Market Advisory Committee

Agenda

Meeting No.	65
Location:	IMO Board Room Level 17, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Wednesday 9th October 2013
Time:	12.00pm – 5.30pm

Item	Subject	Responsible	Time
1.	**WELCOME**	**Chair**	2 min
2.	**MEETING APOLOGIES / ATTENDANCE**	**Chair**	2 min
3.	**MINUTES FROM MEETING 63**	**Chair**	5 min
4.	**ACTIONS ARISING**	**Chair**	10 min
5.	**LOAD FOLLOWING**		
	a) Presentation: Load Following 101	**SM**	45 min
	b) Update: Load Following Investigation	**SM**	45 min
6.	**MARKET RULES EVOLUTION PLAN UPDATE**	**IMO**	30 min
7.	**AFTERNOON TEA**	**IMO**	30 min
8.	**CONCEPT PAPERS**		
	a) CP_2013_06: Dynamic Refunds and Reserve Capacity Price	**IMO**	40 min
9.	**MARKET RULES**		
	a) Market Rule Change Overview	**IMO**	10 min
	b) PRC_2013_16: Availability, Outages and Constraint Payments for Non-Scheduled Generators	**IMO**	20 min
10.	**MARKET PROCEDURES**		
	a) Overview	**IMO**	10 min

11.	**WORKING GROUPS**		
	a) Overview and membership updates	**IMO**	5 min
12.	**GENERAL BUSINESS**		
13.	**NEXT MEETING: Wednesday 13th November 2013**		

INDEPENDENT MARKET OPERATOR

Market Advisory Committee

Minutes

Meeting No.	63
Location	IMO Board Room Level 17, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date	Wednesday 7 August 2013
Time	2.00pm – 4.25pm

Attendees	Class	Comment
Allan Dawson	Chair	
Greg Ruthven	Compulsory – IMO	Proxy
Phil Kelloway	Compulsory – System Management	
Shane Duryea	Compulsory – Western Power	Proxy
Will Bargmann	Compulsory – Customer	2.00pm – 3.35pm
Jacinda Papps	Compulsory – Generator	Proxy
Geoff Gaston	Discretionary – Generator	
Andrew Sutherland	Discretionary – Generator	
Shane Cremin	Discretionary – Generator	
Nenad Ninkov	Discretionary – Customer	
Paul Troughton	Discretionary – Customer	Proxy
Peter Huxtable	Discretionary – Contestable Customer Representative	
Paul Hynch	Minister's appointee – Observer	Proxy
Wana Yang	Economic Regulation Authority – Observer	
Apologies	**From**	**Comment**
Nerea Ugarte	Minister's appointee – Observer	
Steve Gould	Discretionary – Customer	
Andrew Everett	Compulsory – Generator	
Kate Ryan	Compulsory – IMO	
Noel Ryan	Compulsory – Network Operator	
Michael Zammit	Discretionary – Customer	

Also in attendance	From	Comment
Dean Sharafi	System Management	Observer
Fiona Edmonds	Alinta Energy	Observer
Andy Stevens	Bluewaters Power	Observer
Jenny Laidlaw	IMO	Presenter
Erin Stone	IMO	Presenter
Aditi Varma	IMO	Presenter
Sam Beagley	IMO	Observer
Natasha Cunningham	IMO	Observer
Alex Penter	IMO	Observer
Courtney Roberts	IMO	Minutes

Item	Subject	Action
1.	**WELCOME** The Chair opened the meeting at 2.00 pm and welcomed members to the 63rd meeting of the Market Advisory Committee (MAC).	
2.	**MEETING APOLOGIES / ATTENDANCE** The following **apologies** were received: • Kate Ryan (Compulsory – IMO) • Noel Ryan (Compulsory – Network Operator) • Andrew Everett (Compulsory – Generator) • Nerea Ugarte (Minister's appointee – Observer) • Steve Gould (Discretionary – Customer) • Michael Zammit (Discretionary – Customer) The following **proxies** were noted: • Greg Ruthven for Kate Ryan (Compulsory – IMO) • Jacinda Papps for Andrew Everett (Compulsory – Generator) • Shane Duryea for Noel Ryan (Compulsory – Network Operator) • Paul Troughton for Michael Zammit (Discretionary – Customer) The following **presenters** and **observers** were noted: • Jenny Laidlaw (presenter) • Erin Stone (presenter) • Aditi Varma (presenter) • Dean Sharafi (observer, System Management) • Fiona Edmonds (observer, Alinta) • Andy Stevens (observer, Bluewaters Power) • Natasha Cunningham (observer)	

	• Sam Beagley (observer) • Alex Penter (observer) • Courtney Roberts (Minutes) The Chair acknowledged Mr Will Bargmann as the new Synergy representative, replacing Mr Stephen MacLean. The Chair also introduced Mr Alex Penter as the new Graduate Analyst in the Development and Capacity team.	
3.	**MINUTES OF PREVIOUS MEETING** The minutes of MAC Meeting No. 59, held on 10 April 2013, were amended to reflect additional changes that were raised at the June MAC meeting and re-circulated to the MAC for final endorsement. Mrs Jacinda Papps questioned whether the email between Mr Andrew Everett and Ms Courtney Roberts about the percentage used for calculating the average planning outage factor had been addressed. Ms Roberts confirmed that the minutes had been amended to reflect Mr Everett's point. Mr Bargmann questioned if the action to address Mr MacLean's request for information about consumption on peak load days and business versus non-business days had been completed. The Chair confirmed that this action had been completed and closed. The minutes of MAC Meeting No. 61, held on 12 June 2013, were circulated to members prior to the meeting. The following points were raised by members during the meeting: ***Section 3: Minutes of Previous Meeting, page 2 of 7 second point*** • Mrs Papps noted that 14.8% needed to be amended to 15%. • Mr Phil Kelloway requested clarification as to whether the issuance of a Dispatch Advisory by System Management would constitute 'best endeavours' notice of likely dispatch. Mr Kelloway noted that these advisories are based on a forecast. However, System Management may forecast one situation but see another situation. Mr Greg Ruthven noted that the proposed Amending Rules addressed this concern, requiring System Management to issue a Dispatch Advisory when it becomes aware that dispatch of Demand Side Programmes is likely to occur. Subject to the above amendment, the MAC agreed that the minutes were a true and accurate record of the meeting. *Action Points:* *The IMO to amend the minutes of Meeting No. 61 and publish with the minutes of Meeting No. 59 as final.*	**IMO**
4.	**ACTIONS ARISING** The Chair introduced Mr Ruthven to update the MAC on the current actions. The following points were noted: • **Item 61:** Mr Ruthven noted that the IMO is still waiting on a response from the Public Utilities Office (PUO).	

	• **Item 22:** Mr Ruthven questioned whether this item should now be closed as the workshop had been completed. Mr Kelloway noted that System Management was compiling information on the types and levels of outages that were evaluated. Mr Kelloway suggested that the action remains open until System Management provides it to the IMO and circulates it to members. • **Item 24:** The Chair advised that there has been some limited progress. The IMO has recently received System Management's Ancillary Services Report, which indicated that the frequency performance levels achieved were 99.96%, significantly higher than the target set by System Management. Due to the limited progress to date, the IMO and System Management have committed to a weekly work plan and to provide the MAC with regular updates on the progress. Mr Andrew Sutherland requested additional information from Mr Kelloway on the difference between load following and droop control. The Chair noted the full agenda and invited Mr Sutherland and others to provide comments through to the IMO on the topics on which they would like further information. Ms Jenny Laidlaw suggested that System Management prepare a presentation for the next MAC meeting. Mr Kelloway requested that the IMO develops a list of questions that members would like answered. The Chair agreed that the IMO would develop some points that need to be addressed and this list would be circulated to members for input. The final list would be provided to System Management for it to prepare a presentation to the next MAC meeting.	
5a.	**CP_2013_04: Outage Planning – Phase 2** The Chair introduced Ms Jenny Laidlaw to present the concept paper. A copy of the presentation is available on the Market Web Site. The following key points were noted: • This package of work is the second phase of changes to implement the recommendations of the Outage Planning Review completed in October 2011. • In mid-2012, the IMO circulated a list of the outstanding recommendations. This list has since been updated to include new issues raised by MAC members, the IMO and System Management. Some of the issues included in the list have been addressed through other rule changes. • Generally this package contains technical changes to streamline the outage planning process and clarification of the obligations of Rule Participants around outage planning. Ms Laidlaw outlined the major issues addressed in the concept paper for members. • Mrs Papps questioned whether the IMO had considered a longer time span for Opportunistic Maintenance, such as 36 hours. Ms Laidlaw replied that the IMO had not considered a longer period as to date it had not been presented with a good reason for such a change. • Mr Stevens suggested it should be possible to request an outage of	

any length at any time, provided that sufficient margin was available. Ms Laidlaw noted that the IMO disagreed with this concept, as it would reduce the forward planning and transparency of outages, and would make it easier for Market Participants to use Planned Outages to avoid capacity refunds.

- Mr Kelloway agreed that the proposal to make capacity unavailable in the Balancing Merit Order (BMO) before requesting an outage is good, but noted some potential complexities. In particular, he considered that it would be necessary for System Management to make sure that the BMO reflected a request for an outage, which currently it is not required to do. The Chair proposed that the obligation should be placed on the Market Participant to ensure that capacity is unavailable in the BMO before requesting an outage, rather than being on System Management to ensure that the availability matched.
- Mr Kelloway questioned how long System Management would have to assess a late Opportunistic Maintenance request. Ms Laidlaw confirmed that the intention was to retain the current arrangements for approval, which provide System Management with the ability to reject a request if it has insufficient time to adequately consider it.
- Mrs Papps questioned whether Verve Energy would be required to request Opportunistic Maintenance four and a half hours before gate closure. Ms Laidlaw agreed that this could be the case if the time limit for Opportunistic Maintenance requests was linked to gate closure times, but committed to working through the three options to confirm that they worked appropriately for Verve Energy Facilities.
- Ms Laidlaw asked members to provide their views to the IMO on the appropriate deadline for Opportunistic Maintenance requests, noting that there was a trade-off between flexibility for generators to request Opportunistic Maintenance and transparency of information for others to respond based on the BMO.
- Mr Stevens suggested that the concept paper only indicated that Market Participants had asked for an ex post conversion from a Forced Outage to a Planned Outage, rather than the ability to apply, while on a Forced Outage, to have a Planned Outage after a certain timeframe. Ms Laidlaw confirmed that both options had been requested by Market Participants. The Chair added that the proposed framework will allow for the latter option.
- Mr Sutherland questioned what limit was proposed for an extension of an outage. The Chair confirmed that initially no time limit would be imposed.
- Mr Sutherland sought to clarify how the extension of an outage would work given that Market Participants are required to submit a request two days in advance. Mr Stevens discussed the benefits of reducing the incentive to overstate the length of an outage. Ms Laidlaw agreed to review the interaction of Opportunistic Maintenance and outage extensions, and proposed to discuss further the practicalities with Mr Sutherland.
- Dr Paul Troughton supported the IMO's approach to the treatment of DSPs. He noted that moving to a dynamic baseline in the future may

5b.	raise the requirement to log outages. The Chair suggested that real-time telemetry for DSPs will provide the data required to assess the situation further. Ms Laidlaw confirmed that DSPs would not be included on the equipment list and therefore would not need to follow the outage planning process. • Mr Shane Duryea questioned what problem the IMO was trying to address with the addition of distribution network equipment to the equipment list. Ms Laidlaw noted that the intent was to provide visibility of network outages for distribution-connected generators. Mr Kelloway also noted that the IMO may wish to review the discretion that System Management currently has in relation to the inclusion of equipment on the equipment list. He noted that the rules allow but do not require System Management to require the Network Operator to coordinate the timing of an outage with the affected generator. • Mr Shane Cremin noted the increasing use of run-back schemes and suggested that the impact and interaction of such schemes will need to be reviewed at some point. Ms Laidlaw and the Chair agreed. The Chair noted that the quality of network access may override the price being offered by a generator, which could have unintended consequences and may lead to uneconomic dispatch. • Ms Laidlaw sought feedback on the need for proactive reporting of Forced Outages by the Network Operator for both distribution connected generators that are on the equipment list and those that are not. Mr Duryea noted that Planned Outages are more problematic because of their nature. Ms Laidlaw noted that if only very short notice is available for a Planned Outage then perhaps it is not a Planned Outage. • Mrs Papps questioned how the approval process would work for Consequential Outages that were requested before their start time. Mr Kelloway replied that he agreed it should be possible to gain approval of a Consequential Outage in advance, but would need to check the details with his team. • Ms Laidlaw noted the IMO's intention to present a pre Rule Change Proposal to the October 2013 MAC meeting and invited further comment from members in the interim. *Action Points:*	
	The IMO to ensure that the proposed changes to the Opportunistic Maintenance process outlined in the Concept Paper: Outage Planning Phase 2 – Outage Process Refinements (CP_2013_04) work appropriately with Verve Energy's different bidding timeframes.	**IMO**
	MAC members to provide their views to the IMO on the appropriate deadline for Opportunistic Maintenance requests and the need for the proactive reporting of Forced Outages affecting distribution-connected generators by the Network Operator.	**MAC**
	The IMO to review the interaction of Opportunistic Maintenance and outage extensions, including further discussion of the practicalities with Mr Sutherland..	**IMO**
5b.	**CP_2013_05: Availability, Outages and Constraint Payments for**	

	Non-Scheduled Generators The Chair introduced Ms Erin Stone to present the concept paper. The following points were noted: • The concept paper was developed primarily to address issues related to constrained on/off payments. A number of other related issues have been brought into the paper to help clarify the obligations around outages. Ms Stone noted that there is the potential for issues in the two concept papers to move between the Rule Change Proposals based on the required drafting. • Mr Cremin questioned the intent of the requirement to define incidents such as an automatic trip of a wind farm due to extreme winds as an outage, noting that it would be complex to determine pro-rated outage quantities based on an ex-post review of each minute interval. The Chair noted that the rules don’t currently require outages to be logged on a turbine by turbine basis. Mr Cremin offered to discuss the practicalities of the required rules to log outages for Intermittent Generators. Ms Stone committed to work with Mr Cremin to ensure that there were no unintended consequences of the proposed rule change. • Mr Cremin questioned the necessity to align incentives to make capacity available for Non-Scheduled Generators to that for Scheduled Generators on the basis that Non-Scheduled Generators have sufficient commercial incentive to be available. Ms Laidlaw noted that the assessment of outages for certification of a generator (under clause 4.11.1(h) of the Market Rules) includes both Scheduled and Non-Scheduled Generators. While an Intermittent Generator is unlikely to fail the test, the IMO could not justify the removal of the test for Non-Scheduled Generators. Ms Laidlaw noted that the intent is to cover situations where a facility is either not functioning for a considerable period of time or that the facility didn’t exist. • The Chair confirmed that the relocation of the TES and out of merit calculations to the appendix and represent them as mathematical equations was to remove the ability for incorrect payments being seen as a breach of the Market Rules, and ensure that they were represented more as a settlement adjustment. *Action Point - Ms Stone to work with Mr Cremin to ensure no unintended consequences arise with respect to the requirement for Intermittent Generators to log outages.*	 **IMO**
6a.	**Market Rule Change Overview** Ms Stone provided an update on the current Rule Change Proposals under consultation and development. She noted that since the meeting papers were circulated, the Final Rule Change Report was published for RC_2012_03: Assignment of Capacity Credits to Network Control Services Facilities, which is currently awaiting commencement. Given the large agenda for the October MAC meeting, Mrs Papps requested that papers be circulated earlier to allow sufficient time for members to review. The Chair confirmed that as soon as papers are available they will be circulated, allowing sufficient review time.	

	Mr Sutherland questioned the issues that would be included in the dispatch package. Ms Stone provided some examples of issues that were currently on the log that would be reviewed, including the clarification of tie-break rules, calculation of tolerance ranges and dispatch compliance issues. Ms Stone welcomed members to contact her for updates on the progress of any particular issues. Mr Kelloway questioned the difference between a concept paper and a pre Rule Change Proposal. Ms Stone noted that the biggest difference was that a concept paper was primarily for in-principle approval, where a pre Rule Change Proposal has drafting included. The Chair confirmed that both a concept paper and a Pre Rule Change Proposal were prior to the commencement of the formal process. Mrs Papps questioned the status of the proposal to establish the ability to dispute or disagree with TES calculations, which was originally on the work program to be delivered earlier this year. Ms Stone responded that she would follow this up. Mr Ruthven noted that the IMO has received a request from a Market Participant to extend the timeframe of the second consultation period for RC_2012_10: Limits to Early Entry Capacity Payments. An extension notice will be issued in the next day or two extending the deadline by two weeks. *Action Points:* *The IMO to circulate the papers for the October MAC earlier where possible.* *Ms Stone to confirm with Mrs Papps which work package the issue about TES Calculations has been included in.*	 **IMO** **IMO**
6b.	**PRC_2012_23: Prudential Requirements (and associated Market Procedure)** The Chair introduced Ms Aditi Varma to present the proposal. The following discussion points were noted: • Ms Varma advised that the pre Rule Change Proposal had been updated with three new issues. The first issue relates to the notification from Market Participants to the IMO of changes that may warrant an increase or a decrease in their Credit Limit. The second issue relates to the option for Market Participants to make pre-payments to increase their Trading Margin. The third issue involved strengthening the drafting of clauses related to Credit Support and Reserve Capacity Security arrangements. She noted that the Market Procedure for Prudential Requirements had also been included in the meeting papers for information purposes and would be discussed in the forthcoming IMO Procedures Working Group. • Mr Bargmann questioned whether creditworthiness was taken into account when determining a Market Participant's Credit Limit. Ms Varma confirmed that under proposed clause 2.37.5, the IMO could use its discretion to include any other factor including creditworthiness. • Mrs Papps noted that PRC_2012_23 appeared to be changing	

	clauses that were amended in 2011 via RC_2010_36: Acceptable Credit Criteria. Ms Varma confirmed that this was not the case and the only part that was proposed to be amended was that the obligation to submit the Acceptable Credit Criteria evidence was being placed on the Market Participant instead of the bank. She also confirmed that a new Acceptable Credit Criteria form was only required where a Market Participant was proposing to use a bank that was not on the list maintained by the IMO on the website. The Chair confirmed that the IMO was not proposing to change the list. *Action Points:* *The IMO to review RC_2010_36 and confirm with Mrs Papps as to the application of the proposed Amending Rules.* *The IMO to submit PRC_2012_23 into the formal process and progress the proposal under the Standard Rule Change Process.*	**IMO** **IMO**
6c.	**PRC_2013_10: Harmonisation of Supple-Side and Demand-Side Capacity Resources** The Chair invited Mr Ruthven to present the proposal. The following discussion points were noted: • Mr Ruthven mentioned that since CP_2013_10: Harmonisation of Supply-Side and Demand-Side Capacity Resources was presented at the June 2013 MAC meeting, the IMO had made the following updates: i. all issues have now been included in the complete drafting of the pre-Rule Change Proposal; ii. the drafting in relation to the relaxation of the fuel requirement is now consistent with the description of the concept; and iii. discussions with System Management had allowed the IMO to include potential approaches and outcomes on the development of a "real-time" data service from Demand-Side Provider's (DSP's) to System Management. • Mr Duryea noted that the proposed options in issue three were ambiguous with regard to the reference between System Management and Western Power Networks. The Chair suggested this confusion might have been from the entity that provided the information to the IMO. • The Chair noted the IMO believed it would be simpler and cause less confusion to proceed with option two, being the web-based solution. • Mr Geoff Gaston questioned whether the intent of issue three was to achieve "real-time" data from each DSP or every Associated Load. The Chair noted it was the IMO's intent to receive data at the Associated Load level. Mr Gaston supported this approach. • Mr Kelloway noted that further work will be required before System Management could commit to a solution to receive and manage data at the Associated Load level. • Dr Troughton highlighted that the costing of option one did not include costs for each DSP to provide their terminal for	

communication between the Associated Loads, therefore making option one a less attractive choice. Dr Troughton subsequently concurred with the Chair that option two was the premium solution.

- Mr Ruthven highlighted the change to the DSP refund formula, which had been amended since the June MAC meeting. No comment was made by the MAC members.
- The Chair sought comment from members on the pre Rule Change Proposal as a whole. Mrs Papps enquired whether the IMO had looked at the possibility for DSPs to pay Market Fees. Mr Sam Beagley noted that it is being considered separately, as this pre Rule Change Proposal was designed to only address the outputs of the Reserve Capacity Mechanism Working Group (RCMWG). The Chair noted that the issue around DSPs paying Market Fees was a lower priority as voted by Market Participants in the Market Rules Evolution Plan but may become a higher priority since a Market Participant had recently proposed changes to the Market Fee structure.
- Mr Cremin added that the IMO should also consider licensing in any analysis conducted around re-structuring Market Fees. The Chair advised that the IMO had written to the Economic Regulation Authority (ERA) regarding this issue but had received no response to date.
- The Chair noted that in his personal view he believed that DSM providers should be licenced similarly to a retailer. Ms Laidlaw stated that when this approach was explored by the IMO there was a lack of substance as to what licence obligations DSM providers should have to comply with and why.
- The Chair suggested that the IMO writes to the ERA highlighting this issue and request their views on whether they believe DSM providers should be licenced. Ms Wana Yang confirmed that she will make the ERA aware of this and noted that licensing is governed by the Electricity Act.
- Dr Troughton identified a potential issue with the current approach to re-designing the Non-Balancing Dispatch Merit Order (DMO). As there is a lag of 24 hours between the Non-Balancing DMO and the data used to formulate it, the current structure does not account for a DSP that is dispatched on the Scheduling Day. Mr Beagley noted Dr Troughton's concern and committed to consider this further.
- Mr Gaston suggested that this approach to the Non-Balancing DMO incentivised all providers to price the same. Mr Troughton confirmed that this was already the case. Mr Gaston also raised the concern that DSPs were incentivised to disaggregate to make them less likely to be dispatched. Ms Laidlaw stated there was nothing stopping System Management from dispatching multiple DSPs at the same time. Mr Ruthven also stated that under the current Market Rules System Management must dispatch larger DSPs first but that this PRC_2013_10 would remove that criterion.
- Mr Sutherland enquired as to the ability of DSM aggregators to move Associated Loads between DSPs. Mr Ruthven stated this is possible under the Rules but was a registration process that took a

	number of business days. • Mr Peter Huxtable questioned the new process for the relaxation on the thermal fuel requirements and how the IMO would assess this. Mr Ruthven noted that this would be addressed in the relevant Market Procedure. Mr Beagley noted that proposed amendments to the Market Procedure would be available during the Rule Change Process to allow stakeholders to consider these changes when preparing submissions. • Mrs Papps highlighted that it could be difficult to make submissions on a rule change without knowing the changes to the relevant Market Procedure. The Chair confirmed the aim was to present the relevant Market Procedure at the next IMO Procedure Working Group due to be held in September 2013. This will provide submitting parties with the opportunity to comment on the changes to the Market Procedure prior to the conclusion of the consultation period for this rule change. • Mr Gaston requested clarification on the principle presented in issue seven. Mr Ruthven confirmed that this was consistent with the principle accepted by the RCMWG. Mr Gaston indicated that this principle was not unanimously accepted by the RCMWG. Mr Ruthven noted that he was aware of this but the RCMWG as a whole accepted this approach. • Mr Gaston stated he did not understand the logic behind using the IRCR values multiplied by 1.65 because it would not result in a lower number. Noting that Relevant Demand was a physical number and IRCR was a value that could never be provided. The Chair noted it would be hard to compare regardless. • The Chair concluded discussions and stated that PRC_2013_10 would be progressed into the formal process as soon as the issues discussed were reflected in the proposal. *Action Points:* *The IMO to update PRC_2013_10 to include further clarification of the implementation cost of option one to introduce telemetry before it is formally submitted.* *The IMO to request the ERA to review the necessity of a DSP to be licensed.* *The IMO to present the amended Market Procedure for Certification of Reserve Capacity at the IMOPWG in September 2013.* *The IMO to submit PRC_2013_10 into the formal process and progress the proposal under the Standard Rule Change Process.*	**IMO** **IMO** **IMO** **IMO**
7.	**MARKET PROCEDURES** Ms Stone provided an update of the status of the current Market Procedures and noted that the IMO intends to hold the next IMO Procedures Working Group in September to discuss a number of the Market Procedures that will be submitted into the process.	
8a.	**WORKING GROUP UPDATE** Mr Ruthven noted that an IMO Procedures Working Group will be	

	scheduled for the second half of September and is expected to include Market Procedures related to RC_2013_09: Incentives to Improve Availability of Scheduled Generators, RC_2012_23: Prudential Requirements RC_2013_10, Harmonisation of Supply-side and Demand-side Capacity Resources and RC_2013_08, Market Participant Fees – Clarification of GST Treatment. Mr Ruthven noted that the membership listed in the Terms of Reference for the System Management Power System Operating Procedure (PSOP) Working Group was out of date. Mr Gaston advised that Mr John Nguyen would replace Mr Michael Frost as the Perth Energy representative. Mr Ruthven noted that Mr MacLean is listed as the Synergy representative and would need to be replaced. Mrs Papps questioned whether Verve Energy may appoint an observer. Mr Kelloway agreed to this request. *Action Point: The IMO to update the Terms of Reference for the System Management PSOP Working Group to reflect the updated membership.*	**IMO**
9.	**GENERAL BUSINESS** The Chair invited Mr Kelloway to present the information paper on governor action and Load Following Ancillary Services. The following discussion points were noted: • Mr Kelloway noted that the intent of the paper was to draw the distinction between governor action as required under the Technical Rules and Load Following that is required under the Market Rules. • Mr Kelloway described governor action as something that is triggered by deviations in frequency to stabilise the system frequency for large swings that would occur very rapidly, as opposed to Load Following which is a solution to changes in longer term system load. Governor action is a local, closed loop, high speed control mechanism. Load Following is provided through a centralised and coordinated AGC facility. • The Chair questioned if governor action is the first method of response when there is a frequency deviation. Mr Kelloway confirmed that this is correct and that while governor response would stabilise the frequency System Management uses Load Following to bring the frequency back to 50Hz. • Mr Sutherland suggested that if governor action is required by the Technical Rules it is essentially free to the market. The Chair confirmed that this is correct as it is a requirement for compliance with the Technical Rules. • Mr Huxtable questioned whether the compliance cost was different for different types of generators. Mr Stevens agreed that the cost was likely to vary between coal and gas generators based on the capability differences. • Mr Sutherland noted that the LFAS market started providing 80MW of Load Following which was subsequently dropped to 72MW. He questioned whether if Load Following drops to 40MW or 20MW the lights would stay on because of droop control. Mr Kelloway agreed but noted that the frequency would stay down until Load Following corrects it. Mr Stevens stated the need for a “Load Following 101”	

	course. Mr Sutherland reiterated the requirement to understand the interaction between dropping the Load Following requirement to get expenses down and the impact on other generators. The Chair noted the intention to provide a presentation on this topic at the next MAC. The Chair committed the IMO to provide a list of issues that the MAC would like addressed by Mr Kelloway in his presentation. *Action Point: The IMO to put together and circulate to members a list of questions on Load Following for Mr Kelloway to answer in a presentation at the next MAC meeting.* Mr Cremin asked the Chair if there was an update on the progress or details of the merger of Verve and Synergy. The Chair noted that the IMO did not have any details from the implementation group yet but advised the MAC that it had reviewed the Market Rules to identify rules that may be affected. The Chair indicated that it will largely depend on the ring-fencing arrangements but it is likely that the major rule change will be around market power, market surveillance and monitoring. The Chair also noted that it is unlikely that a rule change will be able to be progressed prior to the merger being effective on 1 January 2014.	**IMO/SM**
CLOSED: The Chair declared the meeting closed at 4.25 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
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	Complete. PUO provided response on 20 August 2013.
22	2013	System Management to provide details at the PRC_2013_09 discussion forum regarding the types and level of outage requests it receives.	SM	Apr	Forum held on 08 May 2013. System Management still to provide information.
24	2013	The IMO/SM Working Group to share finding of the LFAS working group at the next MAC meeting.	IMO/SM	Apr	Complete. On October MAC Agenda
30	2013	The IMO to amend the minutes of Meeting No. 61 and publish with the minutes of Meeting No. 59 as final	IMO	Aug	Complete.
31	2013	The IMO to ensure that the proposed changes to the Opportunistic Maintenance process outlined in the Concept Paper: Outage Planning Phase 2 – Outage Process Refinements (CP_2013_04) work appropriately with Verve Energy's different bidding timeframes.	IMO	Aug	Complete.

#	Year	Action	Responsibility	Meeting arising	Status/Progress
32	2013	MAC members to provide their views to the IMO on the appropriate deadline for Opportunistic Maintenance requests and the need for the proactive reporting of Forced Outages affecting distribution - connected generators by the Network Operator.	MAC	Aug	Complete.
33	2013	The IMO to review the interaction of Opportunistic Maintenance and outage extensions, including further discussion of the practicalities with Mr Sutherland.	IMO/ERM	Aug	Complete.
34	2013	The IMO to work with Mr Cremin to ensure no unintended consequences arise with respect to the requirement for Intermittent Generators to log outages.	IMO/APA	Aug	Underway.
35	2013	The IMO to circulate the papers for the October MAC earlier where possible.	IMO	Aug	Complete. Papers circulated.
36	2013	The IMO to confirm with Mrs Papps which work package the issue about TES Calculations has been included in.	IMO/Verve	Aug	Complete.
37	2013	The IMO to review RC_2010_36 and confirm with Mrs Papps as to the application of the proposed Amending Rules.	IMO/Verve	Aug	Complete.
38	2013	The IMO to submit PRC_2012_23 into the formal process and progress the proposal under the Standard Rule Change Process.	IMO	Aug	Complete. RC_2012_23 was published on 14 August 2013.
39	2013	The IMO to update PRC_2013_10 to include further clarification of the implementation cost of option one to introduce telemetry before it is formally submitted.	IMO	Aug	Complete.
40	2013	The IMO to request the ERA to review the necessity of a DSP to be licensed.	IMO	Aug	Underway.
41	2013	The IMO to present the amended Market Procedure for Certification of Reserve Capacity at the IMOPWG in September 2013.	IMO	Aug	Complete. IMOPWG was held on 20 September 2013.
42	2013	The IMO to submit PRC_2013_10 into the formal process and progress the proposal under the Standard Rule Change Process.	IMO	Aug	Complete. RC_2013_10 was published on 21 August 2013.

#	Year	Action	Responsibility	Meeting arising	Status/Progress
43	2013	The IMO to update the Terms of Reference for the System Management PSOP Working Group to reflect the updated membership.	IMO	Aug	Completed
44	2013	The IMO to put together and circulate to members a list of questions on Load Following for Mr Kelloway to answer in a presentation at the next MAC meeting.	IMO/SM	Aug	Complete. Email circulated to members on 2 September 2013. Feedback tabled at the October meeting.

LFAS Requirement Investigation: Analysis of LFAS causes and usage

Report to MAC

9 October 2013

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1. Introduction

1.1. Background

In December 2012 the IMO and System Management began working together to investigate the LFAS Requirement for the Wholesale Electricity Market (WEM). The team was formed following the 14 November 2012 meeting of the Market Advisory Committee (MAC), where the IMO presented an update to MAC members on the Pre Rule Change Proposal: Ancillary Services Payment Equations (PRC_2010_27)[1]. During the presentation a number of concerns were raised around LFAS provision in the WEM, including that:

- the cost of LFAS is unacceptably high; and
- there is a lack of clarity around LFAS provision in the WEM, e.g. it is unclear how much LFAS is actually required and used.

The LFAS cost is a combination of the LFAS price and the quantity provided. The focus of the team has been on the quantity component of LFAS, rather than the price component which is determined in the LFAS Market and monitored by the IMO's compliance team and the Economic Regulation Authority (ERA).

The team is investigating how the LFAS Requirement can be minimised by:

- minimising the quantity of LFAS actually needed in each Trading Interval; and
- more accurately estimating the LFAS Requirement in advance of each Trading Interval.

The team is also seeking to improve clarity around the provision of LFAS by:

- clarifying the boundary between Balancing and LFAS, particularly for the Verve Energy Balancing Portfolio (VEBP);
- clarifying the differences and boundaries between governor control, LFAS, Spinning Reserve and Load Rejection Reserve; and
- improving and formalising the processes for monitoring and reporting LFAS usage (this will also support the work to minimise the LFAS Requirement and allow its progress to be assessed).

The team has undertaken an initial analysis of LFAS usage in the South West interconnected system (SWIS) over March 2013. The aim of the analysis was to assess how much LFAS was used during that month and develop measures for the different factors that contribute to the need for LFAS, in order to:

- inform the market via the MAC;
- identify any issues that need to be resolved;
- prioritise future work;
- provide a starting point for further analysis; and
- develop methodologies to support ongoing forecasting, monitoring and reporting of LFAS

[1] For further details see http://www.imowa.com.au/MAC_55. PRC_2010_27 sought to introduce a "causer pays" approach to LFAS cost allocation. Following the discussion the MAC agreed that PRC_2010_27 would not be progressed and that the IMO would continue to investigate the issues raised in its presentation.

usage.

1.2. Structure of this report

The remainder of the document is structured as follows:

- section 2 provides a high level overview of the methodology used for the analysis;
- section 3 discusses the analysis of the four primary causes of LFAS;
- section 4 discusses the analysis of LFAS usage;
- section 5 discusses the current definition of the Minimum Frequency Keeping Capacity in the Market Rules;
- section 6 summarises the main findings of the analysis;
- section 7 discusses options for potential improvements; and
- section 8 provides a summary of recommendations.

2. Overview of the analysis

The analysis was undertaken using historical Dispatch Instruction, forecast generation and actual generation records extracted from System Management's IT systems.

Four primary causes of the need for LFAS were examined in detail:

- variations between forecast and actual system load;
- variations between forecast and actual Non-Scheduled Generator (NSG) output;
- deviations of Scheduled Generators (SGs) from their Dispatch Instructions; and
- variations between SG Dispatch Instructions and forecast SG output due to the dispatch of Independent Power Producers (IPP) SGs at their Balancing Merit Order (BMO) ramp rates.

For each cause a separate analysis was undertaken. Each analysis involved comparing values from two time series (e.g. forecast system load versus actual system load) for each minute of the analysis month. A difference between the values indicates an error or deviation that contributes to the overall LFAS requirement in that minute – a negative result indicates a need for Downward LFAS while a positive result indicates a need for Upwards LFAS.

A percentile analysis was then used to assess the distribution and extent of the deviations, and to compare the relative impacts of the different causes. In addition the periods during which the largest deviations occurred were examined, to gain a better understanding of the underlying causes and how the deviations could be minimised or better predicted in future.

A similar analysis was undertaken to assess the actual usage of the LFAS Facilities during the month. This analysis compared the actual output of the active LFAS Facilities in each minute with their expected output. Output in excess of the expected level represented the provision of Upwards LFAS, while output below the expected level represented the provision of Downwards LFAS.

The LFAS usage analysis requires calculation of the expected output of the VEBP for each minute, based on "notional" Dispatch Instructions. The Market Rules are silent on the methodology for this calculation and there are several possible options, each with different advantages and disadvantages. The team considered and prepared LFAS usage statistics for five of the possible options.

2.1. Exclusion of intervals from the analysis

Several time periods were excluded from the analysis after an initial review of the historical data. These include:

- 2:00pm - 3:00pm on 6 March, due to an under-frequency load shedding event involving approximately 220 MW of sudden load reduction;
- 4:30pm – 5:30pm on 14 March, due to an under-voltage load shedding event involving approximately 220 MW of sudden load reduction;
- 109 10 minute periods for which load forecasts were not created; and
- seven Trading Intervals with extreme load forecast errors, where the load forecast was clearly spurious. The periods excluded were:
  - 2:30pm – 3:00pm on 1 March;
  - 8:00pm – 9:00pm on 1 March;
  - 2:00pm – 3:00pm on 13 March; and
  - 4:30pm – 5:30pm on 21 March.

The seven Trading Intervals were excluded following a visual check of the periods with the largest forecast errors. The decision to exclude seven Trading Intervals rather than a greater or lesser number was to some extent arbitrary. The periods were removed because the load forecasts were clearly implausible and the errors, while not having any physical impact on the LFAS Facilities at the time, were generating unrealistic outlier values. However, other Trading Intervals with similar (although smaller) forecast errors were included in the analysis. The impact of excluding the seven Trading Intervals on the analysis of variations between forecast and actual system load is shown in section 3.1 of this report.

In total, 1,420 of the 44,640 minutes in March 2013 (approximately 3%) were excluded from the analysis.

2.2. Limitations of the analysis methodology

It is important to note that this is a preliminary analysis only and the results should be regarded with caution. In particular:

- due to the manner in which the VEBP is dispatched, the LFAS usage results presented in this report will tend to exaggerate the extent to which VEBP generator output is being adjusted to provide LFAS;
- the results are based on one minute average MW quantities and so may not reflect the impact of fluctuations occurring within each minute (although these are not expected to be large); and
- the analysis is for a single month - it is uncertain how much the results may vary between months due to either seasonal factors or dispatch process improvements. (Note the team is currently analysing the historical data for July 2013 and intends to present its findings at the October 2013 MAC meeting.)

It should also be remembered that the LFAS Requirement will always need to be set to a level that provides some buffer over the expected usage level.

2.3. Independent review of analysis methodology and results

The IMO engaged the Sapere Research Group (Sapere) to provide an independent verification of the March 2013 analysis. The verification included a critical review of the methodology and the re-calculation of results. The work was carried out by Dr Richard Tooth and Dr James Swansson.

Sapere was able to successfully reproduce the analysis results using the input data and methodology provided. Sapere also suggested the investigation of some other potential causes of variation, relating to the translation of "generated" system load forecasts to "sent out" Dispatch Instruction target MW quantities. Sapere's suggestions have not been incorporated into this analysis due to time constraints but will be taken into consideration for future analyses. The impact of the additional causes is, however, expected to be relatively low.

Sapere has also been asked to provide a verification of the calculations for July 2013.

3. Analysis of primary causes

3.1. Cause 1: Variation from system load forecast

This analysis compared the forecast system load (average MW) for each minute against the actual load.

3.1.1. Methodology

For the purposes of this analysis, forecast system load is the quantity predicted by System Management's forecasting system. This is a generated rather than a sent out quantity, defined as "the market generated load, being the energy entering the Wholesale Electricity Market (WEM) plus that used on works by WEM generators". The quantity excludes behind the fence loads at the Southern Cross Energy, Parkeston/Newmont and BP Refinery Intermittent Load sites. The forecast requirement is converted from a generated quantity to a sent out quantity when Dispatch Instructions are created by the Real Time Dispatch Engine (RTDE).

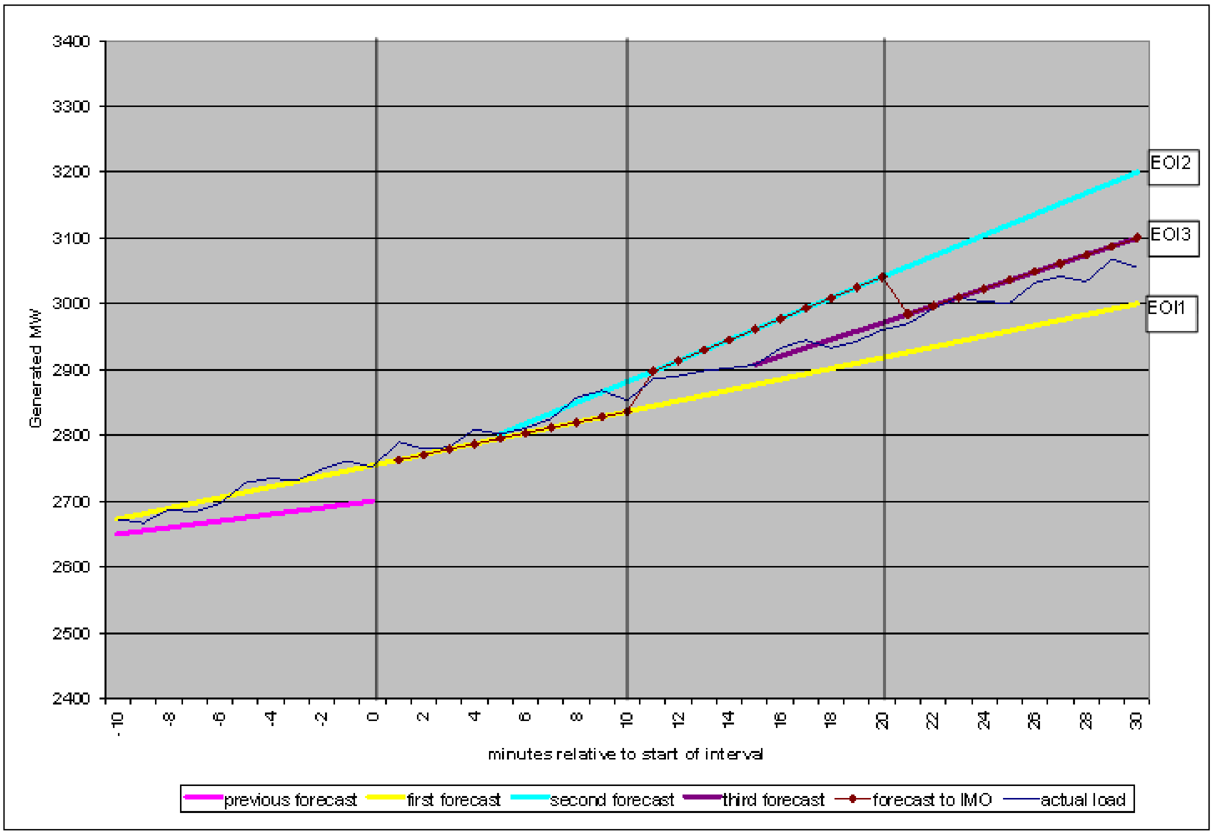
The actual load value for each minute was sourced from System Management's "PI Historian" database.

Forecast load values were extracted from System Management's Operational Database System (ODS). For each 10 minute period, the "end of Trading Interval" (EOI) load forecast quantity used to generate Dispatch Instructions for that period was extracted. Note that under the current RTDE configuration:

- 10 minutes before the start of a Trading Interval, Dispatch Instructions to apply from the start of the Trading Interval are generated;
- 5 minutes after the start of a Trading Interval, Dispatch Instructions to apply from the eleventh minute of the Trading Interval are generated; and
- 15 minutes after the start of a Trading Interval, Dispatch Instructions to apply from the twenty-first minute of the Trading Interval are generated.

The one minute forecast values for each 10 minute period were calculated using linear interpolation, from the actual load at the time the Dispatch Instructions for the period were generated to the EOI load forecast used in their generation. This is shown graphically in Figure 1 below.

Figure 1 Calculation of one minute forecast load values



When the actual load is greater than the forecast load an Upwards LFAS requirement is created. Conversely, when the actual load is less than the forecast load a Downwards LFAS requirement is created.

3.1.2. Results

A summary of the one minute calculation results (actual load – forecast load) is provided in Table 1. Percentiles were calculated both with and without the seven Trading Intervals excluded from the other analyses, to give an indication of their impact.

Table 1 Cause 1: Variation from system load forecast – analysis summary

	7 TI Excluded		7 TI Included
Number of samples	43,220		43,430
Average	1		1
Percentiles			
0.05%	-77	Downwards LFAS	-131
0.50%	-52	Downwards LFAS	-55
1%	-45	Downwards LFAS	-45
2%	-37	Downwards LFAS	-38
3%	-33	Downwards LFAS	-33
4%	-29	Downwards LFAS	-29
5%	-27	Downwards LFAS	-27
10%	-19	Downwards LFAS	-20
50%	1	Upwards LFAS	1
90%	22	Upwards LFAS	22
95%	30	Upwards LFAS	30
96%	32	Upwards LFAS	32
97%	35	Upwards LFAS	36
98%	39	Upwards LFAS	40
99%	47	Upwards LFAS	49
99.5%	55	Upwards LFAS	59
99.95%	83	Upwards LFAS	118

The intervals with values outside the 99.9% confidence level (i.e. with results less than -77 MW or greater than 83 MW) were examined to determine any common underlying causes. Graphical examples of these variations are available in **Error! Reference source not found.** of this report.

Some of the periods examined showed large and irregular fluctuations in the actual load. Likely causes of these variations include:

- network disturbances that result in load shedding;
- unexpected changes to the consumption of large block loads; and
- the impact of rooftop photovoltaic (PV) systems during periods of variable cloud cover.

However, in many of the periods examined the variations appear to relate to spurious load forecasts rather than to volatility in the system load. These variations are likely to be due to problems with either the inputs to or the internal processing of the forecasting system.

As mentioned above, the process of generating Dispatch Instructions involves converting the load forecasts from generated to sent out quantities. This process may also introduce variations that contribute to the need for LFAS, although System Management does not expect there to be any significant impact. The potential impacts of the conversion process were not considered in this preliminary analysis.

3.2. Cause 2: Variation from non-scheduled generation forecast

This analysis compared the forecast average MW output of NSGs for each minute against the actual output of these generators.

3.2.1. *Methodology*

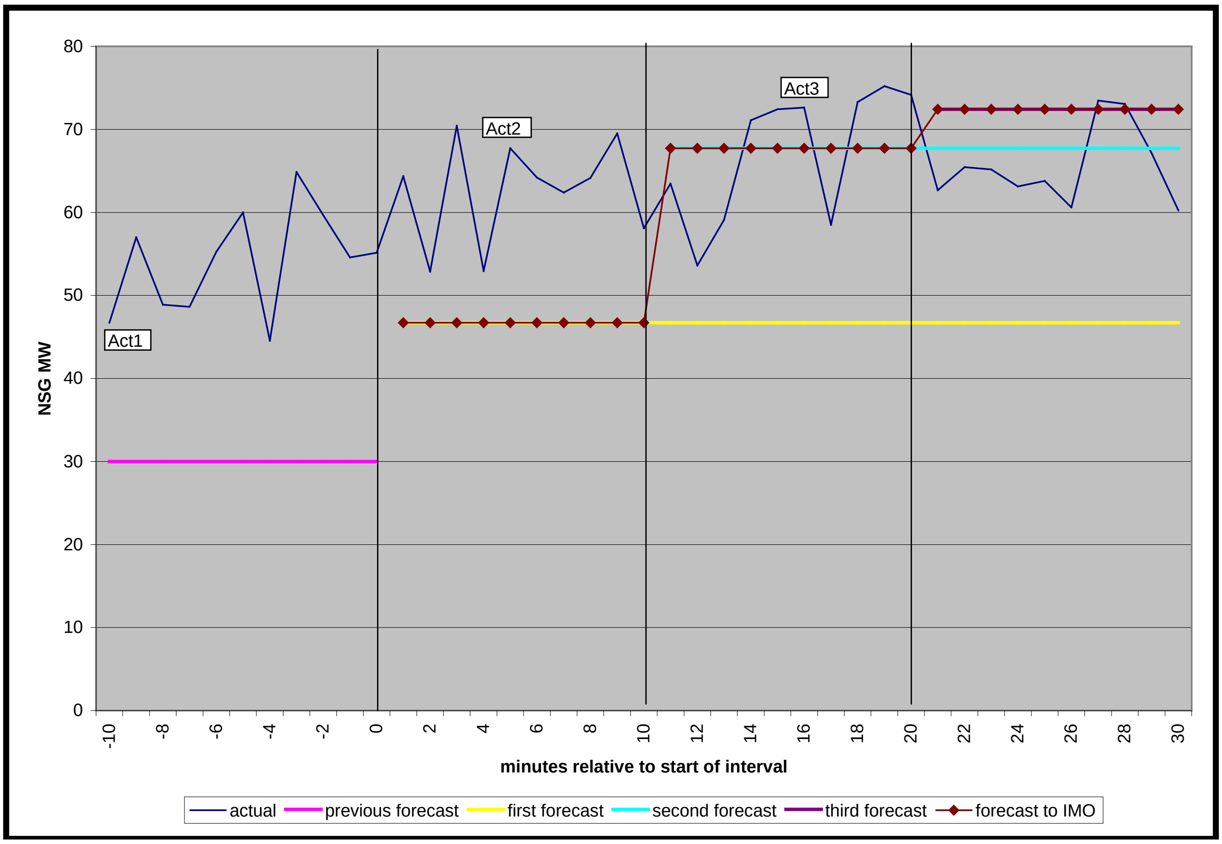
The actual NSG output value for each minute was sourced from System Management's "PI Historian" database.

The forecast NSG output values were derived from the actual output values using the "persistence" forecast method used by the RTDE. For each Trading Interval the values were set:

- for minutes 1-10, to the actual output value for minute 21 of the previous Trading Interval (the "current" output at the time the forecast was created);
- for minutes 11-20, to the actual output value for minute 6; and
- for minutes 21-30, to the actual output value for minute 16.

This is shown graphically in Figure 2 below. When the actual NSG output is less than the forecast NSG output an Upwards LFAS requirement is created. Conversely, when the actual NSG output is greater than the forecast NSG output a Downwards LFAS requirement is created.

Figure 2 Calculation of one minute NSG output values



3.2.2. *Results*

A summary of the one minute calculation results (forecast NSG output – actual NSG output) is provided in Table 2 below.

Table 2 Cause 1: Variation from non-scheduled generation forecast – analysis summary

Number of samples	43,220	
Average	0	
Percentiles		
0.05%	-89	Downwards LFAS
0.50%	-43	Downwards LFAS
1%	-33	Downwards LFAS
2%	-24	Downwards LFAS
3%	-21	Downwards LFAS
4%	-18	Downwards LFAS
5%	-16	Downwards LFAS
10%	-11	Downwards LFAS
50%	0	
90%	11	Upwards LFAS
95%	16	Upwards LFAS
96%	18	Upwards LFAS
97%	20	Upwards LFAS
98%	24	Upwards LFAS
99%	29	Upwards LFAS
99.5%	36	Upwards LFAS
99.95%	74	Upwards LFAS

All the intervals with values outside the 99.9% confidence level were associated with one of six events which are shown graphically in **Error! Reference source not found.**. Most of the events appear related to wind variations, in particular to the passing of wind fronts over the major wind farms (and in particular Collgar). As well as causing rapid increases in output the fronts can also be responsible for rapid reductions as individual turbines may trip off when the wind reaches a high enough speed.

The 10 March 2013 event however appears to have been caused by an internal problem with the NSG rather than wind variability.

There were also a few cases of individual NSGs with sudden and large output reductions that appeared to be avoidable. For example, the average output of one NSG reduced 31 MW (from 56 MW to 25 MW) in a minute due to a transmission line maintenance outage. In this case the ramp down rate was controlled by the Market Participant.

3.3. Variation from scheduled generation forecast

An analysis of the variations between forecast and actual SG output was also prepared. SG output was calculated as (load – NSG output), using the load values described in section 3.1 and the NSG output values described in section 3.2 of this report. The SG analysis reflects the net impact of Causes 1 and 2.

When the actual SG output is greater than the forecast SG output an Upwards LFAS requirement is created. Conversely, when the actual SG output is less than the forecast SG output a Downwards LFAS requirement is created.

3.3.1. Results

A summary of the one minute calculation results (actual SG output - forecast SG output) is provided in Table 3 below.

Table 3 Variation from scheduled generation forecast – analysis summary

Number of samples	43,220	
Average	1	
Percentiles		
0.05%	-96	Downwards LFAS
0.50%	-67	Downwards LFAS
1%	-55	Downwards LFAS
2%	-45	Downwards LFAS
3%	-40	Downwards LFAS
4%	-36	Downwards LFAS
5%	-33	Downwards LFAS
10%	-23	Downwards LFAS
50%	2	Upwards LFAS
90%	25	Upwards LFAS
95%	34	Upwards LFAS
96%	36	Upwards LFAS
97%	40	Upwards LFAS
98%	45	Upwards LFAS
99%	54	Upwards LFAS
99.5%	65	Upwards LFAS
99.95%	94	Upwards LFAS

3.4. Cause 3: Deviation of Scheduled Generators from Dispatch Instructions

This analysis compared the actual (average MW) output of IPP SGs for each minute against the output levels specified in their Dispatch Instructions. The analysis included all IPP SGs, but excluded NewGen Kwinana in periods when it was providing LFAS, as in these periods the Facility is expected to deviate from its underlying dispatch instruction path. (The VEBP was excluded from this analysis for the same reason.)

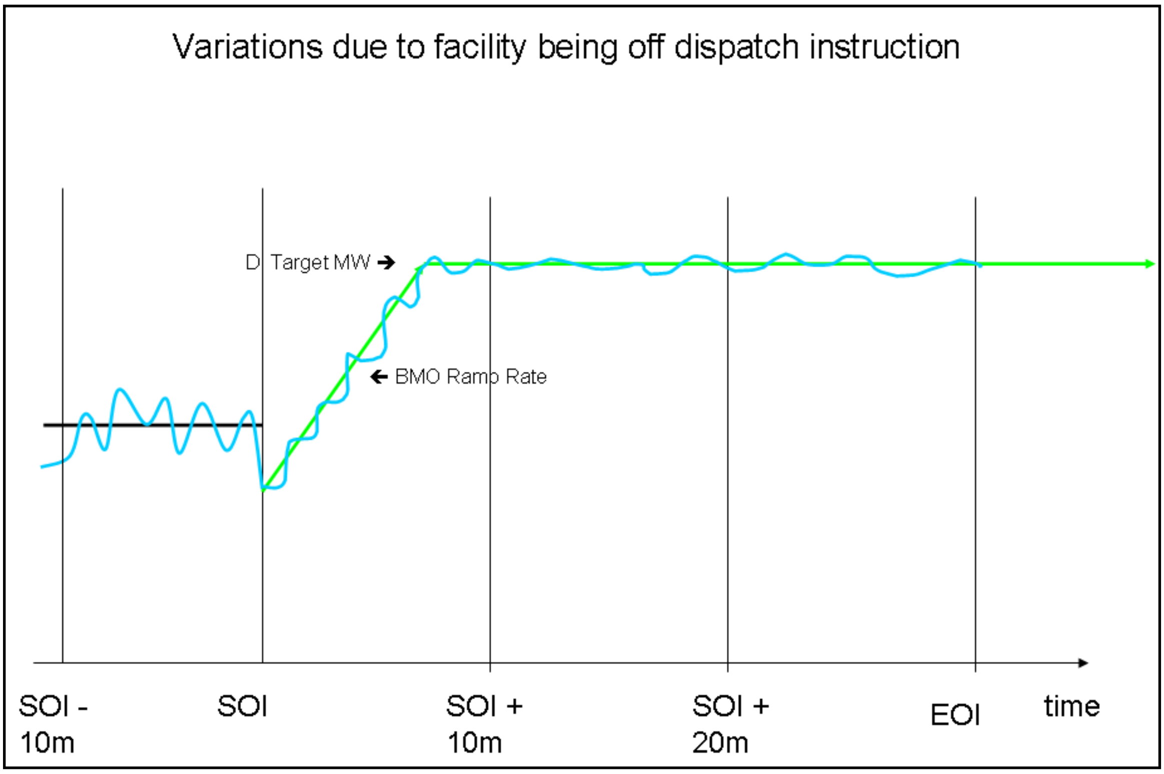
3.4.1. Methodology

The actual output value (average MW sent out) for each SG and minute was sourced from System Management's "PI Historian" database. Gaps in the time series for each generator were filled using the most recent previous "good" value available for that generator.

The Dispatch Instruction output value for each SG and minute was calculated using actual output values and Dispatch Instructions. The calculation method assumes that each time a new Dispatch Instruction takes effect the SG ramps from its current (actual) position at its Dispatch Instruction ramp rate until it reaches its target MW level, and then remains at that output level until the start time of its next Dispatch Instruction.

This is shown graphically in Figure 3 for a particular Trading Interval. The actual output of the Facility is shown in blue while the Dispatch Instruction output is shown in green.

Figure 3 Deviation of a Scheduled Generator from its Dispatch Instruction



The individual SG values were then summed to produce a total actual output value and total Dispatch Instruction output value for each minute.

When the total actual output is less than the total Dispatch Instruction output an Upwards LFAS requirement is created. Conversely, when the total actual output is greater than the total Dispatch Instruction output a Downwards LFAS requirement is created.

3.4.2. Results

A summary of the one minute calculation results (Dispatch Instruction output – actual output) is provided in Table 4 below.

Table 4 Cause 3: Deviation of Scheduled Generators from Dispatch Instructions – analysis summary

Number of samples	43,220	
Average	7	
Percentiles		
0.05%	-30	Downwards LFAS
0.50%	-14	Downwards LFAS
1%	-9	Downwards LFAS
2%	-6	Downwards LFAS
3%	-4	Downwards LFAS
4%	-3	Downwards LFAS
5%	-3	Downwards LFAS
10%	-1	Downwards LFAS
50%	5	Upwards LFAS
90%	16	Upwards LFAS
95%	20	Upwards LFAS
96%	21	Upwards LFAS
97%	23	Upwards LFAS
98%	26	Upwards LFAS
99%	32	Upwards LFAS
99.5%	50	Upwards LFAS
99.95%	69	Upwards LFAS

The distribution is skewed, requiring more Upwards LFAS than Downwards LFAS. This is in line with System Management's observation that SGs tend to be slower in ramping up to a target than in ramping down to a target.

An examination of the intervals with values outside the 99.9% confidence level revealed a variety of underlying causes. The most common causes were:

- delays in an SG starting to respond to a Dispatch Instruction, in particular to an instruction to reduce output;
- an SG ramping up at a slower rate than specified in its Dispatch Instruction, and in some cases failing to meet its target output level;
- delays in issuing new Dispatch Instructions to reflect changes in the output of a commissioning SG. For example, when Muja 4 shut down at around 4:45 am on 17 March its current Dispatch Instruction (which had a target output of 55 MW) was not replaced until 6:30 am; and
- delays in issuing new Dispatch Instructions to an SG that suffered a Forced Outage (in some cases for several hours).

3.5. Cause 4: Variations due to dispatch at BMO ramp rates

This analysis examined the impact of Dispatch Instruction ramp rates on the requirement for LFAS.

Dispatch Instructions are currently issued using the ramp rates listed in the BMO (which are the Ramp Rate Limits from the Facilities' Balancing Submissions) rather than the ramp rates that would best match the minute to minute SG forecast requirement. This approach was incorporated into the design of the RTDE to minimise constrained on/off compensation.

For example, if a change to the total SG output forecast required an increase of 60 MW over a Trading Interval, then ideally the SGs would be dispatched so as to increase the total SG output by a steady 2 MW/minute. However, the SGs are dispatched at their individual Ramp Rate Limits, which are unlikely to be the same as the "preferred" 2 MW/minute ramp rate. Any variations will contribute to the overall LFAS requirement.

The analysis excluded the VEBP and its component generators on the basis that the VEBP is not actually dispatched at its BMO ramp rate.

3.5.1. Methodology

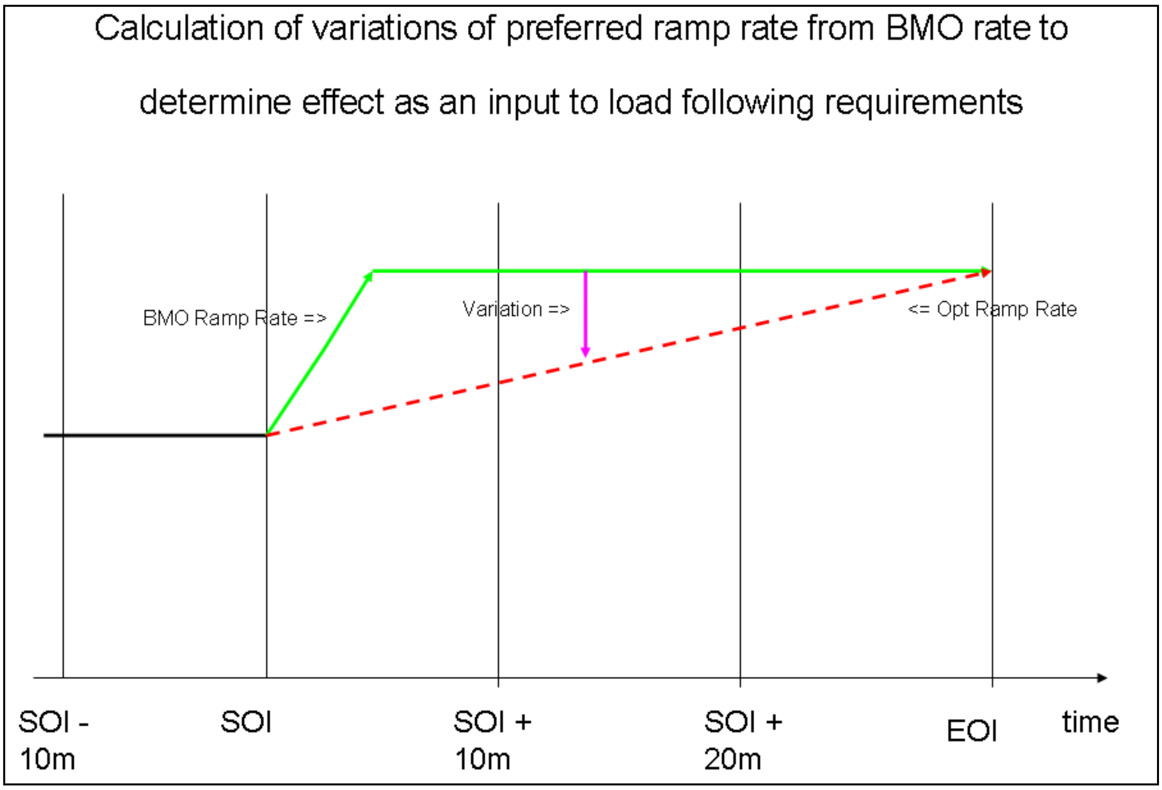
To measure the impact, the expected output level ("Dispatch Instruction output") of each IPP SG in each minute was calculated, assuming first the BMO ramp rate and then the preferred ramp rate. In both cases the SGs were assumed to follow their Dispatch Instructions exactly, so that the actual output level of the SG at the time each new Dispatch Instruction started was the same as its Dispatch Instruction output. This assumption was made to prevent the analysis results from being affected by any variations of SGs from their Dispatch Instructions.

The "BMO" Dispatch Instruction output values were calculated assuming that each time a new Dispatch Instruction takes effect the SG ramps from its current position at its (BMO) Dispatch Instruction ramp rate until it reaches its target MW level, and then remains at that output level until the start time of its next Dispatch Instruction.

The "preferred" Dispatch Instruction output values were calculated assuming that each time a new Dispatch Instruction takes effect the SG ramps from its current position towards its target MW level at the constant ramp rate that will cause it to reach the target MW level at the end of the Trading Interval.

This is shown graphically in Figure 4 below. The green line shows the BMO Dispatch Instruction output, while the red line shows the preferred Dispatch Instruction output.

Figure 4 Illustration of BMO ramp rate vs preferred ramp rate



The individual SG values were then summed to produce total BMO Dispatch Instruction output and total preferred Dispatch Instruction output values for each minute.

When the BMO Dispatch Instruction output is less than the preferred Dispatch Instruction output an Upwards LFAS requirement is created. Conversely, when the BMO Dispatch Instruction output is greater than the preferred Dispatch Instruction output a Downwards LFAS requirement is created.

3.5.2. Results

A summary of the one minute calculation results (preferred Dispatch Instruction output – BMO Dispatch Instruction output) is provided in Table 5 below.

Table 5 Cause 4: Variations due to dispatch at BMO ramp rates – analysis summary

Number of samples	43,220	
Average	0	
Percentiles		
0.05%	-74	Downwards LFAS
0.50%	-43	Downwards LFAS
1%	-34	Downwards LFAS
2%	-25	Downwards LFAS
3%	-20	Downwards LFAS
4%	-17	Downwards LFAS
5%	-14	Downwards LFAS
10%	-7	Downwards LFAS
50%	0	
90%	6	Upwards LFAS
95%	14	Upwards LFAS
96%	17	Upwards LFAS
97%	20	Upwards LFAS
98%	24	Upwards LFAS
99%	32	Upwards LFAS
99.5%	43	Upwards LFAS
99.95%	74	Upwards LFAS

Looking at the intervals with values outside the 99.9% confidence level, the negative results all occurred in minutes between 5:00 am and 7:30 am. This is not unexpected, as SGs are more likely to be ramping up at a higher than ideal rate in the morning. Similarly, the larger positive results tended to occur in the evening, when more SGs are ramping down.

A brief examination of variations exceeding 50 MW shows:

- no minutes with results below -50 MW occurred between 8:30 pm and 5:00 am; and
- only one minute with a result above 50 MW occurred between 12:00 am and 6:00 am or between 12:30 pm and 7:00 pm.

3.6. Comparison of LFAS causes

A summary of the results of the four analyses is provided in Table 6 below.

Table 6 Summary of LFAS cause analysis results

Percentile	Cause 1 Load	Cause 2 NSG	Total SG	Cause 3 SG dev from DI	Net Excl Ramping	Cause 4 BMO ramping	Net All Causes
0.05%	-77	-89	-96	-30	-92	-74	-103
0.50%	-52	-43	-67	-14	-60	-43	-65
1%	-45	-33	-55	-9	-49	-34	-54
2%	-37	-24	-45	-6	-39	-25	-43
3%	-33	-21	-40	-4	-34	-20	-38
4%	-29	-18	-36	-3	-30	-17	-33
5%	-27	-16	-33	-3	-27	-14	-30
10%	-19	-11	-23	-1	-18	-7	-20
50%	1	0	2	5	8	0	8
90%	22	11	25	16	33	6	35
95%	30	16	34	20	43	14	46
96%	32	18	36	21	46	17	49
97%	35	20	40	23	51	20	53
98%	39	24	45	26	57	24	60
99%	47	29	54	32	69	32	71
99.50%	55	36	65	50	79	43	83
99.95%	83	74	94	69	109	74	116

The “Net Excl Ramping” analysis values were determined by summing the variances for causes 1, 2 and 3 to produce a net variance for each minute. Note that for any particular minute a negative variance from one cause may be counteracted by a positive variance from another cause, reducing the net requirement to be met by LFAS.

The “Net All Causes” analysis was determined by summing the variances arising from all four causes for each minute.

Based on the range of variance between the 1% and 99% percentiles the causes in order of descending impact are:

- Cause 1: Variation from system load forecast;
- Cause 4: Variations due to dispatch at BMO ramp rates;
- Cause 2: Variation from non-scheduled generation forecast; and
- Cause 3: Deviation of Scheduled Generators from Dispatch Instructions.

The 99.5% and 99.95% bands were not used to rank the impacts as they are very sensitive to outliers.

4. Usage of LFAS

In order to ensure that the LFAS Requirement is set to an efficient level, it is important to be able to assess how much LFAS is actually being used over time. The Market Rules do not explicitly define the boundary between LFAS and Balancing (or between LFAS and the other Ancillary Services), or prescribe how LFAS usage should be measured. However for the purposes of this analysis, LFAS usage has been defined for each minute as the difference between the actual output of the active LFAS Facilities in that minute and the expected output of those Facilities based on their Dispatch Instructions (which in the case of the VEBP will be notional Dispatch Instructions).

Currently there are two LFAS providers in the WEM:

- NewGen Kwinana; and
- the VEBP.

The analysis calculated the LFAS usage for each minute as the sum of the LFAS provided by the VEBP and the LFAS provided by NewGen Kwinana in that minute. A negative value indicates the provision of Downwards LFAS, while a positive value indicates the provision of Upwards LFAS.

4.1. Measurement of Dispatch Instruction output for NewGen Kwinana

The NewGen Kwinana Facility, when enabled for LFAS, allows its output to be varied by System Management's Automatic Generation Control (AGC) system approximately every four seconds.

The system limits the output variations to a MW range above and/or below a base point level set in line with the Facility's Dispatch Instructions. To enable an Upwards LFAS quantity of, for example, 10 MW the upper limit of the range is set to be 10 MW greater than the base point. Similarly, setting the lower limit of the range 10 MW below the base point would enable 10 MW of Downwards LFAS. Typically NewGen Kwinana might be enabled to provide 30 MW each of Upwards and Downwards LFAS.

The actual output MW and the upper and lower limits set for NewGen Kwinana are recorded in the PI Historian database. The Facility was deemed to be providing LFAS whenever its upper and lower limits differed by more than 3 MW.

For NewGen Kwinana there is a clear distinction between Balancing and LFAS, as the Dispatch Instructions for the Facility are well defined. During periods when the Facility was deemed to be providing LFAS the LFAS provision was measured as the variation between the actual output of the Facility in each minute (average MW sent out) and its Dispatch Instruction output.

The Dispatch Instruction output values were calculated assuming that each time a new Dispatch Instruction takes effect the Facility ramps from the position it would have been in if it had fully complied with its previous Dispatch Instruction, rather than its actual position. This method was chosen as more accurately reflecting the actual LFAS quantities provided over time, although it may tend to produce slightly larger LFAS usage quantities than if the actual position of the Facility was used as the starting point for new Dispatch Instructions.

4.2. Measurement of Dispatch Instruction output for the VEBP

Under the current Market Rules, Dispatch Instructions are not issued for the VEBP. Instead, System Management dispatches the various Facilities within the VEBP to provide Balancing, LFAS and other Ancillary Services. The VEBP contains a wide variety of generators types, including baseload coal plants, combined cycle gas turbine (CCGT) and open cycle gas turbine (OCGT) units and wind farms. While some Facilities such as the coal fired units are dispatched manually, other Facilities are controlled by the AGC system, receiving instructions to amend their output levels approximately every four seconds.

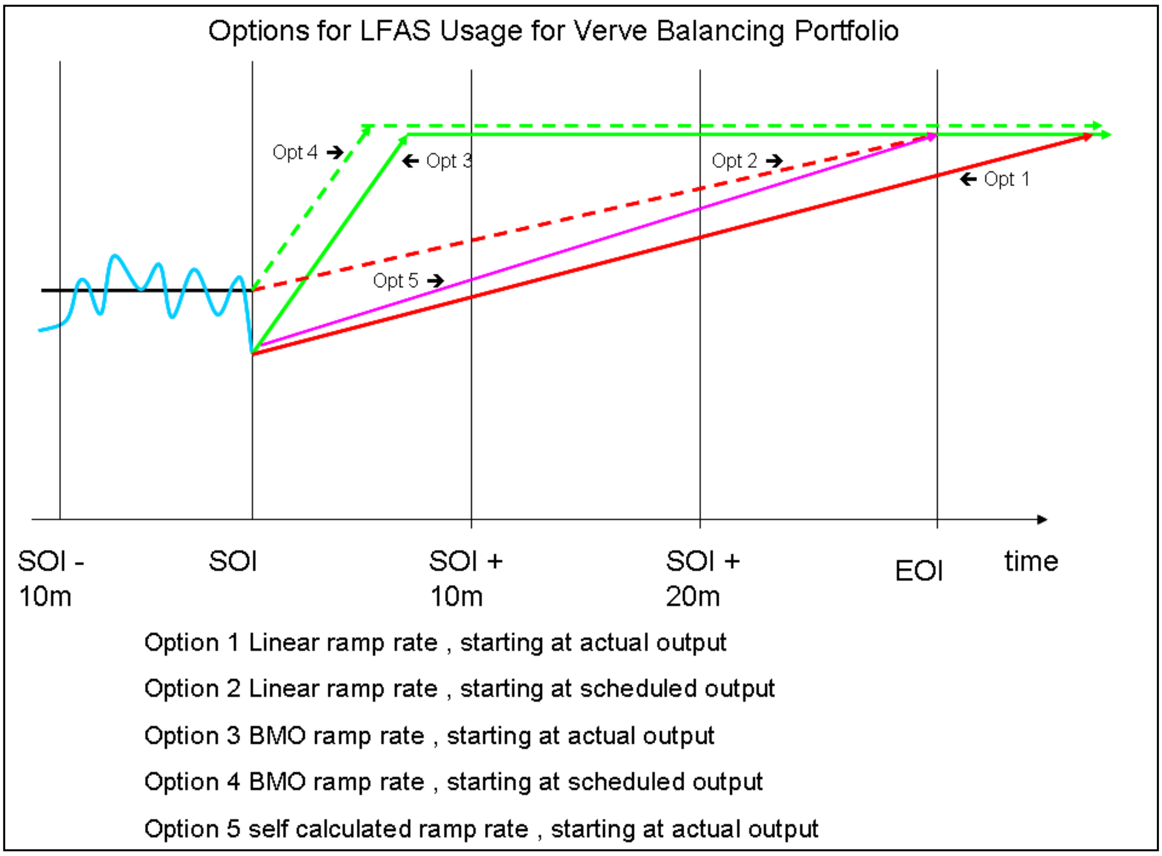
The AGC connected units are not usually assigned specific base points and are used to provide both Balancing and LFAS (and in some cases Spinning Reserve Service and Load Rejection Reserve Service). The total gas fired capacity under the control of the AGC system will frequently exceed the LFAS Requirement for the relevant Trading Interval.

In order to distinguish between LFAS and Balancing movements, it is necessary to define notional Dispatch Instructions for the VEBP and to determine from these instructions the expected output of the VEBP for each minute (i.e. its “Dispatch Instruction output”). The LFAS provision of the VEBP can then be measured by the variation between its actual output and its Dispatch Instruction output.

The RTDE generates and stores notional Dispatch Instructions for the VEBP at the same time as it generates real Dispatch Instructions for IPP Balancing Facilities. These notional instructions were used to construct the one minute Dispatch Instruction output values for the analysis.

Five methods for calculating Dispatch Instruction output for the VEBP were considered. The options are shown graphically in Figure 5 below.

Figure 5 Options for measuring LFAS usage for the VEBP



The options were calculated as follows:

- Option 1: determine the ramp rate for each notional Dispatch Instruction as the difference between the target MW level and the Dispatch Instruction output for the previous minute, divided by the number of minutes remaining in the Trading Interval. (Note that this is the same method as was used to calculate the "preferred" ramp rates for IPP SGs in the analysis of LFAS Cause 4). Assume that each time a new notional Dispatch Instruction takes effect the VEBP ramps from its actual position at the calculated ramp rate until it reaches its target MW level, and then remains at that target level until the start time of its next notional Dispatch Instruction.
- Option 2: determine the "preferred" (linear) ramp rate for each notional Dispatch Instruction in the same manner as for Option 1. Assume that each time a new notional Dispatch Instruction takes effect the VEBP ramps from its current Dispatch Instruction output level (rather than its actual position) at the calculated ramp rate. This should result in the VEBP reaching the target MW level at the end of the Trading Interval, unless a new Dispatch Instruction takes effect before this time.
- Option 3: assume that each time a new notional Dispatch Instruction takes effect the VEBP ramps from its actual position at its BMO ramp rate (usually 10 MW/minute) until it reaches its target MW level, and then remains at this level until the start time of its next notional Dispatch Instruction.
- Option 4: assume that each time a new notional Dispatch Instruction takes effect the VEBP ramps from its current Dispatch Instruction output level at its BMO ramp rate until it reaches its target MW level, and then remains at this level until the start time of its next notional Dispatch Instruction.
- Option 5: determine the ramp rate for each notional Dispatch Instruction dynamically, as the rate needed to reach the target MW level at the end of the Trading Interval (i.e. the difference between the target MW level and actual output level, divided by the number of minutes remaining in the Trading Interval). Assume that each time a new notional Dispatch Instruction takes effect the VEBP ramps from its actual position at the dynamically determined ramp rate. As for Option 2, this should result in the VEBP reaching the target MW level at the end of the Trading Interval, unless a new Dispatch Instruction takes effect before this time.

4.3. Results and discussion

A summary of the one minute calculation results for each of the five options is provided in Table 7 below.

Table 7 Summary of LFAS usage analysis results

	Option 1 Preferred RR actual start	Option 2 Preferred RR DI start	Option 3 BMO RR actual start	Option 4 BMO RR DI start	Option 5 Dynamic RR actual start
Average	1	3	2	3	2
Percentile					
0.05%	-88	-123	-118	-141	-93
0.50%	-62	-96	-86	-100	-64
1%	-52	-83	-75	-90	-54
2%	-42	-70	-65	-77	-44
3%	-37	-62	-58	-69	-39
4%	-34	-56	-53	-63	-35
5%	-31	-52	-50	-59	-32
10%	-23	-38	-37	-44	-23
50%	-2	3	2	4	-1
90%	21	43	41	50	23
95%	31	57	54	65	34
96%	34	62	58	70	37
97%	39	68	64	76	42
98%	45	77	71	84	48
99%	54	94	83	97	59
99.50%	63	108	94	111	71
99.95%	91	149	136	164	105

As can be seen from Table 7, the different options can produce quite different measures of LFAS usage. In general, options that use BMO ramp rates will tend to produce larger results, as will options that assume the VEBP starts each new Dispatch Instruction from its Dispatch Instruction output level (rather than its actual output level).

Given the manner in which the VEBP is currently dispatched, the use of its BMO ramp rate does not reflect the physical dispatch of the generators and introduces an additional source of variation which artificially increases the LFAS usage measurement. For this reason the team does not consider Options 3 and 4 should be used to measure LFAS usage.

The use of actual start positions is consistent with how other Balancing Facilities actually respond to Dispatch Instructions and tends to produce lower results, as it reduces the effect of forecast variations by resetting the VEBP's assumed position at the start of each Dispatch Instruction. However, the options which commence Dispatch Instruction responses from the current Dispatch Instruction output level provide a better representation of the movement levels expected if VEBP generators were dispatched as individual Facilities and provided LFAS in the same way as NewGen Kwinana. For these reasons Option 2 was considered to be the best measure for use in future investigations.

All of the options exaggerate the extent to which the output of the VEBP is adjusted to provide LFAS. This is because in many cases forecasting errors do not affect the physical movement of the LFAS Facilities in the VEBP, as the generators respond to AGC signals rather than Dispatch Instructions and so ignore erroneous forecasts (except where they need to compensate for IPP Facilities that are dispatched out of merit). In particular, the LFAS Facilities in the VEBP are not dispatched to new base points in response to changes to the VEBP's target MW.

The differences in how the VEBP and NewGen Kwinana are dispatched make an accurate assessment of actual LFAS usage more difficult.

It should be noted that the dispatch of the Verve Energy generators on an individual rather than portfolio basis would tend to increase the requirement for LFAS, for two reasons:

- the extent to which the Verve Energy generators were affected by forecast errors would increase; and
- fluctuations in the output of the Verve Energy generators (which include wind farms and generators serving Intermittent Loads) would no longer be absorbed within the VEBP and would instead contribute explicitly to the LFAS Requirement.

5. Minimum Frequency Keeping Capacity calculation

Clause 3.10.1 of the Market Rules defines the standard for LFAS as a level sufficient to provide Minimum Frequency Keeping Capacity (MFKC), which in turn is defined as the greater of 30 MW and "the capacity sufficient to cover 99.9% of the short term fluctuations in load and output of Non-Scheduled Generators and uninstructed output fluctuations from Scheduled Generators, measured as the variance of 1 minute average readings around a thirty minute rolling average".

The calculation has generally been applied to one minute average SG output. Calculations using system load and NSG output have also been used to estimate the relative contribution of each to the overall LFAS requirement.

Table 8 shows the results of the MFKC calculation applied to the one minute system load, non-scheduled generation and scheduled generation data for March 2013, compared with the results of the forecast variation analyses described in sections 3.1 - 3.3 of this report.

The MFKC calculation can provide an indication of the underlying variability of system load, NSG output and SG output. However, it does not provide a measure of forecast error (causes 1 and 2), uninstructed output fluctuations from SGs (cause 3) or variations between the SG forecast and Dispatch Instructions issued at BMO ramp rates (cause 4).

As such the MFKC does not provide a useful measure of the likely requirement for LFAS and so its use in setting the standard for LFAS in the Market Rules may need to be reviewed.

Table 8 Comparison of measured forecast errors with Minimum Frequency Keeping Capacity calculation

Percentile	Load MFKC Calc	Load Forecast Variation	NSG MFKC Calc	NSG Forecast Variation	SG MFKC Calc	SG Forecast Variation
0.05%	-24	-77	-26	-89	-35	-96
0.50%	-18	-52	-16	-43	-22	-67
1%	-16	-45	-12	-33	-19	-55
2%	-13	-37	-10	-24	-16	-45
3%	-12	-33	-8	-21	-14	-40
4%	-11	-29	-7	-18	-13	-36
5%	-10	-27	-6	-16	-12	-33
10%	-7	-19	-4	-11	-9	-23
50%	0	1	0	0	0	2
90%	8	22	4	11	9	25
95%	10	30	6	16	12	34
96%	11	32	7	18	13	36
97%	12	35	8	20	14	40
98%	13	39	10	24	16	45
99%	15	47	12	29	19	54
99.50%	18	55	16	36	22	65
99.95%	25	83	34	74	33	94

6. Summary of main findings

6.1. LFAS causes

During most periods in March 2013 the main contributor to the need for LFAS was load forecast variation. This was followed by BMO ramping and NSG forecast variations, and then SG deviations from Dispatch Instructions. However, the order of impact varies for different confidence levels and also between Downwards LFAS and Upwards LFAS. It should be noted that the analysis was for one month only and the order of impact may be different for other months.

The analysis results suggest that opportunities exist to reduce the actual LFAS requirement associated with each of the four causes. Further it seems likely that a better understanding of the causes will allow the LFAS Requirement to be sculpted, i.e. reduced during periods when the impact of particular causes (e.g. wind and load variability) is less.

When compared with previous studies (including the study undertaken by ROAM Consulting for the Renewable Energy Generation Working Group's Work Package 3: Frequency Control Services[2]), the relative impact of load forecast variation was higher than expected while the relative

[2] For further details see ROAM Consulting's final report to the IMO at: http://www.imowa.com.au/REGWG

impact of NSG forecast variation was lower than expected.

6.2. Minimum Frequency Keeping Capacity calculation

The current MFKC calculation does not provide a useful measure of the current requirement for LFAS in the SWIS and its role in the definition of the standard for LFAS may need to be reviewed. However, the calculation does provide an indicator of the underlying volatility of load and NSG output in the SWIS and the results for March 2013 suggest that improvements in the forecasting of these quantities are possible.

6.3. Measurement of LFAS usage

Due to the manner in which the VEBP is currently dispatched, the team was unable to define an LFAS usage measure that accurately reflects the physical dispatch of Verve Energy generators to provide LFAS.

Of the five LFAS usage measurement options examined option 2 (based on a linear ramp rate from the scheduled output level of the VEBP) was considered to provide the best representation of the movement levels expected if LFAS was provided by individual LFAS Facilities dispatched in the same way as NewGen Kwinana. For this reason option 2 is considered to be the best measure of those identified for use in future monitoring and investigations.

The option 2 LFAS usage results for March 2013 exceed the current LFAS Requirement of +/- 72 MW. The results do not necessarily imply that the LFAS Requirement is too low, as the option 2 results are exaggerating the movement of the VEBP in response to forecasting errors during periods in which it is the marginal Balancing Facility.

However, spurious forecasting errors can and do result in unnecessary LFAS Facility movements and therefore present a problem that needs to be considered. This will be particularly important if more LFAS is to be provided by IPPs and Stand Alone Facilities. (Forecasting errors will also lead to the Out of Merit dispatch of other SGs, although the extent of this issue was not assessed in the analysis.)

The analysis regarded the VEBP as a single large SG, consistent with the VEBP’s treatment under the Market Rules. This meant that any fluctuations of individual generators within the VEBP (including its Intermittent Generators and the generator supplying an Intermittent Load) were hidden within the VEBP’s total output and so not reflected in the measurements of LFAS causes and usage. The LFAS usage results would be expected to increase if the Verve Energy generators were dispatched as individual Balancing Facilities, since the fluctuations and dispatch deviations of the Facilities would no longer be absorbed by the VEBP.

6.4. Reduction of the LFAS Requirement

A reduction in the actual usage of LFAS will provide little benefit to the market unless it can be translated into a reduced LFAS Requirement. This will require improved monitoring of LFAS usage, the development of methodologies to sculpt the LFAS Requirement and changes to System Management’s systems and procedures to make the setting of the LFAS Requirement a dynamic process.

While some “quick wins” may be possible, LFAS Gate Closure timeframes may need to be reduced before more significant results can be achieved. This is because allowing the LFAS Requirement to be decided closer to the start of the relevant Trading Interval may be necessary to increase the reliability of some key inputs used to determine the requirement (e.g. wind forecasts) and so reduce the need to use worst case assumptions in the sculpting process. Note that rule changes would be required to make any significant changes to LFAS Gate Closure timeframes.

7. Options for improvement

7.1. Variation from system load forecast

In recognition of the importance of accurate load forecasts, System Management has established a continuous improvement process for its load forecasting system (MetrixIDR). The process includes weekly reporting and investigation of all load forecast errors in excess of 70 MW. The investigation findings are then used to plan and prioritise system upgrades.

A summary of the recent and planned improvements to the load forecasting function is provided in Appendix 3 of this report.

Regardless of the work undertaken to improve the forecasting system, it is likely that the load forecasting system will still continue to generate occasional large and spurious load forecast errors, at least in the short to medium term. Spurious load forecasts can have a significant impact on LFAS usage, unless they are detected and overridden before being used by the RTDE to generate Dispatch Instructions.

The forecasting system generates new system load forecasts every five minutes. The RTDE generates Dispatch Instructions according to the schedule outlined in section 3.1.1, using the most recent forecast available at the time. A Controller who detects a spurious load forecast is able to switch to a different forecasting method for a period which usually resolves the problem, although if the forecast has been used to generate Dispatch Instructions it is too late to retract those instructions.

For example, during March 2013 the forecasts were overridden 10 times, for a total period of approximately 11 hours (about 1.5% of the month).

The RTDE provides some capability to detect and warn Controllers about spurious load forecasts, but the level of functionality could be improved. It may also be possible to enhance the forecasting system, to alert Controllers about or else prevent the publication of a load forecast that fails to meet certain validation criteria.

Another option is to move to a 10 minute dispatch cycle, where Dispatch Instructions are issued to cover a 10 minute period rather than a period of up to 30 minutes. Eventually this period could be further reduced to five minutes. While this would not be a trivial change, it would help reduce the impact of spurious forecasts (provided they were detected and corrected fairly quickly), by limiting how far a fast ramping SG could move as the result of a single bad forecast. Even where overall forecast quality is good, a forecast generated 15-20 minutes in advance is expected to be more accurate than a forecast issued 25 or 40 minutes in advance.

7.2. Variation from non-scheduled generation forecast

Short term wind forecasting has been the subject of extensive research over recent years, due to the increase in wind generation world-wide. This has resulted in the development of wind forecasting tools that deliver a much greater level of accuracy than the “persistence” forecasting method used by the RTDE. The use of a more sophisticated wind forecasting tool would be likely to improve the accuracy of NSG forecasts, although the practical benefit in terms of reducing the overall LFAS Requirement would need to be carefully assessed against the costs.

It is likely that the current forecasting timeframes of up to 40 minutes ahead would need to be reduced before the benefits of a new NSG forecasting tool could be fully realised. Further, the change to a 10 minute dispatch cycle suggested in section 7.1 could help to minimise the impact of spurious NSG forecasts (as well as spurious load forecasts) regardless of the NSG forecasting tool used.

Currently the RTDE does not allow the persistence forecasts calculated for NSGs to be overridden. This means that even where the persistence forecast is clearly incorrect (e.g. where an NSG is instructed to reduce output or shut down) it cannot be replaced with a more appropriate value. The RTDE could be enhanced to support this functionality, although the net benefit may not be sufficient to make this option a high priority.

An examination of the outlier results for the Cause 2 analysis found that some of the largest fluctuations in NSG output may be avoidable. System Management recently worked with one Market Participant to agree a process to stabilise the NSG's output during high wind conditions, reducing the occurrence of excessive ramp up/down behaviour. There may be benefit in implementing similar arrangements for other NSGs. There would also be benefit in reviewing the current processes around the curtailment of NSGs to prevent, as far as possible, the use of excessive ramp down rates.

In the longer term, it is expected that changes to LFAS cost allocation will encourage Market Participants to choose technologies and practices that limit the volatility of their NSGs.

7.3. Deviation of Scheduled Generators from Dispatch Instructions

The impact of Dispatch Instruction deviations on the need for LFAS is expected to be reducing as the result of:

- an increase in the number of SGs receiving their Dispatch Instructions via Automatic Balancing Control (ABC) or System Management's secure business-to-business gateway; and
- the activities of the IMO's Compliance Team in monitoring failures of SGs to comply with their Dispatch Instructions.

The outlier results for Cause 3 suggest there would be benefit in reviewing current processes around the issuing of Dispatch Instructions when an SG experiences a Forced Outage or deviates from its Commissioning Test Plan.

In the longer term, changes to LFAS cost allocation may encourage Market Participants to minimise their applicable Tolerance Ranges and adhere to their Dispatch Instructions as closely as possible.

7.4. Variations due to dispatch at BMO ramp rates

Currently the RTDE dispatches all SGs, including the marginal unit, at their BMO ramp rates. The RTDE could be upgraded to dispatch the marginal unit (or units) at "optimal" times and ramp rates, to compensate for the ramp rates of the non-marginal units and minimise the difference between Dispatch Instructions and the SG forecast. (It should be noted that the optimal ramp rates would be different from, and often much more complex than the "preferred" ramp rates used in the March 2013 analysis.) The implementation of this option would require extensive changes to the RTDE.

A second option is to move to a 10 minute dispatch cycle, which would limit the extent to which an SG with a high ramp rate could exceed its "preferred" output levels over a Trading Interval. For example, under the current arrangements an SG with a Ramp Rate Limit of 10 MW/minute that was required to increase its output by 30 MW over a Trading Interval would reach its target output level in three minutes. Under a 10 minute cycle the increase would be more gradual (10 MW every 10 minutes), reducing the need for Downwards LFAS to compensate.

The second option would be far less complex and expensive in terms of RTDE changes, but would require significant changes to the calculation of the Balancing Price, Theoretical Energy Schedules and constrained on/off compensation. If this option was progressed then any IT changes could be designed to support a later change to a five minute dispatch cycle.

7.5. Sculpting of the LFAS Requirement

Currently System Management manages the setting of the LFAS Requirement as a “back office” function, with the quantity for each Trading Interval seldom if ever being reduced from the standard value of +/-72 MW. Although further investigation is required, based on the analysis results to date it seems likely that tools could be developed to estimate the LFAS Requirement more dynamically. The tools would use inputs such as time of day, day of week, temperature forecasts, wind forecasts and cloud cover forecasts to identify when the requirement could be reduced safely and to what levels.

To support this, System Management would need to make system and internal process changes to allow Controllers (or some other group available on a 24/7 basis) to take on responsibility for this function.

In the shorter term, it may be possible to achieve some “quick wins” through an analysis of LFAS causes and usage over several sample months, to identify any consistent patterns that could be used to sculpt the LFAS requirement using basic input parameters, e.g. time of day, day of week and basic wind level forecasts.

However, the accuracy of some the critical forecasting inputs (such as the arrival times of wind fronts) may be limited by the current deadlines for finalising the LFAS Requirement. The reduction of the LFAS Gate Closure period and the introduction of rolling gate closure for LFAS (i.e. the removal of the concept of a six hour LFAS Horizon) would allow the LFAS Requirement to be finalised much closer to the start of the relevant Trading Interval. This would improve the reliability of key inputs and may allow System Management to be less conservative when predicting the LFAS Requirement.

8. Recommendations

A summary of recommended actions is provided below. The recommendations have been divided into the following categories:

- issues to be considered for inclusion and prioritisation in the Market Rules Evolution Plan (MREP);
- next steps, for completion by the end of 2013;
- medium term actions, for completion by November 2014, and
- longer term initiatives.

8.1. Candidate issues for the Market Rules Evolution Plan

It is recommended that the following potential changes to the Market Rules be considered. These potential changes will be included in the discussion of the MREP at the October 2013 MAC meeting.

- Reduction of the LFAS Gate Closure period and introduction of the rolling gate closure for LFAS – this change could be combined with MREP Issue 3: Transition to half hour gate closure.
- Transition to a 10 minute dispatch cycle, where Dispatch Instructions are issued to cover a 10 minute period rather than a period of up to 30 minutes.

8.2. Next steps

The team intends to complete the following actions by the end of 2013.

- Complete the analysis of LFAS causes and usage for July 2013, investigating any significant variations in outcomes from the March 2013 results.
- Review Sapere's suggestions for enhancements to the LFAS cause and usage analysis methodology and incorporate these into the methodology as appropriate.
- Develop a plan to provide ongoing monitoring and reporting of the LFAS causes and usage measures developed for the March 2013 analysis, to commence operation from January 2014.
- Prepare the scope of the five yearly review of the Ancillary Service Standards and the basis for setting the Ancillary Service Requirements (Ancillary Services Review). This review, which is required under section 3.15 of the Market Rules, is due for completion by November 2014 and will consider (among other matters) the MFKC calculations and the basis for setting the requirement for LFAS.
- Review the System Management internal processes used to detect and correct extreme system load forecast errors, to reduce their impact on Dispatch Instructions and the usage of LFAS.
- Assess the improvement in accuracy achieved by forecasting system load 15-20 minutes in advance versus 25-40 minutes in advance.
- Review the current processes around the curtailment of NSGs with a view to reduce the use of excessive ramp rates.
- Review the current processes around the issue of Dispatch Instructions when an SG experiences a Forced Outage or deviates from its Commissioning Test Plan.

8.3. Medium term

The following actions are recommended for completion November 2014.

- Develop and implement the system and internal process changes to support dynamic setting of the LFAS Requirement.
- Develop methodologies and tools to estimate (sculpt) the LFAS Requirement for each Trading Interval, using parameters such as season, time of day, day of week, temperature forecast, wind forecast, cloud cover forecast, etc.
- Develop and implement system enhancements to improve the detection of (or prevent the publication of) spurious load forecasts, taking into consideration the outcomes of the review of System Management's internal processes to identify and correct system load forecast

errors.

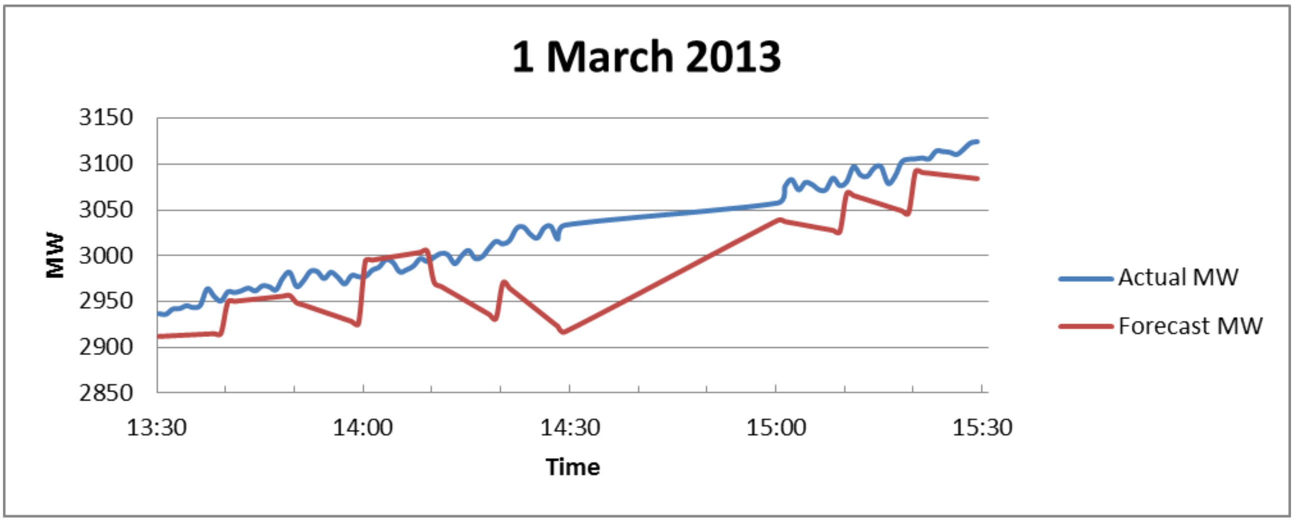
- Consider a broader implementation of arrangements to reduce the occurrence of excessive ramp up/down behavior of NSGs in high wind conditions.
- Complete the Ancillary Services Review.

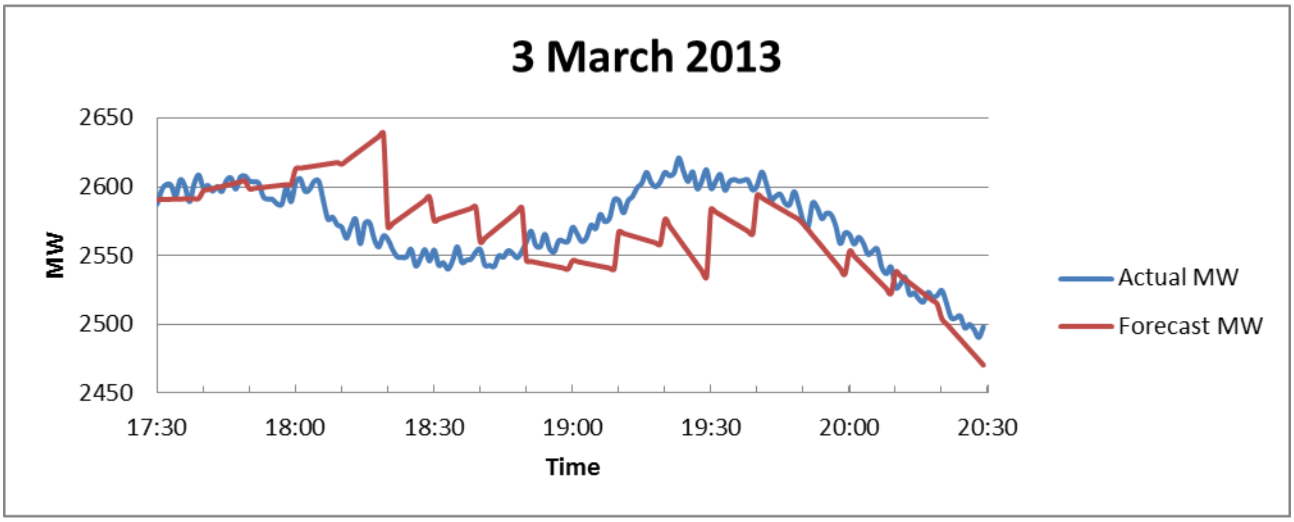
8.4. Longer term

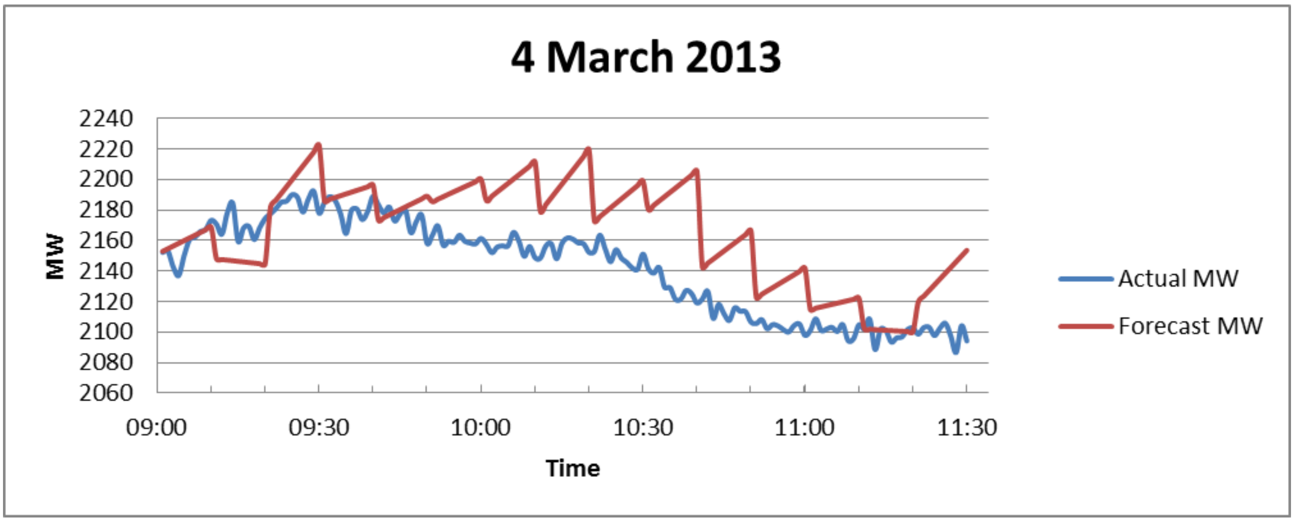
The following actions are recommended but are either dependent on the outcomes of other recommended actions or else would need to be prioritised against other proposals.

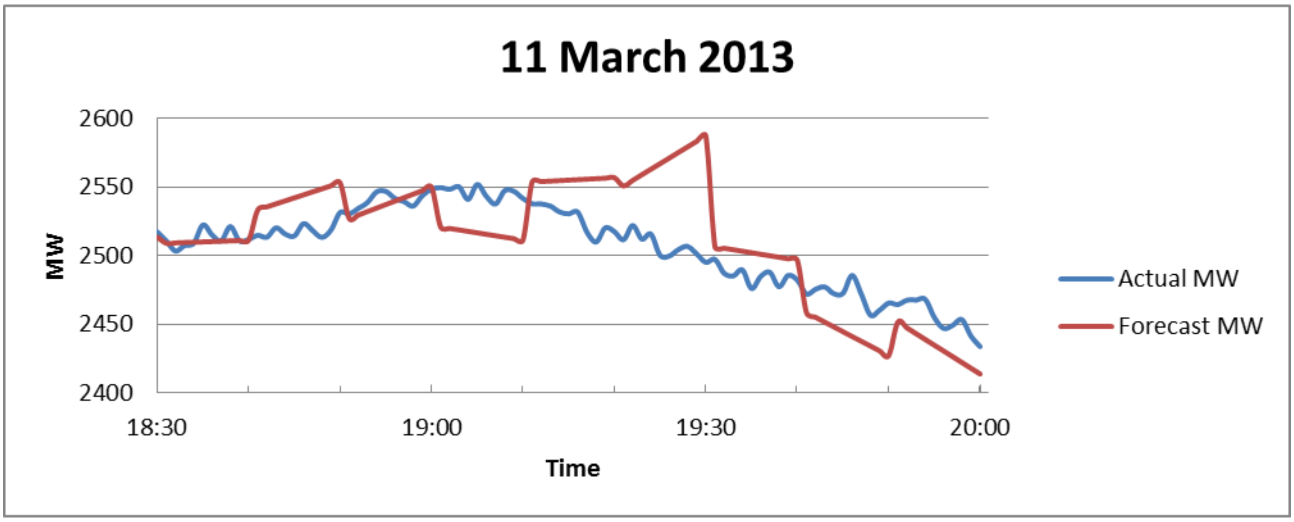
- Implement the recommendations of the Ancillary Services Review.
- Implement a “causer pays” cost allocation methodology for LFAS (following the completion of the Ancillary Services Review).
- Investigate options for more sophisticated wind forecasting tools.
- Upgrade the RTDE to allow the override of default NSG forecasts when better information is available, for example when an NSG is expected to be starting up or shutting down.
- Upgrade the RTDE to support optimal ramping of the marginal unit(s) to minimise the need for LFAS due to the dispatch of SGs at their BMO ramp rates.
- Transition to a five minute dispatch cycle.

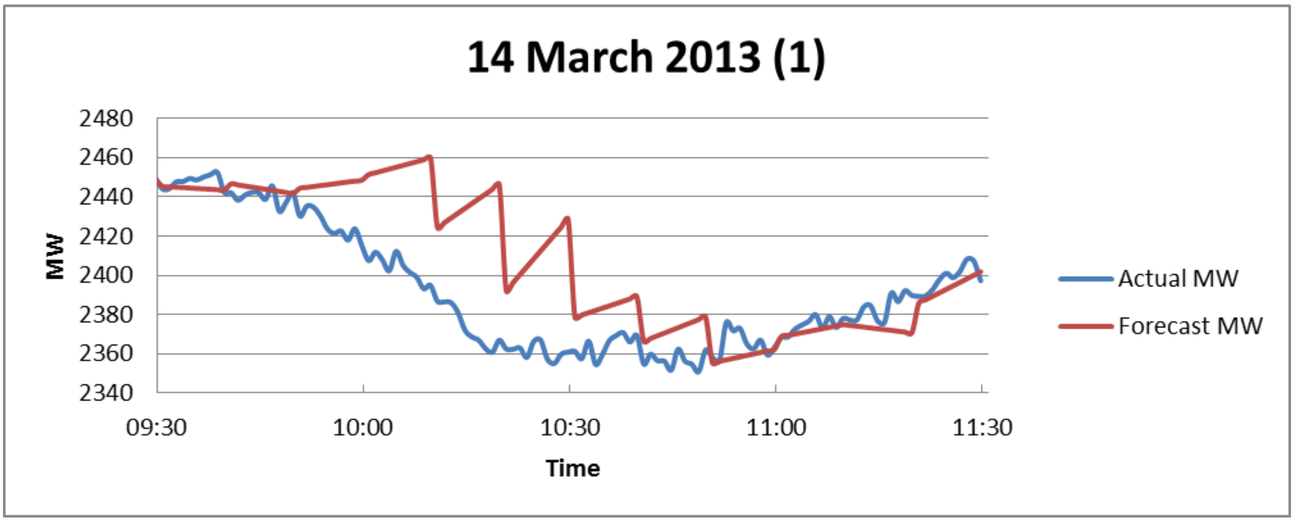
Appendix 1. Examples of variations between forecast and actual system load

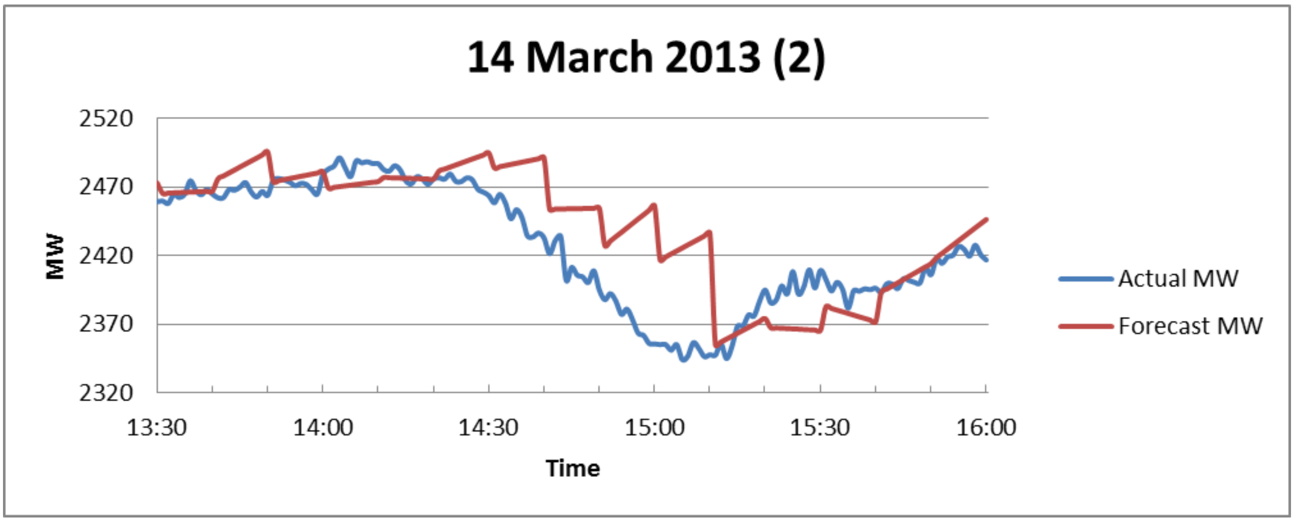


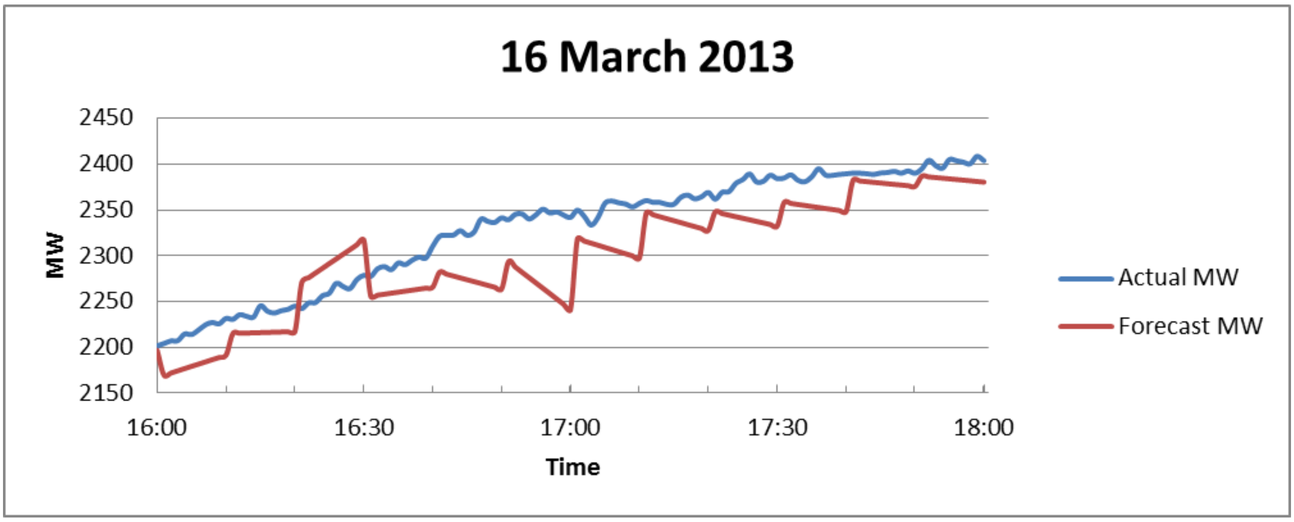


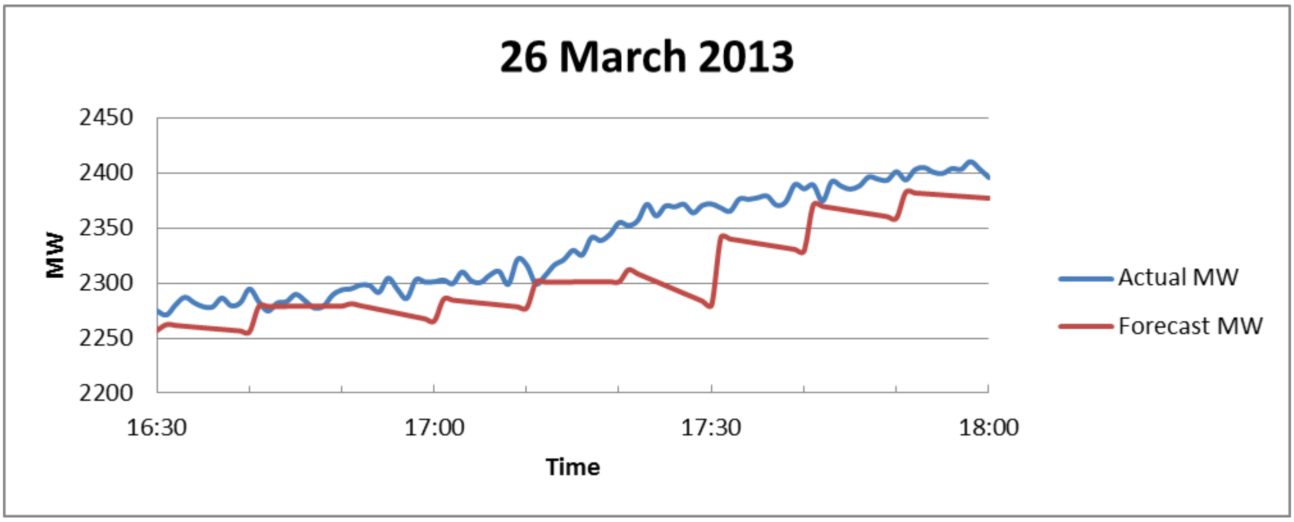


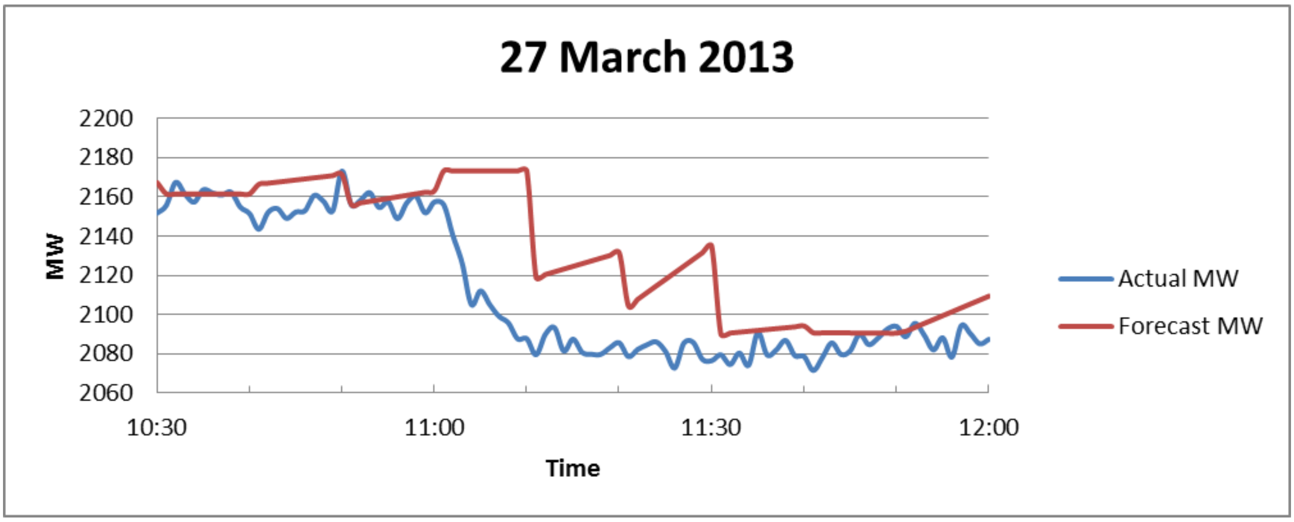

11 March 2013
2600
2550
2500
2450
2400
MW
18:30
19:00
19:30
20:00
Time
Actual MW
Forecast MW

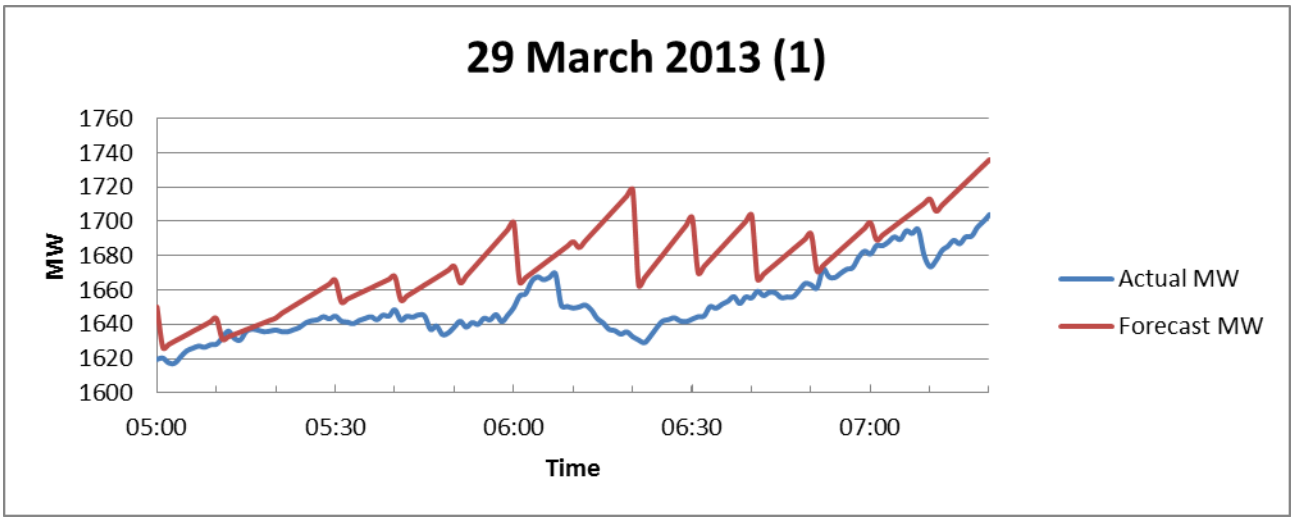

14 March 2013 (1)
2480
2460
2440
2420
2400
2380
2360
2340
MW
09:30
10:00
10:30
11:00
11:30
Time
Actual MW
Forecast MW


14 March 2013 (2)
2520
2470
2420
2370
2320
MW
13:30
14:00
14:30
15:00
15:30
16:00
Time
Actual MW
Forecast MW

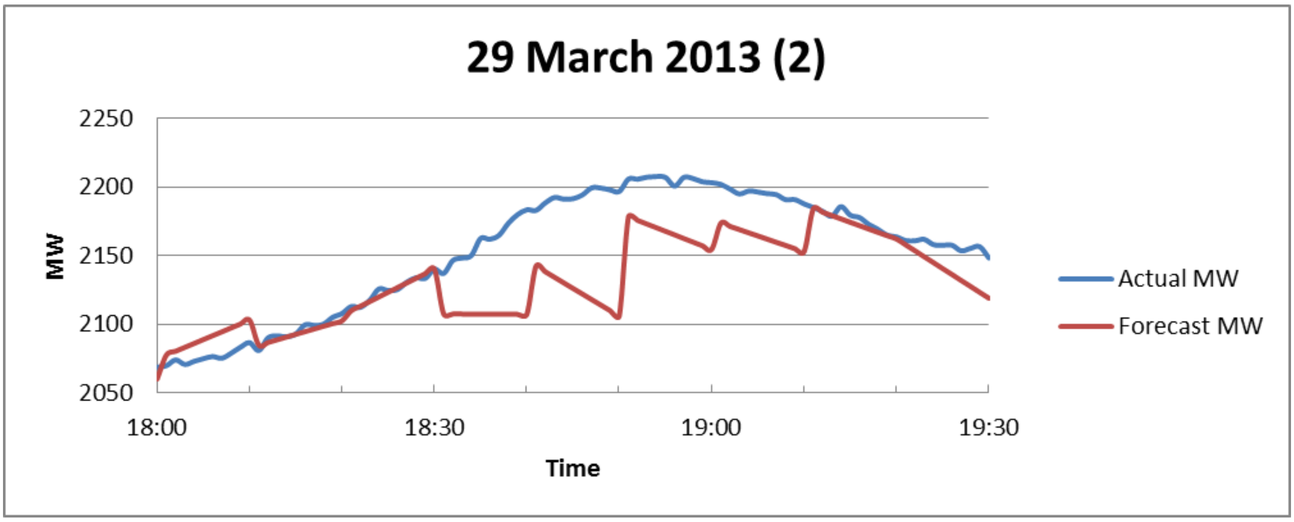

16 March 2013
2450
2400
2350
2300
2250
2200
2150
MW
16:00
16:30
17:00
17:30
18:00
Time
Actual MW
Forecast MW


26 March 2013
2450
2400
2350
2300
2250
2200
MW
16:30
17:00
17:30
18:00
Time
Actual MW
Forecast MW

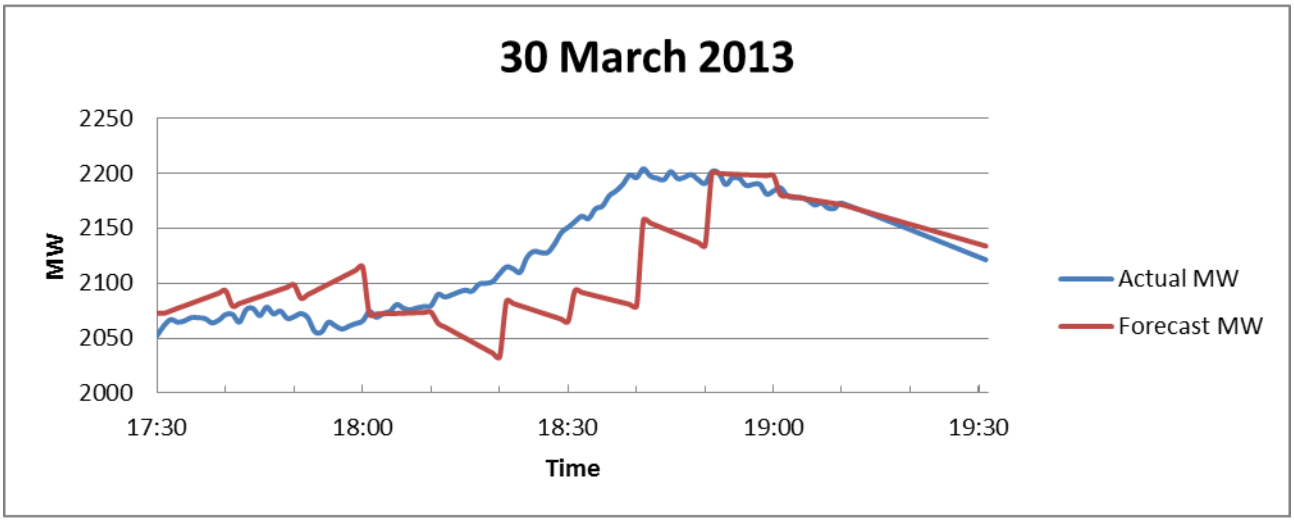

27 March 2013
2200
2180
2160
2140
2120
2100
2080
2060
MW
10:30
11:00
11:30
12:00
Time
Actual MW
Forecast MW



29 March 2013 (1)
1760
1740
1720
1700
1680
1660
1640
1620
1600
MW
05:00
05:30
06:00
06:30
07:00
Time
Actual MW
Forecast MW

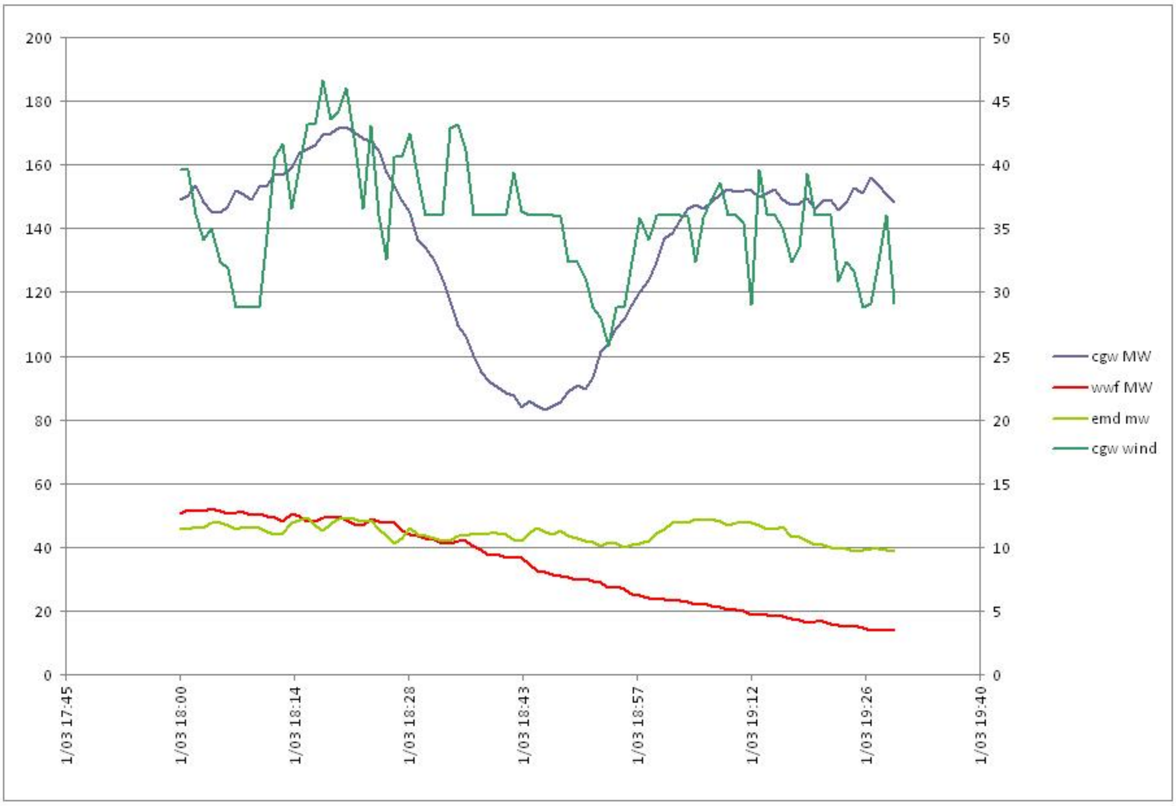


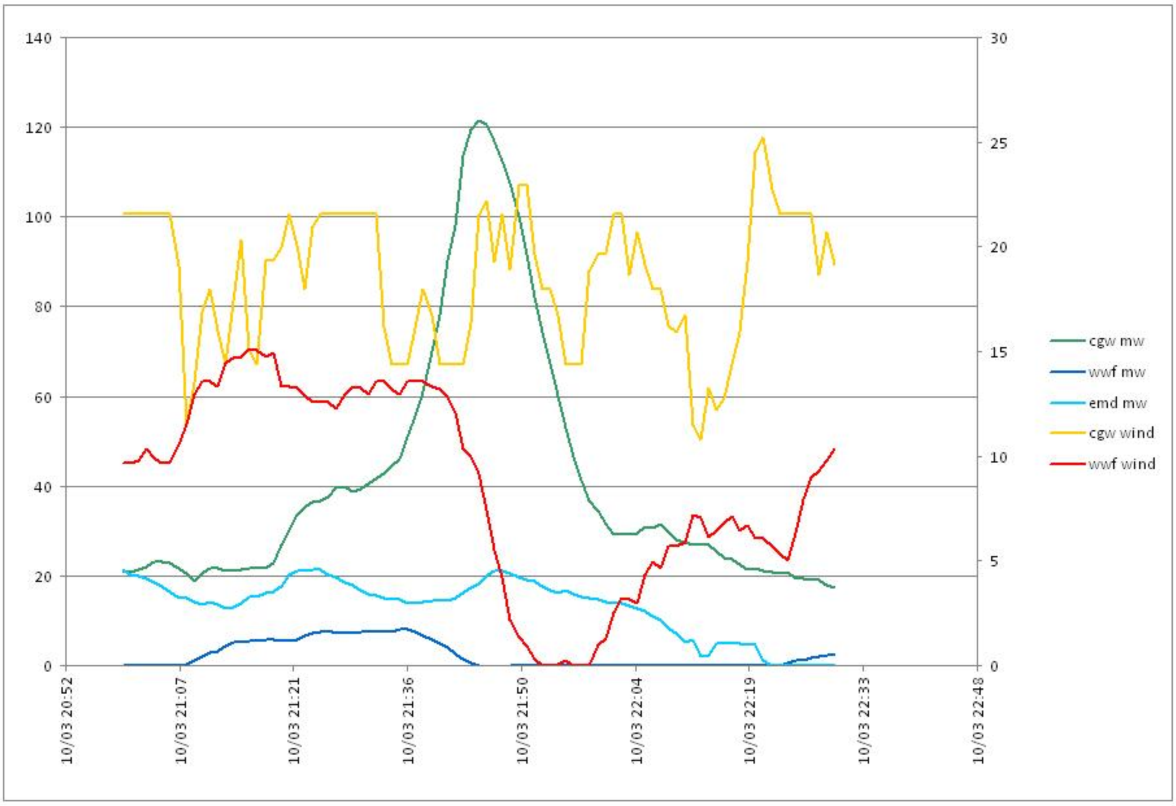
29 March 2013 (2)
2250
2200
2150
2100
2050
MW
18:00
18:30
19:00
19:30
Time
Actual MW
Forecast MW

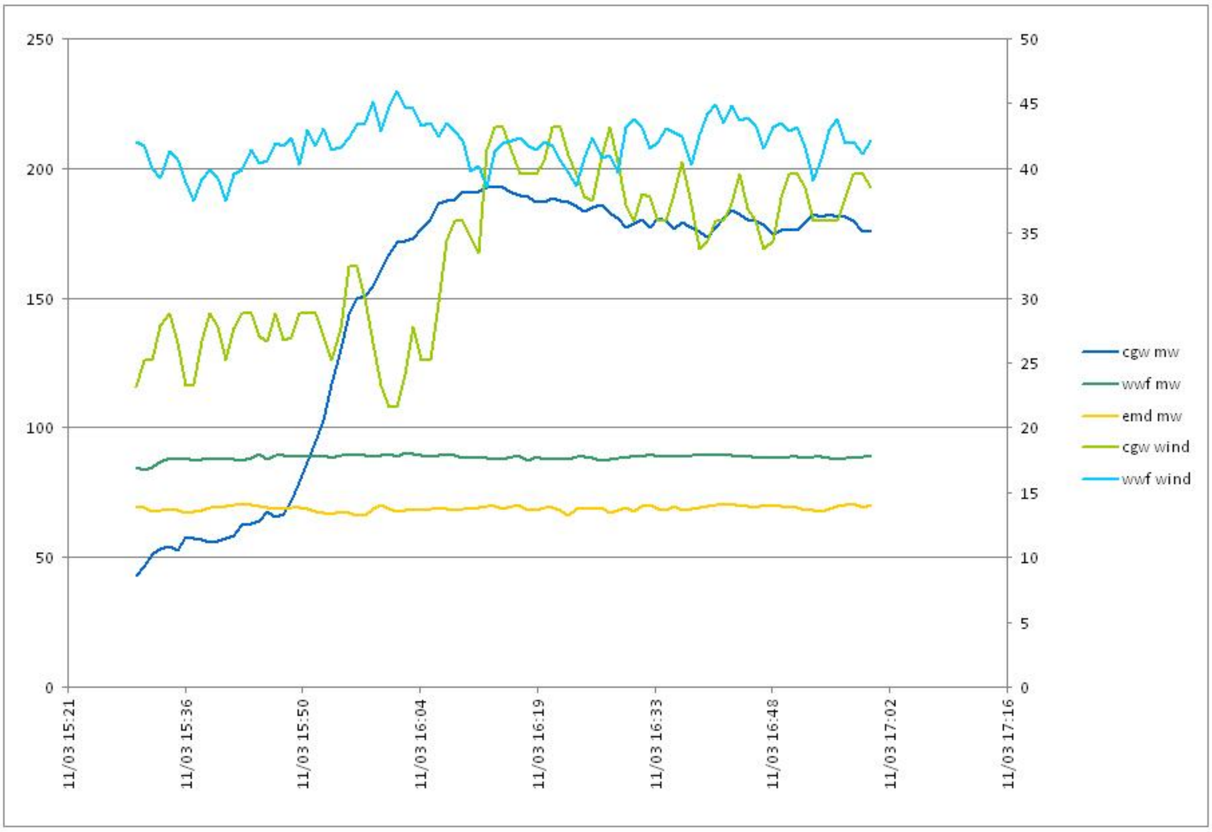


30 March 2013
2250
2200
2150
2100
2050
2000
MW
17:30
18:00
18:30
19:00
19:30
Time
Actual MW
Forecast MW

Appendix 2. Examples of variations between forecast and actual Non-Scheduled Generator output



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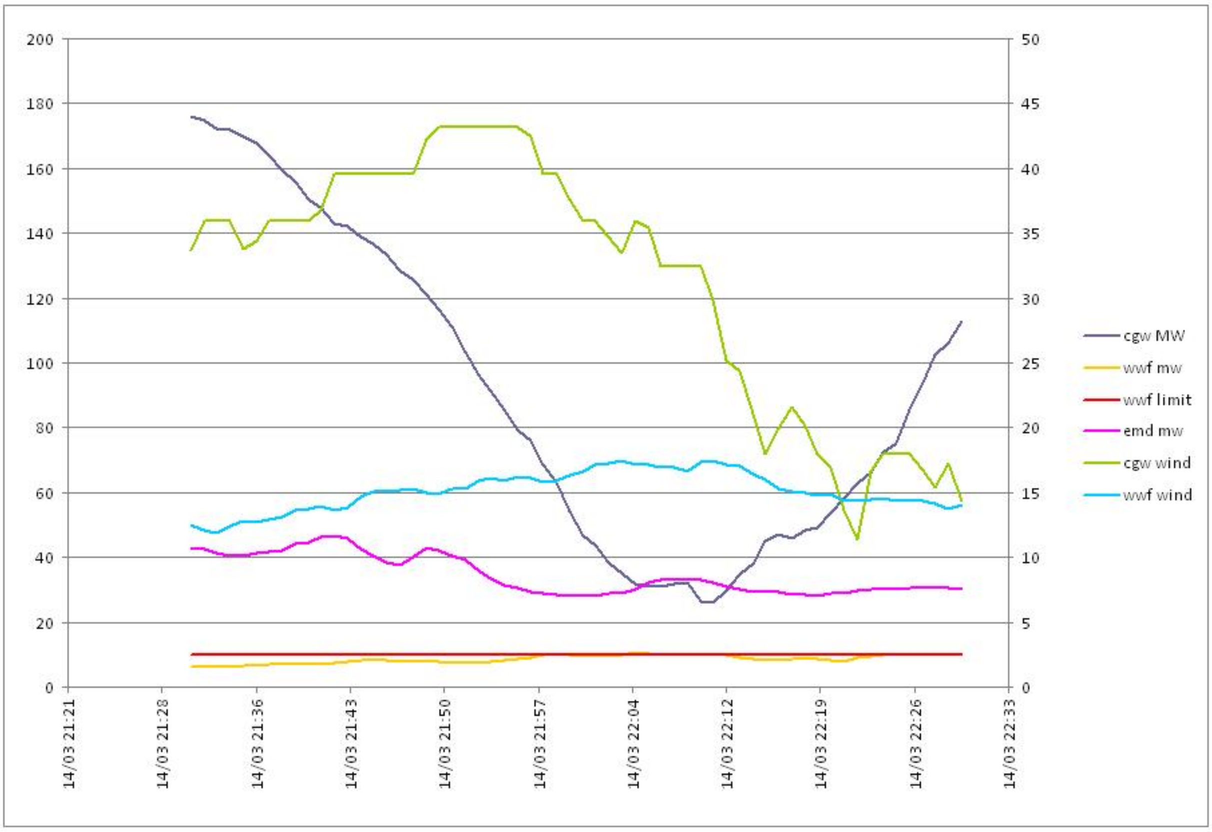
cgw mw
wwf mw
emd mw
cgw wind
wwf wind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120
100
80
60
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5
0
14/03 21:21
14/03 21:28
14/03 21:36
14/03 21:43
14/03 21:50
14/03 21:57
14/03 22:04
14/03 22:12
14/03 22:19
14/03 22:26
14/03 22:33
cgw MW
wwf mw
wwf limit
emd mw
cgw wind
wwf wind

90
80
70
60
50
40
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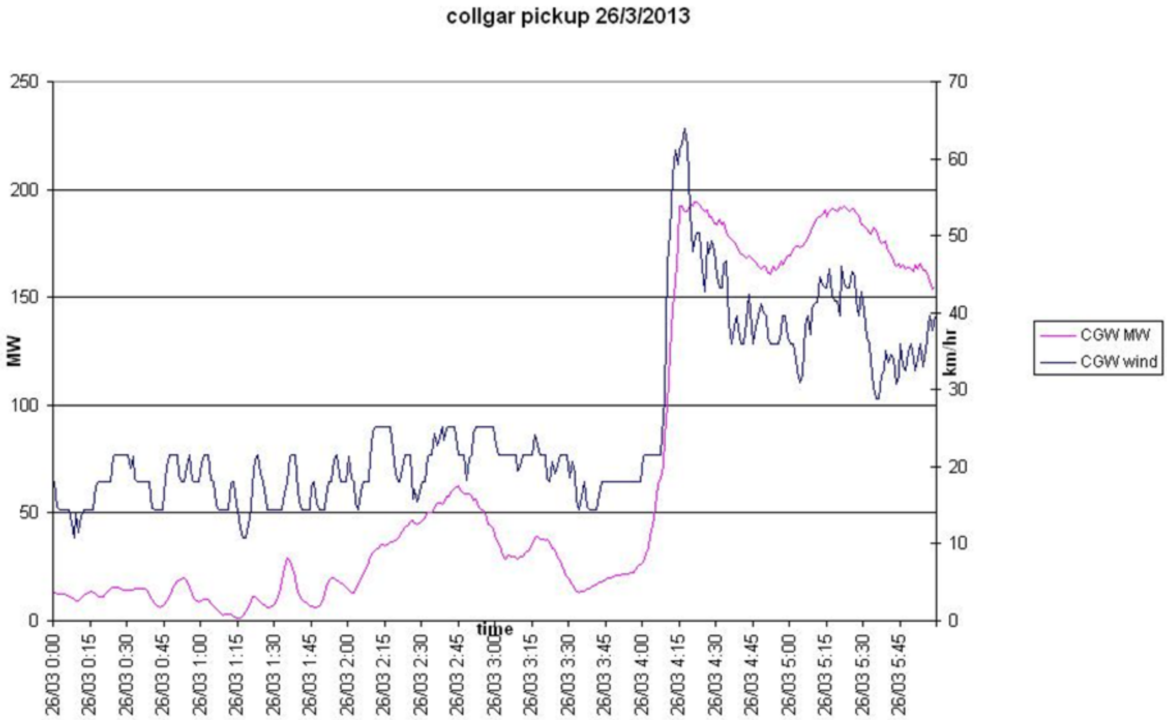
20
10
0
26/03 1:26
26/03 1:33
26/03 1:40
26/03 1:48
26/03 1:55
26/03 2:02
26/03 2:09
26/03 2:16
26/03 2:24
26/03 2:31
26/03 2:38
cgw mw
wwf mw
emd mw
cgw wind
wwf wind



collgar pickup 26/3/2013
MW
km/hr
time
CGW MW
CGW wind

Appendix 3. Forecasting function improvements

This appendix gives an overview of recent improvements to System Management's load forecasting system and what is on the horizon for this function.

In July 2012, System Management upgraded the forecasting software (MetrixIDR) to a unified five-minute modelling framework to be used to satisfy the new Balancing and LFAS Markets.

Below is a recent history of software and modelling improvements:

- introduced software update in October 2012, which improved system update and maintenance;
- resolved Bureau of Meteorology weather time slippage issue in September 2012;
- changed unified forecasts blending models and weights to eliminate forecasting irregularities; and
- introduced system enhancement resolving sudden drop and/or replacement of metered value data.

In March 2013, System Management built software to monitor forecast performance, identify significant forecasting errors and input trend errors, and validate and measure the impact of model changes.

In October 2013, System Management plans to upgrade MetrixIDR. The upgrade will:

- allow Senior Controllers to view/publish similar day profiles;
- fix an intermittent forecasting “bug” which results in sudden forecast "drops";
- allow model estimation steps to be fully automated;
- carry out performance and other studies; and
- provide enhanced emailing and alerting functionality.

The following enhancements are part of System Management's roadmap for MetrixIDR:

- create new 5-minute model to examine impact of PV and growth rate variables in forecasting;
- introduce calibration (or tuning) of day-ahead models;
- add KARARA mining to the base load model; and
- build regional load forecasting models for North Country, South West and Eastern Goldfield regions for use in transmission constraint modelling.

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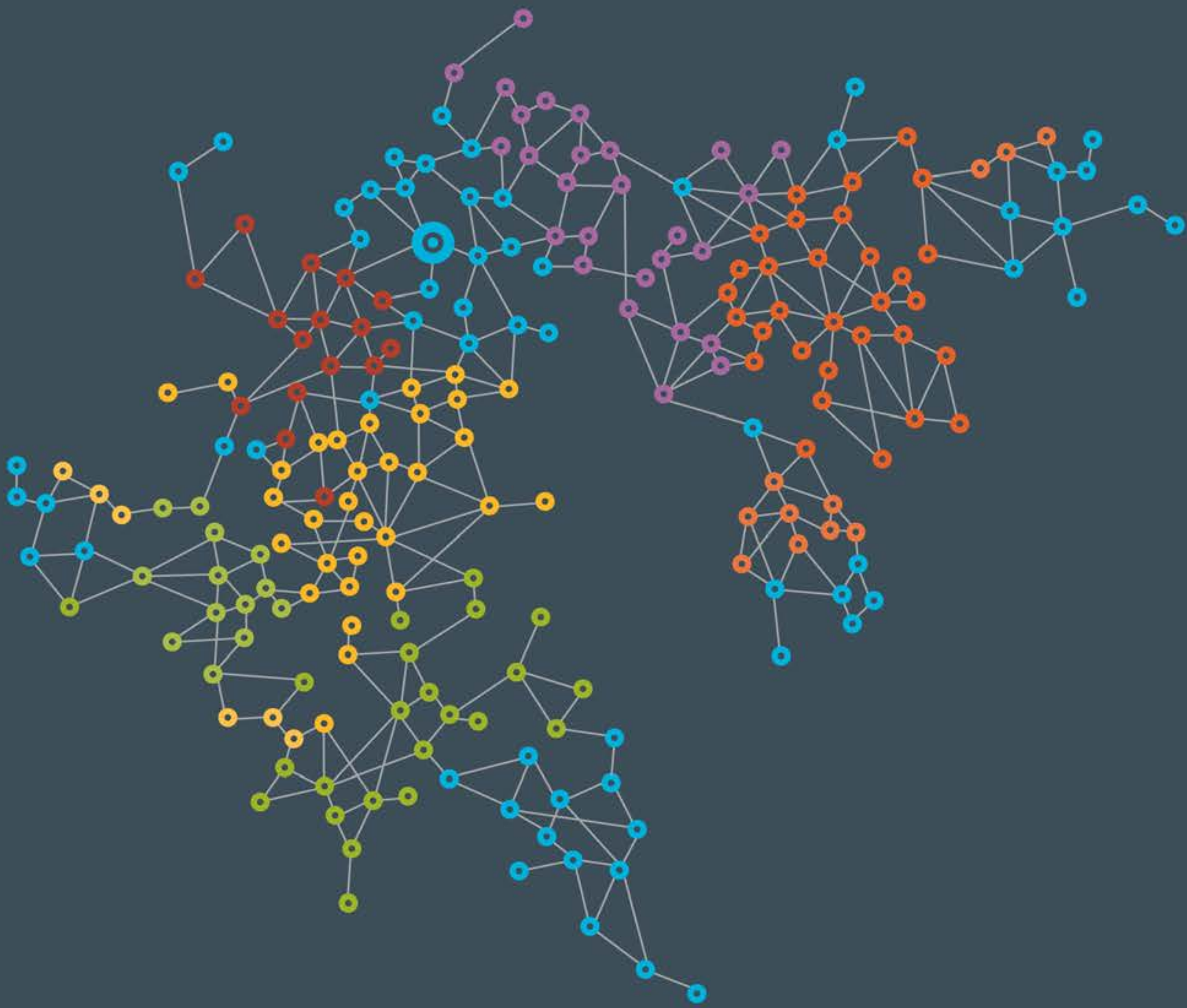
Market Rules Evolution Plan: 2013-2016
October 2013 Update

9 October 2013



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1. Introduction

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

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

To develop the current MREP, candidate issues were identified through review of the previous MREP (for 2009-2013) and direct consultation with industry stakeholders. Issues for which work was already underway or planned for the 2012/13 Financial Year were excluded from consideration. The list of candidate issues was then prioritised by the Market Advisory Committee (MAC) using a ballot process. The final plan was published on the Market Web Site in November 2012.

2. Current Status

The table in Appendix 1 of this paper provides a summary of the issues listed in the MREP and their current status. The issues are listed in the priority order determined by the MAC in the August 2012 ballot.

The IMO notes that a number of competing issues have emerged since the development of the MREP for 2013-2016.

- Merger of Synergy and Verve Energy: The merger of Synergy and Verve Energy will necessitate changes to the Market Rules in relation to the identity of the entities, the treatment of Interruptible Loads and Demand Side Programmes in relation to the Verve Energy Balancing Portfolio, and the Non-Balancing Dispatch Merit Order. The IMO considers that further consideration of issues relating to market power may be required once additional details regarding the structure of the merged organisation are clear.
- Limits to Early Entry Capacity Payments: Many of the submissions received for Rule Change Proposal: Limits to Early Entry Capacity Payments (RC_2012_10) [2] expressed support for changes to remove early entry capacity payments for all facility types during times of excess capacity (or at all times), although specific details of the criteria for allowing the payments for a given Reserve Capacity Cycle and the timeframe for making such decisions were not provided.
- Reduction of LFAS Gate Closure timeframes (see agenda item 5(a)): Under the current Market Rules the period between LFAS Gate Closure for a Trading Interval and the start of that Trading Interval can be more than 10 hours. The reduction of the LFAS Gate Closure period and the introduction of rolling gate closure for LFAS (i.e. the removal of the concept of a six hour LFAS Horizon) would allow the LFAS Requirement to be finalised much closer to the start of the relevant Trading Interval. This would improve the reliability of key inputs and so allow System Management to more accurately predict the LFAS Requirement, which would be expected to reduce LFAS costs over time. Reduced gate closure times for LFAS may also produce more efficient LFAS prices, since some of the information used by LFAS providers to generate their LFAS Submissions (e.g. forecast Balancing Prices) will

[1] Available at: http://www.imowa.com.au/market_rules_evolution_plan
[2] Details of RC_2012_10 are available at: http://www.imowa.com.au/RC_2012_10.

potentially be more accurate closer to the start of the Trading Interval.

- Transition to a 10 minute dispatch cycle (see agenda item 5(a)): A change to a 10 minute dispatch cycle, where Dispatch Instructions are issued to cover a 10 minute period rather than a period of up to 30 minutes, would assist in reducing the causes of LFAS by:
  - allowing the system load forecasts used to generate Dispatch Instructions to be generated nearer to dispatch, improving forecast quality;
  - reducing the impact of spurious load and NSG forecasts, by limiting how far a fast ramping Scheduled Generator could move Out of Merit as the result of a single bad forecast; and
  - reducing the LFAS needed to compensate for the dispatch of Scheduled Generators at the ramp rates in their Balancing Submissions, rather than at the ramp rates that would best match forecast requirements.

  The transition would require changes to the calculation of the Balancing Price, Theoretical Energy Schedules and constrained on/off compensation. These changes could be designed to support a later transition to a five minute dispatch cycle.

- Energy Price Limits review methodology: A review of the Energy Price Limits review frequency was explicitly excluded from the MREP as the work was planned for completion during the 2012/13 Financial Year. However, following the publication of the MREP the IMO decided to delay the proposed review, as the Economic Regulation Authority (ERA) was scheduled to review the methodology for setting the Energy Price Limits during 2013[3]. The IMO decided to delay making any changes to the Energy Price Limits review methodology until it had considered the outcomes of the ERA's review. The ERA is required to provide its report to the Minister by October 2013.

3. Recommendations

The IMO recommends that the MAC:

- notes the update to the status of the issues listed in the MREP;
- discusses whether the current prioritisation of issues in the MREP is still appropriate, including consideration of the emerging issues listed in section 2; and
- considers the requirements for issue 1 (Additional improvements to the Balancing Mechanism) in greater detail.

[3] In accordance with clause 2.26.3 of the Market Rules.

Appendix 1. Market Rules Evolution Plan: 2013-2016 Issue list

A summary of the issues in the current MREP is provided in the following table.

Rank	Issue	Explanation (from MREP)	Source	Status
1	Additional Improvements to the Balancing Mechanism	• Remove requirement to submit Resource Plans; • Investigate removal of STEM submissions requirement, or allow multiple STEM windows catering for multiple STEM transactions within the Trading Day, aligned to the balancing windows; • Investigate closer to real time bilateral nominations/updates/adjustments; • Link between Balancing Submissions and Facility limit so that a Balancing Submission may contain more capacity than the Facility limit but not less; and • Timing of submissions: consider starting at 9:00am or 10:00am instead of 8:00am.	Multiple Stakeholders	Preliminary investigations are underway, may be impacted by the proposed merger of Synergy and Verve Energy. It may be useful to consider changes to Bilateral Submissions and the Short Term Energy Market (STEM) separately from changes to Resource Plans. For discussion at the October 2013 MAC meeting.
2	Emissions Intensity Index (EII)	Amendments to the Market Rules have been proposed to formalise the provision of emissions data by Market Participants to the IMO and the publication by the IMO of an Emissions Intensity Index for the WEM.	IMO	Preliminary investigations are underway. Priority may be affected by the recent Federal election results.
3	Transition to half hour gate closure	It has been suggested that a half hour gate closure would lead to more efficient market outcomes.	ERM Power	Outstanding.
4	Introducing Market in Spinning Reserve	Suggestions have been expressed at MAC that the introduction of a Spinning Reserve Market will increase competition in the WEM.	Multiple Stakeholders	Outstanding, waiting on the outcomes of the five yearly Ancillary Services review.
5	Settlement simplification	A number of participants have commented that the complexity in the Market Rules around market settlements may benefit from simplification.	MREP 2009-2013	Outstanding

Rank	Issue	Explanation (from MREP)	Source	Status
6	Market Rule Change Process	Under the current Market Rules, a Standard Rule Change Process takes a considerable time to complete. A number of Market Participants have commented on this process in various forums over the years. While it is appropriate that the rule change process proceeds in an efficient and timely manner, it should also provide sufficient time for consultation and analysis. Further, some rule changes would be more complex while others would be simpler and a single timeline may not always deliver efficient outcomes. The IMO considers that the efficiency of the market rule change processes should be examined with the objective to streamline the existing prescribed timelines. Any changes to the processes and timelines should provide sufficient flexibility to allow the IMO Board to consider proposed rule changes in session.	MREP 2009-2013	Outstanding
7	New Loads	The non-arrival of new loads (allowed for in the Statement of Opportunities) places a capacity cost onto existing loads as the capacity credited for the new load which did not arrive is paid for by the existing loads. Capacity could be linked to proposed large loads, requiring a security deposit from large loads, or requiring large loads to act as a Demand Side Programme (DSP), with no rights to reliable supply; where, if the opposite occurs and a large load arrives unexpectedly and this results in an supplementary reserve capacity auction, then that load should bear the supplementary reserve capacity cost as targeted capacity.	Synergy	Outstanding
8	Review of Spinning Reserve calculation and cost application	The design of the Balancing market, with intra-interval dispatch instructions, in combination with the current Spinning Reserve cost regime (a fixed charge per block) appears at odds with creating an efficient market. Suggestion to review the Spinning Reserve regime with a view to making it more granular to combat regular per-interval fixed costs.	Griffin	Discussions with Bluewaters Power regarding a Pre Rule Change Proposal in progress. Expected to be discussed at the November 2013 MAC meeting.
9	Feedback on Synergy's actual demand	Earlier feedback on Synergy's actual demand rather than wait for the non-STEM publication. This may morph into changing the settlement timeframe such that settlement occurs more frequently. Such a change has the benefit of reducing the level of participants' prudential requirements.	Synergy	Outstanding

Rank	Issue	Explanation (from MREP)	Source	Status
10	LoadWatch Data Publication	The IMO considers an obligation should be included in the Market Rules for System Management to deliver LoadWatch data to the IMO each Monday prior to noon. The required data would include forecast min and max temperature, and forecast system load, for weekdays. The obligation on the IMO would be to publish the LoadWatch report each Monday.	IMO & ERA	Completed. The Amending Rules for the Rule Change Proposal: LoadWatch, EOI and RDQ Provision (RC_2013_05) commenced on 2 September 2013.
11	Remove some of the uncertainty around Non Temperature Dependent Loads (NTDLs)	Given NTDLs have a much lower capacity ratio than Temperature Dependant Loads (TDLs), if a new NTDL is created in the Capacity Year this changes the TDL ratio for all customers. This ratio variation could be minimised by confirming NTDL status for a Capacity Year in Year 1 of the Reserve Capacity Cycle. A simplification would be to disallow changes from TDL to NTDL within a Capacity Year, allowing these changes only in a future Capacity Year.	Synergy	Outstanding
12	Market Fees	Concerns have been expressed by MAC members around the exemption of Demand Side Aggregators from Market Fees. The IMO notes that there may be benefit in a wider review around Market Fees including allocation of fees to non-energy producing capacity facilities (e.g. peaking capacity).	Multiple Stakeholders	Discussions with Bluewaters Power regarding a Pre Rule Change Proposal in progress. Expected to be discussed at the November 2013 MAC meeting.
13	Reviews	The IMO undertakes a number of reviews (e.g. Energy Price Limits, Margin Values) which require input assumptions for modelling, e.g. fuel costs, heat rates, operating and maintenance costs, etc. Currently the IMO is unable to request confidential operational data from Market Participants for use in these reviews. The Market Rules could be enhanced so that the powers of the IMO to request actual operational data from Market Participants are extended to allow the request of relevant data (on a confidential basis), to provide more accurate inputs to the modelling processes.	IMO & ERA	Outstanding

Rank	Issue	Explanation (from MREP)	Source	Status
14	Intermittent Loads	A number of issues have been identified with respect to the provisions of the Market Rules related to Intermittent Load refunds. This was identified in the original Market Rules Evolution Plan. This noted that the Market Rules relating to the Intermittent Load maximum nominated Reserve Capacity Requirements be reviewed to ensure that the Market Rules cannot be misconstrued as allowing participants to completely avoid Individual Reserve Capacity Requirement (IRCR) charges for Intermittent Loads by setting the requirements to either 0 or a number lower than the actual requirement of the loads in the event of a generator failure.	MREP 2009-2013	Outstanding
15	Capacity Lead time for Demand Side Programmes	It has been noted that the two year lead time for certification could be a significant impediment for generation with shorter lead times, especially smaller generation and Demand Side Management (DSM). Shorter lead times for capacity certification would facilitate smaller generation and DSM more readily. In respect of DSM, a shorter lead time may mean that DSM could be made available spontaneously.	Premier Power	Outstanding
16	Calculation of Loss Factors	By June each year each Network Operator must calculate and provide to the IMO Loss Factors for each connection point in their Network. It has been noted that this is an often time consuming and expensive process to undertake. It has been suggested that this process could be streamlined to make it more efficient while not losing the integrity of the process.	MREP 2009-2013	Outstanding
17	Participation of DSM in Balancing	The Reserve Capacity Mechanism Working Group (RCMWG) has explored the concept of DSM participation in Balancing and it has been proposed to include this on the next MREP for consideration.	RCMWG	Outstanding
18	Treatment of new small generators	Section 4.28B of the Market Rules outlines the Reserve Capacity rules for the treatment of new small generators. The section is applicable to Registered Facilities to which the following conditions apply: • the Facility is a Non-Scheduled Generator and has commenced operation; and • the Facility has a nameplate capacity not exceeding 1 MW. It has been suggested that the threshold for this section be increased from the 1 MW nameplate capacity.	MREP 2009-2013	Outstanding

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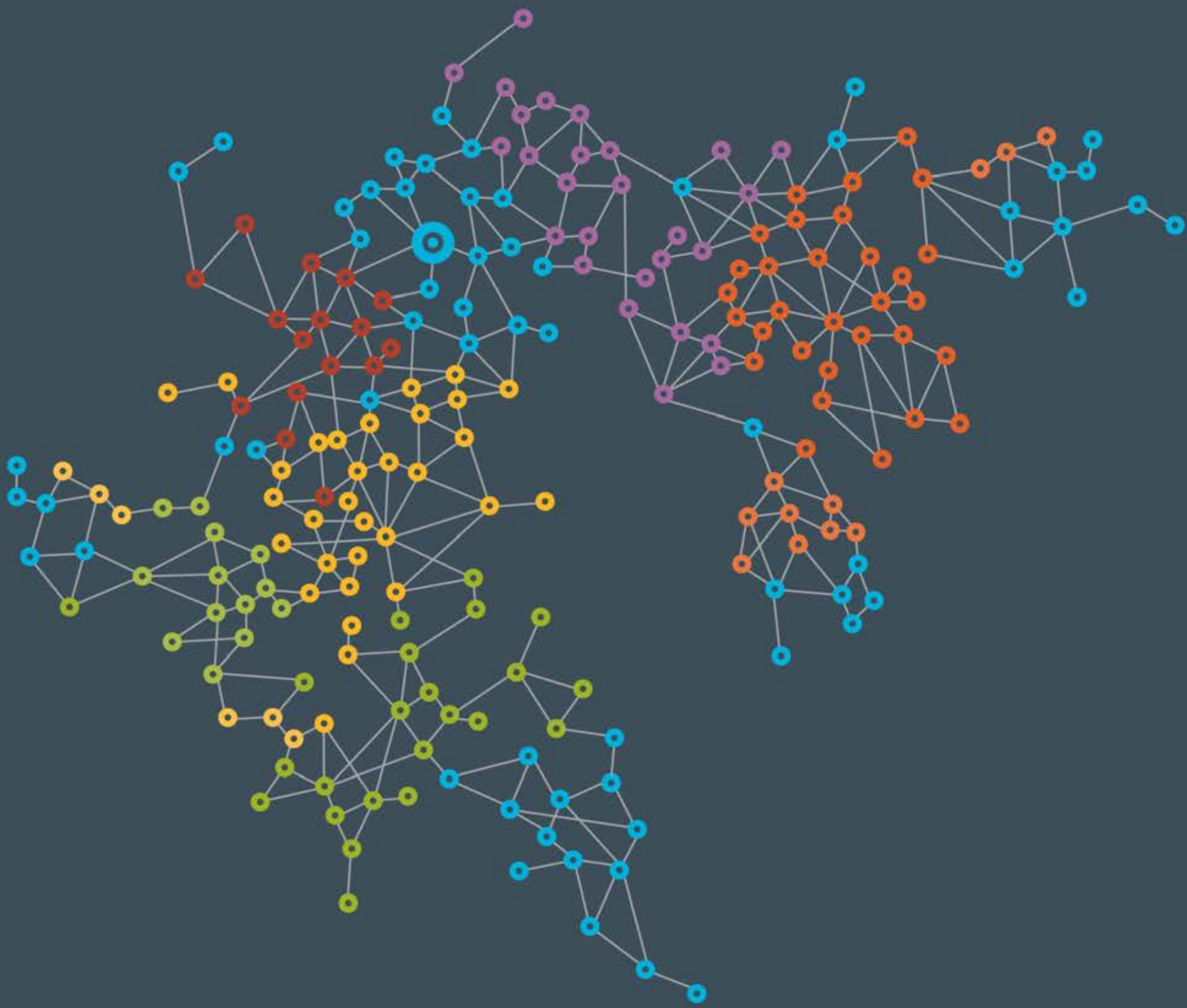
Concept Paper 2013_06: Changes to the Reserve Capacity Price and the Dynamic Refunds Regime

October 2013



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1. Background

The Reserve Capacity Mechanism (RCM) is a mechanism to support the Wholesale Electricity Market (WEM) in the South West interconnected system (SWIS) in ensuring there is sufficient Reserve Capacity to meet reliability targets. Through the RCM, the IMO procures capacity from supply-side resources (generation facilities) or temporary curtailments in demand, known as Demand Side Management (DSM).

In 2011, the IMO Board engaged The Lantau Group to conduct a comprehensive review of the RCM. The Lantau Group prepared a report concluding that the RCM has promoted capacity development and reliability of supply in the Wholesale Electricity Market (WEM) but refinements were needed to improve alignment with the Wholesale Market Objectives[1]. The report highlighted that excess capacity had consistently increased since the inception of the RCM. It identified the poor responsiveness of the RCM to changing market conditions as a contributor to increasing excess capacity. The report noted that if the RCM attracts or supports more capacity than is required, then it would defeat Market Objective (d). On the other hand, more capacity may be argued, in some instances, to assist the achievement of Market Objective (b) by supporting greater competition. Similarly, a failure of the RCM to attract sufficient capacity would also result in a costly failure of the WEM, compromising virtually all of the Market Objectives, except perhaps (e). Clearly, evaluating a specific change to the RCM (or even its current performance) against the Market Objectives involves balancing a number of countervailing forces. The report recommended that a more dynamic but not overly volatile RCM would have the potential to improve considerably on the existing arrangement, while being consistent with the design of the RCM.

The IMO Board recommended that the Market Advisory Committee (MAC) should consider the recommendations detailed in The Lantau Group's report[2].

At the Market Advisory Committee (MAC) meeting held on 5 October 2011, it was agreed that a working group be convened to assess the issues raised in The Lantau Group's report. In February 2012, the Reserve Capacity Mechanism Working Group (RCMWG) was established for this purpose.

The RCMWG members met ten times over 12 months to discuss issues and develop solutions in

[1] The Wholesale Market Objectives 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.

[2] http://www.imowa.com.au/f5415,2873688/09._Agenda_Item_8_Lantau_Report.pdf

the following work-streams[3]:

1. *Work-stream 1:* Reserve Capacity Price (RCP) – The RCMWG members discussed the market responsiveness of the price signal which the IMO applies through the administrative adjustment of the RCP formula in clause 4.29.1 of the Market Rules.

2. *Work-stream 2:* Harmonisation of demand and supply-side sources – The RCMWG members discussed the implications of the differential treatment of demand and supply-side sources noting that in principle, the value attached to a Capacity Credit is the same irrespective of its source. The IMO engaged Sapere Research Group to facilitate discussion and propose recommendations on harmonising the treatment of demand and supply-side resources in the market. Subsequently, the IMO progressed the recommendations in this work-stream in August 2013 with the Rule Change Proposal RC_2013_10: Harmonisation of demand and supply side resources[4].

3. *Work-stream 3:* Dynamic refunds regime – The RCMWG members noted that the refunds regime is currently not aligned with time periods of greatest system need. As a result, it does not signal appropriate incentives to capacity providers for presenting capacity to the market when system need is the greatest.

4. *Work-stream 4:* Individual Reserve Capacity Requirements (IRCR) – The RCMWG members noted that the current methodology for determining IRCR does not adequately represent its economic intent which is to represent the reasonable peak demand expectation of a given Load. Additionally, members supported the implementation of the principle that no Load should be able to offer a DSM capacity value that is greater than its IRCR[5]. Sapere Research Group and the IMO conducted analyses on using peak demand Trading Intervals instead of highest demand Trading Intervals and recommended that it was more appropriate and efficient to use the former. The IMO progressed the recommendations in this work-stream in May 2013 with the Rule Change Proposal RC_2013_11: Selection of the 12 peak Trading Intervals used for calculation of IRCR[6].

The IMO considered that work-streams 1 and 3 should be progressed as a comprehensive package because of their interdependencies. The RCM impacts the value of refund exposure through the RCP because the refund exposure is determined by multiplying the applicable refund factor in the Refund Table with the Monthly RCP. At the same time, the refunds regime may impact on the value expected to be recovered by an investor in Reserve Capacity based on an assessment of plant reliability. Together, the RCP and the refunds regime signal the attractiveness of investment in the RCM. In particular, new investment will only be economic if the combination of energy revenues plus Capacity Credit revenues less any lost revenue from the refund regime is at least equal to the long-run marginal cost of new capacity. Therefore, adjustments to the RCP should only be made with supporting changes to the refunds regime to avoid perverse consequences.

To facilitate discussion in the Working Group, the IMO engaged The Lantau Group to address key

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[3] The RCMWG outcomes in each work-stream are detailed on page 13 of the RCMWG meeting 10 papers: http://www.imowa.com.au/f5415,3566068/Combined_RCMWG_Mtg_10_Papers.pdf

[4] More details on this Rule Change Proposal are available on the Market Web Site: http://www.imowa.com.au/RC_2013_10

[5] The implementation of this principle was developed fully in RC_2013_10

[6] More details on this Rule Change Proposal are available on the Market Web Site: http://www.imowa.com.au/rc_2013_11

issues and develop recommendations for work-streams 1 and 3. Although not unanimously agreed, the RCMWG members decided to progress certain recommendations by developing a Rule Change Proposal. This concept paper summarises the issues and details the recommended solutions as discussed in work-streams 1 and 3.

2. Reserve Capacity Price

Where the number of Capacity Credits to be traded bilaterally (as determined through the Bilateral Trade Declaration process in clause 4.14 of the Market Rules) exceeds the Reserve Capacity Requirement (RCR), the IMO determines their cost by applying the adjusted RCP formula in clause 4.29.1 of the Market Rules. The formula is set at 85% of the Maximum Reserve Capacity price (MRCP)[7] and is further adjusted downward if there is excess capacity. This downward adjustment of the RCP is intended to reduce the value of a Capacity Credit, thereby sending signals to investors to defer new investment in capacity.

2.1. Issue

The RCMWG noted that, despite the downward adjustment of the RCP, excess capacity continued to increase, and now stands at 11% (~564 MW) of the RCR in 2015/16 Capacity Year. Excess capacity can be considered an unnecessary cost to the market in the sense that consumers end up paying more than the efficient economic value of a Capacity Credit.

A number of factors have contributed to the consistent increase in excess capacity[8]. These factors include:

(a) Government policy decisions such as the requirement for Synergy to tender for certain volumes of energy;

(b) Large, lumpy loads not coming online as forecast;

(c) Cessation of demand growth due to increase in solar PV uptake, energy efficiency programs etc.; and

(d) The unresponsiveness of the RCP adjustment to market conditions.

2.2. Proposed solution

In assessing potential improvements to the RCM to address the problem of excess capacity, The RCMWG members deliberated on a number of solutions presented by The Lantau Group to address the persistence of excess capacity. These included[9]:

(a) Limiting the quantity of Certified Reserve Capacity to the level determined by the RCR; and

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[7] The MRCP aims to reflect the marginal cost of providing additional Reserve Capacity in each Capacity Year. It is established by undertaking a technical bottom-up cost evaluation of the entry of a 160MW open cycle gas turbine generation facility entering the WEM in the relevant Capacity Year.

[8] A detailed discussion on various factors contributing to excess capacity is provided on Page 45 in RCMWG Meeting 3 papers:http://www.imowa.com.au/f5415,2873678/Combined_RCMWG_Mtg_3_Papers.pdf

[9] A detailed discussion on various solutions can be accessed on the Market Web Site: http://www.imowa.com.au/f5415,2873740/IMO_RCM_October_WG_to_IMO_Updated.pdf

(b) Ensuring good faith intentions in Bilateral Trade Declarations and withholding payment to capacity that has not been traded bilaterally.

The Lantau Group highlighted that the most feasible solution should seek to address the two key issues of the current RCM:

(a) It is not sufficiently dynamic to respond appropriately to market conditions; and

(b) It creates asymmetrical incentives for capacity providers and capacity users to manage their risk exposure through Bilateral Contracts.

Because of these issues, the RCM is unable to send appropriate signals for investment in or withholding investment from new capacity.

The Lantau Group recommended a solution that would incorporate[10]:

(a) The ability for the RCP to move above the MRCP – recommended to be 110% of the MRCP at 97% of the RCR, such that the price of an uncontracted Capacity Credit would be at 110% of the MRCP when 97% of the RCR has been fulfilled.

    The Lantau Group highlighted that the current initial point of RCP (being 85% of the MRCP) distorts the incentive for retailers to hedge their risks of purchasing Capacity Credits through Bilateral Contracts. By setting the initial point of the RCP as 110% of the MRCP, retailers become exposed to the risk of purchasing Capacity Credits at a higher cost from the IMO, as excess capacity declines. This provides for symmetry of risk for retailers and creates an incentive for a retailer to contract for new capacity as the market requires new investment.

    The RCMWG members also noted that following the five-yearly review completed in 2011, the MRCP has become more representative of a benchmark price. Consequently, the RCMWG members generally considered it appropriate for the RCP to be allowed to exceed the MRCP. The members also considered that the MRCP should be renamed to a more appropriate term such as the Benchmark RCP reflecting its underlying intent.

(b) A steeper slope function recommended to be -3.75[11] replacing the current -1 slope embedded into the Excess Capacity Adjustment component of the RCP formula.

    The Lantau Group highlighted that steepening the slope function creates greater sensitivity to market conditions. The value of a Capacity Credit would decline at a faster rate as excess capacity increases, sending a signal to defer investment that is not required.

A key feature of the recommended RCP formula is that it provides a retailer with the opportunity to bilaterally contract capacity so as to completely hedge against Shared Reserve Capacity Costs. This is illustrated in Figure 1, which shows that the additional cost of shared capacity for a retailer

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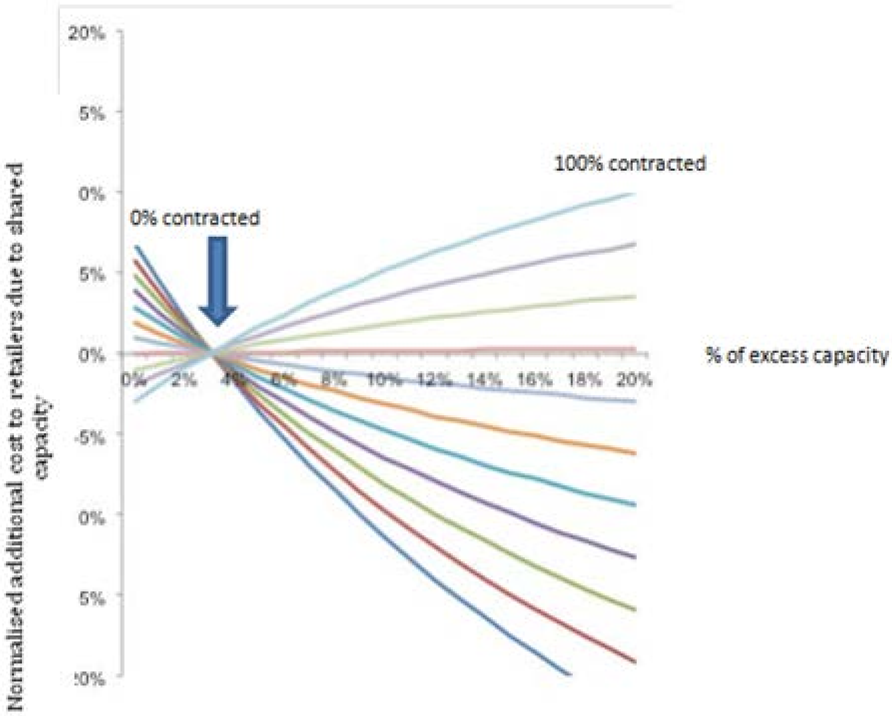
[10] Refer to slide no. 12 http://www.imowa.com.au/f5415,2873740/IMO_RCM_October_WG_to_IMO_Updated.pdf

[11] Note that the slope function was earlier recommended to be -3.25, which was subsequently amended to -3.75 when the recycling of Reserve Capacity refunds was taken into account.

remains at approximately zero where it contracts for 70% of its capacity requirement.[12]

Figure 1: SRCC vis-à-vis excess capacity at different levels of contracting- proposed RCP formula



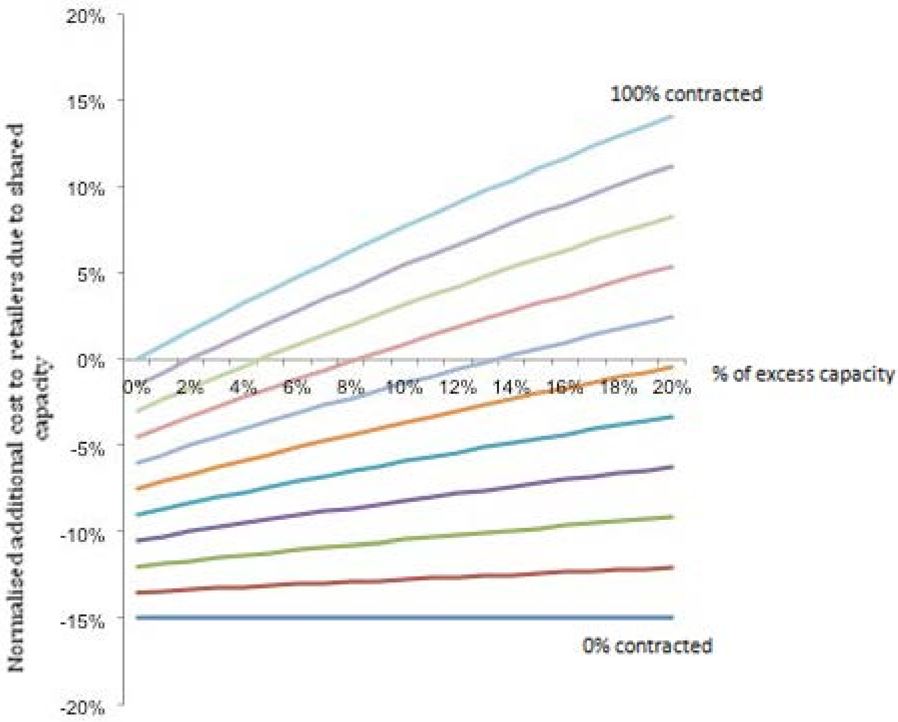
Source: RCM Recommendation- presented by Mike Thomas of The Lantau Group to RCMWG on 11 October 2012

As opposed to Figure-1, Figure 2 below shows the current risk management options available to a retailer. It is worth noting that in the current mechanism, contracting is not a preferred option for a retailer to mitigate the cost of shared capacity.

Figure 3 illustrates the proposed RCP formula *vis-à-vis* the current mechanism.

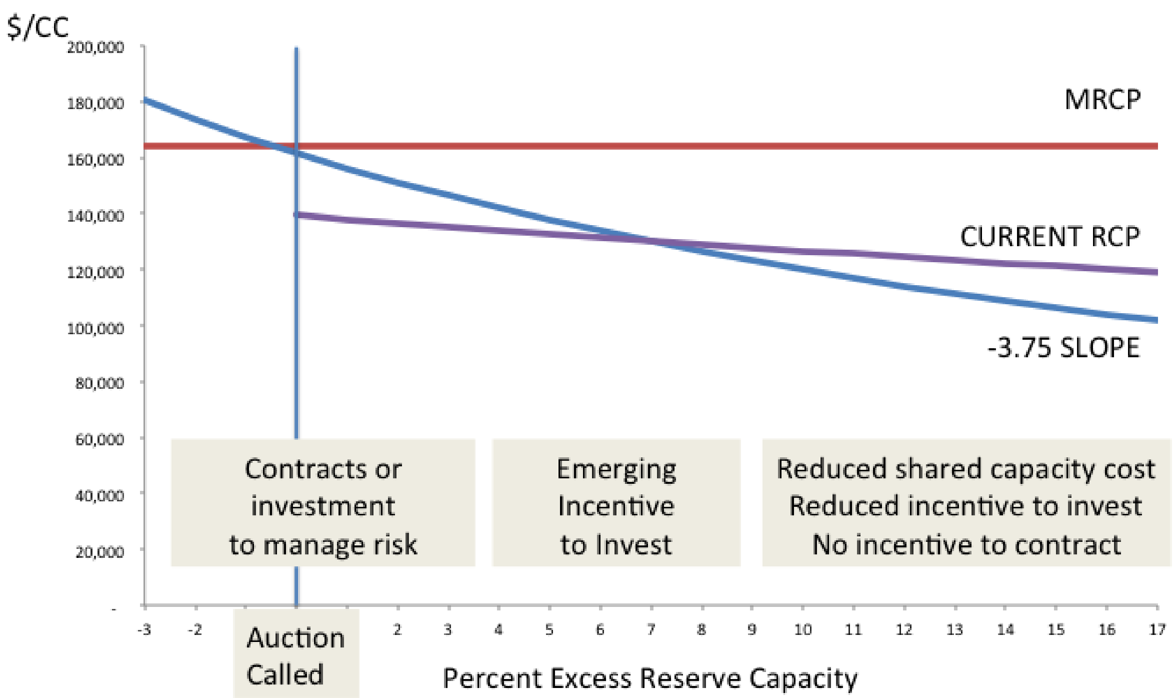
12 Detailed analyses of various hedging options are provided in The Lantau Group's memo available here: http://www.imowa.com.au/f5415,2978683/Combined_Meeting_9_RCMWG_Papers.pdf

Figure 2: SRCC vis-à-vis excess capacity at different levels of contracting- current RCP formula



Source: RCM Recommendation- presented by Mike Thomas of The Lantau Group to RCMWG on 11 October 2012

Figure 3: Proposed RCP formula vis-à-vis current RCP formula



Source: The Lantau Group's paper presented to the RCMWG on 22 November 2012

Overall, the recommended proposal would achieve a more balanced RCM where the RCP would be lower than under the current formula for levels of excess capacity above approximately seven percent, while enhancing the investment incentives necessary to assure capacity adequacy as the excess capacity level declines. The increased dynamism of the steeper slope and adjusted initial point of RCP would create market-oriented incentives within the RCM that address the RCM's primary deficiencies in terms of economic signalling and commercial and behavioural incentives.

The IMO also notes that the changes proposed to the RCP formula would also affect the maximum price that will apply if a Reserve Capacity Auction is called. Clause 4.18.2 of the Market Rules specifies that the Reserve Capacity Price-Quantity Pairs that are offered in a Reserve Capacity Auction (if called) must not have a price greater than the MRCP. Given that the proposal allows the RCP to reach 110% of the MRCP when 97% of the RCR is met, the IMO proposes to amend the ceiling price set in the auction to 110% of the MRCP.

2.3. Proposed Amendments

1. The IMO proposes to amend clause 4.29.1(b) of the Market Rules which outlines the formula that the IMO must use to determine the Reserve Capacity Price in the event no Reserve Capacity Auction is held.

    a. Clause 4.29.1(b)(ii) specifies 85% of the MRCP as the ceiling from which the downward adjustment to the RCP takes place. The IMO proposes to amend this ceiling to initiate at 110% of the MRCP. This ceiling of 110% will apply when the supply of capacity reaches 97% of the RCR; and

    b. The IMO proposes to amend the Excess Capacity Adjustment in clause 4.29.1(c)(ii) to include the recommended slope of -3.75 which will steepen the rate of downward adjustment as excess capacity increases.

2. Clause 4.16 and all other instances of MRCP in the Market Rules will be amended to replace "Maximum" with "Benchmark".

3. The IMO proposes to amend clause 4.18.2(b) of the Market Rules to specify the ceiling price in a Reserve Capacity Auction to be 110% of the Benchmark RCP.

3. Transitional arrangements for RCP formula

Due to the significance of the changes, the RCMWG members determined that certain transitional arrangements for implementing the new RCP adjustment formula should be developed so as to ensure that the expected cost to a Market Participant for implementing these changes does not materially exceed the benefit to the Wholesale Market Objectives.

When the three-year glide path for the RCP was recommended in February 2013, the IMO used the best estimates available at the time. Subsequently, new information has become available, particularly on the impending retirement of Kwinana C (361 MW). It is now known that this unit will not be available from the 2015/16 Capacity Year. Additionally, the IMO has also updated the RCR values from the 2013 Statement of Opportunities (SOO)[13], the total MW of Capacity Credits assigned in 2015/16 and the MRCP determined for 2015/16.

[13] The 2013 SOO can be accessed on the Market Web Site: http://www.imowa.com.au/soo

Table 1 below shows the updated values. Please note that the projected values are estimates only, and actual outcomes are likely to differ.

Table 1: Parameters used in RCP projections

Capacity Year	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Notes
Actual/projected RCR	5312	5308	5119	5263	5438	5604	5759	Projected RCRs taken from 2013 SOO
Actual/projected capacity	6086.8	6040.2	5683.3	5708	5733	5758	5783	Projected capacity assumes increase of 25 MW per year.
Surplus (MW)	775	732	564	445	295	154	24	
Surplus (%)	14.6%	13.8%	11.0%	8.5%	5.4%	2.7%	0.4%	
Actual/projected MRCP	$240,600	$163,900	$157,000	$160,900	$164,900	$169,000	$173,200	Actuals through to 15/16; indexed at 2.5% thereafter

Based on Table 1, the RCP estimates for various Capacity Years have been determined in Table 2 using:

(a) the current formula: *MRCP * 85% * RCR / capacity; capped at 85% of MRCP*;

(b) the proposed formula: *MRCP * 110% / (1 - ((Surplus% + (1-97%)) * (-3.75))); capped at 110% of MRCP*; and

(c) a three-year glide path as follows:

i. In 2016/17, sum of two-thirds of the current formula and one-third of the proposed formula;

ii. In 2017/18, sum of one-third of the current formula and two-thirds of the proposed formula; and

iii. 2018/19 onwards, proposed formula applied in full.

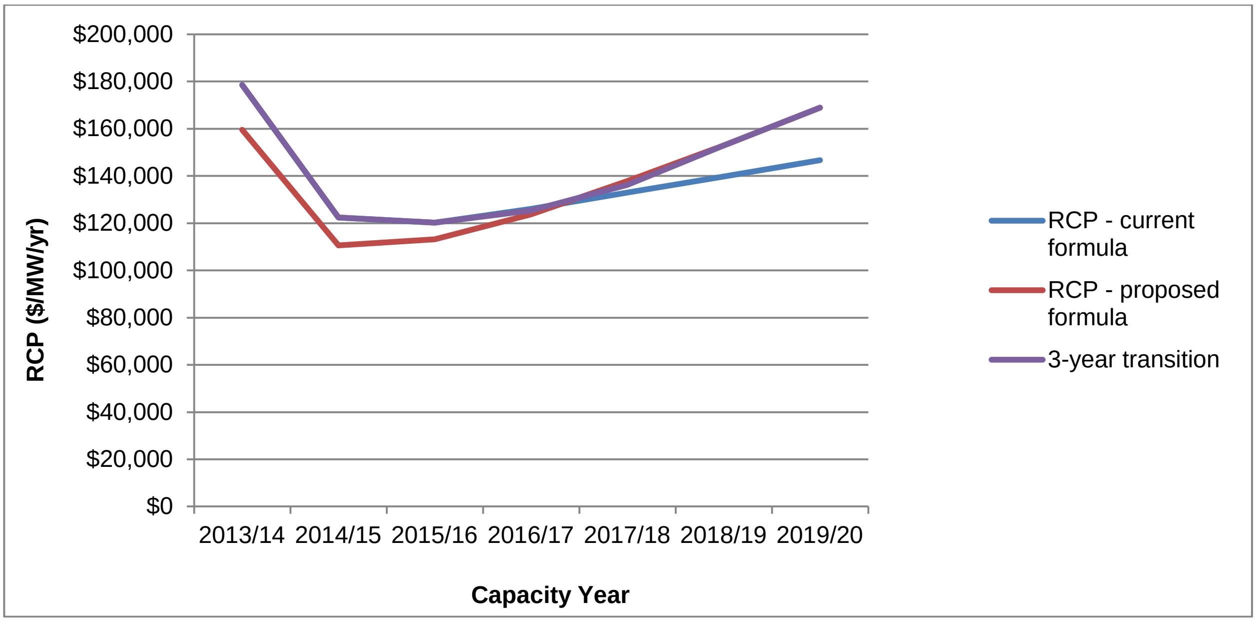
Table 2: RCP projections

Capacity Year	Current formula	Proposed formula without Transition	Transition	Difference between proposed formula and transition
2013/14	$ 178,477	$ 159,483	$ 178,477	
2014/15	$ 122,428	$ 110,624	$ 122,428	
2015/16	$ 120,199	$ 113,179	$ 120,199	
2016/17	$ 126,103	$ 123,806	$ 125,337	-$ 1,531
2017/18	$ 132,953	$ 137,842	$ 136,212	$ 1,630
2018/19	$ 139,808	$ 152,935	$ 152,935	
2019/20	$ 146,609	$ 168,882	$ 168,882	

Values in green are previous or current. Shaded cells indicate the proposed transition years.

Figure 4 displays the projected RCP values graphically.

Figure 4: RCP values



3.1. Proposed amendment

Based on Table 2 and Figure 4, the IMO considers that there is little value in implementing a transition path because the difference between the RCP as determined by the proposed formula and that determined by the transition is within the range of uncertainty of other variables (such as components of the MRCP and the quantity of excess capacity).

Therefore, the IMO proposes to implement the proposed RCP formula in full from the 2016/17 Capacity Year **without any transitional arrangements**.

4. Dynamic refund regime

The objective of the refund mechanism prescribed in clause 4.26 of the Market Rules is to ensure that capacity providers that have been awarded a Capacity Credit present it to the market when required. The intent of the refund mechanism is two-fold:

1. To incentivise capacity providers to manage their long term decision making processes around appropriate maintenance schedules; and

2. To incentivise short-term behaviours to ensure day-to-day operation and maintenance activities are directed to maximising reliability at time of greatest value, generally when actual reserves are lowest.

The current capacity refund mechanism requires Market Generators who have been paid for capacity (through Capacity Credits) to pay refunds if that capacity is not made reliably available to the market. Refund factors are currently set on a time-based schedule specified in the Refund Table in clause 4.26.1 of the Market Rules. Refund factors are weighted to times when high demand is more likely and reserves may be low. They range from a minimum of 0.25 applicable at off-peak times in winter and shoulder seasons to a maximum of 6 applicable at peak times in summer.

In accordance with clause 4.26.4 of the Market Rules, the revenue collected through the refund mechanism is distributed to Market Customers in proportion to their Individual Reserve Capacity Requirements.

4.1. Issues

In April 2011, the IMO put forward a discussion on the weaknesses of the current refunds regime in the paper titled *"Review of Capacity Cost Refunds"*[14] to the Rules Development and Implementation Working Group (RDIWG). The RDIWG concluded that the issues and proposed solutions needed to be considered holistically with corresponding changes to the RCP to avoid unintended consequences such as a substantial reduction in the magnitude of refund at times of excess capacity, which would effectively increase the value of a Capacity Credit when its economic value is in fact lower.

The Lantau Group presented an evaluation of the issues discussed in the IMO's paper to the RCMWG members at meeting no. 5 held on 12 July 2012. The RCMWG members noted the following issues with the current refund mechanism:

(a) Refund factors are not aligned to time periods of greatest system need resulting in inefficient decisions by generators on the scheduling of maintenance and presentation of capacity;

(b) The value of refunds potentially greatly exceeds the economic value of capacity when excess capacity exists in the WEM;

(c) The current refund mechanism is more punitive for generators with high utilisation rates, such as baseload generators as they can be exposed to the risk of refunds in practically every Trading Interval of the year; and

(d) Refunds are distributed to Market Customers, however it is the RCM as a whole, not the performance of individual capacity resources, that is responsible for ensuring adequate capacity. The refund revenue currently received by Market Customers amounts to an uncertain revenue stream with no long-term benefits. The value leakage from generators to retailers would ultimately need to be offset by higher energy costs of higher capacity prices.

4.2. Proposed solutions

Several stakeholders have advocated for the need to consider a dynamic refund regime where capacity is valued according to the prevalent system conditions, with the underlying principle that capacity that fails to deliver at times of greatest system need should be exposed to a higher refund factor.

The IMO proposed a dynamic refund regime in its paper "*Review of Capacity Cost Refunds".* The Lantau Group built the proposed model and presented it to the RCMWG at its 22 November meeting[15]. The solution will work in two ways:

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[14] This paper is available from page 45 in meeting no. 5 papers:
http://www.imowa.com.au/f5415,2873627/Combined_Papers_Mtg_5.pdf

[15] The Lantau Group's presentation can be accessed at:

(a) A dynamic refund regime would be implemented where the refund factor will be determined based on the reserve available in each Trading Interval (rather than from the current time-based schedule). A dynamic regime will appropriately reflect the greater value associated with capacity that is presented when reserve is becoming low. This will focus the incentives for Market Generators to maximise their availability and reduce their risk of exposure to refunds arising from plant failure at times when reserves are running low.

(b) The revenue collected from refunds will be recycled back to Market Generators in the form of rebates based on certain eligibility criteria. The availability of rebates coupled with the avoidance of refunds would strengthen the incentive to generators to ensure that reliable capacity is made available for dispatch.

Each component is discussed in detail below.

(a) Dynamic refund regime

The RCMWG members agreed that a dynamic refund regime should be implemented to improve the alignment of the magnitude of refunds with the prevalent system conditions. However, the members highlighted the need to retain a maximum and a minimum refund factor to reduce volatility in refund exposure.

Maximum refund factor

Although an economic case exists for much higher refund factors as the level of reserve reduces towards zero, financial risk increases as well due in part to the random nature of Outages. The RCMWG members discussed that retaining the maximum refund factor of six as per current refund arrangements would allow certainty around the level of refund exposure in low reserve periods. The maximum refund factor of six will be triggered when the actual reserve in a Trading Interval falls below 750 MW.

Minimum refund factor

Following discussion at the RCMWG, the IMO proposed to apply one (1) as the minimum refund factor that would be triggered when the actual reserve in a Trading Interval exceeds 1500 MW. This minimum refund factor level was based on the principle that a project that has received capacity payments (through the assignment of Capacity Credits) should forfeit all of its payments if it does not present that capacity into the market for the entire Capacity Year. The minimum refund factor of one would ensure that the integrity of the RCM was protected from such an outcome.

Although there was agreement on the principle that a Market Participant should not retain capacity payments when no capacity is provided for a Capacity Year, some RCMWG members considered that the minimum refund factor of one would create perverse consequences for generators with high utilisation factors. In the current regime, generators are exposed to refund factors below one (0.25, 0.50 and 0.75[16]) in off-peak periods. These RCMWG members indicated that increased refund exposure could ultimately be manifested in the form of higher energy prices.

Based on this argument, some members requested that the IMO consider retaining the minimum

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http://www.imowa.com.au/f5415,4028778/Agenda_Item_6._IMO_Refund_Regime_20121122_Final_Read-Only_.pdf

[16] The Refund Table in clause 4.26.1 of the Market Rules lists the refund factors that apply at various time periods.

refund factor of 0.25, with the ability for the minimum to rise to 1 for a project that has received capacity payments but has not provided any capacity during the Capacity Year. The IMO engaged The Lantau Group to explore whether this alternative would supply sufficient incentives without creating perverse consequences for some stakeholders.

Following further consideration of this issue, the IMO has concluded that the minimum refund factor of 0.25 should be adopted to protect generators from punitive refund exposure. However, the IMO proposes that the minimum refund factor should scale up to 1 for generators that were unavailable in the previous 90-day rolling period. In proposing this recommendation, the IMO considered that:

This approach would achieve a balance between implementing the fundamental principle that capacity payments should be forfeited by Market Participants that do not deliver capacity during the Capacity Year, as well as ensuring the protection for generally reliable generators from punitive refund exposure when reserves in the system are relatively high.

(b) Recycling of refund revenue

The RCMWG members generally agreed that recycling of refund revenue to Market Generators strengthens the incentive for generators to make capacity available at times of greatest system need.

During the RCMWG process, the IMO proposed that refunds should be recycled, in the form of rebates, to all Market Generators (other than those on an Outage) that made their capacity available in the affected Trading Interval. This was based on the principle that available resources, irrespective of dispatch, have inherent value. Analyses conducted by The Lantau Group did not indicate a strong correlation between Forced Outages and plant dispatch.

Subsequent to the RCMWG process, the Lantau Group has further analysed the correlation between Forced Outages and plant dispatch and noted that Forced Outages appear to more closely align with periods where there is likely to be more starts, stops or cycling of units. In light of this, pure availability-based rebates would risk creating a value transfer from base-load and mid-merit generators to peaking generators. On the other hand, pure dispatch-based rebates would risk creating a vice-versa value transfer. Clearly, a balance needs to be achieved between risk exposure and the probability of earning reward across the spectrum of generators.

To improve the alignment of the risk (refund) and reward (rebate) exposure, the IMO proposes to introduce an eligibility criterion for generators to qualify for rebates based on dispatch in the previous 30-day rolling period. Those generators that have dispatched for a non-zero MW value in any one Trading Interval in the previous 30 days would qualify for rebates. Rebates for a Trading Interval would be allocated to generators based on their share of available Capacity Credits in that Interval.

The IMO considers that the eligibility criterion would minimise inefficient value transfers by promoting a balance between risk and reward for all generators. It would also promote efficient scheduling of plant maintenance so that capacity is readily available for dispatch when the market needs it the most. Additionally, it would reduce administrative costs of the IMO and System Management with regard to Reserve Capacity Tests for those generators that have already met the eligibility criterion.

Related proposals

The IMO identified the following issues that are related to the recycling of rebates. The IMO proposes certain recommendations on which it solicits feedback:

(a) DSM would be eligible for rebates based on actual dispatch. With the harmonisation of demand and supply side resources underway, the likelihood of dispatch for DSM is relatively greater than before. The IMO considers that it is appropriate to provides rebates to a DSM facility if it has reliably curtailed demand in response to Dispatch Instructions.

(b) Intermittent Generators would not be eligible for rebates because their Reserve Capacity Obligation Quantity is zero. Under clauses 4.26.1 and 4.26.1A of the Market Rules, Intermittent Generators that are in Commercial Operation and have operated at their Required Level are not liable for Capacity Cost Refunds. Given this arrangement, the IMO considers that it is appropriate to exclude them from the eligible rebate pool.

4.3. Proposed Amendments

Based on the above-mentioned recommendations, the IMO proposes the following amendments:

1. The IMO proposes to replace the Refund Table in clause 4.26.1 of the Market Rules with the following formula:

   The Refund Factor for a Facility f in Trading Interval t would be:

   RF(f,t) = Min(6, Max(RF_dynamic(t), RF_floor(f,t))

   Where
   RF_dynamic(t) = 11.75 - 0.00767 * Spare(t), where Spare(t) = Available Capacity – Demand in the Trading Interval
   RF_floor(f,t) = 1 – 0.75 * Availability(f,t), where Availability(f,t)[17] for that Facility is determined for the 90 days prior to that Trading Interval

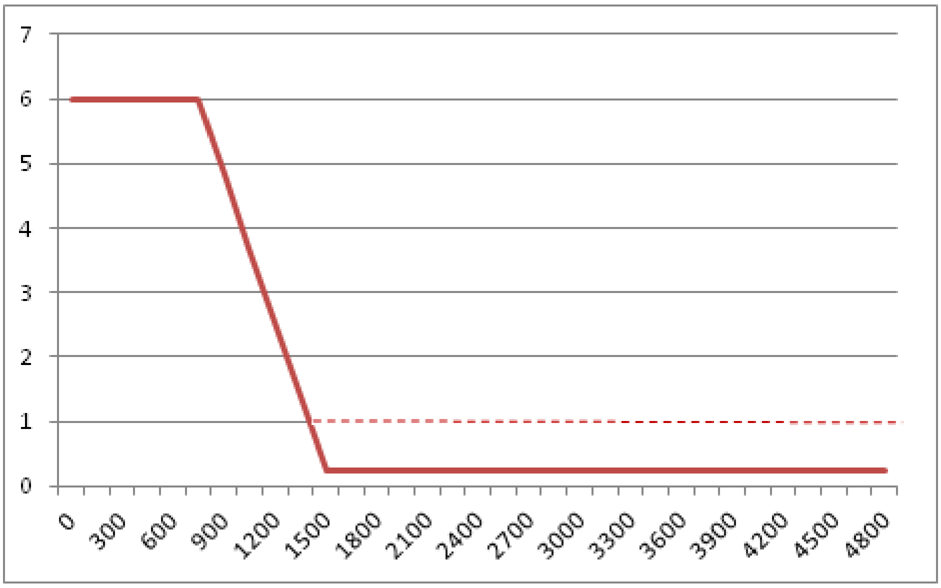
   The formula is illustrated in Figure 4.

2. The IMO proposes to remove clause 4.26.4 of the Market Rules and amend clause 4.28.4 to reflect the application of the rebates to Market Generators.

3. The IMO will propose new clauses to reflect the eligibility criterion and application of rebates.

[17] The IMO is considering the optimal determination of Availability rate and will propose at the Pre-Rule Change Proposal stage

Figure 4: Dynamic refund factors with a floating minimum refund factor



5. Transitional arrangements- recycling of refund revenue

Extending the transitional arrangements recommended for the RCP formula to the dynamic refund regime, the IMO previously considered that the transition of refund revenue from Market Customers to Market Generators would apply as follows:

i. In 2016/17, two-thirds of the refund revenue allocated to Market Customers and one-third to Market Generators;

ii. In 2017/18, one-third of the refund revenue allocated to Market Customers and two-thirds to Market Generators; and

iii. From 2018/19 onwards, full refund revenue allocated to Market Generators.

However, based on the RCP figures provided in Section 3, the IMO notes that the potential revenue loss to Market Customers is expected to be small[18] and would be offset by the adjustments to the RCP formula. Further, based on the proposal to not apply transitional arrangements to the RCP formula, the IMO considers it appropriate to also not apply transitional arrangements to the recycling of refund revenue.

6. Assessment against Wholesale Market Objectives

The IMO considers that the Market Rules as a whole, if amended to reflect the proposed recommendations above, will not only be consistent with the Wholesale Market Objectives but also generally allow the Market Rules to better achieve Wholesale Market Objectives (a), (b), (c) and (d). In Table 3, the IMO presents a high- level assessment of the proposed recommendations against Wholesale Market Objectives.

[18] The estimated magnitude of revenue loss to Market Customers will be presented at the MAC meeting

Table 3: Wholesale Market Objective assessment

Proposal	Benefits	Wholesale Market Objective assessment
Proposed RCP formula	• Improve the market- responsiveness of the RCP thereby promoting economically efficient supply of electricity • Facilitate efficient entry of new competitors by supporting appropriate level of new investment in capacity • Minimise the long-term cost of electricity supply by reducing the cost of excess capacity borne by Market Participants	Better achieves Wholesale Market Objectives (a), (b) and (d)
Dynamic refund factors	• Improve incentives for efficient scheduling of plant maintenance thereby promoting economically efficient and reliable supply of electricity • Avoid discrimination against generation facilities with high utilisation factors by aligning refund factors with prevalent system conditions	Better achieves Wholesale Market Objectives (a) and (c)
Recycling of rebates	• Improve incentives for generators to provide capacity reliably at times of greatest need thereby promoting reliability of supply • Encourage competition between generators by rewarding better availability performance • Improve economic efficiency by allocating the refund revenue to Market Generators instead of Market Customers • Minimise long-term cost of electricity by reducing the administrative costs of the IMO and System Management with regard to Reserve Capacity Testing.	Better achieves Wholesale Market Objectives (a), (b), (c) and (d)

7. Practicality and Cost of Implementation

The IMO does not consider that the proposed recommendations would involve any practicality of implementation issues. However, the IMO considers that Market Participants may decide to build additional functionality into their forecasting models to account for the proposed recommendations. Some Market Participants may also decide to re-negotiate their Bilateral Contract terms.

The IMO considers that it would incur IT costs to build the proposed changes into the Settlement system. Additionally, Market Participants may also incur some costs to incorporate the proposed changes into their business processes.

INDEPENDENT MARKET OPERATOR

Agenda Item 9a: 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)	2nd October 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)	2
Standard Rule Changes with 2nd Submission Period Open	0
Standard Rule Changes with 2nd Submission Period Closed (final report being prepared)	0
Rule Changes - Awaiting Minister's Approval and/or Commencement	1
Total Rule Changes Currently in Progress	**5**

The following table provides an update of the items the Market Development team anticipates progressing to the MAC over coming months.

Issue	Likely timing
Necessary Rules Changes for Verve/Synergy Merger	Pre Rule Change Proposal – November MAC Meeting
Outage Planning – Phase 2	Pre Rule Change Proposal – December MAC Meeting
Reserve Capacity Refunds and Price (package from RCMWG)	Pre Rule Change Proposal – December MAC Meeting
Improvements to the Energy Market - options for STEM, Bilaterals and Resource Plans (MREP)	Discussion Paper and/or presentation – December MAC Dependent on Verve/Synergy Merger outcomes
Settlements package	Pre Rule Change Proposal – Early 2014
Minor Typographical and Manifest Errors	Pre Rule Change Proposal – Early 2014

Issue	Likely timing
Emissions Intensity Index (MREP)	Concept Paper or PRC – Early 2014
Ancillary Services 5 Yearly Review	Review Commencing – Early 2014
Dispatch Issues (from log)	Concept Paper or PRC – Late 2014

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

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

APPENDIX 1: FORMALLY SUBMITTED RULE CHANGES (Current as of 2nd October 2013)

Fast Track Rule Change with Submission Period Open

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2013_07	10/09/2013	Correction of Minor, Typographical and Manifest Errors	IMO	Submissions close	02/10/2013

Standard Rule Change with First Submission Period Open

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2013_10	21/08/2013	Harmonisation of Supply-Side and Demand-Side Capacity Resources	IMO	Submissions close	03/10/2013

Standard Rule Change with First Submission Period Closed

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2013_09	18/06/2013	Incentives to Improve Availability of Scheduled Generators	IMO	Draft Rule Change Report Published	09/10/2013
RC_2012_23	14/08/2013	Prudential Requirements	IMO	Draft Rule Change Report Published	24/10/2013

Standard Rule Change Awaiting Commencement

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2013_08	21/05/2013	Market Participant Fees – Clarification of GST Treatment	IMO	Ministerial Approval by	24/10/2013

INDEPENDENT MARKET OPERATOR

Wholesale Electricity Market
Pre Rule Change Proposal

Rule Change Proposal ID: **PRC_2013_16**
Date received: **TBA**

Change requested by:

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

Introduction

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

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

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

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

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

The objectives of the market are:

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

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

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

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

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

Details of the Proposed Rule Change

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

Background

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

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

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

- definition of an Outage;
- quantity of an Outage that a Non-Scheduled Generator must log;
- requirement for Market Participants to log Outages which they become aware of following the 15 day timeframe, and for System Management to report these to the IMO;
- requirement for the IMO to provide System Management with each Facility's Reserve Capacity Obligation Quantity for the purposes of Outage calculations;

- application of constrained on and off compensation to Market Participants; and
- application of the Forced Outage rate and Planned Outage rate to Non-Scheduled Generators for the purposes of setting Certified Reserve Capacity.

A Concept Paper which outlined these issues was presented at the Market Advisory Committee meeting held on 7 August 2013. Two key questions were raised which have informed the drafting to implement the necessary changes, which related to:

1. the practicalities of logging Outages for a Non-Scheduled Generator, noting that it would be complex to determine pro-rated outage quantities based on an ex-post review of each minute; and
2. the necessity to align incentives to make capacity available for Non-Scheduled Generators, where they already have sufficient commercial incentive to be available.

The IMO has considered these issues in the context of the proposed amendments and has included commentary on each within this pre Rule Change Proposal.

Issues to be addressed in the existing Market Rules

Definition of an Outage

Currently the Market Rules define an Outage as:

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

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

1. a Facility is able to provide capacity but, due to a Network constraint, the Network is unable to accept its capacity while maintaining operation within the Technical Envelope to ensure a safe, reliable and stable network.
2. a Facility's production is limited to reduce the potential of damage to the Facility or to ensure safety of its workers. For example, a wind farm may have an automatic trip in place for periods of extreme wind.
3. a Non-Scheduled Generator which relies on a renewable fuel source may be unable to provide capacity without the appropriate fuel. For example, at night for solar generation and during low wind periods for wind farms.

This lack of clarity around the requirement to log Outages has resulted in an inconsistent approach from Market Participants and has led to spurious payments of constrained off compensation to Market Participants where Outages should have been logged but were not explicitly accounted for in the Market Rules.

In order to ensure all Outages are logged as applicable and thereby address the spurious constrained off compensation payments, the IMO proposes to provide further clarity around the definition of an Outage by introducing a new clause, clause 3.21.1, into the Market Rules.

Logging of an Outage in advance

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

The IMO proposes to amend clause 3.21.2 to allow logging of Outages as soon as the participant is notified of an Outage by the Network Operator or other Rule Participant.

Quantity of de-rating for a Non-Scheduled Generator

The Market Rules currently require Market Participants and the Network Operator to inform System Management of an Outage of a Facility or item on the equipment list under clause 3.18.2, or to which clause 3.18.2A applies, as soon as practicable.

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

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

Similarly, clause 3.21.6 provides the process by which System Management determines the MW reduction of a Facility's output as the result of an Outage. Currently, Market Participants enter Outage data on a sent out basis at 15 degrees Celsius. System Management then converts the value to a sent out basis at 41 degrees Celsius and adjusts it based on the Facility's Reserve Capacity Obligation Quantity (RCOQ). System Management then calculates the total MW quantity of Forced, Planned and Consequential Outages under clauses 3.21.6(b) to 3.21.6(d) and provides this for each Facility to the IMO as required under clauses 7.3.4 and 7.13.1A(b).

However, the application of clause 3.21.6 to a Non-Scheduled Generator is currently inappropriate because Non-Scheduled Generators have an RCOQ of zero. This would result in a negative Outage quantity where the MW reduction in the output of a Facility is greater than its RCOQ.

The IMO proposes to amend clause 3.21.5 to specifically apply to Scheduled Generators and introduce additional rules to provide alternative calculations for Non-Scheduled Generators. The proposed Amending Rules will require the quantity of the reduction in capacity of a Non-Scheduled Generator to be calculated by reference to its Sent Out Capacity.

In addition, the IMO proposes to amend clause 3.21.6 to specifically refer to Scheduled Generators, and provide an alternative calculation of a Facility's Outage for a Non-Scheduled Generator which sums all Forced, Planned and Consequential Outages as applicable.

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

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

However, practically, the IMO cannot determine in advance of a Trading Interval each

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

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

The IMO therefore proposes to amend clause 3.21.6(e) of the Market Rules to align to current practice by requiring the IMO to provide each Facility’s MW value of Capacity Credits, rather than it’s RCOQ. In addition, the IMO proposes to amend clauses 3.21.6(b) to (d) to reflect this.

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

Currently, System Management provides Outage data for each Facility for each Trading Interval to the IMO as temperature adjusted values under clause 7.13.1A of the Market Rules. This means that the IMO often does not know the total MW value of the reduction associated with the Outage.

To ensure that the IMO can calculate the impact of Outages on availability and consider it in the certification process, the IMO also requires Outage data to be provided on a sent out basis at 15 degrees.

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

The definitions for the TES equations have also been clarified to ensure that this information is used to calculate the Minimum TES.

The IMO will also work with System Management to revise section 5.5.5 of the *Power System Operation Procedure (PSOP): Dispatch* to provide greater clarity on calculation of the expected quantity and ensure that all Outages are included for a Non-Scheduled Generator. This value is used in calculating the Minimum TES and affects a Facility’s certification and therefore should be as accurate as possible.

Setting Certified Reserve Capacity for Non-Scheduled Generators

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

Clause 4.11.1(h) of the Market Rules is currently unable to be applied to Non-Scheduled Generators as the calculations of Planned Outage rates and Forced Outage rates referred to in this clause only consider the application to a Scheduled Generator. The *PSOP: Facility Outages* contains the calculations of both the Forced Outage rate and the Planned Outage rate that clause 4.11.1(h) refers to.

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

Further, the calculations as they currently stand in the PSOP rely on the MW value of the Outage being reduced from the MW value of Capacity Credits. While this works for a Scheduled Generator, for a Non-Scheduled Generator, the reduction in capacity of an Outage is likely to be significantly greater than the MW value of Capacity Credits, resulting in a nonsensical Outage value.

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

The IMO also proposes that, with the increasing significance of these calculations as a result of RC_2013_09, they should be removed from the *PSOP: Facility Outages* and introduced as an Appendix in the Market Rules.

Timeframes for providing information of Outages to System Management

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

The IMO proposes to amend clause 3.21.7 to be consistent with clause 3.21.8. This will provide a reference to 15 calendar days following the Trading Day on which the Outage commenced.

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

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

Timeframes for providing information of Outages to the IMO

Clause 7.13.1A currently requires System Management to provide the IMO with the Outage data for a Trading Day within 15 Business Days. Currently, the drafting of this clause does not allow System Management to accept or provide to the IMO any information for Outages logged after the 15 calendar days. This may result in Facilities being assigned Certified Reserve Capacity based on inaccurate information.

In order to ensure that the IMO is aware of all Outages, the IMO proposes to introduce a new sub-clause to clause 7.13.1A to require System Management to capture and provide information of all Outages to the IMO, even after the 15 day Business Day timeframe has lapsed.

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

Constrained on and off compensation is paid where a Facility is not dispatched in accordance with the Balancing Merit Order.

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

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

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

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

The amendments proposed in this pre Rule Change Proposal will result in the Minimum TES reflecting all Outages of a Facility as provided in the Dispatch Schedule, thereby also ensuring that Market Participants are not paid Out of Merit compensation when a Facility is unavailable. The IMO will calculate a Facility's Minimum TES by reference to its Dispatch Schedule. This will require the IMO to calculate the Dispatch Schedule from the Dispatch Instructions provided by System Management. This will require changes to the IMO's IT and settlement systems and processes.

The IMO also proposes that the Maximum and Minimum TES, Out of Merit and constrained on and off calculations are moved to an Appendix of the Market Rules and presented as a mathematical formula to improve clarity.

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

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

Impact on the Regulations

The IMO notes that under the *Electricity Industry (Wholesale Electricity Market) Regulations 2004* (WEM Regulations), clauses 3.21.4 and 7.7.6A are subject to Category C civil penalties.

The IMO considers that under the proposed Amending Rules it is still appropriate for these clauses to remain a Category C civil penalty provisions as the intent of these clauses has not changed.

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

2. Explain the reason for the degree of urgency:

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

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

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

3.21.1 Subject to clause 3.21.1A, an **Outage**:

(a) is a:

i. physical event that results in or gives rise to; or

ii. a circumstance that creates safety concerns that a prudent Market Participant would address by:

a temporary limitation that:

(b) affects the technical capability of:

i. a Facility or item of equipment on the list described in clause 3.18.2; or

ii. a Facility or generation system to which clause 3.18.2A applies; and

(c) results in a partial or complete reduction in:

i. the quantity of electricity that the Facility or generation system would otherwise be able to generate;

ii. the quantity of electrical energy that is available to System Management for dispatch in accordance with clauses 7.6.1 and

7.6.1C (including where the Facility, item of equipment or generation system is temporarily not electrically connected to the SWIS); or

iii. the quantity of electrical energy that can be transferred into a transmission or distribution system that:

1. forms part of the SWIS; or

2. is electrically connected to the SWIS,

in accordance with clause 7.6.1 due to a limitation affecting that transmission or distribution system.

3.21.1A An **Outage**:

(a) includes a lack of fuel provided the elements of clauses 3.21.1(b) and (c) are met;

(b) does not include a limitation referred to in clause 3.21.1(b) to the extent it arises from an intermittent energy source used by a Facility to generate electrical energy.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(b) for a Non-Scheduled Generator, is the reduction in capacity from the relevant Facility's Sent Out Capacity; or

(c) for the Verve Energy Balancing Portfolio, is the sum of the reduction in capacity for all Outages from:

i. the sum of the maximum capacity of all Scheduled Generators in the Verve Energy Balancing Portfolio, measured on a sent out basis at 41 degrees Celsius where the maximum capacity is as found in the Standing Data file for Temperature Dependence provided under Appendix 1(b) iv and converted to a sent out basis at 41 degrees Celsius; plus

ii. the sum of the maximum capacity of all Non-Scheduled Generators in the Verve Energy Balancing Portfolio, where the maximum capacity is the Facility's Sent Out Capacity

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

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

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

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

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

i. zero; and

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

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

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

i. zero; and

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

1. zero; and

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

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

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

i. zero; and

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

1. zero; and

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

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

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

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

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

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

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

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

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

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

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

…

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

…

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

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

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

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

[Note: Drafting of clause 4.11.1 reflects proposed Amending Rules in RC_2013_09: Incentives to Approve Availability of Scheduled Generators]

…

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

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

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

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

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

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

~~i. if the Loss Factor Adjusted Price of the Balancing Price Quantity-Pair in respect of the Balancing Facility is less than or equal to the Balancing Price, then the Sent Out Metered Schedule as determined in accordance with clause 6.15.3(a)(i); and~~

~~ii. otherwise the minimum amount of sent out energy, in MWh, which the Balancing Facility could have generated in the Trading Interval if the Facility had been dispatched downwards at its Ramp Rate Limit from its SOI Quantity; or~~

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

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

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

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

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

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

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

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

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

~~i. the sum of:~~

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

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

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

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

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

~~i. if a Dispatch Instruction was issued to the Balancing Facility to decrease its output and the Loss Factor Adjusted Price of the Balancing Price-Quantity Pair in respect of the Balancing Facility is less than the Balancing Price, then System Management's estimate of the maximum amount of sent out energy, in MWh, which the Balancing Facility would have supplied in the Trading Interval had the Dispatch Instruction not been issued; and~~

~~ii. otherwise the Sent Out Metered Schedule for the Facility as determined in accordance with clause 6.15.3(a)(i); or~~

~~(c) for the Verve Energy Balancing Portfolio, the amount which is the lesser of:~~

~~i. the sum of:~~

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

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

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

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

<u>6.15.2. [Blank]</u>

6.15.3<u>.</u> The IMO must:

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

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

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

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

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

(a) disagreement under clause 9.20.6; or

(b) disputes under clause 9.21.1.

…

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

~~(a) subject to clause 6.16A.1(b), the Sent Out Metered Schedule less the Maximum Theoretical Energy Schedule; or~~

~~(b) zero where:~~

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

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

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

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

~~2. the applicable Settlement Tolerance.~~

6.16A.1. The IMO must calculate the Upwards Out of Merit Generation for a Facility or the Verve Energy Balancing Portfolio, as applicable, in accordance with the methodology described in Appendix 11 as soon as practicable after it:

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

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

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

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

~~(b) zero if:~~

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

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

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

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

2. ~~the applicable Settlement Tolerance; or~~

iv. ~~the Balancing Facility is a Non-Scheduled Generator and System Management has not provided the IMO with a MWh quantity for the Facility and the Trading Interval under clause 7.13.1(eF).~~

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

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

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

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

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

~~(b) zero if:~~

i. ~~System Management has provided a report to the IMO under clause 7.10.7 and the IMO determines that Verve Energy has not adequately or appropriately complied with a Dispatch Order in respect of the Verve Energy Balancing Portfolio; or~~

ii. ~~the sum of any Sent Out Metered Schedules for Facilities in the Verve Energy Balancing Portfolio less the Maximum Theoretical Energy Schedule for the Verve Energy Balancing Portfolio is less than the sum of:~~

1. ~~any increase in sent out energy due to a Network Control Service Contract which System Management instructed a Facility within the Verve Energy Balancing Portfolio to provide;~~

2. ~~if Facilities within the Verve Energy Balancing Portfolio were instructed by System Management to provide LFAS, the sum~~

~~of Upwards LFAS Enablement and Upwards LFAS Backup Enablement, both divided by two so that they are expressed in MWh;~~

~~3. if a Spinning Reserve Event has occurred, any Spinning Reserve Response Quantity; and~~

~~4. the Portfolio Settlement Tolerance.~~

~~6.16B.2. The Portfolio Downwards Out of Merit Generation in a Trading Interval for the Verve Energy Balancing Portfolio equals:~~

~~(a) subject to clause 6.16B.2(b), the Minimum Theoretical Energy Schedule less the sum of any Sent Out Metered Schedules for Facilities in the Verve Energy Balancing Portfolio; or~~

~~(b) zero if:~~

~~i. System Management has provided a report to the IMO under clause 7.10.7 and the IMO determines that Verve Energy has not adequately or appropriately complied with a Dispatch Order; or~~

~~ii. the Minimum Theoretical Energy Schedule of the Verve Energy Balancing Portfolio less the sum of any Sent Out Metered Schedules for Facilities in the Verve Energy Balancing Portfolio is less than the sum of:~~

~~1. any reduction in sent out energy due to a Network Control Service Contract which System Management instructed a Facility within the Verve Energy Balancing Portfolio to provide;~~

~~2. if Facilities within the Verve Energy Balancing Portfolio were instructed by System Management to provide LFAS, the sum of the Downwards LFAS Enablement plus the Downwards LFAS Backup Enablement, both divided by two so that they are expressed in MWh;~~

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

~~4. the Portfolio Settlement Tolerance.~~

…

6.17.3. ~~Subject to clauses 6.17.5B and 6.17.5C, t~~<u>T</u>he IMO must attribute any Upwards Out of Merit Generation from a Balancing Facility<u> and the Verve Energy Balancing Portfolio</u> ~~that is a Scheduled Generator~~ in a Trading Interval~~, as follows:~~<u>in accordance with Appendix 11.</u>

~~(a) Constrained On Quantity1 (ConQ1) equals the lesser of:~~

~~i. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched from the Facility's Balancing~~

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

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

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

~~(c) If the Balancing Facility's Upwards Out of Merit Generation exceeds ConQ1 and a Balancing Price-Quantity Pair exists for the Facility and Trading Interval with a Loss Factor Adjusted Price higher than Price N, then:~~

~~i. additional Constrained On Quantity2 (ConQ2) equals the lesser of:~~

~~1. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched from the Facility's Balancing Price-Quantity Pair N+1 with a Loss Factor Adjusted Price (Price N+1) higher than but closest to the Price N, taking into account when the Balancing Facility's MW level reached the top, or bottom, as applicable, of the quantity associated with the Balancing Price-Quantity Pair N in the calculation in clause 6.17.3(a)(i) and the applicable Ramp Rate Limit; and~~

~~2. the Upwards Out of Merit Generation for the Balancing Facility less ConQ1; and~~

~~ii. Constrained On Compensation Price2 (ConP2) equals the Loss Factor Adjusted Price N+1 identified in clause 6.17.3(c)(i) less the Balancing Price;~~

~~(d) The IMO must repeat the process set out in clause 6.17.3(c) to identify, from the next highest priced Price N+1, any ConQN+1 and ConPN+1 until all Upwards Out of Merit Generation has been attributed to Balancing Price-Quantity Pairs or, otherwise, until there are no remaining Balancing Price-Quantity Pairs;~~

~~(e) The Non-Qualifying Constrained On Generation for the Balancing Facility equals the sum, divided by two so that it is expressed as sent out MWh, of any Upwards LFAS Enablement and, if the Facility is a Stand Alone Facility, any Upwards LFAS Backup Enablement, which the Balancing Facility was instructed to provide by System Management;~~

~~(f) If:~~

~~i. the Non-Qualifying Constrained On Generation exceeds ConQ1, set ConQ1 to zero; or~~

~~ii. otherwise reduce ConQ1 by the amount of Non-Qualifying Constrained On Generation;~~

~~(g) The IMO must repeat the process set out in clause 6.17.3(f) for each ConQN in ascending order until all Non-Qualifying Constrained On Generation has been deducted from ConQN or, otherwise, until there are no remaining ConQN; and~~

~~(h) For settlement purposes under Chapter 9, the IMO must Loss Factor adjust each ConQN calculated in clauses 6.17.3(a) to 6.17.3(f).~~

~~6.17.3A Subject to clause 6.17.5B, for any Balancing Facility that is a Non-Scheduled Generator, in a Trading Interval:~~

~~(a) ConQ1 equals the Upwards Out of Merit Generation, in MWh, for the Trading Interval, which for settlement purposes under Chapter 9 the IMO must Loss Factor adjust; and~~

~~(b) ConP1 equals the greater of:~~

~~i. zero; and~~

~~ii. the Loss Factor Adjusted Price in the Balancing Price-Quantity Pair associated with the Balancing Facility for that Trading Interval less the Balancing Price for that Trading Interval.~~

6.17.4. ~~Subject to clauses 6.17.5B and 6.17.5C, t~~The IMO must attribute any Downwards Out of Merit Generation from a Balancing Facility and the Verve Energy Balancing Portfolio ~~that is a Scheduled Generator,~~ in a Trading Interval~~, as follows:~~ in accordance with Appendix 11.

~~(a) Constrained Off Quantity1 (CoffQ1) equals the lesser of:~~

~~i. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched down from the Facility's Balancing Price-Quantity Pair N, with a Loss Factor Adjusted Price (Price N), taking into account the Available Capacity and actual SOI Quantity of the Balancing Facility and the applicable Ramp Rate Limit, where N is determined from either of the following Balancing Price-Quantity Pairs or, if different, the one with the lower price:~~

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

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

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

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

~~(c) If the Balancing Facility Downwards Out of Merit Generation exceeds CoffQ1 and a Balancing Price-Quantity Pair exists for the Facility and Trading Interval with a Loss Factor Adjusted Price lower than Price N, then:~~

~~i. additional Constrained Off Quantity2 (CoffQ2) equals the lesser of:~~

~~1. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched down from the Facility's Balancing Price-Quantity Pair N+1 with a Loss Factor Adjusted Price (Price N+1) lower than but closest to the Price N, taking into account when the Balancing Facility's MW level reached the bottom, or the top, as applicable, of the quantity associated with the Balancing Price-Quantity Pair N in the calculation in clause 6.17.4(a)(i) and the applicable Ramp Rate Limit; and~~

~~2. the Downwards Out of Merit Generation for the Balancing Facility less CoffQ1; and~~

~~ii. Constrained Off Compensation Price2 (CoffP2) equals the Balancing Price less the Loss Factor Adjusted Price N+1 identified in clause 6.17.4(c)(i);~~

~~(d) The IMO must repeat the process set out in clause 6.17.4(c) to identify, from the next lowest priced Price N+1, any CoffQN+1 and CoffPN+1 until all Downwards Out of Merit Generation has been attributed to Balancing Price-Quantity Pairs or, otherwise, until there are no remaining Balancing Price-Quantity Pairs;~~

~~(e) The Non-Qualifying Constrained Off Generation for the Balancing Facility equals the sum, divided by two so that it is expressed as sent out MWh, of any Downwards LFAS Enablement and, if the Facility is a Stand Alone Facility, any Downwards Backup LFAS Enablement, which the Balancing Facility was instructed to provide by System Management;~~

~~(f) If:~~

~~i. the Non-Qualifying Constrained Off Generation exceeds CoffQ1, set CoffQ1 to zero; or~~

~~ii. otherwise reduce CoffQ1 by the amount of Non-Qualifying Constrained Off Generation;~~

~~(g) The IMO must repeat the process set out in clause 6.17.4(f) for each CoffQN in ascending order until all Non-Qualifying Constrained Off Generation has been deducted from CoffQN or, otherwise, until there are no remaining CoffQN; and~~

~~(h) For settlement purposes under Chapter 9, the IMO must Loss Factor adjust each CoffQN calculated in clauses 6.17.4(a) to clauses 6.17.4(f).~~

~~6.17.4A. Subject to clause 6.17.5B, for any Balancing Facility that is a Non-Scheduled Generator, in a Trading Interval:~~

(a) ~~CoffQ1 equals the Downwards Out of Merit Generation, in MWh, for that Trading Interval, which for settlement purposes under Chapter 9 the IMO must Loss Factor adjust; and~~

(b) ~~CoffP1 equals the Balancing Price for that Trading Interval less the Loss Factor Adjusted Price in the Balancing Price-Quantity Pair associated with the Balancing Facility for that Trading Interval.~~

6.17.5. [Blank]~~Subject to clause 6.17.5C, the IMO must attribute any Upwards Out of Merit Generation from the Verve Energy Balancing Portfolio in a Trading Interval as follows:~~

(a) ~~Portfolio Constrained On Quantity1 (PConQ1) equals the lesser of:~~

i. ~~the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched from the Balancing Price-Quantity Pair N in the Balancing Portfolio Supply Curve with a price (Price N) higher than but closest to the Balancing Price, taking into account the actual Verve Energy Balancing Portfolio SOI Quantity and the Portfolio Ramp Rate Limit; and~~

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

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

(c) ~~If the Portfolio Upwards Out of Merit Generation exceeds PConQ1 and a Balancing Price-Quantity Pair exists in the Balancing Portfolio Supply Curve with a price higher than Price N, then:~~

i. ~~additional Portfolio Constrained On Quantity2 (PConQ2) equals the lesser of:~~

1. ~~the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched from the Balancing Portfolio Supply Curve Balancing Price-Quantity Pair N+1 with a price (Price N+1) higher than but closest to the Price N, taking into account when the Verve Energy Balancing Portfolio MW level reached the top, or the bottom, as applicable, of Balancing Price-Quantity Pair N in the calculation in clause 6.17.5(a)(i) and the Portfolio Ramp Rate Limit; and~~

2. ~~the Portfolio Upwards Out of Merit Generation less PConQ1; and~~

ii. ~~Constrained On Compensation Price2 (PConP2) equals the Price N+1 identified in clause 6.17.5(c)(i) less the Balancing Price;~~

(d) ~~The IMO must repeat the process set out in clause 6.17.5(c) to identify, from the next highest priced Balancing Price-Quantity Pair N+1, any PConQN+1 and PConPN+1 until all Upwards Out of Merit Generation has~~

~~been attributed to Balancing Price-Quantity Pairs or, otherwise, until there are no remaining Balancing Price-Quantity Pairs in the Balancing Portfolio Supply Curve;~~

~~(e) The Non-Qualifying Constrained On Generation for the Verve Energy Balancing Portfolio equals the sum, expressed in sent out MWh, of any increase in energy due to a Network Control Service Contract and of the following Ancillary Services (if any), which System Management instructed Verve Energy to provide from Facilities within the Verve Energy Balancing Portfolio:~~

~~i. Upwards LFAS Enablement;~~

~~ii. Upwards LFAS Backup Enablement; and~~

~~iii. the Spinning Reserve Response Quantity;~~

~~(f) If:~~

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

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

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

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

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

~~(a) Constrained Off Portfolio Quantity1 (PCoffQ1) equals the lesser of:~~

~~i. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched down from Balancing Price-Quantity Pair N, with Price N, in the Balancing Portfolio Supply Curve, taking into account the Available Capacity of the Verve Energy Balancing Portfolio, the MW level at the start of the Trading Interval and the Portfolio Ramp Rate Limit, where N is determined from either of the following Balancing Price-Quantity Pairs or, if different, the one with the lower price:~~

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

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

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

~~(b) Portfolio Constrained Off Compensation Price1 (PCoffP1) equals the Balancing Price less the Price N identified in clause 6.17.5A(a);~~

~~(c) If the Portfolio Downwards Out of Merit Generation (in MWh) exceeds PCoffQ1 and a Balancing Price-Quantity Pair exists in the Balancing Portfolio Supply Curve with a price lower than Price N, then:~~

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

~~1. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched down from the Balancing Portfolio Supply Curve Balancing Price-Quantity Pair N+1 with a price (Price N+1) lower than but closest to Price N, taking into account when the Verve Energy Balancing Portfolio MW level reached the bottom, or top, as applicable, of Balancing Price-Quantity Pair N in the calculation in clause 6.17.5A(a)(i) and the Portfolio Ramp Rate Limit; and~~

~~2. the Portfolio Downwards Out of Merit Generation less PCoffQ1; and~~

~~ii. Portfolio Constrained Off Compensation Price2 (PCoffP2) equals the Balancing Price less the Price N+1 identified in clause 6.17.5A(c)(i);~~

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

~~(e) The Non-Qualifying Constrained Off Generation for the Verve Energy Balancing Portfolio equals the sum, expressed in sent out MWh, of any reduction in sent out energy due to a Network Control Service Contract and of the following Ancillary Services (if any), which System Management instructed Verve Energy to provide from Facilities in the Verve Energy Balancing Portfolio:~~

~~i. Downwards LFAS Enablement;~~

~~ii. Downwards LFAS Backup Enablement; and~~

~~iii. the Load Rejection Reserve Response Quantity ;~~

~~(f) If:~~

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

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

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

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

6.17.5B. [Blank]~~Clauses 6.17.3, 6.17.3A, 6.17.4 and 6.17.4A do not apply to Facilities in the Verve Energy Balancing Portfolio.~~

6.17.5C. Where the IMO is unable to attribute:

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

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

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

…

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

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

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

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

…

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

…

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

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

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

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

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

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

…

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

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

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

i. a sent out basis at 15 degrees Celsius; and

ii. a sent out basis at 41 degrees Celsius.

…

Glossary

Forced Outage: Has the meaning given in clause 3.21.1B.

…

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

…

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

…

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

…

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

…

Appendix 10: Planned and Forced Outage Rate Determination

The IMO must calculate the Planned and Forced Outage rates for a Facility as follows.

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

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

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

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

Where:

- CO is the set of Trading Intervals in the last 36 months for which the Facility has been in Commercial Operation;
- $PO(t)$ is the quantity of Planned Outage in MW for the Facility in Trading Interval t as calculated in accordance with clause 3.21.6(c) and:
    - provided in accordance with clause 7.13.1A(b)(ii) if the Facility holds Capacity Credits and had its Certified Reserve Capacity assigned using the methodology described in clause 4.11.1(a), or
    - provided in accordance with clause 7.13.1A(b)(i) otherwise;

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

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

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

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

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

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

…

Appendix 11: Constrained On and Off Compensation Determination

This appendix provides the calculations necessary to determine the:

(a) Maximum Theoretical Energy Schedule;

(b) Minimum Theoretical Energy Schedule;

(c) Upwards Out of Merit Generation;

(d) Downwards Out of Merit Generation;

(e) Constrained On Quantity;

(f) Constrained On Compensation Price;

(g) Constrained Off Quantity; and

(h) Constrained Off Compensation Price.

Theoretical Energy Schedules

This section describes the method for determining a facility's Maximum Theoretical Energy Schedule and Minimum Theoretical Energy Schedule in a Trading Interval.

The Maximum Theoretical Energy Schedule in a Trading Interval equals:

(a) For a Balancing Facility which is a Scheduled Generator and the Verve Energy Balancing Portfolio:

$$Max\ TES = (Max\ EOI \times 0.5) - \frac{\big((Max\ EOI - SOI\ Quantity) \times Ramp\ Duration\big)}{2}$$

Where:

$$Max\ EOI = max\Big(SOI\ Quantity - (Ramp\ Rate \times 30),\ min(SOI\ Quantity + (Ramp\ Rate \times 30), Max\ Gen\Big)$$

$Max\ Gen = \sum BMO\ Quantities\ in\ MW$, for each tranche submitted where $BMO\ Price \leq Balancing\ Price;$

$$Ramp\ Duration = min\left(0.5, \left(\frac{|Max\ EOI - SOI\ Quantity|}{Ramp\ Rate/60}\right)\right)$$

$Ramp\ Duration$ refers to the duration which a facility is expected to ramp, expressed as a proportion of an hour; and

$Ramp\ Rate$ – Facility or Portfolio Ramp Rate Limit expressed in MW per minute.

(b) For a Balancing Facility that is a Non-Scheduled Generator:

i. If $BMO\ Price \leq Balancing\ Price$, then:

$$Max\ TES = Sent\ Out\ Metered\ Schedule$$

ii. If $BMO\ Price > Balancing\ Price$, then:

$$Max\ TES = (Max\ EOI \times 0.5) - \frac{((Max\ EOI - SOI\ Quantity) \times Ramp\ Duration)}{2}$$

Where:

$Sent\ Out\ Metered\ Schedule$ (SOMS) – Sent out quantities provided by System Management in accordance with clause 6.15.3(a)i;

$$Max\ EOI = max\big(0, SOI\ Quantity - (Ramp\ Rate \times 30)\big)$$

$$Ramp\ Duration = min\left(0.5, \left(\frac{|Max\ EOI - SOI\ Quantity|}{Ramp\ Rate/60}\right)\right)$$

$Ramp\ Duration$ refers to the duration which a facility is expected to ramp, expressed as a proportion of an hour; and

$Ramp\ Rate$ – Facility Ramp Rate Limit expressed in MW per minute.

The Minimum Theoretical Energy Schedule in a Trading Interval equals:

(a) For a Scheduled Generator and the Verve Energy Balancing Portfolio:

$$Min\ TES = min\left(Max\ Sent\ Out\ Energy, (Max\ EOI \times 0.5) - \frac{((Max\ EOI - SOI\ Quantity) \times Ramp\ Duration)}{2}\right)$$

Where:

$$Max\ Sent\ Out\ Energy = max(0, Sent\ Out\ Capacity - Outage\ MW) \times 0.5$$

$Outage\ MW$ = Quantity of Outages in MW for the Facility or the Verve Energy Balancing Portfolio, as received from System Management in accordance with clause 7.13.1A(b)(i);

$$Max\ EOI = max\left(SOI\ Quantity - (Ramp\ Rate \times 30), min(SOI\ Quantity + (Ramp\ Rate \times 30), Max\ Gen\ Below\right)$$

$Max\ Gen\ Below = \sum BMO\ Quantities$, for each tranche submitted where BMO $Price < Balancing\ Price$;

$$Ramp\ Duration = min\left(0.5, \left(\frac{|Max\ EOI - SOI\ Quantity|}{Ramp\ Rate/60}\right)\right)$$

$Ramp\ Duration$ refers to the duration which a facility is expected to ramp, expressed as a proportion of an hour; and

$Ramp\ Rate$ – Facility or Portfolio Ramp Rate Limit expressed in MW per minute.

(b) for a Non-Scheduled Generator

i. If the Non-Scheduled Generator has received a Dispatch Instruction to decrease its output and the Balancing Merit Order Price is less than the Balancing Price, then:

$Min\ TES = Sent\ Out\ Energy\ Estimate\ from\ System\ Management$; or

ii. $Min\ TES = Sent\ Out\ Metered\ Schedule$

Where:

$Sent\ Out\ Energy\ Estimate\ from\ System\ Management$ - Estimate of sent out energy which would have been provided in Trading Interval had the Dispatch Instruction not been issued in accordance with clause 7.13.1(eF)

$Sent\ Out\ Metered\ Schedule$ (SOMS) - Sent out quantities provided by System Management in accordance with clause 6.15.3(a)i.

Out of Merit Generation

This section describes the method for determining a facility's Out of Merit Generation in a Trading Interval.

The following definitions apply to the Out of Merit Generation calculations:

- $DI\ Quantity$ – The theoretical Dispatch Instruction Quantity which would have been provided in Trading Interval had the Facility complied with the Dispatch Instruction, with the exception of any Rectification Dispatch Instruction.
- $Max\ TES$ – Maximum Theoretical Energy Schedule.
- $NCS\ Increase$ – Any increase in sent out energy due to a Network Control Service Contract with System Management in MWh.
- $NCS\ Decrease$ – Any decrease in sent out energy due to a Network Control Service Contract with System Management in MWh.

The Upwards Out of Merit Generation in a Trading Interval equals:

(a) For a Balancing Facility other than the Verve Energy Balancing Portfolio:

$$UOMG = min\ (Sent\ Out\ Metered\ Schedule, DI\ Quantity) - Max\ TES,$$

except when:

i. the IMO has received a report under clause 7.10.7 and has determined that the relevant Market Participant has not adequately complied with a Dispatch Instruction; or

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

iii.

$$(Sent\ Out\ Metered\ Schedule - Max\ TES) < \left(\frac{Upwards\ LFAS\ Enablement + Backup\ Upwards\ LFAS\ Enablement}{2}\right) + Settlement\ Tolerance$$

; or

iv $Max\ TES > Sent\ Out\ Metered\ Schedule,$

where the Upwards Out of Merit Generation equals zero.

(b) For the Verve Balancing Energy Portfolio:

$PUOMG = Sent\ Out\ Metered\ Schedule - Max\ TES$, except when:

i System Management has provided a report to the IMO under clause 7.10.7 and the IMO determines that Verve Energy has not adequately or appropriately complied with a Dispatch Order in respect of the Verve Energy Balancing Portfolio; or

ii

$$(Sent\ Out\ Metered\ Schedule - Max\ TES) <$$

$NCS\ Increase + \left(\frac{Upwards\ LFAS\ Enablement + BackupUpwards\ LFAS\ Enablement}{2}\right) +$
$Spinning\ Reserve\ Response\ Quantity + Portfolio\ Settlement\ Tolerance$

where the Upwards Out of Merit Generation equals zero.

The Downwards Out of Merit Generation in a Trading Interval equals:

(a) For a Balancing Facility other than the Verve Energy Balancing Portfolio:

$DOMG = Min\ TES - max\ \ (Sent\ Out\ Metered\ Schedule, DI\ Quantity)$, except when:

i. the IMO has received a report under clause 7.10.7 and has determined that the relevant Market Participant has not adequately complied with a Dispatch Instruction; or

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

iii.

$$Min\ TES - Sent\ Out\ Metered\ Schedule\ < \left(\frac{Downward\ LFAS\ Enablement + Backup\ Downwards\ LFAS\ Enablement}{2}\right) + Settlement\ Tolerance$$; or

iv. The Balancing Facility is a Non-Scheduled generator and System Management and System Management has not provided the IMO with a MWh quantity for the Facility for the Trading Interval under clause 7.13.1(eF); or

v. $Sent\ Out\ Metered\ Schedule\ >\ Min\ TES$,

where the Downwards Out of Merit Generation equals zero.

(b) For the Verve Energy Balancing Portfolio:

$PDOMG\ =\ Min\ TES - Sent\ Out\ Metered\ Schedule$, except when

i System Management has provided a report to the IMO under clause 7.10.7 and the IMO determines that Verve Energy has not adequately or appropriately complied with a Dispatch Order in respect of the Verve Energy Balancing Portfolio; or ii

$$\text{Min TES} - \text{Sent Out Metered Schedule} < \text{NCS Decrease} + \left(\frac{\text{Downwards LFAS Enablement} + \text{Backup Downwards LFAS Enablement}}{2}\right) + \text{Load Rejection Reserve Quantity} + \text{Portfolio Settlement Tolerance}$$

where the Upwards Out of Merit Generation equals zero.

Constrained On Facility Balancing Quantities and Prices

This section describes the method for determining a facility's Constrained On Prices $ConP(n)$ and Quantities $ConQ(n)$ in a Trading Interval.

The following definitions apply to the Constrained On Prices and Quantities calculations:

- Price(n) – The Price associated with the Price Quantity Pair n.
- $NCS\ Increase$ – Any increase in sent out energy due to a Network Control Service Contract with System Management in MWh.

For Scheduled Generators excluding facilities within the Verve Energy Balancing Portfolio:

Step 1: Determine the amount of Non-Qualifying Constrained On Generation ($NQCon$) in MWh as:

$$NQCon = \frac{\text{Upwards LFAS Enablement} + \text{Upwards LFAS Backup Enablement}}{2}.$$

Step 2: For each Trading Interval, sort all Price Quantity Pairs for a Facility with a Loss Factor Adjusted Price higher than the Balancing Price in ascending order. The Price Quantity Pair with the lowest price will be referenced as Price Quantity Pair 1, and the next lowest price Price Quantity Pair 2 and so on, with the Price Quantity Pair with the highest price being Price Quantity Pair N.

Step 3: For each n from 1 to N, determine the maximum cumulative quantity up to Price Quantity Pair n, $CumQ(n)$, as the maximum cumulative MWh quantity that could have been dispatched within Price Quantity Pairs 1 to n, taking into account the actual SOI Quantity and the Ramp Rate Limit.

Step 4: For each n from 1 to N, determine the Constrained On Quantity for Price Quantity Pair n, $ConQ(n)$, as the quantity of the energy between $NQCon$ and $UOMG$ that would have been dispatched from Price Quantity Pair n if a total of $CumQ(n-1)$ was dispatched from Price Quantity Pairs 1 to $n-1$ and a total $CumQ(n)$ from Price Quantity Pairs 1 to n, which is given by:

$$ConQ(n) = \max\left(0, \min[UOMG, CumQ(n)] - \max[NQCon, CumQ(n-1)]\right),$$

where $CumQ(0)$ is defined to be zero.

Step 5: Loss factor adjust each $ConQ(n)$ value for Settlements purposes.

Step 6: Determine the Constrained Price for each Price Quantity Pair n as:

$$ConP(n) = Loss\ Factor\ Adjusted\ Price(n) – Balancing\ Price.$$

For Non-Scheduled Generators excluding facilities within the Verve Energy Balancing Portfolio:

Step 1: Constrained On Quantity

$$ConQ(n) = Upwards\ Out\ of\ Merit\ Generation\ in\ MWh$$

Step 2: Loss factor adjust each $ConQ(n)$ value for Settlements purposes.

Step 3: The Constrained On Price for each Price Quantity Pair N as:

$$ConP(n) = Loss\ Factor\ Adjusted\ Price(n) – Balancing\ Price.$$

For the Verve Energy Balancing Portfolio:

Step 1: Determine the amount of Non-Qualifying Constrained On Generation ($NQCon$) in MWh as:

$$NQCon = \frac{Upwards\ LFAS\ Enablement\ +\ Upwards\ LFAS\ Backup\ Enablement}{2} + NCS\ Increase + Spinning\ Reserve\ Response\ Quantity.$$

Step 2: For each Trading Interval, sort all Price Quantity Pairs for the Verve Energy Balancing Portfolio, with a Loss Factor Adjusted Price higher than the Balancing Price in ascending order. The Price Quantity Pair with the lowest price will be referenced as Price Quantity Pair 1, and the next lowest price Price Quantity Pair 2 and so on, with the Price Quantity Pair with the highest price being Price Quantity Pair N.

Step 3: For each n from 1 to N, determine the maximum cumulative quantity up to Price Quantity Pair n, $CumQ(n)$, as the maximum cumulative MWh quantity that could have been dispatched within Price Quantity Pairs 1 to n, taking into account the actual SOI Quantity and the Ramp Rate Limit.

Step 4: For each n from 1 to N, determine the Constrained On Quantity for Price Quantity Pair n, $PConQ(n)$, as the quantity of the energy between $NQCon$ and $PUOMG$ that would have been dispatched from Price Quantity Pair n if a total of $CumQ(n-1)$ was dispatched from Price Quantity Pairs 1 to $n-1$ and a total $CumQ(n)$ from Price Quantity Pairs 1 to n, which is given by:

$$PConQ(n) = max\left(0, min[PUOMG, CumQ(n)] - max[NQCon, CumQ(n-1)]\right),$$

where $CumQ(0)$ is defined to be zero.

Step 5: Loss factor adjust each $PConQ(n)$ value for Settlements purposes.

Step 6: Determine the Constrained Price for each Price Quantity Pair n as:

$$PConP(n) = Price\ Quantity\ Pair\ Price(n) - Balancing\ Price.$$

Constrained Off Facility Balancing Quantities and Prices

This section describes the method for determining a facility's Constrained Off Prices ($CoffP(n)$) and Quantities ($CoffQ(n)$) in a Trading Interval.

The following definitions apply to the Constrained Off Prices and Quantities calculations:

- Price(n) – The Price associated with the Price Quantity Pair n.
- $NCS\ Decrease$ – Any decrease in sent out energy due to a Network Control Service Contract with System Management.

For Scheduled Generators excluding facilities within the Verve Energy Balancing Portfolio:

Step 1: Determine the amount of Non-Qualifying Constrained Off Generation ($NQCoff$) in MWh as:

$$NQCoff = \frac{Downwards\ LFAS\ Enablement + Downwards\ LFAS\ Backup\ Enablement}{2}.$$

Step 2: For each Trading Interval, sort all Price Quantity Pairs for a Facility with a Loss Factor Adjusted Price lower than the Balancing Price in descending order. The Price Quantity Pair with the highest price will be referenced as Price Quantity Pair 1, and the next highest price Price Quantity Pair 2 and so on, with the Price Quantity Pair with the lowest price being Price Quantity Pair N.

Step 3: If the sum up the quantities of the Price Quantity Pairs from 1 to N is greater than the Available Capacity of the Facility, then the intersection of the sorted Price Quantity Pairs defined in Step 1 and the Available Capacity will be referenced as Price Quantity Pair 1, and the next highest price Price Quantity Pair 2 and so on, with the Price Quantity Pair with the lowest price being Price Quantity Pair N.

Step 4: For each n from 1 to N, determine the maximum cumulative quantity up to Price Quantity Pair n, $CumQ(n)$, as the maximum cumulative MWh quantity that could have been dispatched within Price Quantity Pairs 1 to n, taking into account the actual SOI Quantity and the Ramp Rate Limit.

Step 5: For each n from 1 to N, determine the Constrained Off Quantity for Price Quantity Pair n, $CoffQ(n)$, as the quantity of the energy between $NQCoff$ and $DOMG$ that would have been dispatched from Price Quantity Pair n if a total of $CumQ(n-1)$ was dispatched from Price Quantity Pairs 1 to $n-1$ and a total $CumQ(n)$ from Price Quantity Pairs 1 to n, which is given by:

$$CoffQ(n) = max\left(0, min[DOMG, CumQ(n)] - max[NQCoff, CumQ(n-1)]\right),$$

where $CumQ(0)$ is defined to be zero.

Step 6: Loss factor adjust each $CoffQ(n)$ value for Settlements purposes.

Step 7: Determine the Constrained Price for each Price Quantity Pair n as:

$$CoffP(n) = Balancing\ Price - Loss\ Factor\ Adjusted\ Price(n).$$

For Non-Scheduled Generators excluding facilities within the Verve Energy Balancing Portfolio:

Step 1: Constrained Off Quantity

$$CoffQ(n) = Downwards\ Out\ Of\ Merit\ Generation\ in\ MWh$$

Step 2: Loss factor adjust each $CoffQ(n)$ value for Settlements purposes.

Step 3: The Constrained Off Price for each Price Quantity Pair N as:

$$CoffP(n) = Balancing\ Price - Loss\ Factor\ Adjusted\ Price(n).$$

For the Verve Energy Balancing Portfolio:

Step 1: Determine the amount of Non-Qualifying Constrained Off Generation ($NQCoff$) in MWh as:

$$NQCoff = \frac{Downwards\ LFAS\ Enablement + Downwards\ LFAS\ Backup\ Enablement}{2} + NCS\ Decrease + Load\ Rejection\ Reserve\ Response\ Quantity.$$

Step 2: For each Trading Interval, sort all Price Quantity Pairs for the Verve Energy Balancing Portfolio with a Loss Factor Adjusted Price lower than the

Balancing Price in descending order. The Price Quantity Pair with the highest price will be referenced as Price Quantity Pair 1, and the next highest price Price Quantity Pair 2 and so on, with the Price Quantity Pair with the lowest price being Price Quantity Pair N.

Step 3: If the sum up the quantities of the Price Quantity Pairs from 1 to N is greater than the Available Capacity of the Verve Energy Balancing Portfolio, then the intersection of the sorted Price Quantity Pairs defined in Step 1 and the Available Capacity will be referenced as Price Quantity Pair 1, and the next highest price Price Quantity Pair 2 and so on, with the Price Quantity Pair with the lowest price being Price Quantity Pair N.

Step 4: For each n from 1 to N, determine the maximum cumulative quantity up to Price Quantity Pair n, $CumQ(n)$, as the maximum cumulative MWh quantity that could have been dispatched within Price Quantity Pairs 1 to n, taking into account the actual SOI Quantity and the Ramp Rate Limit.

Step 5: For each n from 1 to N, determine the Constrained Off Quantity for Price Quantity Pair n, $PCoffQ(n)$, as the quantity of the energy between $NQCoff$ and $PDOMG$ that would have been dispatched from Price Quantity Pair n if a total of $CumQ(n-1)$ was dispatched from Price Quantity Pairs 1 to $n-1$ and a total $CumQ(n)$ from Price Quantity Pairs 1 to n, which is given by:

$$PCoffQ(n) = max\left(0, min[PDOMG, CumQ(n)] - max[NQCoff, CumQ(n-1)]\right),$$

where $CumQ(0)$ is defined to be zero.

Step 6: Loss factor adjust each $PCoffQ(n)$ value for Settlements purposes.

Step 7: Determine the Constrained Price for each Price Quantity Pair n as:

$$PCoffP(n) = \ Balancing\ Price - Price\ Quantity\ Pair\ Price(n).$$

…

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

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

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

The IMO considers that the proposed changes will ensure that all limitations on a

Facility's capacity to generate will be more accurately reflected in a Facility's Minimum TES, thereby improving the accuracy of constrained off compensation and the assignment of Certified Reserve Capacity to Facilities. This will ensure that significant costs as a result of inaccurate compensation payments are not borne by the market.

In addition, the advanced notification of Consequential Outages will provide greater transparency to Market Participants and will thereby improve the accuracy of the Balancing Price Forecast.

The IMO considers that the proposed amendments also provide greater clarity and transparency with respect to existing obligations in the Market Rules. This will better equip Market Participants to comply with their obligations.

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

The proposed changes are expected to improve consistency between Scheduled and Non-Scheduled Generators, by providing alternative calculations for Non-Scheduled Generators, consistent with the obligations on Scheduled Generators. In addition, the IMO considers that the resulting clarity around Non-Scheduled Generators' obligations will improve the ability for the IMO to avoid discrimination between Facility Classes.

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

Currently, a significant proportion of the IMO's legal and compliance resources are spent investigating the merit of compensation payments and ensuring the recovery of incorrect payments. However, the proposed amendments will ensure that the majority of these incorrect payments are not made in the initial settlement process, thereby removing the need for many of these investigations, reducing the long-term compliance cost to the IMO.

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

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

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

- for the IMO, approximately $190,000 of costs associated with system and IT changes to allow the transfer of additional Outage information from System Management to the IMO, calculation of each Facility's Dispatch Schedule to determine TES and the testing of the integrity of amended equations for settlement purposes;
- for System Management, approximately $239,000 of costs associated with system changes to allow logging of Outages after the 15 day timeframes, the provision of Outage data by Facility, by Trading Interval on a sent out basis at 15 degrees Celsius and the addition of a rectification Dispatch Instruction flag to signal non-compliance. This includes around $55,000 for System Management to transfer the capability and functionality to retain and distribute Dispatch Instructions and produce compliance

analysis reports from the current system (SMITTS) to the new system (SMARTS); and

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

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

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

INDEPENDENT MARKET OPERATOR

Agenda Item 10a: Overview of Recent and Upcoming IMO and System Management Procedure Change Proposals

Legend:

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

ID	Summary of Changes	Status	Next Step	Date
IMO Procedure Change Proposals				
PC_2012_11 **Notices and Communications**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project. • Reflect the IMO's updated contact details.	• PC_2012_11: Notices and Communications was published on 18 June 2013.	• Submissions closed on 16 July 2013. The IMO is currently preparing the Procedure Change Report.	TBA
PC_2013_02: **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;	• PC_2013_02: Participant Registration and Deregistration was published on 2 July 2013.	• Submissions closed on 29 July 2013. The IMO is currently preparing the Procedure Change Report.	TBA

ID	Summary of Changes	Status	Next Step	Date
	• Ensure consistency with the Amending Rules from the Rule Change Proposal: Change of Review Board Name (RC_2010_18)			
PC_2013_03 **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)	• PC_2013_02: Facility Registration, Deregistration and Transfer was published on 2 July 2013.	• Submissions closed on 29 July 2013. The IMO is currently preparing the Procedure Change Report.	TBA
PC_2013_04 **Prudential Requirements**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Move more of the prescriptive detail from the Market Rules to the	• The IMO rejected this Rule Change Proposal on 19 November 2012. • Modified Rule	• Updated Market Procedure presented at 20 September IMOPWG.	TBA

<table>
<tr><th>ID</th><th>Summary of Changes</th><th>Status</th><th>Next Step</th><th>Date</th></tr>
<tr><td></td><td>Procedure to make the rules more principles-based;
• Include some minor and typographical amendments to improve the integrity of the Market Procedure; and
• Include amendments required as a result of the Pre Rule Change Proposals:
o Prudential Requirements (RC_2012_23);
o Acceptable Credit Criteria (RC_2010_36); and
o Removal of Network Control Services Expression of Interest and Tender Process (RC_2010_11).</td><td>Change Proposal and updated Market Procedure presented to the March 2013 MAC.
• Procedure Change Proposal submitted to April 2013 IMOPWG meeting, but discussion deferred.</td><td>Changes arising from submissions on RC_2012_23 will be incorporated together with IMOPWG feedback and re-circulated to IMOPWG members following publication of the Draft Rule Change Report.</td><td></td></tr>
<tr><td>PC_2013_05 Reserve Capacity Security</td><td>The proposed updates are to:
• Reflect the IMO's new format arising from its Market Procedures project;
• Revise the Market Procedure to provide more details of the relevant processes;
• Include some minor and typographical amendments to improve the integrity of the Market Procedure; and
• Include amendments required as a result of the Pre Rule Change Proposal: Prudential Requirements (PRC_2012_23).</td><td>• Underway</td><td>• Updated Market Procedure to be circulated together with PC_2013_04.</td><td>TBA</td></tr>
<tr><td>PC_2013_06
Certification of Reserve Capacity</td><td>The proposed updates are to:
• Reflect the revised consideration of outages in the assessment of applications for Certified Reserve Capacity, including;
o new outage rates scale in table form; and
o addition of IMO discretions and report requests;
• Reflect the IMO's new format;
• Explain the IMO discretion to assign a level of Reserve Capacity less than full;</td><td>• Underway</td><td>• Updated Market Procedure presented at 20 September IMOPWG. Updated Procedure to be re-circulated to IMOPWG members.</td><td>TBA</td></tr>
</table>

ID	Summary of Changes	Status	Next Step	Date
	• Refine the assessment of fuel and other restrictions by the IMO; • Outline the proposed changes to the Availability Classes; and • Reflect the treatment of Facilities that share a Declared Sent Out Capacity.			
PC_2013_07 **Settlement**	The proposed updates are to: • Reflect the necessary changes arising from RC_2013_08: Market Participant Fees - Clarification of GST Treatment; • Reflect the IMO's new format; • Provide greater clarity to potential and existing Rule Participants on the settlement process by improving the information provided around: o STEM and Non-STEM settlement processes and timelines; o Adjustment processes and timelines; o Process for settlement of the market in case of default situations; o Invoicing and the application of GST and interest to settlement transactions; and o Disagreement and dispute processes and timelines; • Improve the structure of the Procedure; and • Define new terms.	• Underway	• Updated Market Procedure presented at 20 September IMOPWG. Updated Procedure to be re-circulated to IMOPWG members	TBA
PC_2013_08 **IMS Interface Procedure**	The proposed updates are to: • Implement the proposed Amending Rules in RC_2012_11: Transparency of Outage Information, with details of the data elements including; o description; o transfer timing; and o references to the Market Rules.	• PC_2013_08: IMS Procedure was published on 30 August 2013.	• The IMO published the Procedure Change Report on 1 October 2013 and commenced the amended Market Procedure on 2 October 2013.	Commenced 2 October 2013

ID	Summary of Changes	Status	Next Step	Date
PC_2013_09 **Reserve Capacity Performance Monitoring**	The proposed updates are to: • Reflect the additional performance monitoring steps proposed in RC_2013_09; • Reflect the IMO's new format; • Remove steps made redundant by deleted clauses; and • Describe the new performance reports that may be requested by the IMO, including; o performance improvement reports; and o the format of reports.	• Underway	• Updated Market Procedure presented at 20 September IMOPWG. Updated Procedure to be re-circulated to IMOPWG members.	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
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

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

ID	Summary of Changes	Status	Next Step	Date
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 System Management's Procedure Change Report on 22 May 2013.	• The IMO published its decision to reject this Procedure Change on 1 August 2013.	01/08/2013
PPCL0025 **Commissioning and Testing**	The proposed updates are to: • Include amendments required as a result of RC_2012_12 and RC_2012_15; • Expand Appendix C to clarify Load Following and Spinning Reserve requirements around commissioning inline with the Ancillary Services Report; and • Include 'plus ramp range' in Load Following for Maximum Ramp Rate tests.	• PPCL0025: Commissioning and Testing was published on 28 June 2013. Submissions closed on 26 July 2013.	• System Management are currently preparing the Procedure Change Report.	TBA

ID	Summary of Changes	Status	Next Step	Date
PPCL0026 **Facility Outages**	The proposed updates are to: • Reflect the new outage transparency rules resulting from RC_2012_11.	• Draft amended PSOP was circulated to the System Management PSOP WG for comment. The IMO provided feedback on 31 July 2013.	• System Management are updating the Procedure to reflect feedback received prior to re-circulating to WG members.	TBA
PPCL0027 **Dispatch**	The proposed updates are to: • Reflect the updated commitment/de-commitment rules resulting from RC_2012_22.	• PPCL0027 was initially submitted to the IMO to be put into the formal process. The IMO provided feedback to System Management on 6 August 2013 and discussed at the PSOP WG on 14 August 2013. Subsequently the PSOP change was withdrawn to be updated based on IMO feedback and re-circulated to WG members.	• System Management are updating the Procedure to reflect feedback received prior to re-circulating to WG members.	TBA

Agenda Item 11a: Working Group Overview

Working Group (WG)	Status	Date commenced	Date concluded	Latest meeting date	Next scheduled meeting date
System Management Procedures WG	Active	Jul 07	Ongoing	14/08/2013	TBA
IMO Procedures WG	Active	Dec 07	Ongoing	20/09/2013	TBA