecting Discretionary Class members and the involvement of the IMO in the process. Mr Forward noted that the IMO Board had requested the IMO to further consider the operation of the membership process for Discretionary Class membership on the MAC. As a result, the IMO had engaged Marchment Hill Consulting (MHC) to review the options for selection. MHC's report recommends a hybrid model for appointment process be adopted. The following points were raised by members: • Mr Huxtable noted that there was no class of participant for contestable customers and so MHC's proposition would not work in that respect.	

Item	Subject	Action
	• Mr Rhodes questioned how the processes for creating a shortlist and the IMO making its decision would work in practice. Dr Gould also questioned what the difference between the hybrid model and the current process would be. Mr Pullella noted that there would be difficulties in getting all Market Participants involved in the process and as such the decision should rest with the IMO. • Dr Gould noted that he was not convinced that Market Participants would be organised enough to determine their own members. Mr Cremin noted that there were some established groups that could assist but that not all Market Participants are members of these groups. Mr Forward noted that there is still benefit in IMO involvement in membership decisions as the overall membership balance of the MAC was an important consideration. Mr Cremin suggested that, as a pseudo step not outlined in the Market Rules, a Market Participant class could nominate candidates. • The Chair noted that the IMO's view is that the current process is not broken, however the IMO Board wanted to explore whether changes could be practically made. The Chair also noted that the MAC's role is to advise the IMO Board, and that there is merit in the Board having some role in the selection process • Mr Kelloway confirmed whether the requirement for Compulsory Class members to provide details of their skills, experience and background would continue. The Chair noted that it is not about the skill set of these members but rather getting the overall composition of the MAC right. The Chair noted that MHC's solution would simply include another step in the process. • Mr Forward suggested that as the IMO had only undertaken one review to date following the new regime it might be reasonable to allow the process to be undertaken again. • Mr Ben Connor noted that MHC did not consider the process to be broken and that there was no reason why Market Participants should not have a greater involvement in selecting their representation. However, the requirement for the MAC to have a broad range of skills is a driver for the involvement of a central party such as the IMO in the process. • Mr Connor noted that transparency was an important aspect of the process and that the Appointment Guidelines document was not as clear as it could be that a balance of skills is required. Mr Connor noted that a detailed assessment process had been undertaken by the MAC Evaluation committee (an internal IMO committee). Mr Connor suggested that further detailing the process would be more transparent. • It was noted that there was always an option for non-members to be observers during meeting and that there had not been many incidences of Market Customers or Market Generators taking up this offer previously. • The Chair asked the MAC if a change was needed. Mr Pullella noted that the adoption of the hybrid model may encourage collusion between Market Participants. An open process would create the fairest system for selection. • Mr Forward acknowledged that there is merit in providing greater visibility around the process, noting that, for example that neither he nor the Chair	

Item	Subject	Action
	had been involved in the initial decision making due to the potential for a conflict in interest. • Dr Gould questioned whether there was merit in a probity audit of the IMO's process. Mr Cremin suggested that this was not appropriate if the process is transparent and robust. The MAC agreed that the IMO should retain its role in selecting the MAC Discretionary Members and present the process for the 2011 review to the MAC. *Action Point: The IMO to present an overview of the current process for the selection of both compulsory and discretionary MAC members for consideration at the November 2010 MAC meeting.*	**IMO**
8b	**SRC UPDATE** Mr Forward requested the MAC's views on whether Capacity Cost Refunds should be held in a consolidated fund to pay for SRC in the first instance, and if so whether this should be addressed as part of the RDIWG. Mr Forward noted that the RDIWG would provide an opportunity for effort and resource to be allocated towards further consideration/development of this concept however this would represent an increase in the RDIWG's scope. The Chair asked if the MAC would prefer the IMO progress this issue outside of the RDIWG. The MAC supported this approach. The Chair also noted that Synergy had previously expressed concerns around the windfall gains associated with receiving Capacity Cost refunds. Mr Rhodes noted that is the IMO holding Capacity Cost Refunds in a consolidated fund to pay for SRC in the first instance is Synergy's preferred position. *Action Point: The IMO to prepare a Pre Rule Change Discussion Paper to propose that Capacity Cost Refunds are held in a consolidated fund to pay for SRC.*	**IMO**
9	**MAC MEETING DATES** The Chair noted that there may need to be a MAC meeting held in January 2011. The MAC noted the meeting dates for 2011.	
10	**GENERAL BUSINESS** There was no general business raised.	
11	**NEXT MEETING** Meeting No. 33 will be held on Wednesday 10 November 2010. Mrs Papps requested that the meeting time be extended to 12:00 - 5:00pm due to the large agenda. The MAC agreed. The IMO indicated that lunch would be provided.	
CLOSED: The Chair declared the meeting closed at 12.20pm.		

Agenda item 4: 2009/2010 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.

#	Action	Responsibility	Meeting arising	Status/Progress
62	The IMO to send a letter to the Office of Energy and the ERA on behalf of the MAC requesting the introduction of licensing obligations for DSM Providers.	IMO	May	Letter drafted. This will be sent once the Rule Change Proposal for Curtailable Loads (on today's agenda for discussion) is formally submitted into the Rule Change Process.
78	System Management to further develop the details of option 3 for the future procurement of Spinning Reserve and Load Following and then provide an update to the MAC.	SM	June	Meeting scheduled between the IMO and System Management on Monday 8 November 2010. A verbal update will be provided at the MAC meeting.

#	Action	Responsibility	Meeting arising	Status/Progress
88	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	The IMO has requested this and will circulate it once received.
89	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.
102	The IMO to investigate the potential double dipping issue regarding Dispatch Instruction and energy payments for Curtailable Loads raised by Andrew Sutherland.	IMO	August	Completed. Included in the Curtailable Loads Pre Rule Change Discussion Paper, on today's meeting agenda.
103	The IMO to develop a Pre Rule Change Discussion Paper to reflect the recommendations contained in the (Curtailable Load) Relevant Demand Analysis paper.	IMO	August	Completed. A Pre Rule Change Discussion Paper on today's meeting agenda.
111	The IMO to formally submit its updated Reserve Capacity Security Rule Change Proposal RC_2010_12.	IMO	September	Undergoing process mapping and external legal review.
117	The IMO to update its Market Fees Rule Change Proposal (PRC_2010_20) to reflect the amendments suggested by the MAC and then formally submit the Rule Change Proposal.	IMO	September	Completed. The first submission period closes 22 November 2010. See: www.imowa.com.au/RC_2010_20
119	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	
121	The IMO to present to the MAC a worked example comparing the payments associated with the dispatch of a peaker against those associated with the dispatch of a Demand Side Programme.	IMO	September	This will be provided during the MAC meeting when presenting the Curtailable Load Pre Rule Change Discussion Paper (agenda item 5e).
122	The IMO to amend the minutes of Meeting No. 31 to reflect the points raised by the MAC and publish on the website as final.	IMO	October	Completed.
123	The IMO to extend RC_2010_24: Adjustment of the Relevant Level for	IMO	October	Completed. The IMO has

#	Action	Responsibility	Meeting arising	Status/Progress
	Intermittent Generators until the latest possible time where, if the REGWG Work Package 2 Rule Change Proposal is not likely to be approved and operational in time, this proposal could progress and the system changes be completed in time for the 2011 Relevant Level calculation.			extended the second submission period until 20 January 2011 and the publication of the IMO's final decision until 1 April 2011. See the extension notice: www.imowa.com.au/RC_2010_24
124	The MAC to reconfirm its advice to the IMO to extend RC_2010_24 at the November MAC meeting.	IMO	October	To discuss at the MAC meeting.
125	The IMO to progress the Rule Change Proposal: Removal of NCS procurement from the Market Rules (RC_2010_11) into the formal rule change process, subject to any implementation date being tied to the outcomes of the OoE's regulatory changes.	IMO	October	Completed. First submissions close 29 November 2010. See: www.imowa.com.au/RC_2010_11
126	The OoE and Western Power to provide bi-monthly updates to the MAC on status of any regulatory changes relating to NCS procurement.	OoE and WP	October	To discuss at December meeting.
127	The MAC Chair to write to Western Power to request it to include a requirement for appropriate metering for settlement in any NCS contracts.	MAC Chair	October	Letter underway.
128	The IMO and System Management to discuss whether any additional amendments to the Market Rules are required to ensure that NCS is included in the Dispatch Merit Order.	IMO and SM	October	
129	The IMO to include future amendments to support NCS instructions to Non-Scheduled Generators to decrease output on its potential rule change log, pending further consideration by the IMO.	IMO	October	Completed. On the Rule Change and Issues Log for future consideration.
130	The IMO to consider whether further information on new large loads should be included in the Statement of Opportunities.	IMO	October	
131	The IMO to progress the Rule Change Proposal: Certification of Reserve Capacity (RC_2010_14) into the formal rule change process, subject to the agreed amendments to the drafting.	IMO	October	
132	The IMO to consider whether it is possible to provide provisional settlement statements to Market Participants prior to the first settlement statements	IMO	October	The IMO has formed a preliminary view that the concept

#	Action	Responsibility	Meeting arising	Status/Progress
	being provided.			of provisional invoices is technically feasible. The IMO has yet to explore issues around timing with respect to the availability of metering data or moving the initial settlement run. The IMO would appreciate receiving MAC's feedback on its view of the relative priority of the IMO's further exploration of this issue.
133	The IMO to progress the Rule Change Proposal: Providing Price Related Standing Data to System Management (RC_2010_21) into the formal process.	IMO	October	Completed. First submissions close 29 November 2010. See: www.imowa.com.au/RC_2010_21
134	The IMO to update the drafting of RC_2010_23 to clarify that an authorised officer of the company would be required to affirm that a Consequential Outage had occurred and provide relevant details to the best of its knowledge of the events which resulted in the Consequential Outage.	IMO	October	Underway. This will be included in the Draft Rule Change Report, due for publication 11 November 2011.
135	The IMO to progress the simplistic solution to the Rule Change Proposal: Consequential Outage- Relief from Capacity Refunds and Unauthorised Deviation Penalties (RC_2010_23), subject to an annual review of Consequential Outages by System Management being included in the Amending Rules and details of the information requirements being provided in a Market Procedure.	IMO	October	Underway. This will be included in the Draft Rule Change Report, due for publication 11 November 2011.
136	The IMO to consider incorporating: • an ability to draw down of Reserve Capacity Security prior to the end of the Capacity Year and diverting this to a SRC fund; and • potential adjustments to the capacity price as a result of reducing a Market Participants Capacity Credits to zero, and update the Pre Rule Change Discussion Paper: Capacity Credit	IMO	October	Underway. An updated paper is due to be presented at the December 2010 MAC meeting.

#	Action	Responsibility	Meeting arising	Status/Progress
	Reduction (PRC_2010_28) accordingly.			
137	The IMO to present an updated version of the Pre Rule Change Discussion Paper: Capacity Credit Reduction (PRC_2010_28) to the MAC for further discussion at the December 2010 MAC meeting.	IMO	October	Underway, see above.
138	The IMO to distribute the comments received from EnerNOC on the Pre Rule Change Discussion Paper: Limits to Early Entry Capacity payments (PRC_2010_30) to all MAC members	IMO	October	Completed. Distributed to MAC members 22 October 2010.
139	The IMO to assess the Pre Rule Change Discussion Paper: Limits to early entry capacity payments (PRC_2010_30) against the Market Objectives and report back to the MAC on whether the proposed amendments would better the Market Objectives at the November MAC meeting.	IMO	October	Completed. Paper on today's meeting agenda.
140	The IMO to present an overview of the current process for the selection of both compulsory and discretionary MAC members for consideration at the November 2010 MAC meeting.	IMO	October	Completed. Paper on today's meeting agenda.
141	The IMO to prepare a Pre Rule Change Discussion Paper to propose that Capacity Cost Refunds are held in a consolidated fund to pay for SRC.	IMO	October	

Agenda Item 5: Rationalisation of the confidentiality status classes in the Wholesale Electricity Market

1. BACKGROUND

Chapter 10 of the Wholesale Electricity Market (WEM) Rules (Market Rules) governs the information policy for the WEM. Broadly this chapter outlines:

- the information confidentiality statuses applied in the WEM (clause 10.2.2);
- the guiding principles for the IMO in setting the confidentiality status of each type of market related information or document produced (clause 10.2.3); and
- more specifically, the information to be released by the IMO via the Market Website (clause 10.5.1).

At the 11 November 2009 Market Advisory Committee (MAC) meeting Pacific Hydro presented on the concept of introducing greater availability of market data in the WEM. Pacific Hydro compared the availability of information in the WEM to that of the National Electricity Market (NEM), noting that the rules governing the NEM provide for a broad power to publish relevant information. In particular the Australian Energy Market Operator has the power to collect and disseminate the information "necessary to enable the market to operate efficiently".

Pacific Hydro suggested that the Independent Market Operator (IMO) should:

- consider redrafting the Market Rules to "authorise the IMO to have the responsibility of determining what information is necessary for publication for the efficient operation of an energy market";
- Consult with the industry to identify commercially sensitive information; and
- Consider a planned rollout of market data based on availability, cost and importance for market efficiency.

Since the Pacific Hydro presentation the IMO has embarked on a significant review of information confidentiality.

2. LECG REVIEW

The IMO engaged an independent expert from the Law and Economics Consulting Group (LECG) to review the confidentiality status classes in the Market Rules (there are currently seven to administer), with a view to rationalising these. Specifically, LECG was tasked with:

- Reviewing the classes of confidentiality status that currently apply in the WEM;
- Reviewing the information that is currently set under each of the classes of confidentiality status;
- Assessing whether these classes of confidentiality status can be rationalised;

- Recommending the appropriate classes of confidentiality status; and
- Preparing a first draft of the rule changes that may be required to implement its recommendations.

When undertaking the assessment LECG had regard to the guiding principles for the provision of information to the market. That is, the IMO is to maximise the number of parties that may view any information or documents, subject to the information not containing commercially sensitive or potentially defamatory information in relation to a particular Rule Participant (clause 10.2.3).

The LECG report and suggested rule changes are attached as appendices 1 and 2 to this paper respectively.

3. PROCESS FROM HERE

Following the MAC discussion, the IMO intends to prepare a Rule Change Proposal implementing the proposed confidentiality status classes. Once the Rule Change process is complete the IMO will classify all the documents produced and information exchanged by the Market Rules into the new confidentiality classes. When undertaking this final phase of the project, regard will be given to the guiding principles for the provision of information to the market (noted in section 2 of this paper). This phase will be done in consultation with the market (and will most likely require a working group).

4. RECOMMENDATIONS

It is recommended that the MAC:

- **Discuss** this LECG Report; and
- **Note** that the IMO will prepare, and formally submit, a detailed Rule Change Proposal with a view to rationalising the confidentiality status classes as recommended by LECG.

LECG

Rationalisation of the Confidentiality Status Classes in the WEM

Toby Stevenson and Tim Bradley
October 2010

About LECG

LECG is a global expert services firm with highly credentialed experts and professional staff with specialist knowledge in regulation, economics, financial and statistical theories and analysis, as well as in-depth knowledge of specific markets and industries. The company's experts provide independent testimony, original authoritative studies and strategic advice to both public and private sector clients including legislative, judicial, regulatory, policy and business decision-makers.

LECG is listed on the NASDAQ Stock Exchange and has approximately 1000 experts and professional staff worldwide. These experts are renowned academics, former senior government officials, experienced industry leaders and seasoned consultants.

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1 About this report

In January this year, the IMO commissioned LECG to undertake a review of the value of information in electricity markets. Our study evaluated and compared the information disclosure requirements across in a series of markets including the WEM, the NEM, New Zealand, Singapore, Ireland and North America.

This study was part of a larger work program by the IMO to increase the transparency and availability of market related information, and has been motivated by stakeholder concerns that current arrangements may impose a barrier to entry into the WEM.

Having completed this initial research task, the IMO engaged LECG to review the confidentiality status for each type of market related information and document produced or exchanged in accordance with the Wholesale Electricity Market Rules (the Rules) or Wholesale Electricity Market Procedures (the Procedures).

Clause 10.2.1 of the Rules requires the IMO to set and publish the confidentiality status for each type of market related information and document produced or exchanged. The classes of confidentiality that currently apply are outlined in Clause 10.2.2. They consist of:

- Public;
- SWIS Restricted;
- Rule Participant Market Restricted;
- Rule Participant Dispatch Restricted;
- System Management Confidential;
- IMO Confidential; and
- Rule Participant Network Restricted.

We note that the IMO considers that administering seven different classes of confidentiality status may be unduly complex with the potential for high administrative overhead. In light of this, there could be potential for rationalisation of these classes.

Accordingly, the objectives of this report include:

- review the classes of confidentiality status that are currently apply in the WEM;
- review the information that is currently set under each of the classes of confidentiality status;
- assess whether these classes of confidentiality status can be rationalised, and if so, recommend the appropriate classes of confidentiality status to the IMO.

Any recommendations are to include an assessment of the impact on the Wholesale Market Objectives (Market Objectives). The objectives of the market are listed in box 1.1. Recommendations are also to have regard to the guiding principles for the provision of information to the market.

Box 1.1: WEM Objectives[1]

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.

1.1 Report structure

The remainder of this report is as follows.

- Section 2 — provides an overview of the role of information disclosure and confidentiality in the market;
- Section 3 — reviews the current confidentiality arrangements in the WEM and provides a comparison against the NEM regime;
- Section 4 — presents our assessment of the WEM confidentiality regime and provides our recommendations.

[1] Wholesale Market Rules, clause 1.2.1.

2 Disclosure and confidentiality

In a previous report for the IMO, LECG reviewed the regulatory approaches adopted with regards to information disclosure in electricity markets in Australia and overseas. In general, our report concurred with a consensus in the literature that: “on average the well-informed participants will make better trades than those less informed”[2] and that information disclosure will therefore lead towards competitive behaviour.

Two distinct regulatory approaches regarding information disclosure were highlighted in the report. The first being to release as much information as possible, and as close to real time as is practical, unless is it proven that there are high costs associated with disclosure. The second is to release information only where a positive benefit is proven. We note that it is an objective of the WEM to maximise the number of parties that may view any information or documents.

Notably both philosophies implicitly recognise that there are both benefits and costs associated with disclosure. On the one hand, disclosure can provide transparency and promote market competition. Competition in a general sense can be expected to yield more efficient outcomes than price and entry regulation, and to put downward pressure on energy costs. Further, by increasing transparency, competition can undermine efforts by interest groups to use the regulatory process to pursue their own agendas.[3] Other desirable features include market depth, self regulation and price transparency.

On the other hand however, the disclosure of sensitive commercial practices and strategies, for example, has the potential to stifle competitive forces. Similarly, it is important regulators can undertake investigations without defaming the parties involved. Indeed, LECG’s report noted that:

> *…the changes inherent in an evolving market will create substantial threats and opportunities for providers and participants. In setting requirements for the disclosure of information, care needs to be taken to protect proprietary information of members or of the market itself, such as price information, as well as considering the overall effects on transaction costs and the ensuing effect on market efficiency.*

Consequently, while the benefits of disclosure — and transparency more broadly — are significant, a careful balancing of benefits and costs must be undertaken. Furthermore, failing to institute mechanisms that will protect commercially sensitive information may mean that some efficiency gains will go unrealised.

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[2] Murray, K. *The Publication of Bids and Offers in the Electricity Market*. LECG

[3] Joskow, 2007.

One way this balancing can be achieved is by restricting the audience of particular types of information. Information of a commercially or legally sensitive nature, which does not actively promote market transparency and competition, can be classified as 'confidential.'

Access to this information can then be restricted to those parties for whom it is necessary. Forwarding confidential information to parties without access can be guarded against — to an extent — with the imposition of fines and other penalties.

Given the sensitivity of some confidential information however, caution needs to be taken regarding how access is provided. It is the nature of information that once released, it cannot be 'put back in the bottle.' It is imperative then that appropriate measures be undertaken to ensure its security — beyond just the imposition of penalties.

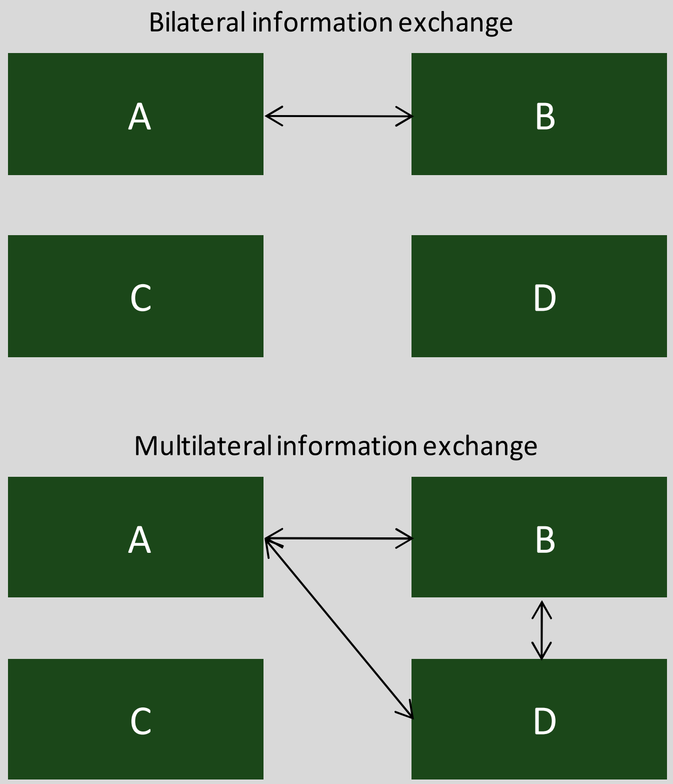
In a bilateral exchange of information (between say a market participant and the regulator), it is relatively straightforward to ascertain which party is responsible for a confidentiality breach. However, in a multilateral exchange (between say two participants and the regulator), the task is made more difficult. The difference between a bilateral and a multilateral information disclosure model is depicted, conceptually, in the figure below.

Another key issue concerns the complexity of the confidentiality regime. Participants need to clearly understand what information is considered confidential, and who is authorised to view this information. Ambiguity can result in unintentional consequences, including potentially withholding of information that would otherwise be released. Administration and compliance burdens associated with information disclosure are also likely to be greater the more complex the regime.

How well the regime is able to account for these two factors (security and clarity about a participant's obligations and expectations) may have a significant impact on how efficiently the market is able to function. Moreover, how these factors are accounted for in the Market Rules, is likely to have an impact on each of the Market Objectives.

Figure 2.1: Alternative models of information exchange

The diagram below depicts two alternative models of confidential information exchange. Under the bilateral model, information is exchanged between A and B. In the multilateral model, only C is excluded from accessing the information.



3 Current arrangements

This section reviews current arrangements regarding confidential information in the WEM.

Determining whether or not the WEM's current arrangements are appropriate for a maturing market can be assisted by drawing on arrangements in other, like jurisdictions. Arrangements in the National Electricity Market (NEM) in particular may serve as a useful yard stick for the exercise being conducted here.

3.1 Wholesale Electricity Market

Issues relating to market information in the WEM are considered in Chapter 10 of the Rules. Chapter 10 provides details as to what information must be collected by market participants, what information will be released, and details of the different confidentially statuses that apply.

Accounting for commercial sensitivities and defamatory information,[4] the Rules' guiding principle regarding information is to 'maximise the number of parties that may view [any] information or documents.'[5]

Clause 10.2.1 of the in the Rules requires the IMO to set and publish the confidentiality status for each type of market related information and document produced or exchanged. Seven different classes of confidentiality are outlined in Clause 10.2.2.

Information classified under these seven statuses can be shared with other market participants permitted to view the information. No information exists which cannot be viewed by the WEM's governing bodies (the IMO, the ERB and the ERA). Information must also be shared with other WA Government agencies if required to by WA legislation.

Classified information must not be shared by a Rule Participant (according to clause 10.2.4), unless (according to clause 10.2.5) that information is:

- in the public domain;

[4] Market Rules clause 10.2.3 (a).

[5] Market Rules clause 10.2.3 (g).

- already known to the person receiving it;
- required to be provided by law or a stock exchange having jurisdiction over the Rule Participant; or
- required in connection with resolving a dispute.

3.1.1 WEM classified information statuses

The classes of confidentiality that currently apply in the WEM consist of the following.

- Public
- SWIS Restricted
- Rule Participant Market Restricted
- Rule Participant Dispatch Restricted
- System Management Confidential
- IMO Confidential
- Rule Participant Network Restricted.

Each of the statuses is discussed in greater detail below, and table XX provides an overview of how the classes are applied.

Table 1: Current WEM arrangements[6]

Information Confidentiality Status class	IMO	Energy Review Board	Economic Regulatory Authority	Other WA Government (as required)	Rule participants	System management	Network operator	Market Advisory Committee	Public
Public	✓	✓	✓	✓	✓	✓	✓	✓	✓
SWIS Restricted	✓	✓	✓	✓	✓	✓	✓	✓	
Rule Participant	✓	✓	✓	✓	Spec.				

[6] Market Rules, clause 10.2.2.

Table 1: Current WEM arrangements[6]

Market Restricted									
Rule Participant Dispatch Restricted	✓	✓	✓	✓	Spec.	✓			
System Management Confidential	✓	✓	✓	✓		✓			
IMO Confidential	✓	✓	✓	✓					
Rule Participant Network Restricted	✓	✓	✓	✓	Spec.	✓	✓		

Public

Information considered Public, may be made available to any person, by any person.[7] The information required to be classified with this status is listed under clause 10.5.1. It mostly includes information that is necessary for a well functioning market to exist. Information required to be listed as Public includes:

- information relating to the Rules and Procedures;
- instructions on how to initiate a Rule or Procedure Change Process;
- details of all Rule Participants;
- details of bid, offer and clearing price limits;
- information relating to Reserve Capacity;
- key trading data, including bids and offers;
- load forecasts;
- the most current Statement of Opportunities Report;
- public consultation proceedings;
- public reports of the IMO, System Management, the ERA and ERB;
- budget information relating to the IMO and System Management;
- event reports explaining unusual market or dispatch events;
- a schedule of fees for services provided by the IMO; and

[7] Market Rules, clause 10.2.2 (a).

- other market related information.

SWIS Restricted

Information considered SWIS Restricted can only be viewed by Rule Participants (including the IMO, ERA, ERB and other bodies as required by legislation). This status is the most inclusive classification after Public, and is an example of a multilateral platform.

Information required to be SWIS Restricted is detailed in clause 10.6.1, and includes:

- summary information on Disputes in progress that may impact other Rule Participants;
- schedules of Planned Outages;
- the current Dispatch Merit Order;
- audit reports; and
- documentation of the functionality of :
- any software used to run the Reserve Capacity Auction;
- the STEM Auction software; and
- the Settlement System software.

Rule Participant Market Restricted

Information under this classification is restricted to the WEM's governing bodies, other agencies required by legislation and specified Rule Participants. Depending on the number of Participants granted access to information receiving this classification, this status might reflect either a bilateral or multilateral exchange model.

Generally this type of information relates to Participant specific information, such as bilateral trade arrangements and data, 'special' obligations, and STEM and non-STEM Settlement Statements. A complete list can be found in clause 10.7.1 of the Rules.

Rule Participant Dispatch Restricted

Information receiving this classification can be shared between the WEM governing body, specified Participants (as required) and System Management. The IMO is required to set the class of confidentiality status for a Market Participant Specific Dispatch Schedules under clause 10.2.1, as Rule Participant Dispatch Restricted Information and the IMO must make this information available from the Market Website for each Trading Interval in completed Trading Months for the past 12 Trading Months.

Additionally, the IMO must set the class of confidentiality status for all Electricity Generation Corporation information specified in clauses 7.6A as Rule Participant Dispatch Restricted Information with the exception of information specified by the Electricity Generation Corporation under clauses 7.6A.2(g) and 7.6A.3(c).

System Management Confidential

Information receiving this status is shared only between WEM governing bodies and System Management. Clause 10.2.3 (e) states: 'the IMO can declare incomplete working documents of System Management to be System Management Confidential.'

IMO Confidential

Information under this status class is not shared outside of the WEM governing bodies. Clause 10.2.3 (f) states: 'the IMO can declare incomplete working documents to be IMO Confidential.'

Rule Participant Network Restricted

This status of confidentiality was added to the Rules in 2008.[8] The class was added in order to make decision-making processes more robust. The IMO considered that it should be able to seek more comprehensive information from Network Operators in relation to applications for Certified Reserve Capacity.

As it was recognised that information provided by the Network Operator may be of a commercially sensitive nature, a new class of confidentiality status was created that would apply to the information received from Network Operators in connection with applications for Certified Reserve Capacity. All information would be confidential to the relevant Market Participant, the Network Operator that provided the information to the IMO.

3.2 National Electricity Market

The NEM's approach to confidential information is notably different to that in the WEM. Whereas the WEM employs a multitude of classifications, only two classes are (implicitly) employed in the NEM. These being:

- public information; and
- confidential information.[9]

Public information in the NEM largely refers to information of a similar nature to public information in the WEM. The NEM's National Electricity Rules (NER) specify what information the Australian Energy Market Operator (AEMO) is to collect and report. Some of this information is listed under clause 3.13, and includes information regarding:

- systems and procedures;

[8] See rule change RC_2008_14.

[9] The NEM rules only define the status of confidential information. All other information implicitly assumes the public information class.

- standing data;
- the statement of opportunities;
- spot market and market ancillary services;
- ancillary services conducted by AEMO;
- market forecasts (including errors);
- market data;
- details of market audits;
- results of inter-network tests;
- carbon intensity; and
- other matters considered to be public.

In addition, AEMO is also required to provide any information concerning the operation of the market (not listed above) to Scheduled Generators, Semi-Scheduled Generators and Market Participants on request, so long as it is not defined by the AEMC or the Rules as either confidential or commercially sensitive.[10]

In the NER, confidential information assumes essentially the same meaning as commercially sensitive information. Confidential information is defined as:[11]

> *…information which is or has been provided to that Registered Participant or AEMO under or in connection with the Rules and which is stated under the Rules, or by AEMO, the AER or the AEMC, to be confidential information or is otherwise confidential or commercially sensitive. It also includes any information which is derived from such information.*

The NER defines specific information items as confidential — such as the System Restart Plan, the establishment/modification of a connection, user account details and systems testing.[12] As defined in the rule, confidential information might:

- remain confidential to the AEMO, the AER (and the ACCC), or a market participant; or

[10] NEM Market Rules, clause 3.13.1 (a).

[11] NEM Market Rules, pg. 973.

[12] See for example NEM Market Rules, clauses 3.13.3 (k) and 3.13.3 (l).

- remain confidential between two parties, such as between AEMO and a market participant.

Access to confidential information is considered on a item by item basis, and is defined in the NER. That said however, the NER generally retain a degree of flexibility regarding confidentiality. Information, for example, which can be 'reasonably claimed' as commercial information, can generally remain confidential.

Sharing of confidential information beyond authorised parties is permitted under the exemption classes defined in clause 8.6.2. Exemptions include:

- information that is in the public domain;
- the sharing of information between employees and advisors (such as legal advisors and consultants);
- disclosure in connection with a dispute;
- trivial information;
- disclosure to the AER, AEMC or ACCC;
- consensual release; and
- other defined exemptions.

4 Rationalising information classes

The WEM and NEM present two markedly different regimes regarding confidential information.

Importantly, both markets have established a common commitment to transparency and information disclosure to enhance market competition. This is done by imposing a requirement in the respective market rules on both participants and operators to collect and report specific data items and analysis.

Where confidential information is exchanged in the NEM, the NER broadly follows a bilateral model. The sharing of confidential information occurs at most between two parties (typically a market participant and AEMO). Information that might be considered confidential is listed explicitly in the NER, as are the parties with authorised access.

The NER also provides for information of a commercially sensitive nature, or information that is sensitive to AEMO operations, to remain confidential to those parties on a unilateral basis. Information of this nature is either explicitly listed in the NER, or where a 'reasonable case' can be made for it to remain confidential.

The WEM on the other hand has adopted a mix of multilateral and bilateral models. This is a consequence of alternative confidential information statuses. Considering the WEM's governing bodies — the IMO, the ERB and ERA — as a single entity, the Market Rules provide:

- two bilateral status classes:
  - Rule Participant Market Restricted
  - System Management Confidential
- three multilateral status classes:
  - SWIS Restricted
  - Rule Participant Dispatch Restricted
  - Rule Participant Network Restricted

(The IMO Confidential status provides confidential information on a unilateral basis.)

Two key pitfalls emerge from the WEM regime. The first being increased complexity. As in the NEM, participants in the WEM need to be aware of what information is confidential and what information is public. Unlike the NEM however, participants also need to be aware of which participants are authorised to view which pieces of information. This has the potential to impose additional burdens on participants — including governing agencies — and to disrupt how information is circulated, if at all.

The second key pitfall regards security. As discussed in section 2, a multilateral exchange model will have an implicit security risk. Breaches of confidentiality are relatively straightforward to identify when confidential information is passed from one party to just one other — especially in cases where one party is damaged from its release.

In a multilateral model, identifying the source of a breach is less straightforward. For example, it would be difficult to identify the specific sources of a breach when information is classified as SWIS Restricted. Even if one party were to gain a significant advantage, conclusive evidence may not exist. If the regime is unable to identify where a breach occurs, then enforcement of the confidentially status remains weak.

Both of these pitfalls could be justified to a degree were there evidence significant benefits that could be achieved. However, it is difficult to see — especially in light of the security issue — what additional benefits alternative confidentiality classes can offer. (The NEM is able to overcome both of these issues through its use of bilateral exchange.)

Another key concern is how the WEM's confidentiality classes interact with the WEM's objectives regarding competition. The Rules should facilitate competition both within the market, and from outside the market. The SWIS Restricted status in particular, has the potential of imposing a divide between market insiders and outsiders that could be detrimental to competition.

Together, these factors may have an adverse impact on how efficiently the WEM can operate. Achieving economically efficient outcomes in any market requires clear, well-understood and enforceable rules.

It is not obvious that the current WEM arrangements, in regards to confidential information, reflect these principals — as best they could. And, as consequence, there is an argument to reform how confidential information is treated.

4.1 Recommendations

Based on the analysis above, we would support the following recommendations.

The IMO continue to promote competition, efficiency and transparency in the WEM. To date, the IMO has a strong track record for promoting efficiency in the WEM, and installing institutions which improve competitive measures. The IMO should take measures that continue this record as the WEM matures.

The treatment of confidential information in the Rules be rationalised such that information is considered either 'Public' or 'Confidential.' In doing so, this would reduce complexity and administrative/compliance burden that currently exists within the

WEM's confidentiality regime. The NEM provides an effective yardstick for how this could be implemented in the WEM.

The Rules explicitly list obligations regarding data to be provided on a Public basis, a Confidential basis, and the parties authorised to view Confidential information. It is important that the Rules clearly identify the necessary reporting and record keeping obligations of all Market Participants. The current Rules detail information that is to be considered Public under clause 10.5.1. Confidential information should be identified throughout the Rules, and parties privy to such information identified.

Authorisation to view confidential information be limited to the WEM's governing bodies — the IMO, the ERA and ERB — and at most one other party (unless otherwise specified in the Rules). This measure would help strengthen the security of confidential information. The source of a confidentiality breach will be clearer by switching to a bilateral model of information exchange. Relevant exemptions to this recommended approach may be required — such as in the event of a dispute — such that third parties, including other Market Participants and advisors, can also view confidential information.

4.2 Impacts

The reforms outlined in this paper have been specifically designed to enhance the Market Objectives (see box 1.1). This is achieved by:

- decreasing complexity in the Rules, and thereby reduce their administrative and compliance burdens;
- increasing the security of confidential information;
- enhancing measures in the Rules that provide for information disclosure and market transparency; and
- increasing the overall efficiency of the WEM and its competitive pressures.

The proposed reforms would assist the pursuit of Objectives (a) through (e). That is, the proposed reforms would promote:

- efficient, safe and reliable production and supply of electricity and electricity related services in the SWIS;
- competition among generators and retailers including the facilitating efficient entry of new competitors;
- the avoidance of discrimination in that market against particular energy options and technologies;
- the minimisation of long-term cost of electricity supplied to customers; and
- the taking of measures to manage the amount of electricity used and when it is used.

4.3 Proposed rule changes

Implementing some of the above changes will require some amendments be made to the Market Rules. The majority of these changes will concern chapter 10.

An example of the type of proposed rule change necessary to implement some of the recommendations made here is provided as an attachment to this document. Additional changes may be necessary throughout the Market Rules.

Agenda Item 5, appendix 2: Suggested amendments to Chapter 10

The proposed amendments to chapter 10 of the Market Rules to implement LECG's recommendations are provided below. Additional changes may be necessary throughout the remainder of the Market Rules. This will be undertaken while preparing the Rule Change Proposal.

The following clauses will need to be amended (~~deleted text~~, added text):

10 Market Information

Information Policy

10.1. Record Retention

10.1.1. The IMO must develop and publish a list of all information and documents that relate to the Wholesale Electricity Market activities that Rule Participants must retain.

10.1.2. Effective from the date that the IMO publishes a list containing the relevant information or document, Rule Participants must retain any information or documents of that kind for a period of seven years from the date it is created, or such longer period as may be required by law.

10.2. Information Confidentiality Status

The proposed changes reflect a need for rationalisation of confidentiality status classes. The proposed changes will reduce the number of status classes from seven, to two. This has the intention of reducing the complexity of the Market Rules, and the security of sensitive information.

10.2.1. The IMO must, in accordance with the Market Rules and Market Procedures, set and publish the confidentiality status for each type of market related information and document produced or exchanged in accordance with the Market Rules or Market Procedures.

10.2.2. The classes of confidentiality status are:

(a) Public, in which case the relevant information or documents may be made available to any person by any person;

(b) Confidential ~~SWIS Restricted~~, in which case the relevant information or documents may only be made available to parties as specified in the Market Rules and Market Procedures or as considered necessary by the IMO.

~~i. Rule Participants;~~

~~ii. the Market Advisory Committee;~~

~~iii. the IMO;~~

~~iv. the Electricity Review Board;~~

~~v. the Economic Regulation Authority; and~~

~~vi. other Regulatory or Government Agencies in accord with applicable laws;~~

~~(c) Rule Participant Market Restricted, in which case the relevant information or documents may only be made available to:~~

~~i. a specific Rule Participant;~~

~~ii. the IMO;~~

~~iii. the Electricity Review Board;~~

~~iv. the Economic Regulation Authority; and~~

~~v. other Regulatory or Government Agencies in accord with applicable laws;~~

~~(d) Rule Participant Dispatch Restricted, in which case the relevant information or documents may only be made available to:~~

~~i. a specific Rule Participant;~~

~~ii. System Management~~

~~iii. the IMO;~~

~~iv. the Electricity Review Board;~~

~~v. the Economic Regulation Authority; and~~

~~vi. other Regulatory or Government Agencies in accord with applicable laws;~~

~~(e) System Management Confidential, in which case the relevant information or documents may only be made available to:~~

~~i. System Management;~~

~~ii. the IMO;~~

~~iii. the Electricity Review Board;~~

~~iv. the Economic Regulation Authority; and~~

~~v. other Regulatory or Government Agencies in accord with applicable laws;~~

~~(f) IMO Confidential, in which case the relevant information or documents may only be made available to:~~

~~i. the IMO;~~

~~ii. the Electricity Review Board;~~

~~iii. the Economic Regulation Authority; and~~

~~iv. other Regulatory or Government Agencies in accord with applicable laws; and~~

~~(g) Rule Participant Network Restricted, in which case the relevant information or documents may only be made available to:~~

~~i. a specific Rule Participant;~~

~~ii. the relevant Network Operator;~~

~~iii. System Management;~~

~~iv. the IMO;~~

~~v. the Electricity Review Board;~~

~~vi. the Economic Regulation Authority; and~~

~~vii. any other Regulatory or Government Agencies in accord with applicable laws.~~

10.2.3. In setting the confidentiality status of a type of market related information or document under clause 10.2.1, the IMO must have regard to the following principles:

(a) commercially sensitive or potentially defamatory information pertaining to a Rule Participant is not made public or revealed to other Rule Participants except in accordance with legal requirements or requirements of these Market Rules;

(b) subject to paragraph (a), Rule Participants are to have access to information pertaining to current and expected future conditions of the power system that may impact on their ability to trade, deliver, or consume energy;

(c) the IMO can make available to a person information if the IMO is required to do so by law or these Market Rules;

(d) the IMO can restrict the availability of information to a person where this is required by law, or these Market Rules;

(e) the IMO can declare incomplete working documents to be ~~IMO~~ Confidential, and to be viewed only by the IMO, the Electricity Review Board, the Economic Regulatory Authority, or other Regulatory or Government Agencies in accord with applicable laws ~~Confidential~~;

(f) the IMO can declare incomplete working documents of System Management which are provided to the IMO to be ~~System Management~~ Confidential, and to be viewed only by System Management, the IMO, the Electricity Review Board, the Economic Regulatory Authority, or other Regulatory or Government Agencies in accord with applicable laws; and

(g) subject to this clause 10.2.3, the confidentiality status must maximise the number of parties that may view the information or document.

10.2.4. Subject to clauses 10.2.5, 10.2.6 and 10.4.1, a Rule Participant must not provide Confidential information or documents ~~of a given confidentiality status~~ to any person.

10.2.5. Clause 10.2.4 does not apply to information or documents:

(a) in the public domain;

(b) already known to the person receiving it;

(c) required to be provided by law or a stock exchange having jurisdiction over the Rule Participant; or

(d) required in connection with resolving a dispute.

10.2.6. A Rule Participant may disclose information or a document to:

(a) any person (including another Rule Participant) where the confidentiality status of the information or document is set as Public by the IMO under clause 10.2.1;

~~(b) any other Rule Participant where the confidentiality status of the information or document is set as SWIS Restricted by the IMO under clause 10.2.1;~~

(c) the specific Rule Participant able to receive the information or document in accordance with the conditions of that confidentiality ~~status, where the confidentiality status of the information or document is set as either Rule Participant Market Restricted or Rule Participant Dispatch Restricted by the IMO under clause 10.2.1~~ as specified within the Rules; or

(d) a Representative of the Rule Participant or a Representative of any person able to receive the information or document under paragraphs (a), (b) or (c).

10.2.7 The IMO must document the Market Procedure it follows in setting and publishing the confidentiality status of information in clause 10.2. The IMO must comply with that documented Market Procedure.

10.3. The Market Web Site

10.3.1. The IMO must maintain a Market Web Site for the purpose of:

(a) providing information on the nature and operation of the market;

(b) providing information on market performance; and

(c) disseminating reports and documents.

10.3.2. Subject to clause 10.4.2, the IMO must not require a fee for information or documents released by the IMO via the Market Web Site.

10.3.3. Where these Market Rules require System Management to provide information and documents to the IMO to be published on the Market Web Site, and the IMO is not required to approve or alter such information or documents, then, with System Management's agreement, the IMO may delegate to System Management the authority to directly post such information or documents on the Market Web Site. The IMO retains the right to cancel such delegation without consultation with System Management.

10.3.4. Where the IMO allows System Management to post information or documents on the Market Web Site in accordance with clause 10.3.3 the IMO's obligation under these Market Rules to publish such information or documents will transfer to System Management.

10.3.5. The IMO must document the protocols by which System Management and the IMO can change the Market Web Site in a Market Procedure and the IMO and System Management must comply with that documented Market Procedure in respect of changing the Market Web Site.

10.4. Information to be Released on Application

10.4.1. The IMO must make information and documents available on application by any person subject to that person being a member of the class of persons able to receive information or documents in accordance with the relevant confidentiality status.

10.4.2. The IMO may charge a person a fee for providing information or documents provided in accordance with clause 10.4.1, where that fee may not exceed the IMO's costs, not otherwise included in the IMOs budget, of:

(a) collating and transmission of information or documents; and

(b) preparing documents not otherwise required by the Market Rules, applicable law or regulation.

Information to be Released via the Market Web Site

10.5. Public Information

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:

(a) the following Market Rule and Market Procedure information and documents:

i. information on the records that must be maintained by Rule Participants;

ii. the list of the confidentiality status of information and documents pertaining to the Wholesale Electricity Market developed by the IMO in accordance with clause 10.2.1;

iii. the current version of the Market Rules;

iv. information on any Amending Market Rules that have been made in accordance with the Rule Change Process but are yet to commence or to be included in the current version of the Market Rules, including the date those Amending Rules will take affect;

v. any Rule Change Proposals that are open to public comment;

vi. the current version of Market Procedures;

vii. information on any changes to any Market Procedures that have been made in accordance with the Procedure Change Process but are yet to commence or to be included in the current version of the applicable Market Procedure, including the date those Market Procedure changes will take affect;

viii. any Procedure Change Proposals that are open to public comment; and

ix. a document summarising all Rule Change Proposals and Procedure Change Proposals that are no longer open to public comment and whether or not those proposals were accepted or rejected;

(b) instructions as to how to initiate a Rule Change Process and Procedure Change Process.

(c) details of all Rule Participants including:

i. name;

ii. mailing address, telephone and facsimile number;

iii. the name and title of a contact person;

iv. details of applicable licenses held;

v. applicable Rule Participant classes;

vi. applicable Market Participant classes; and

vii. names and capacities of Registered Facilities;

(d) the precise basis for determining the Bank Bill Rate;

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

i. the Maximum Reserve Capacity Price;

ii. the Maximum STEM Price;

iii. the Alternative Maximum STEM Price; and

iv. the Minimum STEM Price,

including rules that could cause different values to apply at different times;

(f) the following Reserve Capacity information (if applicable):

i. Requests for Expressions of Interest described in clause 4.2.3 for the previous five Reserve Capacity Cycles;

ii. the summary of Requests for Expressions of Interest described in clause 4.2.7 for the previous five Reserve Capacity Cycles;

iii. the Reserve Capacity Information Pack published in accordance with clause 4.7.2 for the previous five Reserve Capacity Cycles;

iv. for each Market Participant holding Capacity Credits, the Capacity Credits provided by each Facility for each Reserve Capacity Cycle.

In the case of a Market Participant with a Demand Side Programme, the IMO must publish the total Capacity Credits for the programme and not for each Curtailable Load comprising the programme;

v. the identity of each Market Participant from which the IMO procured Capacity Credits in the most recent Reserve Capacity Auction, and the total amount procured, where this information is to be published by January 7th of the year following the Reserve Capacity Auction;

vi. for each Special Price Arrangement for each Registered Facility:

1. the amount of Reserve Capacity covered;

2. the term of the Special Price Arrangement; and

3. the Special Reserve Capacity Price applicable to the Special Price Arrangement,

where this information is to be current as at, and published on, January 7th of each year;

vii. all Reserve Capacity Offer quantities and prices, including details of the bidder and facility, for a Reserve Capacity Auction, where this information is to be published by January 7th of the year following the Reserve Capacity Auction; and

viii. reports summarising facility tests and reasons for delays in those tests, as required by clause 4.25.11.

ix. The following annually calculated and monthly adjusted ratios:

1. NTDL_Ratio as calculated in accordance with Appendix 5, STEP 8;

2. TDL_Ratio as calculated in accordance with Appendix 5, STEP 8; and

3. Total_Ratio as calculated in accordance with Appendix 5, STEP 10.

(g) the Ancillary Service report referred to in clause 3.11.11(b);

(h) for each Trading Interval in each completed Trading Day in the previous 12 calendar months:

i. the sum of the Metered Schedule generation for Scheduled Generators and Non-Scheduled Generators registered to the Electricity Generation Corporation;

ii. the sum of the Metered Schedule generation for Scheduled Generators and Non-Scheduled Generators registered to Market Participants other than the Electricity Generation Corporation; and

iii. the sum of the Resource Plan schedule generation for Scheduled Generators and Non-Scheduled Generators registered to Market Participants other than the Electricity Generation Corporation;

(i) the following STEM summary information:

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

1. the total STEM Offer quantity;

2. the total STEM Bid quantity;

3. whether the STEM was suspended in relation to the relevant Trading Interval;

4. where the STEM was not suspended, the STEM quantity purchased by the IMO; and

5. where the STEM was not suspended, the STEM Clearing Price;

ii. for each Trading Interval in each Trading Day during the 12 calendar months, before the end of the seventh day from the start of the Trading Day:

1. the STEM Offers by Market Participant;

2. the STEM Bids by Market Participant;

3. the quantity bought or sold in the STEM by Market Participant; and

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

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

i. the values of MCAP, UDAP and DDAP;

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

iii. the sum of the Metered Schedule load for all Non-Dispatchable Load, Dispatchable Load, Interruptible Load and Curtailable Load;

iv. estimates of the energy not served due to involuntary load curtailment; and

v. any shortfalls in Ancillary Services;

(k) any Market Advisories and Dispatch Advisories released in the previous 12 months;

(l) Loss Factors for each network connection point in accordance with clause 2.27;

(m) the most current Statement of Opportunities Report;

(n) the medium term PASA report described in clause 3.16.9;

(o) the short-term term PASA report described in clause 3.17.2;

(p) details of resolved Disputes, including all Public Information associated with the dispute, but not aspects of the resolution or information associated with the resolution which, in accordance with its confidentiality status class, cannot be made public

(q) public consultation proceedings;

(r) Public Reports pertaining to the Wholesale Electricity Market issued by:

i. the IMO;

ii. System Management;

iii. the Electricity Review Board;

iv. the Economic Regulation Authority; or

v. the Minister.

(s) event reports explaining what happened during unusual market or dispatch events but not aspects of such reports which, in accordance with its confidentiality status class, cannot be made public;

(t) the IMO and System Management budget information for the current financial year;

(u) a schedule of fees for services provided by the IMO;

(v) summary information pertaining to the account maintained by the IMO for market settlement for the preceding 24 calendar months, including;

i. the end of month balance;

ii. the total income received for transactions in each of the Reserve Capacity Mechanism, the STEM, Balancing, Market Fees, System Operation Fees, Regulator Fees and a single value for all other income;

iii. the total outgoings paid for transactions in each of the Reserve Capacity Mechanism (excluding Supplementary Capacity Contracts), Supplementary Capacity Contracts, the STEM, Balancing and a single value for all other expenses; and

iv. Service Fee Settlement Amount paid to the IMO, System Management and the Economic Regulation Authority;

(vA) the non-compliance cost described in clause 9.10A.2;

(vB) reports providing the MWh of non-compliance of the Electricity Generation Corporation by Trading Interval, as specified by System Management in accordance with clause 7.13.1A(a), for each Trading Month which has been settled;

(vC) reports providing the MWh quantities of energy dispatched under Balancing Support Contracts by Facility and Trading Interval, as specified by System Management in accordance with clause 7.13.1(dA), for each Trading Month which has been settled;

(w) the STEM Price for each Trading Interval of the current Trading Month for which STEM auction results have been released to Market Participants; and

(x) for each Trading Interval of the current Trading Month for which balancing price results have been released to Market Participants;

i. the values of MCAP, UDAP and DDAP; and

ii. the load forecast prepared by System Management in accordance with clause 7.2.1(b).

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

i. the total generation in that Trading Interval;

ii. the total spinning 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; and

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

i. the total generation;

ii. the total spinning 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.

It is proposed that any information previously considered SWIS Restricted Information, is to be considered Public. This information was insecure under its previous confidentiality class, and has been made public in the interests of inclusion, transparency and market efficiency.

(za) the following information relating to the SWIS:

(i) summary information on Disputes in progress that may impact other Rule Participants;

(ii) schedules of Planned Outages;

(iii) the current Dispatch Merit Order;

(iv) audit reports; and

(v) documentation of the functionality of any software used to run the Reserve Capacity Auction; the STEM Auction software; and the Settlement System software.

This amendment replaces previous clauses relating to specific status classes. Under this proposed change, the same information will be made available to the same parties, but on terms similar to commercially sensitive information.

10.6. Confidential Information ~~SWIS Restricted Information~~

10.6.1. In addition to Confidential Information listed elsewhere in the Market Rules, the following information is to be considered Confidential. Information is to be viewed only by the IMO, the Electricity Review Board, the Economic Regulatory Authority, other Regulatory or Government Agencies in accord with applicable laws and:

(a) Rule Participants as specified by the IMO:

i. all Reserve Capacity Offer information issued by that Market Participant and all details of Special Price Arrangements for that Market Participant prior to the publication of that information in accordance with clause 10.5.1(f);

ii. Market Participant specific Reserve Capacity Obligations;

iii. Market Customer specified Individual Capacity Reserve Requirements partitioned into those associated with Intermittent Loads and those not associated with Intermittent Loads;

iv. for each completed Trading Day for the past 12 months:

Market Participant specific Bilateral Submissions, Resource Plan Submissions, Balancing Data Submissions and Standing Balancing Data submissions used in the absence of a Balancing Data Submission;

Market Participant specific STEM Submissions and Standing STEM Submissions used in the absence of a STEM Submission except that information published in accordance with clause 10.5.1(i);

v. for the past 12 months:

Non-STEM Settlement Statements; and

STEM Settlement Statements

(b) System Management and Rule Participants as specified by the IMO:

i. Market Participant Specific Dispatch Schedules. This information must be made available by the IMO through the Market Website for each Trading Interval in completed Trading Months for the past 12 Trading Months; and

ii. all Electricity Generation Corporation information specified in clauses 7.6A with the exception of information specified by the Electricity Generation Corporation under clauses 7.6A.2(g) and 7.6A.3(c).

~~The IMO must set the class of confidentiality status for the following information under clause 10.2.1, as SWIS Restricted Information and the IMO must make this information available from the Market Web Site:~~

~~(a) summary information on Disputes in progress that may impact other Rule Participants;~~

~~(b) schedules of Planned Outages;~~

~~(c) the current Dispatch Merit Order;~~

~~(d) audit reports; and~~

~~(e) documentation of the functionality of :~~

~~i. any software used to run the Reserve Capacity Auction;~~

~~ii. the STEM Auction software; and~~

~~iii. the Settlement System software.~~

~~10.7. Rule Participant Market Restricted Information~~

~~10.7.1. The IMO must set the class of confidentiality status for the following information under clause 10.2.1, as Rule Participant Restricted Information and the IMO must make this information available from the Market Web Site:~~

~~(a) all Reserve Capacity Offer information issued by that Market Participant and all details of Special Price Arrangements for that Market Participant~~

~~prior to the publication of that information in accordance with clause 10.5.1(f);~~

~~(b) Market Participant specific Reserve Capacity Obligations;~~

~~(c) Market Customer specified Individual Capacity Reserve Requirements partitioned into those associated with Intermittent Loads and those not associated with Intermittent Loads;~~

~~(d) for each completed Trading Day for the past 12 months:~~

~~i. Market Participant specific Bilateral Submissions, Resource Plan Submissions, Balancing Data Submissions and Standing Balancing Data submissions used in the absence of a Balancing Data Submission;~~

~~ii. Market Participant specific STEM Submissions and Standing STEM Submissions used in the absence of a STEM Submission except that information published in accordance with clause 10.5.1(i);~~

~~(e) for the past 12 months:~~

~~i. Non-STEM Settlement Statements; and~~

~~ii. STEM Settlement Statements~~

~~10.8. Rule Participant Dispatch Restricted Information~~

~~10.8.1. The IMO must set the class of confidentiality status for a Market Participant Specific Dispatch Schedules under clause 10.2.1, as Rule Participant Dispatch Restricted Information and the IMO must make this information available from the Market Website for each Trading Interval in completed Trading Months for the past 12 Trading Months.~~

~~10.8.2. The IMO must set the class of confidentiality status for all Electricity Generation Corporation information specified in clauses 7.6A as Rule Participant Dispatch Restricted Information with the exception of information specified by the Electricity Generation Corporation under clauses 7.6A.2(g) and 7.6A.3(c).~~

Independent Market Operator

Agenda Item 6a: 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	Active	Mar 08	Ongoing	02/09/2010	11/11/2010
System Management Procedures WG	Active	Jul 07	Ongoing	28/10/2010	TBA
IMO Procedures WG	Active	Dec 07	Ongoing	26/10/2010	30/11/2010
Maximum Reserve Capacity Price WG	Active	May 10	Ongoing	15/09/2010	TBA
Rules Development Implementation WG	Active	Aug 10	Ongoing	02/11/2010	23/11/2010

2. WORKING GROUP MEMBERSHIP UPDATES

In accordance with the Terms of Reference (ToR) the Market Advisory Committee (MAC) must approve the appointment and substitution of members for the System Management Power System Operation Procedures Working Group and the Maximum Reserve Capacity Price (MRCP) Working Group.

The MAC has received requests from:

- Neil Hay to replace Alistair Butcher as System Management's representative on the System Management Power System Operation Procedures Working Group; and
- Adam Boyd to replace Nenad Ninkov as Pacific Energy's representative on the MRCP Working Group.

The Updated ToR (with tracked changes) is attached as Appendix 1 and 2.

3. RECOMMENDATIONS

The IMO recommends that the MAC:

- **Agree** the proposed amendments to the membership of the Maximum Reserve Capacity Price Working Group and the System Management Power System Operation Procedures Working Group.

Agenda Item 6a: Appendix 1

Terms of Reference

The System Management Procedure Change and Development Working Group

SCOPE

The Working Group's scope of work includes consideration; assessment and development of changes to System Management Market Procedures which the Market Rules require System Management to develop. A Report on each Procedure Change proposed by the Working Group will be provided to MAC which demonstrates that the proposed change is consistent with the Wholesale Market Objectives and the Market Rules.

MEMBERSHIP AND PROCESS

- Members of the Working Group are appointed and substituted by MAC.
- The members of the Working Group are:

Phil Kelloway (Chair)	-	System Management
Debra Rizzi	-	Industry Representative, Alinta Limited
Pete Ryan	-	Industry Representative, The Griffin Group
Michael Frost	-	Industry Representative, Perth Energy
Rene Kuypers	-	Industry Representative, Infigen Energy
Steve Gould	-	Industry Representative, Landfill Gas & Power
Nick Walker	-	Verve Representative
Wesley Medrana	-	Synergy Representative
~~TBD~~ Neil Hay	-	System Management
Fiona Edmonds	-	IMO
Jacinda Papps	-	IMO

- An issue can be referred to the Working Group for consideration by MAC or the IMO. Generally, issues referred to the Working Group will relate to proposed Procedure Changes.
- The Working Group will meet as required to provide MAC and the IMO with a detailed analysis and advice regarding the issue referred to them.
- The Working Group will consider and develop, where appropriate, Procedure changes within the timeframes set by the Chair with respect to each proposed Procedure change.
- Procedure Changes proposed by the Working Group must be consistent with the Wholesale Market Objectives and the Market Rules
- Members are expected to attend as many Working Group meetings as practicable.
- MAC may review, amend and extend these terms of reference, as necessary.

Agenda Item 6a: Appendix 2

Terms of Reference

The Maximum Reserve Capacity Price Working Group

BACKGROUND

This Working Group has been established, in accordance with Clause 2.3.17 of the Wholesale Market Rules and the associated Section 9 of the Constitution of the Market Advisory Committee (the MAC). Consistent with these authorised functions and powers, the overarching function of *any* Working Group established under the MAC is to assist the MAC in providing advice to the Independent Market Operator (the IMO) and System Management in matters relating to Wholesale Electricity Market (WEM) Rule and Procedural Change Proposals, WEM operation and South West Interconnected System (SWIS) operational matters, and the evolution of the Market Rules more generally.

SCOPE

The Maximum Reserve Capacity Price Working Group's (MRCPWG's) Scope of Work includes consideration, assessment and development of changes to the Market Procedures associated with the determination of the Maximum Reserve Capacity Price and the methodology for the determination of the associated Weighted Average Cost of Capital (WACC).

INITIAL TERMS OF REFERENCE

The initial Terms of Reference for the MRCPWG are to:

- Consider the issues identified in the IMO's Issues Register relating to the functioning of the Maximum Reserve Capacity Price. Identify other critical matters and prioritise the comprehensive register of issues from an impact perspective on the ability of the Wholesale Electricity Market (the WEM) to deliver against its Market Objectives;
- Develop an initial Work Plan for submission to the MAC of issues and an approach to give such issues due consideration; and
- Assess critical/high priority issues and identify possible solutions. Develop an integrated suite of solutions, including drafted Procedure Change Proposals to be presented to the MAC by way of presentation/s and supporting discussion paper/s.

The Terms of Reference include a full impact assessment prior to any recommendations being put forward to the MAC, including:

- Consideration of the implications of any changes to the MRCP on improving the delivery of the Market Objectives;
- Detailed feedback as to the implications to the operation of the existing WEM processes and physical outcomes; and
- Consideration of the financial costs and benefits of implementation.

Consistent with Section 9.5 of the MAC Constitution, all matters which are identified as falling outside the Scope and Terms of Reference of this Working Group must be referred back to the MAC for consideration.

OBJECTIVES AND PRINCIPLES

The MRCPWG must provide advice and report the extent to which its advice meets or is consistent with the Wholesale Market Objectives and the general principles reflected in the current Market Rules.

The Market Objectives are as outlined in Section 122 of the Electricity Industry Act 2004 and Clause 1.2.1 of the Market Rules.

MEMBERSHIP

The MRCPWG consists of a Chair and members appointed by the MAC from nominees, being representatives of Rule Participants and other interested stakeholders. In addition, staff, representatives and consultants of the IMO work with and support the group. Replacement and/or new nominees can be submitted to the MAC for consideration at any time.

Troy Forward	- IMO (Chair)
Greg Ruthven	- IMO
Corey Dykstra	- Market Customer
Stephen MacLean	- Market Customer
Steve Gould	- Market Customer
Patrick Peake	- Market Generator
Shane Cremin	- Market Generator
Brad Huppatz	- Market Generator
~~Nenad Ninkov~~ Adam Boyd	- New Investor
Pablo Campillos	- DSM Aggregator
Neil Gibbney	- Western Power
Neil Hay	- System Management
Chris Brown	- Economic Regulation Authority (Observer)

TENURES

The Chair and members are appointed by MAC and remain in tenure until the appointment is duly revoked by the MAC or the Working Group is disestablished.

A member of the Working Group may resign by giving notice to the IMO in writing; this notice of resignation can include an appropriate replacement from the member's entity, for approval by the MAC.

RESPONSIBILITY OF THE CHAIR

The Chair provides guidance to the group to ensure that the outputs are appropriate and that they support the Working Group's role of providing advice to the MAC. The Chair works closely with the MAC, the IMO and the Working Group to achieve this.

In carrying out the above role, the Chair must ensure the documented output reflects a balanced representation of the group views.

RESPONSIBILITY OF MEMBERS

Members have been selected for their particular expertise and accordingly:

- Members are to make themselves available for meetings;
- Members have a duty to prepare for meetings;
- Members are to consider the interests of all stakeholders currently operating within the WEM;
- Members do not represent their own organisations (although the range of commercial and technical experience inevitably adds diversity to the group's capabilities); and
- Any views expressed by members are not to be taken as being those of their employer or nominating organisation.

KEY TASKS AND MILESTONES – THE WORK PLAN

The Chair works with both the IMO and Working Group to develop the Work Plan, setting out the key tasks and milestones within the Terms of Reference. The Work Plan must be agreed by the MAC.

The Chair has responsibility for the implementation of the approved Work Plan, efficient meetings of the Working Group and reporting to the MAC on achievement of agreed milestones.

NATURE OF DELIVERABLES

The MRCPWG delivers reports, advice and comments on the tasks within the scope of the Terms of Reference and as agreed and set out in the Work Plan. Such deliverables may be varied from time to time by direct request from the Chair of MAC.

In some circumstances, the MAC may decide that comments, rather than advice, are required from the group. These circumstances may arise due to:

- Issue complexity and contentiousness;
- Parallel industry wide consultation; and
- Time frames.

The documented output in those circumstances would note the various issues raised by the group and advise on them.

REPORTING ARRANGEMENTS

Routine reporting will be via Working Group reports to the MAC. Consistent with section 9.4 of the MAC Constitution, the Working Group must report back to the MAC once every month.

The Chair will also personally report to the MAC at agreed key milestones. Day to day interaction between the Working Group, the MAC and the IMO will be via the Chair.

ADMINISTRATION

The MRCPWG activities are to be as transparent as practical, and unless specifically agreed otherwise:

- Papers are to be circulated in advance of meetings;
- Papers are to be published on the IMO website as soon as practical after each meeting;
- Minutes are to be published once confirmed at the subsequent meeting; and
- While consensus will be the goal, it may at times be necessary to accept multiple views. All such views will be conveyed to the MAC as an input into its consideration of the issue.

The Chair must ensure that minutes are kept of all proceedings at meetings of the MRCPWG.

NOTICE OF MEETING MUST BE GIVEN

Reasonable notice of meetings must be given to every member, including details of the time and venue.

QUORUM OF FIVE MEMBERS

The MAC has tasked this Working Group with matters of significant importance to the future operation of the WEM. For this reason, a quorum for MRCPWG meetings will be five or more members (excluding the Chair) of that group. No business may be transacted at a meeting of the MRCPWG while a quorum is not present. Members of the MRCPWG may send a suitably qualified alternate in their place if they cannot attend a meeting, following approval by the Chair.

Agenda Item 6b: MRCPWG Update

1. OVERVIEW OF PROGRESS TO DATE

The Maximum Reserve Capacity Price Working Group (MRCPWG) last met on 15 September 2010. The next meeting date is to be confirmed by the IMO contingent on the two Consultant work scopes for reviewing the WACC and deep transmission cost methodologies.

These documents have recently been issued for tender, with appointments due to be made by the IMO by mid-October.

The MRCPWG has now completed reviewing the cost components, though noting those which require the further advice of the Consultants. The following elements have been agreed by the MRCPWG to date:

- The appropriate power station type is an Open Cycle Gas Turbine with low NOx burners and inlet cooling, operating on distillate with 2% capacity factor;
- The appropriate quantity of capacity is 160 MW, provided as a single 160 MW facility;
- The summer de-rating factor (SDF) should be specified by the Consultant who develops the power station costs, according to available turbine and inlet cooling technology, and taking into account humidity conditions, replacing the value of 1.18 currently indicated in the Market Procedure;
- Western Power is the appropriate party to determine transmission connection costs;
- The IMO should continue to determine the WACC with the ERA reviewing this in its approval of the MRCP in accordance with clause 2.26.1 of the Market Rules;
- The Fixed Fuel Cost should include an allowance to maintain sufficient fuel levels for 14 hours of operation at all times, not 12 hours as currently indicated in the Market Procedure;
- The current methodology for determining Fixed Operation and Maintenance Costs is appropriate;
- Landgate is the appropriate party to provide a valuation on Land costs;
- The current list of land locations is appropriate, although there should be greater flexibility to add to the list where appropriate;
- Uplift factors for construction costs in the current list of locations should be specified by the Consultant;
- Land, Transmission and Construction Costs should be optimised to determine the cheapest location;
- A Market Participant may not be required to purchase any required buffer zone if the facility was located in an industrial precinct, so the land size should be standardised to 3 ha with the stipulation that the buffer zone must exist where required; and
- The IMO has appointed consultants (see section 2 of this paper for more detail) to assist in the calculation methodology to be applied in determining:

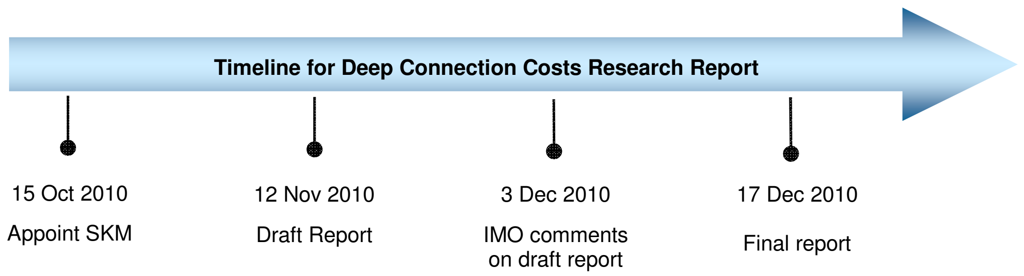
- Deep Connection Costs; and
- The Weighted Average Cost of Capital (WACC).

2. APPOINTMENT OF CONSULTANTS

2.1 Calculation methodology to be applied in determining Deep Connection Costs

The IMO has appointed SKM to prepare a review report, in the context of the Western Australian Wholesale Electricity Market (WEM), on an appropriate calculation methodology for Western Power to follow when estimating deep connection costs associated with connecting a power station to the South West interconnected system (SWIS).

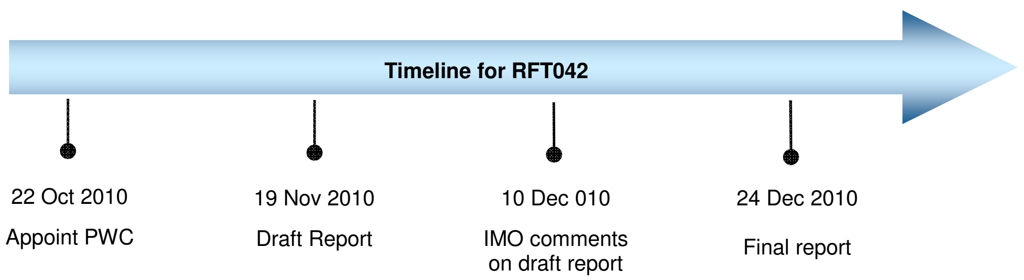
A timeline detailing the remaining project steps is outlined below:



2.2 Calculation methodology to be applied in determining Weighted Average Cost of Capital

The IMO has appointed PricewaterhouseCoopers (PWC) to provide a review report, in the context of the WEM, to the IMO on the calculation and application of an appropriate WACC for the determination of the MRCP.

A timeline detailing the remaining project steps is outlined below:



The IMO will schedule the next meeting of the MRCPWG once it has received the final research reports for both streams of work.

3. RECOMMENDATIONS

It is recommended that the MAC:

- **Note** this update.

Agenda Item 6c: Final Report of the Renewable Energy Generation Working Group

1. BACKGROUND

The Renewable Energy Generation Working Group (REGWG) was convened by the Market Advisory Committee (MAC) at its meeting on 12 March 2008. The REGWG's scope was to consider and assess system and market issues arising from the increase in the national Mandatory Renewable Energy Target (MRET) to 20% by 2020. In particular, the Working Group was tasked to focus on issues related to:

- the treatment of intermittent generators in the Reserve Capacity Mechanism;
- the allocation of ancillary service charges; and
- system security at times of low load.

The REGWG was initially chaired by the Office of Energy with four meetings were held between April 2008 and April 2009. At its meeting on 29 April 2009, the MAC approved the IMO's proposal to chair and provide administrative support for the REGWG. After the IMO received funding approval in July 2009, twelve further meetings were held between August 2009 and September 2010.

After the initial Senergy Econnect report commissioned by the Office of Energy, the REGWG pursued a work programme consisting of four Work Packages:

- Work Package 1: Scenarios for Modelling Renewable Generation in the SWIS
- Work Package 2: Reserve Capacity and Reliability Impacts
- Work Package 3: Frequency Control Services
- Work Package 4: Technical Rules

The work undertaken by the REGWG included the most comprehensive technical review completed since the commencement of the Wholesale Electricity Market in Western Australia.

2. FINAL REPORT

The Final Report of the REGWG provides part of the history of the Working Group, outlines the work undertaken and details the conclusions and outcomes that were reached. The Final Report is attached to this paper.

3. RECOMMENDATIONS

It is recommended that the MAC:

- **Note** the Final Report of the Renewable Energy Generation Working Group.

imo
Independent Market Operator

Independent Market Operator

Title: Report to the Market Advisory Committee from the Renewable Energy Generation Working Group

Date: 29 October 2010

Contents

DOCUMENT DETAILS

Report Title:	Report to the Market Advisory Committee from the Renewable Energy Generation Working Group
Release Status:	Public
Confidentiality Status:	Public domain

Independent Market Operator
Level 3, Governor Stirling Tower
197 St George's Terrace, Perth WA 6000
PO Box 7096, Cloisters Square, Perth WA 6850
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Email: imo@imowa.com.au
Website: www.imowa.com.au

1. INTRODUCTION

The Renewable Energy Generation Working Group (REGWG) was convened by the Market Advisory Committee (MAC) at its meeting on 12 March 2008. The REGWG's scope was to consider and assess system and market issues arising from the increase in the national Mandatory Renewable Energy Target (MRET) to 20% by 2020. In particular, the Working Group was tasked to focus on issues related to:

- the treatment of intermittent generators in the Reserve Capacity Mechanism;
- the allocation of ancillary service charges; and
- system security at times of low load.

The REGWG was initially chaired by the Office of Energy with four meetings were held between April 2008 and April 2009. At its meeting on 29 April 2009, the MAC approved the IMO's proposal to chair and provide administrative support for the REGWG. After the IMO received funding approval in July 2009, twelve further meetings were held between August 2009 and September 2010.

Membership of the Working Group varied during its operation, but included representatives from:

- IMO
- Office of Energy
- Alinta
- Carnegie Wave Energy
- Collgar Wind Farm
- Department of Premier and Cabinet
- Department of Treasury and Finance
- DMTenergy
- Economic Regulation Authority
- Energy Response
- Griffin Energy
- Investec
- Landfill Gas & Power
- Mid West Energy
- New World Energy
- Pacific Hydro
- Skyfarming
- SunPower
- System Management
- Synergy
- Tenet Consulting
- Verve Energy
- WA Solar
- Western Power

It should be noted that the work undertaken by the REGWG included the most comprehensive technical review completed since the commencement of the Wholesale Electricity Market in Western Australia.

2. REVIEW OF CERTIFIED RESERVE CAPACITY CALCULATION METHODOLOGIES FOR INTERMITTENT GENERATORS (SENERGY ECONNECT)

The REGWG review started with work undertaken by Senergy Econnect on behalf of the Office of Energy. This work was established to consider Capacity Credit allocation methods for intermittent generators. Senergy Econnect combined historical weather and generation data series from REGWG members and the Bureau of Meteorology with historical electricity load series to quantify interactions between electricity demand and wind, solar and landfill gas energy resources in the SWIS. Likely Capacity Credit allocations based on a number of allocation methods were compared with the existing method.

Fleet reliability, wind generation during peak load-inducing weather events and variations in wind and solar regimes across the SWIS were also investigated. Probabilistic, whole-of-system analysis is required to evaluate the contribution intermittent generators make to system reliability and was not undertaken as part of this exercise. Instead, it has been addressed through subsequent work.

The Senergy Econnect report and a summary of findings were presented to the REGWG in August 2009.

3. SCOPING DOCUMENT TO ASSESS THE IMPACTS OF INTERMITTENT GENERATION

The IMO commissioned Sinclair Knight Merz (SKM) to develop a work programme to ensure that the various policy, system and market issues related to increasing intermittent generation were adequately considered.

SKM developed a work programme consisting of the following four Work Packages:

- Work Package 1: Scenarios for Modelling Renewable Generation in the SWIS
- Work Package 2: Reserve Capacity and Reliability Impacts
- Work Package 3: Frequency Control Services
- Work Package 4: Technical Rules

This work programme was endorsed by the REGWG and presented to the MAC at Meeting 22 (9 September 2009). The four Work Packages are explained in further detail below.

4. WORK PACKAGE 1: SCENARIOS FOR MODELLING RENEWABLE GENERATION IN THE SWIS

4.1. Background

The SKM scoping study recognised the need to understand the likely development of the generation mix in the market in order to set the priority and timing of developments that will accommodate any increase in intermittent generation levels.

ROAM Consulting was subsequently appointed to undertake Work Package 1 and was required to:

- identify existing policies or regulations that may promote or impede intermittent generators or dispatchable renewable energy generators locating in the SWIS as a precursor to scenario development;
- determine the likely scenarios for the future generation mix in the SWIS as a result of State and Federal Government policies and regulations; and
- identify the key drivers and constraints that determine these scenarios and how changes in those drivers would change the scenario outcomes.

4.2. Outcome

ROAM considered the key drivers that would likely affect the future mix of renewable generation and developed four possible scenarios that explored a range of potential outcomes for the SWIS. The table below lists the variables in the four scenarios[1].

Summary of Scenarios						
	Description	**CPRS[2]**	**Demand growth**	**Gas price**	**CCS[3]**	**Renewable technologies**
1	Strained network	CPRS -15	Low	High	*Not available*	Wind
2	Minimal change	CPRS -5	Medium	Moderate	*Not available*	Wind
3	Low emissions	CPRS -25	Low	Moderate	*Available*	Mix
4	Coal development	CPRS -5	High	High	*Available late*	Wind

ROAM then developed planting schedules for each of the four possible scenarios above, aligning future generator developments (known and theoretical) with forecast demand growth. ROAM also developed an estimate of the likely level of greenhouse gas emissions resulting from each scenario.

The scenarios and planting schedules developed as part of Work Package 1 were utilised in the modelling for Work Package 3.

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[1] From Executive Summary of ROAM report "Scenarios for Modelling Renewable Generation in the SWIS" (25 August 2010), http://www.imowa.com.au/f139,628433/FINAL_WP1_Report_Imo00015_to_IMO_2010-08-25.pdf
[2] CPRS: Carbon Pollution Reduction Scheme
[3] CCS: Carbon Capture and Storage

5. WORK PACKAGE 2: RESERVE CAPACITY AND RELIABILITY IMPACTS

5.1. Background

SKM noted, in its scoping study, the need to reassess the contribution of intermittent generators towards system security and capacity and the appropriate method for remunerating the capacity that they provide. It has been widely acknowledged that the current valuation methodology is unsuitable for solar generation, due to its inclusion of overnight periods, and there are doubts as to whether the 3-year average provides an accurate representation of the value of wind generators at peak demand times.

McLennan Magasanik Associates (MMA) was subsequently appointed to undertake Work Package 2 and was required to:

- review whether capacity based on average output is a reasonable approximation to the capacity value of intermittent generation sources; and
- If not, identify and review other available measures that:
    - reflect the impact on system reliability;
    - are robust with acceptable volatility of measure; and
    - are easy to understand and apply without detailed system modelling.

5.2. MMA Review and REGWG Resolution

MMA tested a reliability-based Loss of Load Probability approach (LOLP) as its starting point[4]. Other valuation methods were also examined by MMA and compared in the graph below[5]. The LOLP method was found to be highly volatile as heavy weighting is applied to 0%-20% PoE (Probability of Exceedance) conditions, for which limited data is available (primarily 2002/03). A method using the average output of the top 750 trading intervals from selected high demand years, scaled to future load forecasts, was recommended by MMA as an interim measure due to similar valuation to LOLP but with reduced volatility. MMA recommended to progress to the LOLP method once data availability improved, noting the limitations of the LOLP method as a result of the lack of historical data.

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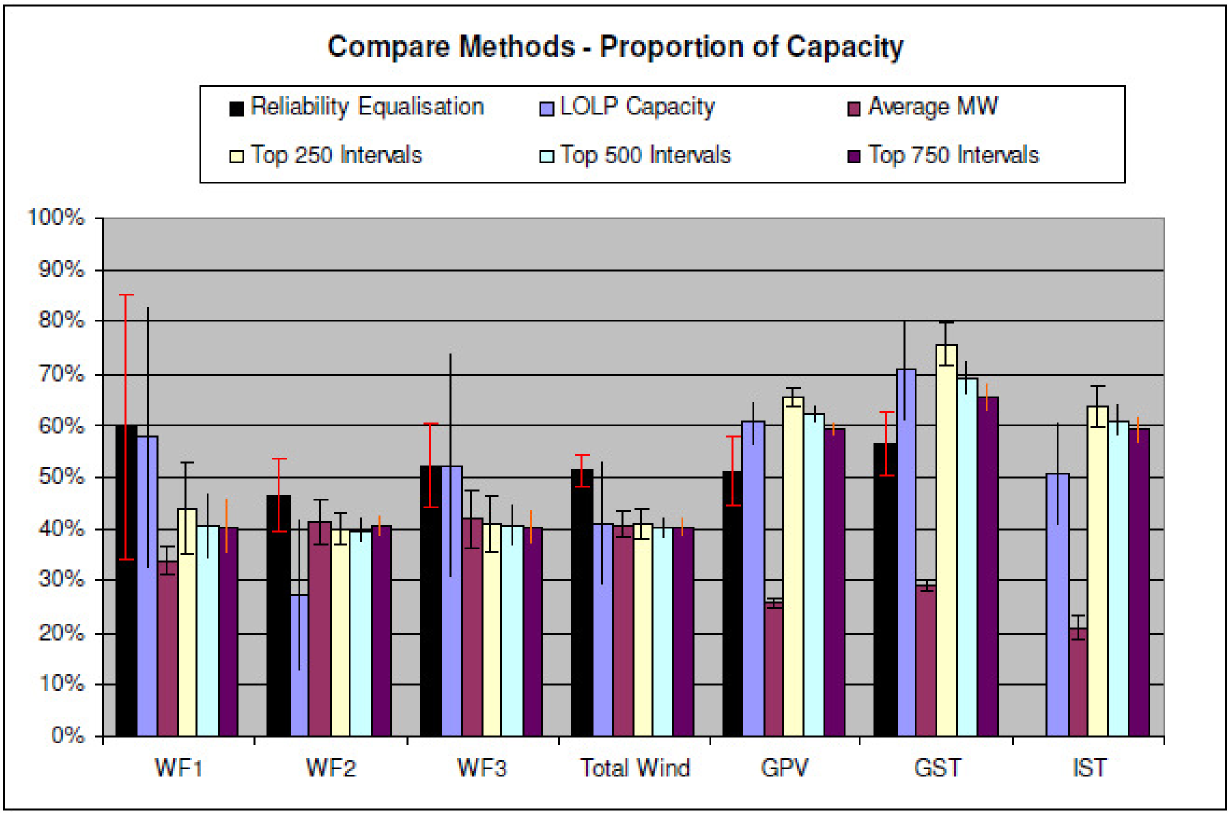
[4] For more information on the LOLP technique, see MMA report "Valuing the Capacity of Intermittent Generation in the South-west Interconnected System of Western Australia" (29 January 2010), http://www.imowa.com.au/f139,628386/04._WP_2_Initial_Report.pdf

[5] Exec Figure 2 from MMA report "Valuing the Capacity of Intermittent Generation in the South-west Interconnected System of Western Australia" (29 January 2010), http://www.imowa.com.au/f139,628386/04._WP_2_Initial_Report.pdf



Consultation on MMA's report with the Office of Energy, Verve Energy, System Management and the Oates Implementation Committee led to MMA issuing a supplementary report. The key issues considered were:

- Questions about the basis of modelled/simulated data, used in the absence of measured wind farm outputs;
- Questions about the relationship of the capacity valuation to the reliability criterion;
- Evaluation of the use of lower numbers of Trading Intervals (12 IRCR intervals, 60, 160) on capacity valuations and volatility;
- Analysis of the effect of increasing wind penetration on valuation (the resulting analysis showed a reducing valuation with increasing penetration of wind, and also suggested that 1,200 MW to 1,500 MW of wind could exist on the SWIS without jeopardising reliability of the system);
- The development of a method of selecting trading intervals based on Load for Scheduled Generation (LSG) rather than peak demand; and
- Consideration of an alternative methodology proposed by the Office of Energy.

The supplementary report will be compiled into one comprehensive study report. MMA continues to recommend that the 750 trading interval method be adopted (Proposal 2A below) using LSG for interval selection, with consideration for a moving average approach to reduce volatility. MMA also proposed an alternative method, denoted as Proposal 2B, using 750 trading intervals from the last three years.

Continued concerns were raised by System Management through this process about the confidence in reliability of intermittent generation from an operational perspective under extreme weather events. System Management developed an alternative approach to valuing the capacity credits assigned to intermittent generation facilities. This is denoted as Proposal 3 in the table below.

In light of concerns raised about the use of modelled data and system reliability, an individual member of the REGWG also proposed an alternative methodology for capacity valuation, denoted as Proposal 1 in the table below.

It must be acknowledged that a lack of available data about the likely performance of intermittent generation facilities during extreme hot weather events has contributed to uncertainty and the concerns raised by System Management.

The operational realities of maintaining power system security must be balanced with accepting an approach which supports longer term investment in intermittent generation in the SWIS through the appropriate assignment of Capacity Credits to all facilities. There is no clear answer to this tradeoff.

The table below summarises and compares the various methods proposed for the capacity credit valuation of intermittent generation facilities as presented to the REGWG[6].

Proposal ► Criteria ▼	1	2A	2B	3
Basis	Fleet POE for 12 TI, shared on last three years 250 TI	750 TI for selected high demand years scaled to forecast	750 TI based on last three years	Fleet POE on 175 TI, shared on 250 TI over last three years
Transparency	Moderate – complex interactions but based on history	Moderate – some interactions and forecasting uncertainty	High – based on history	Moderate – some interactions
Simplicity	Moderate	Moderate	High	Moderate
Fleet POE	95%			90%
Accuracy and Robustness	Low (Conservative)	High –best represents reliability impact	Moderate (Conservative)	Low (Conservative)
Continuity of valuation	Low due to significant interactions among resources	High – changes infrequently, but then substantially	Moderate due to year to year variations	Moderate with significant interactions among resources

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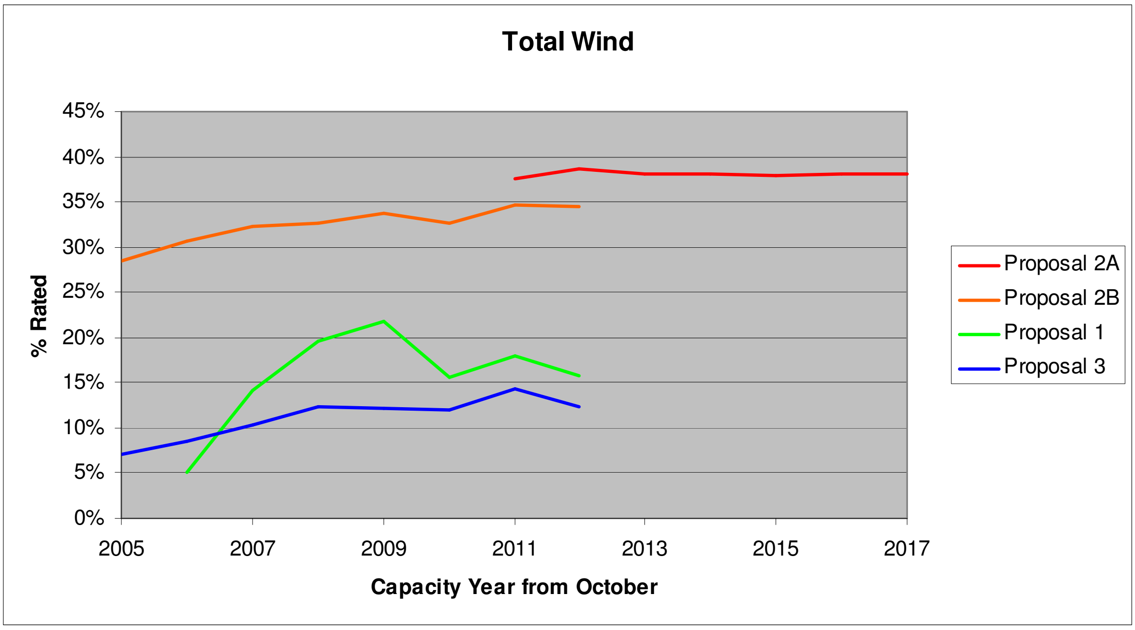
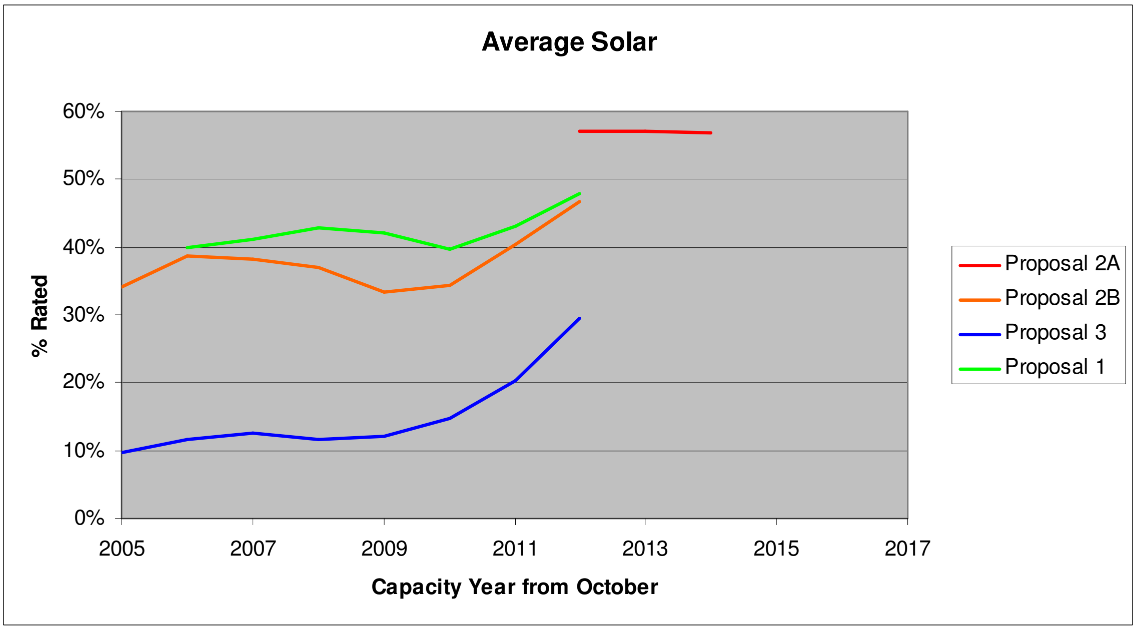
[6] Table 3-3 from MMA report "Analysis of Procedures for Assessing the Capacity Value of Intermittent Generation in the Wholesale Electricity Market" (2 August 2010), found at http://www.imowa.com.au/f139,732955/Agenda_Item_8b_-_MMA_Report_Capacity_Valuation_Methods.pdf

The table and graphs below provide estimates of the capacity valuation that would result from the various methodologies.

Proposal	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Total Wind													
P1		0.05	0.14	0.20	0.22	0.16	0.18	0.16					
P2A							0.38	0.39	0.38	0.38	0.38	0.38	0.38
P2B	0.28	0.31	0.32	0.33	0.34	0.33	0.35	0.34					
P3	0.07	0.08	0.10	0.12	0.12	0.12	0.14	0.12					
Wind + GPV													
P1		0.39	0.39	0.41	0.41	0.35	0.35	0.36					
P2A								0.45	0.44	0.44			
P2B	0.31	0.34	0.35	0.35	0.34	0.34	0.37	0.39					
P3	0.09	0.10	0.11	0.11	0.13	0.15	0.20	0.25					
Wind + GST													
P1		0.38	0.38	0.40	0.42	0.40	0.40	0.41					
P2A								0.45	0.44	0.44			
P2B	0.31	0.34	0.35	0.35	0.34	0.34	0.37	0.39					
P3	0.09	0.10	0.11	0.11	0.13	0.15	0.20	0.25					
Wind + IST													
P1		0.14	0.22	0.26	0.29	0.26	0.28	0.29					
P2A								0.44	0.44	0.44			
P2B	0.29	0.32	0.33	0.33	0.32	0.32	0.35	0.38					
P3	0.06	0.08	0.10	0.09	0.09	0.10	0.15	0.23					





5.3. REGWG Resolution

The REGWG discussed the merits of the proposals at length during the 12 August 2010 and 2 September 2010 meetings. The REGWG was unable to reach a consensus decision for a valuation methodology.

Throughout the debate, System Management maintained that higher valuations could compromise the reliability of the power system. System Management made reference to the capacity allocations to wind farms in the National Electricity Market (NEM), in the order of 5% of nameplate capacity, while noting that the NEM has no capacity market and the lower valuation does not affect the income of individual wind farms. They expressed reservations with the use of modelled data, as well as the limited quantity of data that was available for assessment. System Management also pointed out that the performance of wind farms in peak periods exhibits large variability. System Management stated its preference for Proposal 3 as it focuses on intervals when the capacity is most needed. System Management also indicated that it could only support methodologies that would result in valuations up to 20% of nameplate capacity.

System Management's view was countered by various REGWG members, including Market Participants with existing intermittent generation facilities (Alinta, Griffin), proponents of new intermittent generation facilities (Pacific Hydro, Mid West Energy) and Synergy. These members supported Proposal 2A, suggesting that this proposal, developed and recommended by an expert consultant, has the strongest scientific basis and strongest link to system reliability. They also indicated that any reduction in the capacity valuation for intermittent generators would harm investment in the renewable energy sector in the SWIS, and suggested that grandfathering provisions should be considered for existing facilities.

The IMO suggested Proposal 1 at the 2 September 2010 meeting, which was supported by LGP on the basis that it is a compromise between the other proposals. System Management indicated that, while not its preferred proposal, it could accept Proposal 1 on the grounds that the valuation did not exceed 20% of nameplate capacity. This was not supported by the other parties who continued to advocate Proposal 2A.

While failing to reach a consensus position on the matter of valuing capacity credits for intermittent generation, the REGWG supported the proposal that the IMO would nominate the valuation methodology that it felt best served the Market Objectives and would submit a Rule Change Proposal to the MAC. A Pre Rule Change Proposal, PRC_2010_25, will be presented to the 10 November 2010 MAC meeting.

6. WORK PACKAGE 3: FREQUENCY CONTROL SERVICES

6.1. Background

In its scoping review, SKM recommended a thorough assessment of Frequency Control Services in the SWIS, noting that increasing intermittent generation would lead to uncertainty in the type, quantity and costs for these services.

ROAM Consulting was subsequently appointed to undertake Work Package 3 and was required to:

- determine whether the existing spinning reserve, load following, curtailment and demand response criteria in the SWIS are adequate for the forecast levels of intermittent generation, and the projected scenarios for the overall generation mix;
- determine whether intermittent generators can be used to provide the frequency control services required including load following for overnight load troughs; and

- determine the cost and the method of allocating of these costs associated with the provision of frequency control services for the forecast penetration levels of intermittent generation.

6.2. ROAM Recommendations and REGWG Resolutions

A summary of the ROAM recommendations and the IMO's response is shown in the table below. This summary was reviewed at the 2 September 2010 meeting of the REGWG and has been updated subsequent to the meeting. The IMO intends to proceed as outlined in the IMO Response column of the table.

Summary of ROAM Consulting recommendations and IMO response

	No.	Executive Summary Subheading	ROAM Recommendation	IMO Response
Competitive Procurement of Ancillary Services	1	**Projected load following requirements can be technically provided under the existing rules and with existing infrastructure (Section 7.3)**	Introduce a competitive market for the provision of ancillary services	This recommendation will be progressed. System Management is developing a proposal for a competitive ancillary services market, which will be provided to the new Rules Development Implementation Working Group.
	4	**Equations in the Rules for determination of costs of load following are flawed (Section 14)**	An efficient market for frequency control ancillary services should be established	
	5	**Cost projections are sensitive to changes in assumptions (Section 14.9) (Section 14.8.2)**	Introduce a competitive market for the provision of ancillary services	
	6	**Cost projections are sensitive to changes in assumptions (Section 14.9) (Section 14.8.2)**	Actively seek opportunities to minimise load following costs.	
Ancillary Services Cost Allocation	3	**Equations in the Rules for determination of costs of load following are flawed (Section 14)**	The methodology in the Rules for the determination of the costs of load following and spinning reserve (clause 9.9.2 of WEM Rules) should be updated as a priority (suggested equations proposed in section 14.4).	This recommendation will be progressed, subject to the further review requested by the REGWG.
	7	**The division of cost between load following and spinning reserve needs review (section 14.9)**	Review the methodology in the Rules for allocating the costs of spinning reserve and load following (clause 9.9.2).	
	8	**Intermittent generators should pay the marginal cost of load following (Section 14.10)**	Intermittent generators should pay the marginal cost of the provision of the load following service, above that required for load variability	
Dispatch Merit Order	9	**Dispatch priorities at time of minimum load will become important (Section 12)**	Implement transparent dispatch merit order priorities in the SWIS	The issue of the dispatch merit order and potential wind curtailment will not be reviewed further by the REGWG. This issue will be highlighted to MAC – potential for review by the RDIWG.
	10	**Facilities for wind curtailment are likely to be necessary (Section 12)**	Intermittent generators must be able to curtail if necessary	

Technical Rules	2	**Inertia and governor response are not limiting factors (Section 11.3)**	Arduous requirements for wind farms to provide system inertia should not be applied. Clause 3.10.1 of the WEM Rules is a sufficient standard for the Load Following service.	Agreed. No action to be taken.
	11	**Ramping limits on intermittent generators are ineffective at reducing variability (Section 15)**	Ramp limits should not be applied to intermittent generators individually for the purpose of reducing Load Following requirements and therefore the 15% limit should be removed from the Technical Rules if only for this purpose	Recommendation to be referred to ERA's Technical Rules Committee.
	12	**Intermittent generation is unlikely to be an attractive provider of load following service (Section 16)**	Facilitating intermittent generators to provide load following services should not be an immediate priority.	Agreed. No action to be taken.
Wind Correlation	13	**Wind exhibits correlation within three distinct zones in the SWIS (Section 6.1.2)**	Consider commissioning a detailed wind correlation study	Not recommended to be progressed. It was determined that this would not add value to the REGWG process.

At the 2 September 2010 meeting, the REGWG requested that further review be undertaken in relation to the allocation of Load Following and Spinning Reserve costs, prior to the submission of a Rule Change Proposal. Specifically, the IMO was asked to instruct ROAM to:

- Consider how the impact of Scheduled Generator deviations from dispatch targets can be reflected in the allocation of Load Following costs;
- Consider the suggestions made by Verve Energy for the simplification and staged implementation of the proposed changes to the Market Rules; and
- Investigate the use of a proportioning approach and prepare a comparison of this approach and the difference-based approach.

The outcomes of the further review are presented in the Pre Rule Change Proposal PRC_2010_27, which is also being presented to the 10 November 2010 MAC meeting.

7. WORK PACKAGE 4: TECHNICAL RULES

SKM concluded that increasing penetration of intermittent generators would require evaluation of the current requirements of the Technical Rules and Power System Operating Procedures and consideration of potential revisions. SKM noted that mechanisms were required to ensure that Power System Security is not compromised due to plausible contingency events, while avoiding overly stringent requirements that may be prohibitively expensive for new generators.

SKM was subsequently appointed to undertake Work Package 4 and was required to:

- evaluate the appropriateness of the existing Technical Rules and Power System Operating Procedures as applied to intermittent generators; and
- recommend changes resulting from increased penetration of intermittent generators in the South West Interconnected System (SWIS).

While the Technical Rules and Power System Operating Procedures are generally outside the scope of the REGWG, this Work Package was undertaken to complete the analysis into the issues arising from increasing penetration of intermittent generation. The Final Report was generally accepted by the REGWG at the 12 August 2010 meeting. The REGWG also agreed that the Final Report will be passed to the ERA's Technical Rules Committee for further consideration. This will be issued to the ERA by the end of November 2010.

8. INFORMATION PROVISION OF AGGREGATE INTERMITTENT GENERATION OUTPUT

One of the issues discussed through the course of the review process is the lack of information available on intermittent generation facility outputs. At the 12 August 2010 Meeting of the REGWG, it was agreed that the IMO would develop and progress a rule change proposal to publish aggregated information about the output levels of Intermittent Generation Facilities. It was the IMO's preference at the time for the information to be made available to the WEM in, or as close to, real time as is possible. This action item will be undertaken by the

IMO. The publication of this information will be required in any case should a LSG method be proposed by the IMO.

9. CONCLUSION

This report details part of the history and outworkings of the REGWG process. While it took a significant amount of time and effort to reach the outcomes, the issues are of significant strategic importance to the continued investment in, and delivery of, renewable energy within the Western Australian Wholesale Electricity Market.

Agenda Item 7a: 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)	1 November 2010
Fast track with Consultation Period open	0
Standard Rule Changes with 1st Submission Period Open	4
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)	2
Standard Rule Changes with 2nd Submission Period Open	1
Standard Rule Changes with 2nd Submission Period Closed (final report being prepared)	0
Rule Changes - Awaiting Minister's Approval and/or Commencement	6
Total Rule Changes Currently in Progress	13

Potential changes logged by the IMO- Not yet formally submitted	September	October
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)	22	25 (+5/-2)
Low Priority (may be submitted in the next 12/18 months)	24	24 (+1/-1)
Potential Rule Changes (H, M and L)	46	49
Minor and typographical (submitted in three batches per year)	15	15
Total Potential Rule Changes	61	64

The changes in the rule change and issues log (from September to October) has arisen from:

Priority	Issue	Status
High	N/a	N/a
Medium	In: • Deregistration: A Market Participant which has been wound up cannot be deregistered by the IMO without applying to the Electricity Review Board. This is a costly and time consuming exercise and as such requires an alternative solution. The IMO would like to amend the rules to allow it to deregister participants who have never traded in the market and never intend to. • Payments to Generators for Commissioning Energy: 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. • System Restart Costs: The ERA has set the System Restart total cost as zero for 2011/12 and 2012/13 in its recent Allowable Revenue review. Under the current settlement rules Verve Energy will be charged the total payment paid to other suppliers for System Restart service in addition to providing any further service required by System Management under clause 3.11.7A with no compensation. • Provision of commissioning information by System Management: The updates to Commissioning provisions rule change (RC_2009_08) included a provision for System Management to provide the IMO with upcoming commissioning test information for publication. This rule is due to commence 1 January 2011. When working through the IT implementation of this change, the IMO and System Management have agreed that the transfer of information from System Management to the IMO would be more efficient by 7.30am as opposed to the 4.30pm originally agreed. • SRC: Development of an annual consolidated fund for Capacity Cost Refunds to be used for SRC purposes. As discussed at the October 2010 MAC meeting. Out: • Dispatch Instruction Payments (DIP) for a	• On the Rule Change and Issue Log. • On the Rule Change and Issue Log. • On the Rule Change and Issue Log. The IMO is working with Verve Energy, System Management and the ERA on this issue. • The IMO is currently preparing a Fast Track Rule Change Proposal (RRC_2010_34). The IMO considers that qualifies as it is of a procedural nature (clause 2.5.9(a)). • On the Rule Change and Issue Log. • Included in PRC_2010_29:

Priority	Issue	Status
	Curtailable Load: Clause 6.17.6 (a) relates to when the IMO is required to DIPs. The clause notes that DIPs are to be zero when no Dispatch Instructions have been issued however it then goes on to say that it should also be zero when instructions to Curtailable Loads (6.17.6(d)) are issued. This has been updated to say DIPs are to be zero when *no* Dispatch Instructions have been issued to Curtailable Loads. • SRC: Assessment of whether SRC is required can only be based on the values determined in 4.5.9, which is prepared two years in advance and does not allow for updated forecasts.	Curtailable Loads. • IMO is currently preparing a Fast Track Rule Change Proposal: PRC_2010_35. The IMO considers that qualifies as it is a manifest error (clause 2.5.9(b)).
Low	In: • Assessment of whether rule changes are needed to support NCS instructions to Non-Scheduled Generators to decrease output (from October 2010 MAC meeting). Out: • If a Facility (including a Curtailable Load) fails a second Reserve Capacity Test the IMO must reduce its Capacity Credits from the next Trading Day. This is impossible in a day-ahead market. The IMO has amended this to be the next "Scheduling Day".	• On the Rule Change and Issues Log. • Included in PRC_2010_29: Curtailable Loads.

APPENDIX 1: FORMALLY SUBMITTED RULE CHANGES

Standard Rule Change with First Submission Period Open

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	Submission period ends	29/11/2010
RC_2010_19	25/10/2010	Settlement Cycle Timeline	IMO	Submission period ends	06/12/2010
RC_2010_20	08/10/2010	Market Fees	IMO	Submission period ends	22/11/2010
RC_2010_21	15/10/2010	Providing Price Related Standing Data to System Management	IMO	Submission period ends	29/11/2010

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	17/12/2010
RC_2010_23	03/08/2010	Consequential Outage – Relief from capacity refund and unauthorised deviation penalties	Alinta	Publish Draft Rule Change Report	11/11/2010

Standard Rule Change with Second Submission Period Open

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2010_24	03/08/2010	Adjustment of Relevant Level for Intermittent Generation Capacity	Alinta	Submission period ends	20/01/2011

Fast Track Rule Change Awaiting Ministerial Approval

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2010_26	26/09/2010	Minor, Typographical and Manifest Errors	IMO	Ministerial Approval by	16/11/2010

Standard Rule Change with Final Report Published

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2009_08	21/04/2009	Updates to Commissioning Provisions	IMO	Commencement	01/01/2011
RC_2009_22	15/10/2009	The use of tolerance levels by System Management	System Management	Commencement	01/12/2010
RC_2009_37	14/05/2010	Equipment Tests	System Management	Commencement	01/02/2011
RC_2010_06	27/04/2010	Application of Spinning Reserve to Aggregated Facilities	Griffin Energy	Commencement	01/04/2011

Agenda Item 7b: Partial Commissioning for Intermittent Generators (PRC_2010_22)

1. BACKGROUND

At the May 2010 MAC meeting, a paper was presented outlining a number of issues identified with the administration of Reserve Capacity Security and in particular the return of security to Intermittent Generation Facilities. During the meeting the MAC agreed that all facilities (both conventional and non-conventional) should be entitled to receive their Reserve Capacity Security back when they can prove that they can perform to the level at which their certification is based.

To implement the agreed changes, the IMO prepared the Rule Change Proposal: Required Level and Reserve Capacity Security (RC_2010_12). One component of the proposal is the implementation of a Required Level of output a Facility is required to perform at for the purposes of the return of Reserve Capacity Security, Reserve Capacity Testing and Reserve Capacity refunds. Any resultant amendments to the Market Rules will specify that an Intermittent Generation Facility will be commissioned when it has met 100 percent of its Required Level for two Trading Intervals and is considered by the IMO to be in Commercial Operation.

With the application of the IMO's proposed new Required Level criterion it will be possible that an Intermittent Generator may never be deemed commissioned. A new Intermittent Generator is currently required to make Reserve Capacity refunds until it is deemed to be commissioned by the IMO.

To ensure that the value of the capacity delivered by these Facilities to the market is better reflected, the IMO has prepared the attached Pre Rule Change Discussion Paper which would introduce the concept of partial commissioning of Intermittent Facilities for the purposes of Capacity Cost Refunds.

The IMO notes that the introduction of this concept will be conditional on the outcomes of RC_2010_12 and that any Amending Rules resulting from either Rule Change Proposal would be commenced at the same time.

3. RECOMMENDATIONS

The IMO recommends that the MAC:

- **Agree** for PRC_2010_22 to be formally submitted as Rule Change Proposal

Agenda item 7b, appendix 1:

Wholesale Electricity Market
Pre Rule Change Discussion Paper

Change Proposal No: PRC_2010_22
Received date: TBA

Change requested by

Name:	Troy Forward
Phone:	(08) 9254 4300
Fax:	(08) 9254 4399
Email:	imo@imowa.com.au
Organisation:	IMO
Address:	Level 3, Governor Stirling Tower, 197 St George's Terrace
Date submitted:	TBA
Urgency:	Standard Rule Change Process
Change Proposal title:	Partial Commissioning of Intermittent Generators
Market Rule affected:	4.26.1

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

The IMO has recently undertaken a review of the provisions in the Market Rules around the administration of Reserve Capacity Security. One of the issues identified as part of this review was the treatment of Intermittent Generation Facilities and the uncertainty created around when an Intermittent Generation Facilities would be entitled to receive its security back due to the interrelationship of clauses 4.13.11A and 4.13.10(c).

Clause 4.13.11A (via a reference to clause 4.13.11) stipulates that the Reserve Capacity Security provided will be forfeited for Facilities that cannot, at least once during the Capacity Year, operate at least at 90 percent of the Reserve Capacity Obligation Quantity (RCOQ) level, in a Trading Interval when the RCOQ for that Facility is greater than zero. Intermittent Facilities have an RCOQ level of zero at all times and it is therefore impossible for them to meet the requirements of clause 4.13.11A. At the same time clause 4.13.10(c) stipulates that a Facility captured by that clause (which applies to Intermittent Generation Facilities) should have its security returned by the end of the Reserve Capacity Cycle irrespective of performance. This is in contrast to the requirements under clause 4.13.11A.

At the May 2010 MAC meeting, a paper was presented outlining a number of issues identified with the administration of Reserve Capacity Security and in particular the return of security to Intermittent Generation Facilities. During the meeting the MAC agreed that all Facilities (both conventional and non-conventional) should be entitled to receive their Reserve Capacity Security back when they can prove to the IMO that they can perform to the level at which their certification is based.

To implement the agreed changes, the IMO prepared the Rule Change Proposal: Required Level and Reserve Capacity Security (RC_2010_12). One component of the proposal is the implementation of a Required Level of output a Facility is required to perform at for the purposes of the return of Reserve Capacity Security, Reserve Capacity Testing and Reserve Capacity refunds. The Required Level for each Facility type will be calculated by the IMO as follows:

- for Facilities assigned Certified Reserve Capacity (CRC) under clause 4.11.1(a), using the Metered Schedule and Temperature Dependence Curves submitted to the IMO under clause 4.10.1(e)i. and converted to a sent out basis at 41℃;
- for Facilities assigned CRC under clause 4.11.2(b), using either the:
    - a value which equals the 5 percent probability of exceedance (POE) of the 3-year expected generation output for the Facility, expressed in MW, provided to the IMO under clause 4.10.3; or
    - in the case where the value which equals the 5 percent POE is not considered to be appropriate by the IMO, an alternative value, expressed in MW, to that identified in the report provided under clause 4.10.3; and
- Curtailable Loads and Demand Side Programmes, using the Facility's Relevant Demand minus Capacity Credits assigned to that Facility.

Alternatively a Market Participant who does not consider that its Facility, that was assigned CRC under clause 4.11.2(b), will be able to met the 90 percent requirement (of the Required Level) prior to the end of the relevant Capacity Year, may provide to the IMO a report prepared by one of the IMO's accredited experts that specifies the Facility has been built to the specifications its certification was based on. In this case the security will also be returned to a Market Participant following the end of the Capacity Year.

Note that in determining the Required Level to be met for Facility's assigned CRC under clause 4.11.2(b) (mainly Intermittent Generators), the views of the IMO's panel of independent experts were sought. Further details of the Required Level criterion and the advice received from the independent experts are available in the Rule Change Proposal for RC_2010_12.

Issue

A new Intermittent Generator is currently required to make Capacity Cost Refunds until it is deemed to be commissioned by the IMO. Any amendments to the Market Rules resulting from RC_2010_12 will specify that an Intermittent Generator will be commissioned when it has met 100 percent of its Required Level for two Trading Intervals and is considered by the IMO to be in Commercial Operation.[1] With the application of the IMO's proposed new Required Level criterion it will be possible that an Intermittent Generator may never be deemed commissioned. For example a 100MW wind farm (comprising of 50 2MW turbines)

[1] Note that the IMO proposes in RC_2010_12 to define the term "Commercial Operation" in the Market Rules and the considerations that will taken into account in making its decision as to whether a Facility meets the criteria to be deemed in Commercial Operation. Further details will be specified in the Market Procedure for Reserve Capacity Security (see Appendix 1 of RC_2010_12 for further details).

may have commissioned 20 turbines (40MW) but would not be deemed by the IMO to be completely commissioned and therefore required to make full refunds.

Proposal

The IMO proposes to introduce the concept of partially commissioned Intermittent Generators for the purposes of Capacity Cost Refunds in the Market Rules. Clause 4.26.1 will be amended to allow for a new Intermittent Generator who has not operated at 100 percent of its Required Level but which the IMO considers to be Commercial Operation to only make partial refunds. The level of refund will be determined by the IMO based on the second highest percentage (of its Required Level) that the Intermittent Generator has performed to[2].

The IMO considers that the introduction of the concept of partial commissioning for Intermittent Generators will better reflect the value of the capacity delivered by these Facilities to the Wholesale Electricity Market. Intermittent Generators are paid for a service and should only be required to make refunds to the extent that they do not deliver that service. The IMO considers that for a Facility which it deems to be in Commercial Operation, the Facility's availability is indicated by the highest level of output achieved for two Trading Intervals (second highest level of output) during the Trading Month.

Implementing a partial refund scheme will provide sufficient incentive for Market Participants developing Intermittent Generators to develop projects in accordance with applications made to the IMO. This is while recognising the value of any capacity made available to the market. While there could be an alternative option of implementing a completely dynamic partial refund scheme, the IMO does not consider that this would reflect the Intermittent Generators true availability, given the nature of these types of facilities (e.g. variable wind conditions), and would create additional complexity to both the Market Rules and IMO Settlement System.

The proposed solution will ensure greater consistency between the treatment of new Intermittent Generators and new Scheduled Generators that are no longer undertaking Commissioning Tests. Currently once a Scheduled Generator has completed its Commissioning Tests it is required to make refunds only to the extent that it fails to make all of its capacity available to the market (Clause 4.26.1A)[3]. Requiring new Intermittent Generators to only make refunds to the extent that they were unavailable (as indicated by the Facility's second highest level of output during the Trading Month) will promote a more consistent outcome for the different technology types (Wholesale Market Objective (c)).

The IMO notes that the introduction of the concept of partially commissioned Intermittent Generators for the purposes of Capacity Cost Refunds will be conditional on the outcomes of

[2] Note that this requirement is consistent with the number of Trading Intervals that a Facility must achieve its Required Level to be entitled to receive its Reserve Capacity Security back, as proposed under RC_2010_12.

[3] Note that after 1 October of Year 3 of the Capacity Cycle, Market Generators who have yet to commence operation or that are undertaking late commissioning are required to make full Capacity Cost Refunds. For late commissioning plants full Capacity Cost Refunds will apply for a period of up to four continuous months. Market Generators undertaking late commissioning can make commercial decisions around whether to officially finish commissioning once they have reached a certain level of reliability.

RC_2010_12 and that any Amending Rules resulting from either Rule Change Proposal would be commenced at the same time.

Worked Example

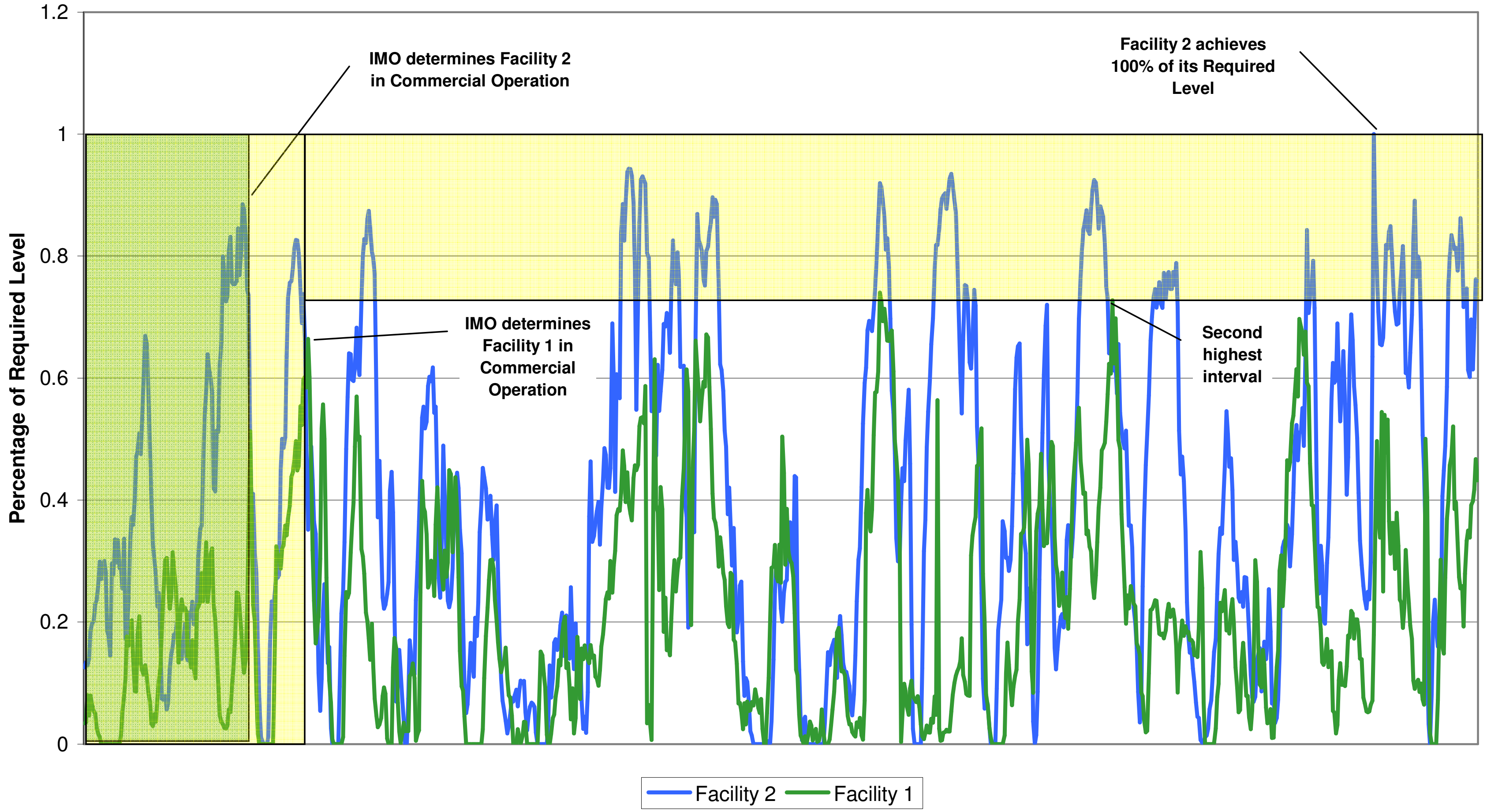
Consider a Market Participant that has not installed all the turbines that its wind farm (Facility 1) was originally certified for, but following an application the IMO considers Facility 1 to be in Commercial Operation. If during a Trading Month the turbines which have been installed for Facility 1 operate at 77 percent of the Facility's Required Level (second highest level of output achieved) the Market Participant will only be required to make refunds of 23 percent (the shortfall in output) of the Facility's Capacity Credits for the Trading Month from the date where the IMO considers that Facility to be in Commercial Operation.

This example is illustrated in the diagram presented below. The yellow section illustrates the amount of refunds that would be required to be made by Facility 1 during the Trading Month (including full refunds prior to the Facility being deemed to be in Commercial Operation and partial refunds subsequently). Note that under the Market Rules (as proposed to be amended under RC_2010_12), Facility 1 would be required to make refunds of 100 percent of its Capacity Credits until such time as it reached 100 percent of its Required Level.

An example of a Facility which the IMO determines is in Commercial Operation and which during the same month reaches 100 percent of its Required Level (Facility 2) is also presented in the diagram below. In this case full refunds would be required to be made for the entire period up until the IMO determined the Facility is in Commercial Operation (indicated by the green section). For the remainder of the Trading Month, once the Facility has been determined to be in Commercial Operation, no refunds will apply. This will also be the case for subsequent Trading Months.

Note that Market Participants wishing for a Facility to be considered by the IMO to be in Commercial Operation will be required to make an application to the IMO for this purpose. Details of the process for applications will be specified in the Reserve Capacity Market Procedure (consistent with the proposed definition of Commercial Operation and criterion for the IMO's determination to be implemented in any Amending Rules resulting from RC_2010_12). The IMO will develop the specific proposed amendments to the Market Procedure during the first submission period for RC_2010_12. This will be in conjunction with the IMO Procedure Change and Development Working Group. This will ensure that interested parties submitting on the Rule Change Proposal will be provided with transparency of the proposed changes to the Market Procedure.

Wind Farm Output during 1 Trading Month



2. Explain the reason for the degree of urgency:

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

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

The proposed amendment to clause 4.26.1 will allow for a partially commissioned Intermittent Facility to only pay partial Capacity Cost Refunds where the IMO considers it to be in Commercial Operation. The IMO proposes to insert the same scaling factor to Capacity Credits assigned at the beginning of the Capacity Year as used for the purposes of the return of Reserve Capacity Security and in determining when a Facility has operated at 100% of its Required Level.

Note that the amendments to clause 4.26.1 proposed under RC_2010_12 have been presented in the drafting to ensure that the further amendments to this clause to allow for partially commissioned Intermittent Facilities to pay partial refunds can be reviewed in context.

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

REFUND TABLE

Dates	1 April to 1 October	1 October to 1 December	1 December to 1 February	1 February to 1 April
Business Days Off-Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)	0.25 x Y	0.25 x Y	0.5 x Y	0.75 x Y
Business Days Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)	1.5 x Y	1.5 x Y	4 x Y	6 x Y
Non-Business Days Off-Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)	0.25 x Y	0.25 x Y	0.5 x Y	0.75 x Y
Non-Business Days Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)	0.75 x Y	0.75 x Y	1.5 x Y	2 x Y

Maximum Participant Refund	The total value of the Capacity Credit payments paid or to be paid under these Market Rules to the relevant Market Participant for the 12 Trading Months commencing at the start of the Trading Day of the previous 1 October assuming the IMO acquires all of the Capacity Credits held by the Market Participant and the cost of each Capacity Credit so acquired is determined in accordance with clause 4.28.2(b), (c) and (d) (as applicable).

Where:

For an Intermittent Facility that ~~has:~~

(a) has operated at 100 percent of its Required Level, scaled to the level of Capacity Credits specified in clause 4.20.1(a), in at least two Trading Intervals; or

(b) has provided the IMO with a report prepared by an independent expert accredited by the IMO in accordance with the Reserve Capacity Procedure before the end of the relevant Capacity Year, where this report specifies that the Facility certified under clause 4.11.2(b) has been built in accordance with the report provided under clause 4.10.3; and

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

Y equals 0.

For an Intermittent Facility that:

(a) has not operated at 100 percent of its Required Level, scaled to the level of Capacity Credits specified in clause 4.20.1(a), in at least two Trading Intervals; and

(b) is considered by the IMO to be in Commercial Operation:

Y is determined by dividing the Monthly Reserve Capacity Price (calculated in accordance with clause 4.29.1) by the number of Trading Intervals in the relevant month, and multiplying this value by the following formula:

$(RL-2 \times Max_2)/RL$

where:

RL is the Required Level, scaled to the level of Capacity Credits specified in clause 4.20.1(a)

Max_2 is the second highest value of the output for the Facility (MWh) achieved during the Trading Month, as measured by the Meter Schedule data (sent out) that has been achieved since the date the IMO determined the Facility to be in Commercial Operation, where this value must be set equal to or greater than the Max_2 applied by the IMO for the previous Trading Month.

For all other facilities, including Intermittent Facilities that ~~following a request to the IMO by a Market Participant~~ are not considered by the IMO to be in Commercial Operation: Y is determined by dividing the Monthly Reserve Capacity Price (calculated in accordance with clause 4.29.1) by the number of Trading Intervals in the relevant Trading M~~m~~onth.

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

The IMO considers that the proposed amendments are consistent with the Wholesale Market Objectives and better address the Wholesale Market Objective (c). In particular, the introduction of the concept of Intermittent Generators being partially commissioned will better reflect the value of the capacity delivered by Intermittent Generators to the market. The IMO considers that requiring new Intermittent Generators who are considered by the IMO to be in Commercial Operation to only make refunds to the extent that they were unavailable during the Trading Month will promote a fairer outcome (and greater consistency with the treatment of new Scheduled Generators) which is consistent with Market Objective (c).

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

Costs:

- The IMO would require changes to its system to calculate the level of partial refunds required once the IMO considers a Facility to be in Commercial Operation.

Benefits:

- Equal treatment of conventional and non-conventional generation.
- Better reflection of the value of the capacity delivered by Intermittent Generators, who are in Commercial Operation, to the market.

Agenda Item 7c: Calculation of the Capacity Value of Intermittent Generation (PRC_2010_25)

1. BACKGROUND

The Renewable Energy Generation Working Group[1] (REGWG), established under the auspices of the MAC, was tasked with the review and investigation of potential issues associated with high levels of penetration of intermittent renewable energy generation projects within the South West interconnected system (SWIS). The REGWG was tasked with assessing the system and market issues arising from increasing penetration of Intermittent Generation. A Work Program which broadly comprises four Work Packages was established to address these issues.

McLennan Magasanik Associates (MMA) was appointed to undertake Work Package 2 which sought to address some of these issues through the development of a capacity valuation methodology that would accurately value the contribution of Intermittent Generators at times of peak demand.

2. METHODOLOGIES ASSESSED

A key concept that was considered and recommended by MMAwas the use of Load for Scheduled Generation (LSG) when identifying the critical peak demand intervals. LSG is calculated using the load that remains after removing the level of intermittent generation in the market. The use of LSG can change the timing of critical system reliability conditions towards those times where the demand on Scheduled Generators is highest. This technique accounts for increasing penetration of Intermittent Generation and promotes diversity of technology types and location. LSG has been incorporated into each of the valuation methodologies explained below.

MMA, through its analysis, recommended a methodology based upon the average output of each facility in 750 peak intervals for selected high demand years, scaled to future load forecasts (proposal 2A). A variant of this methodology, using 750 Trading Intervals from the last three years, was also considered (proposal 2B).

System Management proposed a methodology that assessed the value of the fleet at the 90 percent PoE (probability of exceedance) level of the top 1 percent of Trading Intervals during the last three years. This fleet capacity value is then apportioned between the various Intermittent Generators according to their performance in the top 250 intervals during the last three years (proposal 3).

Finally, a fourth methodology was proposed that assessed the average performance of the intermittent generation fleet over 12 peak Trading Intervals for each year, and then valued the fleet at the 95 percent probability of exceedance (PoE) of these averages from the preceding eight years. The fleet capacity value is then apportioned between the various Intermittent Generators according to their performance in the top 250 intervals during the last three years. This methodology is expected to deliver valuations of between 16 percent and 20 percent of

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

nameplate capacity for wind farms and between 40 percent and 50 percent for solar generation facilities.

A summary of these methodologies and the resultant expected capacity valuations is provided in the table below.

Proposal #	Description	Expected capacity valuation (% of nameplate capacity)	
		Wind Farms	Solar
Proposal 1	Office of Energy Methodology	16 - 20 percent	40 - 50 percent
Proposal 2A	MMA methodology	35 – 40 percent	50 – 60 percent
Proposal 2B	MMA methodology (variation)	28 -34 percent	35- 45 percent
Proposal 3	System Management methodology	6 – 17 percent	10 – 30 percent

While failing to reach a consensus position on the matter of valuing Capacity Credits for Intermittent Generation, the REGWG supported the proposal that the IMO would nominate the valuation methodology that it felt best served the Wholesale Market Objectives and would submit a Rule Change Proposal to the MAC.

3. IMO PROPOSAL

The IMO recommends the implementation of Proposal 1. This solution provides the following advantages. It:

- gives consideration to the reliability impacts of the capacity valuation methodology by valuing the intermittent generation fleet at the 95 percent PoE level;
- focuses on critical intervals of high system demand; and
- more fairly reflects the contribution of solar generation facilities to power system reliability at times of peak demand.

To implement this, the IMO is proposing a new appendix to the Market Rules which outlines the methodology. Arguably, this detailed information could be contained in a Market Procedure.

Discussion point 1: The MAC to discuss the IMO's recommendation to implement Proposal 1; and

Discussion point 2: Should the detailed methodology be included in an appendix to the Market Rules or as a Market Procedure.

4. RECOMMENDATIONS

The IMO recommends that the MAC:

- **Discuss** each of the issues raised in section 3; and
- **Note** that the IMO will submit PRC_2010_25 as a Rule Change Proposal.

Agenda item 7c:

Wholesale Electricity Market
Rule Change Proposal

Change Proposal No: PRC_2010_25

Received date: TBA

Change requested by

Name:	Troy Forward
Phone:	(08) 92544304
Fax:	(08) 92544399
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:	High
Change Proposal title:	Calculation of the Capacity Value of Intermittent Generation
Market Rules affected:	4.11.3A, 7.7.5A, 7.7.5B, 7.7.5C, 10.5.1 and new clause 4.11.3B and Appendix 9

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 completing a Rule Change Proposal Form that must be submitted to the IMO.

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

Independent Market Operator
Attn: Troy Forward, General Manager Development
PO Box 7096
Cloisters Square, Perth, WA 6850
Fax: (08) 9254 4399
Email: market.development@imowa.com.au

The IMO 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 progressed further.

In order for the proposal to be progressed, all fields below must be completed and the rule 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:

Background

A key objective for the Wholesale Electricity Market (WEM) is to ensure that electricity and related services are provided reliably and economically. This is a significant challenge in Western Australia because the electricity system is isolated and supplies cannot be drawn from neighbouring systems during times of system peak demand.

The provision of capacity in Western Australia is achieved through the Reserve Capacity Mechanism (RCM). This is a set of processes through which the IMO determines the amount of generation and Demand Side Management capacity required to meet future peak system demand and reliability requirements.

The current incentives for investment in the WEM, as provided by the RCM, distinguish broadly between Scheduled Generation and Intermittent Generation. They are as follows:

- Scheduled Generation – assigned Capacity Credits at a level equivalent to the level of electrical output produced on a sent-out basis at 41 degrees Celsius (in accordance with clause 4.11.1(a)); and
- Intermittent Generation – assigned Capacity Credits based on their average capacity factor over a three year period (in accordance with clause 4.11.2(b)[1]). This has historically equated to valuing wind farms at 38 to 42 percent of their nameplate capacity. Modelling suggests that a solar generation plant would be valued between 20 percent and 30 percent of its nameplate capacity with this method.

[1] The IMO notes that there is no restriction on the ability of each type of technology to apply for certification in accordance with either of the Capacity Credit allocation methodologies. However, predominantly since market start Intermittent Generators have applied for certification in accordance with clause 4.11.2(b). Note that during the October 2010 MAC meeting, the MAC endorsed that the methodology for certification under clause 4.11.1(a) be limited to Scheduled Generators.

For comparison, a wind farm investing in the National Electricity Market (NEM) is assumed to receive in the order of 5 percent of nameplate capacity for reliability planning purposes. It should be noted that the NEM does not have a capacity market and the lower valuation does not affect the income of the individual wind farms.

Given the expanded Mandatory Renewable Energy Target (MRET) scheme to achieve a national target of 20 percent of renewable generation in 2020, there is a possibility of greater momentum in renewable energy generation growth, particularly wind generation, in the South West interconnected system (SWIS). Greater renewable energy penetration in the SWIS would impact significantly on the composition of the available capacity.

Issues

The intent of the RCM is to ensure that there is sufficient capacity at peak demand times. This intent is reflected in the valuation methodology for Scheduled Generators that focuses on peak demand times by assessing the sent out capacity likely to be available at an ambient temperature of 41°C. By contrast, the current methodology for Intermittent Generators, based on the three-year average output, does not focus on peak demand times and is thus not obviously aligned with the intent of the RCM. The capacity of an Intermittent Generator is subject to technology-specific constraints and risks such as weather conditions which impact on its ability to provide the required capacity during peak periods.

Given the momentum driving the growth in renewable energy providers on the SWIS concerns have been raised regarding the current Capacity Credit valuation methodology for Intermittent Generators. Specifically:

- Doubts have been expressed as to whether the three-year average accurately represents the capacity that can be reliably delivered by wind generators. System Management, in particular, has expressed concern that excessively high valuations for wind farms could reduce the capacity available during a peak demand event and jeopardise the security of the power system.
- It has been widely acknowledged that the current valuation methodology is unsuitable for solar generation and undervalues this capacity. The current method includes overnight and winter periods that are outside peak demand times and during which solar output is low.

These concerns highlight the importance of ensuring that the investment signals provided by the RCM strike a balance between providing appropriate remuneration for Intermittent Generation and ensuring system security and reliability can be maintained.

Renewable Energy Generation Working Group

In light of the expected increase in Intermittent Generation capacity in the SWIS, the appropriateness of the current capacity valuation methodology for Intermittent Generation capacity has been reviewed by the Renewable Energy Generation Working Group (REGWG). The REGWG was convened by the Market Advisory Committee (MAC) at its meeting on 12 March 2008 to consider and assess system and market issues arising from increasing penetration of Intermittent Generation[2]. A work program which broadly comprised four Work Packages was established to address these issues.

Work Package 2 sought to address these issues through the development of a capacity valuation methodology that would accurately value the contribution of intermittent generators at times of peak demand. McLennan Magasanik Associates (MMA) was appointed to undertake Work Package 2 and assessed a range of valuation options.

A key concept that was considered and recommended was the use of Load for Scheduled Generation (LSG) when identifying the critical peak demand intervals. LSG is calculated using the load that remains after removing the level of intermittent generation in the market. The use of LSG can change the timing of critical system reliability conditions towards those times where the demand on Scheduled Generators is highest. This technique accounts for increasing penetration of Intermittent Generation and promotes diversity of technology types and location. LSG has been incorporated into each of the valuation methodologies explained below.

MMA, through its analysis, recommended a methodology based upon the average output of each facility in 750 peak intervals for selected high demand years, which are scaled to future load forecasts. This methodology delivers valuations of between 35 percent and 40 percent of nameplate capacity for the existing wind farms, and between 50 percent and 60 percent for the modelled solar generation facilities. Concern was raised by some REGWG members, particularly System Management, that this methodology based on an average performance level did not represent the capacity that could reliably be delivered by Intermittent Generators. Concern was also raised with the reliance of this method on simulated data. This methodology became known as Proposal 2A. A variant of this methodology, using 750 Trading Intervals from the last three years, was also considered and was known as Proposal 2B.

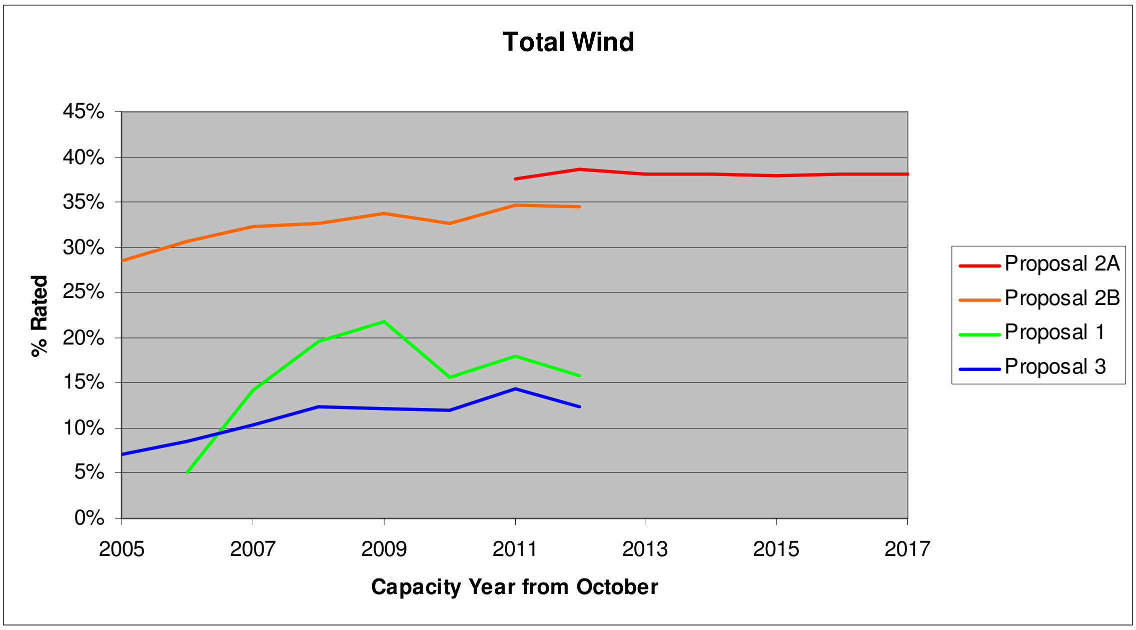
Two further valuation methods were reviewed by the REGWG. System Management proposed a methodology that assessed the value of the fleet at the 90 percent probability of exceedance (PoE) level of the top 1 percent of Trading Intervals during the last three years (175 Trading Intervals per year). This fleet capacity value is then apportioned between the various Intermittent Generators according to their performance in the top 250 intervals during the last three years. This methodology delivers valuations of between 6 percent and 17 percent of nameplate capacity for the existing individual wind farms, and between 10 percent and 30 percent for the modelled solar generation facilities. This methodology, which became known as Proposal 3, delivers the most conservative valuations of the methodologies considered.

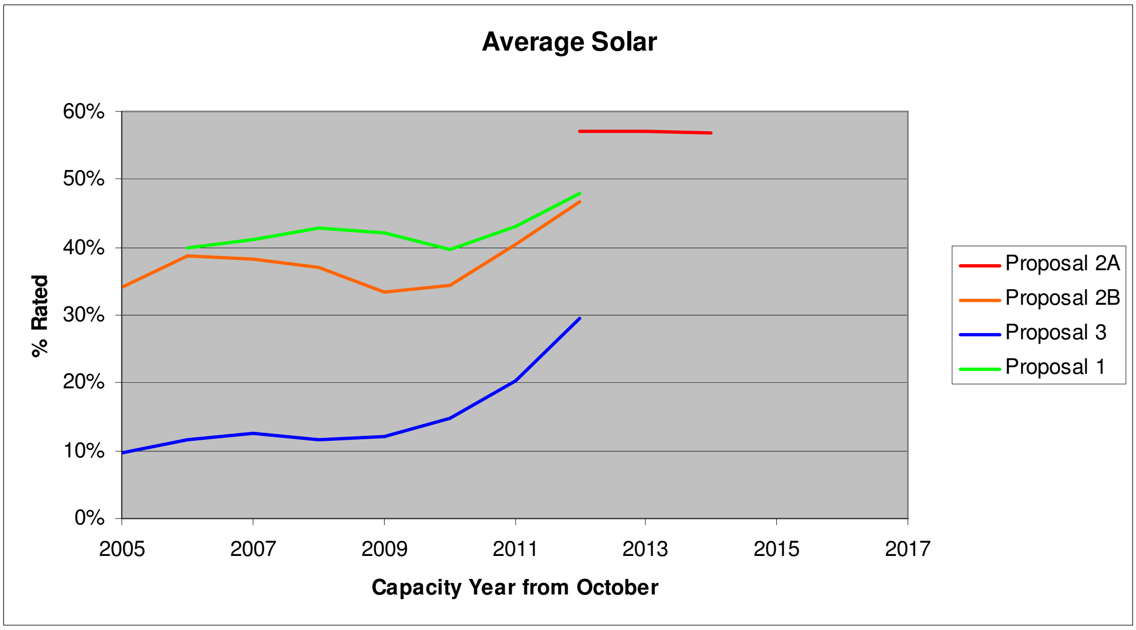
The other methodology, known as Proposal 1, was proposed by an individual REGWG member. This methodology assessed the average performance of the intermittent generation fleet over 12 peak Trading Intervals for each year, and then valued the fleet at the 95 percent PoE level of these averages from the preceding eight years. The fleet capacity value is then apportioned between the various Intermittent Generators according to their performance in the top 250 Trading Intervals during the last three years. This methodology is expected to deliver valuations of between 16 percent and 20 percent of

[2] Additional detail on the REGWG can be found on the IMO website: www.imowa.com.au/REGWG

nameplate capacity for existing wind farms and between 40 percent and 50 percent for the solar generation facilities modelled.

The graphs below provide estimated average valuation levels for wind and solar generation facilities for the various valuation proposals. It should be noted that the valuation level shown for the earlier years for Proposal 1 does not include the full eight years of data, resulting in the appearance of higher volatility than would be experienced in practice.





Throughout the REGWG process System Management maintained that higher valuations could compromise the reliability of the power system. System Management made reference to the capacity allocations to wind farms in the NEM. They expressed reservations with the use of modelled data, as well as the limited quantity of data that was available for assessment. They also noted that the performance of wind farms in peak periods exhibits large variability. System Management stated its preference for Proposal 3 as it focuses on intervals when the capacity is most needed. System Management conceded that it could support other methodologies that would result in valuations up to 20 percent of nameplate capacity for wind generation facilities, and would thus accept Proposal 1.

System Management's views were countered by various REGWG members, including Market Participants with existing Intermittent Generation facilities (Alinta, Griffin Energy), proponents of new Intermittent Generation facilities (Pacific Hydro, Mid West Energy) and Synergy. These members supported Proposal 2A, suggesting that this proposal, developed and recommended by an expert consultant, has the strongest scientific basis and strongest link to system reliability. They also indicated that any reduction in the capacity valuation for Intermittent Generators would harm investment in the renewable energy sector in the SWIS, and suggested that grandfathering provisions should be considered for existing facilities.

The IMO suggested Proposal 1 at the 2 September 2010 meeting, which was supported by LGP on the basis that it is a compromise between the other proposals. System Management indicated that it could accept Proposal 1 provided that the valuation did not exceed 20 percent of nameplate capacity. This was not supported by the other parties advocating Proposal 2A.

While failing to reach a consensus position on the matter of valuing Capacity Credits for Intermittent Generation, the REGWG supported the proposal that the IMO would nominate the valuation methodology that it felt best served the Market Objectives and would submit a Rule Change Proposal to the MAC.

Proposal

The IMO recommends the implementation of Proposal 1. This solution provides the following advantages:

- gives consideration to the reliability impacts of the capacity valuation methodology by valuing the intermittent generation fleet at the 95 percent PoE level;
- focuses on critical intervals of high system demand; and
- more fairly reflects the contribution of solar generation facilities to power system reliability at times of peak demand.

The methodology is as follows:

1. Identify in each of the eight previous years the 12 Trading Intervals which experienced the highest LSG. For this purpose, the LSG is calculated for each Trading Interval by subtracting the output from Intermittent Generation facilities (measured output from existing facilities and modelled output where the facility had not yet entered service) from the total sent out generation during that Trading Interval.
2. For each of the eight years, determine the average output of the Intermittent Generation fleet during the 12 Trading Intervals with the highest LSG.
3. Determine the 95 percent PoE level of the eight annual averages. This is the fleet capacity value.

4. Identify in each of the three previous years the 250 Trading Intervals which experienced the highest LSG.
5. Determine the average output of each individual Intermittent Generation facility for the 750 intervals determined in step 4. This is denoted below as the facility performance level.
6. Determine the sum of the facility performance levels determined in step 5. This is denoted below as the fleet performance level.
7. Apportion the fleet capacity value to each Intermittent Generation facility according to its performance over the 750 intervals.

   Relevant Level = (Facility Performance Level) / (Fleet Performance Level) × Fleet Capacity Value

The IMO has also considered the proposed amendments presented in the Draft Rule Change Report: Adjustment of the Relevant Level for Intermittent Generation (RC_2010_24). As agreed at the October 2010 MAC meeting the IMO has incorporated Alinta's proposed amendments to adjust for Trading Intervals where a Planned or Consequential Outage occurred or where output was curtailed following a request from System Management in the calculation of the highest 12 Trading Intervals for the Fleet each year. Additionally the IMO has adjusted for the incidence of Forced Outages in these intervals to avoid penalising all Non-Scheduled Generators due to Forced Outage at a single Facility.

The IMO has however excluded only periods where a Facility experiences a Consequential Outage from the determination of the 750 intervals for each individual Intermittent Generation facility. This is because instances of a Consequential Outage occurring are outside the control of a Facility. The IMO considers that it is reasonable to include all other instances of outages or curtailment following an instruction by System Management during the 750 Trading Intervals, as this will more appropriately reflect the availability of a facility during peak demand times. Network-related failures that result in a Dispatch Instruction being issued to a Facility should be reported as a Consequential Outage, and would be excluded accordingly.

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2. Explain the reason for the degree of urgency:

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

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

The proposed amendment will specify that the IMO must determine the Relevant Level for a Facility in accordance with the methodology specified in Appendix 9.

4.11.3A. Where the IMO accepts a nomination to use the methodology prescribed in clause 4.11.2(b) to assign Certified Reserve Capacity, the IMO must determine the Relevant Level for that Facility using the methodology described in Appendix 9.

~~The Relevant Level in respect of a Facility at a point in time is determined by the IMO following these steps:~~

~~(a) take all the Trading Intervals that fell within the last three years up to, and including, the last Hot Season;~~

~~(b) determine the amount of electricity (in MWh) sent out by the Facility in accordance with metered data submissions received by the IMO in accordance with clause 8.4 during these Trading Intervals;~~

~~(c) If the Generator has not entered service, or if it entered service during the period referred to in step (a), estimate the amount of electricity (in MWh) that would have been sent out by the facility, had it been in service, for all Trading Intervals occurring during the period referred to in (a) which are prior to it entering service;~~

~~(d) set the Relevant Level as double the sum of the quantities determined in (b) and (c) divided by 52,560~~

The proposed new clause will require the IMO to conduct a five year review of the methodology for determining the Relevant Level for a Facility to ensure it is effective in its application.

4.11.3B At least once in every five year period, commencing from 1 October 2011, the IMO must conduct a review of the methodology for determining the Relevant Level for a Facility specified in clause 4.11.3A.

The proposed amendments are consistent with the amended requirement for all renewable energy generators to provide details of their fuel data for the Facility to System Management (i.e. wind data and number of turbines operating for a wind farm). The provision of wind farm data has previously been optional for Market Participants.

7.7.5A. For the purpose of determining the quantity described in clause 6.17.6(c)(i) for each Trading Interval the quantity is~~:~~

~~(a) where System Management has been provided with information in accordance with clause 7.7.5B,~~ System Management's estimate of the MWh reduction in output, by Trading Interval, of the Non-Scheduled Generator as a result of System Management's Dispatch Instruction~~; or~~

~~(b) in the case of a Non-Scheduled Generator included in a Resource Plan, for which System Management has not been provided with information in~~

~~accordance with clause 7.7.5B, the greater of zero and the MWh difference between the Resource Plan MWh quantity of the Non-Scheduled Generator less the MWh output of the Non-Scheduled generator over the Trading Interval implied by its Dispatch Instruction~~.

7.7.5B. A ~~Market Participant~~ Non-Scheduled Generator ~~may~~ must provide System Management with the information specified in the Power System Operation Procedure to support System Management's ~~the~~ calculation of the quantity described in clause 7.7.5A~~(a)~~ and the IMO's estimation in Appendix 9 of the impact of Planned Outages, Consequential Outages and Forced Outages on the output, by Trading Interval, of a Facility assigned Certified Reserve Capacity in accordance with the methodology specified in clause 4.11.2(b).

7.7.5C. The Power System Operation Procedure must specify the data required to be provided by a Non-Scheduled Generator to System Management for each Facility during each Trading Interval, where this information must be ~~that actual wind data for the site of a wind farm and the number of turbines operating, if made available by a Market Participant to System Management, are~~ sufficient to allow:

a) System Management to determine, in accordance with clause 7.7.5A, what the output of ~~the~~ each Facility ~~a wind farm~~ would have been had no Dispatch Instruction or request to deviate from its Dispatch Plan or change its commitment or output been issued; and

b) the IMO to determine, in accordance with Appendix 9, what the output of the Facility would have been had a Planned Outage, Consequential Outage or Forced Outage not occurred.

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

…

(g) details of the instructions provided to:

i. Curtailable Loads that have Reserve Capacity Obligations; and

ii. providers of Supplementary Capacity;

on the Trading Day; ~~and~~

(h) the identity of the Facilities which were subject to either a Commissioning Test or a test of Reserve Capacity for each Trading Interval of the Trading Day~~.~~; and

(i) the data provided by a Market Participant in accordance with clause 7.7.5B.

The proposed amendment will allow the IMO to publish the relevant information required by Market Participants to determine their certification value. This information will be published as public information by 1 May of each year. Further details of the level of information to be published will be specified in the Market Procedure for Certification of Reserve Capacity. Note that the REGWG at its 12 August 2010 meeting agreed to progress a Rule Change Proposal to publish details of aggregate Intermittent Generator data.

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:

(a) the following Market Rule and Market Procedure information and documents:

…

(f) the following Reserve Capacity information (if applicable):

i. Requests for Expressions of Interest described in clause 4.2.3 for the previous five Reserve Capacity Cycles;

…

ix. The following annually calculated and monthly adjusted ratios:

1. NTDL_Ratio as calculated in accordance with Appendix 5, STEP 8;

2. TDL_Ratio as calculated in accordance with Appendix 5, STEP 8; and

3. Total_Ratio as calculated in accordance with Appendix 5, STEP 10~~.~~; and

x. Fleet-Assessment Load for Scheduled Generation, Facility-Assessment Load for Scheduled Generation and the relevant Trading Intervals as determined under Appendix 9.

Glossary

Facility-Assessment Load for Scheduled Generation: The total sent out generation of all Facilities minus the sent out generation (measured or estimated) of Facilities which applied to be assigned Certified Reserve Capacity in accordance with clause 4.11.2(b) adjusted for the impact of Consequential Outages on those Facilities.

Fleet-Assessment Load for Scheduled Generation: The total sent out generation of all Facilities minus the sent out generation (measured or estimated) of Facilities which applied to be assigned Certified Reserve Capacity in accordance with clause 4.11.2(b) adjusted for the impact on the output of those Facilities due to Consequential Outages, Planned Outages, Forced Outages, Dispatch Instructions and deviations from Dispatch Plans due to instructions from System Management.

The proposed new Appendix 9 will specify the methodology followed by the IMO in determining each Facility's Relevant Level. Alternatively, this could be presented in a Market Procedure.

Appendix 9: Relevant Level Determination

This Appendix presents the methodology for determining the Relevant Level for a Facility which has applied for certification of Reserve Capacity in accordance with the methodology prescribed in clause 4.11.2(b).

The IMO must perform the following steps in determining the Relevant Level for Facility in accordance with clause 4.11.3A:

Determining the Fleet Capacity Value

Step 1: Take all the Trading Intervals that occurred with the eight year period ending on the Trading Day ending on 1 April of Year 1 of the relevant Reserve Capacity Cycle.

Step 2: Determine the amount of electricity (in MWh) sent out by all Facilities applying for Certified Reserve Capacity under clause 4.11.2(b) using the Meter Data Submissions received by the IMO in accordance with clause 8.4 during the Trading Intervals identified in step 1.

Step 3: Identify any Trading Intervals in step 1 where a Facility, as identified in step 2, either:

a) was owned, controlled or operated by a Market Participant other than the Electricity Generation Corporation and was issued a Dispatch Instruction from System Management as notified under clause 7.13.1(c); or

b) was owned, controlled or operated by the Electricity Generation Corporation and was issued an instruction from System Management to deviate from its Dispatch Plan or change its commitment or output as notified under clause 7.13.1(cC); or

c) was affected by a Forced Outage, Planned Outage or Consequential Outage as notified under clause 7.13.1A; or

Step 4: If, as identified in step 3 (a), a Facility's output was reduced in order to comply with a Dispatch Instruction from System Management, issued in accordance with clause 7.7, use:

a) the estimated decrease (in MWh) in the output of each Facility, by Trading Interval, as a result of System Management Dispatch Instructions, provided by System Management in accordance with clause 7.13.1(eB); and

b) the amount of electricity (in MWh) sent out for the Facility in accordance with the Metered Data Submissions received by the IMO in accordance with clause 8.4 for all the Trading Intervals that were identified under step 3 (a)(ii.),

to estimate the amount of electricity (in MWh) that would have been sent out by the Facility, had it not complied with the Dispatch Instruction for all the Trading Intervals identified under step 3(a)(ii.). Use these estimated values to replace the amount of electricity identified in step 2 for the relevant Trading Intervals.

Step 5: If, as identified in step 3 (b), a Facility's output was reduced in order to comply with an instruction from System Management under clause 7.6A.3(a) to deviate from its Dispatch Plan or change its commitment or output, use:

a) the estimated decrease (in MWh) in the output of that Facility, by Trading Interval, as a result of an instruction from System Management in accordance with clause 7.6A.3(a), provided by System Management in accordance with clause 7.13.1(eD); and

b) the amount of electricity (in MWh) sent out for that Facility in accordance with the Meter Data Submissions received by the IMO in accordance with clause 8.4 for all the Trading Intervals that were identified under step 3 (b)(ii.),

to estimate the amount of electricity (in MWh) that would have been sent out by that Facility had it not complied with System Management's instruction for all the relevant Trading Intervals that were excluded under step 3 (b)(ii). Use these estimated values to replace of the amount of electricity identified in step 2 for all the relevant Trading Intervals identified in step 3.

Step 6: If, as identified in step 3 (c), a Facility's output was reduced due to a Forced Outage, Planned Outage or Consequential Outage, as notified under clause 7.13.1A, use:

a) the schedule of Planned Outages, Consequential Outages and Forced Outages provided by System Management in accordance with clause 7.3.4 and 7.13.1A;

b) the amount of electricity sent out for that Facility in accordance with the Meter Data Submissions received by the IMO in accordance with clause 8.4 for all the Trading Intervals that were identified under step 3 (a) (i) and step (b) (i); and

c) the data provided by System Management in accordance with clause 7.13.1(i),

to estimate the amount of electricity (in MWh) that would have been sent out by that Facility had it not experienced a Forced Outage, Planned Outage or Consequential Outage . Use these estimated values to replace of the amount of electricity identified in step 2 for all the relevant Trading Intervals identified in step 3.

Step 7: If a Facility has not yet entered service, or if it entered service during the period referred to in step 1, use the estimates included in the expert report provided in accordance with clause 4.10.3 for the period that Facility was not in service, unless the IMO reasonably believes the report to be inaccurate.

Step 8: Determine, for each Trading Interval during the period described in step 1, the Fleet-Assessment Load for Scheduled Generation by subtracting the sent out generation contribution of all Facilities which applied to be certified under clause 4.11.2(b), as identified in step 2 and updated under steps 4, 5, 6 and 7 as applicable ("Fleet Interval Performance Level"), from the total sent out generation of all Facilities for each Trading Interval.

Step 9: Determine for each year during the period identified in step 1, the 12 Trading Intervals with the highest Fleet-Assessment Load for Scheduled Generation as identified under step 8.

Step 10: Determine for each year during the period identified in step 1, the mean of the Fleet Interval Performance Level ("Fleet Annual Mean Performance Level") during the 12 Trading Intervals identified under step 9.

Step 11 Determine using a t-distribution the mean ("Fleet Mean") and standard deviation ("Fleet SD") of the Fleet Annual Mean Performance Levels for the period identified in step 1.

Step 12: Determine the **Fleet Capacity Value (MW)** by calculating the 5 percent Probability of Exceedance level in accordance with the following formula:

Fleet Capacity Value = 2 x (Fleet Mean – (1.895 x Fleet SD))

Step 13: If the value for the Fleet Capacity Value determined under step 12 is equal to or less than zero then set the Fleet Capacity Value equal to zero.

Determining the Facility Performance Level

Step 14: Take all the Trading Intervals that occurred within the last three year period ending on the Trading Day ending on 1 April of Year 1 of the relevant Reserve Capacity Cycle.

Step 15: Determine the amount of electricity (in MWh) sent out by the Facility using the Meter Data Submissions received by the IMO in accordance with clause 8.4 during the Trading Intervals identified in step 14.

Step 16: Identify any Trading Intervals in step 15 where the Facility was affected by a Consequential Outage as notified under clause 7.13.1A.

Step 17 If, as identified in step 16, the Facility's output was reduced due a Consequential Outage, use

a) the schedule of Consequential Outages a provided by System Management in accordance with clause 7.3.4 and 7.13.1A;

b) the amount of electricity sent out for the Facility in accordance with the Meter Data Submissions received by the IMO in accordance with clause 8.4 for all the Trading Intervals that were identified under step 16; and

c) the data provided by System Management in accordance with clause 7.13.1(i),

to estimate the amount of electricity (in MWh) that would have been sent out by the Facility had it not experienced a Consequential Outage for all the relevant Trading Intervals identified in step 16.

Step 18: If the Facility has not yet entered service, or if it entered service during the period referred to in step 15, use the estimates included in the expert report provided in accordance with clause 4.10.3 for the period that the Facility was not in service, unless the IMO reasonably believes the report to be inaccurate.

Step 19: Determine for each Trading Interval during the period described in step 14 the Facility-Assessment Load for Scheduled Generation by subtracting the sent out generation contribution of all Facilities which applied to be certified under clause 4.11.2(b), as identified in step 15 and updated under steps 17 and 18 as applicable, from the total sent out generation of all Facilities for each Trading Interval.

Step 20: Determine for each year during the period identified in step 14, the 250 Trading Intervals with the highest Facility-Assessment Load for Scheduled Generation as identified under step 19.

Step 21: Determine the **Facility Performance Level** for each Facility that applied to be certified under clause 4.11.2(b). The Facility Performance Level for Facility f is the mean of that Facility's sent out generation during the 750 Trading Intervals identified under step 15 and updated under steps 17 and 18, as applicable.

Determining the Relevant Level for a Facility

Step 22: Determine the Relevant Level for each Facility f (in MW) in accordance with the following formula:

Relevant Level(f) = Facility Performance Level(f) / Sum(f∈F, Facility Performance Level(f)) × Fleet Capacity

Where

F is the set of all Facilities which applied to be certified under clause 4.11.2(b), where "f" is a member of that set.

Step 21. Publish the Fleet-Assessment Load for Scheduled Generation. Facility-Assessment Load for Scheduled Generation and relevant Trading Intervals identified in steps 1, 9 and 14 on the Market Web Site by 1 May of the relevant year.

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

The IMO considers 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 IMO considers that the proposed amendment will better achieve the Wholesale Market Objectives by focussing the IMO's valuation of Capacity Credits for intermittent facilities on periods of peak demand. In particular the IMO considers that the proposed amendments will better achieve both Market Objectives (a) and (c):

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

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

The proposed changes will apply a methodology to the calculation of Capacity Credits for Intermittent Generators that more appropriately reflects the contribution of a renewable generator at times of high system demand. This will:

- Promote greater system security and reliability by providing certainty to System Management that the capacity available in the market can meet peak demand requirements (Market Objective (a)); and

- Remove a current source of discrimination between Scheduled Generators and Intermittent Generators by determining the level of certification of Intermittent Generators during peak demand periods (Market Objective (c))

The IMO considers that the proposed changes are consistent with the other 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 proposed change is not expected to impose additional costs on Market Participants.
- The proposed change is expected to result in a reduction in capacity payments from previous levels to existing renewable generators.

Benefits:

- Provide certainty to proponents of renewable generation projects for one component of their future revenue stream.
- Represents a reasonable balance of the need to accurately reflect the contribution of Intermittent Generators, while not presenting unwarranted complexity and administrative burden on the Market.
- Provides Capacity Credits consistent with the contribution to reliability relative to scheduled plant.

Agenda Item 7d: Ancillary Services Payment Equations (PRC_2010_27)

1. BACKGROUND

The Renewable Energy Generation Working Group[1] (REGWG), established under the auspices of the MAC, was tasked with the review and investigation of potential issues associated with high levels of penetration of intermittent renewable energy generation projects within the South West interconnected system (SWIS). A Work Program which broadly comprises four Work Packages was established to address these issues.

ROAM Consulting was appointed to undertake Work Package 3 and was required to:

- determine whether the existing spinning reserve, load following, curtailment and demand response criteria in the SWIS are adequate for the forecast levels of intermittent generation, and the projected scenarios for the overall generation mix;
- determine whether intermittent generators can be used to provide the frequency control services required including load following for overnight load troughs; and
- determine the cost and the method of allocating of these costs associated with the provision of frequency control services for the forecast penetration levels of intermittent generation.

2. ROAM FINAL REPORT

In its final report, presented at the 12 August 2010 REGWG meeting, ROAM concluded that:

- The Load Following requirement increases substantially in response to penetration of Intermittent Generation;
- Projected Load Following requirements can be technically provided under the existing Market Rules and with existing infrastructure;
- Inertia and governor response are not limiting factors;
- The existing Load Following definition is sufficient;
- The equations in the Market Rules for determination of costs of Load Following are flawed;
- The cost of Load Following increases as wind levels increase;
- Cost projections are sensitive to changes in assumptions;
- The division of cost between Load Following and Spinning Reserve needs review;
- Intermittent generators should pay the marginal cost of Load Following;
- Dispatch priorities at time of minimum load will become important;

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

- Facilities for wind curtailment are likely to be necessary;
- Ramping limits on Intermittent Generators are ineffective at reducing variability;
- Intermittent Generation is unlikely to be an attractive provider of Load Following Service; and
- Wind exhibits correlation within three distinct zones in the SWIS.

These conclusions and their associated recommendations (outlined in the Final Report) broadly fall into five areas:

- Competitive procurement of Ancillary Serices;
- Ancillary Services cost allocation;
- The Dispatch Merit Order;
- Technical Rules; and
- Wind correlation.

This paper focuses on the Ancillary Services cost allocation.

3. ANCILLARY SERVICES COST ALLOCATION

The ROAM Final Report for Work Package 3 included three recommendations for Ancillary Services cost allocation, these were:

- The methodology in the Rules for the determination of the costs of load following and spinning reserve (clause 9.9.2 of the Market Rules) should be updated as a priority;
- Review the methodology in the Rules for allocating the costs of spinning reserve and load following (clause 9.9.2); and
- Intermittent generators should pay the marginal cost of the provision of the load following service, above that required for load variability.

While considering these recommendations, the REGWG requested that further review be undertaken in relation to the allocation of Load Following and Spinning Reserve costs, prior to the submission of a Rule Change Proposal. Specifically, the IMO instructed ROAM to:

- Consider how the impact of Scheduled Generator deviations from dispatch targets can be reflected in the allocation of Load Following costs;
- Consider the suggestions made by Verve Energy for the simplification and staged implementation of the proposed changes to the Market Rules; and
- Investigate the use of a proportioning approach and prepare a comparison of this approach and the difference-based approach.

The Rule Change Proposal, attached as appendix 1 to this paper, includes a series of alternatives for MAC review and decision. Each of these is outlined below.

4. ISSUES

The following possible changes require a decision as to the desired way forward, and therefore have been included as attachments at the end the Rule Change Proposal for possible inclusion:

Issue 1: Clause 3.14.1 - Inclusion of unintended fluctuations of Scheduled Generators in Load Following costs (attachment 1 to the Rule Change Proposal)

Clause 3.10.1 defines the Load Following service as being sufficient to cover short term fluctuations in load, Non-Scheduled Generators (Intermittent Generators) and uninstructed output fluctuations from Scheduled Generators. However, in the existing methodology only Loads and Non-Scheduled Generators are liable for the costs of the Load Following service. While the contribution of the uninstructed fluctuations from Scheduled Generators is likely to be small relative to the other components, it may be considered desirable to include these Market Participants in the settlement process for Load Following for completeness.

Attachment 1 to the Rule Change Proposal provides an alternative formulation of clause 3.14.1 that would implement this, although an additional methodology for distributing costs amongst Scheduled Generators would need to be devised (this will require further analysis).

The IMO is investigating the magnitude of uninstructed fluctuations from Scheduled Generators and will provide an update at the MAC meeting.

Discussion point 1: The MAC to discuss the magnitude of uninstructed fluctuations from Scheduled Generators (presented at the MAC meeting); and

Discussion point 2: Should the Rule Change Proposal be amended to include unintended fluctuations of Scheduled Generators in Load Following costs?

Issue 2: Clause 3.13.1, 9.7.1 - Capacity Cost for Spinning Reserve (attachment 2 to the Rule Change Proposal)

In the existing Market Rules a Capacity Cost for Load Following is defined (Capacity_LF). Capacity Credits are paid to generators providing the Load Following service as though they are not providing this service (clause 9.7.1). The Capacity Credit payment for the amount of capacity providing the Load Following service is then returned to loads in the Reserve Capacity settlement amount (clause 9.7.1). A Capacity Cost for Load Following is then defined to allow recovery of this cost from the appropriate proportion of Loads and Intermittent Generators (clause 3.13.1) according to their contribution to this cost. The treatment of the Load Following Capacity Cost is complicated, but appropriately distributes the cost of providing this capacity to those parties that require it (on a "causer pays" basis).

In the existing rules a Capacity Cost for Spinning Reserve is not defined. This means that this capacity payment is recovered from Loads, instead of scheduled generators (as would be the logical source of this payment in a “causer pays” regime). Thus it could be desirable to introduce a Capacity Cost for Spinning Reserve. It could be argued that the cost will ultimately be borne by customers, so the additional complexity of defining a Capacity Cost for Spinning Reserve is not required. However, different generators contribute different amounts to the Spinning Reserve Requirement, and therefore should bear different costs.

Discussion point 3: Should the Rule Change Proposal be amended to include a Capacity Cost for Spinning reserve and therefore allocate the capacity payment to Scheduled Generators providing the service?

Issue 3: Clause 3.14.1 - Full Load, marginal generation payment for Load Following (attachment 3 to the Rule Change Proposal)

ROAM Consulting has previously proposed[2] that the system load is an inherent part of system operation, and that loads should pay the full proportion of their Load Following requirement (with Intermittent Generators paying the additional increment required for their operation). Some parties have offered an alternative to this concept, proposing instead that the costs of Load Following are distributed in direct proportion to the requirements of loads and Intermittent Generators.

It is worth noting that under the existing rules, loads bear the majority of the Load Following cost (because it is based upon metered schedules rather than contribution to Load Following requirement). The rule changes already proposed in this document for clause 3.14.1 will represent a significant increase in Load Following costs for Intermittent Generators, and a significant reduction in cost for loads. The decision to apportion according to a "full load, marginal generation" approach or a direct proportion approach is relatively minor by comparison. For example, in the 2008/09 year a "full load, marginal generation" approach would attribute 60 percent of the cost of Load Following to loads, and 40 percent to Intermittent Generators. By comparison, a direct proportion approach would attribute 41 percent of the cost of Load Following to loads, and 59 percent to Intermittent Generators. These figures are compared to the existing allocation methodology in Table 1 below.

Table 1 - Estimates of proportions of Load Following Availability Costs payable by Loads and Intermittent Generators under various allocation methodologies[3]

		Proportion of Load Following Availability Cost payable by **Intermittent Generators**	Proportion of Load Following Availability Cost payable by **Loads**
2008-09	Current Market Rules	4%	96%
	Proposed Methodology (Full Load, Marginal Generation)	40%	60%
	Alternative Methodology (Proportional Load and Generation)	59%	41%
2020-21	Current Market Rules	18%	82%
	Proposed Methodology (Full Load, Marginal Generation)	54%	46%
	Alternative Methodology (Proportional Load and Generation)	68%	32%

The main benefit of a "Full Load, Marginal Generation" approach is that Loads will not receive a "windfall gain" at the expense of Intermittent Generators. Loads are liable for the same cost for the Load Following service that they require regardless of the introduction (or not) of Intermittent Generation to the system.

[2] ROAM Consulting report to the Independent Market Operator, "Assessment of FCS and Technical Rules", July 2010.
[3] Data for 2020-21 is an estimate based upon Scenario 1 from the report "Assessment of FCS and Technical Rules, ROAM Consulting report to the Independent Market Operator, July 2010.

The main benefit of a "Proportional Load and Generation" approach is that Loads and Intermittent Generators are treated in an identical fashion, without any consideration of potential fundamental differences between them.

Both methods are equivalent in their implementation, simply requiring a slightly different formulation of the equation in clause 3.14.1.

If it is desired to allocate the Load Following cost to loads and Intermittent Generators in direct proportion to their requirements (rather than via the "full load, marginal generation" approach included in the body of this document) then the alternative formulation of clause 3.14.1 outlined below could be implemented.

Discussion point 4: Should Load Following costs be allocated to Loads and Intermittent Generators in direct proportion to their requirements (rather than via the "full load, marginal generation" approach included in the main body of the Rule Change Proposal?

5. IMPLEMENTATION ISSUES

Given that the IMO is already working on the availability margins for the July 2011 year, the Rule Change Proposal will not be completed in time for the additional availability margins to be determined by the end of November 2010. Verve Energy suggested commencing the Rule Change Proposal in two steps:

- Using only the combined availability margins for the July 2011 year; and
- Using the separate load following and spinning reserve availability margins for July 2012 and subsequent years

The IMO agrees and will incorporate this into the process.

6. RECOMMENDATIONS

The IMO recommends that the MAC:

- **Discuss** each of the issues raised in section 4; and
- **Agree** for the IMO to formally submit PRC_2010_27 as a Rule Change Proposal (following the implementation of any agreed outcomes).

Agenda item 7d, 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) 92544304
Fax:	(08) 92544399
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 Rule affected:	2.30A, 3.4.1, 3.9.1, 3.9.2, 3.9.3, 3.10.1, 3.10.2, 3.10.2A (new), 3.10.5, 3.11.4, 3.11.8, 3.13.1, 3.13.3A, 3.13.3D (new), 3.13.3E (new), 3.14.1, 3.14.2, 3.22.1, 3.22.3, 4.5.12, 9.7.1, 9.9.1, 9.9.1A, 9.9.2, 9.9.3, 9.9.4, 10.5.1(y) and (z), Glossary and Appendix 1(b)(x), (g)(vi), (i)(x) and (m) 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 guarantee 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 Security (ability of SWIS to deliver energy within reliability standards);
- help maintain Power System Reliability (ability of the SWIS to withstand sudden disturbances including restoration in the case of blackout);
- facilitate orderly trading in electricity; and
- ensure that electricity supplies are of acceptable quality.

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

Definition of Ancillary Services

The Market Rules identify the following as Ancillary Services in the Wholesale Electricity Market:

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

This Rule Change Proposal addresses the first two services.

The Load Following service 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 (intermittent) Generators; and
- uninstructed output fluctuations from Scheduled Generators.

The uninstructed output fluctuation from Scheduled Generators is small in comparison with load and Intermittent Generator fluctuations.

The Spinning Reserve requirement is specified in 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 could meet the requirements from both Load Following and Spinning Reserve, their requirements are combined such that services meeting Load Following are 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 Costs

The cost of the Load Following service, as defined in the Market Rules is composed of a capacity cost, and an availability cost, as outlined in 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 year:

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

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 is defined in clause 9.9.2 of the Market Rules. This can be summarised in the following way. The availability cost of Load Following is calculated as the total availability cost, minus the availability cost for providing Spinning Reserve.

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

Equation 3

The Total Availability Cost is given by:

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

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. Off-peak is considered to be 10pm to 8am. This reflects the margin applied to the MCAP which is paid to The Electricity Generation Corporation for being available to provide Ancillary Service during peak (off-peak) Trading Intervals.
MCAP	=	Marginal Cost Administrative Price, \$/MWh calculated two business days after the relevant trading day (defined in each time period t)
SR $\text{Requirement}_{p(op)}$	=	Capacity necessary for Spinning Reserve in peak (off-peak)

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

		intervals
SR provided$_{contracts}$	=	Quantity of Spinning Reserve provided by all contracted Ancillary Service providers in the relevant interval. Does not include Spinning Reserve provided by The Electricity Generation Corporation plant.
Contracts$_{SR}$	=	Sum of all Ancillary service contracts for Spinning Reserve (payments under those contracts)
Contracts$_{LF}$	=	Sum of all Ancillary service contracts for Load Following (payments under those contracts)

In the limiting case where there are no contracts (all Spinning Reserve and Load Following service is provided by The Electricity Generation Corporation):

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

Equation 5

The availability cost of Spinning Reserve 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 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 annually via a simulation process to calculate the cost to The Electricity Generation Corporation 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 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 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 the 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 system Loads consume a much larger quantity of energy than Intermittent Generators produce this means that the majority of the Load Following 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 within the next few years due to the entry of several new wind farms.	Clause 9.9.2 has been re-drafted to address this issue. The proposed formulation of this equation will transition appropriately as the Load Following requirement increases and eventually

	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. This is not a fair or equitable distribution of costs, especially in the case where the Load Following requirement exceeds the Spinning Reserve requirement.	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 The Electricity Generation Corporation 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 for the total availability cost of Load Following does not include a term accounting for Load Following provided by contracted Ancillary Service providers (other than The Electricity Generation Corporation). The form of this equation means that if Load Following services were being procured through contract these would be "double counted", with The Electricity Generation Corporation being paid to provide the service in addition to the contracted Market Participants.	Clause 9.9.2 has been re-drafted to address this issue.
9.9.2, 3.13.3A, 3.13.3D, 3.13.3E	**Marginal cost of Load Following and Spinning Reserve -** The equations for determining the cost of providing the Spinning Reserve and Load Following costs 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 Market Participants.	Clause 9.9.2 and 3.13.3A have been re-drafted to address this issue. Individual Margin_Peak and Margin_Off-Peak have been defined for Load Following and Spinning Reserve. New clauses 3.13.3D and 3.13.3E have been developed to define these terms accurately, including the process for their calibration.
9.9.2, 3.13.3D, 3.13.3E	**Cost of Load Following split equally between Load Following and Spinning Reserve** - The existing equations split the cost of providing the Load Following service equally between Market Participants liable for the costs of Load Following,	Clause 9.9.2 has been re-drafted to address this issue. The costs of each service are calculated and calibrated separately using individual

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

	and Market Participants liable for the costs of Spinning Reserve. This is not a fair distribution of costs, particularly in the case where the two services have different marginal costs.	Margin_Peak and Margin_Off-Peak values (defined in clauses 3.13.3A, 3.13.3D and 3.13.3E). 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 (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 the new clauses 3.13.3D and 3.13.3E.
9.9.2	**Assumed Capacity of Spinning Reserve requirement -** The cost of providing the Spinning Reserve service is calculated based upon an assumed capacity of Spinning Reserve required in peak and off-peak periods. However, the capacity of Spinning Reserve required can vary substantially from Trading Period to Trading Period, and the costs should be calculated as such.	A new variable "GTR(d,t)" has been defined, being the Generator Trip requirement (formerly called the Spinning Reserve requirement), which is a function of the Trading Day d and Trading Interval t. This is used in place of Capacity_R_Peak and Capacity_R_Off-Peak (the assumed capacity of Spinning Reserve in peak and off-peak periods), which are no longer required.
3.14.1	**Distribution of Load Following 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 -	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.

	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.	

MINOR ISSUES

Clause	Issue	Proposed solution
General	**Load Following name -** 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 into "Frequency Keeping". This is also reflected in the terms used as abbreviations in equations, with the abbreviation "FKR" (Frequency Keeping requirement).
3.10.2, 3.10.1, 3.10.2A	**Spinning Reserve definition** - 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 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 the Generator Trip Reserve Service, 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	**General terminology** - A number of terms are defined for use in equations by misleading names. • Capacity_LF is the Capacity Cost of Load Following (rather than the capacity of Load Following required) • Capacity_R_Peak and Capacity R_Off-Peak are the capacity of Spinning Reserve required in Peak and Off-peak periods respectively (rather than the capacity cost of Spinning Reserve) • Reserve_Cost_Share refers specifically to the cost share of the Spinning Reserve service (and does not include the Load Following service).	• The abbreviation "LF" (for Load Following) has been changed to "FKR" (for Frequency Keeping requirement throughout in all terms where they appear • Capacity_LF has been changed to Capacity_Cost_FKR • Capacity_R_Peak and Capacity_R_Off-Peak have been replaced by GTR(d,t) • Reserve_Cost_Share has been changed to GTR_Cost_Share
3.13.3A	**Calibration methodology for**	The calibration procedure for the

	Margin_Peak and Margin_Off-Peak - 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 and Spinning Reserve.	Margin values is now outlined in more detail in the new clauses 3.13.3D and 3.13.3E.
9.9.2	**Factor of 0.5 is superfluous -** Due 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.
3.10.1	The relationship between the Minimum Frequency Keeping Capacity and the Load Following requirement is unclear.	This has been make more explicit in clause 3.10.1
9.9.2	The Sum over Reserve_Share(p,t) is conducted over all Trading Intervals t that are an element of the set Peak and Off-Peak. Strictly speaking this is an empty set, since no Trading Interval can be both Peak and Off-Peak.	This has been corrected in the new proposed clause 9.9.2. The set T is defined to be the set of all Trading Intervals.
9.9.1A	"Participant" is misspelled.	This has been corrected.
9.9.2	"I" is not defined.	This has been corrected.

PROCEDURE CHANGES

Associated changes will be required in Market Procedures, particularly System Management procedures.

PROPOSED REVISIONS

This section outlines the theory behind the proposed rule changes for clause 9.9.2, and relating to clause 3.13.3A, 3.13.3D (new) and 3.13.3E (new).

Calibration of the Margins

The margins and factors used in the calculation of availability costs of Spinning Reserve and Load Following need to be re-calibrated annually. 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 The Electricity Generation Corporation (EGC) of providing only the Load Following service in Trading Interval t (in excess of Load Following provided by contracts, and not providing any Spinning Reserve service).

As in the existing methodology, over a small range the availability cost of Load Following to the EGC in the Trading Interval t is assumed to scale linearly with the MCAP (the system price in $/MWh) and the Load Following requirement (in MW), with the constant of proportionality (Margin_LF_p) giving the correct scaling of the total cost (this factor is to be determined through an annual calibration process outlined below).

Therefore, the availability cost to the EGC of providing only the Load Following service in Trading Interval t can be expressed as:

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

Equation 8

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

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

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:

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

Equation 10

The Margin for Load Following for peak and off-peak periods can therefore be calculated as a rearrangement of this equation:

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

Equation 11

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

Similarly for Spinning Reserve, the availability cost of Spinning Reserve to the EGC is assumed to scale linearly with the MCAP and the Spinning Reserve requirement, with the constant of proportionality ($\text{Margin\_SR}_{p(op)}$) to be determined. Therefore, if only Spinning Reserve services were being provided by The EGC the total availability cost to the EGC 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

The Margin for Spinning Reserve for peak and off-peak periods 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 to the EGC 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. 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 provided by the EGC is larger than the Spinning Reserve provided by the EGC, the "cost saving" will be equal to the availability cost of Spinning Reserve (to the EGC), since this service can be entirely provided by Load Following plant.

In the case where the Spinning Reserve provided by the EGC is larger than the Load Following provided by the EGC, the saving can be quantified in the following way. By operating one additional megawatt of Load Following, the operation of one megawatt 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, Margin_SR$_{p(op)}$ and the Load Following requirement, and is calibrated by the factor Savings_Cal$_{p(op)}$ (equivalent in nature to Margin_Peak and Margin_Off-Peak). The total saving can therefore be expressed as:

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

Equation 14

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

- If the 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, 1MW less of Spinning Reserve is required. This produces a saving that is proportional to Margin_SR$_{p(op)}$, since 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 of 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 can also be expressed as:

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

Equation 15

Where Availability_Cost_Total_EGC$_{p(op)}$ is the cost to the EGC (Electricity Generation Corporation) of providing both the Load Following and Spinning Reserve service simultaneously (forecast via dispatch simulation, for example). Combining the two equations above (Equation 14 and Equation 15), Savings_Cal$_{p(op)}$ is therefore determined as follows:

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

Equation 16

Allocating the saving between Load Following and Spinning Reserve

Once the magnitude of the saving is determined (through the use of Savings_Cal$_{p(op)}$), it must be allocated in an equitable and fair manner to Market Participants. It is proposed that the factor 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 the EGC of providing the Load Following and Spinning Reserve services. If providing Load Following has a much higher total cost than providing Spinning Reserve (either due to a larger Load Following capacity, or a higher per megawatt 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 much 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 50percent 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, 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 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, and Market Participants liable for the costs of Load Following 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, and Market Participants liable for the costs of Spinning Reserve pay the full proportion of their costs.

Importantly, via this methodology neither group of Market Participants (those liable for Spinning Reserve, or those liable for Load Following) can be required to pay for the other service (as can occur in 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 annual calibration process, the availability payments to the EGC for Spinning Reserve and Load Following can be determined.

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

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

Equation 18

where:

$\text{Availability payment\_LF\_EGC}_{p(op)}$	=	Payment to the EGC for Load Following in peak (off-peak) periods by parties liable for costs of Load Following
$\text{Availability payment\_SR\_EGC}_{p(op)}$	=	Payment to the EGC for Spinning Reserve in peak (off-peak) periods by parties liable for costs of

		Spinning Reserve
$Contracts_{LF}$	=	Total payments under Ancillary Service Contracts for Load Following service (payments under clause 3.11.8)
$Contracts_{SR}$	=	Total payments under Ancillary Service Contracts for Spinning Reserve service (payments under clause 3.11.8)

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, or 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 Period as required. This is included in the rule change proposed 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 and Load Following to The Electricity Generation Corporation (EGC):

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

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

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

Categories 1 and 2 - Spinning Reserve provided by EGC > Load Following provided by EGC

The availability payment for Load Following in peak (or off-peak) periods when the Spinning Reserve provided by the EGC exceeds the Load Following provided by the EGC 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:

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

Equation 19

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

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

Equation 20

Combining the two previous equations gives the expression for the availability payments to the EGC for Load Following:

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

Equation 21

The availability payment to the EGC for Spinning Reserve in peak (or off-peak) periods 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:

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

Equation 22

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

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

Equation 23

Combining the two previous equations gives the expression for the availability payments to the EGC for Spinning Reserve:

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

Equation 24

Categories 3 and 4 - Load Following provided by EGC ≥ Spinning Reserve provided by EGC

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

As in the previous case, the availability payment for Load Following in peak (or off-peak) periods 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:

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

Equation 25

The magnitude of the saving allocated to Market Participants liable for Load Following is given by Savings_Alloc$_{p(op)}$ multiplied by the total saving (given in . 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 the previous section, the total availability cost of Spinning Reserve is given by:

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

Equation 27

In this case the payments under contracts for Spinning Reserve 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 the two previous equations gives:

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

Equation 28

Combining this with the earlier equation above gives the expression for the total availability payment for Load Following:

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

Equation 29

The availability payment to the EGC for Spinning Reserve in peak (or off-peak) periods is given by the total cost of providing the Spinning Reserve service in the absence of the Load Following service, minus a proportion of the saving obtained through the dual use of plant to provide both services:

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

Equation 30

The magnitude of the saving allocated to Market Participants liable for Spinning Reserve 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 the previous section, the total availability cost of Spinning Reserve is given by:

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

Equation 32

Combining the previous equations 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 Rules

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

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

Equation 34

Each term is multiplied by GTR_Cost_Share(p,m) when the sum over time is executed, which defines the proportion of the Spinning Reserve availability cost paid by each market participant p. FKR is the Frequency Keeping requirement (formerly the Load Following requirement) and GTR is the Generator Trip Reserve (formally the Spinning Reserve requirement).

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

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

Equation 35

The total availability payment for Load Following is then multiplied by FKR_Cost_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_Cost_Share(p,m) is defined in clause 3.14.1.

ISSUES REQUIRING A DECISION

The following possible changes require a decision as to the desired way forward, and therefore have been included as attachments at the end of this document for possible inclusion:

- **Clause 3.14.1 - Inclusion of unintended fluctuations of scheduled generators in Load Following costs (Attachment 1)** - Clause 3.10.1 defines the Load Following service as being sufficient to cover short term fluctuations in load, Non-Scheduled Generators (Intermittent Generators) and uninstructed output fluctuations from Scheduled Generators. However, in the existing methodology only Loads and Non-Scheduled Generators are liable for the costs of the Load Following service. While the contribution of the uninstructed fluctuations from Scheduled Generators is likely to be small relative to the other components, it may be considered desirable to include these Market Participants in the settlement process for Load Following for completeness. Attachment 1 provides an alternative formulation of clause 3.14.1 that would implement this, although an additional methodology for distributing costs amongst Scheduled Generators would need to be devised (this will require further analysis).
- **Clause 3.13.1, 9.7.1 - Capacity Cost for Spinning Reserve (Attachment 2)** - The existing rules do not define a Capacity Cost for Spinning Reserve, but do define a Capacity Cost for Load Following. For the Load Following service:
    - The generator providing the Load Following service receives Capacity Credits for their full capacity (not reduced due to the provision of the Load Following service) (clause 9.7.1).
    - The cost of the capacity credits for the Load Following requirement is returned to Loads through the calculation of the Reserve Capacity settlement amount (clause 9.7.1)
    - A capacity payment for Load Following is defined in clause 3.13.1
    - The capacity payment for Load Following is distributed amongst liable Market Participants in clause 9.9.1 according to the Load Following Share (defined in clause 3.14.1).

  By comparison, in the existing methodology the capacity necessary for Spinning Reserve is paid for in the following manner:

    - The generator providing the Spinning Reserve Service receives Capacity Credits for their full capacity (not reduced due to the provision of the Spinning Reserve Service) (clause 9.7.1).
    - This cost is borne by Loads through the Reserve Capacity settlement amount (clause 9.7.1).

  The treatment of the Load Following Capacity Cost is more complicated, but appropriately distributes the cost of providing this capacity to those parties that require it (on a "causer pays" basis). The capacity required for the Spinning Reserve service, however, is paid for entirely by Loads (through the Capacity Credit process), rather than being distributed amongst Scheduled Generators that are most likely to experience a problematic generator trip. It could be argued that the cost will ultimately be borne by customers, so the additional complexity of defining a Capacity Cost for Spinning Reserve is not required. However, different generators contribute different amounts to the Spinning Reserve requirement, and therefore should bear different costs.

- **Clause 3.14.1 - Full Load, marginal generation payment for Load Following (Attachment 3)** - ROAM Consulting has previously proposed[5] that the system load is an inherent part of system operation, and that Loads should pay the full proportion of their Load Following requirement (with Intermittent Generators paying the additional increment required for their operation). Some parties have offered an alternative to this concept, proposing instead that the costs of Load Following are distributed in direct proportion to the requirements of Loads and Intermittent Generators.

  It is worth noting that under the existing rules, loads bear the majority of the Load Following cost (because it is based upon metered schedules rather than contribution to Load Following requirement). The rule changes already proposed in this document for clause 3.14.1 will represent a significant increase in Load Following costs for Intermittent Generators, and a significant reduction in cost for loads. The decision to apportion according to a "full load, marginal generation" approach or a direct proportion approach is relatively minor by comparison. For example, in the 2008-09 year a "full load, marginal generation" approach would attribute 60% of the cost of Load Following to loads, and 40% to Intermittent Generators. By comparison, a direct proportion approach would attribute 41% of the cost of Load Following to loads, and 59% to Intermittent Generators.

  If this is desired, the alternative formulation of Clause 3.14.1 is provided in Attachment 3.

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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 <u>underline</u> words added)

2.30A Exemption from Funding ~~Spinning~~ <u>Generator Trip</u> 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~~ <u>Generator Trip</u> Reserve cost.

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

2.30A.2 Where an application is received in accordance with clause 2.30A.1, the IMO must exempt the Intermittent Generator from funding Generator Trip ~~Spinning~~ 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 Generator Trip ~~Spinning~~ Reserve costs.

2.30A.4 If the IMO approves the application for exempting an Intermittent Generator from funding Generator Trip ~~Spinning~~ 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 Generator Trip ~~Spinning~~ 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 Generator Trip ~~Spinning~~ Reserve costs exemption process in the Registration Procedure, and:

(a) applicants for exemption from Generator Trip ~~Spinning~~ 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 Generator Trip ~~Spinning~~ 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 requirements~~ 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;

c) . . .

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:

(a) respond appropriately within 6 seconds and sustain or exceed the required response for at least 60 seconds; or

(b) . . .

3.10.1. The standard for ~~Load Following~~ Frequency Keeping Service is a level which is sufficient to provide the Minimum Frequency Keeping Capacity, where this is the positive value of the Frequency Keeping Requirement.~~:~~

(a) ~~provide Minimum Frequency Keeping Capacity, where the Minimum Frequency Keeping Capacity~~ The Frequency Keeping Requirement (FKR(m)) is the greater of:

i. 30 MW;

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]

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~~ combined Generator Trip Reserve and Frequency Keeping Requirement 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) . . .

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:

(a) . . .

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(m), the capacity necessary to meet the Ancillary Service Requirement for Frequency Keeping ~~Load Following~~ in that month m;

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(m) for ~~Spinning~~ Generator Trip Reserve 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 and System Restart, determined in accordance with the process described in clause 3.13.3B and 3.13.3C; and Dispatch Support service determined in accordance with clause 3.11.8B.

3.13.3A Where the Economic Regulation Authority has not completed its first assessment in accordance with clause 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 to be used in the Settlement System will be determined in accordance with this clause. For each Financial Year, by 31 March prior to the start of that Financial Year, the Economic Regulation Authority must determine values for the parameters Margin_Peak and Margin_Off-Peak, taking into account the Wholesale Market Objectives and in accordance with the following:

(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:

i. for the reserve availability payment margin applying for Peak Trading Intervals, Margin_Peak, the IMO must take account of:

1. the margin the Electricity Generation Corporation could reasonably have been expected to earn on energy sales forgone due to the supply of ~~Spinning~~ Generator Trip 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~~ Generator Trip 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:

1. the margin the Electricity Generation Corporation could reasonably have been expected to earn on energy sales forgone due to the supply of ~~Spinning~~ Generator Trip 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~~ Generator Trip 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.

(c) For the Settlement System:

i Margin_GTR_Peak and Margin_FKR_Peak will be set equal to Margin_Peak;

ii Margin_GTR_Off-Peak and Margin_FKR_Off-Peak will be set equal to Margin_Off-Peak;

iii Savings_Alloc_Peak and Savings_Alloc_Off-Peak will be set equal to 0.5; and

iv Savings_Cal_Peak and Savings_Cal_Off-Peak will be set equal to 1.

3.13.3D 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_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:

(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:

i. for the availability payments for Ancillary Services the IMO must take account of:

1. 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 and Frequency Keeping Requirement;

2. the loss in efficiency of the Electricity Generation Corporation Registered Facilities that System Management has scheduled to provide Generator Trip Reserve and Frequency Keeping Requirement that could reasonably be expected due to the scheduling of those reserves;

ii. the IMO must determine the availability cost of providing Generator Trip Reserve and Frequency Keeping Requirement simultaneously, as well as the availability cost of providing each of the reserves independently in both peak and off-peak Trading Intervals;

iii the IMO must convert these availability costs into 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, where these terms are defined in clause 3.13.3E;

(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.

3.13.3E 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 as follows:

(a) Margin_FKR_Peak = ACFK_Peak / (Sum(d∈D,t∈Peak,MCAP_FKR(d,t) × max(0,FKR(m) - Sum(i∈I,ASP_FKRQ(i,t)))))

(b) Margin_FKR_Off-Peak = ACFK_Off-Peak / (Sum(d∈D,t∈Off-Peak,MCAP_FKR(d,t) × max(0,FKR(m) - Sum(i∈I,ASP_FKRQ(i,t)))))

(c) Margin_GTR_Peak = ACTR_Peak / (Sum(d∈D,t∈Peak,MCAP_GTR(d,t) × max(0,GTR(d,t) - Sum(i∈I,ASP_GTRQ(i,t)))))

(d) Margin_GTR_Off-Peak = ACTR_Off-Peak / (Sum(d∈D,t∈Off-Peak,MCAP_GTR(d,t) × max(0,GTR(d,t) - Sum(i∈I,ASP_GTRQ(i,t)))))

(e) Savings_Alloc_Peak = ACFK_Peak / (ACFK_Peak + ACTR_Peak)

(f) Savings_Alloc_Off-Peak = ACFK_Off-Peak / (ACFK_Off-Peak + ACTR_Off-Peak)

(g) Savings_Cal_Peak = (ACFK_Peak + ACTR_Peak - ACTOT_Peak)/(Margin_GTR(d,t) × Sum(d∈D,t∈Peak,MCAP(d,t) × max(0,FKR(m) -Sum(i∈I,ASP_FKRQ(i,t)))))

(h) Savings_Cal_Off-Peak = (ACFK_Off-Peak + ACTR_Off-Peak - ACTOT_Off-Peak)/(Margin_GTR_Off-Peak × Sum(d∈D,t∈Off-Peak,MCAP(d,t) × max(0,FKR(m) - Sum(i∈I,ASP_FKRQ(i,t)))))

Where:

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;

MCAP(d,t) has the meaning given in clause 9.8.1 and = 0 if MCAP(d,t)<0;

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

I denotes the set of all Ancillary Service Providers providing Ancillary Services under contracts, where “i” is used to refer to a member of that set;

ACFK_Peak is the total availability cost to the Electricity Generation Corporation of providing Frequency Keeping service in peak Trading Intervals (in excess of the services provided by contracts under clause 3.11.8), when Generator Trip Reserve is only provided by contracts under clause 3.11.8 (forecast by simulation);

ACFK_Off-Peak is the total availability cost to the Electricity Generation Corporation of providing Frequency Keeping service in off-peak Trading Intervals (in excess of the services provided by contracts under clause 3.11.8), when Generator Trip Reserve is only provided by contracts under clause 3.11.8 (forecast by simulation);

ACTR_Peak is the total availability cost to the Electricity Generation Corporation of providing Generator Trip Reserve Service in peak Trading Intervals (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 (forecast by simulation);

ACTR_Off-Peak is the total availability cost to the Electricity Generation Corporation of providing the required Generator Trip Reserve Service in off-peak Trading Intervals (in excess of the services provided by contracts under clayse 3.11.8), when the Frequency Keeping service is only provided by contracts under clause 3.11.8 (forecast by simulation);

ACTOT_Peak is the total availability cost to the Electricity Generation Corporation of simultaneously providing the required Frequency Keeping and Generator Trip Reserve Services (in excess of the services provided by contract) in peak Trading Intervals (forecast by simulation);

ACTOT_Off-Peak is the total availability cost to the Electricity Generation Corporation of simultaneously providing the required Frequency Keeping and Generator Trip Reserve Services (in excess of the services provided by contract) in off-peak Trading Intervals (forecast by simulation);

ASP_FKRQ(i,t) is the quantity of Frequency Keeping Requirement provided by Ancillary Service Provider i in Trading Interval t;

ASP_GTRQ(i,t) is the quantity of Generator Trip Reserve provided by Ancillary Service Provider i in Trading Interval t;

MCAP_FKR(d,t) is the system marginal price 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 is only provided by contracts under clause 3.11.8;

MCAP_GTR(d,t) is the system marginal price 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;

GTR(d,t) is the capacity necessary to cover the Ancillary Services Requirement for Generator Trip Reserve for Trading Interval t on Trading Day d;

FKR(m) is the capacity necessary to cover the Ancillary Services Requirement for Frequency Keeping Service for Trading Month m as specified by the IMO under clause 3.22.1(fA);

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(c);

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_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(d);

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);

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 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 for Trading Month m as specified by the IMO under clause 3.22.1(dC);

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 for Trading Month m as specified by the IMO under clause 3.22.1(dD); and

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 for Trading Month m as specified by the IMO under clause 3.22.1(dE).

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_Cost_Share(p,m) which ~~equals~~ is given by:

FKR_Cost_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;
>
> MS_IG (p,m) is the sum of the Metered Schedules for Non-Scheduled Generators registered by Market Participant p for all Trading Intervals during Trading Month m;
>
> MS_IG_total(m) is the sum of the Metered Schedules for Non-Scheduled Generators registered by all Market Participants during Trading Month m;
>
> FKR(m) is the capacity necessary to cover the Ancillary Services Requirement for Frequency Keeping Requirement for Trading Month m as specified by the IMO under clause 3.22.1(fA); and
>
> FKR_Loads(m) is the capacity sufficient to cover 99.9% of the short term fluctuations in load, measured as the variance of 1 minute average readings around a thirty minute rolling average for the Trading Month m as specified by the IMO under clause 3.22.1(fB).

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

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

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

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

3.22.1. 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 and Margin_GTR_Peak as described in clause 3.13.3A or clause 3.13.3D and clause 3.13.3E;

(cB) Margin_FKR_Off-Peak and Margin_GTR_Off-Peak as described in clause 3.13.3A or clause 3.13.3D and clause 3.13.3E;

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

(dA) Savings_Alloc_Peak and Savings_Alloc_Off-Peak as described in clause 3.13.3A;

(dB) Savings_Cal_Peak and Savings_Cal_Off-Peak as described in clause 3.13.3A;

(e) ~~Capacity_R_Peak, the requirement for Spinning Reserve for Peak Trading Intervals assumed in forming Margin_Peak;~~ [Blank]

(eA) GTR(d,t), the requirement for Generator Trip Reserve for Trading Day d and Trading Interval t defined in clause 3.10.2;

(f) ~~Capacity_R_Off-Peak, the requirement for Spinning Reserve for Off-Peak Trading Intervals assumed in forming Margin_Off-Peak;~~[Blank]

(fA) FKR(m) ~~LFR~~ as described in ~~clause 3.13.1(aA)(i)(2)~~ clause 3.10.1;

(fB) FKR_Loads(m), the Frequency Keeping Requirement sufficient to cover 99.9% of the short term fluctuations in load, measured as the variance of 1 minute average readings around a thirty minute rolling average for the Trading Month m;

(fC) FKR_IG(m), the Frequency Keeping Requirement sufficient to cover 99.9% of the short term fluctuations in the output of Non-Scheduled Generators, measured as the variance of 1 minute average readings around a thirty minute rolling average for the Trading Month m;

(g) Cost_LRD as the sum of:

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

ii. the monthly amount for Dispatch Support 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).

3.22.3. 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 Ancillary Service Contract held:

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

1. ~~Spinning~~ Generator Trip Reserve;

2. ~~Load Following~~ Frequency Keeping;

3. . . .

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

(c) . . .

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~~ Frequency Keeping service capacity payment cost for Trading Month m as specified by IMO under clause 3.22.1(a).

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)
+ d(p,i) × ASP_Payment(i,m)
- FKR_Cost_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)) otherwise.

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

ASP_Payment(i,m) is determined in accordance with clause 9.9.3;

~~Load_Following_Share(p,m)~~ FKR_Cost_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~~ Frequency Keeping service 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 availability payment costs, excluding ~~Load Following~~ Frequency Keeping 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~~ Frequency Keeping availability payment costs for Trading Month m, as calculated under clause 9.9.2(d); and

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

9.9.1A. The Ancillary Service settlement amount for Trading Month m for Rule Participant k where Rule ~~Partincant~~ Participant k 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 determined in accordance with clause 9.9.3.

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) = Availability_Cost_GTR(m) + Availability_Cost_FKR(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))~~

(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 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(d∈D,t∈Peak,(d,t)∈FKR_lessthan_GTR,MCAP(d,t)
× GTR_Share(p,t)
× (max(0,GTR(d,t) – Sum(i∈I,ASP_GTRQ(i,t)))
- Savings_Cal_Peak(m) × (1 - Savings_Alloc_Peak(m))
× max(0,FKR(m) - Sum(i∈I,ASP_FKRQ(i,t)))))

+ Margin_GTR_Off-Peak(m)
× Sum(d∈D,t∈Off-Peak,(d,t) ∈FKR_lessthan_GTR ,MCAP(d,t)
× GTR_Share(p,t)
× (max(0,GTR(d,t) – Sum(i∈I,ASP_GTRQ(i,t)))
- Savings_Cal_Off-Peak(m) × (1 - Savings_Alloc_Off-Peak(m))
× max(0,FKR(m) - Sum(i∈I,ASP_FKRQ(i,t)))))

+ Margin_GTR_Peak(m) × Savings_Alloc_Peak(m)
× Sum(d∈D,t∈Peak,(d,t)∈GTR_lessthan_FKR,MCAP(d,t)
× GTR_Share(p,t)
× max(0,GTR(d,t) - Sum(i∈I,ASP_GTRQ(i,t))))

+ Margin_GTR_Off-Peak(m) × Savings_Alloc_Off-Peak(m)
× Sum(d∈D,t∈Off-Peak,(d,t)∈GTR_lessthan_FKR,MCAP(d,t)

× GTR_Share(p,t)
× max(0,GTR(d,t) - Sum(i∈I,ASP_GTRQ(i,t))))

+ Sum(t∈T, GTR_Share(p,t)
× Sum(i∈I,ASP_GTRPayment(i,m) / TITM))

(c) the total ~~Spinning~~ Generator Trip Reserve 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 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(d∈D,t∈Peak,(d,t)∈FKR_lessthan_GTR,MCAP(d,t)
× max(0,FKR(m) – Sum(i∈I,ASP_FKRQ(i,t))))

+ (Margin_FKR_Off-Peak(m)
- Savings_Cal_Off-Peak(m) × Savings_Alloc_Off-Peak(m)
× Margin_GTR_Off-Peak(m))
× Sum(d∈D,t∈Off-Peak,(d,t)∈FKR_lessthan_GTR,MCAP(d,t)
× max(0,FKR(m) – Sum(i∈I,ASP_FKRQ(i,t))))

+ Margin_FKR_Peak(m)
× Sum(d∈D,t∈Peak,(d,t)∈GTR_lessthan_FKR,MCAP(d,t)
× (max(0,FKR(m) – Sum(i∈I,ASP_FKRQ(i,t)))
- Savings_Alloc_Peak(m)
× Margin_GTR_Peak(m) / Margin_FKR_Peak(m)
× max(0,GTR(d,t) - Sum(i∈I,ASP,GTRQ(i,t)))))

+ Margin_FKR_Off-Peak(m)
× Sum(d∈D,t∈Off-Peak,(d,t)∈GTR_lessthan_FKR,MCAP(d,t)
× (max(0,FKR(m) – Sum(i∈I,ASP_FKRQ(i,t)))

- Savings_Alloc_Off-Peak(m)
× Margin_GTR_Off-Peak(m) / Margin_FKR_Off-Peak(m)
× max(0,GTR(d,t) - Sum(i∈I,ASP_GTRQ(i,t)))))

+ Sum(i∈I,ASP_FKRPayment(i,m))

Where

I is the set of all Ancillary Service Providers providing Ancillary Services under contracts, where "i" is used to refer to a member of that set;

~~ASP_SRQ(i,t)~~ ASP_GTRQ(i,t) is the quantity of ~~Spinning~~ Generator Trip Reserve provided by Ancillary Service Provider i in Trading Interval t by contracts under clause 3.11.8 (this being one of the quantities referred to in clause 9.9.3);

ASP_FKRQ(i,t) is the quantity of Frequency Keeping Service provided by Ancillary Service Provider i in Trading Interval t by contracts under clause 3.11.8 (this being one of the quantities referred to in clause 9.9.3);

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

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

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

T denotes the set of Trading Intervals within Trading Day d, where "t" is used to refer to a member of that set;

~~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_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(cA);

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_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(cB);

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(cB);

~~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(d,t) is the capacity necessary to cover the Ancillary Services Requirement for Generator Trip Reserve for Trading Day d and Trading Interval t as specified under clause 3.10.2;

~~LFR(m)~~ FKR(m) is the capacity necessary to cover the Ancillary Services Requirement for ~~Load Following~~ Frequency Keeping for 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;

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;

FKR_lessthan_GTR denotes the set of Trading Intervals on a Trading Day d within a Trading Month m where (FKR(m) - Sum(iɛI,ASP_FKRQ(i,t))) < (GTR(d,t) - Sum(iɛI,ASP_GTRQ(i,t))); and

GTR_lessthan_FKR denotes the set of Trading Intervals on a Trading Day d within a Trading Month m where (GTR(d,t) - Sum(iɛI,ASP_GTRQ(i,t))) ≤ (FKR(m) - Sum(iɛI,ASP_FKRQ(i,t))).

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

(a) the sum over all Ancillary Service Contracts for ~~Spinning~~ Generator Trip Reserve of ~~ASP_SRPayment(i,m)~~ ASP_GTRPayment(i,m), the payment under that contract;

(b) the sum over all Ancillary Service Contracts for ~~Load Following~~ Frequency Keeping of ~~ASP_LFPayment(i,m)~~ ASP_FKRPayment(i,m), the payment under that contract;

(c) the sum over all Ancillary Service Contracts for Load Rejection Reserve of ASP_LRPayment(i,m), the payment under that contract;

(d) the sum over all Ancillary Service Contracts for System Restart of ASP_BSPayment(i,m), the payment under that contract; and

(e) the sum over all Ancillary Service Contracts for Dispatch Support of ASP_DSPayment(i,m), the payment under that contract

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

9.9.4. For each Ancillary Service Provider i and each Ancillary Service Contract, the payments ~~ASP_SRPayment(i,m)~~, ~~ASP_LFPayment(i,m)~~, ASP_GTRPayment(i,m), ASP_FKRPayment(i,m), ASP_LRPayment(i,m), ASP_BSPayment(i,m) and ASP_DSPayment(i,m), as applicable, are

(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) 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:

(a) . . .

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

i. the total generation in that Trading Interval;

ii. the total ~~spinning reserve~~ Generator Trip Reserve and Frequency Keeping Requirement 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; and

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

i. the total generation;

ii. the total Generator Trip Reserve and Frequency Keeping Requirement ~~spinning 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.

11 Glossary

~~Spinning~~ 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.

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

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 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.

(a) . . .

(b)

i . . .

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;
2. ~~Spinning~~ Generator Trip Reserve;
3. [Blank]; and
4. Load Rejection Reserve;

xi . . .

(c) . . .

(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.

1A. Frequency Keeping Requirement

2. [Blank]

vii. . . .

(h) . . .

(i) for a Dispatchable Load:

i. . . .

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

3. [Blank]; and

4. Load Rejection Reserve;

(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 Determine GTR_Share(p,t) ~~Reserve_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 ~~service~~ 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.

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

The IMO considers the changes proposed will have the following impact on the 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.	

This Rule Change Proposal will assist in avoiding discrimination in the market (contributing to the market objective (c)) by avoiding inaccurate pricing of Spinning Reserve and Load Following services that is not related to the actual costs of providing these services. The existing costing structure allocates the costs of Spinning Reserve and Load Following in a manner that is not reflective of the actual costs of providing those services. The Rule Change Proposal addresses this, and allocates these costs more equitably on a 'causer pays' basis between Loads and Intermittent Generators.

This Rule Change Proposal will also promote greater economic efficiency, addressing Market Objective (a). The Rule Change Proposal will allow payments for Load Following and Spinning Reserve to more accurately reflect the actual costs of providing those services, giving more appropriate pricing signals for Ancillary Services (Load Following and Spinning Reserve) to loads, non-scheduled generators and scheduled generators.

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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;
- The IMO's annual review of the Margin Values is increasing from Margin_Peak and Margin_Off-Peak to 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 annual review costs (currently around $30,000 p.a). These costs will be quantified during the first submission period.
- The extra analysis required for proposing the additional variables (outlined in the bullet point above) 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 Market Procedures. 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:

- This 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.

Attachment 1: Inclusion of unintended fluctuations of scheduled generators in Frequency Keeping Costs

The unintended fluctuations of scheduled generators can contribute to the Frequency Keeping Requirement. Although it is likely that this effect will be small by comparison to the Frequency Keeping Requirement for Loads and Intermittent Generators, it may be desirable to include this component for completeness. If this is desired, an alternative formulation of clause 3.14.1 is proposed below.

A methodology would also need to be developed to capture the relative contributions of individual scheduled generators to the Frequency Keeping Requirement (possibly to be outlined in an Appendix in a similar manner to the Generator Trip Reserve Cost Allocation outlined in Appendix 2).

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_Share(p,m)~~ FKR Cost_Share(p,m) which is given by:

FKR_Cost_Share =
(MS_Loads(p,m) / MS_Loads_total(m)) × (FKR_Loads(m) / FKR(m))
+ (MS_IG(p,m) / MS_IG_total(m))
× (FKR-FKR_Loads(m))/(FKR_IG(m)+FKR_SG(m))
× (FKR_IG(m)) / FKR(m)
+ FKR_Share_SG(p,m)
× (FKR-FKR_Loads(m))/(FKR_IG(m)+FKR_SG(m))
× (FKR_SG(m)) / FKR(m)

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

(b) ~~the total contributing quantity of all Market Participants, where a Market Participant's contributing quantity for Trading Month m is the sum of:~~ [Blank]

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~~ [Blank]

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

iii. [Blank]

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;

MS_IG(p,m) is the sum of the Metered Schedules for Non-Scheduled Generators registered by Market Participant p for all Trading Intervals during Trading Month m;

MS_IG_total(m) is the sum of the Metered Schedules for Non-Scheduled Generators registered by all Market Participants during Trading Month m

FKR(m) is the capacity necessary to cover the Ancillary Services Requirement for Frequency Keeping for Trading Month m as specified by the IMO under clause 3.22.1(fA);

FKR_Loads(m) is the Frequency Keeping Requirement sufficient to cover 99.9% of the short term fluctuations in load, measured as the variance of 1 minute average readings around a thirty minute rolling average for the Trading Month m as specified by the IMO under clause 3.22.1(fB);

FKR_IG(m), the Frequency Keeping Requirement sufficient to cover 99.9% of the short term fluctuations in the output of Non-Scheduled Generators, measured as the variance of 1 minute average readings around a thirty minute rolling average for the Trading Month m;

FKR_SG(m), the Frequency Keeping Requirement sufficient to cover 99.9% of the short term uninstructed output fluctuations of Scheduled Generators, measured as the variance of 1 minute average readings around a thirty minute rolling average for the Trading Month m; and

FKR_Share_SG(p,m) is the share of the Frequency Keeping Cost attributable to the unintended fluctuations of scheduled generators paid by market participant p in Trading Month m.

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 and Margin_GTR_Peak as described in clause 3.13.3A or clause 3.13.3D and clause 3.13.3E;

(cB) Margin_FKR_Off-Peak and Margin_GTR_Off-Peak as described in clause 3.13.3A or clause 3.13.3D and clause 3.13.3E;

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

(dA) Savings_Alloc_Peak and Savings_Alloc_Off-Peak as described in clause 3.13.3A;

(dB) Savings_Cal_Peak and Savings_Cal_Off-Peak as described in clause 3.13.3A;

(e) ~~Capacity_R_Peak, the requirement for Spinning Reserve for Peak Trading Intervals assumed in forming Margin_Peak;~~ [Blank]

(eA) GTR(d,t), the requirement for Generator Trip Reserve for Trading Day d and Trading Interval t defined in clause 3.10.2;

(f) ~~Capacity_R_Off-Peak, the requirement for Spinning Reserve for Off-Peak Trading Intervals assumed in forming Margin_Off-Peak;~~ [Blank]

(fA) ~~LFR~~ FKR(m) as described in clause 3.13.1(aA)(i)(2) and clause 3.10.1;

(fB) FKR_Loads(m), the Frequency Keeping Requirement sufficient to cover 99.9% of the short term fluctuations in load, measured as the variance of 1 minute average readings around a thirty minute rolling average for the Trading Month m;

(fC) FKR_IG(m), the Frequency Keeping Requirement sufficient to cover 99.9% of the short term fluctuations in the output of Non-Scheduled Generators, measured as the variance of 1 minute average readings around a thirty minute rolling average for the Trading Month m;

(fD) FKR_SG(m), the Frequency Keeping Requirement sufficient to cover 99.9% of the short term uninstructed output fluctuations from Scheduled Generators, measured as the variance of 1 minute average readings around a thirty minute rolling average for the Trading Month m;

(g) Cost_LRD as the sum of:

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

ii. the monthly amount for Dispatch Support 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).

A methodology would need to be developed to determine FKR_Share_SG(p,m). This could be analogous to the methodology for determining Reserve_Share(p,t) outlined in Appendix 2 (Spinning Reserve Cost Allocation), but would need to capture the relative contributions of individual scheduled generators to the Frequency Keeping Requirement.

Attachment 2: Introduction of a Capacity Cost for Generator Trip Reserve

In the existing rules a Capacity Cost for Frequency Keeping is defined (Capacity_LF). Capacity Credits are paid to generators providing the Frequency Keeping service as though they are not providing this service (clause 9.7.1). The capacity credit payment for the amount of capacity providing the Frequency Keeping service is then returned to loads in the Reserve Capacity settlement amount (clause 9.7.1). A Capacity Cost for Frequency Keeping is then defined to allow recovery of this cost from the appropriate proportion of loads and Intermittent Generators (clause 3.13.1).

In the existing rules a Capacity Cost for Generator Trip Reserve is not defined. This means that this capacity payment is recovered from loads, instead of scheduled generators (as would be the logical source of this payment in a causer pays regime). Thus it could be desirable to introduce a Capacity Cost for Generator Trip Reserve. This affects clauses 3.13.1 and 9.7.1, with the proposed revisions outlined below.

In this methodology the cost "saving" from the dual use of load following plant to provide spinning reserve is split between Market Participants liable for Load Following and Market Participants liable for Spinning Reserve in an manner analogous to the division of availability payments described earlier. This acts to reduce the capacity payments for load following from the existing methdology.

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~~ <u>Frequency Keeping</u> Service for each Trading Month:

i. a capacity payment ~~Capacity_LF~~ <u>Capacity_Cost_FKR</u> calculated as;

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

2. multiplied by ~~LFR~~ <u>FKR(m)</u>, the capacity necessary to meet the Ancillary Service Requirement for ~~Load Following~~ <u>Frequency Keeping</u> in that month <u>m</u>;

<u>3. multiplied by the factor (Sum(d∊D,t∊T,max(FKR(m),GTR(d,t)))/TITM) / (FKR(m) + Sum(d∊D,t∊T,GTR(d,t))/TITM).</u>

ii. an availability payment ~~Availiability_Cost_LF(m)~~ <u>Availiability_Cost_FKR(m)</u> calculated in accordance with clause 9.9.2(d) for that Trading Month;

(b) ~~an amount Availability_Cost_R(m) for Spinning Reserve for each Trading Month, which is calculated in accordance with clause 9.9.2(c) for that Trading Month; and~~ [Blank]

(bA) for Generator Trip Reserve Service for each Trading Month:

i. a capacity payment Capacity_Cost_GTR calculated as;

Capacity_Cost_GTR(m) =
Monthly Reserve Capacity Price(m)
× Sum(dϵD,tϵT,max(FKR(m),GTR(d,t))) / TITM
× (1- FKR(m) / (FKR(m) + Sum(dϵD,tϵT,GTR(d,t))/TITM))

ii. an availability payment Availiability_Cost_GTR(m) calculated in accordance with clause 9.9.2(c) for that Trading Month; and

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

Where:

GTR(d,t) is the capacity necessary to cover the Ancillary Services Requirement for Generator Trip Reserve for Trading Day d and Trading Interval t as specified under clause 3.10.2;

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

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

T denotes the set of Trading Intervals within Trading Day d, where "t" is used to refer to a member of that set.

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(qϵ P,CC_ANSPA(p,q,m)))
+ Sum(a ϵ A, Monthly Special Price(p,m,a) × (CC_SPA(p,m,a)
– Sum(q ϵ 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(m)~~ Monthly Reserve Capacity Price(m)
× Sum(dϵD,tϵT,max(FKR(m),GTR(d,t))) / TITM × Capacity Share(p,m)

Where

Shortfall Share(p,m) =

0, if Sum(nϵP, (IRCR(n,m) – Sum(qϵP, CC_ANSPA(q,n,m)
+ Sum(aϵA, CC_ASPA(q,n,m,a))))) = 0
otherwise,
(IRCR(p,m) – Sum(qϵP, CC_ANSPA(q,p,m)
+ Sum(aϵA, CC_ASPA(q,p,m,a)))) /
Sum(nϵP, (IRCR(n,m) – Sum(q, CC_ANSPA(q,n,m)
+ Sum(aϵA, CC_ASPA(q,n,m,a)))))

Capacity Share(p,m) = IRCR(p,m) / Sum(nϵP, IRCR(n,m))

Monthly Reserve Capacity Price(m) is the Monthly Reserve Capacity Price which applies for Trading Day d defined in accordance with clause 4.29.1;

CC_NSPA(p,m) is the number of Capacity Credits held by Market Participant p in Trading Month m that are not covered by Special Price Arrangements;

CC_ANSPA(p,q,m) is the number of Capacity Credits held by Market Participant p in Trading Month m that are not covered by Special Price

Arrangements and which are allocated to another Market Participant q for Trading Month m under clauses 9.4 and 9.5;

A is the set of all Special Price Arrangements associated with a Facility where “a” is used to refer to a member of that set;

P is the set of all Market Participants, where “p”, “n”, and “q” are all used to refer to a member of that set;

Monthly Special Price(p,m,a) is the Monthly Special Reserve Capacity Price for Special Price Arrangement for Market Participant p defined in accordance with clause 4.29.2 which applies for Trading Day d;

CC_SPA(p,m,a) is the number of Capacity Credits held by Market Participant p in Trading Month m that are covered by Special Price Arrangement a;

CC_ASPA(p,q,m,a) is the number of Capacity Credits held by Market Participant p in Trading Month m that are covered by Special Price Arrangement a and which are allocated to Market Participant q for Trading Month m under clauses 9.4 and 9.5;

IRCR(p,m) is the Individual Reserve Capacity Requirement for Market Participant p and Trading Month m expressed in units of MW;

Capacity Cost Refund(p,m) is the Capacity Cost Refund payable to the IMO by Market Participant p in respect of that Market Participant's Capacity Credits for Trading Month m, as specified in clause 4.29.3(d)(vi);

Intermittent Load Refund(p,m) is the sum over all of Market Participant p's Intermittent Loads of the Intermittent Load Refund payable to the IMO by Market Participant p in respect of each of its Intermittent Loads for Trading Month m, as specified in clause 4.28A.1;

Supplementary Capacity Payment(p,m) is the net payment to be made by IMO under a Supplementary Capacity Contract to Market Participant p for Trading Month m, as specified by the IMO in accordance with clause 4.29.3(e)(i);

Targeted Reserve Capacity Cost(m) is the cost of Reserve Capacity to be shared amongst those Market Customers who have not had sufficient Capacity Credits allocated to them for Trading Month m where this cost is specified for Trading Month m under clause 4.29.3(b);

Shared Reserve Capacity Cost(m) is the cost of Reserve Capacity to be shared amongst all Market Customers for Trading Month m where this cost is specified for Trading Month m under clause 4.29.3(c);

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

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))~~

Availability_Cost(m) = Availability_Cost_GTR(m) +
Availability_Cost_FKR(m)

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

~~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))~~

GTR_Cost_Share(p,m) =
Margin_GTR_Peak(m)
× Sum(d∈D,t∈Peak,(d,t)∈FKR_lessthan_GTR,MCAP(d,t)
× GTR_Share(p,t)
× (max(0,GTR(d,t) – Sum(i∈I,ASP_GTRQ(i,t)))
- Savings_Cal_Peak(m) × (1 - Savings_Alloc_Peak(m))
× max(0,FKR(m) - Sum(i∈I,ASP_FKRQ(i,t)))))

+ Margin_GTR_Off-Peak(m)
× Sum(d∈D,t∈Off-Peak,(d,t) ∈FKR_lessthan_GTR ,MCAP(d,t)
× GTR_Share(p,t)
× (max(0,GTR(d,t) – Sum(i∈I,ASP_GTRQ(i,t)))
- Savings_Cal_Off-Peak(m) × (1 - Savings_Alloc_Off-Peak(m))
× max(0,FKR(m) - Sum(i∈I,ASP_FKRQ(i,t)))))

+ Margin_GTR_Peak(m) × Savings_Alloc_Peak(m)
× Sum(d∈D,t∈Peak,(d,t)∈GTR_lessthan_FKR,MCAP(d,t)
× GTR_Share(p,t)
× max(0,GTR(d,t) - Sum(i∈I,ASP_GTRQ(i,t))))

+ Margin_GTR_Off-Peak(m) × Savings_Alloc_Off-Peak(m)
× Sum(d∈D,t∈Off-Peak,(d,t)∈GTR_lessthan_FKR,MCAP(d,t)
× GTR_Share(p,t)
× max(0,GTR(d,t) - Sum(i∈I,ASP_GTRQ(i,t))))

+ Sum(t∈T, GTR_Share(p,t)
× Sum(i∈I,ASP_GTRPayment(i,m) / TITM))

+ Monthly Reserve Capacity Price(m)
× Sum(dϵD,tϵT, GTR_Share(p,t) × max(FKR(m),GTR(d,t))) / TITM
× (1- FKR(m) / (FKR(m) + Sum(dϵD,tϵT,GTR(d,t))/TITM))

(bA) the total Generator Trip Reserve Cost for Trading Month m is given by:

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

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

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

Availability_Cost_GTR(m) = Total_Cost_GTR(m) - Capacity_Cost_GTR(m)

(d) the total ~~Load Following~~ Frequency Keeping 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(dϵD,tϵPeak,(d,t)ϵFKR_lessthan_GTR,MCAP(d,t)
× max(0,FKR(m) – Sum(iϵI,ASP_FKRQ(i,t))))

+ (Margin_FKR_Off-Peak(m)
- Savings_Cal_Off-Peak(m) × Savings_Alloc_Off-Peak(m)
× Margin_GTR_Off-Peak(m))
× Sum(dϵD,tϵOff-Peak,(d,t)ϵFKR_lessthan_GTR,MCAP(d,t)
× max(0,FKR(m) – Sum(iϵI,ASP_FKRQ(i,t))))

+ Margin_FKR_Peak(m)
× Sum(dϵD,tϵPeak,(d,t)ϵGTR_lessthan_FKR,MCAP(d,t)
× (max(0,FKR(m) – Sum(iϵI,ASP_FKRQ(i,t)))
- Savings_Alloc_Peak(m)
× Margin_GTR_Peak(m) / Margin_FKR_Peak(m)
× max(0,GTR(d,t) - Sum(iϵI,ASP,GTRQ(i,t)))))

+ Margin_FKR_Off-Peak(m)
× Sum(dϵD,tϵOff-Peak,(d,t)ϵGTR_lessthan_FKR,MCAP(d,t)
× (max(0,FKR(m) – Sum(iϵI,ASP_FKRQ(i,t)))
- Savings_Alloc_Off-Peak(m)
× Margin_GTR_Off-Peak(m) / Margin_FKR_Off-Peak(m)
× max(0,GTR(d,t) - Sum(iϵI,ASP_GTRQ(i,t)))))

+ Sum(iϵI,ASP_FKRPayment(i,m))

Where

I is the set of all Ancillary Service Providers providing Ancillary Services under contracts, where “i” is used to refer to a member of that set;

~~ASP_SRQ(i,t)~~ ASP_GTRQ(i,t) is the quantity of ~~Spinning~~ Generator Trip Reserve provided by Ancillary Service Provider i in Trading Interval t (this being one of the quantities referred to in clause 9.9.3);

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

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

TITM is the number of Trading Intervals in the Trading Month (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_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(cA);

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_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(cB);

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(cB);

~~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(d,t) is the capacity necessary to cover the Ancillary Services Requirement for Generator Trip Reserve for Trading Day d and Trading Interval t as specified under clause 3.10.2;

~~LFR(m)~~ FKR(m) is the capacity necessary to cover the Ancillary Services Requirement for ~~Load Following~~ Frequency Keeping for 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;

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;

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

T denotes the set of Trading Intervals within Trading Day d, where "t" is used to refer to a member of that set;

Capacity_Cost_GTR(m) is the Capacity Cost of Generator Trip Reserve for Trading Month m, defined in clause 3.13.1(bA)i;

FKR_lessthan_GTR denotes the set of Trading Intervals on a Trading Day d within a Trading Month m where (FKR(m) - Sum(iεI,ASP_FKRQ(i,t))) < (GTR(d,t) - Sum(iεI,ASP_GTRQ(i,t))); and

GTR_lessthan_FKR denotes the set of Trading Intervals on a Trading Day d within a Trading Month m where (GTR(d,t) - Sum(iεI,ASP_GTRQ(i,t))) ≤ (FKR(m) - Sum(iεI,ASP_FKRQ(i,t))).

Attachment 3: Full Load, Marginal Generation payment for Load Following

ROAM has proposed[6] that the system load is an inherent part of system operation, and that loads should therefore pay the full proportion of their Load Following requirement (with Intermittent Generators paying the additional increment required for their operation). This follows a recommendation by Econnect to the Office of Energy, Western Australia[7]:

> *The apportioning of load following costs to loads and Intermittent Generators is not as straightforward an issue as it first seems. If this is calculated purely on the basis of contribution to the requirement for load following service, then loads and Intermittent Generators should receive identical treatment: a wind farm with a standard deviation of 10 MW will be charged the same as a load with a standard deviation of 10 MW. However, this "equal charging" method will not accurately reflect the 'marginal' impact of new generators or loads on an existing system. In the example above, if existing load on the system has a standard deviation of 10 MW, the generator is charged for variation of approximately 7 MW when its marginal impact on total variability is only about 4 MW. System loads, on the other hand, obtain a 'windfall' benefit due to the presence of the new intermittent generator.*
>
> *It may therefore be considered 'fairer' in a certain sense if the charge for load following service were to reflect the history of past connections. However, an 'historical charging' method along these lines is problematic as it subjects those network participants who connect earlier to an ongoing penalty relative to those who connect later.*
>
> *A third method that avoids these disadvantages is to distinguish between loads and Intermittent Generators, charging loads for their full variability and Intermittent Generators for their marginal variability relative to aggregate system load. This is motivated by the fact that in the real world a generator is not the same as a load. For a load, the consumption of electricity is only the means to an end, while a generator has the production of electricity as its primary purpose. It is therefore load and not generation that ultimately imposes energy variations on networks, and Intermittent Generators should only incur a charge for variability to the extent that it is (collectively) greater than would be the case were the generators not present.*

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

[7] Econnect, South West Interconnected System (SWIS), Maximising the Penetration of Intermittent Generation in the SWIS, Econnect Project No: 1465, prepared for Office of Energy, Western Australia, section 3.2.2.

Some parties have offered an alternative to this concept, proposing instead that the costs of Load Following are distributed in direct proportion to the requirements of loads and Intermittent Generators.

It is worth noting that under the existing rules, loads bear the majority of the Load Following cost (because it is based upon metered schedules rather than contribution to Load Following requirement). The rule changes already proposed in this document for clause 3.14.1 will represent a significant increase in Load Following costs for Intermittent Generators, and a significant reduction in cost for loads. The decision to apportion according to a "full load, marginal generation" approach or a direct proportion approach is relatively minor by comparison. For example, in the 2008/09 year a "full load, marginal generation" approach would attribute 60 percent of the cost of Load Following to loads, and 40 percent to Intermittent Generators. By comparison, a direct proportion approach would attribute 41 percent of the cost of Load Following to loads, and 59 percent to Intermittent Generators. These figures are compared to the existing allocation methodology in Table 1 below.

Table 1 - Estimates of proportions of Load Following Availability Costs payable by Loads and Intermittent Generators under various allocation methodologies[8]

		Proportion of Load Following Availability Cost payable by **Intermittent Generators**	Proportion of Load Following Availability Cost payable by **Loads**
2008-09	Current Market Rules	4%	96%
	Proposed Methodology (Full Load, Marginal Generation)	40%	60%
	Alternative Methodology (Proportional Load and Generation)	59%	41%
2020-21	Current Market Rules	18%	82%
	Proposed Methodology (Full Load, Marginal Generation)	54%	46%
	Alternative Methodology (Proportional Load and Generation)	68%	32%

The main benefit of a "Full Load, Marginal Generation" approach is that Loads will not receive a "windfall gain" at the expense of Intermittent Generators. Loads are liable for the same cost for the Load Following service that they require regardless of the introduction (or not) of Intermittent Generation to the system.

[8] Data for 2020-21 is an estimate based upon Scenario 1 from the report "Assessment of FCS and Technical Rules, ROAM Consulting report to the Independent Market Operator, July 2010.

The main benefit of a "Proportional Load and Generation" approach is that Loads and Intermittent Generators are treated in an identical fashion, without any consideration of potential fundamental differences between them.

Both methods are equivalent in their implementation, simply requiring a slightly different formulation of the equation in clause 3.14.1.

If it is desired to allocate the Load Following cost to loads and Intermittent Generators in direct proportion to their requirements (rather than via the "full load, marginal generation" approach included in the body of this document) then the alternative formulation of clause 3.14.1 outlined below could be implemented.

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_ Share(p,m)~~ FKR_Cost_Share(p,m) which ~~equals~~ is given by:

FKR_Cost_Share(p,m) =

MS_Loads(p,m) / MS_Loads_total(m) × FKR_Loads(m) / (FKR_Loads(m)+FKR_IG(m))

+ MS_IG(p,m) / MS_IG_total(m) × FKR_IG(m)/ (FKR_Loads(m)+FKR_IG(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;

MS_IG (p,m) is the sum of the Metered Schedules for Non-Scheduled Generators registered by Market Participant p for all Trading Intervals during Trading Month m;

MS_IG_total(m) is the sum of the Metered Schedules for Non-Scheduled Generators registered by all Market Participants during Trading Month m;

FKR_Loads(m) is the Frequency Keeping Requirement sufficient to cover 99.9% of the short term fluctuations in load, measured as the variance of 1 minute average readings around a thirty minute rolling average for the Trading Month m as specified by the IMO under clause 3.22.1(fB); and

FKR_IG(m) the Frequency Keeping Requirement sufficient to cover 99.9% of the short term fluctuations in the output of Non-Scheduled Generators, measured as the variance of 1 minute average readings around a thirty minute rolling average for the Trading Month m as specified by the IMO under clause 3.22.1(fC);

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

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

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

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~~[Blank]

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

iii. [Blank]

Agenda Item 7e: Curtailable Loads and Demand Side Programmes (PRC_2010_29)

1. BACKGROUND

The IMO has recently undertaken a comprehensive review of the Market Rules relating to Curtailable Loads in the Wholesale Electricity Market which identified a number of relevant issues. An issues paper was presented at the 12 May 2010 Market Advisory Committee (MAC) meeting. The issues paper was also supplemented with further analysis regarding the measurement of Curtailable Load performance at both the 16 June 2010 and 11 August 2010 MAC meetings[1].

During the MAC's discussion of the issues a number of action points were raised. Among these was for the IMO to develop a Pre Rule Change Discussion Paper to reflect the agreed solutions (action point 103).

The IMO has now completed preparing the Pre Rule Change Discussion Paper which also reflects the resolution of the additional action points agreed at the MAC. The outcomes of the IMO's consideration of these action points are presented below (section 2). The Pre Rule Change Discussion Paper is attached for review and discussion by the MAC.

In preparing the Pre Rule Change Discussion Paper the IMO has also identified the need for transitional arrangements for existing Demand Side Programmes. Further details of the IMO's proposal are also presented below (section 3)

2. OUTCOMES OF ACTION ITEMS

Action Point 102:"*The IMO to investigate the potential double dipping issue regarding Dispatch Instructions and energy payments for Curtailable Loads raised by Andrew Sutherland" (August 2010 meeting)*

Update: If a Curtailable Load is instructed to reduce its consumption by System Management then, all else being equal, one or more Facilities providing Balancing services will be required to reduce output accordingly. In theory the reduction would also leave the Market Customers associated with the Curtailable Load with an excess of energy over their Net Contract Positions, which would be sold to the market at MCAP. As a retailer would have already purchased the energy from a Market Generator the sale of the excess energy at MCAP should be considered a refund.

The IMO considers it is reasonable for a Curtailable Load (to be amended to Demand Side Programme (DSP) in the Pre Rule Change Discussion Paper) to receive a Dispatch Instruction Payment in incidences where it has curtailed its consumption following a request from System Management. While the Market Customer would also receive a payment during this period (for its excess energy), from a market perspective there is a requirement for either a generator to increase its output or a DSP to curtail its load to ensure system security. The IMO considers that in these circumstances the benefit that the market would derive from the services of the DSP would warrant the payment to both the DSP and potential MCAP payment to the relevant

[1] To review the previous MAC papers and minutes see: www.imowa,com.au/MAC

retailer. The IMO notes that for the marginal unit (Load) dispatched by System Management, the opportunity cost of a load curtailing (i.e. the output that could be produced by a manufacturing facility (Load)) would be equivalent to the operating costs for a generator able to offer a similar service (i.e. fuel costs). Note that if a generator were issued a Dispatch Instruction to increase its output then it would also receive a payment for being dispatched.

The IMO however considers that during periods when either a Reserve Capacity test or Verification Test is being undertaken the market should not pay the DSP. During these periods there is no market requirement for either an increase in generation or curtailment of load to ensure that the system security is maintained, as such no form of payment for the curtailment is justified. The IMO notes that not paying a DSP for these periods would ensure that during these Trading Intervals no cross subsidy would be incurred.

The IMO proposes that Demand Side Programmes not be paid for any energy reduced during either a Reserve Capacity test or Verification Test (clause 6.17.6).

Discussion point 1: Should a Curtailable Load (to be amended to Demand Side Programme (DSP) in the Pre Rule Change Discussion Paper) receive a Dispatch Instruction Payment in incidences where it has curtailed its consumption following a request from System Management. If so, no additional rule changes will be required. If not, a new Rule Change Proposal will be required; and

Discussion point 2: Should Curtailable Load's (to be amended to Demand Side Programme (DSP) in the Pre Rule Change Discussion Paper) not be paid for any energy reduced during either a Reserve Capacity test or Verification Test?

Action Point 121:"*The IMO to present to the MAC a worked example comparing the payments associated with the dispatch of a peaker against those associated with the dispatch of a Demand Side Programme".*

Update: The IMO will present the worked example during the MAC meeting.

3. COMMENCEMENT OF AMENDING RULES

The IMO has identified the need for arrangements to be put in place for existing Market Participants with Curtailable Loads prior to the commencement of the majority of the Amending Rules resulting from PRC_2010_29. The IMO proposes to:

- Clarify that any Load currently registered as a Curtailable Load and that has Capacity Credits associated with if for a future Reserve Capacity Cycle will be treated as a Non-Dispatchable Load associated with the DSP as of 1 October 2011 (new clause 2.29.5F); and
- Specify that any Market Participant with a DSP that has Capacity Credits associated with it for a future Reserve Capacity Cycle may disaggregate the comprising Loads and associate them with an individual DSP prior to 1 October 2011 (new clause 2.29.5G).

Dependent on the IMO's final decision, these rules will commence as soon as possible following the publication of the Final Rule Change Report. The remainder of the Amending Rules resulting from this Rule Change Proposal (excluding these two rules) are proposed to commence on 1 October 2011. The IMO considers that this staggered approach to the implementation of any Amending Rules will allow for a period to occur where existing Market Participants may make any necessary amendments to the association of their existing Loads/DSPs.

4. RECOMMENDATIONS

The IMO recommends that the MAC:

- **Discuss** the issues raised in section 2 of this paper;
- **Note** the IMO's worked example comparing the payments associated with the dispatch of a peaker against those associated with the dispatch of a Demand Side Programme (as presented at the MAC meeting);
- **Notes** the IMO's proposed commencement arrangements for any Amending Rules resulting from PRC_2010_29; and
- **Agree** for PRC_2010_29 to be formally submitted as Rule Change Proposal.

Agenda item 7e

Wholesale Electricity Market
Pre Rule Change Discussion Paper

Change Proposal No: *PRC_2010_29*
Received date: *TBA*

Change requested by

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Date submitted:	TBA
Urgency:	High
Change Proposal title:	Curtailable Loads and Demand Side Programmes
Market Rule(s) affected:	Clauses 2.27.1, 2.27.1A, 2.27.2, 2.27.4, 2.29.1A, 2.29.5, 2.29.8A, 2.29.8B, 2.29.9A, 2.29.9B, 2.29.9C, 2.30.3, 2.30B.2, 2.30B.5, 2.33.1, 2.33.4, 2.35.1, 3.14.1, 3.17.5, 4.8.3, 4.10.1, 4.11.1, 4.11.4, 4.11.4A, 4.12.1, 4.12.4, 4.12.8, 4.14.1, 4.18.1, 4.18.2, 4.25.1, 4.25.2, 4.25.4, 4.25.4E, 4.25.4F, 4.25.9, 4.25.10, 4.25A.1, 4.25A.2, 4.25A.3, 4.25A.4, 4.25A.5, 4.26.1A, 4.26.1C, 4.26.2, 4.26.2C, 4.26.2D, 4.26.3A, 4.26.4, 6.3A.2, 6.5A.1, 6.11.1, 6.11.2, 6.11A.1, 6.12.1, 6.15.2, 6.16.1, 6.17.6, 7.1.1, 7.2.2, 7.6.10, 7.7.3, 7.7.4, 7.7.4A, 7.7.10, 7.13.1, 9.3.3, 9.3.4, 9.3.7, 9.13.1, 10.5.1, the Glossary, Appendix 1 and Appendix 3 and new clauses 2.29.5A, 2.29.5B, 2.29.5C, 2.29.5D, 2.29.5E, 2.29.5F and 2.29.5G.

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: General Manager Development
PO Box 7096
Cloisters Square, Perth, WA 6850

Fax: (08) 9254 4339
Email: market.development@imowa.com.au

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

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

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

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

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

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

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

Details of the proposed Market Rule Change

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

Background

Market Participants that are electricity retailers serve numerous domestic, commercial and industrial users (Loads). Most of these will be Non-Dispatchable Loads[1] (NDLs), for which there are currently no registration provisions in the Market Rules. Some users are willing to curtail their energy usage at times of peak demand or at times of system stress under contract. Demand Side Management (DSM) providers aggregate such users to form Curtailable Loads (CLs) in order to receive payment for providing Reserve Capacity. Clause 2.30.3 of the Market Rules facilitates this practice.

DSM has made a positive contribution to the Reserve Capacity Mechanism within the Wholesale Electricity Market, currently contributing approximately 5 percent of the total Reserve Capacity for the 2012/13 Capacity Year.

Users can also form part of a Demand Side Programme (DSP) which may interact with the energy market through one Market Participant (their electricity retailer) and with the capacity

[1] A Load which is not a Dispatchable Load, Curtailable Load or an Interruptible Load, and is therefore self-scheduled.

mechanism through a different Market Participant (their DSM provider). One key issue with this is that the Market Rules do not currently allow for a Load to be registered to two Market Participants.

Issues and Proposed Solutions

Some elements of the Market Rules surrounding CLs are inconsistent with the treatment of other capacity types, inconsistent with the way the IMO has applied the Market Rules in the past, inconsistent with common practice in other jurisdictions, or are simply impractical. The IMO intends to ensure that DSM options in the market are treated in a similar manner to other capacity types.

Currently the IMO is required to assess the appropriateness of a CL which makes up a DSP. The IMO considers it appropriate that the risks associated with non-compliance of CL's for the provision of demand reduction services are borne by the DSP provider. This is rather than the IMO being responsible for determining "acceptable" CLs.

After a comprehensive review of the Market Rules the IMO identified a number of issues relevant to Curtailable Loads. A paper outlining the issues was presented at the 12 May 2010 Market Advisory Committee (MAC) meeting.

The issues paper was also supplemented with further analysis regarding the measurement of Curtailable Load performance at both the 16 June 2010 and 11 August 2010 MAC meetings[2]. At both these meetings the MAC agreed with a number of recommendations put forward by the IMO. In preparing this paper, the views expressed by the MAC have been taken into account.

Issue 1: Registration of Curtailable Loads

<u>*Overview:*</u> Currently, if a DSP provider wishes to use a Load(s) to fulfil the obligations of its DSP, the IMO is required to register the comprising Load(s) as a CL belonging to the DSP provider (clause 4.8.3(b)). This has a number of flow-on effects in the calculation of the energy associated with that Load because the Load's connection point now essentially "belongs" to two different Market Participants:

- Firstly as an un-registered NDL to the energy provider (as supported by the Meter Registry); and
- Secondly as a CL to the DSP provider.

Since Energy Market Commencement the IMO has allowed the registration of CLs to DSP providers who are not also the energy provider.

The association of the connection point with both the energy market and capacity mechanism creates an issue with not clearly delineating that a Load associated with a DSP through a Market Participant who is not the energy retailer should <u>only</u> be paid for capacity. That is, there should be no Metered Scheduled determined for a DSP as this would result in an energy market payment also occurring. Currently the Market Rules require a Metered

[2] To review the previous MAC papers and minutes see: www.imowa.com.au/MAC

Schedule to be determined for a Curtailable Load which incorporates a Curtailable Load into the energy side of the market.

Agreed Outcomes: The MAC endorsed the IMO's recommendation to amend the Market Rules so that a Market Participant other than the Market Customer is able to contract for the Reserve Capacity associated with Curtailable Loads (12 May 2010 meeting).

The IMO's proposed solution: To implement the recommendation the IMO proposes to remove the concept of a CL as a Registered Facility from the Market Rules and replace this with the concept of the DSP being the Registered Facility. The DSP will then have NDLs associated with it for the purposes of capacity obligations, dispatch and settlements.

Issue 2: Facility Definition

Overview: Currently the Market Rules treat a DSP as a single (aggregated) Facility for some purposes, and the CLs comprising the DSP as individual Facilities for other purposes. The Market Rules imply that a DSM provider applies for certification of Reserve Capacity for the DSP as a whole but the Loads comprising a DSP must be registered individually (clause 4.8.3(b)). This creates an issue when a DSP is expected to be made up of, potentially, hundreds of smaller CLs. That is, when attempting to satisfy the obligations of the DSP, a Market Participant will be required to apply for registration of all the comprising CLs at the same time.

The registration process requires a large amount of information from DSP providers about each CL regarding both energy and capacity. This is operationally inefficient for both the IMO, in assessing the applications, and for the DSP provider in providing the relevant information for the registration process. For the purposes of the RCM the most important aspect of this is evidence that the Facility has the capacity to be dispatched to the level of Capacity Credits held by the Facility.

Additionally, each application costs the Market Participant $280[3] and can take the IMO up to 10 days to process. Therefore if a Market Participant with a 50MW DSP applies for registration of the 100 CLs that make up the DSP, the Market Participant would be required to pay registration fees of $28,000.

Furthermore, Dispatch Instructions may only be issued to Registered Facilities (clause 7.7.2(b)). If a DSP is not registered as a single Facility, the Dispatch Instructions could only be issued to its component Loads and System Management would have to decide which Loads are required to deliver any reduction in consumption. For operational efficiency, System Management would prefer to issue a Dispatch Instruction to the DSP provider, who would then decide how to deliver the requested curtailment.

Finally, clause 4.8.3(c) of the Market Rules implies that the DSP provider will seek Certified Reserve Capacity for the DSP as a whole, but that the Reserve Capacity Obligations are transferred from the programme to its component Loads as they are registered. This implies that it is not possible to have more capacity associated with CLs in a programme than the quantity of Certified Reserve Capacity assigned to the DSP. However it is normal that DSP providers oversubscribe the level of capacity within a programme to manage the risk and provide some redundancy.

[3] Effective 1 July 2010.

Agreed Outcome: The MAC endorsed the IMO's recommendation to amend the Market Rules to allow for the registration of a DSP as a Registered Facility (12 May 2010 meeting). This will allow for the dispatch of a DSP instead of dispatching each CL within the DSP. This will become increasingly important as the expected number of CLs comprising DSPs will be between 200 and 500 by 2012/13.

The MAC also endorsed the IMO's recommendation that the Market Rules be amended to specify (and operationalise) the ability for DSPs to be over-subscribed. While this practise is not currently prohibited by the Market Rules, it is neither contemplated as a possibility.

Proposed Solution: This issue is solved via the solution outlined in issue 1 above i.e. if a DSP is a Registered Facility, System Management will be able to dispatch the Facility itself, and will not be required to dispatch each of the CLs comprising the DSP.

The IMO also proposes an amendment to the Relevant Demand calculation to allow for the possibility that a programme will be oversubscribed. This is outlined in further detail in issue 4. The proposed amendments will amend the calculation to no longer limit the amount of curtailability a DSP will be able to offer. This will be consistent with the treatment of Scheduled Generators. This is in the same way there is no limit on the amount of generation a Scheduled Generator can provide even if it requests its capacity to be certified at a level below the nameplate capacity of the Facility.

Issue 3: Market Fees

This issue is presented for completeness only, and no amendments to the current Market Rules are anticipated.

Overview: The Market Rules require Market Fees to be paid on a proportionate level to the net amount of energy supplied or consumed by the Market Participant. This is as determined through the Market Participant's Metered Schedules. Under the current arrangement a DSP who contracts solely for capacity is not required to pay any Market Fees. The IMO identified this as an area requiring further consideration due to the inconsistencies with the current requirements for other Market Participants. Several options were identified by the IMO:

1. DSM providers could pay no Market Fees, requiring no change to the Market Rules.
2. DSM providers could pay Market Fees based on the quantity of energy dispatched for curtailment, which is consistent with the Market Fee calculation for other Market Participants.
3. DSM providers could pay an annual Market Fee based on the number of Capacity Credits. This introduces additional complexity to the current Market Fee structure.
4. The entire Market Fee structure could be replaced with an arrangement based on both capacity and energy. This could introduce additional complexity to the current Market Fee structure.

Agreed Outcome: The MAC agreed that DSPs should not be required to pay Market Fees (12 May 2010 meeting).

Issue 4: Measurement of CL Performance

Overview: The Rule Change Proposal: Demand Side Management - Operational Issues (RC_2008_20) introduced a new concept for measuring the curtailability of Curtailable Loads. This is known as the Relevant Demand (RD) level. The RD level determines the median value that a Curtailable Load consumes during 32 Trading Intervals of highest demand during the preceding Hot Season, reflecting a normal operating level during the intervals when the DSP is most likely to be dispatched.

The Market Rules also give a CL/DSP the ability to perform maintenance over these peak intervals without this reducing the corresponding RD level for the Facility. The IMO considers that the exclusion of maintenance from the calculation gives a dual incentive to Market Participants to perform maintenance during intervals they assume will be IRCR intervals[4]. For example a Market Participant can currently attempt to reduce its load over intervals which it considers will be Peak Trading Intervals. Note that the IRCR and RD intervals are likely to be similar intervals and as such a Market Participant's IRCR are likely to be reduced. To minimise the cost of these reductions if a Market Participant performs maintenance on a Facility over these intervals, that Market Participant can also apply to the IMO to exclude these intervals resulting in a higher RD level than they would otherwise have had calculated. As a result the Market Participant not only has a reduced IRCR cost but also received a higher RD level and so receives a higher Capacity Credit payment in the following year.

As noted above the RD level is intended to reflect the normal operating level during intervals when the DSP is most likely to be dispatched, however in the case outlined above the RD level will not be representative of this peak load operating level. The IMO therefore recommended that the ability to exclude Trading Intervals where maintenance was being performed be removed from the Market Rules. The IMO considers that here is already a payment incentive in place to reduce consumption over peak periods in the IRCR calculation.

The IMO notes that if a Facility was undertaking maintenance or experiencing an unplanned outage during any of the 32 Trading Intervals of highest demand used in the RD calculation, and these do not match up with any of the 12 IRCR Trading Intervals, then the Market Participant would not receive the benefit of a reduction in its IRCR and would have a lower RD level calculated (resulting in a reduced level of Capacity Credits being assigned). As a result the IMO commissioned Data Analysis Australia (DAA) to consider the use of the IRCR Trading Intervals as the basis for the RD calculation. DAA's analysis found that the use of the IRCR intervals would produce a more reliable result which better reflects the normal operating level during intervals when the DSP is most likely to be dispatched. Further details of DAA's analysis and the MAC's subsequent discussion are available on the IMO webpage: http://www.imowa.com.au/MAC_28

A separate issue identified in the measurement of the performance of CLs is that the Market Rules do not currently contemplate the ability for a Facility to be oversubscribed. As such the measurement of these oversubscribed Facilities is also not accounted for. The following options to account for oversubscribed facilities were identified by the IMO, either to:

1. Measure the reduction of each individual Load compared to its individual RD level; or

[4] The 12 peak Trading Intervals during the Hot Season preceding the initial calculation.

2. Measure the aggregated DSP as a single Facility with a RD Level based on the sum of the comprising Loads.

Currently a reduction of a DSP is measured for those Loads which the DSP directed to curtail. This is similar to the first option presented above and results in only curtailment of output being associated with the DSPs performance and not any increases in load which may have occurred by Loads within the DSP (outside of any directions having been issued). The IMO considered that it is appropriate that the DSP is responsible for the level of operation of the DSP as a whole, which would include any natural movement in Loads above and/or below the DSPs RD level which were not as a result of directions having been issued.

Following the outcomes of DAA's analysis which found no significant difference between the two options, the IMO did not consider it is necessary to calculate the RD level for each individual Load as this would create unnecessary operational overhead and not improve the RD levels ability to reflect the normal operational level of the DSP during required intervals.

<u>Agreed Outcome:</u> The MAC agreed that:

- The RD level calculation methodology should be changed to be calculated on the IRCR intervals;
- The exclusion due to maintenance, clause 4.26.2C(d) should be removed from the Market Rules; and
- The RD level should be calculated based on the aggregated output of the DSP, and not by aggregating the RD of each CL associated with a DSP (11 August 2010 meeting).

<u>Proposed Solution:</u> The IMO notes that the solutions to issues 1 and 2 (which will ensure that only the DSP is visible to the market and not the comprising loads) combined with the RD level being calculated based on the aggregated output of the DSP, and not by aggregating the RD of each CL associated with a DSP will ensure that the correct measurement of the DSP as a whole. This will ensure that a DSP is treated similarly to other Facilities (by measuring consumption at an aggregate level) with regard to how it satisfies its Reserve Capacity Obligations and simplifies the measurement of the DSP's consumption.

Issue 5: Capacity Cost Refunds

<u>Overview:</u> The Rule Change Proposal: DSM – Operational Issues (RC_2008_20) implemented a methodology for calculating Capacity Cost Refunds for Curtailable Loads. This methodology requires a DSM provider to pay refunds only if it fails to deliver curtailment when dispatched.

An unintended consequence of this is that a DSM provider is not required to pay refunds, even if they fail to procure any CLs into the programme, until such time as they fail to meet a Dispatch Instruction or fail a Reserve Capacity test. The IMO considers that this is a manifest error as a DSM provider will continue to receive payment for the capacity even if it is unavailable to the market.

<u>Agreed Outcome:</u> The MAC agreed that a DSP should have the same obligations as a Market Generator, therefore a DSP consisting of one or more CLs, will be liable to pay refunds if at any time the programme is not filled completely (12 May 2010 meeting).

Proposed Solution: The IMO proposes to amend the Market Rules so that a DSP consisting of one or more CLs, is liable to pay refunds if at any time the program is not filled completely, at the amount by which the DSP falls short of its capacity requirements This includes times where this is the result of a component Facility being on a Forced Outage.

Issue 6: Reserve Capacity Security

This issue is presented for completeness only, and no amendments to the Reserve Capacity Security Market Rules have been included in this paper.

Overview: Currently the arrangements for a DSP (and Intermittent Generators) regarding the return of Reserve Capacity Security are unclear and inconsistent. For example a DSP that contracted 90 percent of the certified curtailment capacity will not have its Reserve Capacity Security returned at all, whereas a Scheduled Generator would have the security released at the end of the Reserve Capacity Year. The IMO does not consider that this is equitable.

Clarity around the return of security will be achieved by allowing DSM aggregators to aggregate their Loads as a single DSP. This will ensure consistency with the Market Rules governing the return of security for Market Generators. The IMO has recently presented a number of amendments to the current provisions in the Market Rules around the administration and provision of Reserve Capacity Security. For further details please refer to: http://www.imowa.com.au/MAC_31

Agreed outcome: The MAC agreed that a DSP should be entitled to have its security returned immediately if they operate at 100 percent of their RCOQ in at least one Trading Interval, or at the end of the Capacity Year if they operate at 90 percent of their RCOQ during the Capacity Year. Otherwise the Reserve Capacity Security would be forfeited in the same way as would be applied to a generation Facility. This would ensure consistency of treatment (12 May 2010 meeting).

Proposed Solution: The IMO has proposed under the Rule Change Proposal: Required Level and Reserve Capacity Security (RC_2010_12) to amend the Market Rules so that a DSP is considered as a single Facility for the purpose of evaluating a request for the return of Reserve Capacity Security.

Issue 7: Stipulated Default Loads

Overview: Stipulated Default Loads are a type of CL which must drop consumption to a defined level, as opposed to a typical CL which must drop consumption from a defined level.

There is no clear way of determining the demand level of a Stipulated Default Loads from which to assign Certified Reserve Capacity (i.e. what can the load drop “from”). Currently the IMO uses the RD level when assigning CRC to a Stipulated Default Load, however at the time of assigning CRC the RD level is based on data that will be two years out of date when the associated obligation comes into effect.

The IMO considers that, due to this calculation issue and the fact that there is only minimal difference between a Stipulated Default Load and a CL once the RD is used to calculate the CRC, it is preferable to use the RD calculation provisions for CLs, rather than the provisions for Stipulated Default Loads, in all cases. Therefore the DSP's level of Capacity Credits would be based on the most recent summer's data instead of data from two years previously.

The IMO considers that this will ensure a more rigorous and accurate estimate of a Loads reduction in consumption is obtained which will ensure Capacity Credits accurately reflects the true curtailability of a DSP.

Note that there are only two Stipulated Default Loads in the market representing approximately 32 MW of capacity.

Proposed Solution: The IMO proposed that the Market Rules be amended to combine the concept of a CL and Stipulated Default Load into the DSP concept.

Issue 8: Potential Double Payment

Overview: Currently if a CL is requested to curtail its consumption by System Management then in accordance with clause 6.17.6 (d) the DSM Provider will be paid for the reduction in its consumption. During the August 2010 MAC meeting, a member raised concerns regarding the potential double payment for curtailment as a result of both a Dispatch Instruction Payment to the DSM Provider and an MCAP payment to relevant retailer for the Load reduction.

The IMO notes that if a CL is instructed to reduce its consumption by System Management then, all else being equal, one or more Facilities providing Balancing Services will be required to reduce output accordingly. In theory the reduction would also leave the Market Customers associated with the Load with an excess of energy over their Net Contract Positions, which would be sold to the market at MCAP. As a retailer would have already purchased the energy from a Market Generator the sale of the excess energy at MCAP should be considered a refund.

The IMO considers it is reasonable for a CL (to be amended to DSP) to receive a Dispatch Instruction Payment in incidences where it has curtailed its consumption following a request from System Management. While the Market Customer would also receive a payment during this period (for its excess energy), from a market perspective there is a requirement for either a generator to increase its output or a DSP to curtail its load to ensure system security. The IMO considers that in these circumstances the benefit which the market would derive from the services of the DSP would warrant the payment to both the DSP and potential MCAP payment to the relevant retailer. The IMO notes that for the marginal unit (Load) dispatched by System Management, the opportunity cost of a load curtailing (i.e. the output that could be produced by a manufacturing Facility (Load) during that period) would be equivalent to the operating costs for a generator (i.e. fuel costs). Note that if a generator were issued a Dispatch Instruction to increase its output then it would also receive a payment for being dispatched.

The IMO however considers that during periods when either a Reserve Capacity test or Verification Test is being undertaken the market should not pay the DSP. During these periods there is no market requirement for either an increase in generation or curtailment of load to ensure that the system security is maintained, as such no form of payment for the curtailment is justified. The IMO notes that not paying a DSP for these periods would ensure that during these Trading Intervals no cross subsidy would be incurred. This is consistent with the outcomes recently agreed by the MAC regarding Network Control Services (October 2010 MAC meeting).

Proposed Solution: The IMO proposes that DSPs not be paid for any energy reduced during either a Reserve Capacity test or Verification Test.

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2. Explain the reason for the degree of urgency:

The IMO proposes 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)

The proposed amendments will remove the requirement for the Network Operator to calculate a Loss Factor for each connection point at which a Curtailable Load is connected. This is consistent with the general removal of Curtailable Loads from the Market Rules. The Loss Factor will be created for the Non-Dispatchable Loads that make up the program.

2.27.1. By 1 June of each year Network Operators must calculate and provide to the IMO Loss Factors for each connection point in their Network at which is connected a:

(a) Scheduled Generator;

(b) Non-Scheduled Generator;

(c) Non-Dispatchable Load;

(d) Interruptible Load; or

~~(e) Curtailable Load; or~~

(f) Dispatchable Load

The proposed amendment will clarify that a Non-Dispatchable Load is a Facility (not a Registered Facility). This is required because a Non-Dispatchable Load is not a Registered Facility. The proposed amendment will improve the integrity of the Market Rules.

2.27.1A. A Market Participant may request, during the process of obtaining a relevant Arrangement for Access, that the relevant Network Operator determine and provide to the IMO, Loss Factors to apply to a Registered F~~f~~acility or a Non-Dispatchable Load where there are no Loss Factors applying to the connection point at which the Registered F~~f~~acility or the Non-Dispatchable Load will be connected.

The proposed amendment is consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove a Curtailable Loads association with the energy side of the WEM.

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

…

(c) Loss Factors must be calculated using:

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

iA for a new Registered F~~f~~acility or a Non-Dispatchable Load, any other relevant data provided by the Market Participant and as agreed with the Network Operator and the IMO, and

…

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

i. Scheduled Generator;

ii. Non-Scheduled Generator;

~~iii. Curtailable Load;~~

iv. Interruptible Load;

v. Dispatchable Load; and

vi. Non-Dispatchable Load above 1000kVA peak consumption;

…

The proposed amendment will reflect the removal of the requirement for the Network Operator to calculate a Loss Factor for a Curtailable Load. This will remove Curtailable Loads from the Market Rules.

2.27.4. A Market Participant may seek a re-assessment by the IMO of any Loss Factor applying to a Scheduled Generator, Non-Scheduled Generator, ~~Curtailable Load,~~ Interruptible Load, Dispatchable Load or Non-Dispatchable Load registered by that Market Participant in accordance with the following process:

The proposed new clause will clarify the classes of Facility in section 2.29 of the Market Rules (Facility Registration Classes). The definition of Facility Classes will also remain in Chapter 11, albeit with the deletion of Curtailable Load and the inclusion of Demand Side Programme. The IMO considers that this proposed amendment will improve the integrity to the Market Rules and ensure that new Market Participants can clearly understand the registration process.

2.29.1A. The Facility Classes are:

(a) Network;

(b) Scheduled Generator;

(c) Non-Scheduled Generator;

(d) Interruptible Load;

(e) Dispatchable Load; and

(f) Demand Side Programme.

The proposed amendment is consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove a Curtailable Loads association with the energy side of the WEM.

2.29.5 Subject to clauses 2.29.9 and 2.29.8A, a Market Customer that owns, operates or controls a Load:

…

(b) ~~may register that Load as a Curtailable Load if that Load can be interrupted on request~~ [BLANK];

…

The proposed new clause will allow a Market Customer with a contract with a Non-Dispatchable Load (or a Market Customer that plans to enter into a contract with one) to register a Demand Side Programme. Note that a Demand Side Programme provider will also be able to register as a Market Customer in accordance with clause 2.28.13.

2.29.5A. Subject to clause 2.29.8A, a Market Customer that enters into, or plans to enter into, a contract with a Non-Dispatchable Load to be available for curtailment, where that Load can be curtailed upon request, may, but is not required to, register a Demand Side Programme.

The proposed new clause will allow a Demand Side Programme to be filled with Non-Dispatchable Loads.

2.29.5B A Market Customer may associate a Non-Dispatchable Load ("**Associated Non-Dispatchable Load**") with a Demand Side Programme if it provides contractual evidence, in accordance with the Registration Market Procedure, that the Non-Dispatchable Load has been contracted to provide curtailment upon request. The evidence must include:

(a) the connection point of the Non-Dispatchable Load;

(b) the minimum load of the Non-Dispatchable Load;

(c) contracted start date; and

(d) contracted end date.

The proposed new clause will ensure that a Non-Dispatchable Load cannot be associated with two Demand Side Programmes simultaneously.

2.29.5C A Non-Dispatchable Load cannot be associated with two Demand Side Programmes for the contracted time as specified in clauses 2.29.5B(c) and 2.29.5B(d).

The proposed new clause will ensure that a Non-Dispatchable Load cannot be associated with two Demand Side Programmes at the same time by requiring the IMO to disassociate a Non-Dispatchable Load from the relevant Demand Side Programme the Trading Day after the contracted end date. This is consistent with the requirements of new clause 2.29.5C.

2.29.5D The IMO must disassociate a Non-Dispatchable Load from the relevant Demand Side Programme by the Trading Day after the date specified in clause 2.29.5B(d).

The proposed new clause will ensure that a Demand Side Programme, which reduces its ability to curtail demand, will be reflected in the programme's associated Relevant Demand. This will ensure that the Relevant Demand for the programme accurately reflects its ability to curtail demand when required.

2.29.5E During the contracted time that a Demand Side Programme has Reserve Capacity Obligations, as specified in clause 2.29.5B, the IMO must within 10 Business Days recalculate the Relevant Demand for that Demand Side Programme, in accordance with clause 4.26.2C, when:

(a) a Load is associated with that Demand Side Programme in accordance with clause 2.29.5B; or

(b) a Load is disassociated with that Demand Side Programme in accordance with clause 2.29.5D.

The proposed new clause will specify that exisiting Loads registered as Curtailable Loads which have been assigned Capacity Credits by the IMO will be treated as a Non-Dispatchable Loads associated with Demand Side Programmes from 1 October 2011 onwards. The IMO notes that this clause will commence prior to any of the subsequent Amending Rules to replace the concept of a Curtailable Load with a Demand Side Programme commencing.

2.29.5F Any Load that is registered as a Curtailable Load and has Capacity Credits associated with it for a future Reserve Capacity Cycle will be treated as a Non-Dispatchable Load associated with a Demand Side Programme as of 1 October 2011.

The proposed new clause will allow an existing Demand Side Programme to disaggregate its comprising Loads and associate these each with an individual Demand Side Programme.

The IMO notes that this clause will commence prior to any of the subsequent Amending Rules to replace the concept of a Curtailable Load with a Demand Side Programme commencing.

2.29.5G Any Market Participant with a Demand Side Programme with Capacity Credits associated with it for a future Reserve Capacity Cycle may disaggregate the comprising Loads and associate them with an individual Demand Side Programme prior to 1 October 2011.

The proposed amendments will clarify that that Interruptible Loads, Dispatchable Loads or a Non-Dispatchable Load associated with a Demand Side Programme must have an interval meter.

2.29.8A. ~~A Rule Participant must ensure an Interruptible Load, Curtailable Load or Dispatchable Load registered by that Rule Participant is equipped with an interval meter.~~ The following Loads must be equipped with an interval meter:

(a) Interruptible Loads;

(b) Dispatchable Loads; or

(c) any Non-Dispatchable Loads associated with a Demand Side Programme.

The proposed amendment will remove duplication of the requirements currently specified under clause 4.25A. This will improve the integrity of the Market Rules. The removal of this clause will also remove a current issue requiring a Market Participant to have completed a verification test within 20 Business Days of having registered the Curtailable Load. The IMO notes that it is unlikely that a Curtailable Load would necessarily be available within 20 Business Days of registration.

2.29.8B. ~~When a Rule Participant registers a Curtailable Load the Rule Participant must undertake a Verification Test in accordance with clause 4.25A within 20 Business Days of registration.~~ [Blank]

The proposed amendment is consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove a Curtailable Loads association with the energy side of the WEM.

2.29.9A A Rule Participant may not register a Demand Side Programme ~~Curtailable Load after 1 April 2009~~ where the minimum notice period required for dispatch exceeds four hours.

The proposed amendments to 2.29.9B and 2.29.9C are consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove Curtailable Loads association with the energy side of the WEM.

2.29.9B ~~Where a Rule Participant has registered a Curtailable Load with a minimum notice period required for dispatch that is less than four hours the minimum notice period may be increased to no more than four hours.~~ [Blank]

2.29.9C ~~Where a Rule Participant has registered a Curtailable Load with a minimum notice period required for dispatch that is equal to or greater than four hours the minimum notice period may not be increased.~~[Blank]

The proposed amendment will remove the current ability for a Market Participant to aggregate Curtailable Loads at different locations. This will no longer be required as the requirement for the Demand Side Programme will to be available for the correct amount of availability hours. For the avoidance of doubt the Non-Dispatchable Loads associated with a Demand Side Programme can be at different locations, as long as they are available for the correct amount of availability hours. The Loads comprising a Demand Side Programme will no longer be visible to the market.

2.30.3. ~~Subject to clause 2.30.5, Curtailable Loads at different locations, but operated by a single Market Participant, may be aggregated with respect to their annual hours of availability so as cumulatively provide Reserve Capacity with an annual number of hours of availability greater than that of any of the individual facilities.~~ [Blank]

The proposed amendment will remove the connection of energy associated with a Curtailable Load from being able to be associated with an Intermittent Load. Under the proposed amendments the energy from the Non-Dispatchable Load will now be associated with the Intermittent Load.

2.30B.2 For a Load to be eligible to be an Intermittent Load the following conditions must be satisfied:

…

(d) the Load must be an Interruptible Load~~, Curtailable Load,~~ or a Non-Dispatchable Load.

The proposed amendment will remove the connection of energy associated with a Curtailable Load from being able to be associated with an Intermittent Load.

2.30B.5. A Market Customer, or applicant to become a Market Customer, may apply for a Load to be treated as an Intermittent Load as part of Market Customer registration (for a Non-Dispatchable Load) or Facility registration (for an Interruptible Load ~~or Curtailable Load~~).

The proposed amendment will allow a DSM provider to apply to register as a Market Customer without an Access Arrangement

2.33.1. The Rule Participant registration form prescribed by IMO must require that an applicant for registration as a Rule Participant provide the following:

…

(h) if the application relates to <u>the sale of electricity to Contestable Customers by an applicant for </u>the Market Customer class<u>:</u>

i. evidence that the applicant holds an Arrangement for Access for the purpose of taking power from the electricity grid; and

ii. the information described in Appendix 1(f);

…

The proposed amendment will remove the current requirement for an applicant to provide a proposed date for a Curtailable Load to cease operation that is no earlier than one month after the date of application. This sub-clause was originally put in place to take into account the churn of Curtailable Loads from one Demand Side Programme to another. This will be taken into account in the proposed new clauses 2.29.5B – E. The Loads comprising a Demand Side Programme will be no longer visible to the market under the proposed amendments.

2.33.4. The Facility de-registration form prescribed by IMO must require that the applicant provide the following:

…

(d) a proposed date on which that Registered Facility is to cease to be registered in the name of that Rule Participant where that date must be;

…

ii. the date the application is accepted in the event that the Facility has been rendered permanently inoperable;~~ or~~ <u>and</u>

iii. ~~not earlier than one month after the date of application if the Facility is a Curtailable Load, which is associated with a Demand Side Programme and has been registered in accordance with clause 4.8.3; and~~

…

The proposed amendment reflects the general changes to the Market Rules regarding a Demand Side Programme being a Registered Facility.

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

The proposed amendment reflects that as there will be no energy associated with the Curtailable Load there will be no need for a Market Participant to be incorporated into the Load Following Service payment cost calculation.

3.14.1. Market Participant p's share of the Load Following Service payment cost in each Trading Month m is Load_Following_Share(p,m) which equals :

(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~~,~~ and Interruptible Loads~~, Curtailable Loads~~ registered by the Market Participant for all Trading Intervals during Trading Month m; and

…

The proposed amend will ensure that System Management is provided the necessary information for Demand Side Programmes. This is consistent with current practice.

3.17.5. Unless otherwise directed by System Management, Rule Participants must submit information to System Management before 10 AM every Thursday, consisting of:

…

(c) for a Market Customer, availability over the next Short-Term PASA Horizon of all its Registered Facilities ~~which are Loads~~ and demand forecasts for any other load facilities designated as significant by System Management.

The proposed amendment will remove clause 4.8.3 which currently allows a Market Customer to apply for certification of a Demand Side Programme. Under the proposed amendments a Demand Side Programme will be a type of Facility and so may apply for Certified Reserve Capacity through the same mechanisms as any other Facility (via either clause 4.11.1(a) or clause 4.11.2(b)).

~~4.8.3. A Market Customer may apply for the certification of a Demand Side Programme including Loads at different locations as a Curtailable Load subject to the following conditions and provisions:~~

~~(a) No Intermittent Load may be included in the Demand Side Programme.~~

~~(b) The Loads comprising the Demand Side Programme must be registered as Curtailable Loads if they are to count towards satisfying the relevant Reserve Capacity Obligations of the Demand Side Program and must not have been separately awarded Capacity Credits.~~

~~(c) As the Loads comprising the Demand Side Program are registered, the IMO must assign Certified Reserve Capacity and Reserve Capacity Obligations to those Facilities and must correspondingly reduce the Certified Reserve Capacity and Reserve Capacity Obligations associated with the Demand Side Programme during the time those Facilities are registered.~~

~~(d) After accounting for the modifications in (c), if at any time a Market Customer has Reserve Capacity Obligations associated with its Demand Side Programme then, for settlement purposes, the Demand Side Programme must be treated by the IMO as a Facility that has failed to satisfy its Reserve Capacity Obligations.~~

~~(e) Loads comprising the Demand Side Programme must have the same or higher availability as the Demand Side Programme.~~[Blank]

The proposed amendment will remove Stipulated Default Loads as there will no longer be any difference between a Demand Side Programme (previously referred to as Curtailable Load) and a Stipulated Default Load. The proposed amendments will also replace any references to Curtailable Loads with Demand Side Programmes. The IMO also proposed changes to ensure that availability of a Demand Side Programme allows for multiple calls (at least six). This will ensure that a programme could not specify availability for one 24 hour call. In this case the programme would meet its certification requirements but no longer be available during the Capacity Year.

4.10.1. The information to be submitted with an application for certification of Reserve Capacity must pertain to the Reserve Capacity Cycle to which the certification relates and must include:

…

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

iii. key project dates occurring after the date the request is submitted to the IMO, including, as applicable, but not limited to:

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

…

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

….

(f) for Interruptible Loads, ~~Curtailable Loads~~ Demand Side Programmes and Dispatchable Loads, details for each of up to three blocks of capacity of:

i. ~~either~~

~~1.~~ the Reserve Capacity expected to be available; ~~or~~

~~2. the Stipulated Default Load;~~

ii. the maximum number of hours per year the block is available to provide Reserve Capacity, where this must be not less than 24 hours;

iii. the maximum number of hours per day that the block is available to provide Reserve Capacity if called, where this must be not:

1. less than four hours; and

2. greater than the period specified in sub-clause (vi);

iv. the maximum number of times the block can be called to provide Reserve Capacity during a 12 month period, where this must be equal to or greater than six times;

v. the minimum notice period required for dispatch of the block, where this must not be more than 4 hours; and

vi. the periods when the block can be dispatched, which must include the period between noon and 8:00pm on all Business Days.

The proposed amendments will reflect that Demand Side Programmes will not have the same requirements as generators when applying for certification. In particular, currently the IMO can not take into account availability of the programme as specified in clause 4.10.1(f)(vi.).

4.11.1. Subject to clause 4.11.7, the IMO must apply the following principles in assigning a quantity of Certified Reserve Capacity to a Facility for the Reserve Capacity Cycle to which the application relates:

(a) subject to paragraphs (d), ~~and~~ (e), and (j) and clause 4.11.2, the Certified Reserve Capacity for a Facility for a Reserve Capacity Cycle is not to exceed the IMO's reasonable expectation as to the amount of capacity likely to be available from that Facility, after netting off capacity required to serve Intermittent Loads, embedded loads and Parasitic Loads, at daily peak demand times in the period from the:

…

(h) the IMO may decide not to assign Certified Reserve Capacity to a Facility if:

i. the Facility has operated for at least 36 months and has had a Forced Outage rate of greater than 15% or a combined Planned Outage rate and Forced Outage rate of greater than 30% over the preceding 36 months; or

ii. the Facility has operated for less than 36 months, or is yet to commence operation, and the IMO has cause to believe that over a period of 36 months the Facility is likely to have a Forced Outage rate of greater than 15% or a combined Planned Outage rate and Forced Outage rate of greater than 30%,

where the Planned Outage rate and the Forced Outage rate for a Facility for a period will be calculated in accordance with the Power System Operation Procedure. (The IMO may consult with System Management in deciding whether or not to refuse to grant Certified Reserve Capacity under this paragraph); ~~and~~

(i) the Certified Reserve Capacity assigned to a Facility is to be expressed to a precision of 0.001 MW~~.~~; and

(j) the Certified Reserve Capacity for a Demand Side Programme for a Reserve Capacity Cycle is not to exceed the IMO's reasonable expectation as to the amount of capacity likely to be available from that Facility for each block during each of the periods specified in clause 4.10.1 (f)(vi), after netting off capacity required to serve minimum loads, from the Trading Day starting on 1 October in Year 3 of the Reserve Capacity Cycle to the end of July in Year 4 of the Reserve Capacity Cycle.

The proposed amendment is consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove a Curtailable Loads association with the energy side of the WEM.

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

The IMO notes that the removal of this clause is required as it will no longer be necessary (and in most cases not possible) to calculate the Relevant Demand at the time of certification as the identity of the Non-Dispatchable Loads comprising the programme will not be known. This calculation will be undertaken in accordance with clause 2.29.5E.

4.11.4A. ~~If the capacity of a Curtailable Load is specified in accordance with clause 4.10.1(f)(i)(1), the Certified Reserve Capacity assigned by the IMO to that Curtailable Load, including during the registration of that Curtailable Load in accordance with clause 4.8.3(c), must not exceed the Relevant Demand for the Curtailable Load set by the IMO in accordance with clause 4.26.2C~~ [Blank]

The proposed amendment will remove the energy associated with a Curtailable Load from the determination of a Market Participant's Reserve Capacity Obligations as the energy will be incorporated into the energy consumption associated with the Non-Dispatchable Load (this is covered under the "energy to be consumed by the Market Participant…" aspect of sub-clause 4.12.1(a) iiA).

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

(a) a Market Participant (other than the Electricity Generation Corporation) must ensure that for each Trading Interval:

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

…

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

…

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

…

The proposed amendments will ensure that a Facility's RCOQ will be adjusted if a Demand Side Programme is dispatched by System Management.

The proposed amendments will ensure that periods when a Facility is undertaking a Reserve Capacity test will be treated additionally to a Facility's availability obligations. Demand Side Programmes will in general be available for up to 24 hours, where the 24 hours of availability is provided in six blocks of four hours. If a Facility is tested by the IMO in accordance with clause 4.25, it will only be tested for one hour. Under clause 4.12.4 currently, this test would use up one of the four hour blocks of availability for the Facility. However the changes to clause (i) and (ii) will mean that even with this change they will not be required to be available for more than 24 hours.

The IMO notes that there will be system changes required to implement this proposed amendment to the determination of a Facility's RCOQ. The IMO also notes that under the proposed amendments a Demand Side Programme will not be paid for the energy curtailed during the test.

4.12.4. Subject to clause 4.12.5, the IMO must apply the following principles in establishing the initial Reserve Capacity Obligation Quantity to apply for a Facility for a Trading Interval:

(a) the Reserve Capacity Obligation Quantity is not to exceed the Certified Reserve Capacity held by the Market Participant for the Facility;

…

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

i. must be ~~required~~ specified as dropping to zero once the capacity from the block has been dispatched ~~to be available~~ for ~~a~~ the number of hours per year ~~that does not exceed the maximum number of hours per year~~ as specified in accordance with clause 4.10.1(f)(ii);

ii. must be ~~required~~ specified as dropping to zero for the remainder of a Trading Day in which the capacity from the block has been dispatched ~~to be available~~ for ~~a~~ the number of hours per day ~~that does not exceed the maximum number of hours per day~~ as specified in accordance with clause 4.10.1(f)(iii);

iii. must be specified as dropping to zero once the capacity from the block has been ~~called~~ dispatched the maximum number of times per year, excluding where the Facility has been requested to perform a Reserve Capacity test in accordance with clause 4.25, as specified in accordance with clause 4.10.1(f)(iv); and

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

v. must be specified as zero for intervals which fall outside of the period specified in clause 4.10.1(f)(vi).

The proposed amendments to clauses 4.12.8, 4.14.1, 4.18.1 and 4.18.2 are consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove Curtailable Loads association with the energy side of the WEM.

4.12.8. Where a ~~Curtailable Load~~ Demand Side Programme is dispatched to a level equal to its Reserve Capacity Obligation Quantity on two consecutive days the Reserve Capacity Obligation Quantity for the following day shall be zero.

4.14.1. Subject to clause 4.14.3, each Market Participant holding Certified Reserve Capacity for the current Reserve Capacity Cycle must, by the date and time specified in clause 4.1.14 provide the following information to the IMO for each Facility or, in the case of Interruptible Loads, ~~Curtailable Loads~~ Demand Side Programmes and Dispatchable Loads with at least two blocks holding Certified Reserve Capacity in different Availability Classes, for each block in respect of which it holds Certified Reserve Capacity (expressed in MW to a precision of 0.001 MW):

…

4.18.1. A Reserve Capacity Offer must include the following information:

…

(c) a single Price-Quantity Pair for each Facility except for Interruptible Loads, ~~Curtailable Loads~~ Demand Side Programmes and Dispatchable Loads, where a single Price-Quantity Pair is to be included for each block of Certified Reserve Capacity associated with the Facility.

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

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

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

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

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

The proposed amendment will clarify the Trading Intervals during which the Demand Side Programme can be tested. This will be consistent with the periods identified for certification, as specified under clause 4.10.1(f) (vi).

4.25.1. The IMO must take steps to verify, in accordance with clause 4.25.2, that each Facility providing Capacity Credits:

(a) in the case of a generation system can, during the term the Reserve Capacity Obligations apply, operate at its maximum Reserve Capacity Obligation Quantity at least once during each of the following periods and such operation must be achieved on each type of fuel available to that Facility notified under clause 4.10.1(e)(v):

i. 1 October to 31 March; and

ii. 1 April to 30 September; and

(b) can, during the six months prior to the Reserve Capacity Obligations for the first Reserve Capacity Cycle taking effect, operate at its maximum Reserve Capacity Obligation Quantity at least once and, in the case of a generating system, such operation on each type of fuel available to that Facility notified under clause 4.10.1(e)(v). This paragraph (b) does not apply to facilities that are not commissioned prior to their Reserve Capacity Obligations coming into force.

(c) in the case of a ~~Curtailable Load~~ Demand Side Programme can, during the term the Reserve Capacity Obligations apply, and during the period specified in clause 4.10.1(f)(vi) operate at its maximum Reserve Capacity Obligation Quantity at least once during the period between 1 October to 31 March.

The proposed amendment is consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove Curtailable Loads association with the energy side of the WEM.

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

(a) by the IMO observing the Facility operate at the required level at least once as part of normal market operations in Metered Schedules specific to the Facility; or

(b) by the IMO:

i. in the case of a generation system, requiring System Management in accordance with clause 4.25.7 to test the Facility's ability to operate at the required level for not less than 60 minutes and the Facility successfully passing that test; and

ii. in the case of Interruptible Loads, ~~Curtailable Loads~~ Demand Side Programme and Dispatchable Loads, requiring System

Management, in accordance with clause 4.25.7, to test the Facility's ability to reduce demand to the required level for not less than one Trading Interval and the Facility successfully passing that test.

The proposed amendment is consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove Curtailable Loads association with the energy side of the WEM. The IMO also proposes to amend the requirement for the IMO to reduce the Capacity Credits for a Facility from "the next Trading Day" to "the next Scheduling Day". This is a manifest error in the Market Rules as due to the day ahead nature of the WEM it is not possible for the IMO to change a Facility's Capacity Credits for the next day (Trading Day). The IMO notes that this is currently a problem for all Facilities, including Curtailable Loads.

4.25.4. Subject to clause 4.25.3B, the IMO must, in the event that a Facility fails a Reserve Capacity test under clause 4.25.2(b), require System Management to re-test that Facility in accordance with clause 4.25.2(b), not earlier than 14 days and not later than 28 days after the first test. If the Facility fails this second test, then the IMO must, from the next ~~Trading Day~~ Scheduling Day:

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

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

The proposed amendment is consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove Curtailable Loads association with the energy side of the WEM.

4.25.4E. Where the Capacity Credits associated with a ~~Curtailable Load~~ Demand Side Programme are reduced in accordance with clause 4.25.4C the Market Participant must refund all Reserve Capacity Payments associated with the reduced Capacity Credits for the relevant Reserve Capacity Year to the IMO.

The proposed amendment is consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove Curtailable Loads association with the energy side of the WEM.

4.25.4F. A Market Participant may not offer a ~~Curtailable Load~~ Demand Side Programme for Supplementary Reserve Capacity if the ~~Curtailable Load~~ Demand Side Programme has had its Capacity Credits reduced in accordance with clause 4.25.4C for any part of that Capacity Year.

The proposed amendment is consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove Curtailable Loads association with the energy side of the WEM. The proposed amendment will also clarify the notice period System Management must give for before a Demand Side Programme can be tested. This will be consistent with the notice period identified for certification, as specified under clause 4.10.1(f) (v).

4.25.9. In conducting a test, System Management must:

(a) subject to paragraphs (b), (c) and (d), endeavour to conduct the test without warning;

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

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

(d) in the case of an Interruptible Load or a ~~Curtailable Load~~ Demand Side Programme allow sufficient time, in accordance with the information provided under clause 4.10.1(f)(v), for arrangements to be made for the Facility to be triggered;

(e) report to the IMO whether the test was successfully performed;

(f) maintain adequate records of the test to allow independent verification of the test results; and

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

The proposed amendment is consistent with the IMO's proposal that a DSP is not paid for any energy reduced during either a Reserve Capacity test or a Verification Test.

4.25.10. Where a Facility, excluding a Demand Side Programme, is tested in accordance with this clause 4.25, the Dispatch Schedule for that Facility during the period of the test is to reflect the energy scheduled in the test.

4.25A. Verification Test for a ~~Curtailable Load~~ Demand Side Programme

The proposed amendments will ensure that a verification test of a Demand Side Programme will occur during a period where the Non-Dispatchable Load associated with the Demand Side Programme would be likely to be operating. For example is a Facility has notified the IMO that if will be available between noon and 8pm, as part of its certification, the same Facility will not be able to use a period at midnight when all the comprising loads might be turned off as evidence that the Demand Side Programme is able to curtail to the required amount. The proposed amendment will also correct a current manifest error which would allow a programme to be tested both within 20 Business Days of registration, if applicable, or each year. The IMO considers that the requirement should be for a programme to be tested once after registration and then each year prior to 1 December in subsequent years. The IMO also proposes to amend the reference to Market Participants rather than Rule Participants when referring to the requirements for Verification Tests to be undertaken. The IMO considers that this was an oversight in RC_2008_20.

4.25A.1. A ~~Rule~~ Market Participant must undertake a Verification Test of each ~~Curtailable Load~~ Demand Side Programme registered by the ~~Rule~~ Market Participant during the period specified in clause 4.10.1(f)(vi) in each Reserve Capacity Year:

(a) within 20 Business Days of registration of the ~~Curtailable Load~~ Demand Side Programme, if applicable; or

(b) between 1 October and 30 November ~~of each Reserve Capacity Year~~.

The proposed amendment will ensure that when reviewing the results of a Verification Test the IMO will be certain that the test was as the result of an activation and not an instance of happenstance. For example the loads in the programme just happened to all be 10 percent lower because of normal variation. The IMO also proposes to amend the reference to Market Participants rather than Rule Participants when referring to the requirements for Verifications Tests to be undertaken.

4.25A.2. To undertake a Verification Test the ~~Rule~~ Market Participant will activate the ~~Curtailable Load~~ Demand Side Programme and ~~advise~~ provide evidence to the IMO of the Trading Intervals during which the Verification Test was conducted.

The proposed amendment is consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove Curtailable Loads association with the energy side of the WEM.

4.25A.3. The Verification Test is failed if a reduction in demand equal to at least 10% of the Capacity Credits is not identified from the ~~Curtailable Load~~ Demand Side Programme's meter data.

The proposed amendment is consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove Curtailable Loads association with the energy side of the WEM.

4.25A.4. Where a Verification Test is failed the IMO must reduce the Capacity Credits assigned to the ~~Curtailable Load~~ Demand Side Programme to zero.

The proposed amendment is consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove Curtailable Loads association with the energy side of the WEM. The IMO also proposes to amend the reference to Market Participants rather than Rule Participants when referring to the requirements for Verifications Tests to be undertaken.

4.25A.5. Where the Verification Test is failed the ~~Rule~~ Market Participant may request a second Verification Test be undertaken. If the ~~Curtailable Load~~ Demand Side Programme fails this second Verification Test then the Capacity Credits assigned are to remain at zero until the end of the relevant Reserve Capacity Year.

The proposed amendments will ensure that an undersubscribed Demand Side Programme will be required to make Capacity Cost Refunds if at any time the Demand Side Programme would not be able to deliver the level of capacity reduction for which it has been certified. Note that the requirement is for the value to be positive. This will ensure that a Demand Side Programme which is over subscribed will not receive a negative refund (essentially a payment from the market for being over subscribed).

4.26.1A. The IMO must calculate the Forced Outage refund for each Facility ("**Facility Forced Outage Refund**") as the lesser of:

(a) the sum over all Trading Intervals t in Trading Month m of the product of:

i the Off-Peak Trading Interval Rate or Peak Trading Interval Rate determined in accordance with the Refund Table applicable to Trading Interval t; and

ii the Forced Outage Shortfall in Trading Interval t,

where the Forced Outage Shortfall for a Facility is equal to which ever of the following applies:

iii. if the Facility is required to have submitted a Forced Outage under clause 3.21.4, the Forced Outage in that Trading Interval measured in MW; or

iv. if the Facility is an Intermittent Facility which is deemed to have not been commissioned, for the purposes of clause 4.26.1, the number of Capacity Credits associated with the relevant Intermittent Facility; or

v. if, from the Trading Day commencing on 30 November of Year 3 for Reserve Capacity Cycles up to and including 2009 or 1 October of Year 3 for Reserve Capacity Cycles from 2010 onwards, the Facility is undergoing an approved Commissioning Test and, for the purposes of permission sought under clause 3.21A.2, is a new generating system, the number of Capacity Credits associated with the relevant Facility; or

vi. if, from the Trading Day commencing on 30 November of Year 3 for Reserve Capacity Cycles up to and including 2009 or 1 October of Year 3 for Reserve Capacity Cycles from 2010 onwards, the Facility is not yet undergoing an approved Commissioning Test and, for the purposes of permission sought under clause 3.21A.2, is a new generating system, the number of Capacity Credits associated with the relevant Facility; ~~and~~ or

vii. if the Facility is a Demand Side Programme, the amount of the Relevant Demand minus the sum of the values specified in clause 2.29.5B(b) of the Associated Non-Dispatchable Loads is less than the Capacity Credits assigned to that Facility, where this amount must be a positive value.

…

The proposed amendment is consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove Curtailable Loads association with the energy side of the WEM.

4.26.1C. If a Market Participant holding Capacity Credits associated with a ~~Curtailable Load~~ Demand Side Programme fails to comply with its Reserve Capacity Obligations applicable to any given Trading Interval then the Market Participant must pay a refund to the IMO calculated in accordance with the provisions of this clause 4.26.

The proposed amendment to sub-clause (b) is consistent with the IMO's general removal of Curtailable Loads from the Market Rules and replacement with a Demand Side Programme. As there will be no energy associated with a Demand Side Programme (only capacity) the reference to Curtailable Load has not been replaced with a reference to Demand Side Programme in sub-clause (d). This will ensure that any energy associated with a load is not potentially double counted in the Net STEM Shortfall calculation.

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

....

(b) the sum of the product of:

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

ii. the Reserve Capacity Obligation Quantity for each Facility

for all Market Participant p's Registered Facilities, excluding ~~Curtailable Loads~~ Demand Side Programmes;

…

(d) subject to paragraph (c), for the case where Market Participant p is not the Electricity Generation Corporation, the sum of:

…

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

…

The proposed amendment to clause 4.26.2C and new clauses 4.26.2CA, 4.26.2CB, and 4.26.2CD will allow for a Demand Side Programme's Relevant Demand to be set at the level of the loads it has associated with it at any point in time. A Market Participant will be responsible for ensuring that a Non-Dispatchable Load is associated with a programme at an optimal time. In particular the proposed amendments will remove the reference to the eight consecutive highest system demand Trading Intervals and instead use the IRCR intervals in the calculation. Additionally, the proposed amendments will ensure that the Relevant Demand will be based on the Demand Side Programme as a whole (Issue 3(c)).

Note that a Demand Side Programme Load will be a negative value as the Metered Schedules for these loads are negative. This is reflective of the load drawing energy from the system.

The IMO proposes to introduce the concept of a Demand Side Programme Load which will be defined in Glossary and used as the basis for calculating the Required Level for a Demand Side Programme under the Rule Change Proposal: Reserve Capacity Security (RC_2010_12).

4.26.2C. The IMO must:

(a) Prior to the start of a Reserve Capacity Year for which a Demand Side Programme will have Reserve Capacity Obligations;

(b) at the request of a Market Participant who has a registered Demand Side Programme with Reserve Capacity Obligations for the current Reserve Capacity Year; or

(c) in accordance with clause 2.29.5E,

set the Relevant Demand in accordance with clause 4.26.2CA ,4.26.2CB, or 4.26.2CC, whichever is relevant.

~~(a) Identify the eight consecutive Trading Intervals with the highest aggregate system demand in each month during the preceding Hot Season;~~

~~(b) Subject to clause 4.26.2C(c), set the Relevant Demand (in MW) for the Curtailable Load equal to the median of the metered consumption during the 32 Trading Intervals identified in clause 4.26.2C(a), where the Relevant Demand is a positive number.~~

~~(c) Where the metered consumption during the 32 Trading Intervals identified in clause 4.26.2C(b) is not available the IMO must set the Relevant Demand based on:~~

~~i. Available Meter Data, or~~

~~ii. Load information provided by the Rule Participant, or~~

~~iii. Other relevant information.~~

~~(d) Where evidence is provided by the Market Customer that the Curtailable Load was operating at below capacity due to its consumption being reduced at the request of System Management or because of maintenance during one or more of the 32 Trading Intervals identified in clause 4.26.2C(a), the IMO must set the Relevant Demand based on the IMO's estimate of the Curtailable Load consumption during those intervals.~~

4.26.2CA Subject to paragraph clause 4.26.2C, the IMO must set the Relevant Demand (in MW) for the Demand Side Programme equal to the median of the sum of the

Metered Schedules of the associated Non Dispatchable Loads, adjusted to a non-loss adjusted value (“**Demand Side Programme Load**”), during the 12 peak Trading Intervals identified in Appendix 5 Step 1 where the Relevant Demand is a positive number.

4.26.2CB Where the metered consumption for an Associated Non- Dispatchable Load during the 12 Trading Intervals identified in clause 4.26.2CA is not available or is considered by the IMO to be inappropriate, the IMO must set the Metered Schedule for that load to be used in the Relevant Demand calculation in 4.26.2CA based on the latest median of the 4 peak Trading intervals identified in Appendix 5 Step 5 at the time the Non-Dispatchable Load is associated with the Demand Side Programme under clause 2.29.5B.

4.26.2CC Where evidence is provided by the Market Customer that the Demand Side Programme was operating at below capacity due to its consumption being reduced at the request of System Management during one or more of the Trading Intervals identified in clause 4.26.2CA or 4.26.2CB, the IMO must set the Relevant Demand (in MW) based on the IMO’s estimate of the Demand Side Programme’s consumption during those intervals.

The proposed amendments will remove the reference to Stipulated Default Loads from the IMO’s calculation of the Capacity Shortfall. This is consistent with the IMO’s merging of the concept of Curtailable Loads and Stipulated Default Loads. The proposed amendments will also remove the current reference to a Curtailable Load and replace this with a Demand Side Programme.

4.26.2D. The IMO must determine the capacity shortfall (“Capacity Shortfall”) in Reserve Capacity supplied by each Market Participant p holding Capacity Credits associated with a ~~Curtailable Load~~ Demand Side Programme in each Trading Interval t of Trading Day d and Trading Month m relative to its Reserve Capacity Obligation Quantity as:

(a) for Capacity Credits assigned in accordance with clause 4.10.1(f)(i)(1), and where System Management has issued a Dispatch Instruction to the ~~Curtailable Load~~ Demand Side Programme for the Trading Interval as advised to the IMO by System Management under clause 7.13.1:

i. zero; if negative two multiplied by the ~~Metered Schedule~~ Demand Side Programme Load is less than the Relevant Demand set in clause 4.26.2C minus the Capacity Credits assigned to the ~~Curtailable Load~~ Demand Side Programme;

ii. the greater of:

1. zero, or

2. the required decrease, in MW, minus the load reduction, where the load reduction is equal to the Relevant Demand set in clause 4.26.2C minus negative two multiplied by the ~~Metered Schedule~~ Demand Side Programme Load for the Trading Interval,

if the Capacity Credits assigned to the ~~Curtailable Load~~ Demand Side Programme are greater than the Dispatch Instruction for the Trading Interval; or

iii. negative two multiplied by the ~~Metered Schedule~~ Demand Side Programme plus the Capacity Credits assigned to the ~~Curtailable Load~~ Demand Side Programme minus the Relevant Demand set in clause 4.26.2C;

(b) ~~for Capacity Credits assigned in accordance with clause 4.10.1(f)(i)(2), and where System Management has issued a Dispatch Instruction to the Curtailable Load for the Trading Interval as advised to the IMO by System Management under clause 7.13.1:~~

~~i. zero, if negative two multiplied by the Metered Schedule is less than the Stipulated Default Load;~~

~~ii. the greater of:~~

~~1. zero, or~~

~~2. negative two multiplied by the Metered Schedule minus the load reduction, where the load reduction is equal to the Stipulated Default Load plus the Capacity Credits assigned to the Curtailable Load minus the Dispatch Instruction for the Trading Interval,~~

~~if the Capacity Credits assigned to the Curtailable Load are greater than the Dispatch Instruction for the Trading Interval; or~~

~~iii. negative two multiplied by the Metered Schedule minus the Stipulated Default Load, if the Capacity Credits assigned to the Curtailable Load are less than the Dispatch Instruction for the Trading Interval; and~~ [Blank]; and

(c) ~~for Capacity Credits assigned in accordance with either clause 4.10.1(f)(i)(1) or 4.10.1(f)(i)(2), and~~ where System Management has not issued a Dispatch Instruction to the ~~Curtailable Load~~ Demand Side Programme for the Trading Interval as advised to the IMO by System Management under clause 7.13.1, zero.

The proposed amendment will ensure that the calculation of the Capacity Cost Refund for a Demand Side Programme will capture the refund payments described in clause 4.26.1A.

4.26.3A. The Capacity Cost Refund associated with a ~~Curtailable Load~~ Demand Side Programme is equal to the lesser of:

(a) twelve times the Monthly Reserve Capacity Price multiplied by the number of Capacity Credits associated with the Facility, less all Capacity Cost Refunds applicable to the Market Participant in previous Trading Months falling in the same Capacity Year as Trading Month m; and

(b) the sum over all Trading Intervals t in Trading Month m of:

i. 12 * Monthly Reserve Capacity Price * S / (2 * H)

Where:

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

H is the maximum number of hours that the Facility was certified to be available in accordance with clause 4.10.1(f)(ii)~~.~~

plus;

ii. the Facility Forced Outage Refund determined in accordance with clause 4.26.1A.

The proposed amendment will ensure that the IMO will apply any revenue generated from the application of Capacity Cost Refunds from either a generating system (clause 4.26.3) or Demand Side Programme (clause 4.26.3A).

4.26.4. The IMO must apply any revenue generated from the application of clause 4.26.3 and 4.26.3A to Market Customers in accordance with clause 4.28.4.

The proposed amendment will remove the need to the IMO to calculate a consumption limit for a Curtailable Load – the consumption limit will be calculated for the Non-Dispatchable Load. This amendment is consistent with the IMO's general removal of Curtailable Loads from the Market Rules.

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 respected by that Market Participant in forming its STEM Submissions for each Trading Interval in the Trading Day:

…

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

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

…

The proposed amendment will ensure that in the case where a Demand Side Programme is requested to reduce its load by System Management it will be paid at the price it has specified in its Balancing Data Submission (as provided in clause 6.11A.1(d)(ii)) for the Trading Interval. In the case where the Market Participant has not provided a price for the Trading Interval the price to be applied will correspond with that specified in the Facility's Standing Data (as provided in accordance with Appendix 1 (h))

6.5A.1. Market Participants other than the Electricity Generation Corporation that are Market Generators or that are Market Customers with Dispatchable Loads or ~~Curtailable Loads~~ Demand Side Programmes may submit Balancing Data Submission data for a Trading Day to the IMO between:

…

The proposed amendment will remove the reference to a Curtailable Load. The demand to be consumed by the Market Participant will now be associated with the Non-Dispatchable Load.

6.11.1 A Market Participant submitting Resource Plan Submission data or Standing Resource Plan Submission data must include in the submission:

…

(d) the total Loss Factor adjusted demand to be consumed by that Market Participant for each Trading Interval including demand associated with any ~~Curtailable Load or~~ Interruptible Load, but excluding demand associated with any Dispatchable Load; and

…

The proposed amendment will remove the current exclusion of Curtailable Loads from Resource Plan Submission data. This is consistent with the removal of Demand Side Programmes from the energy side of the market.

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

…

(c) it must not include Interruptible Loads~~ or Curtailable Loads~~; and

…

The proposed amendment is consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove Curtailable Loads association with the energy side of the WEM.

6.11A.1. A Market Participant submitting Balancing Data Submission data must include in the submission:

…

(d) for each Demand Side Programme ~~Curtailable Load~~ registered by the Market Participant:

…

The proposed amendment will remove the reference to Scheduled Generators and Dispatchable Loads and replace this with a Registered Facility. The Dispatch Merit Order should list Scheduled and Non-Scheduled Generators, Dispatchable Loads, Interruptible Loads and Demand Side Programmes. The reference to Registered Facility will cover all these classes of Market Participant. The IMO notes that the class of Registered Facility also includes the Network Operator, but as it is not possible to dispatch the Network Operator this should not be an issue. The proposed amendment is consistent with the IMO's general removal of the term Curtailable Load from the Market Rules.

6.12.1.

(a) By 1:30 PM on the Scheduling Day, (or within 40 minutes of a closing time extended in accordance with clause 6.5.1(b) or clause 6.5A.1(b)), the IMO must determine the Dispatch Merit Orders identified in paragraphs (b) to (g). A Dispatch Merit Order lists the order in which the Registered Facilities ~~Scheduled Generators and Dispatchable Loads~~ of Market Participants other than the Electricity Generation Corporation will, in the absence of transmission limitations or limitations necessary to maintain Power System Security, be issued Dispatch Instructions to increase or decrease output.

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

i. this Dispatch Merit Order must list all Scheduled Generators, ~~Curtailable Loads~~ Demand Side Programmes and Dispatchable Loads registered by Market Participants other than the Electricity Generation Corporation;

…

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

i. this Dispatch Merit Order must list all Scheduled Generators, ~~Curtailable Loads~~ Demand Side Programmes and Dispatchable Loads registered by Market Participants other than the Electricity Generation Corporation;

..

(h) Where the prices in Balancing Data or payments described in Standing Data, as applicable, for two or more Registered Facilities ~~Market Participants~~ are equal, then for the purpose of determining the ranking in any Dispatch Merit Order other than those for decommitment, the IMO must rank a Registered Facility with a greater sent out capacity registered in Standing Data before a Registered Facility with a lesser sent out capacity. For a Dispatch Merit Order for decommitment, the IMO must rank a Registered Facility with a greater name plate capacity registered in Standing Data before a Registered Facility with a lesser name plate capacity.

The proposed amendment will remove the requirement for the Dispatch Schedule to equate to the Metered Schedule for a Curtailable Load as the Dispatch Schedule (and any deviations) will be now captured by the Non-Dispatchable Load. Note that a Demand Side Programme will not have a Dispatch Schedule or a Metered Schedule associated with it under the IMO's proposed amendments.

6.15.2. The Dispatch Schedule for a Trading Interval for any of the following Facilities equals the corresponding Metered Schedule:

(a) a Non-Scheduled Generator;

(aA) a Scheduled Generator to which clauses 3.21A.14 or 4.25.10 apply;

(b) a Non-Dispatchable Load;

(c) ~~a Curtailable Load;~~ [Blank]

(d) an Interruptible Load;

(e) a Scheduled Generator or Dispatchable Load registered by the Electricity Generation Corporation; and

(f) a Scheduled Generator or Dispatchable Load registered by a Market Participant (other than the Electricity Generation Corporation) where a

Dispatch Instruction of the type described in clause 7.7.3(d)(ii) was issued to the Market Participant in respect of the Facility.

The proposed amendment will reference clause 9.3.3 which notes that a Demand Side Programme has no Metered Schedule. This is similar to a network, which is also a Registered Facility that does not have a Metered Schedule. The IMO considers that this will improve the integrity of the Market Rules and is consistent with the IMO's general removal of Demand Side Programmes from the energy side of the market.

6.16.1. Subject to 9.3.3, ~~T~~the Metered Schedule for a Trading Interval for a Registered Facility or Non-Dispatchable Load is determined by the IMO in accordance with clause 9.3.4.

The proposed amendment will limit the Dispatch Instruction Payment made to a Market Participant with a registered Demand Side Programme to only occurring when System Management requests the programme to reduce its consumption. Currently the IMO is required to make a Dispatch Instruction Payment to a Curtailable Loads in all intervals where they are operating below their Relevant Demand level. The IMO also proposes to remove the reference to "issued instructions described under either (c) or (d)" as in both cases the Non-Scheduled Generator or Demand Side Programme are Registered Facilities and so will have been issued Dispatch Instructions by System Management. The proposed amendments will also remove the current reference to a Stipulated Default Load. The IMO notes that the proposed amendment is to the Amending Rules which will commence as a result of RC_2008_20 on 1 October 2011. As a result the following proposed amendments would not also commence until 1 October 2011.

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:

(a) zero, if Market Participant p:

i is the Electricity Generation Corporation; or

ii was issued no Dispatch Instructions ~~or was issued instructions described by either (c) or (d) for the Trading Interval~~;

…

(d) the sum over all ~~Curtailable Loads~~ Demand Side Programmes registered by the Market Participant of the amount that is the product of:

i. the quantity by which the ~~Curtailable Load~~ Demand Side Programme reduced its consumption at the request of System Management, where the quantum of reduction in any Trading Interval is equal to the lesser of:

1. ~~for a Curtailable Load that has nominated that its measurement is to be based on its Capacity Credits, the quantum of reduction in any Trading Interval is to be equal to half of the lesser of~~ half of the Reserve Capacity (in MW),

2. half of the Dispatch Instruction amount (in MW) provided by System Management in accordance with clause 7.1.13(eC); and

3. the difference between the Relevant Demand set in clause 4.26.2C and negative two multiplied by the Demand Side Programme Load ~~twice the absolute value of the metered quantity~~ (in MW~~h~~) measured in the Trading Interval; and

~~2. for a Curtailable Load that has nominated that its measurement is to be based on the Stipulated Default Load, the quantum of reduction in each Trading Interval is to equal half of the lesser of the Relevant Demand (in MW) minus Stipulated Default Load (in MW), and the Relevant Demand (in MW) minus twice the absolute value of the metered quantity (in MWh) measured in the Trading Interval; and~~

ii. the price defined in ~~clause 6.11A.1(d)(ii)~~ the Market Participant's Balancing Data Submission provided in accordance with clause 6.5A, that was current at the time of the Trading Interval, for the ~~Curtailable Load~~ Demand Side Programme (accounting for whether the Trading Interval is a Peak Trading Interval or an Off-Peak Trading Interval).

…

The proposed amendment will remove the requirement for System Management to maintain a dataset of Forced Outages and Consequential Outages for Curtailable Loads. The IMO does not propose to require System Management to maintain this same data set for a Demand Side Programme as it is not possible for a Demand Side Programme to experience a Forced Outage.

7.1.1. System Management must maintain the following data set, and must use this data set when determining which Dispatch Instructions it will give:

…

(i) Scheduled Generator, Non-Scheduled Generator, Dispatchable Load, ~~Curtailable Load~~ and Interruptible Load Forced Outages and Consequential Outages by Trading Interval received from Market Participants in accordance with clause 3.21;

…

The proposed amendments to clauses 7.2.2 and 7.6.10 are consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove Curtailable Loads association with the energy side of the WEM.

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

(a) represent Non-Dispatchable Load~~, Curtailable Load~~ and Interruptible Load net of forecast Non-Scheduled Generation;

…

7.6.10. Where a Market Participant has Capacity Credits granted in respect of a ~~Curtailable Load~~ Demand Side Programme:

(a) the IMO must provide System Management with the details of the Reserve Capacity Obligations to enable System Management to dispatch the ~~Curtailable Load~~ Demand Side Programme.

(b) System Management may issue directions to the ~~Curtailable Load~~ Demand Side Programme in accordance with the Reserve Capacity Obligations.

The proposed amendment will allow System Management to issue a Dispatch Instruction to a Demand Side Programme which specifies the required decrease quantity (measured against the Relevant Demand level). As System Management will no longer issue instructions to each individual load the IMO considers it would be more appropriate for System Management to request a Demand Side Programme to reduce its consumption by an amount rather than to reduce to a specific level.

The IMO notes that this is similar to the current requirement specified in clause 7.7.5D (which will be amended to being [Blank] on 1 October 2011 in accordance with RC_2008_20)

7.7.3. Each Dispatch Instruction must contain the following information:

(a) the Registered Facility to which the Dispatch Instruction relates;

(b) the time the Dispatch Instruction was issued;

(c) the time by which response to the Dispatch Instruction is required to commence (which must not be earlier than the time it was issued, except as contemplated by clause 7.7.7(b);

(d) the required level of sent out generation or consumption which may be either:

i. a target MW output; ~~or~~

ii. a minimum MW level; or

iii. a required decrease in MW;

(e) the ramp-rate to maintain until the required level of sent out generation or consumption is reached.

The proposed amendments to clause 7.7.4, 7.7.4A, 7.7.10 and 7.13.1 are consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove Curtailable Loads association with the energy side of the WEM.

7.7.4. System Management must determine which Facilities will be the subject of Dispatch Instructions by applying the Dispatch Merit Order relevant to the action required, except where:

…

(c) the Dispatch Merit Order would otherwise require that System Management dispatch a Demand Side Programme ~~curtail a Curtailable Load~~ when, due to limitations on the availability of the Demand Side Programme ~~Curtailable Load~~, such ~~curtailment~~ dispatch would prevent that Demand Side Programme ~~Curtailable Load~~ from being available to System Management at a later time when it would have greater benefit with respect to maintaining Power System Security and Power System Reliability.

7.7.4A. When selecting Demand Side Programmes ~~Curtailable Loads~~ from the Dispatch Merit Order System Management must select them in accordance with the Power System Operation~~s~~ Procedure, where the selection process specified in the Power System Operation~~s~~ Procedure must only discriminate between Demand Side Programmes ~~Curtailable Loads~~ based on size of the capacity, response time, availability and cost of different Demand Side Programmes ~~Curtailable Loads~~.

7.7.10 When System Management has issued a ~~d~~Dispatch ~~i~~Instruction to a Demand Side Programme ~~Curtailable Load~~ to reduce demand it may issue a further instruction terminating the requirement for the Demand Side Programme ~~Curtailable Load~~ to reduce demand providing that:

(a) Such instruction is issued no less than four hours before it is to come into effect, and

(b) The minimum period for which the Demand Side Programme ~~Curtailable Load~~ has been instructed to reduce demand is not less than two hours.

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

…

(eC) the required decrease, in MWh, ~~in the consumption~~ of each ~~Curtailable Load~~ Demand Side Programme, by Trading Interval, as a result of System

Management Dispatch Instructions, where this is to be used in settlement as the quantity described in clause 6.17.6(d)(i).

(g) details of the instructions provided to:

i. ~~Curtailable Loads~~ Demand Side Programme that have Reserve Capacity Obligations; and

ii. providers of Supplementary Capacity;

…

The proposed amendment will specify the types of Facilities that the IMO will determine a Metered Schedule for. Under the proposed amendments a Metered Schedule will not be determined for a Demand Side Programme. This will ensure that a Demand Side Programme is only paid for its capacity and not any energy.

9.3.3. The IMO must determine the Metered Schedule for each of the following Facilit~~y~~ies ~~and Non-Dispatchable Load~~ for each Trading Interval~~.~~:

(a) Non-Dispatchable Load;

(b) Interruptible Load;

(c) Dispatchable Load;

(d) Scheduled Generator; and

(e) Non-Scheduled Generator.

The proposed amendment will amend the clause to list the specific types of Facilities. This will correct for the current situation where this requirement would be applied to a Network Operator.

9.3.4. Subject to clause 2.30B.10, the Metered Schedule for a Trading Interval for each of the following ~~a~~ Facilities ~~or Non-Dispatchable Load,~~:

(a) Non-Dispatchable Load, excluding those Non-Dispatchable Loads referred to in clause 9.3.4A;

(b) Interruptible Load;

(c) Dispatchable Load;

(d) Scheduled Generator; and

(e) Non-Scheduled Generator,

~~,~~ is the net quantity of energy generated and sent out into the relevant Network or consumed by the Facility ~~or Non-Dispatchable Load (as applicable)~~ during that Trading Interval, Loss Factor adjusted to the Reference Node, and determined from Meter Data Submissions received by the IMO in accordance with clause 8.4

or SCADA data received from System Management in accordance with clause 7.13.1(cA) where interval meter data is not available.

The proposed amendment is consistent with the IMO's general removal of the term Curtailable Load from the Market Rules. This will remove Curtailable Loads association with the energy side of the WEM. There will also no longer be a Metered Schedule determined for a Curtailable Load.

9.3.7. The IMO must determine the Consumption_Share(p,m) for Market Participant p in each Trading Month m, which equals

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

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

where the contributing quantity for a Market Participant for Trading Month m is the sum of the Metered Schedules for the Non-Dispatchable Loads, Interruptible Loads~~, Curtailable Loads,~~ and Dispatchable Loads registered to the Market Participant for all Trading Intervals during Trading Month m.

The proposed amendment will remove the reference to Curtailable Load as there will be no Metered Scheduled calculated for these types of loads.

9.13.1. The applicable Market Participant Fee settlement amount for Market Participant p for Trading Month m is:

MPFSA(p,m) = (-1) x (Market Fee rate + System Operation Fee rate
+ Regulator Fee rate) x
(Monthly Participant Load(p,m) + Monthly Participant Generation(p,m))

Where

Market Fee rate is the charge per MWh for IMO's services determined in accordance with clause 2.24.2 for the year in which Trading Month m falls;

System Operation Fee rate is the charge per MWh for System Management's services determined in accordance with clause 2.24.2 for the year in which Trading Month m falls;

Regulator Fee rate is the charge per MWh for funding the Economic Regulation Authority's activities with respect to the Wholesale Electricity Market determined in accordance with clause 2.24.2 for the year in which Trading Month m falls;

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

where

Metered Load(p,d,t) for a Market Participant p for a Trading Interval t is the sum of the mathematical absolute values of the Metered Schedules for the Non-Dispatchable Loads, Dispatchable Loads~~,~~ and Interruptible Loads~~ and Curtailable Loads~~, registered to the Market Participant for Trading Interval t; and

Monthly Participant Generation(p,m)

= Sum($d \in D, t \in T$, Metered Generation(p,d,t));

where

Metered Generation(p,d,t) for Market Participant p for Trading Interval t is the sum of the mathematical absolute values of the Metered Schedules for Scheduled Generators and Non-Scheduled Generators, registered to the Market Participant for Trading Interval t; and

D is the set of all Trading Days in Trading Month m, where “d” is used to refer to a member of that set;

T is the set of all Trading Intervals in Trading Day d, where “t” is used to refer to a member of that set.

The proposed amendment will remove the status of Metered Schedule information for a Curtailable Load as being public. Under the proposed amendments there will be no longer a Metered Schedule calculated for a Curtailable Load. The proposed amendment will also remove the clarification that the Capacity Credits not be published for each Curtailable Load comprising of a DSP. This will no longer be necessary as there will be no visibility to the market of the Loads comprising a DSP.

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:

…

(f) the following Reserve Capacity information (if applicable):

iv. for each Market Participant holding Capacity Credits, the Capacity Credits provided by each Facility for each Reserve Capacity Cycle. In the case of a Market Participant with a Demand Side Programme, the IMO must publish the total Capacity Credits for the programme ~~and not for each Curtailable Load comprising the programme~~;

…

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

i. the values of MCAP, UDAP and DDAP;

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

iii. the sum of the Metered Schedule load for all Non-Dispatchable Load, Dispatchable Load~~,~~ and Interruptible Load ~~and Curtailable Load~~;

iv. estimates of the energy not served due to involuntary load curtailment; and

v. any shortfalls in Ancillary Services;

…

Chapter 11: Glossary

Associated Non-Dispatchable Load: Has the meaning given in clause 2.29.5B

~~**Curtailable Load**: A Load through which electricity is consumed where such consumption can be curtailed at short notice by the party managing the Load or in response to a request from System Management to the party managing the Load, and registered as such in accordance with clause 2.29.5(b).~~

Demand Side Programme: Means a programme, registered in accordance with clause 2.29.5A, under which a Market Customer contracts Loads to be available for curtailment upon request of the Market Customer or System Management.

Demand Side Programme Load: Has the meaning given in clause 4.26.2C.

Facility Classes: Network, Scheduled Generator, Non-Scheduled Generator, Interruptible Load, ~~Curtailable Load~~ ~~and~~ Dispatchable Load and Demand Side Programme.

Facility Forced Outage Refund: Has the meaning given in clause 4.26.1A

Load: Has the meaning given in clause 2.29.1D

Non-Dispatchable Load: A Load which is not a Dispatchable Load~~, a Curtailable Load~~ or an Interruptible Load, and is therefore self scheduled. Non-Dispatchable Loads can be associated with Demand Side Programmes in accordance with clause 2.29.5D.

Relevant Demand: The consumption of a ~~Curtailable Load~~ Demand Side Programme as determined in clause 4.26.2C. Relevant Demand is used to ~~set the maximum Certified Reserve Capacity that can be assigned to a Curtailable Load. It is also used to~~ determine Reserve Capacity shortfalls.

~~**Stipulated Default Load**: The maximum energy consumption to be maintained by an Interruptible Load, Curtailable Load or Dispatchable Load if activated, as specified in its Reserve Capacity Obligations.~~

The proposed amendment will remove the energy associated with the Demand Side Programme from being provided as Standing Data. This is consistent with the IMO's general removal of energy from being connected with a Demand Side Programme. The IMO notes that the proposed amendments also remove requirements for Standing Data that would no longer be relevant for a Demand Side Programme (these requirements relate to the underlying Loads comprising the programme which will no longer be visible to the market).

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 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.

(a) for a Network:

…

(h) for a ~~Curtailable Load~~ Demand Side Programme:

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 2.3~~6~~5 are in place and operational;

iii. the maximum amount of load that can be curtailed;

iv. the maximum duration of any single curtailment;

v. [Blank]

vi. for a facility that is registered to a Market Participant other than the Electricity Generation Corporation, Standing Balancing Data comprising;

1. a Consumption Decrease Price for Peak Trading Intervals; and

2. a Consumption Decrease Price for Off-Peak Trading Intervals;

where these prices must be not less than the Minimum STEM Price, not more than the Alternative Maximum STEM Price, and must be expressed in units of $/MWh to a precision of $0.01/MWh;

vii. the minimum response time before the facility can begin to respond to an instruction from System Management to change its output;

~~viii. the Metering Data Agent for the facility;~~

~~ix. the single line diagram for the facility, including the locations of transformers, switches, operational and settlement meters;~~

x. ~~the network nodes at which the facility can connect;~~

xi. ~~the short circuit capability of facility equipment;~~

xii. ~~whether the Curtailable Load is an Intermittent Load~~;

xiii. ~~if the Curtailable Load is an Intermittent Load, the maximum allowed level of Intermittent Load, where this cannot exceed the quantity in (i);~~

xiv. ~~if the Curtailable Load is an Intermittent Load, the maximum level of net consumption behind the meter associated with the Curtailable Load which is not separately metered and which is not Intermittent Load~~; and

xv. ~~if the Curtailable Load is an Intermittent Load, the separately metered generating systems and loads behind that meter associated with the Curtailable Load which are not to be included in the definition of that Intermittent Load.~~

…

(k) For each Registered Facility:

i. Reserve Capacity information including:

5. for Interruptible Loads and ~~Curtailable Loads~~Demand Side Programmes, the maximum number of times that interruption can be called during the term of the Capacity Credits;

…

The proposed amendment will ensure that Demand Side Programmes are explicitly assigned an Availability Class and so not automatically included in Availability Class 1. This is consistent with the decision made under RC_2008_20: DSM – Operational Issues, that Availability Class 1 should comprise of only generation to ensure that sufficient generation is brought into the system to limit energy shortfalls as required by clause 4.5.9(b). The IMO notes that the proposed revised clause 4.11.4 will specify that a Demand Side Programme must not be assigned to Availability Class 1.

Appendix 3: Reserve Capacity Auction & Trade Methodology

This appendix describes a single algorithm which performs two functions. One version of the algorithm is used to prevent the IMO accepting bilateral trades that have insufficient availability to usefully address the Reserve Capacity Requirement. Another version of the algorithm is used in the conduct of the Reserve Capacity Auction as required by clause 4.19.1.

The parameter "a" denotes the active Availability Class where "a" can have a value of {1, 2, 3, 4}. For the purpose of identifying which capacity can be applied to satisfying capacity requirements the minimum availability of each Availability Class is set to the maximum availability of the next Availability Class. However the algorithms in this appendix allow capacity from an Availability Class with high availability to be used in place of capacity from an Availability Class with lower availability. The following table indicates the required availability of capacity offered for each Availability Class:

Availability Class (i.e. value of "a")	Minimum Hours of Availability Per Year	Maximum Hours of Availability Per Year
1	96	All
2	72	96
3	48	72
4	24	48

All Certified Reserve Capacity associated with Interruptible Loads, ~~Curtailable Loads~~ Demand Side Programmes or Dispatchable Loads is explicitly assigned an Availability Class, whereas all other Certified Reserve Capacity is automatically in Availability Class 1.

…

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

The IMO's assessment of the impact of each of the proposed changes is presented below:

Issue 1: Registration of a Curtailable Load

The IMO considers the changes proposed to remove the concept of a CL as a Registered Facility from the Market Rules and replace this with the concept of the DSP being the Registered Facility will have the following impact on the Market Objectives.

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

The IMO considers that the proposed amendments will promote Market Objective (a) by allocating the risks associated with determining appropriate Loads for inclusion in Demand Side Programmes from the IMO to the DSM providers (the correct party to manage these). This will promote greater economic efficiency.

Issue 2: Facility Definition

The IMO considers the changes proposed to allow for the registration of a DSP as a Registered Facility will have the following impact on the Market Objectives:

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

The IMO considers that the proposed amendments will promote Market Objective (a) by allowing System Management to issue a Dispatch Instruction to the DSP provider, who would then decide how to deliver the requested curtailment. This would improve the allocative efficiency of System Management resources.

The proposed amendments will also promote Market Objective (b) by ensuring that DSM can be used more effectively as a competitive product. By removing a potential barrier to System Management being able to effectively dispatch a DSP provider's portfolio of NDLs, the IMO considers that System Management will be able to more effectively rely on the provision of load reduction services as an alternative to generation. This will promote greater competition between generators and DSM providers in the WEM.

The IMO considers that the proposed amendments, which:

- allow System Management to issue a Dispatch Instruction to the DSP provider; and
- DSM to be used more effectively as a competitive product,

will also promote Market Objective (e) as these effects combined will further encourage the taking of measures to manage the amount of electricity used and when it is used.

Issue 3: Market Fees

The IMO notes that it does not propose any amendments to the current Market Fee requirements for DSPs.

Issue 4: Measurement of Curtailable Load performance

The IMO considers the changes proposed to amend the calculation of the Relevant Demand to be based on the aggregated output of the DSP and be calculated on the IRCR intervals will have the following impact of the Market Objectives.

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

The IMO considers that by considering the consumption of a DSP at the aggregated level (rather than for each individual Load) a DSP will be treated equivalently to Market Generators whose output is currently measured at one connection point (which incorporates behind the fence load).

Issue 5: Capacity Cost refunds

The IMO considers the changes which will require a Market Participant to make Capacity Credit refunds where its DSP has not be filled will have the following impact on the Market Objectives:

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

The IMO considers that the proposed amendment would promote Market Objective (a) by requiring a DSP which fails to meet its capacity obligations to pay refunds to the level at which it didn’t meet its obligations. For the Reserve Capacity Mechanism to operate effectively, it is essential that there are the correct incentives for DSP to be fully available at all times (particularly during the Hot Season and peak times).

The requirement for a DSP to make refunds at any time when it would not be able to deliver the level of capacity reduction for which it has been certified, will better reflect the incentive structure the Refund Mechanism was intended to provide. The proposed amendment will promote the reliable supply of energy in the SWIS.

Issue 6: Reserve Capacity Security

The IMO notes that it does not propose any amendments within this rule change proposal to the reserve Capacity Security provisions for DSPs. These amendments are contained in RC_2010_12: Required Level and Reserve Capacity Security.

Issue 7: Stipulated Default Loads

The IMO considers the using the current Relevant Demand calculation provisions for Curtailable Loads, rather than Stipulated Default Loads will have the following impact on the Market Objectives:

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

The IMO considers that the proposed amendments would promote Market Objective (a) by ensuring that a more rigorous and accurate estimate of a Loads reduction in consumption is obtained will ensure that the Capacity Credits assigned to a Facility will more accurately reflect the true availability of a Demand Side Programme. The proposed changes will ensure that the safe and reliable supply of electricity can be maintained by System Management.

Issue 8: Potential Double Payment

The IMO considers that the proposal to clarify that DSPs are not be paid for any energy reduced during either a Reserve Capacity test or Verification Test will be consistent with the Market Objectives.

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

Costs:

- Updates to the IMO's systems will be required.

Benefits:

- Reduce complexity within the Market Rules associated with CLs and DSPs;
- Clearly delineate between the energy market and capacity mechanism aspects of DSPs; and
- Allocate the risks associated with determining appropriate Loads for inclusion in Demand Side Programmes from the IMO to the DSM providers (the correct party to manage these).

- Remove the current energy market cross subsidy associated with DSP's undertaking Reserve Capacity test or Verification Tests.

Agenda Item 7f: Limits to early entry capacity payments (PRC_2010_30)

1. BACKGROUND

Currently the timeframe for new capacity to enter the Reserve Capacity Mechanism is a four-month window centralised around the start of a new Capacity Year on 1 October (the window for entry is between 1 August and 30 November). This timeframe allows new Facilities to enter the market and receive the benefit of Capacity Credits and any associated income stream from 1 August of Year 3 of the Reserve Capacity Cycle. The current window of entry applies for Reserve Capacity Cycles up to and including 2009.

In 2009, the IMO proposed to retain the four month window of entry but brought the window forward to start on 1 June, with all capacity to be fully available no later than 1 October each year[1]. This new timeframe allows new Facilities to enter the market and receive the benefit of Capacity Credits and any associated income stream from 1 June of Year 3 of the Reserve Capacity Cycle. This changed window of entry applies for Reserve Capacity Cycles from 2010 onwards.

Alinta has submitted a Pre-Rule Change Discussion Paper (attached as appendix 1) which seeks to preclude any newly accredited Facility's that are not Scheduled or Non-Scheduled Generators from being able to receive Capacity Credit payments prior to the close of the Reserve Capacity window in the year that the Reserve Capacity Obligation first applies.

The MAC discussed the Pre-Rule Change Discussion Paper at its 13 October 2010 meeting. The following issues were discussed:

- Alignment of the proposal with the 1 October Reserve Capacity Year or the close of the window of entry. The MAC agreed that it was more appropriate that the proposal align with the 1 October Reserve Capacity Year;
- The commissioning activities undertaken by DSM aggregators i.e. installation of pulse meters;
- The potential regulatory risk associated with implementation of the Rule Change Proposal for the 2009 and 2010 Reserve Capacity Cycles given that DSM aggregators have already contracted on the current Market Rules currently in effect; and
- The assessment of the proposal against the Wholesale Market Objectives.

As a result of the MAC discussion, the IMO engaged Marchment Hill Consulting to undertake as assessment of the Rule Change Proposal against the Wholesale Market Objectives. This assessment is attached as appendix 2 to this paper.

3. RECOMMENDATIONS

The IMO recommends that the MAC:

- **Discuss** the assessment against the Wholesale Market Objectives.

[1] www.imowa.com.au/RC_2009_11

Agenda item 7f, appendix 1:

Wholesale Electricity Market
Pre Rule Change Proposal Form

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

Change requested by:

Name:	Corey Dykstra
Phone:	9486 3749
Fax:	9221 9128
Email:	corey.dykstra@alinta.net.au
Organisation:	Alinta Sales Pty Ltd
Address:	Level 9, 12-14 The Esplanade, PERTH WA 6000
Date submitted:	<date submitted to the IMO>
Urgency:	1 - High
Change Proposal title:	Limits to early entry capacity payments
Market Rule(s) affected:	4.1.26

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:

Rule Change Proposal

The Rule Change Proposal is for any **newly** accredited Facility that is not a Scheduled or a Non-Scheduled Generator to be precluded from being able to receive capacity payments prior to the close of the reserve capacity window in the year that the Reserve Capacity Obligation first applies (i.e. 1 December 2011 and thereafter 1 October).

The effect of the proposed rule change would be to preclude **newly** accredited Curtailable Loads, Dispatchable Loads and Interruptible Loads from being able to receive capacity payments prior to 1 December 2011 or thereafter 1 October in the year that the Reserve Capacity Obligation first applies.

Background

Capacity from newly accredited Facilities may currently be made available to the market at any time during a four-month window (currently between 1 August and 30 November) centralised around 1 October. Market Participants are able to nominate any date within the window, and may revise their expected entry date as the project nears completion.

It is understood that the objective of allowing 'new' Facilities to enter the market and receive Capacity Credit payments from as early as 1 August was to encourage 'new' Scheduled or Non-Scheduled Generators to enter the market as early as possible, so that should there be any subsequent delays in commissioning and/or unplanned outages (i.e. Forced Outages) then these events would be less likely to affect the security and reliability of the power system over the summer period when demand reaches system peaks.

From 2012 onwards, the four-month window will shift, so that capacity payments may be received as early as 1 June in the year that the Reserve Capacity Obligation first applies.

The early entry of new capacity imposes a financial cost on the market as the capacity price is not adjusted to account for the additional capacity made available to the market. However, it appears that this additional cost has been judged as being appropriate in order to support the effective commissioning of new scheduled or non-scheduled generation, which then reduces the risk to power system security and reliability over the summer period when demand reaches system peaks.

Reason for the Rule Change Proposal

An outcome of the early entry provisions of the Market Rules is that capacity provided by any newly accredited Facility is able to receive capacity payments as early as 1 August (or 1 June from 2012) in the year that the Reserve Capacity Obligation first applies. Such newly accredited 'Facilities' include capacity from Curtailable Loads, Dispatchable Loads and Interruptible Loads.

- For capacity year 2011/12, which commences on 1 October 2011, if all of the estimated capacity provided by newly accredited Curtailable Loads sought to receive capacity payments from 1 August 2011, the estimated additional cost to the market would be around $2.5 million.
- For capacity year 2012/13, which commences on 1 October 2012, it is estimated that more than 400 MW of Curtailable Load has been accredited, which represents an increase of around 200 MW on the amount accredited for the 2011/12 capacity year. If all of the estimated capacity provided by these newly accredited Curtailable Loads sought to receive capacity payments from 1 June 2012, the estimated additional cost to the market would be around $8.5 million.

Alinta considers that the risk to power system security and reliability associated with capacity provided by newly accredited Facilities that are not Scheduled or Non-Scheduled Generators differs materially to that of newly accredited Scheduled or Non-Scheduled Generators.

This is principally because capacity provided by newly accredited Facilities that are not Scheduled or Non-Scheduled Generators (i.e. Curtailable Loads, Dispatchable Loads and Interruptible Loads) are typically existing loads, and so would not be expected to require an extended period to ensure they are 'commissioned'. Even if newly accredited Curtailable Loads, Dispatchable Loads and Interruptible Loads were not existing loads, it appears unlikely that capacity provided by such loads would represent a risk to the security and reliability of the power system over the summer period when demand reaches system peaks.

Consequently, Alinta considers that the additional cost to the market of **newly** accredited Facilities that are not Scheduled or Non-Scheduled Generators receiving capacity payments prior to 1 October in the year that the Reserve Capacity Obligation first applies cannot be justified based on the reduction in risk to power system security and reliability over the summer period when demand reaches system peaks.

2. Explain the reason for the degree of urgency:

It appears that for the 2009/10 capacity year, a significant proportion of the capacity from newly accredited Facilities that were not Scheduled or Non-Scheduled Generators sought to receive capacity payments from the earliest possible date, being 1 August 2010.

It appears reasonable to assume that for future capacity years, capacity from newly accredited Facilities that were not Scheduled or Non-Scheduled Generators will similarly seek to receive capacity payments from the earliest possible date, being 1 August 2011 and then from 1 June each year.

Given the unprecedented increase in capacity being made available to the market from newly accredited Facilities that are not Scheduled or Non-Scheduled Generators, the resulting cost to the market will be significant.

As noted above, it is considered that the additional cost imposed on the market due to **newly** accredited Facilities that are not Scheduled or Non-Scheduled Generators receiving capacity payments prior to 1 October in the year that the Reserve Capacity Obligation first applies cannot be justified based on the reduction in risk to power system security and reliability over the summer period when demand reaches system peaks.

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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)

4.1.26. Reserve Capacity Obligations apply:

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

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

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

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

(b) for subsequent Reserve Capacity Cycles up to and including 2009:

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

ii. from the Trading Day commencing on the scheduled date of commissioning, as specified in accordance with clause 4.10.1(c)(iii)(7), or as revised in accordance with clause 4.27.11A or clause 4.27.11D, for Scheduled and Non-Scheduled Generation Facilities commissioned between 1 August of Year 3 and 30 November of Year 3~~.~~; and

iii. from the Trading Day commencing on 1 December of Year 3, for Interruptible Loads, Curtailable Loads or Dispatchable Loads; and

(c) for subsequent Reserve Capacity Cycles from 2010 onwards:

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

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

iii. from the Trading Day commencing on 1 October of Year 3, for Interruptible Loads, Curtailable Loads or Dispatchable Loads.

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

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

Alinta considers that the Rule Change Proposal as proposed to be amended or replaced, are consistent with, and better achieve, the Wholesale Market Objectives. Specifically, Alinta considers that the Rule Change Proposal would:

- better achieve Market Objective (a) as it would reduce the cost to the market by not paying for new capacity where such payment does not provide commensurate market benefits;
- better achieve Market Objective (b) as it removes an incentive for the inefficient early entry of capacity from Facilities that are not Scheduled or Non-Scheduled Generators;
- better achieve Market Objective (c) by avoiding discrimination in that market against particular energy options and technologies, as the need to commission Scheduled and Non-Scheduled Generators makes it practically impossible for capacity from these Facilities to be made available to the market at the start of the reserve capacity window (i.e. 1 August 2011 or 1 June thereafter);
- better achieve Market Objective (d) by minimising the long-term cost of electricity supplied to customers from the South West interconnected system; and
- is not inconsistent with Market Objective (e).

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

Alinta has not been able to identify that there would be any costs associated with the Rule Change Proposal.

As outlined above, if all of the estimated capacity provided by newly accredited Curtailable Loads sought to receive capacity payments in 2011 and 2012, the estimated additional cost to the market would be around $11 million.

It appears reasonable to assume that for future capacity years, capacity from newly accredited Facilities that were not Scheduled or Non-Scheduled Generators will similarly seek to receive capacity payments from the earliest possible date, being 1 June each year.

Given the unprecedented increase in capacity being made available to the market from newly accredited Facilities that are not Scheduled or Non-Scheduled Generators, the resulting cost to the market will be significant.

Agenda Item 7f, appendix 2: MHC assessment against the Wholesale Market Objectives

Conclusion and recommendations (from MHC)

Market Objective	Impact	Rationale for assessment
(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system	**Minor positive** (on balance)	Likely to reduce quantity of early-commissioned capacity (positive) BUT socialises commissioning risks (negative)
(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors.	**No impact**	
(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.	**Major negative**	The rules change is prima facie discriminatory with no evidence to suggest a market benefit from favouring one type of capacity provider over another.
(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system.	**Minor positive**	Reducing the quantity of early-commissioned capacity will reduce the total cost of capacity to the market
(e) to encourage the taking of measures to manage the amount of electricity used and when it is used	**No impact**	

1. MHC finds the most significant impact of the proposed Rule Change to be negative in terms of Objective (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.*
2. MHC notes however the likelihood that positive impacts in terms of Objectives (a) and (d) could be expected from the proposed Rule Change.

Agenda Item 7g: Acceptable Credit Criteria (RC_2010_36)

1. BACKGROUND

Credit Support or Reserve Capacity Security provided by a Market Participant (or Network Operator in the case of Credit Support) must be from an entity (Provider) that meets the Acceptable Credit Criteria (ACC), as set out in clauses 2.38.6 and 4.13.7 respectively. To confirm whether the Provider meets the ACC a Market Participant (or Network Operator) must complete the Acceptable Credit Criteria Form (ACC Form) available on the IMO's website. One requirement of this process is ensuring that the ACC Form has been signed by a solicitor who is a partner of reputable commercial law firm acceptable to the IMO.

A number of Market Participants have raised concerns with the IMO that it is difficult to find a solicitor that will sign the ACC Form due to the requirement for the solicitor to certify that the Provider meets the ACC by stating that the they have reviewed *all* relevant martial. The IMO has also found that the short timeframes associated with providing security along with a signed ACC Form increase this difficulty of finding a solicitor who is able to fulfil the requirements of the ACC Form. The IMO notes that this can have significant financial effects on Market Participants, including a potential reduction in Certified Reserve Capacity (CRC).

Synergy has proposed an amendment to these requirements in its Rule Change Proposal titled Acceptable Credit Criteria (RC_2010_36). Specifically, Synergy proposes to remove the need for a Market Participant (or Network Operator in the case of Credit Support) to have a solicitor sign the ACC Form by requiring the IMO to maintain a list of Providers which meet the ACC.

Note that prior to the start of the 2010 CRC process, the IMO amended the ACC Form to allow for the solicitor to state that their declaration was based on their *opinion* rather than that their responses were 100 percent true and correct. The IMO received some positive feedback from Market Participants during the CRC process that this small change had helped with the issue of finding a solicitor to sign the ACC Form. This change however does not address the issue raised by Synergy that a solicitor cannot review *all* relevant material – only that which is publically available.

2. IMO REVIEW OF ACC REQUIREMENTS

The IMO agrees that the proposed amendments will remove the issue associated with Market Participants (or Network Operators) being able to have their ACC Form signed off by a solicitor. Additionally, the IMO considers that the proposed amendments will address the issues associated with short timeframes identified in section 1 above.

The IMO however notes that it has recently engaged an external Consultant to conduct a review of the issues raised by Market Participants around the ACC requirements and in particular the associated timeframes. The results of this review are expected to be made available to the IMO by the end of November 2010.

The IMO notes that the findings of the review may offer a complementary or alternative methodology to that proposed by Synergy. Following from the outcomes of this review the IMO will progress either a separate Rule Change Proposal or Procedure Change Proposal, as applicable.

3. RECOMMENDATIONS

The IMO recommends that the MAC:

- **Note** the changes proposed under RC_2010_36 have been formally submitted into the Rule Change Process.

Agenda item 7g, appendix 1

Wholesale Electricity Market
Rule Change Proposal Form

Change Proposal No: *RC_2010_36*
Received date: *29 October 2010*

Change requested by:

Name:	Catherine Rousch
Phone:	6212 1125
Fax:	
Email:	catherine.rousch@synergy.net.au
Organisation:	Synergy
Address:	228 Adelaide Terrace Perth 6000
Date submitted:	29 October 2010
Urgency:	1-low
Change Proposal title:	Acceptable Credit Criteria
Market Rule(s) affected:	2.38.6, 4.13.7, and new clauses 2.38.6A, 2.38.6B, 4.13.7A and the Glossary

Introduction

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

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

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

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

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

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

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

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

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

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

Details of the proposed Market Rule Change

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

Under clause 2.38.1 of the Market Rules, any time a Market Participant or a Network Operator, does not meet the Acceptable Credit Criteria set out in clause 2.38.6, then the Market Participant or Network Operator must ensure that it provides the IMO with Credit Support.

To confirm whether the Credit Support meets the Acceptable Credit Criteria listed in clause 2.38.6 a Market Participant or Network Operator must, under the Market Procedure for Prudential Requirements, complete the Acceptable Credit Criteria Form (**Form**) (refer to Appendix A) available on the IMO's website. This includes ensuring that the Form has been signed by a solicitor of reputable commercial law firm acceptable to the IMO.

Synergy has found a growing reluctance by solicitors to sign the Form as it requires responses to statements concerning the credit provider. Solicitors can only base their responses on information in the public domain and, as such, are reluctant to be held accountable for failings of the credit provider.

The IMO provides, on its website, a List of Acceptable Credit Providers (**List**). This List (refer to Appendix B) includes financial institutions that the IMO has deemed as meeting the Acceptable Credit Criteria. The List preamble indicates that the financial institution inventory will be reviewed and updated annually.

Synergy proposes a change to the Market Rules such that, for the purposes of clause 2.38.6, an entity is deemed to meet the Acceptable Credit Criteria if it is on the IMO's List. A solicitor signed Form would not be required for such an entity providing the Credit Support.

2. Explain the reason for the degree of urgency:

This Rule Change Proposal is not considered urgent. However, its acceptance will ensure a faster and more streamlined approach to submitting Credit Support.

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)

2.38.6. An entity meets the Acceptable Credit Criteria if it is:

(a) either:

i. under the prudential supervision of the Australian Prudential Regulation Authority; or

ii. a central borrowing authority of an Australian State or Territory which has been established by an Act of Parliament of that State or Territory;

(b) resident in, or has a permanent establishment in, Australia;

(c) not an externally-administered body corporate (within the meaning of the Corporations Act), or under a similar form of administration under any laws applicable to it in any jurisdiction;

(d) not immune from suit;

(e) capable of being sued in its own name in a court of Australia; and

(f) has an acceptable credit rating, being either:

i. a rating of A-1 or higher for short term unsecured counterparty obligations of the entity, as rated by Standard and Poor's (Australia) Pty. Limited; or

ii. a rating of P-1 or higher for short term unsecured counterparty obligations of the entity, as rated by Moodys Investor Services Pty. Limited~~.~~ ; or

(g) if it is named on the List of Acceptable Credit Providers posted on the Market Web Site.

2.38.6A If an entity is named on the List of Acceptable Credit Providers then the Market Participant or Network Operator is not required to submit an Acceptable Credit Criteria Form to the IMO.

2.38.6B The IMO must maintain a list of Acceptable Credit Criteria providers on the Market Website (**List of Acceptable Credit Providers**), and must update this list at least once a year before 1 April.

4.13.7. An entity meets the Acceptable Credit Criteria if it is:

(a) either:

i. a bank under the prudential supervision of the Australian Prudential Regulation Authority; or

ii. a central borrowing authority of an Australian State or Territory which has been established by an Act of Parliament of that State or Territory;

(b) resident in, or has a permanent establishment in, Australia;

(c) not an externally-administered body corporate (within the meaning of the Corporations Act), or under a similar form of administration under any laws applicable to it in any jurisdiction;

(d) not immune from suit;

(e) capable of being sued in its own name in a court of Australia; and

(f) has an acceptable credit rating, being either:

i. a rating of A-1 or higher for short term unsecured counterparty obligations of the entity, as rated by Standard and Poor's (Australia) Pty. Limited; or

ii. a rating of P-1 or higher for short term unsecured counterparty obligations of the entity, as rated by Moodys Investor Services Pty. Limited~~.~~; or

(g) if it is named on the List of Acceptable Credit Providers posted on the Market Web Site.

4.13.7A If an entity is named on the List of Acceptable Credit Providers then the Market Participant is not required to submit an Acceptable Credit Criteria Form to the IMO.

List of Acceptable Credit Providers: Listing of acceptable financial institutions posted on the Market Web Site and updated annually in accordance with clause 2.38.6B.

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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 proposed Market Rule change would allow the Market Rules to better address Wholesale Market Objectives:

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

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

by ensuring a more simple, efficient and cheaper way of certifying that an entity meets the Acceptable Credit Criteria.

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

Engaging a solicitor to complete the Form for an entity already deemed by the IMO as meeting the Acceptable Credit Criteria is expensive and time-consuming and the additional costs incurred are ultimately passed on to end consumers.

Appendix A - Acceptable Credit Criteria Form

VERSION 3.1

ACCEPTABLE CREDIT CRITERIA FORM

"**Entity**" means:

Name of entity --

ABN (if applicable): --

Principal address: --

Please specify a contact person for the entity

Name --

Title --

Telephone --

Email --

Please provide a response ("true" or "false") in respect of each statement for the entity:

Statement	**Response (indicate "true" or "false")**
1. The entity is: (a) under the prudential supervision of the Australian Prudential Regulation Authority;	
(b) a central borrowing authority of an Australian State or Territory which has been established by an Act of Parliament of that State or Territory.	
2. The entity resides in, or has a permanent establishment in Australia.	
3. The entity is **not** an externally administered body corporate (within the meaning of the Corporations Act), or under a similar form of administration under any laws applicable to it in any jurisdiction.	
4. The entity is **not** immune from suit.	
5. The entity is capable of being sued in its own name in a court of Australia.	

6. The entity has a: (a) rating of A-1 or higher for short term unsecured counterparty obligations of the entity, as rated by Standard and Poor's (Australia) Pty Limited;	
(b) rating of P-1 or higher for short term unsecured counterparty obligations of the entity, as rated by Moodys Investor Services Pty Limited.	

Solicitor's Certificate

I *[Solicitor name]* of *[insert address]*, solicitor, certify as follows:

1. I am a partner of *[name of reputable commercial law firm]*.
2. I have examined all material relevant to the verification of the above statements as I have considered necessary or appropriate and have carried out such searches as I have deemed relevant and necessary.
3. Based on 2., in my opinion each response given above is true and correct and no response is misleading or deceptive either by reason of content or by reason of any omission.
4. I am aware the Independent Market Operator will be relying on the responses given to the above statements as being true and correct and not misleading or deceptive in assessing whether the entity meets the Acceptable Credit Criteria under clause 2.38.6 of the Wholesale Electricity Market Rules.
5. That the *[insert as applicable: Letter of Credit for Credit Support / Deed of Guarantee for Credit Support / Deed of Security Deposit for Credit Support]* executed by the entity is consistent with the most recent proforma version available from the Independent Market Operator and only modified to the extent contemplated in the proforma version.

Dated the day of 200 .

Signature:

Appendix B - List of Acceptable Credit Providers

List of Acceptable Credit Providers

An entity providing Security must meet the Acceptable Credit Criteria set out in clause 4.13.7 or 2.38.6 of the Market Rules as appropriate.

Following is the list of financial institutions that have met the Acceptable Credit Criteria and may be used for applications for Prudential Support. This list will be reviewed and updated annually. Rule Participants may use other financial institutions to provide Security by following the process outlined in the Prudential Requirements Procedure as appropriate.

Australia and New Zealand Banking Group Limited
ABN: 11 005 357 522
100 Queen Street, Melbourne, VIC 3000

Queensland Treasury Corporation
ABN: 15 736 217 171
Level 14, 61 Mary Street, Brisbane, QLD 4000

Westpac Banking Corporation
ABN: 33 007 457 141
Level 3, 255 Elizabeth Street, Sydney, NSW 2000

Commonwealth Bank of Australia
ABN: 48 123 123 124
Level 7, 48 Martin Place, Sydney, NSW 2000

Bank of Western Australia
ABN: 22 050 494 454
BankWest Tower, 108 St Georges Terrace, Perth, WA 6000
Citibank, N.A.
ABN: 34 072 814 058
2 Park Street, Sydney, NSW 2000

Agenda Item 8a: 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_2009_09	Supplementary Reserve Capacity (SRC)	The proposed new Market Procedure describes the process that the IMO and System Management will follow in: • acquiring Eligible Services, • entering into SRC Contracts; • determining the maximum contract value per hour of availability for any contract; and • Details the information that is required to be exchanged. This Market Procedure needs to be published (as required by the Market Rules) and will be revised following any rule changes (if applicable).	Discussed at Working Group Meeting 7 (26 October 2010)	• IMO to submit into Procedure Change Process	November 2010
PC_2010_01	Procedure Administration	The proposed update is to revise to conform to recently adopted style changes.	Final report published 1 November.	• To commence 8 November 2010.	8 November 2010

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
PC_2010_02	Notices and Communications	The proposed update is to revise to conform to recently adopted style changes.	Final report published 1 November.	• To commence 8 November 2010.	8 November 2010
PC_2010_03	Monitoring Protocol	The proposed updates are to: • Allow the IMO to disclose the identity of System Management as a participant that notifies us of alleged breaches; and • Update to conform to recently adopted style changes.	Discussed at Working Group Meeting 7 (26 October 2010)	• The IMO to submit into the Procedure Change Process.	November 2010
PC_2010_05	Reserve Capacity Performance Monitoring	The proposed updates are to: • Include the changes to the Amending Rules arising from RC_2010_11, RC_2009_19 and RC_2010_02; • Update to conform to recently adopted style changes.	Undergoing final IMO review prior to formally submitting into the Procedure Change Process.	• The IMO to submit into the Procedure Change Process.	November 2010
PC_2010_06	Certification of Reserve Capacity	The proposed updates are to: • ensure that an appropriate amount of CRC for each Facility is set, and allow the IMO to determine the viability of a new project and its prospects of proceeding through to completion before the start of the relevant Capacity Year • specify the steps for applying for and approving Early Certified Reserve Capacity. This will ensure consistency with the Rule Change Proposal: Early Certified Reserve Capacity (RC_2009_10); and • improve the integrity of the Market Procedure by including a number of minor and typographical amendments.	Final Report being prepared.	• IMO preparing Final Report	November 2010

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
PC_2010_07	Market Procedure for Web Site Changes	The proposed updates are to: • Updated to the new IMO procedures format; • expand the associated market documents to include the confidentiality status document (step 1.4.2); and • note the process where System Management has not been delegated the authority to directly post information or documents on the Market Web Site (step 2.1.1).	Discussed at Working Group Meeting 7 (26 October 2010)	• The IMO to submit into the Procedure Change Process.	November 2010
System Management Procedure Change Proposals					
PPCL0016	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. 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.	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.	TBD
	Facility Outages	The proposed update is to amend the procedure to reflect the commenced RC_2010_05 'Confidentiality of Accepted Outages by System Management'.	Discussed at Working Group Meeting (28 October 2010)	• System Management to submit into the Procedure Change Process.	TBD
	Commissioning and Testing	The proposed update is to amend the procedure to reflect the commenced RC_2010_37 'Equipment Tests'.	Discussed at Working Group Meeting (28 October 2010)	• System Management to submit into the Procedure Change Process.	TBD

Agenda Item 9: 2011 Review of MAC Composition

1. BACKGROUND

Clause 2.3.9 of the Wholesale Electricity Market Rules (Market Rules) requires that the Independent Market Operator (IMO) annually review the composition of the Market Advisory Committee (MAC). The IMO may remove and appoint members following the review.

2. POSITIONS FOR RENEWAL

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

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

RC_2010_15: MAC Membership Review commenced on 1 November 2010. Therefore the IMO has the ability to appoint at least three and not more than four Market Customer and Market Generator representatives (with Synergy and Verve Energy being compulsory members in each of their representative classes). Therefore there are an additional two positions available on the MAC:

- One Market Customer; and
- One Market Generator.

It should be noted that when appointing members to the MAC the IMO must use reasonable endeavours to ensure equal representation of Market Generators and Market Customers.

3. IMO'S REVIEW AND ASSESSMENT PROCESS

At the October 2010 MAC meeting, it was agreed that the IMO continue in its role selecting the MAC Discretionary members. However, during this discussion it was noted that transparency was an important aspect of the process.

A detailed assessment process to ensure that the representation of the MAC was balanced had been undertaken by the MAC Evaluation committee (an internal IMO committee) during the 2010 review. However, this process was not evident to all stakeholders and therefore it was agreed that the IMO would publish this process for all stakeholders for the 2011 Review.

The following table outlines the process that the IMO will follow for the 2011 review:

Step	Event	Date
1	IMO assess the positions up for renewal (see section 2 of this paper for the 2011 positions available).	Before November MAC meeting.
2	IMO inform the MAC that the annual review is about to commence.	November MAC meeting.
3	IMO prepare a call for nominations for the available	End of November, closing

Step	Event	Date
	membership positions.	late December.
4	IMO establish an internal evaluation panel (comprising members from across the organisation[1]) to assess all nominations received and ensure a high standard of probity is maintained.	Before close of call for nominations.
5	IMO prepare an Evaluation Panel handbook (attached as appendix 1 to this paper) outlining what each panel member is required to do. This includes: • Assessment of the nominees against the pre-qualification[2] and compliance criteria[3]; • Assessment of the nominees against the qualitative criteria using the information provided in the response to the call for nominations[4]; and • Rating each nominee against the qualitative criteria using a pre-defined rating 0 – 9 point rating scale.	Before close of call for nominations.
6	Panel members assess each nominee in accordance with the Evaluation Panel handbook.	Following close of call for nominations and before the end of January.
7	Evaluation Panel meeting to determine a consensus score for each of the nominees.	
8	Evaluation Panel create a shortlist of candidates for each class based on the consensus qualitative ranking.	
9	To ensure an appropriate balance of skills and experience the Evaluation Panel will undertake the second stage assessment including reviewing the relevant qualifications, years of experience and backgrounds of nominees to determine the best possible composition for the MAC (taking into account the relevant skills and experiences of the compulsory members).	
10	Draft a recommendation report to present to the MAC Chair for review.	
11	Evaluation panel to reassess its recommendations (if required).	

[1] The Evaluation Panel will contain members from Market Development, Legal and Compliance, Finance and Administration and Market Operations teams from the IMO. Please note, Troy Forward will not be a member of the Evaluation Panel due to the potential conflict of interest arising from the requirement for the panel to assess his application. Additionally, Allan Dawson is not a member of the Evaluation Panel. This is to allow for a separate assessment step (as MAC Chair) and to ensure a rigorous process.

[2] These are: Nomination lodged on time and confirmation that the nominee is an employee or consultant employed by the Rule Participant.

[3] These are: Nomination form completed in full, contains the details of the class applying for, and meets the requirements to represent the class it has applied for.

[4] Demonstrated skills, experience and knowledge of energy sector issues (20%); Demonstrated skills and knowledge of the WEM (30%); Demonstrated ability to contribute actively to the MAC (30%); and Relevant background (20%).

Step	Event	Date
12	Prepare a recommendation report to present to the IMO Board for its review and approval.	February Board meeting.
13	The IMO Board to decide the MAC membership. Following the Board's decision, inform the nominees of the outcome of the assessment process.	End of February.
14	All MAC members (incoming and outgoing) to attend a handover MAC meeting.	March MAC meeting.

The IMO has included the information contained in section 3 of this paper in the MAC Appointment Guidelines as tracked changes (attached as appendix 2 to this paper).

4. TIMELINES FOR 2011 REVIEW

The following specific timelines for the 2011 review are expected:

- 29 November 2010 – Call for nominations;
- 22 December 2010 – Nominations closing date;
- 15 January 2011 – IMO convene the Evaluation Panel;
- 9 February 2011 – Current MAC members attend MAC meeting;
- 17 February 2011 – IMO Board ratify the new MAC membership;
- 18 February 2011 – Letters sent to existing MAC members and nominees outlining the IMO's decision; and
- 9 March 2011 – New and previous MAC members attend the March 2011 MAC meeting.

Further details of the process involved and requirements for applications are outlined in the MAC Constitution and MAC Appointment Guidelines which will be made available on the IMO website: http://www.imowa.com.au/market-advisory-committee

6. RECOMMENDATIONS

It is recommended that the MAC:

- **Note** the IMO's review and assessment pocess;
- **Note** the amended MAC Appointment Guidelines; and
- **Note** this timelines for the 2011 review.

A GUIDE FOR "[DATE] MARKET ADVISORY COMMITTEE REVIEW" EVALUATION PANEL MEMBERS

Title:	[DATE]Market Advisory Committee Review Evaluation Panel Handbook
Agency:	Independent Market Operator
IMO Contact Persons:	Jacinda Papps (08) 9254 4353 0421 585 114 jacinda.papps@imowa.com.au

1 OVERVIEW

1.1 BACKGROUND

The purpose of this evaluation handbook is to assist members of the [DATE] Market Advisory Committee (MAC) Review Evaluation Panel (the Evaluation Panel) to assess nominations for membership on the MAC for the [DATE] calendar year. The evaluation handbook provides information in relation to:

a) The evaluation process and timetable of events;

b) Assessing nominations for representatives to serve on the MAC during 2010 and procedural fairness; and

c) Scoring sheets for undertaking the assessment.

1.2 EVALUATION PANEL – KEY OBJECTIVES

The key objectives of the panel are to:

a) Make a recommendation, to the Market Development team of the Independent Market Operator (IMO), as to the nominees that would best represent the market's interests and collectively possess the required skills, knowledge and experience, as outlined in section 4.2 of the MAC Appointment Guidelines Document;

b) Ensure the assessment of nominations is undertaken fairly and impartially according to a predetermined weighting schedule; and

c) Ensure that the requirements specified in the request for nominations are evaluated in a way that can be measured and documented.

The IMO Chief Executive Officer will make the final decision and recommend appropriate representatives to the IMO Board for endorsement.

1.3 EVALUATION PANEL MEMBERS

The members of this evaluation panel are:

Name	Job Title	Voting/Non Voting Member
		Chair, non voting
		Voting
		Voting
		Voting
		Minutes, non voting

2 THE EVALUATION PROCESS

2.1 SUMMARY

The proposed evaluation process is as follows:

a) Following the closing of nominations, panel members will receive a copy of each nomination along with this evaluation handbook, these nominations will be split into compulsory members (if reviewing) and discretionary members[1];

b) The handbook contains an evaluation scoring sheet for each of the MAC nominees;

c) Panel members will individually score each nominee against each qualitative criterion using the 0-9 rating scale provided in section 5.3.1 of this handbook;

d) The panel will then meet and reach a consensus score for each nominee;

e) The panel will undertake a skills gap assessment to determine any potential weaknesses in the composition of the MAC based on the top rated nominees;

f) Based on the individual assessments and the skills gap assessment, the panel shall reach a consensus as to the recommended nominees to be short-listed for further clarification;

g) A draft recommendations report will then be written which summarises the evaluation process;

h) Panel members, once satisfied with the content of the recommendations report, shall sign off on the report;

i) The recommendations report will then be considered for endorsement by the IMO's CEO and approval by the IMO Board; and

j) Upon endorsement and finalisation of any outstanding issues, an acceptance letter will be issued to the successful nominees.

[1] Note that Members who represent a single entity (System Management, the IMO, the Electricity Generation Corporation, the Electricity Retail Corporation, and the Electricity Networks Corporation) are Compulsory class members. Members who represent a class of participants but are not compulsory members (Market Generators, Market Customers, Network Operators, small-use consumers, and Contestable Customers) are Discretionary class members.

3 TIMETABLE OF EVENTS

3.1 TIMETABLE

For this request, the proposed timetable of events is as follows:

TASK	DATE
MAC nominations close	
Handout evaluation handbooks	
Handout of tender submissions	
Panel members individually assess tender submissions	
Panel meets to discuss nominations and reach a consensus score	
Clarification / short listing process (if required)	
Recommendations report draft prepared by Market Development	
Recommendations discussed and agreed with Chair	
Board paper with recommendations to Board	
Board approval of recommendations	
All applicants advised in writing of the outcomes of the appointment process	
All new and previous members of the MAC to attend the March MAC meeting	

3.2 NOMINATIONS RECEIVED

The details of the nominees as received by the IMO and a copy of their respective nominations and any additional supporting information will be provided to Panel members on [DATE].

4 PROCEDURES & PRINCIPLES FOR EVALUATION OF NOMINATIONS TO SERVE ON THE MAC

4.1 INTRODUCTION

Each year the IMO is required to assess the composition of the MAC. The IMO has recently undergone a process of reviewing the MAC Constitution and associated Market Rules in order to develop a robust and transparent annual review process.

As an outcome of the review the IMO proposed a number of changes to the Market Rules[2] and MAC Constitution and developed the MAC Appointment Guidelines. These changes enable the IMO to have a basis for making changes to the MAC membership on an annual basis and to make appointments to the MAC on the basis of merit. Prior to these changes the IMO had no basis specified in the constitutive documents of MAC for changing membership.

As there is now 'excess demand' for membership on the MAC the IMO must ensure that its evaluation of nominations meets appropriate standards of probity. Evaluation Panel's are part of these processes and, therefore, it is important that members of the MAC [DATE] Review Evaluation Panel are aware of the principles underlying probity.

Note that the IMO has also detailed selection criteria in the Appointment Guidelines document and developed a standard application form for nominees to ensure probity in the Evaluation Panel's decisions. A copy of each of these documents will be provided to the Evaluation Panel.

4.2 WHY SHOULD EVALUATION PANEL MEMBERS BE CONCERNED ABOUT PROCESS

There are two main reasons why members of the Evaluation Panel should be concerned:

a) Nominees are entitled to a fair process; and

b) Failing to follow a fair process may lead to the IMO being subject to criticism which would potentially raise questions about the integrity of the MAC and its role in advising the IMO.

4.3 WHAT ARE THE REQUIREMENTS OF FAIRNESS

The following principles must be adhered to in the nomination evaluation process:

[2] See: RC_2009_28: MAC Constitution and Operating Practices

4.3.1 APPROPRIATE KNOWLEDGE

Before commencing on the nomination evaluation process, the Evaluation Panel and any supplementary members must have an understanding of:

a) The contents of each nomination;

b) The selection criteria against which nominations will be rated as outlined in section 2.4 of the Appointment Guidelines document; and

c) The process by which each nomination will be rated.

4.3.2 RELEVANT CONSIDERATIONS

The Evaluation Panel must consider all relevant considerations related to each nomination. This would include the nominees responses to the selection criteria and any other supporting information nominees have provided. If information is considered irrelevant, the reason must be stated in the selection report.

4.3.3 IRRELEVANT CONSIDERATIONS

The nomination evaluation process must not be based on irrelevant considerations, that is, anything outside the selection criteria or information requested in the standard application form. Material changes to the nomination evaluation process should be communicated, in writing, to all interested parties where the original process had previously been communicated to them.

4.3.4 BIAS

The nomination evaluation process must be free of bias and any perception of bias. Any connections between an Evaluation Panel member and a nominee must be disclosed to the Evaluation Panel Chairperson.

Any possible issue of bias should be discussed with the Evaluation Panel Chairperson as soon as it arises.

4.3.5 EVIDENCE OF PROBITY

Evaluation ratings and selections must be made on the basis of the material requested and included in the nomination rather than mere speculation or suspicion.

4.3.6 CONFIDENTIALITY

The contents of each nomination should not be disclosed to any party outside of the formal evaluation process. Each nomination should be viewed as confidential information.

4.4 RECORDING OF NOMINEES SCORES

The Evaluation Panel and any supplementary members must fully record their nomination evaluation against the selection criteria.

4.5 CONCLUSION

By observing and implementing these guidelines, the Evaluation Panel and any supplementary members will ensure that the nomination evaluation process is 'visible', and auditable.

Following these guidelines not only ensures that the nomination evaluation process is fair, but also helps to ensure that the best MAC for the market is determined.

5 SCORING THE NOMINATIONS

5.1 SUMMARY

In this section information will be provided as to:

a) Assessing the different components of the nomination;

b) Assessing the overall composition of the MAC; and

c) The scoring rating scales.

5.2 ASSESSING THE NOMINATIONS

There are four stages:

5.2.1 PRE-QUALIFICATION REQUIREMENTS

The first stage of the evaluation process is determining whether the nomination meets the pre-qualification requirements. The pre-qualification requirements are not point scored. Rather, an assessment is made on a "yes/no" basis. In making this assessment, a nomination must comply with every detail of every requirement.

The Market Development Team will assess this section and provide the information to the Evaluation Panel at the consensus meeting.

5.2.2 COMPLIANCE CRITERIA

The second stage of the evaluation process is determining whether the nomination meets the compliance criteria. The compliance criteria are not point scored. Rather, an assessment is made on a "yes/no" basis.

The Market Development Team will assess this section and provide the information to the Evaluation Panel at the consensus meeting.

5.2.3 QUALITATIVE CRITERIA

For those nominations that are compliant, an evaluation is then made of each nominee's response to the questions in the member nomination form. A rating scale of 0-9 is used to evaluate each nominee's response. A copy of the rating scale is shown in section 5.3.1 of the handbook.

In considering the score to be given to a nominee for each requirement, evaluation panel members should consider:

a) Whether the nominee understands the qualitative requirements;

b) Whether the nominee has the capability in relation to the qualitative requirements (as provided in their written application and any supporting information provided); and

c) The level of confidence that the Evaluation Panel has that the nominee will be able to meet each requirement.

This is to be completed by each Evaluation Panel member prior to the consensus meeting. At the consensus meeting the Evaluation Panel will need to come to a consensus score for each qualitative criterion for each nominee.

5.2.4 COMPOSITIONAL CRITERIA

Once the Panel has evaluated each nomination it will determine the top rated nominees for each representative class and undertake an assessment of the nominees assessment against the qualitative criteria to determine any gaps in the skills, experience and knowledge of the MAC as a whole. This will ensure that the best possible MAC will be appointed. A skills gap assessment is used to evaluate the overall composition of the MAC. If any gaps are determined then the Panel will use its composite scores for other highly rated nominees to attempt to fill any gaps.

This assessment will be undertaken at the consensus meeting.

5.3 EVALUATION RATING SCALE

A rating scale of 0-9 (as shown below) will be used for evaluating each tender submission response to the qualitative criteria. 'In between' scores are acceptable.

5.3.1 RATING SCALE

SCORE	DESCRIPTION
0	The nominee does not address the qualitative requirements **OR** The Evaluation Panel is **not confident** that the nominee will be able to satisfactorily meet the qualitative requirement(s).
3	The Evaluation Panel has **some reservations** that the nominee will be able to satisfactorily meet the qualitative

	requirement(s). If **Minor** concern: rate higher (4). If **Major** concern: rate lower (1 or 2).
5	The Evaluation Panel is **reasonably confident** that the nominee will be able to satisfactorily meet the qualitative requirement(s).
7	The Evaluation Panel is **confident** that the nominee will be able to satisfactorily meet the qualitative requirement(s).
9	The Evaluation Panel is **completely confident** that the nominee will be able to satisfactorily meet the qualitative requirement(s).

6 CHECKLIST

To ensure that the evaluation process is completed in the most efficient and effective manner, panel members should ensure, prior to the consensus meeting that they have:

a) Received a copy of each nomination received as shown in Section 3.2;

b) Scored each nomination (using the scoring sheets provided) and taken sufficient notes to explain the scores; and

c) Brought copies of the nominations and scoring sheets to the consensus panel meeting.

7 EVALUATION SCORE SHEETS

The evaluation sheets are provided on the following pages. Only one evaluation sheet should be completed for each nominee. Please note, some sections are to be completed prior to the consensus meeting, as indicated.

Any questions in relation to the scoring sheets or scoring process should be directed to the IMO contact person listed on the cover of this Handbook.

1. PRE-QUALIFICATION CHECKLIST (to be populated by Market Development)

Nominee:		
Organisation:		
Discretionary or Compulsory class member?		
Criteria	**Yes**	**No**
Nomination lodged by closing date		
Nomination lodged by email, fax or post		
Nominee is an employee (either full time or part time) or a consultant employed by a Rule Participant		

2. COMPLIANCE CRITERIA (to be populated by Market Development)

Nominee:		
Organisation:		
Discretionary or Compulsory class member?		
Criteria	**Yes**	**No**
Nomination form is completed and includes details of class of representation which the nomination is for?		
Nominee meets the requirements to represent the class it has applied for?		
Any additional supporting information provided that should be taken into account?		

3. QUALITATIVE CRITERIA (to be populated by each Evaluation Panel member for each nominee prior to the consensus meeting)

Nominee:		
Class of Representation:		
(a)	**Demonstrated skills, experience and knowledge of energy sector issues (20%)**	**Score** [ ]

Information about the skills, experience and knowledge of nominees with the regard to general energy sector knowledge:

To consider

(a) Knowledge of energy sector issues;

(b) Experience – with a particular emphasis on energy sector issues; and

(c) Ability to understand subject matter proposals made to the MAC.

Comments:

Nominee:		
Class of Representation:		
(b)	**Demonstrated skills and knowledge of the WEM (30%)**	**Score** [ ]

Information about the skills and knowledge of nominees with specific regard to the WEM:

To consider

(a) Understanding of the Market Rules and other relevant legislation including the powers and obligations of both the IMO and System Management; and

(b) Broad understanding of the technical, design and commercial aspects of the Wholesale Electricity Market.

Comments:

Nominee:		
Class of Representation:		
(c)	**Demonstrated ability to contribute actively to the MAC (30%)**	**Score** [ ]

Information about the experience of nominees on similar committees and their demonstrated skills relating to the MAC's advisory role:

To consider

(a) Ability to assess rule and procedure changes against the Wholesale Market Objectives;

(b) Ability to consider market design issues and options for the evolution of the Market Rules

(c) Experience at middle-management level or above, or similar;

(d) Ability to work as a member of a small team;

(e) Previous experience on industry advisory committees. Including any Working groups constituted under the auspices of the MAC;

Comments:

Nominee:		
Class of Representation		
(d)	**Relevant background (20%)**	**Score** [ ]

Information about the skills and expertise of the nominée :

To consider:

(a) Background – including relevant qualifications; and

(b) Ability to contribute to the MAC and the Wholesale Market Objectives.

Comments:

3. *COMPOSITE SCORE FOR NOMINEE* (to be determined at the consensus meeting)

Proponent Name	Composite Score
Demonstrate skills, experience and knowledge of energy sector issues	
Demonstrated knowledge of the WEM	
Demonstrated ability to contribute actively to the MAC	
Relevant Background	

OVERALL COMMENTS

5. COMPOSITIONAL CRITERIA (to be determined at the consensus meeting)

Assessment of any gaps for the MAC, as a whole, based on the composite scores of the top rated nominees for each representative class.

Member	Nominee	Demonstrate skills, experience and knowledge of energy sector issues	Demonstrated knowledge of the WEM	Demonstrated ability to contribute actively to the MAC	Relevant Background
Discretionary Class Membership					
Market Generator Class					
Market Customer Class					
Compulsory Class Membership					
Observers (self appointed)					

MARKET ADVISORY COMMITTEE APPOINTMENT GUIDELINES

~~July 2009~~ November 2010

1. Scope and purpose

1.1 These guidelines for the appointment of members to the Market Advisory Committee (MAC) have been developed to inform industry groups, Rule Participants and their respective nominees of the selection and appointment processes applied by the Independent Market Operator (IMO).

1.2 These guidelines set out the details of:

- the background to the MAC;
- the requisite skills, knowledge and experience of MAC members;
- the requirements for representation of MAC members;
- the terms of appointment for MAC members;
- the steps involved in the appointment process; and
- any other matters that the IMO considers will contribute to good governance and the effective operation of the MAC.

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

2. Related documents

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

- clauses 2.3.1 to 2.3.17 of the Wholesale Electricity Market Rules (Market Rules); and
- the MAC Constitution.

3. Background to the Market Advisory Committee

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

- to advise the IMO regarding Rule Change Proposals;
- to advise the IMO and System Management regarding Procedure Change Proposals, if required, or if requested by any Working Groups established under clause 2.3.17;
- to advise the IMO regarding market operation and South West interconnected system operation matters; and
- to advise the IMO regarding market evolution matters.

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

- three members representing Market Generators of whom one must represent the Electricity Generation Corporation;
- one members representing Contestable Customers;
- at least one and not more than two members representing Network Operators, of whom one must represent the Electricity Networks Corporation;
- three members representing Market Customers, of whom one must represent the Electricity Retail Corporation;
- one member nominated by the Minister to represent small-use consumers;
- one member representing System Management;
- one member representing the IMO; and
- a chairperson of the Market Advisory Committee, who must be a representative of the IMO.

The Minister and the ERA may also each appoint a representative to attend MAC meetings as observers, as outlined in clauses 2.3.6 and 2.3.7 of the Market Rules.

3.3 The MAC is an advisory committee and does not vote on issues. The MAC may make recommendations to the IMO if a consensus is achieved. Any recommendations made by the MAC are based on the consensus decision of members, excluding the opinion of observers. However, for the avoidance of doubt, observers on the MAC otherwise have full speaking rights.

3.4 The MAC must have regard to the Wholesale Market Objectives in carrying out its functions.

4. Skills, knowledge and experience of members

4.1 The applicants for appointment to the MAC should collectively possess the skills, knowledge and experience specified in clause 4.2 below. <u>The IMO's assessment process will ensure that there is balanced representation of skills knowledge and experience across the MAC.</u>

4.2 The IMO will take into account, but is not limited to, the following expected skills, knowledge and experience of the MAC (as a body) when making appointment decisions:

- Knowledge and/or demonstrated experience of energy sector issues;
- Broad understanding of the technical, design and commercial aspects of the WEM;
- Ability to contribute to the MAC and the Wholesale Market Objectives;
- Ability to work as a member of a small team;
- Ability to assess proposed rule and procedure changes against the Wholesale Market Objectives;
- Demonstrated ability to understand the subject matter proposals made to the MAC;
- Ability to consider market design issues and options for market evolution;
- Understanding of the Market Rules and other relevant legislation; and
- Knowledge of the powers and obligations of both the IMO and System Management and the frameworks in which they operate.

4.3 The IMO anticipates that nominations will be of people at middle management level or with similar experience.

5. Representation of members

5.1 MAC members are required to act in the best interests of the Wholesale Electricity Market.

5.2 Compulsory class members are individuals who represent a single entity. Compulsory class members must demonstrate their eligibility against the criteria for membership and necessary skills, knowledge and experience. This is to allow the IMO to consider the skills and experience of the compulsory class members when making discretionary appointment decisions to ensure that the MAC is a well-rounded committee.

5.3 Discretionary class members are individuals that represent a class of participants but are not Compulsory class members. 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 i.e. Market Generators, Market Customers or Contestable Customers. Discretionary class members must demonstrate their eligibility against the criteria for membership and necessary skills, knowledge and experience.

6. Term of appointment

6.1 Inaugural membership on the MAC for the 2010 year for both discretionary and compulsory class members will be for either one or two years with the opportunity for reappointment after this time period has lapsed.

6.2 For the calendar year beginning 1 January 2010 the term of membership will be determined by the IMO conducting a ballot. Half of the then current members will be appointed for one year and the remainder will be appointed for a two-year term. The ballot will be designed so that no particular class of membership will be completely rotated out in a single year. For example all Market Generator representatives would not be rotated out of the MAC in a single year. Members chosen by ballot for a one year term will be eligible for reappointment to an additional two year term if they meet the appointment criteria at the time.

6.3 Thereafter, the term of appointment of Discretionary class members will be rotated every two years, to ensure consistency in decision making and that all sections of the industry are adequately represented as the market matures.

6.4 Compulsory classes membership, after inaugural membership has expired, is for two years to ensure consistency of representation.

6.5 The IMO may appoint new members into compulsory and discretionary class positions, if necessary, when members are no longer representative of the class.

6.6 There are no restrictions on the number of times a member can be reappointed to the MAC, but in making appointments the IMO's objective is to get the best representation of the industry over time to ensure a dynamic MAC.

6.7 MAC members will be reappointed based on the IMO's assessment of individuals against the appointment criteria to ensure that they conform to the requirements and are representative of their class.

7. The nominations and appointment process

7.1 Each year the IMO will review the performance and attendance of MAC members. If any changes are required these will be addressed at the same time the IMO commences the annual appointment process for discretionary and compulsory class members whose tenure has lapsed.

7.2 On completion of the annual review the IMO will seek nominations from industry groups and Rule Participants. Industry consultation includes, but is not limited to:

- Chamber of Commerce and Industry of Western Australia;
- Chamber of Minerals and Energy of Western Australia; and
- Western Australian Sustainable Energy Association

7.3 The IMO will advertise for nominations on its public website and via direct contact with appropriate industry groups. The IMO will also send an email notification to people/entities on its market advisory mailing list maintained by the Market Development team.

7.4 Any company or individual can make nominations. Nominations must:

- Be in writing;
- Address the eligibility criteria for appointment to the MAC as set out in the Market Rules, MAC Constitution and this document;
- Have attached a current CV outlining the experience of the nominee with respect to the class(es) of nomination (two page maximum);
- Include contact details of the nominee (to demonstrate evidence of the persons willingness for appointment); and
- Be received by the IMO by the published due date.

7.5 Nominee details provided to the IMO will be kept private. A high-level assessment of all the nominees against the appointment criteria may be made publically available by the IMO if requested by an interested party.

7.6 An individual may be nominated for as many categories relevant to the entity to which they belong and for which the nominee meets the eligibility criteria. For example an entity which is both a Market Generator and Market Customer may nominate individuals for both of these categories.

7.7 The IMO can only appoint one individual from any one entity to serve on the MAC at any one time.

7.8 The IMO will consider nominations received, determine the appropriate composition of the MAC, and finalise appointment arrangements by March of every year, using the following assessment steps:

Step	**Event**	**Date**
1	IMO assess the positions up for renewal.	Before November MAC meeting.
2	IMO inform the MAC that the annual review is about to commence.	November MAC meeting.

Step	Event	Date
3	IMO prepare a call for nominations for the available membership positions.	End of November, closing late December.
4	IMO establish an internal evaluation panel (comprising members from across the organisation[1]) to assess all nominations received and ensure a high standard of probity is maintained.	Before close of call for nominations.
5	IMO prepare an Evaluation Panel handbook outlining what each panel member is required to do. This includes: • Assessment of the nominees against the pre-qualification[2] and compliance criteria[3]; • Assessment of the nominees against the qualitative criteria using the information provided in the response to the call for nominations[4]; and • Rating each nominee against the qualitative criteria using a pre-defined rating 0 – 9 point rating scale.	Before close of call for nominations.
6	Panel members assess each nominee in accordance with the Evaluation Panel handbook.	Following close of call for nominations and before the end of January.
7	Evaluation Panel meeting to determine a consensus score for each of the nominees.	
8	Evaluation Panel create a shortlist of candidates for each class based on the consensus qualitative ranking.	
9	To ensure an appropriate balance of skills and experience the Evaluation Panel will undertake the second stage assessment including reviewing	

[1] The Evaluation Panel will contain members from Market Development, Legal and Compliance, Finance and Administration and Market Operations teams from the IMO. Please note, the IMO member will not be a member of the Evaluation Panel due to the potential conflict of interest arising from the requirement for the panel to assess his application. Additionally, MAC Chair is not a member of the Evaluation Panel. This is to allow for a separate assessment step (as MAC Chair) and to ensure a rigorous process.

[2] These are: Nomination lodged on time and confirmation that the nominee is an employee or consultant employed by the Rule Participant.

[3] These are: Nomination form completed in full, contains the details of the class applying for, and meets the requirements to represent the class it has applied for.

[4] Demonstrated skills, experience and knowledge of energy sector issues (20%); Demonstrated skills and knowledge of the WEM (30%); Demonstrated ability to contribute actively to the MAC (30%); and Relevant background (20%).

Step	Event	Date
	the relevant qualifications, years of experience and backgrounds of nominees to determine the best possible composition for the MAC (taking into account the relevant skills and experiences of the compulsory members).	
10	Draft a recommendation report to present to the MAC Chair for review.	
11	Evaluation panel to reassess its recommendations (if required).	
12	Prepare a recommendation report to present to the IMO Board for its review and approval.	February Board meeting.
13	The IMO Board to decide the MAC membership. Following the Board's decision, inform the nominees of the outcome of the assessment process.	End of February.
14	All MAC members (incoming and outgoing) to attend a handover MAC meeting.	March MAC meeting.