Market Advisory Committee

Agenda

Meeting No.	59
Location:	IMO Board Room Level 17, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Wednesday 10th April 2013
Time:	2.00pm – 5.00pm

Item	Subject	Responsible	Time
1.	**WELCOME**	**Chair**	2 min
2.	**MEETING APOLOGIES / ATTENDANCE**	**Chair**	2 min
3.	**MINUTES FROM MEETING 58**	**Chair**	5 min
4.	**ACTIONS ARISING**	**Chair**	15 min
5.	**MARKET RULES**		
	a) Market Rule Change Overview	**IMO**	5 min
	b) PRC_2013_11: Selection of the 12 peak Trading Intervals used for calculation of IRCR	**IMO**	20 min
	c) PRC_2013_09: Incentives to Improve Availability of Scheduled Generators	**IMO**	20 min
	d) PRC_2013_08: Market Participant Fee - Clarification of GST Treatment	**IMO**	15 min
6.	**MARKET PROCEDURES**		
	a) Overview	**IMO**	5 min
7.	**WORKING GROUPS**		
	a) Overview and membership updates	**IMO**	5 min
8.	**GENERAL BUSINESS**		
9.	**NEXT MEETING: Wednesday 8th May 2013**		

INDEPENDENT MARKET OPERATOR

Market Advisory Committee

Minutes

Meeting No.	58
Location	IMO Board Room Level 17, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date	Wednesday 20 March 2013
Time	2.05pm – 5.25pm

Attendees	Class	Comment
Allan Dawson	Chair	
Kate Ryan	Compulsory – IMO	
Noel Ryan	Compulsory – Network Operator	
Phil Kelloway	Compulsory – System Management	
Andrew Everett	Compulsory – Generator	
Stephen MacLean	Compulsory – Customer	
Geoff Gaston	Discretionary – Generator	
Andrew Sutherland	Discretionary – Generator	
Shane Cremin	Discretionary – Generator	
Steve Gould	Discretionary – Customer	
Nenad Ninkov	Discretionary – Customer	
Michael Zammit	Discretionary – Customer	
Peter Huxtable	Discretionary – Contestable Customer Representative	
Peter Hynch	Minister's appointee – Observer	Proxy
Wana Yang	ERA – Observer	
Apologies	**Class**	**Comment**
Nerea Ugarte	Minister's appointee – Observer	

Also in attendance	From	Comment
Lizzie O'Brien	IMO	Minutes
Murray Cribb	IMO	Presenter (departed at 3.20pm)
Greg Ruthven	IMO	Presenter
Aditi Varma	IMO	Presenter
Anne Hill	IMO	Presenter
Miles Jupp	Collgar	Presenter (departed at 2.50pm)
Alistair Craib	Collgar	Observer (departed at 2.50pm)
Doug Aberle	Collgar	Observer (departed at 2.50pm)
Anastasia Papadopoulos	Ernst & Young	Observer (departed at 3.20pm)
Emily Sargent	Ernst & Young	Observer (departed at 3.20pm)
Matthew Fairclough	Western Power	Observer (departed at 4.35pm)
Paul Troughton	Enernoc	Observer
Fiona Edmonds	Alinta	Observer
Andy Stevens	Bluewaters	Observer
Ben Tan	Tesla	Observer (arrived at 2.40pm and departed at 4.20pm)
Natasha Cunningham	IMO	Observer
Jenny Laidlaw	IMO	Observer (arrived at 4.50pm)

Item	Subject	Action
1.	**WELCOME** The Chair opened the meeting at 2.05 pm and welcomed members to the 58th meeting of the Market Advisory Committee (MAC).	
2.	**MEETING APOLOGIES / ATTENDANCE** The following apologies were received: • Nerea Ugarte (Minister's appointee - Observer) The following other attendees were noted: • Peter Hynch (proxy for Nerea Ugarte) • Lizzie O'Brien (minutes) • Murray Cribb (presenter) • Greg Ruthven (presenter) • Aditi Varma (presenter) • Anne Hill (presenter) • Miles Jupp (presenter) • Alistair Craib (observer) • Doug Aberle (observer)	

	• Anastasia Papadopoulos (observer) • Emily Sargent (observer) • Matthew Fairclough (observer) • Paul Troughton (observer) • Fiona Edmonds (observer) • Andrew Stevens (observer) • Ben Tan (observer) • Natasha Cunningham (observer) • Jenny Laidlaw (observer)	
3.	**MINUTES OF PREVIOUS MEETING** The minutes of MAC Meeting No. 56, held on 12 December 2012, were circulated prior to the meeting. The minutes were accepted as a true record of the meeting. Subsequent to this meeting the IMO identified a number of minor amendments to the December 2012 MAC minutes that System Management had requested in December 2012, which had not been raised or endorsed at the March 2013 MAC meeting. *Action Point: The IMO to amend the minutes for MAC Meeting No.56 and recirculate for endorsement by the MAC.*	**IMO**
4.	**ACTIONS ARISING** The following comments were noted on the action items: • **Items 10 and 56:** The Chair noted that both these items were included for discussion on today's agenda as PRC_2012_03 and PRC_2013_06. • **Item 11:** Mr Phil Kelloway noted that a draft document had been prepared which he would provide to the Chair for circulation to MAC members. He noted that the issue was one of coordination between distribution network outages and generators and how the generator is impacted by outages. Mr Kelloway further noted that there was a process in place which generally worked but did not meet the requirements of the Market Rules. The distribution network outage process included three business days notification. Mr Kelloway noted that System Management was looking to make further improvements to the process. *Action Point: System Management to provide a copy of the draft process to the Chair for circulation to MAC members.* • **Item 29:** Mr Kelloway noted that this item, which deals with loads and network outages, involved a similar process to what was outlined in action item 11. He noted that there was a three day notification process but that load customers may prefer to have a more formal process to align with the Market Rules. Like the process for generation (subject of item 11), this process is also being examined by System Management.	**System Mgmt**

	• **Item 47:** Mr Andrew Everett noted that the item appeared in the meeting papers to have been completed. He requested the Chair provide an update. The Chair noted that two weekly meetings with System Management were being held and Mr Kelloway confirmed that the process of ensuring the values and the standard are correct had started. *Action point: IMO to reopen action item 47 and provide an update on the outcome at the next MAC meeting.* • **Item 53:** Completed. Collgar made a presentation to the MAC as agenda item 4a. • **Item 61:** Chair to provide update at next meeting. • **Item 62:** Chair to provide update at next meeting. *Action point: IMO to include items 61 and 62 on the agenda at the next MAC meeting.*	**IMO** **IMO**
4a.	**PRESENTATION: Impact of Changes to the Allocation of Capacity Credits to Intermittent Generators** The Chair invited Mr Miles Jupp from Collgar Wind Farm to make his presentation. The following discussion points were noted: • Mr Shane Cremin enquired as to when the next review was due. Mr Greg Ruthven confirmed that the next review would take place during 2014, with any rule changes to be in place for 2015. Mr Jupp clarified that Collgar's request was to bring forward the review by one year such that the outcome impacted the 2016-17 Capacity Year rather than the 2017-18 Capacity Year. • The Chair pointed out that the review leading to the allocation of Capacity Credits to Intermittent Generators was a costly and laborious process. • Mr Stephan MacLean noted concern at the possibility that a wider discussion would be re-opened. Mr MacLean stated he considered Sapere's report suggested a review of a more limited scope than the previous review and that on the basis of the review's scope being limited, he would be comfortable with the review being brought forward. Mr Cremin agreed that if the review was limited and there were grounds for review based on material impact then he would be happy to bring it forward. The Chair responded that the IMO would have to remove other items from its work program in order to accommodate the review. The Chair also pointed out that the time and effort involved in undertaking the review earlier may outweigh the benefits to Collgar from any methodology change. • Discussion on the fairness of the allocation methodology and the material impact on Collgar ensued. • Mr Everett stated that the issue for the MAC was whether Collgar had been unfairly impacted. The Chair agreed and sought the views of MAC members without commercial interest in the issue. Mr Michael Zammit responded that the MAC should be presented with the analysis. • The Chair stated that that the IMO would be able to provide the	

	necessary data however it would require permission from Collgar to circulate that information. Mr Jupp, on behalf of Collgar Wind Farm, consented to the data being circulated to MAC members. • Mr MacLean stated that he considered that Collgar had been unfairly impacted since they faced costs which were outside of the expected cost for the entire market. He suggested that the review should be brought forward and should consider the use of LSG and the U and K factors. The Chair responded that it may be difficult to start a review on those limited issues without the scope becoming much wider. • Mr Jupp suggested that Market Participants were generally unsatisfied with the LSG methodology. Dr Steve Gould reflected that he had previously objected to the LSG methodology however he'd suggested at the time that the opinion of an independent consultant be sought and as such he supported the process and its outcome. He raised concern at the prospect of there being two reviews. *Action Point: The IMO to circulate data on Collgar's performance during peak intervals to MAC members.*	**IMO**
5a.	**Concept Paper: CP_2013_02 Market Participant Fee – Clarification of GST** The Chair invited Mr Murray Cribb to make a presentation. The following discussion points were noted: • The Chair initiated discussion by extended an apology that this matter had arisen. The IMO had sought and received comprehensive GST advice around the settlement of the Wholesale Electricity Market on more than one occasion. He stated that the Australian Taxation Office (ATO) Ruling with regards to GST of the Regulator Fee had come as a surprise and was inconsistent with the advice that the IMO had received previously. • Mr MacLean questioned who would bear the cost of the problem. The Chair clarified that it was incorporated into the market fee however the Market Participants had effectively faced a lower fee from the Economic Regulation Authority (ERA) over the last five years as a result of including the tax amount as revenue rather than passing it onto the ATO. The result of the tax ruling is that the IMO would be increasing its fee for the next 12 months by half a million dollars to recover the GST that was not remitted to the ATO. • Mr Andrew Sutherland sought clarification on what had happened to the tax which was paid but not passed onto the ATO. He raised that it appears that the ERA had been overpaid by half a million dollars and queried whether the ERA had taken that into account in its allowable revenue such that it essentially reduced its revenue requirements over time. • The Chairman clarified that there was no net effect to the market given that the ATO hadn't sought to charge the IMO any penalties. Mr MacLean suggested that Market Participants had been receiving the cash flow from the reduced ERA fees which should have gone to the ATO and now the ATO is expecting to have that money returned (to balance against imputation credits issued for the period). The	

	Chair confirmed this was correct. • Ms Wana Yang stated that from the ERA's perspective the issue started in 2008. She outlined that the ERA charges are a regulator fee which is a government levy and government levies do not attract GST. Ms Yang noted that the ERA had always provided a GST exclusive amount to the IMO and expected to receive money back that was GST exclusive. She stated that the ERA never believed that any amount needed to be given to the ATO. Mr Cribb disagreed but acknowledged extending the debate would not be constructive. • Mr Kelloway stated that System Management had not been involved in any discussions regarding the GST issue to date. The Chair responded that System Management was not in the same position as the IMO with regards to claimed credits. • Mr Geoff Gaston questioned whether the determination was going to affect Market Participants GST statements retrospectively. The Chair responded that it was unlikely noting discussions with the ATO were ongoing. The Chair said that from 1 January 2014, Market Participants would receive an invoice that had elements which attracted GST and elements that do not attract GST. He clarified that the IMO was proposing the 1 January 2014 timing to allow sufficient time for any required modifications to tools and systems which take GST amounts into consideration to be properly considered and updated prior to the changed circumstances taking effect. • Mr Andrew Stevens raised the topic of the IMO acting as a principal and requested clarification. The Chair clarified that the IMO is seeking to perform a clearing house function, similar to settlement structures in financial, commodity and other electricity markets, including the National Electricity Market. • Mr Stevens identified that there may be an issue with this resulting in the need for contracts to be re-negotiated. The Chair clarified that the IMO intended to deal only with the physical transactions and bilateral contracts weren't intended to be affected by the arrangements. • Mr McLean questioned whether the possible implications for Renewable Energy Certificates (RECs), and specifically whether the how the liability of RECs is determined, had been considered. He pointed out that there had been discussions with the regulator regarding RECs because there were differences between the WEM and NEM and consequently the size of liability that applies. The Chair responded that the IMO had not considered this issue and requested that Mr McLean outline some of the concerns to the IMO for consideration.	
	Action Point: Mr Stephen MacLean to provide information on the RECS liability issue to the IMO.	**Synergy**
	Action Point: The IMO to prepare the Pre Rule Change and present it at the April MAC meeting.	**IMO**
5b.	**Concept Paper: CP_2013_01 Incentives to Improve Availability of Scheduled Generators**	

	The Chair invited Ms Anne Hill to make a presentation. Ms Hill outlined three proposals that the IMO was putting forward: • Amend clause 4.11.1(h) to allow the IMO to assign Certified Reserve Capacity between zero and full allocation, specify factors to be considered in the decision and progressively reduce the outage threshold; • Amend clause 4.27 to grant the IMO discretion to monitor performance of individual high-outage Facilities regardless of system capacity availability, to better inform clause 4.11.1(h) decisions; and • Introduce a Performance Adjustment to reduce capacity payments to high-outage Facilities. A fourth option, to limit the hours of Planned Outages exempt from Reserve Capacity Refunds, was proposed for future consideration. The following points were noted in an extensive discussion: • The Chair highlighted to the MAC members that clause 4.11.1(h) was an 'all or nothing' clause and that there was currently very little guidance as to the intention of the clause. • Mr MacLean commented that historically the thresholds in clause 4.11.1(h) had been generous. The Chair agreed and suggested the possibility that the drafters of clause 4.11.1(h) never actually thought the clause would be used. • Mr Cremin queried the relationship between future reliability and reliability over the previous 36 months. He suggested that trying to understand, monitor and audit the Facility to predict future operation is irrelevant. He stated that clause 4.11.1(h) should result in the Facility not getting any capacity credits since that is the penalty for breaching the 30% outage cap. The Chair commented that clause was an option rather than an obligation. He stated that the consequences were quite severe and that the Board, when determining whether or not to exercise the right to not allocate Capacity Credits last year, had found the lack of guidance in the Market Rules other than the Market Objectives to be a challenge. • Mr Nenad Ninkov queried what legal advice the IMO had sought in relation to clause 4.11.1(h). Ms Hill clarified that the legal advice was that clause 4.11.1(h) had an all or nothing effect: the IMO had to allocate either all or no Reserve Capacity Credits to a Facility that breached the outage threshold. • Mr Cremin and Mr Ninkov questioned whether the Board felt that it was unable to make use of the clause. The Chair responded that the Board considered that it could use the measure however that it considered the clause could have quite severe consequences for the wider market. The Chair noted that the IMO Board had given great consideration to the consequences for the wider market when determining whether to make use of clause 4.11.1(h). The Chair stated that the IMO considered that there needed to be more flexibility and structure in the mechanism than was currently available. • Mr Ninkov stated that he had an issue with the change because he	

considered that the clause provided a strong signal for when plants should be retired. Mr Ninkov questioned whether the percentage of time that generation plant is available was more important than its reliability, or being available when needed. He said he felt incentivising plant to be available 100% of the time may not be an efficient use of money.

- The Chair clarified that the expectation was not that facilities be available 100% of the time but that lack of availability of 40% to 50% over three years. He reiterated Ms Hill's analysis which showed that some of the plant in Western Australia was in the worst-performing decile of generators internationally.
- Mr Tan, Mr Ninkov, and Mr Cremin each suggested the length of time for non-acceptable performance before the IMO would do something was too long. They suggested that by allowing non-performing facilities to retain Capacity Credits, the market was effectively rewarding non-performance.
- Mr Cremin suggested that if after three years of non-acceptable performance by a generator, the IMO decided to allocate it only 50% of Capacity Credits in two and a half years' time, then this really amounted to accepting five years of non-performance.
- Mr Sutherland suggested that taking Capacity Credit revenue away from plants, such as Kwinana C, because of high outages may mean the plant would not be viable and therefore would be taken out of the Merit Order for the whole year. He stated that this would mean the energy price may increase. Mr Stevens responded that this may provide an incentive for construction of another plant such as Bluewaters 3.
- Ms Hill indicated that the IMO's proposal included reducing the outage threshold progressively from 30% to 20% over five years; a level that would still put the standard a little below what would be regarded as good industry practice. She also indicated that the proposed changes to clause 4.27 essentially allowed the IMO the ability to performance monitor in relation to capacity availability. Ms Hill also stated that this would provide the IMO with more information to make decisions with regard to clause 4.11.1(h).
- Ms Hill explained that there were a certain number of planned outage hours that could be expected each year but that plants which took excessive planned outages would be putting their Reserve Capacity revenue at risk through the proposed Performance Adjustment.
- Mr Stevens asked how the Forced Outage Refunds were factored in because generators would have already paid for the Forced Outage element. The Chair confirmed that under the proposal both the Forced Outage Refunds and the Performance Adjustment would have to be paid, but noted that the Forced Outage percentages on the high-outage plant was very low.
- Mr Ninkov queried whether Planned Outages were approved by System Management. Mr Kelloway confirmed that the Planned Outages were approved by System Management on the basis that the generator was not required for system security that day, and

	they would have gone through the process requirements. • Mr Tan queried the manner in which a rolling percentage discount proposed for capacity allocations would be applied. He commented that the proposal seemed to imply that if there were five years of non-performance for example with 40% outages, a generator would still be receiving 60% of their Capacity Credits. The Chair clarified that under the proposal the actual amount of Capacity Credits would not be affected; there would simply be an adjustment on the dollar value equivalent to the previous outage rate and the capacity price. • Mr Tan expressed concern that non-performing generators would get the rolling average of their past performance which may mean that they would not spend any money on the plant to address the issues, rather they would simply continue to be paid at the minimum 40%. The Chair responded that this was exactly the reason why the IMO had proposed to retain the discretion to not allocate Capacity Credits under clause 4.11.1(h). • The discussion moved on to the definition of Planned Outages. The Chair commented that Ms Hill's research had indicated that the Planned Outage definition in the WEM was very generous by international standards. • Ms Hill outlined the alternative proposal to limit the number of Planned Outages that could be taken without exposure to the Reserve Capacity Refunds. Mr Cremin stated that he preferred this option to the others presented. He highlighted some of the bureaucratic and administrative issues that might arise with the other proposals and argued that the issue is that the WEM allows Market Participants too many Planned Outages. He suggested that there should be a certain amount of Planned Outages each year and beyond that, Planned Outages would incur refunds. He added that recycling the refunds to available generators reinforces this message. Mr Cremin agreed that there still needed to be the ability for the IMO to refuse to allocate Reserve Capacity Credits to generators who persisted in demanding capacity revenue while not improving their plant. • The Chair asked the MAC for advice on what level of Planned Outages should be allowed and it was agreed that this level would be critical. • Discussion on the incentives that may exist between the gradual reduction of Capacity Credits overtime and the potential Planned Outage definition followed. Mr Cremin noted that if there was a certain amount of Planned Outages allowable for the year, then generators would have to make their decision about whether and when to take a Planned Outage knowing the value of the plant [*in earning capacity and energy revenue*] is based on its ability to produce. He felt that this would create a better incentive. • Mr Stevens raised the concern that all plant needed some minimum amount of Planned Outages. He stated that a major outage may take around 50 days every three years, and that sometimes additional damage is revealed at that time which necessitates a longer outage period. He stated that delays may be due to importing parts or other issues which could result in not being able to re-start	

	for maybe a further 45 days. He pointed out that any Planned Outage limit needed to recognise such situations. • The Chair stated that there could be a two-pronged threshold with a limit of say 15% over three years and then a 50 day annual limit and both would need to be breached. Mr Stevens agreed. • Mr Everett said that, from a market perspective, he felt that all the proposals were an over-reaction to the issue and would increase the risk on generators and therefore increase energy prices in the market. From a Verve perspective, he contend that the high outage rates on some of the Verve Energy machines did not equate to poor performance, but was a result of a large investment in extending the life of the plant, particularly Muja, which would produce cheap electricity. Mr Everett stated that the high outage rates in Verve Energy plant over the last few years were a temporary aberration and Verve Energy has a plan to have lower outage rates. He believed that by the time the rule changes took effect, Verve Energy's outage rates would be at a level where the rules would not have an impact. Mr Ninkov and Mr Tan pointed out that if that were the case, then the rule change would not be likely to affect anyone and the proposed change should proceed as it would protect the market if high Planned Outage rates occurred in the future. • Mr Stevens suggested simplifying the proposal by not combining Planned and Forced Outages. He suggested this on the basis that Forced Outages are already penalised with refunds, so the new thresholds should just focus on Planned Outages. Mr Kelloway commented that it made sense to use the existing refund mechanism. Mr Cremin and Mr Gaston emphasised that they did not support recycling the refunds to generators as proposed by the Reserve Capacity Mechanism Working Group (RCMWG). • Ms Yang emphasised the value of making the IMO's decisions transparent and suggested that naming the plants with poor availability, regardless of the IMO's decision under clause 4.11.1(h), can itself be a deterrent. She pointed out that since the ERA had started publishing outage rates for individual plants, the performance had improved. • Mr Cremin raised the point that clause 4.11.1(h) is currently a non-reviewable decision and that people like to have some recourse if they feel a decision is not just, especially if it is meant to be a guillotine for Capacity Credit allocation. The Chair agreed that these were good suggestions. • The Chair thanked the MAC member for their constructive advice and stated that consideration would be give to the comments in drafting of the Rule Change Proposals. *Action Point: The IMO to review proposals based on the MAC's discussion and prepare a Pre Rule Change Proposal.*	**IMO**
6a.	**MARKET RULE CHANGE OVERVIEW** Ms Kate Ryan provided an update to the MAC on the current Rule Change Proposals under consultation and development. Specifically that there were twelve rule changes currently in progress, and that a number of Market Rule issues had gone into the log including a couple	

	of medium level issues which had arisen since the last meeting. The IMO is now in the process of looking at these issues. Mr Everett questioned whether the response from the Public Utilities Office (PUO) to the IMO listed on page 66 of the Meeting Papers related to both RC_2012_06 and RC_2012_12 and so the commencement date for both proposals would be moved to 1 June 2013. At a later stage during the meeting, Ms Ryan confirmed that the PUO's concerns only related to RC_2012_06. The commencement for RC_2012_06 would be moved to 1 June 2013, and the commencement date for RC_2012_12 would remain as 1 April 2013. The MAC noted the existing and new issues on the log.	
6b.	**PRC_2012_02: Assignment of Capacity Credits to NCS Facilities** Mr Ruthven presented an overview of the IMO's Pre Rule Change Proposal: Assignment of Capacity Credits to Network Control Services (NCS) Facilities (PRC_2012_03). Mr Ruthven noted that the issue had been presented at the April 2012 MAC and that, following the concerns raised at that meeting around the appropriateness of the market paying Capacity Credits for NCS Facilities, the IMO discussed the issues with Western Power as well as the PUO and the ERA. Mr Ruthven outlined the main consensus points that arose following those discussions and highlighted a number of perverse outcomes and incentives that would result if Facilities that are subject to a NCS Contract or a Long Term Special Price Arrangement (LT-SPA) are not assigned Capacity Credits. Mr Ruthven then invited Mr Noel Ryan from Western Power to make a presentation to address concerns that came out of the April 2012 MAC meeting on how Capacity Credits would be taken into account in assessing options to address network constraints. Mr Ryan highlighted that the New Facilities Investment Test (NFIT) that Western Power must apply to capital expenditure is based on the need to efficiently minimise costs. He also noted that the Access Code is very explicit in that it requires consideration of net benefits from a market perspective that includes generation, transport, and end consumers (rather than from a Western Power perspective only). The following points were raised during the ensuing discussion: • There was some debate as to whether the market assessment presented by Western Power was correct in including Capacity Credits for both the network option and the NCS option. Mr Matthew Fairclough clarified that in the assessment presented, Western Power had assumed that there would be new generation required to service the load which prompted the network constraint. Several MAC members suggested that this may not be a reasonable assumption in a market where there is already excess capacity. The issue in such a market is simply the existence of a network constraint which prevents existing capacity getting to load not a lack of generation and as such it would be a delivery issue not a demand or capacity problem. • Mr Gaston raised concern that nobody with a commercial aspect had attended the workshop between Western Power, the IMO, PUO	

	and the ERA. • Mr Gaston then queried the interaction with the Balancing Merit Order (BMO). Ms Lizzie O'Brien clarified that an NCS Facility would receive an Operating Instruction when it was required to provide an NCS. The Facility would then be required to bid into the Balancing Market to reflect that it is required to run. Dispatch Instructions would therefore reflect the updated BMO and as such there would be no Constrained On payments or out of merit dispatch. She also stated that the only time when there could be an issue would be when the Operating Instruction (and dispatch) occurred without sufficient time for the bidding to be updated. This would occur if the need to operate the NCS Facility arises within the two hour pre-dispatch window. In this case, provisions in the Market Rules ensure the NCS Facility is not paid Constrained On payments; however the marginal generator that is displaced would still receive a Constrained Off payment. • The MAC agreed for the IMO to progress PRC_2012_03. *Action Point: The IMO to submit PRC_2012_03 into the formal process and progress the proposal under the Standard Rule Change Process.*	**IMO**
6c.	**PRC_2012_23: Prudential Requirements** Ms Aditi Varma presented an overview of the IMO's Pre Rule Change Proposal: Prudential Requirements (PRC_2012_23). The following points were raised during the ensuing discussion: • Mr MacLean questioned whether the 48 month or 24 month time period was up for debate. Ms Varma responded that analysis had been conducted as to the most appropriate timeframe. The Chair noted a number of Market Participants had materially changed their businesses over the past 48 months and the more current billing periods were a much more relevant indicator of likely market exposure. • Mr Ninkov questioned whether the IMO had worked out the implications of the shorter time frame for each of the Market Participants. Discussion ensued and it was agreed that the IMO would distribute information to each of the MAC members on an individual basis. *Action Point: The IMO to disseminate Credit Limit information to individual Market Participants.* • Mr MacLean queried whether the estimate of Synergy's Notional Wholesale Meter data was used in the Trading Margin calculation. He queried whether this calculation would be sufficiently robust for Synergy to use it in its own forecasting system. The Chair responded that the responsibility for assessing changes in load lies with Synergy. He also pointed out that the IMO's prudential exposure estimate would be on a dollar per half hour basis. Ms Varma also clarified that the IMO's forecast estimate was based on previously invoiced amounts. • Mr Gaston queried whether the Margin Call amount would be determined using the Trading Margin. Ms Varma responded that the	**IMO**

	Trading Margin would indicate what the Margin Call amount should be. She added that the IMO would also take into account any voluntary pre-payments that might be made by the Market Participant to reduce its liability. • Mr Gaston queried whether the IMO could reject a STEM submission. Ms Varma responded that the IMO could do so under the Market Rules. However, she added that there was also an obligation on the Market Participant to not make a submission that would result in a transaction exceeding its Trading Margin. • MAC members agreed that the IMO should progress the Rule Change Proposal but should also disseminate information on impacts on Credit Limits to individual Market Participants. *Action Point: The IMO submit PRC_2012_23 into the formal process and progress the proposal under the Standard Rule Change Process.*	**IMO**
6d.	**PRC_2013_01: Clarification of Dispatch Compliance Obligations** Ms Ryan presented an overview of the IMO's Pre Rule Change Proposal: Clarification of Dispatch Compliance Obligations (PRC_2013_01). The following points were raised during the ensuing discussion: • Mr Kelloway queried whether there were additional implications for System Management. Ms Ryan responded that System Management had already been providing all the relevant information to the IMO despite the potential for ambiguity that exists in the Market Rules. • Mr MacLean noted that this was an appropriate proposal to progress through the Fast Track Rule Change Process. • The MAC agreed for the IMO to progress PRC_2013_01. *Action Point: The IMO to submit PRC_2013_01 into the formal process and progress the proposal under the Fast Track Rule Change Process.*	**IMO**
6e.	**PRC_2013_03: LFAS Facility Definition** Ms Ryan presented an overview of the IMO's Pre Rule Change Proposal: LFAS Facility Definition (PRC_2013_03). The following points were raised during the ensuing discussion: • The Chair considered that it was unfair for Verve Energy to be excluded from receiving compensation for LFAS because the Verve Energy Balancing Portfolio was erroneously omitted from the definition of LFAS Facility in the Market Rules. The Chair noted that the IMO had not stopped paying Verve Energy for the service it was providing. The dispatch process for Load Following Services was working and the Rule Change Proposal simply sought to fix a definition problem in the Market Rules. • The MAC agreed for the IMO to progress PRC_2013_03. *Action Point: The IMO to submit PRC_2013_03 into the formal process and progress the proposal under the Fast Track Rule Change Process.*	**IMO**

6f.	**PRC_2013_05: LoadWatch, EOI and RDQ Provision** Ms Ryan presented an overview of the IMO's Pre Rule Change Proposal: LoadWatch, EOI and RDQ Provision (PRC_2013_05). The following points were raised during the ensuing discussion: • The Chair noted that the EOI Quantity and Relevant Dispatch Quantity (RDQ) data provided to the IMO by System Management within five minutes of the end of each Trading Interval is not confidential and the IMO planned to build some mechanisms for publishing this timely SCADA information. • Ms Ryan further clarified that System Management currently provides the information under the IMS Interface Market Procedure, but that the Rule Change Proposal is to formalise that obligation in the Market Rules. • Mr Kelloway questioned the repeated use of the term "must" in the drafting, suggesting that a "best endeavours" requirement might be more appropriate to allow for the possibility of IT failures. • Mr MacLean questioned whether there were any civil penalties that apply to the clauses and the Chair confirmed that there were none. • Ms Yang questioned whether there had been any recognition that the SCADA data may not be reliable. The Chair clarified that there are two SCADA data deliveries: one five minutes after each Trading Interval and the other following the end of each Trading Day. The second set of SCADA data is more reliable (as it is "cleaned" by System Management) and is the data used in the settlement calculations by the IMO. • The MAC agreed for the IMO to progress PRC_2013_05. *Action Point: The IMO to submit PRC_2013_05 into the formal process and progress the proposal under the Standard Rule Change Process.*	**IMO**
6g.	**PRC_2013_06: Exclusion of LFAS Quantities from Daily Ancillary Service Files** The Chair provided an overview of the IMO's Pre Rule Change Proposal: Exclusion of LFAS Quantities from Daily Ancillary Service Files (PRC_2013_06). Mr Kelloway queried whether there may be scope for simplification of the process by completely eliminating the daily Ancillary Service files. The Chair responded that consideration of a Spinning Reserve Market, which was the second highest priority in the Market Rules Evolution Plan, was likely to prompt further review of how the energy market functions with the Ancillary Services market. Ms Ryan suggested that Mr Kelloway's suggestion be logged for future consideration. The MAC agreed for the IMO to progress PRC_2013_06. *Action Point: The IMO to submit PRC_2013_06 into the formal process and progress the proposal under the Fast Track Rule Change Process.* *Action Point: The IMO to include System Management's suggestion to remove the daily Ancillary Service file from the Market Rules to the IMO*	**IMO** **IMO**

	Rule Change Suggestion Log.	
7a.	**MARKET PROCEDURE CHANGE OVERVIEW** Ms Ryan informed the MAC that a number of amendments to Market Procedures were in progress and considered that, if required, a more detailed discussion may be deferred to the next MAC meeting.	
8a.	**WORKING GROUP OVERVIEW** The Chair noted that Ms Kate Ryan would replace Ms Suzanne Frame as the IMO representative on the IMO Procedures Working Group and the System Management Procedures Working Group.	
8b.	**RCMWG UPDATE** The Chair noted that the RCMWG had concluded its work and that a number of Rule Change Proposals would be progressed. Debate ensued over the number of Rule Change Proposal packages that resulted from the group's work and whether the package for work stream three in particular could be further separated into several Rule Change Proposals. Mr MacLean suggested separating package three on the basis that it deals with quite separate items and separation would give the market the opportunity to comment on each of the items. Mr Cremin supported this view on the basis that the decision to pass a Rule Change is determined on the balance of whether the amendments met the market objectives or not but noted that he hadn't given this specific package sufficient consideration. The Chair thanked the MAC for their comments.	
9.	**GENERAL BUSINESS** Mr Kelloway highlighted a number of developments in the load following space and suggested an update on be provided at the next MAC meeting. The Chair agreed that an update would be appropriate. *Action Point: The IMO and System Management to provide an update on load following developments at the April MAC meeting.*	**IMO and System Mgmt**
CLOSED: The Chair declared the meeting closed at 5.25 pm.		

Agenda item 4: 2013 MAC Action Points

Legend:

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

#	Year	Action	Responsibility	Meeting arising	Status/Progress
11	2012	System Management to consider whether any process changes for approving network outages could be possible to ensure that Market Generators are provided with sufficient notice of the outage.	SM	Apr	System Management to provide update at April MAC.
29	2012	System Management to advise the MAC on the arrangements for notifying customers with important large loads on the distribution network of outages.	SM	Aug	System Management to provide update at April MAC.
61	2012	The IMO to contact the PUO to seek clarification and advice on the Metering Code and the confidentiality status of data captured by Notional Wholesale Meters.	IMO	Dec	Email sent to PUO.
62	2012	The IMO to report back to the MAC at its February 2013 meeting on the impact of extending its decision to apply to all spurious Constrained On/Off Compensation that has been allocated to Non-Scheduled Generators due to the manifest error addressed in RC_2012_19	IMO	Dec	Update to be provided to April MAC.
1	2013	The IMO to recirculate the minutes for MAC Meeting No.56 for endorsement by the MAC.	IMO	Mar	Completed. Circulated for endorsement at April MAC.

#	Year	Action	Responsibility	Meeting arising	Status/Progress
2	2013	System Management to provide a copy of the draft process for approving network outages to the Chair for circulation to MAC members.	SM	Mar	
3	2013	IMO to reopen action item 47 and provide an update on the outcome at the next MAC meeting. *'The IMO to seek the ERA's interpretation on the 99% standard and information on the origin of the requirement in the Technical Rules for system frequency to stay within a 49.8 to 50.2 hz band 99% of the time'*	IMO	Mar	Completed. Included as attachment – Western Power: Frequency Relaxation Survey Responses.
4	2013	IMO to include items 61 and 62 on the agenda at the next MAC meeting.	IMO	Mar	Completed. Update to be provided to April MAC.
5	2013	The IMO to circulate data on Collgar's performance during peak intervals to MAC members.	IMO/Collgar	Mar	
6	2013	Mr Stephen Maclean to provide information on the RECS liability issue to the IMO.	Synergy	Mar	Completed.
7	2013	The IMO to present PRC_2013_08: Clarification of GST, at the April MAC meeting.	IMO	Mar	Completed. On April MAC Agenda.
8	2013	The IMO to review rule change proposal on CP_2013_01: Incentives to Improve Availability of Scheduled Generators, based on the MAC's discussion and prepare Pre Rule Change Proposal.	IMO		Completed. On April MAC Agenda.
9	2013	The IMO to formally submit the Pre Rule Change Proposal: Assignment of Capacity Credits to NCS Facilities (PRC_2012_03) and progress the proposal.	IMO	Mar	Completed. The IMO published the rule change proposal on 27 March 2013.
10	2013	The IMO to disseminate Credit Limit information to individual Market Participants.	IMO	Mar	
11	2013	The IMO submit PRC_2012_23 into the formal process and progress the proposal under the Standard Rule Change Process.	IMO	Mar	Underway.

#	Year	Action	Responsibility	Meeting arising	Status/Progress
12	2013	The IMO to submit PRC_2013_01: Clarification of Dispatch Compliance Obligations and progress the proposal using the Fast Track Rule Change Process.	IMO	Mar	Underway.
13	2013	The IMO to submit PRC_2013_03 and progress the proposal using the Fast Track Rule Change Process.	IMO	Mar	Underway.
14	2013	The IMO submit PRC_2013_05 and progress the proposal using the Standard Rule Change Process.	IMO	Mar	Underway.
15	2013	The IMO submit PRC_2013_06 and progress the proposal using the Fast Track Rule Change Process.	IMO	Mar	Completed. The IMO published the rule change proposal on 27 March 2013.
16	2013	The IMO to include System Management's suggestion to remove the daily Ancillary Service file from the Market Rules to the IMO Rule Change Suggestion Log.	IMO	Mar	Completed.
17	2013	The IMO and System Management to provide an update on load following developments at the April MAC meeting.	IMO/SM	Mar	

Frequency Relaxation Survey Responses

Western Power

March 2013

PUBLIC VERSION

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Background

The issue of load following quantity and the resulting frequency standard in the Market Rules has been the focus of much attention since the price increases associated with the introduction of the LFAS market into the SWIS on 1 July 2012.

At the MAC meeting 56 on 12 December 2012 System Management advised the MAC that it would undertake a consultation process with generators and end use customers regarding what level of frequency variation might be acceptable. MAC members noted that the feedback process should focus on assessing what sort of costs would be imposed on different participants as a result of the reduction in the frequency standard.

Consequently in March 2013 a request for technical responses to proposed variation to the power system frequency control was initiated by System Management of Western Power.

The request was a follows:

"For the attention & action of your Electrical Supervisor / Operations Manager

You may be aware that the Independent Market Operator (IMO) led Market Advisory Committee (MAC) is reviewing the cost of load following ancillary services.

Western Power is consulting with industry, customers and stakeholders regarding the impact of a proposal to relax frequency control practices in order to find the right balance between customer impacts and the cost of load following ancillary services.

Your business has been identified as being potentially affected by the proposed changes.

Western Power is seeking your feedback on the proposed changes by **8 March 2013.**
Your feedback will assist the MAC to better understand the impact of relaxing frequency control practices.

Western Power is also particularly interested to understand any technical impacts the proposed changes may have on your business. A fact sheet containing information on the proposed changes is attached for your reference.

Please do not hesitate to contact me if you have any queries regarding this proposal or require further information

Feedback requested

The technical and commercial effects of frequency variations on customers are not readily observable.

Western Power is seeking information in regard to possible technical impacts-

► *Do you have specific requirements for power system frequency performance?*

► *How do you expect your requirements in respect of power system frequency to change in future?*

► *What form of customer plant is sensitive to frequency, such as motor drives & generators?*

► Are there any material impacts caused by frequency variations in the range 49.5 to 50.5 Hz, in particular those which may result in increased costs? "

This document provides the responses received in regard to this request.

Note this document does not purport to give any recommendations as a result of these responses as this requires further consideration

Table 1 : Summary of Customer Response with no impact on equipment

Company Name	Contact	Process Type	Equipment Type	Comment
Karara Pty Ltd	Mahendra Kuruppu	Mine Site	VSD	
Doral Rockingham	Peter Norton		VSD	
BOC	Claudi Lima	Gas Processing	VSD	
RCR Resources	Greg Harris	Heat Treatment		
Tronox	Karen Boyce	Cogeneration	Cogen gas turbine	
Alinta	Fiona Edmonds	Cogeneration	Cogen gas turbine	
St John of God	Steve Gaffey	Hospital	Cogen & VSD	
West Australiann Newspapers	David Belohlawek	Printing		
Withheld		Material Manufacturer		**CONFIDENTIAL**
Withheld		Industrial Gas		**CONFIDENTIAL**
Laminex Group	Greg Neill		VSD	
Withheld		Combined Cycle	Combined Cycle	**CONFIDENTIAL**
Newgen Neerabup	Bruno Lanciano	Electricity Generation	Open Cycle Gas Turbine	
Cockburn Cement	Saeid Bossaghzadeh	Manufacturing	VFD	
Withheld		Manufacturing		**CONFIDENTIAL**

Table 2 : Summary of Customers Responses with impact on equipment

Company Name	**Contact**	**Process Type**	**Equipment Type**	**Comment**
Withheld		Manufacturing	Speed Controller	**CONFIDENTIAL**
Verve Energy	Andrew Everett	Electricity Generation	Steam Turbine	
Boral	Nigel Salter		Fixed Speed Motor	
KWINANA INDUCTRIES COUNCIL	Debbie Hoey	Multiple Industrial Companies		
Withheld		Manufacture	VSD	**CONFIDENTIAL**
Withheld		Sports Venue		**CONFIDENTIAL**

Table 3 : Summary of Customer Responses requesting more information

Company Name	**Contact**	**Process Type**	**Equipment Type**	**Comment**
Collgar Windfarm	Alistair Crabb	Wind Generator	Wind Generator	Wishes to see results first

Customer Responses – Non Confidential

KARARA POWER PTY LTD

KARARA
POWER PTY LTD

Level 8, London House
216 St Georges Terrace
Perth WA 6000

Telephone +61 8 6298 1888
Facsimile +61 8 6298 1099
ACN 137 632 001

22nd February 2013

Brendon Clarke
System Operations Development
Planning Market Operations
Western Power
East Perth WA

RE: Investigation into the Impact of Increased Power System Frequency Variations

Dear Brendon,

From a technical perspective Karara Mine site equipment won't be impacted by relaxing the system frequency range to 49.5Hz to 50.5Hz. Most remote mineral processing facility with in-house power stations will be subjected to larger frequency variation than proposed values, a plant such as Karara Mine site will be able operate without anyone noticing proposed frequency fluctuations.

Any speed critical equipments are controlled via variable speed drives that will be able to adjust output frequency as desired.

Karara welcome this review and in return the expected operating savings to the WEM.

Karara believe in a prudent and secure power system for Southwest of WA (SWIN) and would welcome greater review of power system performance standards outline under Technical Rules 2011.

Yours Sincerely,

Mahendra Kuruppu
Utilities Superintendent
Karara Mining Limited/Karara Power Pty Ltd
Mob: 0409 687 501

DORAL

Hello Brendan

I Have received feedback from our electrical consultants and can advise that we do not expect any impacts to our plant equipment with frequency variations in the range of 49.5 to 50.5Hz as per your proposal. I have paraphrased our consultant's report as per below:

There is no equipment at Doral which would be affected by a wider frequency range, provided that the frequency changes are slow (which they probably would be).

The speed of motors would change up or down as the frequency changes, and only if the frequency changes down very rapidly, when there may be regeneration, would there be a problem.

Your VSD's should not be affected.

The control system is almost certainly supplied by a UPS. This would be synchronised to the mains except when the mains changes frequency outside normal bands, and so the PC's and PLC's should not be affected.

The pumps and conveyors would change speed very slightly as the frequency changes, but this should not be noticeable.

So, in general, a wider range of frequency up to +/- 1% would not affect the plant.

I hope this is satisfactory.

Best regards

Peter Norton | Projects and Development Manager |

Doral Rockingham Operations | PO Box 84 | Rockingham Western Australia 6168 |

Phone +61 8 9439 8812 | Fax +61 8 9439 2892 | Mobile +61 421 347 025 |

BOC LIMITED

Hello Brendan,

I've been asked by Allen Gower to reply to your questions on frequency relaxation.

Please find below my answers in *red italic* under each one of your questions.

Please keep my answers confidential

Kind Regards

Claudio Lima

Electrical Engineering Manager

Tonnage Operations - South Pacific

Tel: +61 2 8874 4576 / Fax: 9886 9109 / Mob: 61 2 407 671 110

Claudio.Lima@boc.com

BOC Limited

A Member of The Linde Group

Riverside Corporate Park | 10 Julius Av. North Ryde NSW 2113 Australia

Feedback requested

The technical and commercial effects of frequency variations on customers are not readily observable.

Western Power is seeking information in regard to possible technical impacts-

► *Do you have specific requirements for power system frequency performance?*

In regards to our large synchronous motors, our minimum requirements are for compliance with IEC 6034, clause 7.3 "Voltage and frequency variations during operation".

► *How do you expect your requirements in respect of power system frequency to change in future?*

It is unlike to become stricter than current requirements. Equipment more sensitive to power fluctuation tends to be supplied through UPS.

► *What form of customer plant is sensitive to frequency, such as motor drives & generators?*

HV synchronous motors driving large air compressors and online generators

► *Are there any material impacts caused by frequency variations in the range 49.5 to 50.5 Hz, in particular those which may result in increased costs?*

No significant material impacts for short duration 0.5 Hz frequency variations

RCR RESOURCES

Hi Brendan,

Please see answers below

Regards

Greg Harris | Operations Manager

RCR Resources | Heat Treatment

239 Planet Street, Welshpool WA 6106

PO Box 141, Welshpool DC WA 6986

Ph: +61 8 9355 8100 | Fax: +61 8 93558112

Dir: +61 8 9355 8170 | RCR IP: 11*170 | Mob: 0407 995 054

Feedback requested

The technical and commercial effects of frequency variations on customers are not readily observable.

Western Power is seeking information in regard to possible technical impacts-

► *Do you have specific requirements for power system frequency performance? No*

► *How do you expect your requirements in respect of power system frequency to change in future? No*

► *What form of customer plant is sensitive to frequency, such as motor drives & generators? We have variable speed drives but do not expect that the proposed frequency changes will have any significant impact.*

► *Are there any material impacts caused by frequency variations in the range 49.5 to 50.5 Hz, in particular those which may result in increased costs?* No

TRONOX

Karen,

I apologise for not sending these through earlier as there is no effect for the KMK Cogen facility with the proposed changes.

Answers to the questions are as follows.

1. Do you have specific requirements for power system frequency performance?
Not at the KMK Facility. The generator is synchronised to the Grid and the proposed limits are well within any trips and safety limits for the Gas Turbine and Generator control systems. Additional periods and excursions from 50HZ as proposed are within the capability of the GT control system

2. Do you expect your requirements in respect of power system frequency to change in future?
The proposed Control system (Speedtronic) upgrade when implemented will have no adverse effects on the Gas Turbine and Generator control capabilities or operating systems.

3. What form of customer plant is sensitive to frequency, such as motor drives & generators?
No part of the KMK Cogen facility is sensitive to the frequency response changes that have been proposed

4. Are there any material impacts caused by frequency variations in the range 49.5 to 50.5 Hz which can cause economic loss?
No material impacts are expected at the KMK Cogeneration facility.

Regards,

Tim Harrison
Project Manager

Monadelphous Group Limited | KMK Cogeneration Facility | Kwinana, WA, 6167
T 08 6316 3461 | M 0418244611 | www.monadelphous.com.au

ALINTA ENERGY

alintaenergy

12 February 2013

Brendan Clarke
System Operations Development Engineer
Planning and Market Operations
Western Power
Email: Brendan.clarke@westernpower.com.au

Dear Brendan

RE: TECHNICAL REVIEW OF POWER SYSTEM FREQUENCY CONTROL

Alinta Energy (Alinta) appreciates the opportunity to provide input into the current technical review of Power System Frequency Control being undertaken by System Management. Alinta understands that the review has been undertaken as a consequence of the increase in costs experienced in Load Following Ancillary Services (LFAS) market since its inception on 1 July 2012.

Participants in the Western Australian electricity market are currently exposed to a number of increased costs including those associated with the LFAS market. Alinta is generally supportive of any initiatives being undertaken to reduce unnecessary costs and notes its wider concerns with the increase in LFAS costs since 1 July 2012.

Process for identifying potential solutions

Alinta commends System Management on proactively identifying potential solutions to the issue of increased LFAS costs and investigating the feasibility of an initiative to reduce power system frequency requirements. Alinta is however concerned that there has been insufficient consideration of whether the costs being incurred in the LFAS market are the result of:

1. moving from a previously administered price and therefore are now cost reflective; and/or
2. an overstatement of the Load Following requirement in each Trading Interval.

The process for considering the increased costs in the Load Following market needs to first establish whether it is the case that the costs are appropriate and then look to potential solutions to reduce the costs.

Refinements to the LFAS market to remove unnecessary distortions (i.e. inappropriate prices or quantities) should be the first priority for the IMO and System Management. Alinta considers that these "first order" refinements, such as better shaping the quantity of LFAS procured in each Trading Interval, should be able to be implemented relatively quickly and would deliver significant market benefits without imposing additional costs on both market and non-market participants. These refinements will ensure that the market is functioning as originally intended.

Once any identified first order refinements are underway it would then be appropriate to consider whether "second order" refinements (i.e. indirect changes) may be available that would reduce LFAS costs overall by either decreasing the quantity of LFAS required or the cost of services being offered.

Alinta notes that second order refinements such as increasing system frequency requirements (reduced quantity of LFAS) may simply result in a shift of costs. For example there are indirect costs imposed on both market and non-market participants as a consequence of increasing the frequency band i.e. costs associated with re-tuning the governors, greater planned maintenance costs, greater system risk and lost sales of electricity. Whether the indirect costs associated with increased frequency requirements might be outweighed by the reduction in LFAS costs needs to be identified along with whether there are alternative solutions that have a greater net benefit for Western Australia.

Alinta Sales Pty Ltd • (ABN 92 089 531 984) trading as Alinta Energy
A The Quadrant Level 13, 1 William Street, Perth WA 6000 Australia
T +61 8 9486 3000 • F +61 8 9486 3951 • W alintaenergy.com.au

Alinta recommends the following approach be adopted in considering this issue (in order):

- The ERA, with the IMO's assistance, investigate whether:
  - the prices in the LFAS market are cost reflective and there is no anomalous market behaviour; and
  - the appropriate quantity of LFAS is being procured in each Trading Interval[1];
- Dependent on the outcomes of the IMO/ERA investigation, the IMO and System Management identify and progress, in consultation with the Market Advisory Committee (MAC) and wider industry, any first order amendments to the LFAS market design that will reduce costs. Given the implications to end-users associated with increased power prices following the implementation of the LFAS market these changes should be progressed as a matter of priority; and
- The IMO and System Management identify all second order amendments that may decrease costs associated with the LFAS market and, in consultation with the MAC and wider industry, identify the relative costs/benefits of each with a view to identifying areas where the net benefit to industry is maximised. Any change(s) that are agreed with industry (and if necessary supported by Government) should then be progressed via the relevant processes.

Alinta also considers that a review of the design of the LFAS market should be undertaken by the IMO in the next 12 months to identify whether any further refinements are necessary to assist the market design in better meeting the Wholesale Market Objectives. Such a review should be incorporated into a wider review of the market given the interdependencies between the various components of the current market design.

Reductions to power system frequency requirements

While Alinta's preliminary assessment of the technical implications of adjusting the system frequency requirements has not to date identified any technical concerns with the approach, Alinta is concerned that the proposed approach of reducing the power system frequency requirements simply shifts costs on to generators, including non-market participants. As a consequence the appropriateness of such a change should be considered by a policy body such as the Public Utilities Office and assessed against alternative second order options prior to being progressed.

In terms of the economic impacts of the proposed change, Alinta will incur a one-off cost to retune the governors at its Pinjarra and Wagerup facilities. There will also be an indirect cost to Alinta associated with the loss of energy sales (MWs) to enable the facilities to respond to the increased frequency range via governor droop. This is not anticipated to be significant at this stage. Specific details of these costs should however be incorporated into any assessment of the net benefits of the proposal.

Alinta intends to further consider this issue over the next few weeks and will provide any further details to System Management as necessary. In the interim, if you have any queries in relation to the above matters please do not hesitate to contact me directly. Additionally, Alinta would appreciate the opportunity to meet with you directly to discuss the wider processes to address the issue of increased LFAS costs over the next few weeks.

Yours sincerely

Fiona Edmonds
Wholesale Regulation Manager

[1] Alinta understands that the IMO is currently investigating whether the quantity of LFAS in each Trading Interval is appropriate. There are however likely to be issues associated with defining the quantity of energy procured from the Verve Energy Balancing Portfolio that is for Load Following vs. Balancing purposes. Alinta considers that definitional assumptions should be made to enable this assessment and then reflected in the Market Rules at a later date (if necessary).

VERVE ENERGY

Our Ref: 3518808
Enquiries: Jacinda Papps
Telephone: (08) 9424 1917
Email: Jacinda.papps@verveenergy.com.au

12 February 2013

Mr Brendan Clarke
System Management
Electricity Networks Corporation
8 Joel Terrace
EAST PERTH WA 6004

By email: Brendan.Clarke@westernpower.com.au

Dear Brendan

FREQUENCY RELAXATION PROPOSAL

Thank you for the opportunity to comment on the proposed relaxation of power system frequency standards.

Verve Energy is strongly opposed to the proposal. Verve Energy submits that any attempt to widen the practical allowable limits for frequency, by changing the duration of allowable variation from nominal, will have an immediate deleterious effect to all generators operating conditions by way of sustained ongoing process disturbances resulting in widespread wear and tear on control elements within the plants.

Whilst most electrical machines manufactured to credible international standards are intended to operate continuously within a +- 2% frequency band, generally these extremities are intended to be infrequent and transient conditions.

As you are aware, any variation to power system frequency implies the acceleration or deceleration of every rotating machine (both synchronous and asynchronous) connected to the power system with the inherent disturbance to real power flows. The magnitude of these disturbances is directly proportional to the quantum of the departure from a nominal speed (frequency) setpoint.

Because of the mix of modern electro-hydraulic and mechanical governing systems present in the Wholesale Electricity Market (WEM), the allowable deadband installed on newer generators (minimum 50mHz) dictates that there will be a disproportionate response from mechanically governed units for a frequency deviation.

More frequent response by generators resulting from system frequency moving beyond their deadband limits will result in a more aggressive response back to nominal setpoint. This will have the implication of extremely large accelerative torques being generated in electrical machines (including customer equipment). We are not aware of any modelling that considers the matter of accumulated cyclic fatigue generally across electrical machines for cases where power systems are permitted to consistently drift from the nominal setpoint followed by aggressive correction.

In your presentation to the Generator Forum of 17th January, a potential issue of wear and tear on governors was identified. Whilst this is correct, it is also noteworthy that even for generators with governor dead band applied; the physical change in rotating speed for a frequency deviation in itself will result in a process upset.

For example, for a steam turbine/generating unit, the change in turbine speed will result in a change in mass flow of steam to the turbine irrespective of any governor action. This change in steam flow will be reflected in control signal response to boiler plant (to match energy demands) with a resultant oscillation moving across the plant. Whilst arguably this could be detuned, this would then be contrary to the aggressive response normally required to major system disturbances (6 second and 60 second response in particular).

Similarly, for a combustion turbine a change in compressor speed resulting from a frequency departure will result in a change to air mass flow and will result in the need to vary fuel inputs and/or cause a variation to exhaust temperatures – a further process upset to units operating in combined cycle mode.

Verve Energy reiterates that any attempt to widen the practical allowable limits for frequency by changing the duration of allowable variation from nominal will have an immediate deleterious effect to all generators operating conditions by way of sustained ongoing process disturbances resulting in widespread wear and tear on control elements within the plants. Intuitively, Verve Energy considers that there is also a propensity for an associated increase in accumulated fatigue damage to consumer plant that has not been analysed or quantified with this proposal.

Should you require additional information could you please contact Jacinda Papps on (08) 9424 1917 or jacinda.papps@verveenergy.com.au.

Yours sincerely

ANDREW EVERETT
MANAGER TRADING & REGULATION

cc. Cameron Parrotte, System Management
Andy Wearmouth, Verve Energy

DMS#: 3472748v1

ST JOHN OF GOD SUBIACO

John,

Answers within your email below in black.

Thanks

Steve Gaffey I Chief Engineer **I** St John of God Subiaco Hospital

Level 01, 12 Salvado Road SUBIACO WA 6008

P: 08 9382 6309 **F:** 08 9382 6100 **M:** 0421 141 031 **E:** steve.gaffey@sjog.org.au

Feedback requested

The technical and commercial effects of frequency variations on customers are not readily observable.
Western Power is seeking information in regard to possible technical impacts-

► *Do you have specific requirements for power system frequency performance? No. We have an 11KV cogeneration plant that synchronises with Western Power supply. We have 2 x emergency generators a number of UPS's and VSD's throughout the site. We understand these will not be affected by the change.*

► *How do you expect your requirements in respect of power system frequency to change in future? There are no planned changes with existing services into the future.*

► *What form of customer plant is sensitive to frequency, such as motor drives & generators? We have an 11KV cogeneration plant, 2 x emergency generators, a number of UPS's and VSD's throughout the site.*

► *Are there any material impacts caused by frequency variations in the range 49.5 to 50.5 Hz, in particular those which may result in increased costs?* Not that we're aware of.

BORAL RESOURCES

Brendan - see response below

Nigel Salter
Regional Manufacturing Manager

Telephone: (08) 9273-5508
Mobile: 0401-896-668
Fax: (08) 9273 5134
Email: Nigel.Salter@boral.com.au

Feedback requested

The technical and commercial effects of frequency variations on customers are not readily observable.

Western Power is seeking information in regard to possible technical impacts-

► *Do you have specific requirements for power system frequency performance? Yes*

► *How do you expect your requirements in respect of power system frequency to change in future? no change in the medium term*

► *What form of customer plant is sensitive to frequency, such as motor drives & generators? Brick Making and automated handling equipment using fixed speed motors*

► *Are there any material impacts caused by frequency variations in the range 49.5 to 50.5 Hz, in particular those which may result in increased costs?* potentially yes impacting product quality and machine performance

WEST AUSTRALIAN NEWSPAPER

Brendan,

The following information was forwarded to me by our Production Director. I have reviewed the information and have sourced some assistance from our relevant equipment manufacturers and also from our plant design electrical consulting engineer and we believe an increased frequency variation in the range of 49.5 to 50.5 Hz will not currently affect our business.

Please keep us informed of any further developments.

Kind Regards

David Belohlawek
Reliability Co-ordinator
Herdsman Print Centre
West Australian Newspapers Limited.
Phone – 08 9482 9786 Mobile – 0403 001 126

LAMINEX GROUP DARDANUP

Dear Brendon,

We have reviewed the proposal and can offer the following comments:

- We at the Dardanup Laminex site have no specific requirements for minor frequency changes that are not likely to impact performance within limits.
- At this point in time we do not believe that this will have any major impact on our requirements that will affect our operations into the future.
- The more sensitive plant assets onsite that could be affected are our Variable Speed Drives (VSD) – we are confident that the operational range of the VSD will fit within the scope of changes outlined for power system frequency.
- We believe that increases in cost would not occur, however if the power system frequency was to affect, for example the forming line speed etc, then cost of production would increase. Based on the information provided we do not believe that we will be affected.
- We appreciate any further input or information from Western power on this subject going forward

If you require anything further please do not hesitate to contact us.

Regards

Greg

Greg Neill
Engineering and Maintenance Systems Manager

The Laminex Group | Dardanup Plant
184 Moore Road, Dardanup, WA 6236
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KWINANA INDUSTRIES COUNCIL

Kwinana INDUSTRIES COUNCIL

Ref CO/djh/KIC 2013 09

7 March 2013

Mr Brendan Clarke
Market Advisory Committee
Western Power

By Email brendan.clarke@westernpower.com.au

Dear Mr Clarke

KIC Submission: Investigation into the Impact of Increased Power System Frequency Variations

I represent Kwinana Industries Council (KIC) and we are writing to you in regards to Western Power proposal to relax the South West Interconnected System (SWIS) grid frequency control.

By way of background, the KIC is an incorporated business association with membership drawn from the Kwinana Industrial Area (KIA). The current KIC membership is 11 full members, who include all the major industries found within the KIA, and 26 associate members covering the support and service sectors. KIC members employ approximately 5,000 workers directly and another 26,000 indirectly, and its economic activity contributes $1.6 billion annually to the State economy. The KIC was established in 1991 with its primary goals being:

- To promote a positive image of Kwinana industries;
- To work towards the long-term viability of Kwinana industry;
- To coordinate a range of intra-industry activities including water quality, air quality, monitoring and emergency management;
- To highlight the contribution Kwinana industry makes to community; and
- To liaise effectively with local communities, Government and Government agencies.

The KIC is well recognised as being almost unique in Australia for what it represents, how it operates and for what it has achieved. It pursues its goals through a range of formal committees set up to provide input on a range of issues of common interest to the KIC member companies. Committee members are delegates with appropriate experience and authority drawn from the member companies. The output from the various committee activities is then used as the basis for communication to the KIC's stakeholders such that Kwinana industry is seen as speaking with one voice.

INDUSTRY + COMMUNITY + ENVIRONMENT

11 Stidworthy Court, Kwinana WA 6167 - PO Box 649, Kwinana WA 6967 admin@kic.org.au
TEL: (08) 9419 1855 Fax: (08) 9419 1899 WEB: kic.org.au ABN 62 018 571 097

The KIA is the premier industrial estate in Western Australia, covering an occupied area approximately 8km north-south and 2km east-west, on the eastern side of Cockburn Sound some 22km south of the Perth central area.

Western Power's proposal to relax the South West Interconnected System (SWIS) grid frequency control has come to KIC's attention and we wish to provide feedback on behalf of our members. We are hopeful that our feedback on the proposal will assist the Market Advisory Committee to better understand the real impact of relaxing frequency control practices.

At our February 2013 KIC Board meeting KIC members discussed this matter and it was agreed that our collective position is to strongly oppose the Wester Power proposal on the grounds that the stability of the South West Interconnected Network (SWIN) grid frequency is a key parameter in ensuring low risk, steady, safe and reliable operation of our members Kwinana based facilities.

Introducing additional frequency variability will lead to additional safety risk potential, process upsets, production losses and their associated consequential costs to our business as described below:-

1. Many of our members operate process plant facilities which are classified and regulated Major Hazard Facilities (MHFs). All of these facilities are required to be strictly regulated under the Dangerous Goods Safety Act 2004, including the associated Regulations. This requirement is by virtue of the scale, inventory holding and inherent risk of the operations that store and handle Schedule 1 Dangerous Goods at these facilities. The Department of Mines and Petroleum of WA is the government authority responsible for regulating these industries.

   One of the key implications of the classification is the requirement of these MHFs to formally demonstrate that the risks from any potential major incident is acceptable and reduced to as far as reasonably practicable (by authority of Regulation 25 of the Dangerous Goods Safety (Major Hazard Facilities) Regulations 2007, otherwise known as the MHF Regulations).

   These KIC members are required to meet these statutory requirements and introducing a greater variation in SWIN frequency increases the variability of our processes (described in item 2. below) and this will thereby increase the potential for unintended events to occur.

   Whilst our members will always remain fully committed to protecting their employees and stakeholders (including the community and neighbouring industries), the latent potential for major incidents at a MHF can never be fully statistically eliminated. Therefore despite the likelihood of such major a hazard incident event actually transpiring may be extremely low, given the high consequence impact of any major incident statistically still remains (albeit very rare), KIC would like to ensure this potential remains minimised to the extent that it is justifiably as far as reasonably practicable.

2. Some of the continuous processes that feature within the Kwinana industrial area to name but a few include; oil refining, catalytic cracking and hydrogenation, hydrocarbon distillation, liquefied petroleum gas separation, titanium dioxide production, chlorine gas production, alumina production, hydrogen gas production, ammonium sulphate crystallisation, nickel matt production, ammonia production, nitric acid production, sodium cyanide production, fluorosilicic acid production, specialty chemicals and fertiliser production. All of our members' processing plants are tightly controlled and rely on close control of ratios of process materials /fluids. The flow rate of the various raw material substances used within the processing is controlled through the use of various types of dynamic control equipment (eg variable speed conveyors, pumps and fans which are driven by induction motors, compressors on a common shaft with steam turbines and synchronous generators). Variations in SWIN frequency will cause the speed of the all motors and generators connected to the SWIN to change their speed in direct proportion to the frequency change and will upset the process condition leading to a real risk of the plant;

    a. not meeting its optimum operating point or
    b. introducing instability in the operation of the plant which can cause significant deviations in the process or
    c. causing the plant to trip due to operation outside the safe boundaries

   In the past all of these impacts described above have been attributed to large or oscillating changes in frequency of the SWIN. A number of our members have witnessed these changes and their unfortunate flow-on effects when rare changes in frequency have previously occurred during unexpected SWIN faults.

3. A number of the members operate steam turbines connected to synchronous generators. KIC is advised that a one per cent shift in frequency, coupled with Western Power's Technical Rule requirements of four per cent droop characteristic, means that there will be a 25 per cent change in generator power and hence an equivalent change in steam flow. This is a very significant change in steam rejected or steam called for by the turbo-generator. Such large changes in steam flow can directly affect our members' plants and have in the past caused the same effects as noted in item 2 above.

Our members that have complex processing plants have had experiences that when a trip occurs this can often incur other various undesired impacts. Some of these heightened potentials during unsteady state, shutdown or start up activities include: risk of an over pressure event, risk of an over temperature event, risk of consequential equipment damage, risk of injury to personnel, risk of harm to the environment, significant production losses, and wasted utilities (power, gas, water, nitrogen) during plant restart. Also some of our members plants can take many days to restart and for this impost to be created due to the simple effect of "expected" variability in SWIN frequency is unacceptable to KIC and its members.

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As previously mentioned a number of our members' plants are MHFs and are complex in nature. Some of these plants operate at high temperatures and pressures as part of their steady state operations. The process design within some of these critical applications is such that the equipment is operating close to critical limits of the exotic materials and equipment used. Thus the effects of cooling down, heating up and the inherent risks in starting up or shutting down a plant or a part of a plant is something to be resisted when there is no important reason to necessitate a change from steady state operation. Regrettably, some shutdowns of our members' plants have in the past resulted in some major consequential damage or extended plant outages and we seek to minimise this future potential as much as practicable.

The document Western Power has provided states, "*The control of the frequency does not come without costs however. The costs arise from having to burn more expensive fuels in frequency controlling generators, compared to those fuels that would have been used if the control was not provided. In the SWIS, the cost of this service is in the order of $50M/year.*"

This statement suggests there is a $50 million per year cost saving by supporting greater variability of SWIN frequency. KIC's view is that the statement is purely made from a network owner's perspective and does not in any way consider the raft of potential flow on effects of whole of business including the impact on all downstream customers impacted.

When considering the salient points we have raised, our view is that there is a highly unfavourable net increase in true total cost when one also considers the likely loss events incurred by all "24/7" continuous processing plants connected to the SWIN. These losses will likely far exceed the stated savings cited within your advice. Given the heightened potential for significantly higher losses by your customers - like KIC's members that utilise process equipment that rely on stable frequency on a continuous basis from a base load network power supply, we firmly believe no such $50M/year cost benefit exists when a holistic net cost benefit review that includes all end users is considered.

In summary, when the SWIN and the frequency rapidly swings (more than 0.25 hertz), our members' plants become exposed to a higher potential for the introduction of major risk, and consequently our members' businesses as well as their downstream customers are then exposed to major interruption and costs.

Therefore, we are opposed and **do not support the proposed change** by Western Power to relax the SWIN grid frequency control.

Furthermore, in anticipation of an alternate proposal to only perform a limited pilot trial of such a scheme, we believe that this should not be considered as an alternative since the outcome will not have reliable data unless the trial is run sufficiently long that the full gamut of frequency changes are experienced. During any such long duration of establishment time our members will have needed to have suffered the unacceptable outcome of considerable financial loss (as will also other similar industries) for this trial outcome to be faithfully demonstrated to have a net negative benefit.

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Even if Western Power were to hypothetically underwrite all our members' direct and consequential losses, including added risks of damage, injury, environment, the costs of restarting, failure to supply / loss of customer good will as a result of a frequency variation, our members would still be reluctant to agree to the trial. We would still see these risks as unacceptable to any party, regardless of their own appetite and willingness for taking on the risk. Many of our members' supply essential products including transport fuel, sanitation chemicals, agricultural fertilisers, and essential chemicals for much of the Western Australia's mining activities, so irrespective of who is held accountable for any interruption in supply, the outcome of an interruption with these far reaching economic impacts and this remains unacceptable.

Thank you for the opportunity to provide this feedback. If required I can be contacted on (08) 9419 1855 to discuss this matter further.

Yours sincerely

Chris Oughton
Director Kwinana Industries Council

NEWGEN NEERABUP

07 March 2013

Mr Brendan Clarke

RE: Load Following Ancillary Services: Letter & Factsheet regarding frequency relaxation

Dear Brendan,

Please find responses below to the request of information relating to the frequency tolerance relaxation;

► Do you have specific requirements for power system frequency performance?

No.

► How do you expect your requirements in respect of power system frequency to change in future?

We do not expect our requirements will change.

► What form of customer plant is sensitive to frequency, such as motor drives & generators?

Any changes to the tolerance band may add additional time required to synchronise a Neerabup Generator. The synchronisation time will likely increase (under low grid frequency conditions) with a relaxation of the tolerance.

► Are there any material impacts caused by frequency variations in the range 49.5 to 50.5 Hz, in particular those which may result in increased costs?

None expected – Neerabup believes that we can handle the relaxation of the frequency tolerance bands. However we as a market participant reserve the right to have the ability to return to the current/existing frequency tolerance range if material impacts are experienced.

Yours sincerely,

Bruno Lanciano

Station Manager

NewGen Neerabup Partnership

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• 123 EAGLE ST, BRISBANE Q 4000 • GPO BOX 7152, BRISBANE Q 4001
ABN 63 218 761 290 • PH: (+61 7) 3020 5100 • FAX: (+61 7) 3220 6110
www.ermpower.com.au

COCKBURN CEMENT LTD

Hi Brendan / David

I am writing this email on behalf of Cockburn Cement Limited in response to your email regarding the proposed frequency relaxation of the SWIS electrical system.

Since this proposition received on relatively short notice, CCL have not been able to engage a power system analyst / engineer to fully assess the impact of Western Power's proposition on CCL electrical equipment. For the same reason, a thorough investigation has not been performed. As you may be aware, some of CCL electrical equipment is in excess of 50 years old, hence not adequate documentation / data sheets / manuals exist to provide detailed information as to what frequency tolerance is acceptable for their operation. Nevertheless, a preliminary survey of CCL electrical system and frequency dependant equipment such as VFDs, reveals no adverse impact from the proposed frequency relaxation, providing it will not increase beyond 1% (49.5Hz and 50.5Hz).

In summary CCL do not expect any obvious impact on its electrical equipment. The actual impact of the proposed frequency relaxation practice will only be fully perceived once it is tested. Naturally, CCL reserve the right to review and proclaim the adverse impacts of this practice after the initial trial period is completed.

I hope the above answers your question.

Thank you

Regards,

Saeid Bossaghzadeh

Electrical Engineer

Cockburn Cement Ltd

Lot 242 Russell Road East, Munster WA 6166

Mob: +61 407 960 379

Ph: +61 8 9411 1094

Fax: +61 8 9411 1346

Email: Saeid.Bossaghzadeh@cockburncement.com.au

COLLGAR WINDFARM

Hi Brendan

I write on behalf of Collgar Wind Farm (CWF) in response to the above proposal as described in your presentation to the Generator Forum of January 17th and as discussed subsequently with our Senior Advisor, Doug Aberle.

With respect to impacts on the Vestas V90-2MW Wind Turbine Generators, we confirm that they can operate continuously between 53Hz and 47Hz so we do not see any material impacts on the machines per se of frequency variations in the range 49.5Hz to 50.5Hz.

It should be noted that the over-frequency protection scheme covering the entire wind farm is currently set (at Western Power's direction) to trip turbines progressively feeder by feeder in the event of an excursion beyond 50.3Hz. The loss of feeders in this scenario requires site attendance by technicians to return machines to service so there is potential for material loss of revenue to CWF in this event.

Depending on the actual frequency of these excursions in the event of relaxation of standards, this cost may outweigh reduced charges for LFAS services to Collgar which may (or may not) arise from the relaxation.

We at CWF acknowledge that the intention of the trial is to gain data as to what actually occurs both to the system and the market if frequency relaxation is allowed.

On this basis and on the understanding that if any negative impacts on CWF emerge when analyzing the results of the trial there will be no obligation to accept the adjustment as permanent, we endorse the proposal to proceed with testing the impact of progressively relaxing frequency standards.

Kind Regards

Alistair Craib

CEO Collgar Wind Farm

Agenda Item 5a: Overview of Market Rule Changes

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

Rule changes: Formally submitted (see appendix 1)	**3rd April 2013**
Fast track with Consultation Period open	1
Standard Rule Changes with 1st Submission Period Open	1
Fast Track Rule Changes with Consultation Period Closed (final report being prepared)	0
Standard Rule Changes with 1st Submission Period Closed (draft report being prepared)	3
Standard Rule Changes with 2nd Submission Period Open	3
Standard Rule Changes with 2nd Submission Period Closed (final report being prepared)	2
Rule Changes - Awaiting Minister's Approval and/or Commencement	3
Total Rule Changes Currently in Progress	**13**

Potential changes logged by the IMO – Not yet formally submitted	**February/ March**	**April**
High Priority (to be formally submitted in the next 3/6 months)	0	0 (+0/-0)
Medium Priority (may be submitted in the next 6/12 months)	25	26 (+1/-0)
Low Priority (may be submitted in the next 12/18 months)	27	27 (+0/-0)
Potential Rule Changes (H, M and L)	**52**	**53**

The changes in the rule change issues log from March to April are outlined below:

Priority	Issue
High	• N/A
Medium	**In:** • **Resource Plans for Non-Scheduled Generators:** With the introduction of the new Balancing Market, the requirement to submit Resource Plans under clause 6.5.1A was extended to Market Generators whose only Registered Facilities were Non-Scheduled Generators. However, the validation tests for a Resource Plan prescribed in clause 6.11.3 do not always work correctly for these Market Participants. For example, in the case of a Market Generator, whose only Registered Facility is a Non-Scheduled Generator, has sold no energy for a Trading Interval through either bilateral contracts or the STEM, the Net Contract Position of the Market Generator would be zero for the Trading Interval. If the participant submits a Resource Plan for the Trading Interval in accordance with clauses 6.5.1A and 6.11.1 (which defines the required format) then, assuming the participant expects to generate some energy in the Trading Interval, the submission would fail to satisfy the tests prescribed in clauses 6.11.3(a) and 6.11.3(b). **Out:** • **N/a**
Low	**In:** • N/a

The IMO also notes that it keeps a log of Minor and Typographical issues and Rule Change Suggestions that is updated on a regular basis. The Issues contained within the Minor and Typographical Log are collated and submitted in batches during the year. Rule Change Suggestions contained on the IMO's log form the basis for the Market Rules Evolution Plan.

APPENDIX 1: FORMALLY SUBMITTED RULE CHANGES (Current as of 3rd April 2013)

Fast Track Rule Change with Submission Period Open

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2013_06	27/03/2013	Exclusion of LFAS Quantities from Daily Ancillary Service Files	IMO	Submissions close	19/04/2013

Standard Rule Change with First Submission Period Open

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2012_02	27/03/2013	Assignment of Capacity Credits to Network Control Facilities	IMO	Submissions close	13/05/2013

Standard Rule Change with First Submission Period Closed

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2012_02	03/09/2012	Relevant Demand of a Demand Side Program	EnerNOC	Draft Rule Change Report Published	15/05/2013
RC_2012_10	22/06/2012	Limits to Early Entry Capacity Payments	Synergy	Draft Rule Change Report Published	22/04/2013
RC_2012_20	21/01/2013	Consideration of Network Constraints for Certified Reserve Capacity	IMO	Draft Rule Change Report Published	06/03/2013

Standard Rule Change with Second Submission Period Open

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2012_07	20/11/2012	Loss Factor Determination	IMO	Submissions close	16/04/2013
RC_2012_22	11/12/2012	Commitment and De-commitment Notification Requirements	System Management	Submissions close	22/04/2013
RC_2012_24	18/12/2012	Cure Notices and Credit Support	IMO	Submissions close	04/04/2013

Standard Rule Change with Second Submission Period Closed

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2012_11	30/07/2012	Transparency of Outage Information	IMO	Final Rule Change Report Published	16/04/2013
RC_2012_21	20/11/2012	5-Yearly Review of Planning Criterion	IMO	Final Rule Change Report Published	18/04/2013

Fast Track Rule Change Awaiting Ministerial Approval

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2012_25	21/01/2013	Constrained On/Off Compensation Removal where a Facility is Non-compliant with Dispatch Instructions	IMO	Ministerial Approval	24/04/2013

Standard Rule Change Awaiting Commencement

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2011_02	10/03/2012	Reassessment of Allowable Revenue during a Review Period	ERA	Commencement	01/07/2013
RC_2012_06	07/11/2012	Clarification of Reviewable Decisions and Definitions of Regulations	IMO	Commencement	01/06/2013

Wholesale Electricity Market
Pre Rule Change Proposal

Rule Change Proposal ID: **PRC_2013_11**
Date received: **TBA**

Change requested by:

Name:	Allan Dawson
Phone:	9254 4333
Fax:	9254 4399
Email:	allan.dawson@imowa.com.au
Organisation:	IMO
Address:	Level 17, 197 St Georges Terrace, Perth 6000
Date submitted:	TBA
Urgency:	Medium
Change Proposal title:	Selection of the 12 peak Trading Intervals used for calculation of IRCR
Market Rule(s) affected:	Appendix 5

Introduction

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

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

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

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

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

The objectives of the market are:

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

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

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

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

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

Details of the Proposed Rule Change

---

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

Background

As part of the Reserve Capacity Mechanism (RCM), the IMO must determine for each Capacity Year the Reserve Capacity Requirement (RCR). The RCR is an estimate of the capacity that would be required to:

- meet the forecast peak demand (assuming expected growth and with a 10% probability of exceedance) plus an additional reserve margin and allowance for Load Following Service; and
- limit expected energy shortfalls to 0.002% of annual energy consumption.

In practice the first criterion is dominant, which means that the key factor in determining the RCR for a Capacity Year is the forecast system demand for the highest demand Trading Interval in that year.

To fund capacity that is procured through the RCM, each Market Customer is assigned an Individual Reserve Capacity Requirement (IRCR) obligation. The IRCR for a Market Customer is a quantity of capacity (expressed in MW) which represents that customer's share of the RCR for the relevant Capacity Year.

IRCRs are determined by dividing the RCR among Market Customers based on their relative contribution to metered output during the “12 peak Trading Intervals” in the previous Hot Season (December to April inclusive). The calculation is based on the median output from the 12 Trading Intervals selected as the “3 highest demand Trading Intervals on each of the 4 Trading Days with the highest daily demand, where demand refers to total demand, net of embedded generation, in the SWIS"[1]. "Highest daily demand" is calculated based on total sent out energy during the Trading Day.

Issue

The Reserve Capacity Mechanism Working Group has recently undertaken a review of a number of aspects of the RCM, including a consideration of the allocation of capacity costs among Market Customers. During the review, a misalignment between the determination of the RCR and IRCRs was identified.

The current IRCR allocation is based on Trading Intervals selected from the four Trading Days with the highest daily consumption in the Hot Season. However, the RCR is calculated based on demand during peak Trading Intervals and not on daily consumption. The Trading Days with the highest daily demand do not always align with the Trading Days with the peak demand Trading Intervals. In each of the last five Hot Seasons, at least one of the four Trading Days used was not in the top four demand days as measured by peak demand. This creates a risk of selecting Trading Intervals that are unrepresentative of a system peak demand event, upon which the RCR is conceptually based.

An illustration of this is the inclusion, under the current IRCR methodology, of three Trading Intervals from Australia Day (26 January 2012) in the 12 Peak Trading Intervals used for IRCR calculations for the 2012/13 Capacity Year. The consumption profile on a public holiday differs to that of a Business Day (containing a higher proportion of residential load and lower proportion of commercial load), and it is unlikely that the highest demand Trading Intervals would occur on such days.

If the Trading Day selection had been based on the maximum demand for each Trading Day, the three Trading Intervals used in the IRCR calculation would instead have been selected from 1 February 2012, which was a Business Day. This would have resulted in an IRCR allocation which more accurately reflected each Market Customer's likely contribution to system peak load.

Proposal

The IMO proposes to amend Appendix 5 of the Market Rules to select the 12 Trading Intervals from the 4 Trading Days in the previous Hot Season with the highest maximum demand, rather than the 4 Trading Days in the previous Hot Season with the highest daily consumption.

The IMO also proposes a minor amendment to Appendix 5 to clarify that the demand in a Trading Interval is measured as the sum of the Sent Out Metered Schedules of all Scheduled Generators and Non-Scheduled Generators in that Trading Interval.

2. Explain the reason for the degree of urgency:

The IMO submits that this Rule Change Proposal should be progressed via the Standard Rule Change Process.

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

[1] Appendix 5 of the Wholesale Electricity Market Amending Rules

Appendix 5: Individual Reserve Capacity Requirements

This Appendix presents the method for annually setting and monthly adjusting Individual Reserve Capacity Requirements.

For the purpose of this Appendix:

- Steps 1 to 10 are repeated every month.
- All references, apart from those in Step 5A, to meters are interval meters.
- The Notional Wholesale Meter is to be treated as a registered interval meter measuring Temperature Dependent Load. This meter is denoted by Temperature Dependent Load meter v=v*.
- The New Notional Wholesale Meter, determined in accordance with Step 5A, is to be treated as a registered interval meter measuring Temperature Dependent Load.
- The meter registration data to be used in the calculations is to be the most current complete set of meter registration data as at the time of commencing the calculations.
- The values of RR (the Reserve Capacity Requirement) and FL (forecast peak demand associated with that Reserve Capacity Requirement as specified in clause 4.6.2) may be modified from their standard values in accordance with clause 4.28.11A.
- In the case of the first Reserve Capacity Cycle, the IMO may use meter data relating to periods prior to Energy Market Commencement as if the energy market had commenced prior to the time periods covered by that meter data.
- In Steps 1 and 5 the demand in a Trading Interval is measured as the sum of the Sent Out Metered Schedules of all Scheduled Generators and Non-Scheduled Generators in that Trading Interval.
- In Step 1 the maximum demand for a Trading Day is the highest demand measured for any Trading Interval in that Trading Day.

STEP 1: Define the 12 peak Trading Intervals during the Hot Season preceding the initial calculation of Individual Reserve Capacity Requirements for a Reserve Capacity Cycle (the "preceding Hot Season") as corresponding to the 3 highest demand Trading Intervals on each of the 4 Trading Days with the highest ~~daily~~ maximum demand~~, where demand refers to total demand, net of embedded generation, in the SWIS~~.

…

STEP 5: When determining the Individual Reserve Capacity Requirements for Trading Month n identify meters that were not registered with the IMO during one or more of the 12 peak Trading Intervals in the preceding Hot Season but which were registered by the end of Trading Month n-3.

Identify the 4 Peak SWIS Trading Intervals of Trading Month n-3, being the 4 highest demand Trading Intervals~~, where demand refers to total demand, net of embedded generation, in the SWIS~~.

For a new meter u that measures Non-Temperature Dependent Load set NMNTCR(u) to be 1.1 times the MW figure formed by doubling the median value of the metered consumption for that meter during the 4 Peak SWIS Trading Intervals of Trading Month n-3.

For a new meter v that measures Temperature Dependent Load set NMTDCR(v) equal to be 1.3 times the MW figure formed by doubling the median value of the metered consumption for that meter during the 4 Peak SWIS Trading Intervals of Trading Month n-3.

For a new meter w that measures Intermittent Load set IILRCR(w) in accordance with Appendix 4A to the value applicable to Trading Month n.

…

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

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

The proposed methodology more accurately (and more equitably) allocates the costs of Reserve Capacity among Market Customers, through better aligning each Market Customer's IRCR with its contribution to peak demand. This provides price signals that encourage Market Customers to reduce their peak demand, which contributes to the following Wholesale Market Objectives:

- minimising the long-term cost of electricity supplied to customers (Wholesale Market Objective (d)) by providing incentives to reduce peak load, which has the effect of reducing the RCR and the need for investment in network infrastructure; and
- encouraging the taking of measures to manage the amount of electricity used and when it is used (Wholesale Market Objective (e)).

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

The IMO will incur some costs associated with implementing the necessary changes to the IMO's systems. These costs are not expected to be significant.

Wholesale Electricity Market
Pre - Rule Change Proposal

Rule Change Proposal ID: **PRC 2013_09**
Date received: **TBC**
Change requested by: **IMO**

Name:	Allan Dawson
Phone:	08 9254 4333
Fax:	08 9254 4399
Email:	Allan.Dawson@imowa.com.au
Organisation:	*IMO*
Address:	L17, 197 St Georges Tce, Perth WA 6000
Date submitted:	TBC
Urgency:	*2-medium*
Change Proposal title:	Incentives to Improve Availability of Scheduled Generators
Market Rule(s) affected:	2.17, 4.11, 4.12, 4.26, 4.27, Chapter 11 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: Group Manager, Development and Capacity
PO Box 7096
Cloisters Square, Perth, WA 6850
Fax: (08) 9254 4339
Email: market.development@imowa.com.au

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

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

The objectives of the market are:

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

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

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

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

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

Details of the Proposed Rule Change

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

1.1 Background

The existing Wholesale Electricity Market Amending Rules (Market Rules) provide inadequate incentives to Market Participants to maximise the number of Trading Intervals that their Scheduled Generators are available to the energy markets.

In recent years, some Scheduled Generators have displayed very poor availability levels, driven primarily by excessive planned outage rates for which there is currently no direct financial consequence under the Market Rules. According to statistics published by the Energy Supply Association of Australia[1], the availability performance of the Western Australian generation sector has deteriorated in the last five years and WA now has the worst generation availability factor and highest planned outage factor in Australia.

The implications of this situation for the South West Interconnected System (SWIS) include:

- Poor value for money – Customers are paying a significant amount for Reserve Capacity for which the probability of availability is low.
- Inefficiency – The unavailability, due to frequent planned outages, of Scheduled Generators with low short-run marginal costs (SRMC) reduces competitive pressure in the Short Term Energy Market (STEM) and Balancing Market, potentially resulting in higher-than-necessary average energy prices.

[1] ESAA: Electricity Gas Australia, published annually.

- Higher risk – The frequent unavailability of large amounts of low-SRMC capacity due to planned outages reduces the effective reserve margin and increases the risk that a generation plant failure will result in price spikes.
- Inequity within facility class – The worst-performing generators are receiving capacity revenue per available hour that is significantly higher than the best-performing generators[2].
- Retention of inefficient and unreliable generating plant – Subsidising unreliable plant with capacity payments mutes the normal commercial incentives for retirement of inefficient, unreliable or obsolete generation facilities.
- Misleading supply signals – The assignment of full Reserve Capacity to frequently unavailable Scheduled Generators may discourage investors by suggesting an apparent system reserve margin higher than the generation capacity that is actually reliably available.

The situation is inconsistent with the Market Objectives of economically efficient, safe and reliable supply of electricity, encouraging competition, and minimising the long-term cost of electricity to customers.

The Independent Market Operator (IMO) acknowledges that Scheduled Generators require periodic testing, inspections and overhauls to maintain them in a reliable and efficient condition. Traditional industry practice for steam turbines has involved minor outages/overhauls (typically two to four weeks) every two to four years and major overhauls (typically four to eight weeks) every three to nine years, with allowance for the number of starts and operating hours. Gas turbines have tended to have a higher-frequency overhaul cycle. Many operators now use risk-based or condition-based maintenance strategies in which operating conditions and test results, rather than elapsed time or operating hours, dictate overhaul frequency. The aim of this approach is generally to reduce the frequency of overhauls.

The IMO also appreciates that occasionally an overhaul will reveal a previously unknown problem that requires rectification. However three or more successive years with average Planned Outages in excess of 15 weeks annually is a significant variation from accepted industry practice for a commercial generator. This indicates either an extremely unreliable plant for which retirement should be a serious option, or a need to improve availability incentives.

The Economic Regulation Authority (ERA) and a number of industry stakeholders have expressed concern about the very high levels of unavailability among some large generating Facilities, the potential impact that this has on the energy markets, and whether the existing Market Rules provide an effective mechanism for ensuring the economically efficient provision of generation capacity to the SWIS.

[2] For example, the capacity revenue received per Capacity Credit per available hour by the Scheduled Generators with the lowest availability in the 2010/11 and 2011/12 capacity years was $35.49 and $27.06 respectively, while those with the highest availability received $16.51 and $15.06 per Capacity Credit per available hour

1.2 Effect of existing Market Rules

Clause 4.11.1(h)

(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[3]. The IMO may consult with System Management in deciding whether or not to refuse to grant Certified Reserve Capacity under this clause 4.11.1(h);

The clause 4.11.1(h) threshold criteria were set at a time when the average Forced Outage Factor of SWIS-connected generation was around 4% and the Planned Outage Factor was approximately 10% (equating to an Availability Factor[4] of 86%) and Availability Factors had been mostly in the range 85-92% for the previous decade. A combined outage rate of >30% over multiple years was (and still is) indicative of the worst-performing decile of thermal generating plant performance by comparison with international benchmarks.

To support the IMO in making a decision under clause 4.11.1(h), it may use information provided by the applicant under clause 4.10.1 including expected (clause 4.10.1(e)(vi)) and actual (clause 4.10.1(e)(vii)) forced and unforced outage rates. The Market Procedure for Certifying Reserve Capacity allows for the IMO to seek additional information from the applicant, including the causes of the past outages, the steps being taken by the applicant to reduce the outage rates, and the applicant's expectation of the level of future outages. The IMO may assess the likelihood that the applicant's actions will reduce the outage rates and decide whether the expected outages are likely to compromise the security and reliability of the SWIS. It may consult with System Management in making its decision.

The Market Rules do not explicitly state the purpose of clause 4.11.1(h). Clause 4.11.1(h) provides no guidance to the IMO in identifying and assigning relative importance to the factors to be considered in the exercise of its discretion under this clause. Decisions made under clause 4.11.1(h) are not Reviewable Decisions under clause 2.17.1.

Clause 4.11.1(h) of the Market Rules is a 'go/no go' filter. The IMO has the discretion to refuse to assign any Certified Reserve Capacity to a Facility that breaches the 36-month outage rate threshold. However, if it does not exercise this discretion, it has no power to adjust the quantity of Capacity Credits to be assigned to reflect the Facility's reliability.

[3] The outage definitions used in the Market Rules and the outage performance indicators defined in the Power System Operation Procedure: Facility Outages are not standard industry definitions. The terms 'Forced Outage rate' and 'Planned Outage rate' used in the Market Rules and Power System Operation Procedure are approximately aligned to the IEEE-762 standard definitions of 'Equivalent Forced Outage Factor' and 'Equivalent Planned Outage Factor'. However, many outages classified as 'Planned' in the WEM would be classified as 'Forced' under standard industry definitions.

[4] 'Availability Factor' (and 'Equivalent Availability Factor') are standard industry performance indicators. They measure the proportion of a given operating period in which a generating unit is available without any outages.

Clauses 4.11.1(a), (b) and (g) place upper limits on the level of Reserve Capacity that the IMO may certify for a Facility, which implies that a lower level may be assigned. However, there are no provisions in clause 4.11.1 or Appendix 3 of the Market Rules, or in the Market Procedure for Certifying Reserve Capacity, that make provision for considering outage-related availability when Certified Reserve Capacity amounts are determined for a Scheduled Generator.

Clause 4.11.1(a) refers to the *'IMO's reasonable expectation of the amount of capacity likely to be available….for Peak Trading Intervals on Business Days'* between 1 October in Year 3 of the Reserve Capacity Cycle and 31 July in Year 4. Neither this nor any other clause specifies a minimum proportion of those Peak Trading Intervals during which the IMO should be able to reasonably expect that the capacity will be available.

Clause 4.12.3

4.12.3. The IMO must use the information described in clauses 4.10.1 and 4.25.12 to set the Reserve Capacity Obligation Quantity to apply to a Facility in each Trading Interval. The Reserve Capacity Obligation Quantity to apply to a Facility may differ between Trading Intervals.

The information provided by the applicant under clause 4.10.1 of the Market Rules includes previous and expected outage rates for the Facility as well as other restrictions on availability identified by the applicant.

In effect, the Market Rules require the IMO to consider the expected outage rates of a Scheduled Generator when assessing how many Capacity Credits the Facility will be obliged to provide, but do not permit the IMO to consider outage rates when assessing the number for which it will be paid.

Clause 4.12.6(b)

4.12.6 (b) subject to clause 4.27.9, during Trading Intervals where there is a Consequential Outage or a Planned Outage for a Facility provided to the IMO by System Management in accordance with clause 7.3.4, the IMO must reduce the Reserve Capacity Obligation Quantity for that Facility, after taking into account any adjustments in accordance with paragraph (a), to reflect the amount of capacity unavailable due to that outage;

The effect of clause 4.12.6(b) is to grant Facilities an uncapped entitlement to have their Reserve Capacity Obligation Quantity reduced for the Trading Intervals during which their capacity is unavailable due to Planned Outages.

This protects Market Participants from the Reserve Capacity Deficit Refund which would otherwise apply under clause 4.26 to a Scheduled Generator failing to deliver its Reserve Capacity Obligation Quantities in any Trading Interval.

Clause 4.27.9 suspends the operation of clause 4.27.6(b) under specified circumstances for selected Scheduled Generators. The criteria for the operation of the existing clause 4.27.9 relate to total system capacity availability over an extended period, and are unlikely to be met in practice.

The protection that clause 4.12.6(b) provides for unreliable Facilities is significantly increased by the very broad definition of Planned Outages, defined in clause 3.19.11 as any outage that is approved by System Management under clause 3.19.4.

- Clauses 3.18.5 and 3.18.5A allow Market Participants to submit an Outage Plan to System Management for approval up to two days prior to the proposed commencement of the outage.
- Clause 3.19.2 allows Market Participants to seek System Management's approval for unscheduled Opportunistic Maintenance with as little as one hour's notice, for an outage confined to a single Trading Day for minor maintenance that does not require changes to scheduled energy or ancillary services. Opportunistic Maintenance is specifically classified as a Planned Outage under clause 3.19.11.

Clause 4.27

Clause 4.27 provides the potential for greater scrutiny and intervention by the IMO regarding Facilities with excessive Planned Outage rates. The effectiveness of this clause is severely limited by being dependent on '*the number of days in the preceding 12 months where the total available capacity in the SWIS dropped below 80% (during the Hot Season), and 70% (in either the Intermediate Season or Cold Season), of the total Capacity Credits held by Market Participants for more than six hours*'.

If these criteria are met for more than 40 days, clause 4.27.3 obliges the IMO to require reports from Market Participants responsible for Scheduled Generators that are unavailable due to Planned Outages for more than 1,000 hours (Planned Outage rate of 11.4%) in the preceding 12 months.

Under clause 4.27.4, these reports must include explanations of the Planned Outages and measures being taken to increase the availability of the Facility, and a statement of the expected Planned Outage days to be taken in the next 24 months, with reasons for each.

Clause 4.27.7 permits the IMO, at its discretion, to limit the number of Planned Outage days that may be taken in the next 24 months if it considers that the Market Participant's proposed level of Planned Outages is unjustified based on good industry practice. This limit does not prevent the Market Participant seeking approval from System Management for Planned Outages in excess of this limit, and only has a tangible effect if clause 4.27.9 is triggered.

Clause 4.27.9 is triggered only if the total available system capacity is reduced significantly for 80 days in the previous 12 months. This clause obliges the IMO to cease adjusting Reserve Capacity Obligation Quantities for the Scheduled Generators referred to in clause 4.27.3 once they exceed the number of days of Planned Outage predicted by the Market Participant under clause 4.27.4(b) or determined by the IMO under clause 4.27.7. The Facility would then be exposed to the risk of being liable for Reserve Capacity Deficit Refunds for Planned Outages in excess of the limit.

The IMO does not have any discretion to apply clauses 4.27.3 – 4.27.9 unless the thresholds for reduction of total system available capacity are first exceeded. The 40 day threshold has not been exceeded since the commencement of the market, and the probability of it being exceeded in the future is negligible.

Clause 4.29

Clause 4.29 sets a single Monthly Reserve Capacity Price which applies to all Capacity Credits. Clause 4.29.4 allows for the IMO to adjust the quantity of Capacity Credits for which a Market Participant is paid to reflect the proportion of a Trading Month for which the Capacity Credit existed. This applies when a Capacity Credit has been terminated, created or reinstated for any reason.

There is no provision for adjusting these quantities to reflect the proportion of a Trading Month for which the capacity associated with those Capacity Credits was unavailable due to outages. However, the Reserve Capacity Refund Mechanism (clause 4.26.1A) partially addresses this issue with respect to Forced Outages taken by Scheduled Generators.

1.3 Proposed changes to the Market Rules

A Concept Paper was prepared and circulated to members of the Market Advisory Committee, proposing a number of options to address the issues identified above and improve incentives for Market Participants to maximise the number of Trading Intervals that their Scheduled Generators are available in the energy markets.

The IMO has considered the matters raised and views expressed by members of the Market Advisory Committee, and proposes to amend the Market Rules to:

- **Improve the practicality and effectiveness of Clause 4.11.1(h)** by:
    - o Permitting the IMO more flexibility in assigning a quantity of Certified Reserve Capacity (between zero and full allocation) to Scheduled Generators displaying excessive outage rates over 36 months;
    - o Specifying a range of factors for the IMO to consider in making its decision, adding certainty, structure and transparency to the process;
    - o Progressively tightening the combined Planned Outage rate and Forced Outage rate thresholds that trigger clause 4.11.1(h), from 30% to 20% over five years, commencing in 2016, with corresponding changes to the Forced Outage rate threshold; and
    - o Making the IMO's decisions under this clause reviewable.
- **Impose an upper limit on the number of Trading Intervals in a three-year period for which a generator can claim a reduction of its Reserve Capacity Obligation Quantities due to Planned Outages**.
    - o After the Facility reaches this cap, the IMO will no longer be required to reduce the Reserve Capacity Obligation Quantity for that Facility to reflect the amount of capacity unavailable due to Planned Outages.
    - o The relevant Market Participant will be liable to pay Reserve Capacity Deficit Refunds for subsequent Planned Outages taken by that Facility in that year, as well as for its Forced Outages.
    - o A three-year cap has been selected to accommodate periodic major overhauls through allowing Facilities to smooth their Planned Outage rates over a longer period.
    - o The proposed initial cap of 7,800 Trading Intervals (3,900 hours or 23.2 weeks) over three Capacity Years is equivalent to an average annual Planned Outage Factor of 14.8%. This figure is consistent with the discussion at the Market Advisory Committee on 20 March 2013, where a Planned Outage cap of 15% was suggested. This is substantially higher than the historical rates

for most Scheduled Generators, and it is proposed that this cap be reviewed within five years of operation.

  - Trading Intervals will not count towards the cap if no adjustment to Reserve Capacity Obligation Quantities was made and the Market Participant was required to pay a Reserve Capacity Deficit Refund in relation to that Trading Interval.

- **Improve the practicality and effectiveness of Clause 4.27** by:

  - Granting the IMO a discretionary power to require a performance report and performance improvement reports from the relevant Market Participant concerning a Scheduled Generator with an excessive planned outage rate, regardless of the availability of total system capacity.

  - Deleting clauses 4.27.7 and 4.27.8, which become redundant as a result of the change to clause 4.12 that imposes a cap on Planned Outages for which a reduction in Reserve Capacity Obligation Quantities may be claimed.

  - Permitting the IMO to temporarily adjust the cap on the number of Trading Intervals eligible for a reduction of Reserve Capacity Obligation Quantities if the system capacity availability criterion in clause 4.27.9 is met. This is a consequential change required to maintain the intent of clause 4.27.9 in the event that the total system is under extreme capacity stress due to generator unavailability. The probability of the criterion in clause 4.27.9 being met is considered negligible.

2. Explain the reason for the degree of urgency:

Some Scheduled Generators have demonstrated poor availability over several years, with little indication that the frequent and extended Planned Outages have improved the availability of the Facilities. Previous assurances that availability would improve for these Facilities have not been met. Incentives to change behaviour need to be put in place to discourage further deterioration in performance, and the consequential negative impact on the market.

Delays in making these changes will increase the cost to the market of the continued high level of generation unavailability.

Some of the proposed Rule Changes will include a transition time to allow affected Market Participants to implement remedial measures and if necessary adjust business plans and maintenance strategies to manage the impact of the changes. Notification of the timetable for the commencement of the Rule Changes should be provided as soon as possible.

Approval of these Rule Changes by August 2013 would enable changes to be initiated in the 2013/14 Capacity Year and long-lead-time changes to commence having a tangible effect by the 2015/16 Capacity Cycle.

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

3.1 Proposed Changes to Clause 2.17.1 Reviewable Decisions

Note that since this clause is a Protected Provision, Ministerial consent will be required under clause 2.5.8.

2.17.1. Decisions by the IMO or System Management, as applicable, made under the following clauses are Reviewable Decisions:

(a) clause 2.3.8;
(b) clause 2.5.9;
(c) clause 2.6.4(f);
(d) clause 2.7.8(e);
(e) clause 2.10.2A;
(f) clause 2.10.13;
(g) clause 2.10.14;
(h) clause 2.13.28;
(i) clause 2.28.16;
(j) clauses 2.30.4 and 2.30.8;
(k) clause 2.31.10;
(l) clause 2.32.7E(b);
(m) clause 2.34.7;
(n) clause 2.34.7A(b)(ii);
(o) clause 2.34.7C(c);
(p) clause 2.34.11;
(q) clauses 2.37.1 to 2.37.3;
(r) clause 4.9.9;
(rA) clause 4.11.1(h)
(s) clause 4.15.1;
(sA) clause 4.20.11;
(t) clause 4.27.7;
(u) clause 4.28.7;
(v) clause 7A.1.11; and
(w) clause 10.2.1.

3.2 Proposed Changes to Clause 4.11.1 Setting Certified Reserve Capacity

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

i. the Facility has operated for at least 36 months and has had a Forced Outage rate or a combined Planned Outage rate and Forced Outage rate greater than the applicable percentage specified in clause 4.11.1(hC) 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 or a combined Planned Outage rate and Forced Outage rate greater than the applicable percentage specified in clause 4.11.1(hC),

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 clause 4.11.1(h);~~

(hA) In making its decision under this clause 4.11.1(h), the IMO may:

i. seek such additional information from the relevant Market Participant that the IMO considers is relevant to the exercise of its discretion;

ii. may use information provided in reports related to the Facility submitted by the Market Participant under clauses 4.27.3 or 4.27.3A;

iii. consult with:

a. System Management; and

b. any person the IMO considers suitably qualified to provide an opinion on issues relevant to the exercise of the IMO's discretion.

iv. require the relevant Market Participant to pay the IMO's expenses incurred in consulting a person commissioned by the IMO under clause 4.11.1(hA).iii.b.

(hB) In making its decision under clause 4.11.1(h), the IMO must:

i. consider the extent to which the Reserve Capacity that can be provided by the Facility is necessary to meet the Reserve Capacity Target;

ii. consider whether the Reserve Capacity provided by the Facility is of critical importance to the SWIS, having regard to:

a. the size of the Facility;

b. the operational characteristics of the Facility;

c. the extent to which the Facility contributes to the security of the system through fuel diversity or location;

d. the demonstrated reliability of the Facility;

iii. consider the likelihood that strategies proposed by the applicant to maximise the availability of the Facility in the relevant Capacity Cycle will be effective;

iv. consider whether a decision to not assign Certified Reserve Capacity to the Facility is likely to result in a material decrease in competition in at least one market;

v. consider any positive or negative impacts on the long term price of electricity supplied to consumers that might arise if Certified Reserve Capacity was not assigned to the Facility;

vi. consider any other matter the IMO determined to be relevant; and

vii. be satisfied that its decision under clause 4.11.1(h) would not, on balance, be contrary to the Market Objectives.

The IMO must publish the reasons for its decision on the Market Web Site to the extent those reasons do not contain any confidential information.

(hC) The relevant outage criteria to apply under clause 4.11.1(h) in a particular Capacity Year is as set out in the following table:

For IMO decisions related to the Capacity Year	Forced Outage rate greater than	Combined Planned Outage rate and Forced Outage rate greater than
Prior to 2016/17	15%	30%
2016/17	14%	28%

2017/18	13%	26%
2018/19	12%	24%
2019/20	11%	22%
2020/21	10%	20%
Thereafter	subject to review	subject to review

The IMO will undertake a review, to be completed by 31 December 2018, of the operation of clause 4.11.1(h) in which it must consider the merits of further reducing the outage thresholds under clause 4.11.1(hC) for Capacity Years on and after 2021/2022. The review will include, but not be limited to, an assessment of:

i. the availability performance of the WA generation sector compared with analogous generating plant in other markets, using Industry Standard Generation Performance Indicators;

ii. the number of Facilities in the SWIS to which the criteria in clause 4.11.1(h) have applied in each of the previous five Capacity Years;

iii. the impact on the Wholesale Electricity Market of decisions made by the IMO under clause 4.11.1(h) in the previous five Capacity Years.

3.3 Proposed Changes to Clause 4.12 Setting Reserve Capacity Obligations

4.12.6 (b) subject to clause 4.12.9 and clause 4.27.9, during Trading Intervals where there is a Consequential Outage or a Planned Outage for a Facility provided to the IMO by System Management in accordance with clause 7.3.4, the IMO must reduce the Reserve Capacity Obligation Quantity for that Facility, after taking into account any adjustments in accordance with paragraph (a), to reflect the amount of capacity unavailable due to that outage;

4.12.9 Subject to clause 4.12.10, the number of Trading Intervals during which the IMO reduces the Reserve Capacity Obligation Quantity under clause 4.12.6(b) in respect of Planned Outages must not exceed 7,800 in any three consecutive Capacity Years for any Facility.

4.12.10 No later than five years after the commencement of clause 4.12.9, the IMO must review the whether the number of Trading Intervals referred to in clause 4.12.9 should be altered to better meet the Market objectives.

3.4 Proposed Changes to Clause 4.26 Financial Implications of Failure to Satisfy Reserve Capacity Obligations

4.26.1A(a)iii. If the Facility is required to have submitted a Forced Outage under clause 3.21.4, or has taken a Planned Outage for which the IMO has not adjusted the Facility's Reserve Capacity Obligation Quantity under clause 4.12.6(b), the Forced or Planned Outage in that Trading Interval measured in MW; or

3.5 Proposed Changes to Clause 4.27 Reserve Capacity Performance Monitoring

4.27.1. The IMO must monitor the total availability of capacity in the SWIS on a daily basis. The total available capacity should equal:

(a) the total Capacity Credits held by Market Participants on that day; less

(b) the maximum amount of capacity unavailable at any time due to Planned Outages.

4.27.2. By the twenty fifth day of each month, the IMO must assess the number of days in the preceding 12 calendar months where the total available capacity in the SWIS dropped below 80% (during the Hot Season), and 70% (in either the Intermediate Season or Cold Season), of the total Capacity Credits held by Market Participants for more than six hours on the day.

4.27.2A By the twenty fifth day of each month, the IMO must assess the number of Equivalent Planned Outage Hours taken by each Facility in the preceding 12 calendar months.

4.27.3. If the number of days determined in accordance with clause 4.27.2 exceeds 40, then the IMO must require reports to be filed by those Market Participants holding Capacity Credits for each Facility which:

(a) has been unavailable due to Planned Outages for more than 1000 hours during the preceding 12 calendar months; and

(b) has not been included in such a report during the preceding 12 calendar months.

4.27.3A If the number of Equivalent Planned Outage Hours for a Facility, as determined under clause 4.27.2A, exceeds 1750 hours for the preceding 12 calendar months, the IMO may require the Market Participant holding Capacity Credits for that Facility to provide to the IMO:

(a) an explanatory report as described in clause 4.27.4; and

(b) performance improvement reports at specified intervals on the effectiveness of measures being taken by the Market Participant to improve the availability of the Facility.

The IMO may not require status reports under clause 4.27.3A(b) at intervals more frequent than quarterly.

4.27.3B In making its decision whether to require a report under clause 4.27.3A, the IMO must assess whether the number of Equivalent Planned Outage Hours taken by the Facility in the previous 12 months was attributable to a specific, infrequent occurrence or is indicative of an underlying performance deficiency, and may consider any matters it considers relevant in making this assessment. The IMO may consult System Management in deciding whether or not to require a report.

4.27.4. The reports described in clause 4.27.3 and 4.27.3A(a) must include:

(a) explanations of all Planned Outages taken by the Facility in the preceding 12 calendar months;

(b) a statement of the expected maximum number of days of Planned Outages to be taken by the Facility in each of the next 36 months commencing from the month in which the report is requested, including adequate explanation to make clear the reason for each Planned Outage; and

(bA) the relationship of the Planned Outages to the long term asset management strategy and established maintenance plan for the Facility;

(c) measures being undertaken or proposed by the Market Participant to increase the availability of the Facility, and their actual and anticipated effect on the frequency of Planned Outages;

(d) any other information concerning the availability of the Facility that the IMO may request.

4.27.4A The reports described in clause 4.27.3A(b) must include:

(a) descriptions of the measures proposed, being undertaken or already undertaken by the Market Participant to increase the availability of the Facility;

(b) the target and actual availability and reliability of the Facility as measured by Industry Standard Generation Performance Indicators; and

(c) explanation of any variation between expected and actual improvement of the availability of the Facility as a resuilt of the measures taken.

4.27.5. A Market Participant must provide a report described in clause 4.27.3 or clause 4.27.3A to the IMO in a format specified in the Reserve Capacity Procedure within 20 Business Days of being requested to do so, and provide reports described in clause 4.27.4A by the dates specified by the IMO.

4.27.6. The IMO must consult with System Management on the implications of the report and may also consult, at the Market Participant's expense, with any person the IMO considers suitably qualified to provide an opinion.

4.27.7. ~~If the IMO considers the number of days reported in accordance with clause 4.27.4(b) to be unjustified based on good industry practice it may, at its sole discretion, limit the number of days on which Planned Outages are to be taken by the Facility in each of the next 24 months for the purposes of clause 4.27.8 and 4.27.9, and must notify the Market Participant who filed the report described in clause 4.27.3 or clause 4.27.3A of the limit.~~ [*Repeal this clause*]

~~4.27.8. If the IMO limits the number of days in accordance with clause 4.27.7 then the modified value is to supersede the corresponding value specified in the report described in clause 4.27.4.~~ [*Repeal this clause*]

4.27.9. If the number of days determined in accordance with clause 4.27.2 exceeds 80 then the IMO ~~must~~:

(a) notify all Market Participants that this has occurred; and

(b) during the 12 months commencing from the first Trading Day of the following month, may adjust the maximum number of Trading Intervals eligible for reduction of Reserve Capacity Obligation Quantities referred to in clause 4.12.9. ~~cease to adjust Reserve Capacity Obligation Quantities under clause 4.12.6(b) in response to Planned Outages for Facilities:~~

~~i. referred to in clause 4.27.3; and~~

~~ii. for which the number of days of Planned Outage during that 12 month period has exceeded the total number of days of Planned Outage predicted for that 12 month period in accordance with clause 4.27.4(b), as modified by clause 4.27.8.~~

3.6 Proposed Changes to Chapter 11 Glossary

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

Industry Standard Generation Performance Indicators: means the most recent edition of the IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity (IEEE 762), as published by the Institute of Electrical and Electronics Engineers, or appropriate equivalent.

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

The Reserve Capacity Mechanism is intended to serve a dual purpose. It provides a capacity revenue stream as an incentive for the provision of generation capacity to meet peak summer demand with an efficient reserve margin (Reserve Capacity Target). However, all generators in receipt of an allocation of Certified Reserve Capacity are expected to participate in the energy markets unless their plant is unavailable due to a Forced or Planned Outage.

Scheduled Generators that are unavailable due to Forced Outages are required to pay a Reserve Capacity Deficit Refund, providing an effective incentive to minimise unavailability due to Forced Outages. However, there is no corresponding incentive in the Reserve Capacity Mechanism to minimise unavailability due to Planned Outages.

Under the existing Market Rules, a Scheduled Generator may take Planned Outages as frequently as System Management is prepared to approve, without any consequential reduction in capacity revenue. System Management, rightly, makes its decision only on the basis of whether system security might be impaired by the capacity being unavailable. When forecast demand is low relative to available capacity, approval can generally be expected. If the generator must bid into the energy market(s) at its Short Run Marginal Cost, then a Planned Outage at such times also results in minimal revenue penalty due to foregone energy sales.

The proposed changes to clause 4.12 and 4.26 of the Market Rules will encourage Scheduled Generators to maintain plant availability at high levels by addressing this asymmetry in market incentives, while recognising the critical role that legitimate Planned Outages play in safeguarding system security and reliability.

In determining the quantity of Certified Reserve Capacity to assign to a Scheduled Generator, the existing Market Rules value Reserve Capacity on the basis of system security and reliability during hot-weather-related peak demand periods. Capacity Credits are allocated based on the reasonable expectation of the maximum summer sent-out capacity of which the Facility is capable. There is no consideration in the allocation mechanism of how frequently this capacity may be available from a Scheduled Generator (in contrast to the approach taken with Intermittent Generators).

The proposed changes to clauses 4.11.1 and 4.27 allow the IMO to recognise the value of the availability of generation capacity in stimulating competition and efficiency in the energy market. The potential capacity available from a Scheduled Generator with chronically high outage rates may be discounted (in whole or in part) by the IMO to reflect the fact that it is available significantly less frequently than most other generators that have been allocated Certified Reserve Capacity. Scheduled Generators with sub-standard availability would therefore see a future reduction in their capacity revenue.

This would provide a strong financial signal that the impact of excessive Planned Outages on market competition and market price is considered to be inconsistent with the Market Objectives.

Should the IMO decide under clause 4.11.1(h) not to allocate the maximum Certified Reserve Capacity to a Facility, the decision would only affect the Facility's potential capacity revenue. The Facility remains entitled to fully compete in the energy markets in which it is eligible to participate.

1. The proposed changes to clause 4.11.1 of the Market Rules would better address the Market Objectives of:

   (a) *Economically efficient, safe and reliable production and supply of electricity*, by:

      i. providing the IMO with the discretion to value frequently unavailable capacity lower than high-availability capacity when assigning Certified Reserve Capacity to a Scheduled Generator;

      ii. providing for the IMO to ensure that Scheduled Generators with high outage rates do not receive a higher effective Reserve Capacity Price per available hour than Scheduled Generators with low outage rates;

      iii. reducing incentives for Market Participants to retain inefficient, high-maintenance Scheduled Generators with poor Availability Factors.

   (b) *Encourage competition among generators...in the South West interconnected system, including by facilitating efficient entry of new competitors*, by:

      i. better matching nominal Reserve Capacity to reliably available capacity;

      ii. providing greater opportunities for investment in more efficient and reliable generation plant by reducing incentives for retention of, unreliable Scheduled Generators; and

      iii. increasing the transparency of the IMO's decisions under clause 4.11.1(h).

   (c) *Minimise the long-term cost of electricity supplied to customers*, by:

      i. ceasing to pay full Reserve Capacity Price for frequently unavailable capacity;

      ii. increasing the competitive pressure on energy prices by increasing the availability of registered Scheduled Generators bidding into the energy markets;

      iii. reducing the incentive to retain inefficient and obsolete Scheduled Generators at the expense of more efficient replacements.

2. The proposed changes to clause 4.12 of the Market Rules would better address the Wholesale Market Objectives of:

   (a) *Economically efficient, safe and reliable production and supply of electricity*, by:

      i. improving accountability for unavailability by limiting the number of Planned Outage hours that can be taken by a Scheduled Generator without exposure to Reserve Capacity Deficit Refunds.

      ii. ensuring that Scheduled Generators taking excessive Planned Outages do not receive a higher effective hourly Reserve Capacity Price per available Megawatt of capacity than Scheduled Generators with high Availability Factors; and

iii. reducing incentives for Market Participants to retain inefficient, high-maintenance Scheduled Generators with poor Availability Factors.

(b) *Encourage competition among generators...in the South West interconnected system, including by facilitating efficient entry of new competitors*, by:

i. reducing incentives for retention of unreliable, high-maintenance Scheduled Generators, providing greater opportunities for investment in more efficient and reliable generation plant.

(c) *Minimise the long-term cost of electricity supplied to customers*, by:

i. requiring Scheduled Generators with excessive Planned Outage rates to compensate the market for their unavailability through payment of Reserve Capacity Deficit Refunds; and

ii. increasing the competitive pressure on energy prices by increasing the availability of registered Scheduled Generators bidding into the energy markets;

iii. encouraging the replacement of inefficient, unreliable high-maintenance Scheduled Generators with more efficient generating Facilities

3. The proposed changes to clause 4.27 of the Market Rules would better address the Wholesale Market Objectives of:

(a) *Economically efficient, safe and reliable production and supply of electricity*, by:

i. establishing a mechanism for the IMO to independently monitor the performance of individual Scheduled Generators with high outage rates, and consider that performance in assigning Certified Reserve Capacity; and

ii. improving the information available to the IMO in making Certified Reserve Capacity decisions under clause 4.11.1(h).

(b) *Miinimise the long-term cost of electricity supplied to customers*, by:

i. closer scrutiny of the efficiency and effectiveness of Market Participants in improving the availability of their low-availability Scheduled Generators; and

ii. encouraging the replacement of inefficient, unreliable and high-maintenance Scheduled Generators with more efficient and reliable generating Facilities.

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

These changes will reduce the capacity revenue earned and retained by Market Participants holding Capacity Credits for Scheduled Generators with high total outage rates. The cost incurred by Scheduled Generators with very high Planned Outage rates may be substantial. However, the Market Participant holding the Capacity Credits for those Scheduled Generators has considerable discretion concerning the level of risk, which is directly affected by its outage decisions.

The financial cost of the proposed Rule Changes for the market as a whole is expected to be neutral or minimal.

- Reserve Capacity Revenue refunded by Market Participants operating high-outage Scheduled Generators would be retained and redistributed within the market;
- Some additional administrative cost for the IMO will be incurred through greater performance monitoring of individual Scheduled Generators, but this is expected to diminish as the incentives for lower Planned Outage rates take effect and fewer Facilities meet the criteria for individual reporting under clause 4.27.3A.
- Reporting costs for the Market Participants are not expected to be significant, as it is anticipated that a competent operator would already be collecting the information requested as standard asset management practice.

It is difficult to quantify the benefits that accrue from incentives targeting behavioural change, because the effectiveness of the incentives depends on multiple factors. These include conflicting incentives for the affected party, the net financial impact, and the Market Participants' perception of the IMO's willingness to apply sanctions.

However, the market is likely to experience a net economic benefit as a result of:

- Increasing the number of available Scheduled Generators in the energy markets, increasing competition and reducing the risk of price spikes in the event of unforeseen supply interruptions;
- Imposing greater accountability for poor availability performance;
- Reducing subsidies to frequently unavailable Scheduled Generators;
- Improving the quality of information available to the IMO to inform its decisions regarding Reserve Capacity allocation; and
- Reducing perverse incentives that encourage the retention of inefficient, obsolete, unreliable and high-maintenance Scheduled Generators, leading to efficiency and competition benefits in the longer term.

All Market Participants will be better placed to monitor the value for money being provided by the Reserve Capacity Mechanism, and to identify emerging trends that may need to be addressed through market incentives.

Implementing the proposed changes will be a clear statement that an efficient Reserve Capacity market contributes to an efficient energy market, subject to the capacity market providing incentives to maximise the availability of that capacity to the energy market.

INDEPENDENT MARKET OPERATOR

Wholesale Electricity Market
Rule Change Proposal

Rule Change Proposal ID: **PRC_2013_08**
Date received: **TBA**

Change requested by:

Name:	Allan Dawson
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Address:	Level 17, 197 St Georges Terrace, Perth WA 6000
Date submitted:	TBA
Urgency:	High
Change Proposal title:	Market Participant Fee - Clarification of GST Treatment
Market Rule(s) affected:	Clauses 9.1.2, 9.16.3, 9.16.3A, 9.19.1, 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: Group Manager, Development & Capacity
PO Box 7096
Cloisters Square, Perth, WA 6850
Fax: (08) 9254 4339
Email: market.development@imowa.com.au

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

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

The objectives of the market are:

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

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

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

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

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

Details of the Proposed Rule Change

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

Background

From market start, the IMO has been collecting Market Fees, System Operation Fees and Regulator Fees (collectively known as the Market Participant Fees) from Market Participants to recover its own costs, and costs on behalf of System Management and the Economic Regulation Authority (ERA) respectively.

The Regulator Fees compensate the ERA for the costs of providing the services it is required to perform in undertaking its functions under the Market Rules and, similarly, the System Operation Fee compensates System Management for the costs of providing the services it is required to perform in undertaking its functions under the Market Rules.

From market start, all three fees have been invoiced to the Market Participants subject to GST. The IMO has then passed the fees collected on behalf of ERA and System Management to each entity as received (also subject to GST) and has issued the entities with Recipient Created Tax Invoices which itemised the GST amounts.

In November 2009 the ERA informed the IMO that they had not been passing on the GST they had been receiving from the IMO to the Australian Taxation Office (ATO), but had been keeping it (as revenue). This resulted in disagreement between the IMO and the ERA as to the GST classification of the Regulator Fee.

On 21 December 2011, the ERA forwarded to the IMO a copy of a private ruling it had received from the ATO (dated 7 October 2011) in respect of the GST classification of the

Regulator Fee, the effect of which was to make the Regulator Fee GST exempt. The IMO received a copy of the ruling from the ERA after the 60 day objection period to the ruling had lapsed.

Conscious of the impacts this ATO ruling would have on WEM Settlement Systems, IMO business processes and Market Participant systems and processes, the IMO lodged its own application for a private ruling which sought to overturn the earlier ruling provided to the ERA.

In September 2012, the ATO issued its private ruling in response to the IMO's submission, advising that the Regulator Fee passed onto the ERA should have been exempt from GST from market commencement. The ruling also suggested that the Market Fee was exempt from GST from 1 July 2012 following the introduction of new legislation. The ruling did not suggest that the System Operation Fee was also exempt from GST but indicated that System Management should undertake a self-assessment of the GST treatment of this fee in accordance with the new legislation.

GST is still being applied to all transactions under the Market Rules between the IMO and the Market Participants, and between the IMO and System Management. However from June 2012, no GST has been passed on by the IMO to the ERA, the IMO ceased claiming any input tax credits on the Regulator Fees it pays to the ERA and the IMO has continued to remit all amounts of GST collected from the Market Participants in respect of the Regulator Fee to the ATO.

The ATO Ruling

The ATO's key findings were that:

- the Market Fee component of the Market Participant Fees does not constitute a taxable supply under the A New Tax System (Goods and Services Tax) Regulations 1999 (GST Regulations); and

- the IMO receives the Regulator Fee and System Operation Fee as a collection agent for the ERA and System Management respectively - the ERA and System Management make supplies directly to the Market Participants.

Following from the above, the IMO does not make a credible acquisition from the ERA when it pays the ERA the amount referred to as the Regulator Fee and therefore is acting only as an agent on behalf of the ERA in respect to the recovery of Regulator Fee amounts.

The ERA's own private ruling found that the Regulator Fee was exempt from GST under Division 81 of the GST Act.

A consequence of the ATO's private ruling on the IMO is that:

- The IMO is not entitled to invoice Market Participants directly, in its own name, for the Regulator Fee and the System Operation Fee, as it has done since market start.

- The IMO was not entitled to claim GST credits for any period in relation to payments to the ERA for the amount referred to as the Regulator Fee and must recover and pay the ATO the value of these credits to account for the ATO's shortfall from October 2008 (in line with ATO recovery time frames).

- The Regulator Fee and the Market Fee are exempt from GST. It is also likely that the System Operation Fee will also be exempt from GST following self-assessment under the new GST provisions.

The IMO is working with the ATO to develop the necessary changes to give effect to the ruling. The following reflects discussions to date:

- The ATO has indicated that it has no intention of unwinding transactions historically between the IMO and the Market Participants and (if applicable) between the IMO and System Management which may have been incorrectly treated.

- The IMO will recover the incorrectly claimed GST credits dating back to market commencement in respect to payments to the ERA in the first year of its next Revenue Period (2013/14). This cost was included as a one off item in the IMO's Allowable Revenue Submission approved by the ERA on 2 April 2013. The total cost to be recovered is $543,480 which includes $43,929 of interest.

- The recovery of the $543,480 does not represent a second cost to the market since the incorrectly paid GST was treated by the ERA as revenue and was passed back to Market Participants in the form of reduced Regulator Fees in each subsequent financial year (consistent with the requirement of clause 2.24.5A of the Market Rules).

- The ATO agreed that the IMO will not be subject to any penalty or further interest charge on the above amount.

- Since June 2012, the IMO has ceased claiming any input tax credits on the Regulator Fees it pays to the ERA. However, the IMO continues to remit all amounts of GST collected from the Market Participants in respect of the Regulator Fee to the ATO.

- Consistent with the indication not to unwind any historical transactions, the ATO has also indicated that it does not intend to unwind any transactions relating to the Regulator Fees that Market Participants continue to pay to the IMO and the associated input tax credits being claimed until the IMO makes necessary adjustments to the invoicing and settlement systems.

The IMO, in order to give effect to the findings of the ATO in the ruling, must change the GST treatment of the Market Participant Fees charged to Market Participants and the way these fees are invoiced.

The IMO is working with the ATO to establish a timeframe within which these changes will be implemented. Given the proposed amendments to the Market Rules, necessary amendments to Market Procedures and systems changes involved, the IMO has suggested that a 1 January 2014 start date would be feasible. This time frame is also designed to enable adequate time for the full implications on Market Participants to be assessed and any consequential system changes to be effected. This matter is currently the subject of dialogue between the IMO and the ATO.

Implications of the Ruling

The ruling has several practical consequences for the IMO and Market Participants:

- The IMO's market settlement systems which were designed to add GST to all payments including the Regulator Fee, Market Fee, and the System Operation Fee (pending self-assessment) need to be adjusted to reflect the ruling.

- The IMO's invoicing and clearing procedures need to be reviewed to reflect the ruling.

- Market Participants will no longer be charged GST or be able to claim input credits for the relevant fees going forward.

- The Credit Limits for Market Participants will marginally reduced over time and the procedures and calculation may require review.

- Market Participants' systems which interface directly with the IMO's systems may require adjustments.

Issue with the Market Rules

The ruling has highlighted an issue in the Market Rules that means that the IMO would no longer be able to 'bundle' all Market Participant invoices in the manner it currently does.

While the ATO found that the IMO collected the Regulator Fee and System Operation Fee as a collection agent for the ERA and System Management, the ATO did not go as far as to recognise an agency agreement, either express or implied, between any of the parties. As a result, the IMO is not entitled to issue tax invoices to the Market Participants in respect of these fees. Under the ATO's interpretation, the IMO would need to invoice Market Participants separately (and expressly on behalf of the ERA and System Management) for each of these fees, or the ERA and System Management would need to invoice Market Participants directly.

The prudential security held by the IMO with respect to each of these fees is also affected by the Ruling. As the Regulator Fee and the System Operation Fee do not represent amounts 'owed to the IMO', these amounts may no longer be covered by the Credit Limit provisions in the current Market Rules.

March MAC meeting

A Concept Paper which outlined this issue was presented at the MAC meeting held on 20 March 2013. This Concept Paper presented two options for resolving the issue. The first option, which was recommended at the time, was for the Market Rules to be amended to specify that the IMO is the principal in all market transactions. The second option was to formalise the IMO's role as an agent for the collection of System Operation Fees and Regulator Fees.

Several key issues were raised at the meeting which have resulted in the IMO conducting further investigations of the options. Specifically,

- MAC members expressed concern about the possible broader legal implications of the IMO being the principal in all market transactions, specifically the interaction between the ownership of energy and the existing bilateral contracts.

- The Chair clarified in the meeting that the IMO was seeking to formalise its role as the central clearing house in the SWIS. He noted that similar roles occurred in financial, commodity and other electricity markets including the NEM

- A further concern was raised in relation to liabilities associated with the Renewable Energy Target.

The IMO has considered the issues raised and in particular the potential implications and liability associated with clarifying its role as the principal in all transactions under the Market Rules. Although it considers that this is a reasonable and appropriate role in terms of the Balancing Market, the continued existence of bilateral contracts as part of the Short Term Energy Market creates structural issues.

The IMO sought preliminary legal advice on the principal role in relation to the GST. The IMO has determined that further consideration of a number of issues would be required and that there existed a number of difficulties associated with clarifying the GST invoicing and settlement issues if the IMO went forward with the original solution proposed in the Concept Paper.

As such, the IMO has given further consideration to the alternative option of formalising the IMO's role as an agent for the purposes of collecting the System Operation Fees and Regulator Fees.

Proposal

The IMO proposed to clarify its role as an agent for the collection of these fees and its ability to issue valid invoices to Market Participants directly for services provided by the ERA and System Management.

The amendments would formalise the IMO's 'agency' role in the Market Rules. To formalise the relationship, the Market Rules would be amended to specify that the IMO was the agent with respect to all fees payable to the IMO for services provided by the ERA and System Management under the Market Rules.

Formalising the relationship in this way removes any ambiguity and allows the IMO to issue invoices for all the fees and settlement amounts in its own name. This will allow the IMO to continue making settlement calculations and issuing invoices to Market Participants in the same manner as it does currently (albeit without GST on the relevant fees).

Invoices for Non-STEM settlements would continue to be bundled. These invoices currently include the three market fees as well as up to nine other settlement amounts. Market Participants would also be able to continue making payments or taking receipt of payments in the same manner that they have always.

The only adjustment would be that Market Participants will receive invoices which include several items that do not attract GST (the Market Fee, Regulator Fee, and, following self-assessment, possibly also the System Operation Fee).

Market Participants would also need to be aware that for the first year after the implementation date, they will continue to receive some wash-up invoices where GST is still being charged (and is eligible to be claimed) on the Market Participant Fees. This is a product of the Settlement Adjustment process used in the market.

The IMO understands that Market Participant's reconciliation and verification systems as well as invoice processes procedures may need to be reviewed with regards to the changed GST circumstances.

In relation to the Regulator Fee collected on behalf of the ERA, which has not attracted GST since June 2012, the IMO would continue to treat the amount as though it attracted GST (as it does now) and remit all amounts of GST collected from Market Participants to the ATO. This would ensure that Market Participants may treat all three fees as attracting GST up until the single commencement date rather than processing these payments differently from one another for a period of time.

The IMO proposes adjustments to rules relating to prudential requirements to ensure that the fees that the IMO recovers on behalf of other Rule Participants and other persons under the Market Rules, can continue to be accounted for in the calculation of Credit Limits and that the IMO would be able to draw on security for the purposes of making payments to the ERA and System Management in the event of default.

This solution would enable the IMO to continue clearing the market using the IMO's current systems and processes. It would avoid the need for multiple invoices to be issued and cleared (at a direct cost to Market Participants) and removes the risk of additional costs associated with amending or creating new settlement processes for the affected fees (either by the IMO or by either of the other entities).

The solution avoids any ambiguity as to the settlement responsibilities for amount payable under the Market Rules by ensuring that the IMO is the only agent who may issue invoices with respect to amounts payable to the IMO. This avoids any potential costs associated with additional settlement systems and processes being established by other agencies with respect to the settlement of the market. The changes also avoid the need for prudential security to be held with respect to amounts settled by the IMO by other agencies.

Proposed Amendments

[Note: The IMO considering the proposed amendments to clause 9.1.2 which would give effect to the formalisation of the agent relationship and address the invoicing issues. The IMO has sought legal advice and is in discussion with the ATO with regard to the drafting. The IMO will finalise the proposed amendments following receipt of that advice.]

The IMO has also taken the opportunity to address a number of minor typographical issues and cross referencing errors in several affected clauses. This includes specifying each of the Market Participant Fees in clause 9.19.1 for the Adjustment Process so that clause 9.19.1 is consistent with clause 9.16.3. This issue was raised by Verve Energy in a submission to RC_2012_25.

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2. Explain the reason for the degree of urgency:

As outlined above, the IMO proposes that the commencement date for the changes be 1 January 2014.

The IMO is proposing this Rule Change be considered under the Standard Rule Change Process as the amendments do not satisfy the requirements for a Fast Track Rule Change Process.

The proposed 1 January 2014 commencement date allow for adequate consultation on the changes including time for Market Participants to properly consider any system changes that may be required to ensure that validations tools and verification processes align with the changed GST treatment.

The finalisation of process would also occur with allowance of sufficient time for the IMO to progress any related changes to Market Procedures and to update and undertake adequate testing of its own systems prior to the commencement of the change.

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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)*

As noted above, the IMO considering the proposed amendments to clause 9.1.2 which would give effect to the formalisation of the agent relationship and address the invoicing issues. The IMO has sought legal advice and is in discussion with the ATO with regard to the drafting. The IMO will finalise the proposed amendments following receipt of that advice. The *following drafting should not be taken as final.*

In addition, these changes also reflect clause 9.16 and 9.19 as amended by RC_2012_25 which is currently awaiting Ministerial Approval.

9.1.2. With respect to the treatment of GST:

(a) all prices, fees and other charges under these Market Rules (other than under this clause 9.1.2) are exclusive of GST;

(b) in this clause 9.1.2, “**adjustment notes**”, “**consideration**”, ~~“**GST**”,~~ “**GST group**”, “**input tax credit**”, “**member**”, “**recipient**”, “**recipient created tax invoice**”, “**representative member**”, “**supplier**”, “**supply**”, “**tax invoice**”, ~~and~~ “**taxable supply**” and “**valid tax invoice**” each have the meaning given to the relevant term in the GST Act~~legislation under which GST is imposed~~;

(c) where a Rule Participant makes a taxable supply to another Rule Participant or person under these Market Rules, the other Rule Participant or person must also pay the first Rule Participant making the supply an additional amount equal to the GST payable in respect of that supply;

(d) the IMO must include in Settlement Statements and Invoices issued under these Market Rules the additional amounts contemplated by paragraph (c);

(e) Rule Participants must, if requested by the IMO, do everything necessary (including the entering into of recipient created tax invoice agreements) to enable the IMO to issue valid tax invoices, recipient created tax invoices and adjustment notes in respect of all taxable supplies made by or to the IMO under these Market Rules;

(f) ~~however,~~ if the additional amount paid or payable to the IMO or a Rule Participant or another person under this clause 9.1.2 in respect of a taxable supply differs from the actual amount of GST payable by the Rule Participant under the GST Act~~relevant legislation~~ in respect of the relevant supply, then adjustments must be made under clause 9.~~21~~19 so as to ensure the additional amount paid under this clause in respect of the supply is equal to the actual amount of GST payable under the GST Act~~relevant legislation~~ in respect of the supply;

(g) if the IMO determines that:

i. a party is entitled to payment of any costs or expenses by way of reimbursement or indemnity; or

ii. a price, fee or other charge payable under these Market Rules (other than Market Fees, System Operation Fees and Regulator Fees) is calculated with reference to a cost or expense incurred by a party,

then the payment or cost or expense (as the case may be) must exclude any part of the cost or expense which is attributable to GST for which the party (or a representative member of any GST group of which the party is a member) is entitled to an input tax credit.9.1.2.

Note: Further changes to clause 9.1.2 will be required to clarify that the IMO is the agent for the collection of System Operation Fees and Regulator Fees – the drafting of these changes is still under development.

9.16.3. The IMO must undertake a process for adjusting settlements ("**Adjustment Process**") in accordance with clause 9.19. The purpose of the process is to review the ~~r~~Relevant Settlement Statements which were issued in the nine months prior to the commencement of the Adjustment Process ("**Relevant Settlement Statements**") to facilitate corrections, as applicable, resulting from:

(a) Notices of Disagreement,

(b) the resolution of Disputes,

(c) revised metering data provided by Metering Data Agents;~~,~~

(d) any revised Market Fee rate, System Operation Fee rate or Regulator Fee rate; ~~and~~

(e) any determination made in accordance with clauses 6.16A.1(b)(i), 6.16A.2(b)(i), 6.16B.1(b)(i), or 6.16B2(b)(i)~~.~~; and

(f) any adjustment required for GST purposes under clause 9.1.2.

Adjustments may only be made to Relevant Settlement Statements. Adjustments may not be made to Settlement Statements outside of an Adjustment Process.

9.16.3A. A Relevant Settlement Statement is:

(a) Any STEM Settlement Statement or Non-STEM Settlement Statement that requires correction as the result of the resolution of a dispute raised under clause 2.19, ~~or~~ where the IMO has indicated under clause 9.20.7 that it will revise information in response to a Notice of Disagreement, or where an adjustment is required in accordance with clause 9.1.2; and

(b) Any Non-STEM Settlement Statement for which the Invoicing Date occurred in the month that is three, six or nine months prior to the start of the Adjustment Process, and for which the IMO has received revised metering data from a Metering Data Agent or made any determinations in accordance with clauses 6.16A.1(b)(i), 6.16A.2(b)(i), 6.16B.1(b)(i), or 6.16B2(b)(i).

9.19.1. When undertaking an Adjustment Process the IMO must:

(a) recalculate the amounts included in the Relevant Settlement Statements in accordance with this Chapter but taking into account any:

i. revised metering data which has been provided by Metering Data Agents;

ii. actions arising from a Notice of Disagreement;

iii. the resolution of any Dispute;~~ and~~

iv. determinations made under clauses 6.16A.1(b)(i), 6.16A.2(b)(i), 6.16B.1(b)(i), or 6.16B2(b)(i); ~~and~~

v. any revised Market Fee rate, System Operation Fee rate or Regulator Fee rate; and

vi. any adjustment required for GST purposes under clause 9.1.2; and

(b) provide adjusted STEM Settlement Statements and adjusted Non-STEM Settlement Statements to Rule Participants in accordance with the timeline specified under clause 9.16.4 in respect of the relevant Adjustment Process.

Glossary

GST: means Goods and Service Tax and has the meaning given in the GST Act.

GST Act: means the A New Tax System (Goods and Services Tax) Act 1999 (Cth).

Market Fees: The fees payable by Market Participants to the IMO determined by the IMO in accordance with clause 2.24, and calculated for each Market Participant in accordance with clause 9.13.1.

Regulator Fees: The fees determined by the IMO in accordance with clause 2.24, and payable by Market Participants to the IMO for the services provided by the Economic Regulation Authority in undertaking its Wholesale Electricity Market related functions and other functions under these Market Rules.

System Operation Fees: The fees determined by the IMO in accordance with clause 2.24, and payable by Market Participants to the IMO for the services provided by System Management as determined under these Market Rules.

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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 amendments seek to formalise agency arrangements between the IMO and both the Economic Regulation Authority and System Management (for the purpose of the collection of certain fees) in a way that allows for the continued use of existing market processes. The change will minimise the long-term cost of electricity supplied to customers because it avoids a changes which would necessitate more substantial costs to be the market. Therefore, the IMO considers that the amendments meet the Wholesale Electricity Market Objective (d).

The amendments are consistent with the remaining Wholesale Electricity Market Objectives.

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

Benefits:

The proposed changes allow all existing settlement systems and invoicing processes to continue to be used in the current manner, albeit with GST removed from the relevant fees, thereby avoiding the cost of any significant changes being borne by the market.

The changes formalise the relationship between the agencies thereby bringing the Market Rules into line with the ATO's ruling and relevant tax legislation.

Costs:

There will be some costs associated with making and testing necessary changes to the settlement systems so that GST is no longer added to the relevant fees for settlement and prudential purposes from the commencement date.

The IMO has received preliminary advice on the changes with regards to the WEM settlement systems to remove the GST from selected fees. The necessary adjustments are likely to involve only relatively simple configuration changes to the systems. The changes will need to be confirmed and properly tested but are not expected to have a significant cost. The IMO will, however, be exposed to more internal resources being allocated to settlement and GST administration during the period where the IMO is managing initial settlement runs with GST excluded for Market Participant Fees and wash-up settlement runs with GST included on these fees. These additional resource allocations can be accommodated by internal re-prioritisation and should not impose any additional costs to the market.

The IMO understands that some Market Participants will have reconciliation and validation systems that will need to be amended to reflect the GST Ruling. To allow time for these changes, the IMO has proposed 1 January 2014 as the commencement date.

The changes to the invoicing within the IMO are likely to be minimal however the IMO is continuing discussions with the ATO to ensure invoices are valid and that the changes give effect to the ATO's private ruling.

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

Legend:

Shaded	Shaded rows indicate procedure changes that have been completed since the last MAC meeting.
Unshaded	Unshaded rows are procedure changes still being progressed.
Red Text	Red text indicates any updates to information

ID	Summary of Changes	Status	Next Step	Date
IMO Procedure Change Proposals				
PC_2011_04 **Prudential Requirements**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Include some minor and typographical amendments to improve the integrity of the Market Procedure; • Include amendments required as a result of the Pre Rule Change Proposal: Prudential Requirements (PRC_2011_09) and o RC_2010_36 Acceptable Credit Criteria; and o RC_2011_04 List of entities meeting Acceptable Credit Criteria	• The IMO rejected this Rule Change Proposal on 19 November 2012. • Modified Rule Change Proposal and updated Market Procedure to be presented to the February 2013 MAC.	• Modified Rule Change Proposal and updated Market Procedure presented at March MAC and to be submitted into the process along with RC_2012_23: Prudential Requirements	TBA

ID	Summary of Changes	Status	Next Step	Date
PC_2012_07 **Certification of Reserve Capacity**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with the Amending Rules under the following Rule Change Proposals: o Certification of Reserve Capacity (RC_2010_14); o Curtailable Loads and Demand Side Programmes (RC_2010_29), Including the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10)	• The submission period has closed and the IMO is preparing the Procedure Change Report.	• IMO to publish Procedure Change Report.	TBA
PC_2012_09 **Loss Factors**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; and • Better clarify the processes in the Market Procedure. • Ensure consistency with amendments to the Market Rules which have occurred since Market Start; and • Reflect proposed changes under PRC_2012_07: Determination of Loss Factors	• Currently out for submission	• Submissions close	16/04/2013

ID	Summary of Changes	Status	Next Step	Date
PC_2012_10 Amendments to Market Procedure for IMS Interface	The proposed updates are to: • Clarify and amend the Market Procedure to ensure transparency and improve overall integrity and to address a number of minor technical inconsistencies in the practical implementation of the procedure.	• This Procedure Change Proposal went out for a further round of consultation which closed on 18 February 2013. The IMO is currently preparing the Procedure Change Report.	• Publish Procedure Change Report	TBA
PC_2012_11 **Notices and Communications**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project. • Reflect the IMO's updated contact details.	• The Procedure was presented and discussed at the 27 November 2012 IMOWG.	• The Market Procedure to be updated to reflect the amendments agreed by the IMOWG and submit into the formal process.	TBA
TBC **Undertaking the LT PASA and conducting a review of the Planning Criterion**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Include some minor and typographical amendments to improve the integrity of the Market Procedure, including re-ordering some sections; and • Include both reviews required under clause 4.5.15 of the Market Rules (Planning Criterion and forecasting processes).	• As advised at the August 2012 working group meeting, the IMO is currently undertaking the five yearly review of the IMO's forecasting processes. Following the completion of the review the IMO may make further changes to the Market Procedure.	• Updated procedure to be presented back to the Working Group for discussion	TBA

ID	Summary of Changes	Status	Next Step	Date
TBC **Participant Registration and Deregistration**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Revise the Market Procedure to provide more details of the relevant processes, including restructuring the Market Procedure to better present the process; • Reflect the new MPR system; • Ensure consistency with the Amending Rules from the Rule Change Proposal: Change of Review Board Name (RC_2010_18)	• Underway.	• To be discussed by IMO Procedures Working Group	TBA

ID	Summary of Changes	Status	Next Step	Date
TBC **Facility Registration, Deregistration and Transfer**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Reflect the new MPR system; • Revise the Market Procedure to provide more details of the relevant processes including: o restructuring the Market Procedure to better present the process; o providing further details of the consultation processes with System Management; o clarifying that there should not be any restriction on the ability to provide notifications in a manner outlined in the Market Procedure for Notifications and Communications; and o reflect the new processes for digital certificates • Ensure consistency with the Amending Rules from the following Rule Change Proposals; o Curtailable Loads and Demand Side Programmes (RC_2010_29); and o Change of Review Board Name (RC_2010_18), Including the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10)	• Underway.	• To be discussed by IMO Procedures Working Group	TBA

ID	Summary of Changes	Status	Next Step	Date
TBC **Settlement**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with the Amending Rules from the following Rule Change Proposals: o Settlement in Default Situations (RC_2010_04) o Change of Review Board Name (RC_2010_18); o Minor and typo (RC_2010_26) o Settlement Cycle Timelines (RC_2010_19) o Acceptable Credit Criteria (RC_2010_36)	• Underway.	• To be discussed by IMO Procedures Working Group	TBA
TBC **Meter Data Submission**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Clarify that the Procedure is part of the Settlement Market Procedures; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by the IMO Procedures Working Group	TBA
TBC **Capacity Credit Allocation**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Clarify that the Procedure is part of the Settlement Market Procedures; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by IMO Procedures Working Group	TBA

ID	Summary of Changes	Status	Next Step	Date
TBC **Intermittent Load Refund**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by IMO Procedures Working Group	TBA
TBC **Individual Reserve Capacity Requirements**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by IMO Procedures Working Group	TBA
TBC **Reserve Capacity Performance Monitoring**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with the Amending Rules from the Rule Change Proposal: Reserve Capacity Performance Monitoring (RC_2009_19)	• Underway.	• To be discussed by IMO Procedures Working Group	TBA
TBC **Treatment of Small Generators**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by IMO Procedures Working Group	TBA

ID	Summary of Changes	Status	Next Step	Date
TBC **Reserve Capacity Testing**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Reflect the new Temperature Dependence Curve; • Ensure consistency with the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10)	• Underway.	• To be discussed by IMO Procedures Working Group	TBA
TBC **Information Confidentiality**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10) along with all other rule changes which have occurred since Market Start.	• Underway.	• To be discussed by IMO Procedures Working Group	TBA

System Management Procedure Change Proposals				
PPCL0024 **Monitoring and Reporting Protocol**	The proposed updates are to: • Address a current SM non-compliance issue. The issue is that the Tolerance Range formula set out in the PSOP: Monitoring and Reporting differs to the Tolerance Range formula applied in practice in regards to the definition of the Rate of Change component within the formula; • Remove the reference to Non-Scheduled Generators in the Section 4.1 as the formula applies only to Scheduled Generators; • Include several changes have also been made to clarify Section 4.3 of the PSOP in regards to the process for determining a Facility Tolerance Range; • Include some minor revisions to correct typographical errors and improve consistency throughout the PSOP; and • Include amendments required as a result of PRC_2013_01	• The IMO published this Procedure Change on 14 March 2013. It is currently out for submission.	• Submissions close	19/04/2013

Agenda Item 7a: Working Group Overview

Working Group (WG)	Status	Date commenced	Date concluded	Latest meeting date	Next scheduled meeting date
System Management Procedures WG	Active	Jul 07	Ongoing	12/12/2011	TBA
IMO Procedures WG	Active	Dec 07	Ongoing	27/11/2012	TBA
Reserve Capacity Mechanism WG	Closed	Feb 12	28/02/2013	28/02/2013	-