Rules Development Implementation Working Group (RDIWG)

Meeting No. 11: Agenda

Location: Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth

Date: Tuesday, 5 April 2011

Time: 9.30am – 2.00pm

1. Previous meeting's minutes
2. Balancing Market Proposal
   (a) Cost Benefit Analysis on the Balancing proposal
   (b) Modelling of the Balancing proposal
   (c) Recommendation paper on the Balancing and Load Following Ancillary Services proposal
3. Reserve Capacity Refunds
   (a) Recommendation paper on Reserve Capacity Refunds
   (b) Proposal from The Griffin Group
4. General Business
5. Outstanding Action items
6. Next meeting date and time: Tuesday, 3 May 2011 (9.30am – 2.00pm)

Independent Market Operator

Rules Development Implementation Working Group

Minutes

Meeting No.	10
Location:	IMO Board Room Level 3, Governor Stirling Building, 197 St Georges Terrace, Perth
Date:	Tuesday 15 March 2011
Time:	Commencing at 9.37am to 2.15pm

Attendees	
Allan Dawson	IMO (Chair)
Troy Forward	IMO
John Rhodes	Market Customer
Corey Dykstra	Market Customer
Steve Gould	Market Customer
Geoff Gaston	Market Customer
Andrew Everett	Market Generator
Shane Cremin	Market Generator
Andrew Sutherland	Market Generator
Phil Kelloway	System Management
Wana Yang	ERA
Jacinda Papps	Minutes
Jim Truesdale	Presenter
Greg Thorpe	Presenter
Kieran Murray	Presenter
Preston Davies	Presenter
Ashley Milkop	Presenter
Douglas Birnie	Observer
Ben Williams	Observer
Steve Black	Observer
Cameron Parrotte	Observer (from 10.20am to 1.47pm)
Chris Brown	Observer
Apologies	
Paul Hynch	Office of Energy (for lateness)
Cameron Parrotte	System Management (for lateness)

Item	Subject	Action
	WELCOME AND APOLOGIES / ATTENDANCE The Chair opened the 10th meeting of the Rules Development Implementation Working Group (RDIWG) at 9.37am. The Chair welcomed Wana Yang to the RDIWG, it was noted that Wana would be the ERA representative going forward. Apologies, for lateness, were noted from Mr Paul Hynch and Mr Cameron Parrotte. The Chair noted that the meeting included a big agenda and requested that members stay on topic, noting that, if required, he would restrain extra discussion in order to allow time for discussion of all the agenda items.	
1.	**PREVIOUS MEETING'S MINUTES** The minutes of RDIWG Meeting No. 9, held on 22 February 2011, were circulated prior to the meeting. There was concern from one member about the level of detail in the minutes produced for the last meeting. The Chair reminded the group that prior to the 30 September 2010 the IMO did not take minutes of the RDIWG meetings. At the request of the ERA it was agreed that the IMO would provide brief minutes for each meeting of the RDIWG. The minutes would only contain a summary of the issues discussed, agreements reached and action points raised during the meetings. With regards to the minutes of RDIWG Meeting No. 9, the following request for change was made: • Box 4: IPP Offers/Bids and Verve Energy PSC <u>There was some discussion about Verve Energy's rebidding arrangements and how Verve Energy would identify the LFAS PSC. It was noted that the design document indicated that Verve Energy would need to submit a separate LFAS PSC. It was agreed that the IMO would discuss the formation of the LFAS PSC with Andrew Everett.</u> Subject to the agreed amendment, the RDIWG endorsed the minutes as a true and accurate record of the meeting. *Action Point: The IMO to amend the minutes of Meeting No. 9 to reflect the points raised by the RDIWG and publish on the website as final.*	**IMO**
2.	**RESERVE CAPACITY REFUNDS** Mr Greg Thorpe presented the Review of Capacity Cost Refunds paper, noting it contained three areas for discussion: • Creation of a dynamically calculated refund regime and the level of refunds; • Replacement of the Net-STEM Shortfall refund requirement with a compliance regime incorporating an Operational Test; and	

Item	Subject	Action
	• Creation of the Market SRC Fund. The Chair noted the submissions received prior to the meeting had been taken into account in the updated version of the paper. System Management noted that it still intended to submit on the proposal. The RDIWG discussed each of the three areas of the paper specifically. <u>Creation of a dynamically calculated refund regime and the level of refunds</u> The following points were discussed/noted: • Some members represented that refunds, while incurred by capacity providers, are indirectly passed back to customers through bi-lateral contract pricing; • It was questioned whether DSM should be included when defining the reserve margin. The Chair noted that this is a new issue; • A dynamically calculated refund regime should lead to a more efficient outcome in the right circumstances; • It was questioned whether the model went far enough regarding allocative risks with respect of different plant types; • The proposal changes a participant's risk profile, some members represented that the refund factor should be lowered and other members represented that it should be increased; • The proposal provides a signal as to the value of capacity as well as incentives for Market Participants (with the sufficient data) to manage the level reserve in the market; • It was noted that participants need to help manage the reserve margin and that increased transparency of outages could assist in this. System Management noted that the PASA's provide the quantum and period of outages at present. System Management indicated that it was the IMO’s responsibility to publish this information and noted the Outage Planning review currently underway. It was agreed that a dynamically calculated refund should be established. There was not agreement about the reserve capacity refund multiplier and potential exposure given the differences in members’ views, but members acknowledged that the IMO would recommend no change to these aspects. <u>Replacement of the Net-STEM Shortfall refund requirement with a compliance regime incorporating an Operational Test</u> The following points were discussed/noted: • System Management noted a concern with the proposed level of surveillance and monitoring. System Management questioned whether the Net STEM Shortfall should be removed; • It was noted that Net STEM Shortfall calculation impacts base load/"must run" type plant versus peaking plant differently;	

Item	Subject	Action
	• It was noted that there will be a learning curve with the changes to the compliance regime for all involved; • The proposed compliance regime will be implemented so that it does not create unnecessary burden for the Market. However the proposed regime is likely to be administratively burdensome for those participants who regularly and significantly deviate from Resource Plans. • In response to a question, the IMO noted that compliance shouldn't be light-handed, but instead should be a pragmatic administration of regimes; • The IMO also noted that there needs to be trade-offs with removing the automatic penalty and providing adequate incentives for appropriate behaviour.; • System Management noted a concern with being able to meet ongoing Operational Test requirements and requested the triggers for undertaking an Operational Test; • It was noted that the implementation of this change is likely to include compliance/monitoring tools to "red flag" capacity provider's performance. It was reiterated that the proposed compliance regime should not create unnecessary burden for the Market. It was agreed that, subject to the establishment of an appropriate compliance/monitoring regime (incorporating an Operational Test), the Net STEM Shortfall refund requirement be removed. <u>Creation of the Market SRC Fund to receive first call on capacity refunds and be the first source of funding for SRC</u> The following points were discussed/noted: • A member noted that he needed to review the original SRC rule change prior to providing support, noting that there are some aspects of the SRC regime that currently do not work i.e. allocating the costs to the causer. *Action point: Mr Dykstra to review the SRC rule change within 1 week of this meeting and inform the IMO whether he supported the SRC fund proposal or not.* • The quantum of the proposed fund was discussed. It was questioned whether there could be an annual review to set the size of such a fund. It was noted that the fund would be substantive and refunds may flow into this for a number of years until the required level is met. • The allocation of refunds, once the fund is full, was discussed. A member suggested consideration of refunding the excess by market fees rather than the current methodology (to Market Customers based on consumption share). It was noted that there is no justification to change the methodology noting that SRC will remain an uncapped liability for Market Customers once the SRC Fund is exhausted. It was agreed that, subject to one member providing his support/or not, that a market SRC fund should be created to receive first call on refunds and be the first source of funding for SRC.	

Item	Subject	Action
	The Chair noted that, given the support for the proposal, the IMO would prepare a decision paper for the MAC and the IMO Board for endorsement and then progress through the Rule Change Process.	
3.	**BALANCING MARKET PROPOSAL** **<u>(a) Updated Balancing Design Details</u>** On the premise that all members had read the updated paper, the floor was opened for discussion: • It was questioned whether "Balancing" was the correct term to use, and whether the term adequately captures all the concepts in the proposal. It was agreed that the concepts need to be adequately described in the documentation but the use of the current terminology would remain; Members discussed the design principles underpinning the Balancing and LFAS proposals (page 41 of the meeting papers). The following points were noted/discussed: • The use of "all Market Participants" in principle 1 was discussed in detail. While it was agreed, in principle, that this should be broad and that it is a theoretical possibility that all Market Participants could participate, it was noted that the majority of benefits still sit with Market Generators. It was agreed that a footnote be included outlining this. • It was agreed that "balancing price" be amended to "energy price in principle 3. *Action point: IMO to update the design principles underpinning the Balancing and LFAS proposals, as agreed at the meeting.* **<u>(b) Scenarios/modelling - update</u>** Mr Jim Truesdale provided the RDIWG with an update of where the scenario/modelling is at, noting that both generic and specific models had been developed. The specific model includes Resource Plan, Capacity and Standing Data from three months ago. It was noted that the model is a snapshot and not a full market simulation model. It was agreed that: • The IMO demonstrate the model to Geoff Gaston and Shane Cremin; • the generic model be distributed for wider use; and • the IMO would write to participants to request whether the specific model could be distributed. *Action point: IMO to write to participants requesting whether the specific balancing model can be distributed.* **<u>(c) Cost Benefit Analysis</u>** Mr Kieran Murray of Sapere presented the Cost Benefit Analysis, a copy of this presentation is available with the meeting papers on the	

Item	Subject	Action
	website: www.imowa.com.au/RDIWG. The following points were noted/discussed: • The 10% compounding efficiency gain was discussed. It was noted that this was assumed to relate to System Management labour costs on the premise of the level of substitution between labour costs and system changes. It was noted that the discount does not apply to all resources, only new resources. Members were sceptical that resources would reduce over time in an organisational context. It was noted that retaining the staff may lead to other benefits. It was agreed that Sapere would discuss this in additional detail at its meeting with Synergy; • A member noted that there was not a lot of explanation in the report, and a reader needs to accept the numbers. It was noted that some of the information leading to the results is confidential. It was agreed that after Sapere had met with individual participants it would ascertain what additional information is needed in the final report; • It was noted that 40 - 50% of costs are allocated to Market Customers, but there seemed to be little focus on the benefits to Market Customers. It was agreed that Sapere would include a section on the benefits to Market Customers; • System Management noted that it thought that the costs from avoiding cycling would be higher, citing its own analysis which supported this theory. It was agreed that System Management would provide this analysis to Sapere; • A member noted that he thought the benefits would be higher. It was noted that the focus was on tangible benefits only and that the intangible benefits would increase the level of benefits (if they were taken into account); • A member suggested presenting the analysis in terms of a payback period (i.e. 3.5 years) rather than the benefit/cost ratio over 7 years. It was noted that there is a series of meetings/presentations already planned on the analysis. Sapere asked members to request additional meetings if required. **(d) System Management "simpler options" paper** Mr Cameron Parrotte presented the System Management "simpler options" paper, noting that it considered its proposal would get similar benefits for less cost and complexity. The Chair opened the floor for discussion, the following points were discussed/noted: • System Management's proposal 1 was similar to Pete Ryan's design, it was noted that considerable time/effort was spent reviewing this. It was noted that this proposal works well only for plant with flexible fuel access, but that was also the reason why it was discounted; • System Management's proposal 2 was similar to the proposal under development, with the main difference being the gate closures. It was noted that the development costs associated with	

Item	Subject	Action
	the IMO's proposal and System Management's proposal would not be too dissimilar. System Management noted that it considered the ongoing costs for its proposal would be less; • Sapere had briefly reviewed System Management's proposal from a cost benefit perspective and estimated that approximately two-thirds of the benefits would be lost; • It was noted that the System Management proposal did not go far enough, and that there is significant benefit with the flexibility arising from multiple gate closures; • It was questioned whether the System Management proposal was any better than the status quo (i.e. would be similar to STEM model); • It was questioned how participants would make decisions/participate without the market forecasts and increased flexibility of the Balancing proposal ; • System Management suggested consideration of multiple gate closures by facility type. It was noted that this was likely to be inconsistent with Market Objective (c); • It was noted that the System Management proposal removes a logistical barrier, but not a commercial barrier, i.e. it solves half of the problem only; and • System Management noted a concern with lots of to and fro-ing under the proposal, questioning how markets overcome this. It was noted that markets converge on results and that this had been proven in a number of other jurisdictions. It was discussed whether System Management would benefit from being exposed to another market, with a similar design to the IMO proposal. One member asked if the generator representatives around the RDIWG saw the System Management proposal as likely to enable them to compete meaningfully in balancing. These representatives indicated that this was not likely to be the case. In light of this, the Chair noted that there was sufficient concern that System Management's proposal did not go far enough and that there should be no further consideration of it. **<u>Summary</u>** The Chair noted that the aim for the next RDIWG meeting was to agree with a final design for a recommendation to go to MAC, therefore requested any outstanding issues from members. This is so that the IMO can take these into account when preparing the decision papers. The following outstanding issues were noted: • Verve Energy resubmissions; • Gate closure; • Ancillary Services and how it fits into the design; and • Implementation timing. With regards to implementation timing it was noted that the IMO was aiming to get a market trial in place by 1 December 2011 with full	

Item	Subject	Action
	implementation in 1 April 2011 (as agreed with System Management). The Chair requested whether the IMO could table a design at the next meeting for an in principle decision and endorsement to send to the MAC. The RDIWG affirmed.	
4.	**PROJECT TIMEFRAMES/MILESTONES - VERBAL UPDATE** The RDIWG did not discuss the project timeframes/milestones.	
5.	**RESPONSE TO SUBMISSIONS** The RDIWG did not discuss the response to submissions.	
6.	**GENERAL BUSINESS** A member requested clarification on the Capacity Cost Refunds discussion held earlier in the meeting. In response, the Chair noted that: The RDIWG agreed to: • a dynamically calculated refund being established, with the IMO indicating it would recommend no change to the quantum of the multiplier and potential exposure; • subject to the establishment of an appropriate compliance/monitoring regime (incorporating an Operational Test), the Net STEM Shortfall refund requirement be removed; and • subject to one member providing his support/or not following a review of the original SRC rule change, that a market SRC fund should be created to receive first call on refunds and be the first source of funding for SRC.	
7.	**OUTSTANDING ACTION POINTS** The RDIWG did not discuss the outstanding action points.	
8.	**NEXT MEETING** Meeting No. 11 will be held on Tuesday 5 April 2011 (9.30am-2.00pm).	
9.	**CLOSED:** The Chair thanked members and declared the meeting closed at 2.15pm.	

sapere
research group

MEMORANDUM

DATE:	30 March 2011
TO:	Douglas Birnie, Project Manager MEP
FIRM:	Independent Market Operator
FROM:	Kieran Murray
RE:	Update on Balancing Cost-Benefit Analysis

Key messages

- Comments from, and discussion with, members of the RWIG on the CBA added to our knowledge and understanding of the processes to be modelled and informed us on how we can better describe the results.
- We are re-crafting aspects of the paper to streamline the text and better explain our estimates and the nature of the costs and benefits.
- We have sought additional information (in relation to intermittent generation and costs of cycling) from some stakeholders to complete the paper.
- Revised modelling will result in slight adjustments (up and down) to some costs and benefits.
- The net effect of the additional work does not materially alter the basic conclusion - that the benefits of the balancing proposal outweigh the costs.
- The additional information sought from stakeholders will increase the net benefits somewhat.

Background and purpose

The RDIWG considered a draft of our cost-benefit analysis (CBA) paper at its meeting on 15 March. Following the meeting, we met with stakeholders who requested one-on-one meetings to further discuss the paper.

This note summarises the major questions raised in those meetings and subsequent written feedback, outlines the actions taken as a result, and provides an indication of the remaining work required to complete the paper.

Summary of feedback received

We received feedback in the following high-level categories:

- Drafting issues - more explanation and clarification sought in terms of what is included in the cost and benefit estimates, and some members felt that the qualitative benefits should be given more profile.
- Calculation issues -specific areas raised include:
    - Outages - distinguishing planned and forced outages and whether the claimed benefit was “too high’.
    - Avoided costs of cycling plant benefits appear to be substantially underestimated.
    - STEM price forecasts - estimated price levels appear too high; gas price assumptions need revising and the role that STEM price forecasts plays is not clear

sapere research group

  - The distribution of costs and benefits among stakeholders should be articulated, as well as disaggregating the impacts of the proposal into impacts that result from a "clean balancing price" versus those from the introduction of competition.
  - The effect of intermittent generation on the benefits calculations was questioned.
- Assumptions - questions were posed in relation to the:
  - Quantum of benefits assumed to arise from IPP STEM offers being available for balancing.
  - Discount rate and time period used in the study.
  - "Productivity" factor applied to System Management costs.

Responses to feedback

To respond effectively to some feedback we sought additional information from some stakeholders in relation to intermittent generation and the costs of cycling plant (information not yet received).

Work we were able to do on the paper without the additional information includes:

- Re-modelling costs and benefits based on altered assumptions in relation to:
  - The "productivity factor" for System Management costs.
  - The quantum of generation available to return following outages.
  - The effects on benefits estimates of intermittent generation on balancing requirements as well as removing some of the distortions in the formation of the balancing price.
  - Re-assessing the calculation process and eventual outcomes in relation to the STEM price forecast
  - Re-casting the high, medium and low benefits scenarios using a consistent estimation approach for each scenario and conducting sensitivity analysis around these.
- Providing additional text in relation to:
  - Describing the nature and quantum of costs and benefits (including instruction guides to the relevant cost and benefit estimation spreadsheets)
  - Updating information for factual accuracy following clarification from stakeholders
- In addition, we have also developed a list of potential further improvements such as case study material to better illustrate some of the benefits using actual date and events, as well as introducing additional sensitivities.

The additional work has not materially altered the basic results of the study - the benefit-cost ratio is still strongly positive. If we are able to get the further data from a few Market Participants we hope to have a final CBA paper for distribution at the RDIWG – if not it will be ready a few days thereafter.

Kind regards

Kieran Murray

imo Independent Market Operator

Agenda Item 2c: Balancing and Load Following Ancillary Services Recommendation Paper

1. Purpose

This paper sets out the key issues for consideration by the RDIWG in relation to the nature of the advice/recommendations the group will give to the Market Advisory Committee (MAC) regarding the Balancing and Load Following Ancillary Services proposal.

2. Background: Issues with the current Wholesale Electricity Market (WEM)

Since the WEM was established in 2006, the opportunity for Market Participants to be engaged in the balancing market has been limited. Verve Energy has had the role of default balancer, while the opportunity for Independent Power Producers (IPP) to provide balancing energy has been restricted to occasions such as times when there has been a shortfall between the Market's requirements and Verve Energy's supply capacity or when Verve ran out of non-liquid plant or when system security requirements cannot otherwise be maintained (as covered by Market Rule 7.6).

In feedback gained during consultation undertaken by the Independent Market Operator (IMO), privately owned Market Participants expressed a need to improve the current balancing mechanism to allow the opportunity to provide balancing, while the current default balancer and others expressed concerns regarding the existing balancing pricing method.

The Market Advisory Committee (MAC) was presented with a list of the issues of concern in relation to the WEM – and following a voting procedure – improving the balancing mechanism was identified as the top priority in August 2009.

MAC was then presented with advice on pathway options for progressing some of these issues (particularly around balancing) and agreed in August of last year that:

> "*Initial development work should assume the retention of the current hybrid market design, evolving the design as far as practicable, prior to considering exploration of further market design options". (MAC Meeting Minutes August 11, 2010.)*

The IMO Board accepted MAC's advice but considered that a detailed review of all the design changes (including those addressing competitive balancing) should be made available to the Board no later than June 2011 to ensure the priority issues identified were capable of being effectively and efficiently addressed under the hybrid model. Should the Board consider this not to be the case then it could ask for an assessment of more fundamental Market re-design options.

MAC then established the Rules Development and Implementation Working Group to investigate a list of 10 issues confronting the WEM including the issues surrounding balancing pricing and provision.

The RDIWG's Terms of Reference are attached in Appendix 1 and the relevant MAC decisions pertaining to balancing and load following ancillary services are attached in Appendix 2.

3. Work done to date

In meetings since August of last year the RDIWG has worked on a number of areas as identified in its work program. In relation to balancing and load following ancillary services, it has:

i. assessed the issues confronting the current calculation of MCAP balancing prices and agreed in principle that the new balancing price should only include balancing resources and that the DDAP and UDAP penalties should be removed (Meeting 3, September 30);

ii. assessed the merits of resolving the balancing pricing issues separately from the competition issues and acknowledged the IMO's recommendation that they not be pursued separately (Meeting 3, September 30);

iii. agreed to further explore the implications of the new balancing market proposal and to ascertain its operational and system impacts and its high level costs and benefits (Meeting 6, November 23);

iv. agreed not to pursue two simpler balancing market proposals presented by System Management given concerns particularly from generator representatives, that the proposals would not provide enough flexibility for IPPs to participate. This followed on from earlier consideration of a similar proposal by a Griffin Energy representative which was found to be similarly too inflexible to enable competition (Meeting 10, March 15);

v. noted that retention of the fundamental WEM design has been assumed to mean:

    a) Bilateral contracts between Generators and Market Customers as the basis for commercial and physical participation in the WEM.

    b) Opportunities for Market Participants to adjust their bilateral positions through the STEM.

    c) Energy supplied in the market determined by:
        a. IPPs operating their facilities in accordance with resource plans (subject to dispatch by SM – net dispatch); and
        b. Verve Energy as default provider of balancing and ancillary services on a portfolio basis.

    d) Continuance of the SM / Verve Energy relationship (portfolio based, gross dispatch) (Meeting 10, March 15)

vi. agreed that it should be made clear that the proposal incorporates opportunities for IPPs to participate in the trading of energy beyond the STEM - i.e. around Verve's net contract position and/or each other's positions - as well as with variations from this net contract position caused by differences in load or unplanned outages

vii. to the following further key principles for the design of the new balancing arrangements (Meeting 10, March 15):

	Principle	***Relevance***
1.	Providing opportunities for all Market Participants to participate in the energy market beyond the day-ahead STEM and in load following ancillary services where that makes economic sense.	Consistent with Market Objective (b) and RDIWG Terms of Reference (1)
2.	Enabling price-based dispatch of resources beyond the day ahead STEM through simple offers/ bids/ flexibility to manage resources efficiently.	Consistent with Market Objective (a)
3.	Ensuring that the price and payments for energy trading beyond the STEM to reflect the marginal cost of dispatch to the extent practical.	Consistent with Market Objective (a) and with RDIWG Terms of Reference (3)
4.	Ensuring that Market Participants receive payment in line with prices offered to the market when dispatched by System Management for balancing support or LFAS.	Consistent with Market Objective (a) and RDIWG Terms of Reference 3
5.	Providing timely and accurate forecasts of market prices and expected operation to assist/ inform decision-making.	Consistent with Market Objective (a) and RDIWG Terms of Reference 8
6.	Ensuring that System Management receives no less information and has no less authority to ensure security and reliability of power system operation.	Consistent with Market Objective (a) and generally accepted principles with operating electricity markets
7.	Reducing reliance on financial penalties to incentivise compliance with moving towards a more traditional surveillance /compliance based regime.	Consistent with Market Objective (b) where the financial penalties are likely to be imposing unnecessary costs and a compliance regime can target poor behaviour more directly
8.	Ensuring to the extent practical consistency with possible future market development options.	Consistent with Market Objective (d)

These decisions are attached in Appendix 2.

4. Outline of the proposal

Under the proposal developed for the RDIWG, IPPs would continue to submit resource plans and Verve Energy would continue in the role of default balancer. However, IPPs would be able to submit offers and bids into the market for dispatch upwards or downwards.

Verve Energy would bid for balancing work on a portfolio basis a day ahead. Other Market Participants would have the ability to submit offers/bids on a facility basis a day ahead and update them up to two hours ahead of the time of supply.

The offers and bids would form a supply curve that would determine which producer (Verve or IPP) would supply electricity and at what market price. The IMO would send this 'balancing merit order' to System Management to dispatch generation.

Verve Energy would have the opportunity to take individual facilities out of its portfolio and bid them in on a facility basis. Verve facility bids would be treated the same as IPP facility bids.

The "clean" pricing arrangements would replace the current MCAP methodology – and the UDAP/DDAP penalties would be removed and replaced with an enhanced compliance regime.

In process terms, the bilateral submissions and STEM process would operate as now and IPP's would continue to submit resource plans (albeit with some minor changes in content). System Management would prepare the initial Verve dispatch plan as now (taking account of resource plans, wind/ demand forecasts and Verve guidelines) although it would do this later in the trading day.

Late in the afternoon, Market Participants would make initial balancing price submissions for the following trading day. Verve would submit its portfolio supply curve along with any individual facility offers/bids for each half hour interval the following day trading day. . IPPs would submit their facility offers and bids based on their resource plans (or gross offers for a facility not in service) for the same time periods.

The IMO would combine all offers and bids to establish the balancing (dispatch) merit order for each trading interval.

IPPs would operate to resource plans unless dispatched off plan by System Management. System Management would schedule facilities within the Verve portfolio as now in accordance with the Verve guidelines (rescheduling if need be to remain within the guidelines, to account for IPPs in the balancing merit order and/ or for system security purposes).

System Management would use the balancing merit order to the extent practical for dispatch purposes (noting discretion for system security purposes) and would advise the IMO of any IPP quantities it has dispatched.

The IMO would establish the marginal price from the total generation that was required and the final balancing merit order that was used by System Management for the interval.

The IMO would identify, from the dispatch information supplied by System management, any out of merit dispatch and establish unauthorised deviations.

IPPs that were dispatched above their resource plans by System Management (authorised) would receive the marginal balancing price (or constrained on payment if necessary). IPPs that were dispatched below their resource plans by System Management (authorised) would pay the marginal balancing price (or constrained off payment if necessary). Verve would be paid/ pay the marginal balancing price for quantities above/ below its Net Contract Position. IPPs with unauthorised deviations would face the marginal balancing price (i.e. no UDAP/DDAP) for the deviations but be required to provide bona fide reasons for compliance purposes.

The full proposal set out in "12 process boxes" - as it reflects RDIWG feedback - is attached separately after this paper – with only one further amendment from the last RDIWG (correcting an incorrect paragraph).

A model of key aspects of the proposal has been trialled by a number of Market Participants.

5. Outstanding issues

A number of issues were outstanding from previous RDIWG meetings in relation to the new proposal. These are as follows along with the recommendations for dealing with them:

Issue	***Recommendation***
Gate closure times	A target outcome would be two hours for those Market Participants bidding by facility – although there may need to be a transition to allow development of dispatch tools and experience.
Verve Resubmission	Proposal is for Verve to be able to resubmit at 8am for the remainder of the trading day (6 hours ahead) and at 5pm for the next trading day.
Ancillary services – deferred until later	See the MAC decision. It is going to be much easier and less expensive to design the balancing and LFAS systems in tandem at the same time. The LFAS selection process itself could be relatively simple to begin with and then replaced by software over time.
Timelines and milestones	The IMO target date is 1 December 2011 for the rules and systems to be in place – for the purposes of a market trial. The target date for full implementation was revised to the 1st of April following discussions with System Management. The IMO will keep this date under review working with System Management and Market Participants.

6. Consistency with the Market Objectives

The RDIWG is required to report back on the consistency of the proposal with the Market Objectives. The following sets out the implications of the new arrangement from an initial IMO perspective:

Market Objective	***New proposal - implications***
To promote the economically efficient, safe and reliable production and supply of electricity and related services in the South West inter-connected system (SWIS);	The proposal would improve the efficiency of the operation of the WEM particularly with greater competition likely to drive down costs and provide clear investment incentives into the future.
To encourage competition among generators and retailers in the SWIS, including by facilitating efficient entry of new competitors;	The proposal opens up balancing and load following ancillary services to competition – particularly among generators
To avoid discrimination in the 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 proposal does not discriminate among different energy options or technologies.
To minimise the long-term cost of electricity supplied to customers from the SWIS;	The proposal will be more likely to achieve this than the status quo given the benefits of competition and the associated investment signals.
To encourage the taking of measures to manage the	The proposal will have no direct impact on this but will

amount of electricity used and when it is used	provide clear price signals from the WEM.

The above seems to indicate the proposal is consistent with the Market Objectives.

7. Impacts on the current WEM

The RDIWG is required to report on the proposal's impact on the current WEM and physical operations.

Overall the new balancing market proposal would:

- enable greater competition in balancing, including opportunities for economically efficient rebalancing (following the one shot STEM process);
- provide a cleaner market price for balancing;
- replace current UDAP and DDAP with a more comprehensive a compliance monitoring regime;
- ensure that those contributing to balancing or the need for balancing are exposed to the positive or negative impacts of their decisions, provide System Management more facilities for managing balancing and load following ancillary services;
- provide the opportunity for Verve to move to individual facility based offers/bids over time;
- extend the life of current market arrangements;
- involve additional costs for System Management, Market Participants and the IMO.

8. High level cost benefit assessment

An independent high level cost benefit assessment of the balancing proposal indicates a range of quantifiable operational benefits to costs of between 1.09 to 2.07 with additional benefits likely to be more significant but not able to be quantified.

The direct costs associated with the proposal were predominantly the system costs for System Management and Market Operator and on-going (typically labour) costs. The quantifiable benefits covered:

(i) The ability by IPP's to bid in lower cost balancing capacity;

(ii) The marginal increase in the bidding of capacity given greater confidence arising from having flexibility to resubmit in response to evolving market conditions;

(iii) The return of capacity from outages;

(iv) The fewer curtailments of base load generation.

Additional benefits were identified by way of better investment incentives for balancing-type capacity, learning over time, and through greater investment certainty.

The aggregated impact of feedback from Market Participants ended up affirming the net benefits outlined above – and indicated the likelihood that the analysis probably understated the net benefits.

9. Market Power

The current mechanisms for mitigating potential market power will continue for the operation of the new balancing and load following ancillary service markets i.e.:

Market Participants will continue to be required to price at short run marginal cost when exerting market power i.e. the Market Rule obligation will remain unchanged. The current Rule requires:

6.6.3. A Market Generator must not, for any Trading Interval, offer prices within its Portfolio Supply Curve that do not reflect the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity when such behaviour relates to market power.

The STEM maximum and minimum price caps will also apply in the balancing and load following ancillary service markets as they do already for IPP balancing data submissions.

Should the proposal proceed to the rule change process, the IMO Board has requested an independent assessment of the market power implications to be available to it when assessing the draft rule changes.

10. Time for a decision?

Answering this question comes down to an assessment of the net benefits of further work as opposed to making a decision now. With this in mind it is worth noting that the new proposal:

- appears technically feasible – with no significant issues yet identified that have not or cannot be resolved technically;
- provides net benefits according to the Cost Benefit Analysis;
- has no obvious outstanding "core concept" questions that remain to be answered;
- has some detail yet to be confirmed – but none that cannot be resolved during preparation of draft rules;
- appears to be the only option thus far identified that will enable IPPs to participate effectively in balancing but in a way that is still consistent with the current hybrid design;
- has been developed within the budget, noting the budget implications for any delays experienced in delivering the programme.

The IMO has prepared an indicative implementation timetable should a decision be taken to proceed. This involves progressing the rule change work simultaneously with the operational and systems' development work commencing as soon as a decision is made. The aim would be to have a market trial operating before the end of the year and the new balancing and load following ancillary service markets in operation by April next year. These dates are flexible, however, subject to the budget for the program – and the IMO would seek to confirm/amend these dates with a more detailed implementation plan if a decision to proceed is made.

11. Recommendations

It is recommended that the RDIWG

a) Note the RDIWG's Terms of Reference as set out in Appendix 1;

b) Note the previous MAC and RDIWG decisions set out in Appendix 2;

c) Note the balancing and load following ancillary services proposal as it now stands – in terms of key components or principles as set out in sections 3 , 4, and 5 of this paper – and the fuller description of the proposal as set out in Appendix 3;

d) Note the:

- (i) consistency of the new balancing and load following ancillary services with the Market Objectives;
- (ii) results of the high level cost benefit assessment of the balancing proposal indicating quantifiable net benefits ratios of between 1.09 and 2.07 and further benefits that were not able to be quantified;
- (iii) impact of the proposal on the WEM in terms of improved efficiencies;

e) Note that the proposal:

- (i) appears technically feasible – with no Participants identifying issues that have not or cannot be resolved technically;
- (ii) provides net benefits according to the Cost Benefit Analysis;
- (iii) has no obvious outstanding "core concept" question that remain to be answered;
- (iv) has some detail yet to be confirmed – but none that cannot be resolved during preparation of draft rules;
- (v) appears to be the only option thus far identified that will enable IPPs to participate effectively in balancing but in a way that is still consistent with the current hybrid design;
- (vi) has been developed within the budget, noting the budget implications for any delays experienced in delivering the programme.

f) Note that existing mechanisms for mitigating potential market power would continue to apply to the new proposal and the IMO Board has asked for an independent assessment of market power issues should the decision be made to proceed with the proposal;

g) Recommend to MAC the creation of new balancing and load following ancillary services markets in accordance with the principles and concepts set out in Sections 3,4 and 5 of this paper;

h) Recommend to MAC that the fuller Balancing and LFAS design proposal paper attached separately be used as the basis for initial rule changes and system and operational development in implementing the new balancing and load following ancillary service markets;

i) Note that the ability to make significant changes to the proposal beyond this decision point will be more limited given the system design and cost implications but it will be possible to amend detailed aspects of the proposal during this Rule consultation phase – as long as the changes do not revisit core aspects of the design;

j) Recommend to MAC that any amendments to the design as set out in Balancing and LFAS design proposal paper attached separately should be consistent with the principles and concepts set out on sections 3, 4 and 5 of this paper and assessed according to their cost and related system development implications before being agreed;

k) Note that the current target date for a market trial of the balancing market is 1 December 2011 and target date for a full roll out is in April 2011 but these dates can be confirmed closer to the time working with System Management and Market Participants subject to consideration of the budgetary implications.

APPENDIX 1: Terms of Reference for the Rules Development Implementation Working Group

1. BACKGROUND

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

2. SCOPE

The Working Group's Scope of Work includes consideration, assessment, development and post-implementation evaluation of changes to the Market Rules associated with the issues list agreed by the MAC at its 11 August 2010 meeting. This issues list is attached as appendix 1 to this document.

3. TERMS OF REFERENCE

The Working Group is to:

- Prioritise the issues agreed by the MAC into an appropriate number of development work streams;
- Agree a work plan and timeline for consideration of each of the work streams;
- Develop an integrated suite of solutions, including drafted Concept Papers and Rule Change Proposals to be presented to the MAC by way of presentation/s and supporting discussion paper/s; and
- Undertake a post-implementation evaluation of the solutions, to identify any remaining shortcomings and recommend an approach to address them.

The Rule Change Proposal(s) must include a full impact assessment prior to any recommendations being put forward to the MAC, including:

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

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

4. OBJECTIVES AND PRINCIPLES

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

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

5. MEMBERSHIP

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

6. TENURES

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

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

7. RESPONSIBILITY OF THE CHAIR

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

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

8. RESPONSIBILITY OF MEMBERS

Members have been selected for their particular expertise and accordingly:

- Members are to make themselves available for meetings;
- Members have a duty to prepare for meetings;
- If sending alternates, members have a duty to ensure their alternates are sufficiently briefed and prepared for meetings;
- Members, or their alternates, are to consider the interests of all stakeholders currently operating within the WEM;

- Members, or their alternates, do not represent their own organisations (although the range of commercial and technical experience inevitably adds diversity to the group's capabilities); and

- Any views expressed by members, or their alternates, are not to be taken as being those of their employer or nominating organisation.

9. KEY TASKS AND MILESTONES – THE WORK PLAN

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

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

10. NATURE OF DELIVERABLES

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

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

- Issue complexity and contentiousness;

- Parallel industry wide consultation; and

- Time frames.

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

11. REPORTING ARRANGEMENTS

Routine reporting will be via Working Group reports to the MAC. Consistent with section 9.4 of the MAC Constitution, the Working Group must report back to the MAC at each MAC meeting. The Chair will also personally report to the MAC at agreed key milestones.

12. ADMINISTRATION

The Working Group activities are to be as transparent as practical. The Chair must ensure that key decisions and action points from meetings are recorded.

Appendix 1:
Design Issues/Problems to be addressed

The design issues/problems to be addressed by the RDI WG are:

1. There is very limited opportunity for participants other than Verve to participate in providing balancing services and this inevitably means the cost of balancing is higher than it needs to be.
2. Provisions for Balancing Support Contracts have not been effective to date.
3. The calculation of MCAP and the role of UDAP and DDAP mean that balancing prices are not cost reflective and this leads to inefficient incentives for decisions about prices and participation and inequitable financial transfers between participants that compromise the integrity of the WEM.
4. At different times the capacity refund arrangements under and over price the value of capacity leading inefficient decisions by participants about the timing of maintenance and presentation of capacity.
5. The timing of operation and single pass design of STEM may be limiting the ability of the market to achieve efficient operation and cost reflective prices and accordingly creates a barrier for participation by all parties.
6. The requirement for resource plans to match STEM outcomes may be limiting participation in STEM and/or forcing inefficient dispatch of IPPs and Verve (as balancer) as IPPs attempt to comply with the resultant resource plans.
7. Poorly aligned gas and electricity mechanisms inhibits flexibility to respond to changing circumstances and produces suboptimal outcomes in the WEM.
8. Lack of transparency inhibits the ability of Market Participants to optimise interaction in the daily energy market.
9. Provision for net bilateral submissions compromises transparency and the accuracy of future price forecasts and may therefore lead to sub optimal decisions about participation by other market participants.
10. Pay as bid pricing for dispatch of IPP plant for balancing (outside a balancing support contract) is incompatible with efficient wider participation in balancing and potentially over compensates IPPs which bid at price caps due to uncertainty of dispatch outcomes.

An additional design issues/problem for noting (i.e. not part of the initial work of the RDIWG) is:

There is very limited opportunity for participants other than Verve to participate in providing Ancillary Services. This is due to the lack of certainty surrounding the pricing mechanism and the requirement to provide the service at a discount to Verve. System Management will look to develop a day-ahead procurement mechanism and present the outcomes of its analysis at the RDIWG.

APPENDIX 2: MAC and RDIWG decisions to date

MAC and the RDIWG have made the following decisions to date in relation to balancing and load following ancillary services:

MAC Decision	Comment
Market Evolution Plan	*"Improved Balancing Mechanism" –- identified as Number 1 Priority in a vote by MAC members – as reported in August 2009.*
Retaining the fundamental WEM design, evolving it as far as practicable, before considering more fundamental change.	*"In particular, the MAC agreed that:* *Initial development work should assume the retention of the current hybrid market design, evolving the design as far as practicable, prior to consider exploration of further market design options."* *MAC Minutes, August 11 2010.*
RDIWG Terms of Reference (10 points)	*Of relevance to balancing:* *(1) There is very limited opportunity for participants other than Verve to participate in providing balancing services and this inevitably means the cost of balancing is higher than it needs to be;* *(2) Provisions for Balancing Support Contracts have not been effective to date;* *(3) The calculation of MCAP and the role of UDAP and DDAP mean that balancing prices are not cost reflective and this leads to inefficient incentives for decisions about prices band participation and inequitable financial transfers between participants that compromise the integrity of the WEM; and* *(8) Lack of transparency inhibits the ability of Market Participants to optimise interaction in the daily energy market.* *MAC Minutes, August 11 2010*
Incorporating a competitive LFAS market to work in conjunction with the balancing market recognising interdependencies between balancing and LFAS capacity to the extent practical.	*"MAC members agreed that the proposals for competitive Balancing and LFAS provision should be developed together as a package."* *MAC Minutes, Dec 15 2010.*

RDIWG decision	Comment
Balancing pricing	*The RDIWG:* *"Agreed in principle that the balancing price curve should only include balancing resources (i.e. clean pricing); and* *Agreed in principle that DDAP/UDAP should be removed, or set to lower levels, better reflecting impacts on balancing requirements."* *RDIWG Minutes, 30 September 2010*
Clean balancing pricing and competition as a package	*"The RDIWG discussed whether the introduction of clear pricing should be conditional upon achieving competition in the provision of balancing services and whether the removal or reduction of DDAP/UDAP could be progressed earlier. The RDIWG acknowledged the IMO's recommendation that these changes should not be pursued in isolation."* *RDIWG Minutes, 30 September 2010*
Further exploration of the Balancing market proposal	*"The RDIWG agreed that the proposal had merit and asked that the proposal be workshopped with operational staff, to identify and address any technical issues affecting the viability of the option and to have its benefits and costs assessed – at a high/summary level."* *RDIWG Minutes, 23 November 2010.*
Simpler Options	*The RDIWG agreed not to pursue two simpler balancing market proposals presented by System Management given concerns particularly from generator representatives, that the proposals would not provide enough flexibility for IPPs to participate.* *RDIWG Draft Minutes, March 15 2011.*
Retention of the current decision	*The RDIWG noted that retention of the fundamental WEM design has been assumed to mean:* *a) Bilateral contracts between Generators and Market Customers as the basis for commercial and physical participation in the WEM.* *b) Opportunities for Market Participants to adjust their bilateral positions through the STEM.* *c) Energy supplied in the market determined by:* *a. IPPs operating their facilities in accordance with resource plans (subject to dispatch by SM – net dispatch); and* *b. Verve Energy as default provider of balancing and ancillary services on a portfolio basis.* *d) Continuance of the SM / Verve Energy relationship (portfolio based, gross dispatch)* *Principles paper discussed at RDIWG meeting, March 15, 2011.*
Principles for new arrangement	*1. Providing opportunities for all Market Participants to participate in balancing where that makes economic sense* *2. Enabling price-based dispatch of resources for balancing/rebalancing through simple offers/ bids/ flexibility to manage resources efficiently* *3. Ensuring that the balancing price and payments for balancing reflect the marginal cost of dispatch to the extent practical.* *4. Ensuring that Market Participants receive payment in line with prices offered to the market when dispatched by System Management for balancing support or LFAS.* *5. Providing timely and accurate forecasts of market prices and expected operation*

RDIWG decision	Comment
	to assist/ inform decision-making. 6. *Ensuring that System Management receives no less information and has no less authority to ensure security and reliability of power system operation* 7. *Reducing reliance on financial penalties to incentivise compliance with moving towards a more traditional surveillance /compliance based regime.* 8. *Ensuring to the extent practical consistency with possible future market development options.* *Agreement recorded in RDIWG Draft Minutes, March 15, 2011.*

New Balancing Market proposal – design details

1. INTRODUCTION

This document describes the key design features proposed for revised arrangements for short term operation of the Wholesale Electricity Market (WEM) in a manner that retains the core hybrid framework of the current design. This is where IPPs develop Resource Plans for their own facilities and System Management develops dispatch plans for the Verve Energy (Verve) portfolio. The design expands on the high level concept previously presented to the RDIWG at its 14 December 2010 meeting.

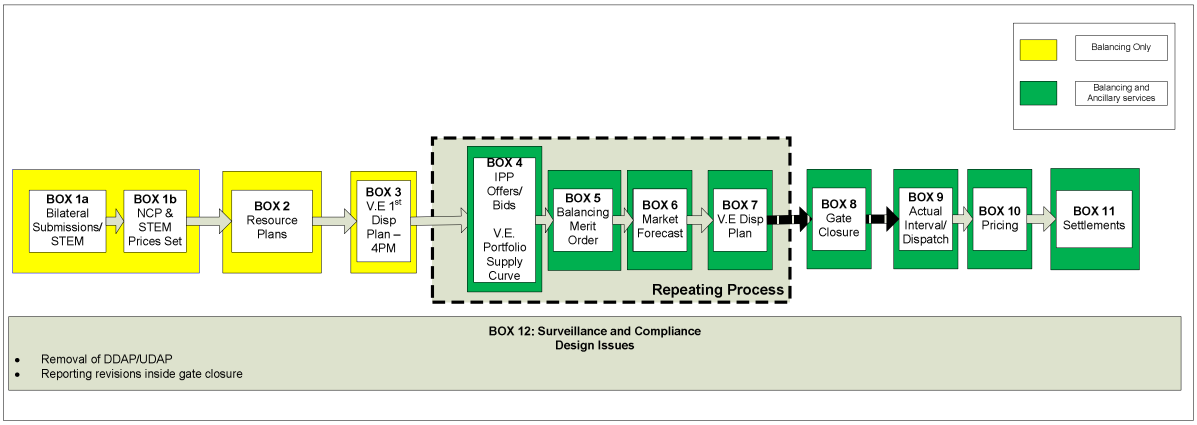
Sections 1 and 2 provide a high level overview (see figure 1). Section 3 provides additional detail of the proposed design in 12 stages.

Appendices A and B provides:

- A more detailed overview showing the roles and responsibilities for each process; and
- an example of the ability of the Balancing design to enable an IPP to de-commit a Facility if appropriate pricing conditions occur.

Finally, appendix C presents a glossary, which outlines the new defined terms that are being proposed in this design paper.

Figure 1: 12 stages of WEM operation



2. DESIGN SUMMARY

- The proposal is designed as an enhancement of the current hybrid design where IPPs are dispatched on the basis of Resource Plans and Balancing submissions (offers up/ bids down) around that level and Verve's portfolio dispatched by System Management on the basis of gross supply offers. The design also allows Verve to submit offers/bids for selected facilities.

- The design will allow for IPPs to participate in Balancing and provide for competitive provision of Ancillary Services.

- Verve will remain the default balancer and default Ancillary Service provider. System Management will continue to provide a dispatch coordination service to Verve and determine the dispatch of Verve's facilities on a portfolio basis in accordance with dispatch guidelines. As system and market conditions change (for example with weather, availability of fuel, capability of unscheduled wind generation) System Management will amend the Verve portfolio dispatch plan (as it does now), including commitment of units to optimise use of those resources whereas IPPs will renominate Balancing bids and offers. Verve will be able to restate its portfolio supply curve following major changes.

- The initial stages of operation of the market are little changed from the status quo (see the sections on bilateral and STEM submissions and operation of STEM – box 1a and 1b from Figure 1).

- Resource plans will be submitted by IPPs (and for any facilities Verve chooses to manage on a Facility basis). Resource plans will be broadly required to match Net Contract Position (NCP) and self-supplied Load (as now) except when the amount of energy (MWh) required by the NCP changes from one interval to the next. In these cases Market Participants will be entitled to elect to include Balancing energy on a planned basis around their Facility MW ramping rates.

- The first significant change to the design will be the introduction of submission of bids/offers for Balancing and Ancillary Service from IPPs and Verve. These submissions will follow the submission of Resource Plans and calculation of the first dispatch plan for Verve plant. IPPs will make these submissions on a Facility basis and Verve on a portfolio basis. The submissions will be for the full or gross potential Balancing range being offered and Ancillary Service capability and note where these might be mutually exclusive (or conditional) (see box 4).

- The market rules will describe the principles for deciding which Balancing offers/ bids and Ancillary Service offers will be selected for service from the conditional gross capabilities submitted (see box 5).

- The Balancing Merit Order (BMO) will be determined from the Balancing submissions taking account of accepted Ancillary Service offers (see box 5).

- IPPs and Verve will have specified rights to update Balancing and Ancillary Services submissions within nominated gate closure times (see box 8).

- System Management will continue to determine the timing of commitment and decommitment of Verve plant (other than facilities Verve has elected to manage outside its portfolio). In the first instance IPPs will manage commitment and decommitment of their facilities, as currently occurs (as expressed in Facility Resource Plans). However the design of the rules around resubmissions and gate closure will facilitate IPP participation in Balancing including decommitment when appropriate (see box 7).

- Non scheduled resources (e.g. wind) may submit an offloading price and will be incorporated in the Balancing Merit Order used by System Management at the time of dispatch.

- System Management will dispatch all plant to meet demand and ensure secure operating conditions are maintained in accordance with the final merit order. The Real Time Balancing Merit Order (RTBMO) is developed by updating the BMO and accounting for operational limitations advised to System Management (see box 9).

- The Balancing price will be determined ex post from the total generation requirements used and the RTBMO used for dispatch – no Upward Deviation Administrative Price (UDAP) or Downward Deviation Administrative Price (DDAP) factors will apply. Constrained on/off payments will be made for Facility offers/bids dispatched at prices inconsistent with their submissions (see box 10).

- System Management will retain wide authority to manage security of operation (see box 9).

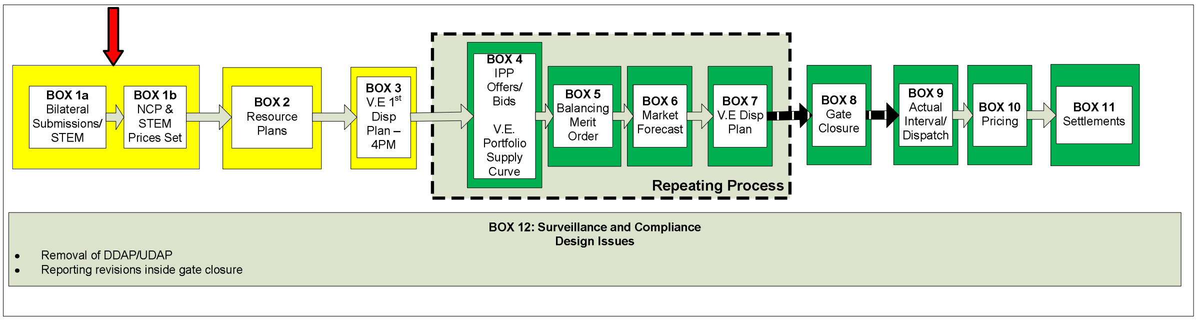
3. DETAILED DESIGN

The following pages describe each of the 12 stages in more detail. This current version of the paper provides only dot point summary of design details and later versions will be expanded with greater detail including rationale for design decisions.

3.1 BILATERAL SUBMISSIONS/STEM AND NCP AND STEM PRICES (Box 1)

3.1.1 Purpose:

This section describes the potential impacts on the current STEM process of implementing the new competitive Balancing market.



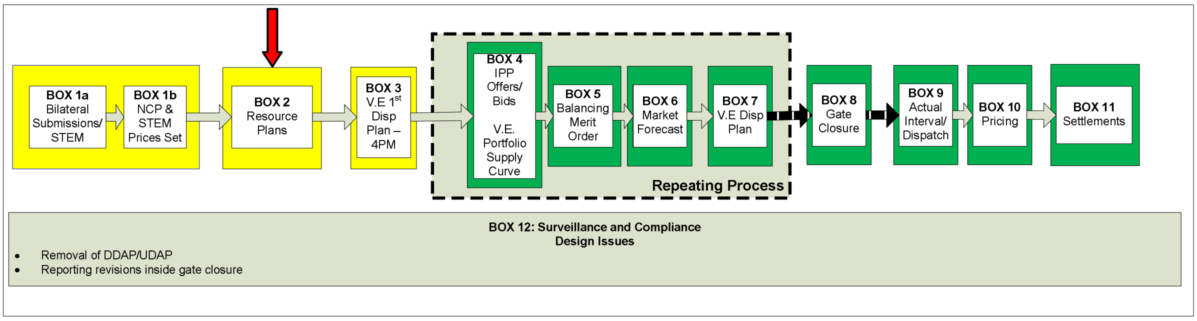
3.1.2 Proposal:

- No Changes to Current STEM process and setting of NCP.

3.2 RESOURCE PLANS (Box 2)

3.2.1 Purpose:

This section explains the role of Resource Plans (RPs).



3.2.2 Background:

Once accepted RPs can be seen as self issued Dispatch Instructions (DIs) that self scheduled facilities need to comply with in order to meet their NCPs and any self supplied load. Proposed RPs must be reviewed and accepted as technically viable by System Management from a system security perspective.

Currently, RPs state the energy (MWh) proposed to be generated in a Facility in each interval and this energy must match the total NCP and self supplied load of the relevant Market Participant.

No change to this general principle is proposed, however, the format of the submissions and the stringent requirement for energy within RPs to match NCP when NCP changes, is to be amended.

3.2.3 Proposal:

- Resource plans will be required for all IPP scheduled facilities (no change) and any facilities Verve elects to operate on a Facility basis. The sum of RPs submitted by a participant must match the participant's NCP plus self-supplied load except where this quantity is changing from one interval to the next:

- For each dispatch interval, RPs are to specify a MW target (sent out) with a specified ramp rate from a specified time:

    - This will make the format of the implied self dispatch instructions through RPs consistent with the form of System Management dispatch instructions for Balancing in any interval (subject to development of necessary dispatch support tools).

    - Facilities operating to a RP will thus ramp up or down linearly in an interval and will be operating at a nominated level by the end of the interval.

    - The linear ramp rates must be realistic estimates of how the participant will dispatch the facility to meet the target level specified, accepting that for practical reasons a facility may not be able to ramp continuously at a uniform rate.

However, the specified ramp rate should reflect the time the participant expects to take, from the start of the interval, to ramp to the specified target MW level.

- The RP will form the reference level for Balancing offers/bids.

- System Management will accept/reject RPs in response to system security concerns caused by RPs.

    - The Market Rules and Market Procedures/ Power System Operation Procedures will specify under what circumstances and what actions System Management will use this judgement.

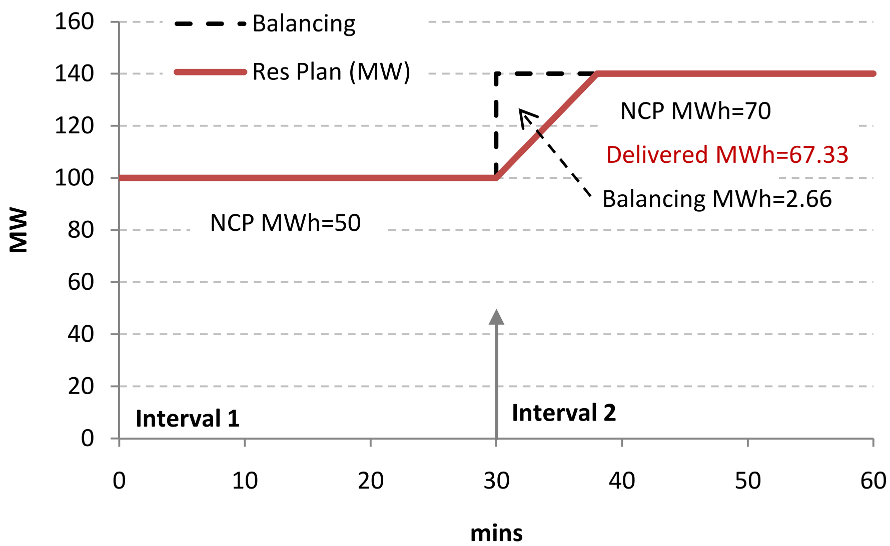
- RPs in each interval from each Market Participant must match the energy (MWh) in the corresponding NCP except when the NCP changes from one interval to the next.

    - When NCP changes from one interval to the next a RP may indicate more or less energy than the relevant NCP, this may result in one of two scenarios:

        1. The total energy provided by the facility is less than NCP (if NCP is increases as illustrated below), or more energy is produced when NCP decreases, this scenario exposes a participant to balancing energy; or

        2. when NCP is increasing (or decreasing) a participant may chose to “overshoot” (or undershoot) the NCP implied MW value, in this scenario a participant will choose a MW target that is above the NCP implied MW value so that the energy produced is equal to the MWhs in the NCP

    - The RP indicates ramping at 5 MW per minute at the start of interval 2 to a target of 140 MW, equivalent to the MW level implied by the 70 MWh NCP.

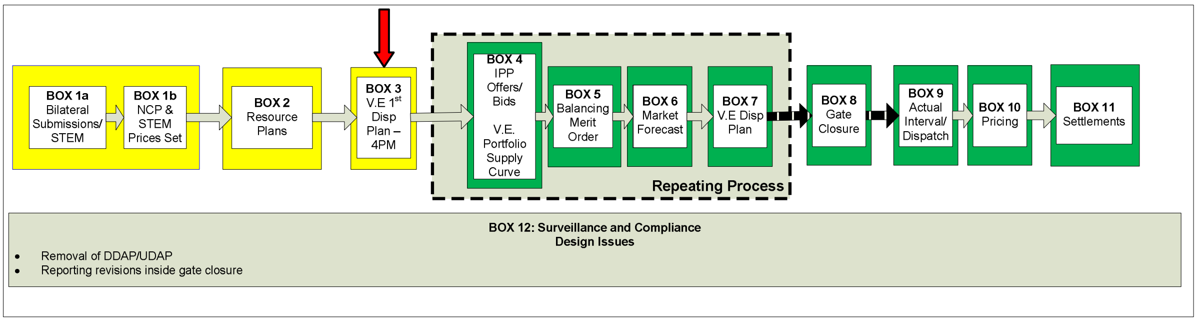


Note: RPs will contain sufficient information for half hour market processes and will not need to account for the level of Balancing or Ancillary Services that may be accepted by System Management. Bids and offers for Balancing and Ancillary Services will be submitted relative to the RPs. Renominations and operational protocols will provide for System Management to receive all information needed for secure operation of the power system through the Real Time Balancing Merit Order (RTBMO) and within half hour operational details e.g. short term interactions between Resource Plan ramping and Balancing capability (for additional information see Box 9).

3.3 VERVE ENERGY 1ST DISPATCH PLAN (Box 3)

3.3.1 Purpose:

This section explains the role of the first System Management created Verve Energy Dispatch Plan in the context of the implementation of the competitive Balancing market.



The Verve Energy Dispatch Plan is a service provided for Verve by System Management under the hybrid market design. System Management reviews and updates the dispatch plan as and when circumstances require.

3.3.2 Proposal:

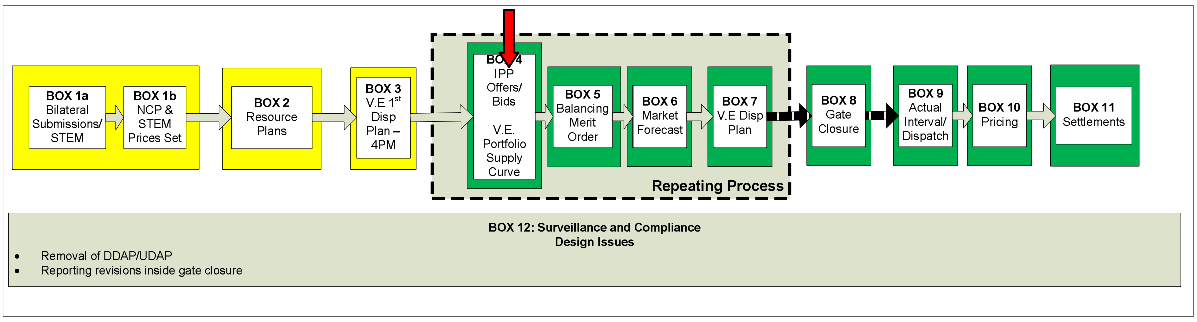
- The Market Rules will require System Management to provide dispatch plans in accordance with the Verve Dispatch Guidelines. As a minimum System Management must provide Verve an initial dispatch plan before Verve is required to submit Balancing offers/bids.

- The Rules will also need to ensure that System Management has the necessary information to account for expected IPP/Verve standalone Facility generation in preparing the Verve dispatch plan (e.g. refer forecasting box 6).

3.4 BALANCING OFFERS/BIDS AND VERVE ENERGY PORTFOLIO SUPPLY CURVE AND LOAD FOLLOWING ANCILLARY SERVICE OFFERS (Box 4)

3.4.1 Purpose:

This section explains how bids and offers will be formulated for Balancing and Load Following Ancillary Services (LFAS) from both IPPs and Verve Energy in the context of the implementation of the competitive Balancing market. Given that VE will remain the default balancer.



3.4.2 Proposal:

Form of bids and offers

- Initial bids/offers for Balancing and Ancillary Services to be submitted by Verve and IPPs at (say 4pm to 5pm).

- As a minimum, Verve will be required to submit a portfolio supply curve for each trading interval comprising multiple pairs of sent out MW and price per MWh for its available capacity. This curve will be required to be submitted at the same time as the first IPP Bids/Offers, approximately 4 or 5PM)

- Verve will be able to submit bids/offers the same as IPP facilities if Verve chooses to separate out a Facility (or facilities) from its portfolio (and reduce capacity offered in its portfolio accordingly). IPP (and Verve stand alone facilities) bids/offers on a Facility basis stating MW range, price:

    - IPPs *must* submit a price for dispatch above Resource Plan up to the full capacity of each Facility (no change from current).

- IPPs *may* divide the capacity between Resource Plan and full capacity into up to [5] bands – these will form the basis for upward Balancing tranches in the Balancing merit order.
- IPPs must submit a price for dispatch below Resource Plan including for decomittment (no change from current arrangement for a price within standing data for emergency de-commitment).
- IPPs *may* divide the capacity below Resource Plan into up to [5] bands. These will form the basis for downward Balancing tranches in the merit order. Strongly negative prices would be expected below minimum load of generators seeking to avoid decommitment.

All capacity expected to be available from a Facility must be included in bids/offers

- Intermittent and non scheduled resources that can only control reduction in output will be able to provide a price for Balancing down. – System Management will dispatch these resources down to the extent of prevailing output at the submitted price (e.g. wind facilities might submit a bid (unspecified quantity) at –ve $40 and System Management will dispatch the prevailing output down if the price would otherwise fall below–ve $40. (Also see boxes 5, 6 and 9).

Ancillary Service offers:

Registered (technically pre qualified) IPP and Verve standalone LFAS Facilities may submit:

- an enablement price ($/MW),
- upward capability (MW),
- downward capability (MW); and
- Steady State Ancillary Service Base point (SSASB) a pre loading quiescent operating level (MW). The SSASB will reflect the any pre loading required when no Ancillary Service is being called on (e.g. system frequency at 50Hz) but is needed in order for the relevant Facility to be capable of providing the service such as part loading of gas turbines.

Verve Energy will be required to submit a portfolio supply curve for the provision of LFAS including:

- An enablement price per tranche ($/MW);
- upward capability per tranche (MW); and
- downward capability per tranche (MW).

Joint Balancing and Ancillary Service Conditions:

Offers (by IPP and verve stand alone Facilities) to provide Balancing and Ancillary Services will be presumed to be mutually exclusive and that Market Participants will be indifferent about which (if either) service is accepted based on the prices submitted. This will mean that a Balancing offer for +/- 30MW and LFAS offer of +/- 20MW can be made for a Facility with a capacity of 200MW providing the Resource Plan is for no more than 170MW. Market systems will determine which combination of Balancing and LFAS it is appropriate to accept at the time of dispatch e.g. 30MW Balancing with 0MW LFAS or 10MW Balancing and 20MW upward LFAS. Final selection will be made by System Management on the basis of data available just prior to time of dispatch.

An alternative approach whereby ancillary service providers would be pre-determined would require a separate consideration of offers to provide ancillary services and for those parties whose offers were accepted to submit resource plans and balancing offers adjusted for those offers. Consistency between capacity, resource plans, balancing and ancillary service amounts would need to be validated. An additional market process would need to be introduced.

Because submissions for provision of balancing and ancillary services are to be made simultaneously and are to be conditional, the submissions from participants will be relatively simple. Market systems (software) will be used to select the combination of successful providers and this selection process can be relatively simple or involve complex trade-offs between balancing and ancillary services. Such a framework allows for simple initial arrangements that can be refined over time by changing the design of the software support within market processes used by both IMO and System Management without need for subsequent changes to submissions.

Importantly details of the timing of submissions, resubmissions and reassignment of ancillary service duty should be chosen to align with the broader balancing market design and design of software support and processes used by System Management.

Resubmissions:

In order to ensure System Management is presented with accurate information about the quantity available from each Facility and to ensure the prices for dispatch of Verve and IPP resources reflect changes in costs across each day:

- Verve will be eligible to re-submit its Portfolio Supply Curve at the beginning of the trading day (say 8 am) and/or when a Facility within the PSC experiences a demonstrable physical outage to one of the Facilities within the Portfolio Supply Curve.
- IPPs and Verve (in respect of resources it elects to submit on a Facility basis) may re-submit up to specified rolling gate closure times (see box 8).

Assessment of conditional Balancing and Ancillary Service offers:

The objective of the assessment is to determine as close to optimum mix of Balancing and Ancillary Service providers at any given time. This section provides an en example of a possible framework to select ancillary service providers – in effect the framework for support software or processes that could be employed. Simpler or more complex frameworks may be appropriate initially and over time. In principle the selection process should account for enablement costs, any SSASB and the resultant Balancing costs and may for example see more expensive Ancillary Services selected to allow cheaper Balancing at an overall lower cost than selecting Ancillary Service only on the enablement cost for Ancillary Service.

Ideally, selections would be based on a full co-optimisation analysis of Balancing and Ancillary Services. A move to full co-optimisation would be a complexity not warranted at such an early stage of an Ancillary Service market. As such approximate or rules based approaches will be needed (Note: the design allows for future development of a more complex selection criteria if needed).

Subject to further refinement before operation under new rules commences, the initial selection procedure will involve:

- A LFAS merit order established by System Management [4] times per day and as appropriate at the discretion of System Management following material changes in operating conditions; and

- The LFAS merit order to be based on minimising the cost of LFAS enablement payment and estimates of the average constrained on/off payments for any SSASB for the relevant period the merit order applies for (e.g. 6 hours). Enablement payments will be specified in Market Participants submissions and constrained on/off payments will be the difference between the market Balancing price and the price for Balancing submitted by the Market Participant. Initially the LFAS merit order will not normally be reviewed in the event of Balancing resubmissions other than at the [4] specified review times.

The procedure recognises that if all Resource Plans and demand forecasts are accurate and system frequency is steady at 50Hz then no Balancing and no LFAS will be dispatched. In this circumstance if no pre loading is required Balancing costs will be zero and unaffected by enablement of facilities to provide LFAS. The only cost relevant to selecting which Facility to provide LFAS will be the LFAS enablement charge.

In the case where a Facility can only provide LFAS if it is pre loaded to a SSASB, the BMO will be adjusted (see Box 5). The LFAS provider will then be entitled to receive a constrained on/off payment and different sources of Balancing will be required. The procedure requires an estimate of the average constrained on/off payment which will be based on the forecast average Balancing price (from the amended BMO). The use of average prices over a number of hours, the normal fluctuations in demand and intermittent generation as well as changes to Balancing submissions will mean that the Balancing price in this calculation will often differ from the final price meaning that there is a risk that when assessed after-the-fact the order in which LFAS was called will be inefficient. Monitoring of the market should include an assessment of the level of inefficiency as one factor in considering the benefit of refinement of the procedure.

Additionally there will be a mechanism within the Market Rules that will require selection to be on the most efficient basis that is practicable in accordance with available decision support tools and a procedure to be developed by the IMO. The selection methodology can be reviewed periodically (potentially each 6 months in consultation with Market Participants). This approach will establish the principle in the Market Rules but allow progressive improvement on a procedural basis

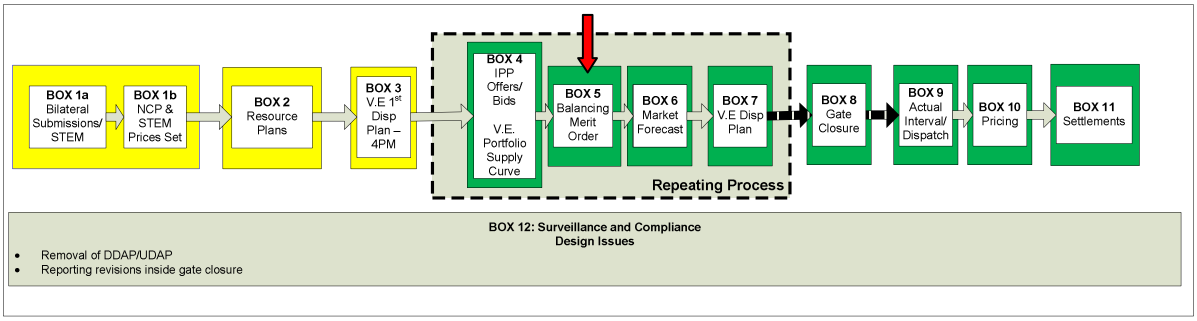
Verve standalone Facilities:

Verve energy will have the ability to elect to submit a “standalone” Facility basis on a trial basis for one month prior to formal removal from the portfolio. Verve Energy will be required to seek System Management (or IMO?) approval for standalone status of a facility at least 1 week prior to the facility being split out on either a trial or permanent basis.

3.5 BALANCING MERIT ORDER (Box 5)

3.5.1 Purpose:

This section explains how the Balancing Merit Order described above will be constructed.



3.5.2 Proposal:

- A market BMO and a Real Time BMO (RTBMO) will be developed. The market BMO will be based on submissions made prior to a defined period before trading the relevant interval (e.g. Facility gate closure). At that time, the Market BMO will become the RTBMO. The RTBMO will continue to be updated as circumstances change and submissions need to be updated (for example, due to a Facility failure) and will be used by System Management for dispatch. Pricing will be based on the final Real Time BMO for each trading interval.

- The BMO for each trading interval will be created by inserting Facility Balancing submission quantities (IPP or standalone Verve facilities) into the Verve Portfolio Supply Curve (Portfolio Supply Curve) in price order. For Facility offers/ bids, maximum Facility ramp up and down rates will also be identified in the BMO.

- Unscheduled / intermittent generation will be included in the BMO based on respective Balancing price submissions and forecast Facility quantities. Inclusion in the RTBMO will be based on their Balancing price submissions and the prevailing capability, which will be available for dispatch by System Management.

- The BMO/RTBMO may also incorporate curtailable, dispatchable and interruptible load so that they can be dispatched downwards in accordance with Balancing price submissions.

- Offers or bids with identical prices will be identified/linked in the BMO/ RTBMO. Their treatment in forecasting and dispatch is discussed later.
- Note that it will not be practical to identify Verve liquids facilities specifically within the BMO/RTBMO unless Verve submits them for Balancing on a Facility basis. i.e. quantity/price pairs within Verve's Portfolio Supply Curve are not linked to individual facilities. Discussed further in relation to dispatch.

3.5.3 Further work:

- Review impact on mechanics of Intermittent Loads in the BMO.
- Incorporating curtailable, dispatchable and interruptible load into the BMO.

3.5.4 Example:

Consider the following (stylised) scenario with Verve and 2 IPP facilities. For now it is assumed that Verve submits a Portfolio Supply Curve for its entire portfolio (i.e. Verve does not present any standalone Facility based submissions). It is also assumed that there is no curtailable load or unscheduled/ intermittent generation.

Verve Submission		
Tranche	MW	$/MWh
14	50	$420
13	400	$276
12	200	$60
11	80	$40
10	300	$35
9	60	$30
8	20	$25
7	20	$5
6	100	$0
5	40	-$3
4	80	-$5
3	150	-$30
2	200	-$50
1	360	-$275
Tot Capacity	2,060	

IPP1 Facility Submission (Resource Plan = 50 MW[1])		
Parameter	**MW**	**$/MWh**
Up 1	10	$50
Down 1	15	$10
Down 2	25	-$275
Total Capacity	50	
	MW/min up	**MW/min down**
Max Facility ramp rate	2	2

IPP1 submitted a Balancing bid for some of the capacity below its Resource Plan at a very low price. That capacity would not be dispatched down and/or off unless System Management has no other options available within the RTBMO for normal Balancing purposes, creating an overall security of supply situation, or has to dispatch the Facility down for a localised security of supply situation.

IPP2 Facility Submission (Resource Plan = 100 MW[2])		
Parameter	**MW**	**$/MWh**
Up 1	50	$70
Down 1	50	$30
Down 2	50	-$275
Total Capacity	150	
	MW/min up	**MW/min down**
Max Facility ramp rate	3	3

Also assume that a wind farm has bid in to be dispatched down for negative $40 per MW and the participant has forecast that the Facility will be operating at 50 MW for the duration of the interval.

Submissions would be aggregated into a market BMO for System Management purposes along the following lines. (In practice, the BMO would also identify any identically priced offers and for Facility submissions maximum ramp up and down rates).

[1] Resource plans will be in the form of ramp rate and MW target as discussed earlier (Box 2). This is ignored here for simplicity but will need to be taken into account in forming dispatch instructions (Box 9). For example, if a Balancing offer is to be dispatched and the Facility will already be ramping in accordance with its Resource Plan.

[2] Resource plans will be in the form of ramp rate and MW target as discussed earlier. This is ignored here for simplicity but will need to be accounted for in formulating dispatch instructions.

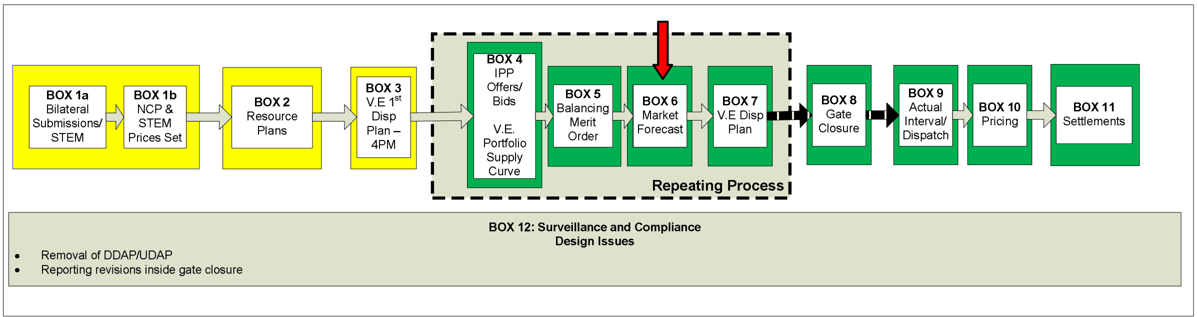
ID	Tranche MW Range From	Tranche MW Range To	Cumulative MW Range[3] From	Cumulative MW Range[3] To
VE PSC	1,610	2,060	1,760	2,210
IPP2	100	150	1,710	1,760
VE PSC	1,410	1,610	1,510	1,710
IPP1	40	50	1,500	1,510
VE PSC	1,030	1,410	1,120	1,500
IPP2	50	100	1,070	1,120
VE PSC	950	1,030	990	1,070
IPP1	25	40	975	990
VE PSC	560	950	585	975
Wind1 Down	50	0	635	585
VE PSC	360	560	435	635
VE PSC	0	360	75	435
IPP2	0	50	25	75
IPP1	0	25	0	25

Information in resubmissions would be used to update the BMO and the RTBMO. Accepted Ancillary Service offers that require pre loading away from Resource Plan in the case of IPPs or Verve where a defined MW quantity is required will be reflected in the BMO as appropriate – for example where partial loading is required on a Facility that would not otherwise be operating would be seen as an increase in the capacity at the bottom of the BMO/RTBMO. Similarly if acceptance of an Ancillary Service offer that was conditionally linked to Balancing and will reduce the amount available for Balancing then the capacity at the bottom of the BMO/RTBMO will increase and the relevant Balancing tranche decrease.

3.6 MARKET FORECAST (Box 6)

3.6.1 Purpose:

This section describes the market forecasts that are envisaged.



3 Aggregate MW range added.

3.6.2 Proposal:

- Market Participants will be provided with regular 2 hourly (rolling) forecasts of the Balancing price and also their expected Balancing quantity to help them to make informed bids and offers, and prepare for any likely dispatch. Forecasts will extend over the period for which Balancing submissions apply. i.e. forecasts issued today before initial bids and offers for the following trading are due (say prior to 4pm) will cover trading intervals out to 8am tomorrow. Forecasts issued after that time, will cover trading intervals out to 8am the day after.

- The forecasts are especially important in relation to Market Participants decisions about commitment, de-commitment and management of constrained fuel supplies etc and resubmissions to give effect to these decisions.

- It is proposed that the following forecasts will be provided at regular intervals leading into gate closure:

  - Expected system generation requirement (to all Market Participants);

  - Expected overall Balancing quantity (to all Market Participants);

  - Expected overall wind/ non scheduled load and curtailment (to all Market Participants)

  - Expected Balancing price (to all Market Participants);

  - Expected balancing price if total generation requirements are +/- 1% from forecast; and

  - Expected Facility Balancing quantities (to relevant Market Participant only) including identification of any security constrained requirements.

- From the market BMO and forecast total generation requirements, taking account of forecast unscheduled generation, a market forecasting model will determine expected dispatch quantities for facilities (IPP and Verve standalone) and Verve's portfolio and expected Balancing prices.

- The initial forecasts for a trading day will effectively be a system generation schedule covering the rest of the current trading day out to the end of the following trading day. System Management will review this information and advise the IMO of any constraints that need to be applied to generation within the schedule (for example due to a local transmission outage/ constraint). The IMO will incorporate this information into subsequent forecasts.

- System Management will use forecast dispatch quantities for Verve's Portfolio Supply Curve and IPPs (Resource Plans +/- expected dispatch of Balancing offers/ bids) in preparing and updating the Verve dispatch plan.

- The above procedure will continue to be carried out each time a bid/offer is updated by an IPP (or Verve Portfolio Supply Curve updates are allowed) with new forecasts being provided to market at regular intervals. It may also be practical to re-issue forecasts whenever there is a change to input forecasts.

- Forecasts will continue to be provided after gate closure so that IPPs can be prepared for any likely Dispatch Instructions which they might receive.

- The adequacy of the forecasts will need to be reviewed after an initial period of time (it is proposed two years). This review will need to assess the accuracy and also the usefulness to MPs.

Appendix A includes an overview of the above processes.

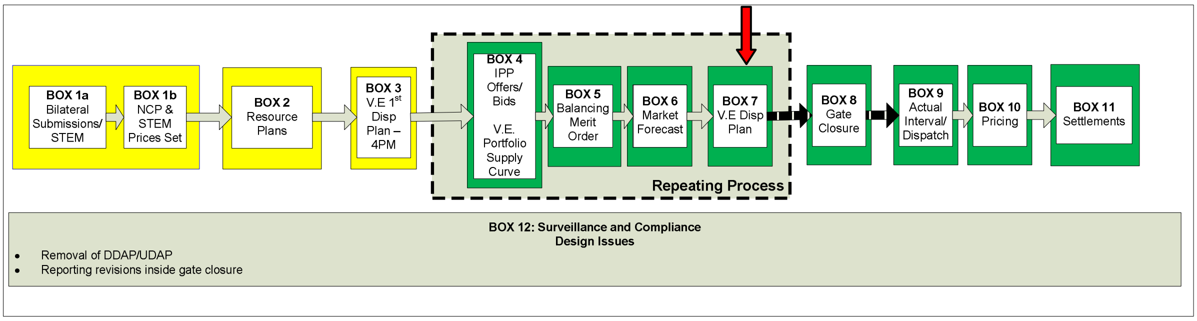
3.6.3 Further Work:

- Discussion with System Management re new systems it may require to support forecasting processes. e.g. more real time load forecasting and/or wind forecasting tools?

3.7 VERVE ENERGY DISPATCH PLAN (Box 7)

3.7.1 Purpose:

This section explains the ongoing need for System Management to re-calculate the Verve Energy DP over the scheduling day to account for forecasted IPP Balancing Bids/offers.

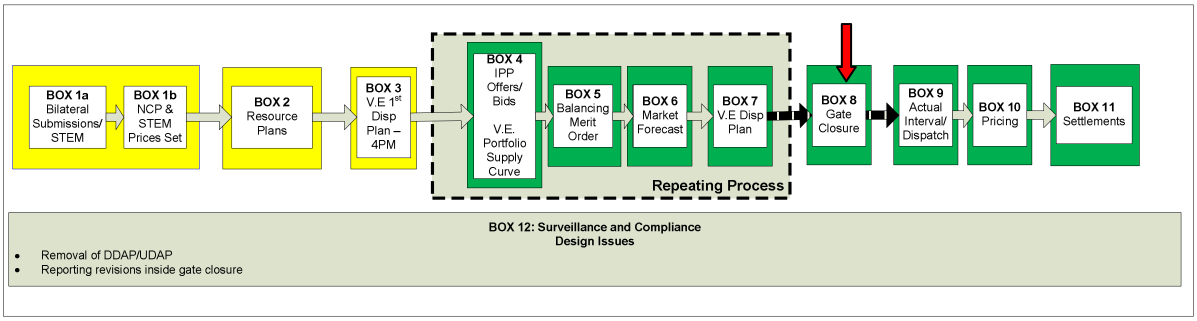


The Verve dispatch plan is prepared by System Management as a service to Verve within the hybrid design and reviewed as needed. In updating the Verve dispatch plan, System Management is in effect undertaking a review and revisions to Balancing bids/offers for facilities within the Verve Portfolio Supply Curve leading up to resubmissions (subject to Portfolio Supply Curve gate closure).

3.8 GATE CLOSURE (Box 8)

3.8.1 Purpose:

This section explains gate closure or the time up to which Market Participants may resubmit specified market information and offers/bids.



3.8.2 Proposal:

- At fixed gate closure times and/ or when a major change in circumstances occurs, such as a Facility failure or having to switch a Facility from gas to liquids Verve may update its portfolio supply curve.

- Up to a normal rolling gate closure, say 2 hours, ahead of dispatch intervals IPPs (and Verve for standalone facilities) may resubmit Facility bids and offers for Balancing/Ancillary Services relative to their Resource Plan.

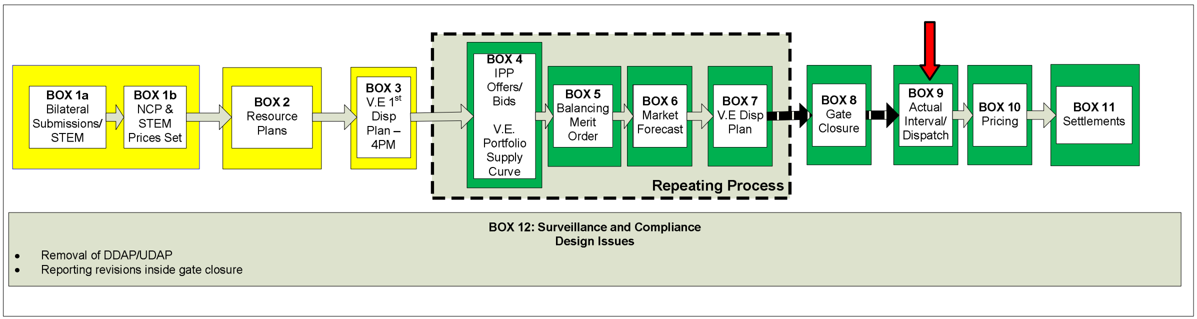
- Normal Facility gate closure requirements may be relaxed if System Management issues a system security advisory indicating a supply shortfall forecast or a supply excess forecast. In these cases Market Participants would be able to increase their offered quantities inside the normal gate closure period in response to a System Management supply shortfall advisory. Market Participants would be able to increase bid quantities (e.g. to effect a de-commitment) within the normal gate closure if System Management has issued a supply excess advisory notice.

- Once normal gate closure has occurred, changes to the BMO/RTBMO will still be required (e.g. for bona fide physical changes to offers/ bids, responses to security advisories, actual wind generation levels etc). The RTBMO used by System Management for dispatch will be the final BMO for pricing purposes.

3.9 ACTUAL INTERVAL/DISPATCH (Box 9)

3.9.1 Purpose:

This section explains how the Balancing market structures outlined above would be implemented. It will explain Dispatch Instructions leading into a half hour period, real time management of load over the half hour and the role of LFAS within the new Balancing Market.



3.9.2 Background:

Instantaneous supply must match instantaneous demand using production under Resource Plans, non-scheduled generation, Balancing service and Ancillary Services.

The Balancing service follows the expected trend during the half hourly dispatch interval in the difference between Resource Plans and the net of total demand, non scheduled resources and steady state requirements of plant providing Ancillary Services4. The load following Ancillary Service tracks the instantaneous difference between demand, including losses, and all other production. This principle is unchanged from the status quo.

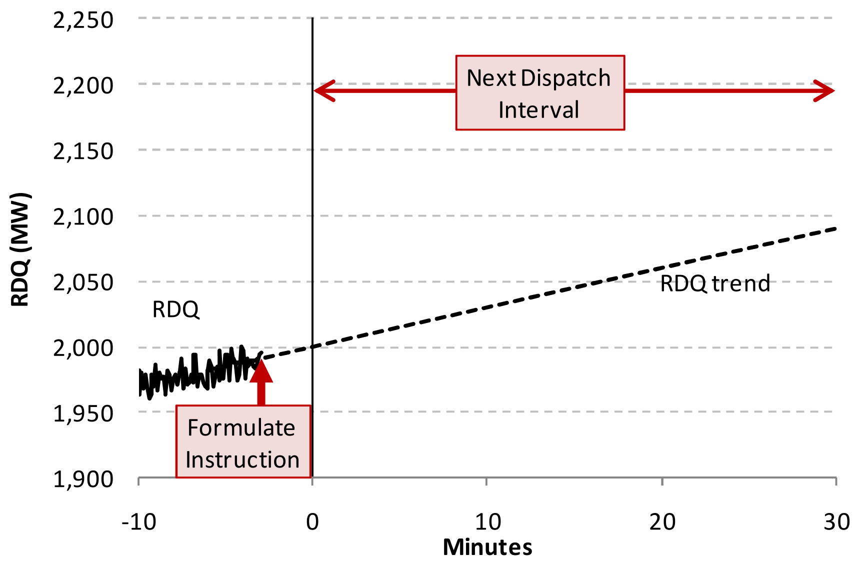
Instructions to deliver Balancing (Balancing dispatch instructions or Balancing DIs) will be formulated just prior to the start of each half hour in accordance with the RTBMO to ramp to specified MW targets at specified ramp rates at (or from) a specified time within the interval.

The primary objective of dispatch is to maintain security and minimise the cost of dispatch.

3.9.3 Proposal:

- System Management will use the RTBMO to formulate Balancing DIs.
- If the facilities providing LFAS are to change, relevant LFAS providers would be instructed to enable/disable the service and System Management would bring the relevant facilities into/out of the AGC system.
- Prior to a dispatch interval, System Management will estimate the underlying MW trend in total generation requirements during the next dispatch interval.
    - This quantity is called Relevant Dispatch Quantity (RDQ) for the remainder of this paper.

[4] See previous discussion on requirements to provide Ancillary Services.



- System Management will formulate Balancing DIs in accordance with the RTBMO so as to meet the expected RDQ with the objective of minimising the cost of dispatch. System Management will need to develop systems to formulate Balancing DIs. Where a Facility is selected for LFAS, AGC capability will be required and any conjoint Balancing DI would be issued via AGC. For facilities not selected for LFAS, systems will be required for System Management to issue and for Market Participants to receive Balancing Dispatch Instructions.

- System Management will have overriding authority to intervene in order to maintain security but will be expected to follow market based processes where feasible.

- System Management would continue to monitor security and Facility responses to Balancing dispatch instructions during an interval and would issue new instructions if required.

Format of Dispatch Instructions:

- A Balancing DI is an instruction to a Facility to change output:

    - For an IPP or Verve standalone Facility, an instruction is relative to RP (assumed to be zero if no Resource Plan submitted).

    - For Verve's portfolio, System Management will issue instructions to facilities to adjust their gross output so that the portfolio is dispatched to meet RTBMO requirements.

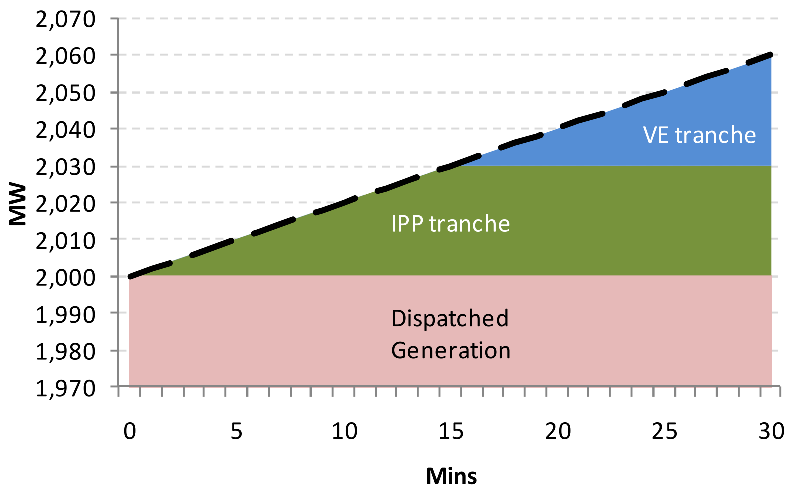
- A Balancing DI is an instruction to change output once and in one direction:

    - System Management will typically issue one only ramp rate and MW target to a Facility just before a trading interval (with LFAS compensating for residual imbalances within the trading interval).

- If necessary, System Management may need to issue new instructions within a trading interval (for example, to maintain LFAS services within their offered MW regulation ranges or to address unexpected system events within a dispatch interval).

- Subject to the above, Balancing DIs will typically be issued prior to an interval and consist of:
  - A MW target;
  - A ramp rate (less than or equal to specified maximum Facility ramp up/down rates); and
  - A time to start ramping (to distinguish clearly between the Balancing and LFAS roles, under normal circumstances this time will be no later than say 15 minutes (to be confirmed) into the interval).

- These concepts are illustrated below:



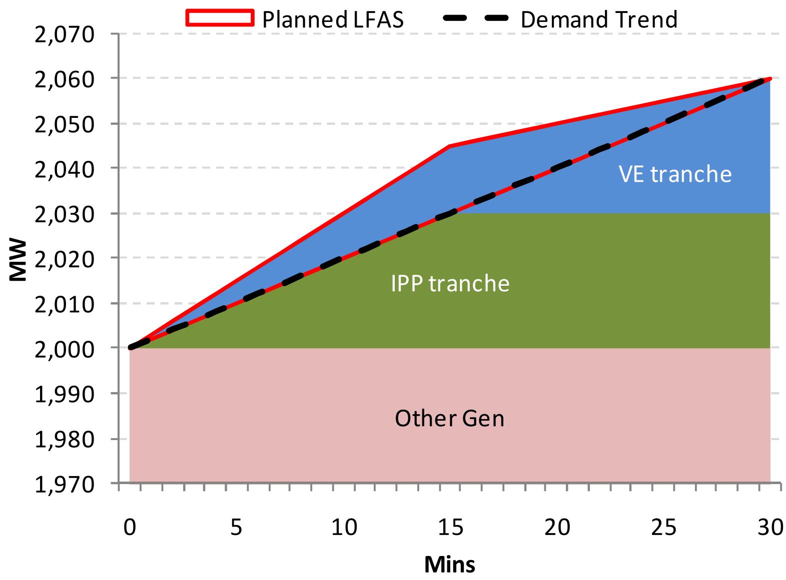
- In the example shown, an IPP Facility Balancing offer is able to be dispatched at less than its specified maximum ramping rate to follow the expected trend in RDQ (the dashed line). This minimises the use of the higher priced Verve tranche.

Planned LFAS:

- A consequence of the above methodology is that where it is necessary to dispatch multiple offer/ bid tranches in a dispatch interval, they could be instructed to ramp up linearly to an end of interval target as illustrated below.

- As illustrated, this implies a certain level of LFAS is in effect planned (aside from variations from trend) during dispatch intervals – which is called “planned LFAS” in the remainder of the paper.

Independent Market Operator



Practical dispatch considerations:

- It is important to recognise that Balancing DIs will be based on market parameters which do not account for all factors that affect operation of a generating Facility within a half hour. For example; to reflect automatic governor response to system frequency changes; having to put equipment in/out of service while ramping (such as coal mills, feed pumps etc); block loading/ ramping/ hold requirements when bringing a Facility into service etc; or Facility problems/ delayed start-ups etc. As a result Balancing DIs are incapable of defining sub half hour production requirements precisely. Dispatch via AGC will reduce some of the sources of imprecision but not all and is not mandatory in order for a Facility to contribute to Balancing.

- To the extent practical, offers/ bids should take all relevant factors into account (being reasonable estimates of the capability of a Facility if dispatched) and Market Participants will be expected to follow instructions to the extent practical. Consistent and material deviations from instructions developed in accordance with bids/offers would be a compliance matter. Deviations from instructed DIs are to some extent inevitable and need to be viewed in the context that half hourly dispatch in any event is inherently imprecise, being based on estimates of trends in demand and intermittent supply during a dispatch interval, and made prior to the interval.

  While System Management is entitled to rely on instructions being implemented in accordance with offers through the market over a half hour, Market Participants will also be required to inform System Management of all relevant limitations on response to DIs. This will enable System Management to determine dispatch of Balancing and Ancillary Services across the power system as a whole.

Outstanding issues:

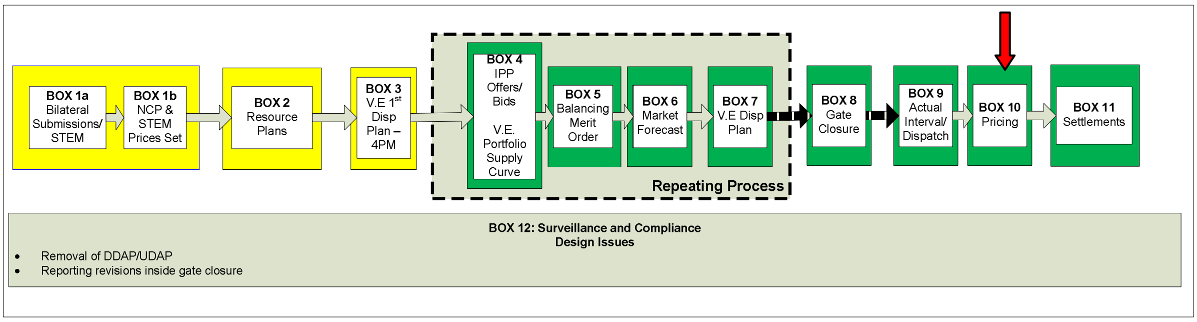
- As noted above, System Management will require decision support software that incorporates the above rules with the total generation forecasts and the RTBMO. For example, to manage the potential of multiple tranches being dispatched in an interval, including one ramping down while another ramps up, to help determine the appropriate start times, targets and ramp rates for Facility instructions (taking into account Resource Plans where a Facility is already ramping to a MW target during the interval).

- Verve liquid facilities: Verve will be able to separate dual fuelled facilities from its portfolio submission, with associated resubmission flexibility up to gate closure. Verve will also be able to update Facility submissions if a material change in circumstances criterion is met (need to define). The alternative of requiring System Management to dispatch IPP submissions ahead of Verve liquid facilities (as now) and adjusting the RTBMO could be considered further but is problematic given that the Verve Portfolio Supply Curve is not Facility specific.

3.10 PRICING (Box 10)

3.10.1 Purpose:

This section describes the calculation of prices within the short term operation of the WEM



Balancing Price:

Objective: balancing price to reflect the marginal price of resources dispatched by System Management to provide actual balancing from IPP and any Verve facility prices and Verve PSC prices.

3.10.2 Proposal:

- The balancing price is to be calculated ex post from the Energy Relevant Dispatch Quantity (ERDQ) and RTBMO for the half hour trading interval, based on actual MW (SCADA) levels for facilities and the Verve portfolio at the start of each interval and maximum facility ramp rates.

- Constrained on/off payments will be made to participants dispatched by System Management where the price of the bid or offer dispatched is inconsistent with the balancing price. This is discussed under Settlements.

3.10.3 Details:

- The ERDQ is the total amount of energy generated ('sent out') by facilities in the trading interval. This will need to be calculated using SCADA given delays in obtaining metering data and lack of metering at Verve facilities. Ideally the ERDQ would be calculated by averaging SCADA readings across the trading interval. Alternatively, end of period readings for the current and previous intervals could be averaged.

- The methodology involves calculating the amounts of energy that could have been generated in merit order from each tranche in the RTBMO, and in the case of unscheduled supply what was actually generated, to satisfy the ERDQ.
- The balancing price will be set the day following the trading day at the price of the marginal tranche in the above calculation.

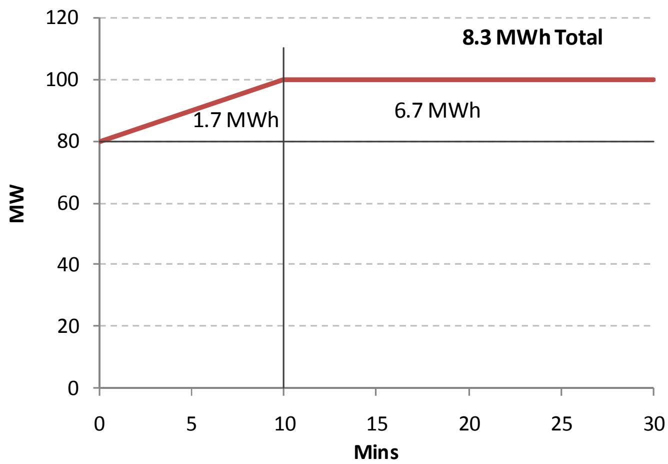
Example:

Basic

- For each facility based tranche in the RTBMO, the maximum and minimum amounts of energy that could have been dispatched in the interval will be calculated. This will take into account the amount of generation from the relevant facility at the start of the trading interval and the maximum ramping rate of the facility.
- For example, consider a 100 MW facility that is operating at its resource plan level of 80 MW at the start of an interval. Suppose the balancing submissions for that facility were as follows:

Facility Submission (Resource Plan = 80 MW flat)		
Parameter	**MW**	**$/MWh**
Offer (Up) 1	20	$50
Bid (Down 1)	80	-$275
Total Capacity	100	
	MW/min up	**MW/min down**
Max facility ramp rate	2	5

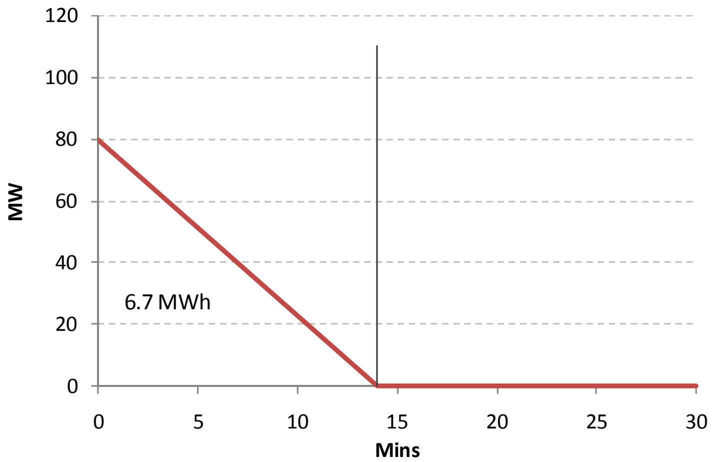
- The maximum amount of energy that the facility could be instructed to generate from the $50 per MWh tranche would be 8.3 MWh as illustrated below:



- The minimum amount of energy that the facility could be instructed to generate from the $50 per MWh would be zero (i.e. if the facility did not need to be dispatched off its resource plan).

- The maximum amount of additional energy that the facility could be instructed to generate from the tranche at negative $275 per MWh would be 40 MWh (i.e. if the facility did not need to be dispatched off its resource plan level).

- The minimum amount of energy that the facility could be instructed to generate at negative $275 per MWh would be 6.7 MWh as depicted below.



- These calculations would be carried out for each facility based tranche in the RTBMO.

- For each Verve portfolio tranche, the maximum and minimum amounts of energy that could have been dispatched would be the maximum quantity offered and zero (no ramp rate constraints).

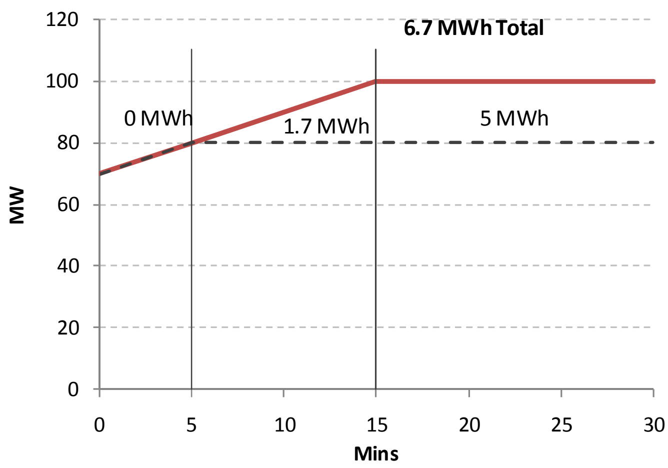
- The dispatchable quantities would then be sorted in price order (as in the RTBMO) to establish the balancing price with reference to the ERDQ. For example, as in the stylised example below. If the ERDQ was anywhere between 540 and 548.3 MWh, the balancing price would be $50 per MWh (set by the shaded IPP offer 1).

Tranche	Min MWh	Max MWh	$/MWh	Cumulative MWh From	Cumulative MWh To
VEPSC3	0	200	$275	548.3	748.3
IPP offer 1	0	8.3	$50	540.0	548.3
VEPSC2	0	300	$40	240.0	540.0
VEPSC1	0	200	-$50	40.0	240.0
IPP bid 1	6.7	40.0	-$275	6.7	40.0

Accounting for ramping within resource plans

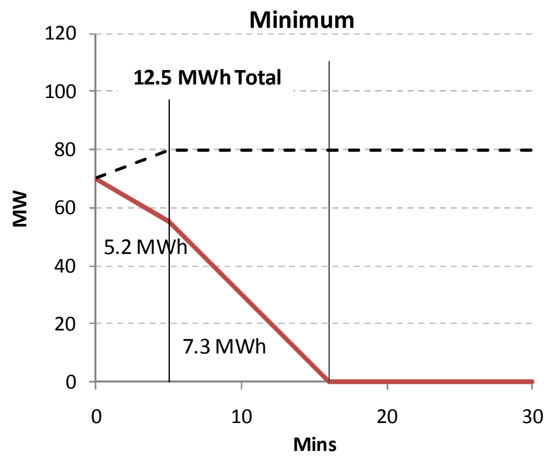
- In the above example, the IPP is operating at the resource plan level at the start of the interval and has a fixed resource plan throughout the interval (i.e. no change in resource plan level (NCP / own load) from the previous interval).

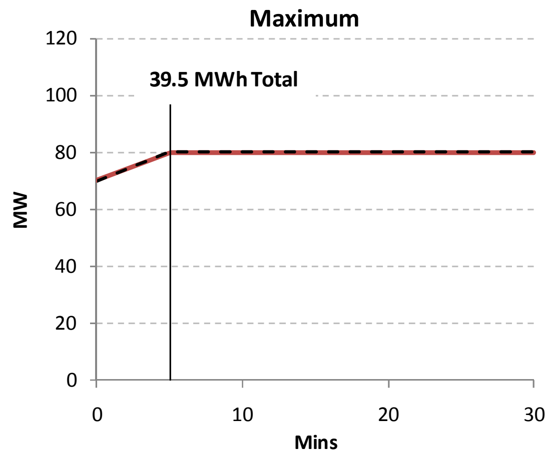
- In practice, the facility's resource plan may include ramping to a new level (refer box 2). For example, assume that in the above scenario, the facility is operating at a resource plan level of 70 MW at the start of the interval and that the resource plan ramps up to 80 MW[5] at 2 MW per minute. As illustrated below, the maximum energy that could be dispatched from the IPP offer 1 tranche is 6.7 MWh. As before, the minimum is zero (if it does not need to be dispatched off resource – the black dashed line).



- For the IPP bid 1 tranche, as illustrated below, the minimum and maximum amounts of energy able to be dispatched in the interval are 12.5 MWh and 39.5 MWh respectively.

5 e.g. 40 MWh NCP.





- The dispatchable energy for IPP offer 1 and IPP bid 2 tranches in the pricing table would then be as follows (changes from the previous table shaded):

Tranche	Min MWh	Max MWh	$/MWh	Cum MWh From	To
VEPSC3	0	200	$275	546.3	746.3
IPP offer 1	0	6.7	$50	539.6	546.3
VEPSC2	0	300	$40	239.6	539.6
VEPSC1	0	200	-$50	39.6	239.6
IPP bid 1	12.5	39.6	-$275	12.5	39.6

Unscheduled generation

- Suppose the above example is extended to include an unscheduled generation facility. Its actual energy production for the interval would be inserted into the above table at the bid price in its balancing submission. For example, suppose a wind farm had submitted a balancing submission of negative $40 per MWh (refer examples in box 5). If the wind farm actually produced 30 MWh during the interval, the above table would be as follows:

Tranche	Min MWh	Max MWh	$/MWh	Cum MWh From	To
VEPSC3	0	200	$275	576.3	776.3
IPP offer 1	0	6.7	$50	570	576.3
VEPSC2	0	300	$40	270	570
Windfarm	0	30	-$40	240	270
VEPSC1	0	200	-$50	40	240
IPP bid 1	12.5	39.6	-$275	12.5	40

Constrained on/off

Constrained on/off payments will be made to participants dispatched by System Management where the price of the bid or offer dispatched is inconsistent with the balancing price. This is discussed under Settlements.

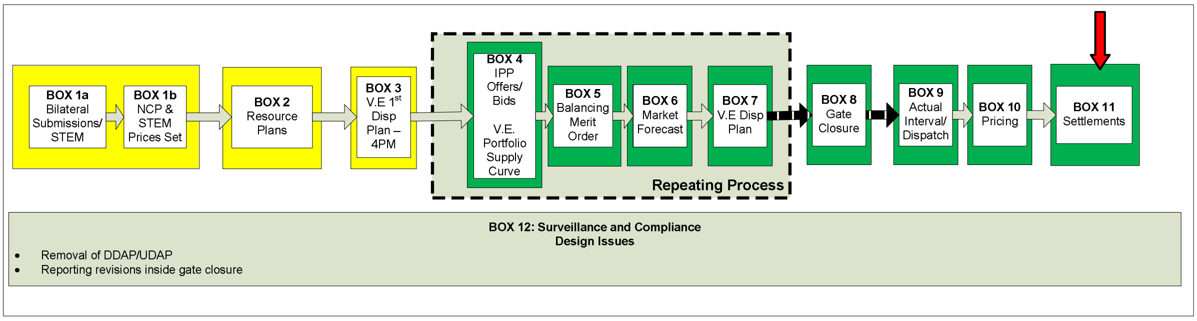
3.10.4 Further work:

The inclusion of load curtailment in the ERDQ.

3.11 SETTLEMENTS (Box 11)

3.11.1 Purpose:

This section describes the primary settlement transactions.



In principle settlement transactions are unchanged from the current market in that

Parties providing Balancing up are paid the Balancing price and parties Balancing down pay the Balancing price.

New transactions are to be created in relation to constrained on/off payments where payments at the Balancing price are inconsistent with participant offers. (For system security constrained on/off situations, the net result will effectively be the same under the current pay as bid constrained on/off regime).

Principle:

- A market transaction will exist whenever metered half hour (hh) dispatch differs from hh NCP (no change).

- A market transaction will have occurred when an IPP Facility or Verve standalone Facility output is increased or decreased from Resource Plan or when Verve's portfolio is dispatched above or below residual NCP (i.e. NCP less any Verve standalone Facility Resource Plans) as a result of:

    - An instruction from System Management for Balancing.

    - An instruction from System Management to load to a specified level, the SSASB, (consistent with the offer from the market participant in order to be capable of providing Ancillary Service (e.g. part loading for LFAS). See also constrained on/off payment).

- Automatic response from individual plant providing Ancillary Service.

- All market transactions will be paid at the Balancing price.

- Under defined circumstances a constrained on/off payment will also be made (discussed below).

- Parties selected to provide Ancillary Service will also receive an enablement payment in accordance with the design of the particular Ancillary Service.

- Market Participants dispatched by System Management to operate at an SSASB that is different to their Resource Plan will be entitled to be paid a constrained on/off payment (as appropriate) in addition to payment for the market transaction at the Balancing price as noted above.

  - Note: dispatch of energy as part of the delivery of an Ancillary Service around a relevant SSASB will not attract a constrained on/off payment (any cost impacts will be presumed to be reflected in the enablement fee submitted by the Market Participant)

- Windfarms will receive payment for being dispatched down based on difference between actual output and ex-post estimate of actual output possible during the interval

Settlement of constrained on/ off amounts:

Objective: To recompense Market Participants where the price of a Facility Balancing offer or bid dispatched by System Management is inconsistent with the calculated Balancing price.

- A Facility dispatched by System Management above (below) its Resource Plan will pay the market Balancing price for the quantity involved (normal settlement of Balancing amounts). Constrained on or off payments may also be required to compensate for differences between the Balancing price and the price of offers or bid tranches dispatched by System Management.

- For example, suppose the Balancing price is determined to be $15 per MWh. A Market Participant that was dispatched down below its Resource Plan by System Management and had a bid price of $10 per MWh, would have expected to pay that amount, not $15/MWh. So the Market Participant would receive a ‘constrained off’ compensation payment of $5/MW to compensate for the difference.

- This holds for negative priced bids as well. For example, had the Balancing price been negative $15 per MWh and the Market Participant’s bid price negative $20 per MWh, the IPP would have paid negative $15 per MWh (i.e. received $15/MWh) but expected to have paid negative $20 per MWh (i.e. receive $20 per MWh) for the quantity of downwards Balancing it provided. In this instance, compensation would be paid at negative $5 per MWh (the Market Participant would receive $5 per MWh) for the quantity of downwards Balancing it was instructed to provide).

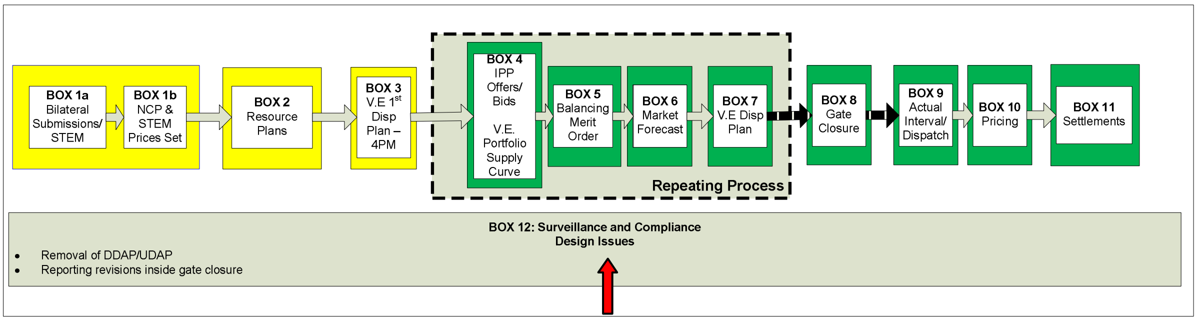
- The constrained off (or on) event may have been because of a system security situation[6] (in effect as now) or (a new requirement) due to approximations that must be made in formulating dispatch instructions to follow expected trends in dispatch intervals and in calculating half hourly Balancing prices ex post.

- Constrained on/off payments will be allocated to Market Customers proportional to their energy use in the interval the payment was made.

3.12 MARKET POWER, SURVEILLANCE AND COMPLIANCE (Box 12)

3.12.1 Purpose:

This section explains the expanded role of surveillance and compliance monitoring in the context of the new competitive Balancing Market.



3.12.2 Background:

Market power can have a positive or negative impact on market outcomes. The ability to exercise market power detrimentally to the objective of the market is common in many electricity markets. On the other hand the threat or actual exercise of temporary of market power can be a key incentive for competitors to enter a market or reduce costs. Detrimental market power can be managed by careful design of the market to incentivise participants to bid at SRMC and/or including provisions such as the requirement in the WEM for parties with market power to bid at SRMC, by countering the effects through contracts and also by ex post penalties or threats of penalty.

Monitoring and surveillance of a market can be used to identify both the exercise of market power and compliance with market rules. Compliance with market rules is important for the orderly conduct of an electricity market especially where coordination of operation must occur in very short timescale. Compliance is also important where rules have been designed to manage market power.

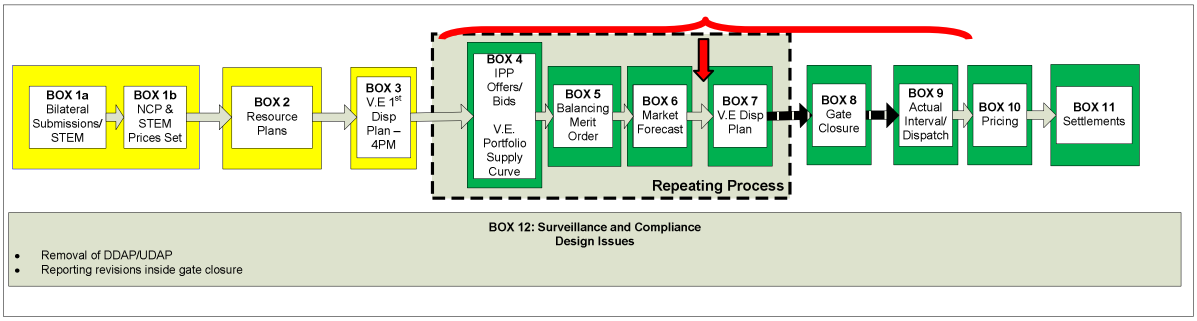
This section briefly notes the impact on market power, surveillance and compliance of the package of changes proposed in this document.

---

[6] The WEM currently provides for as bid payments for security constrained dispatch of IPP facilities. Going forward, that will still be the case $Q_{dispatch}$ * PriceAsBid (now) is same as $Q_{dispatch}$ * $Price_{Balancing}$ + $Q_{dispatch}$ * ($Price_{Balancing}$ - $Price_{bid}$)

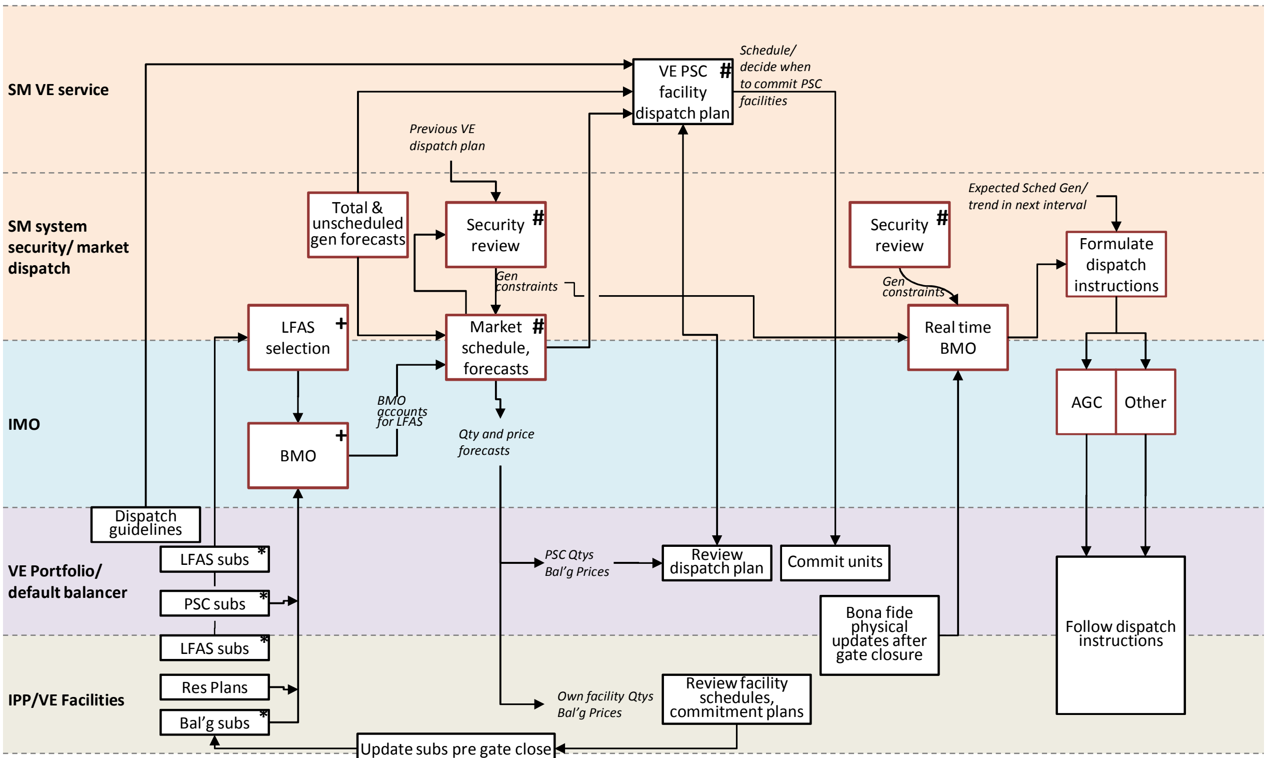
- Compliance with formation of Resource Plans given that UDAP and DDAP penalties are proposed to be removed and the requirement is to be relaxed when NCP changes;
- Surveillance of the basis for renominations – given the proposal to allow renominations under some circumstances such as following material change and for bona fide physical reasons specially within gate closure periods;
- Compliance with Balancing instructions;
- Compliance with provision of Ancillary Services;
- Level and reason for constrained on/off payments (to assist future development);
- Ancillary service offer prices; and
- If appropriate - Operational definition of market power and existing requirement for SRMC prices in bids/offers.

APPENDIX A: PROCESS, ROLES AND RESPONSIBILITIES



The following diagram illustrates the processes (including where process are repeated over the course of a day) and the roles and responsibilities within the proposed design described in the 12 stages.

Overview of Market Processes



Notes:

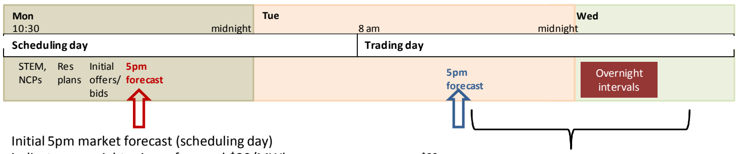
*
- Can revise pre relevant gate closure
- Otherwise only for bona fide reasons
- Or in response to SM 'security states'

\+
- Update when submissions revised and/or regular intervals
- Real time BMO accounts for bona fide changes after gate closure, up to interval

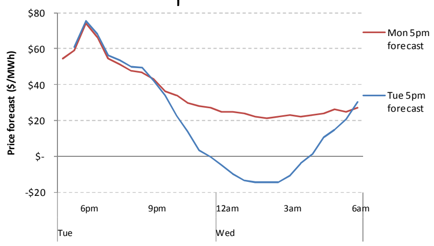
\#
- Ongoing and as required

APPENDIX B: OVERNIGHT EXAMPLE

Overnight example

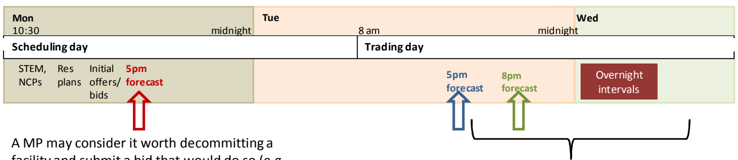


- Initial 5pm market forecast (scheduling day) indicates overnight prices of around $20/MWh
    - Issued 30+ hours ahead of overnight intervals
    - Issued several hours after NCPs established, resource plans submitted
- 5 pm forecast (trading day) indicates lower overnight prices
    - e.g. lower demand/ higher wind than forecast 24 hours beforehand
    - 7-8 hours before overnight intervals*

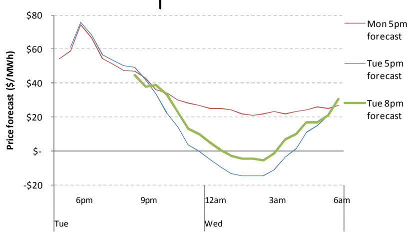


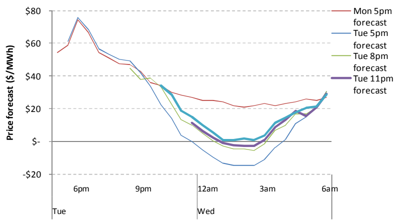
* *Had intermediate price forecasts indicated this trend, participants could have responded earlier given flexibility to revise facility submissions*

Overnight example *(cont'd)*



- A MP may consider it worth decommitting a facility and submit a bid that would do so (e.g. low –ve price)
- Reflected in later 8pm market forecast
- If de-commitment opportunity seen as worthwhile (taking start up into account etc), leave bid at gate closure
- If gate closure 2 hours out, could also leave decision until 11 pm





APPENDIX C: GLOSSARY

Independent Market Operator

Review of Capacity Cost Refunds

Date: 5 April 2011

Contents

DOCUMENT DETAILS

Report Title: Review of Capacity Cost Refunds
Release Status: Public
Confidentiality Status: Public domain

Independent Market Operator
Level 3, Governor Stirling Tower
197 St George's Terrace, Perth WA 6000
PO Box 7096, Cloisters Square, Perth WA 6850
Tel. (08) 9254 4300
Fax. (08) 9254 4399
Email: imo@imowa.com.au
Website: www.imowa.com.au

1. PURPOSE

The Rules Development Implementation Working Group's (RDIWG) terms of reference[1] includes the consideration, assessment, development and post-implementation evaluation of a number of design issues. One of the design issues identified for consideration by the RDIWG relates to capacity refunds in the Wholesale Electricity Market (WEM):

> **Issue 4:** At different times the capacity refund arrangements under and over price the value of capacity leading inefficient decisions by participants about the timing of maintenance and presentation of capacity.

The roles of refunds and how they fit within, and affect, the broader set of market incentives have been presented in a number of previous presentations and papers[2]. The purpose of this paper is to present the outcomes of the IMO's review of the current Reserve Capacity refund arrangements within the wider context of the RDIWG's scope of work. The impact of capacity refunds on the incentives for timely commissioning and reliability performance of facilities are specifically considered. The distribution of refunds is also addressed including the current methodology in the Market Rules and alignment with other capacity processes in the Market and the lumpy nature of the cost of Supplementary Reserve Capacity.

2. BACKGROUND

2.1 The Reserve Capacity Mechanism

The Reserve Capacity Mechanism (RCM) is a central feature of the design of the WEM. Relevant key characteristics of the design and operation of the RCM and its interaction with arrangements for energy trading are:

- A price ($/MW) for capacity is determined and reviewed annually;
- The IMO determines the minimum Reserve Capacity requirement three years in advance;
- Asset owners seek accreditation for capacity to meet the IMO's requirement;
- The Market Rules employs a safety net auction process if insufficient capacity seeks accreditation;
- IMO makes flat monthly payments for accredited capacity at rates referenced to the annual capacity price (or offsets retailer obligations where a retailer has an approved contract with an accredited reserve provider);
  - Accredited capacity must be presented to market unless exempted for a defined maintenance outage approved by System Management;
  - Under the Market Rules the IMO settlement processes deduct capacity refunds in the event accredited capacity is not presented and has not received prior approval for a maintenance outage;

[1] See: http://www.imowa.com.au/f139,788900/RDIWG_Terms_of_Reference_20100901.pdf
[2] For example, refer "Market Rules Design: Problem Statement" available: www.imowa.com.au/RDIWG

- The current design of the capacity refund mechanism is focused on reliability at times of expected peak demand and is shaped accordingly[3] and has implications for the commissioning of new facilities;
- The capacity refund mechanism incorporates a cumulative cap that minimises the exposure of individual participants to a level equal to the amount the generator paying refunds could earn in a Capacity Year;
- Accredited new entrant capacity is required to lodge a security deposit with the IMO that can be withheld in the event the capacity is not presented in accordance with its performance measures within the Rules;
- If a security deposit is withheld it is distributed to Market Customers in a similar ratio to the obligation to fund capacity payments;
- In the event the IMO forecasts the minimum capacity reserve will not be met due to either a lack of response from new entrants or failure of in service facilities the IMO may purchase Supplementary Reserve Capacity (SRC). Market Customers are required to fund SRC purchases through an additional charge at the time of the SRC purchase;
- More generally:
  - The RCM operates in conjunction with energy and Ancillary Service arrangements though the Net Stem Shortfall calculations in the Market Rules;
  - Capacity in the RCM is presented to market on an interval by interval basis (with an allowance for planned outages) either though nomination of bilateral contracts and/or by offering capacity to the market at the Market Participants Short Run Marginal Cost (SRMC);
  - Energy provided by accredited capacity is traded under:
    - bilateral contracts and a day ahead short term market that provides a mechanism for participants to increase or decrease level of contracts, and
    - on-the-day balancing of variations in supply or demand from day ahead net contract positions.

In reviewing arrangements for capacity refunds and SRC charges it is important to consider their role within the design of RCM and more broadly within the WEM. As this paper is limited to consideration of the refund regime and closely related SRC charges it will consider other aspects of the design to the extent needed to ensure internal consistency across the design of the market as a whole. This will allow more focussed consideration of the performance of the refunds and expeditious consideration of any potential changes that may be identified.

2.2 The RCM and Reserve Capacity Refunds

The RCM is a key part of the WEM design and provides a framework for relatively tight management of reliability. A useful way to view the RCM is to consider it as a contract with the IMO on behalf of customers. Like any contract the RCM has terms and conditions such as the flat monthly payment, refunds, the obligation to present capacity and to participate in

[3] See clause 4.26 of the Market Rules.

coordinated maintenance planning. Also, like many contracts the terms and conditions are designed to elicit delivery of a product or service to a defined quality and it therefore includes incentives designed to make this happen. The refunds are a key part of the incentive mechanism within the "contract". They are commercial in nature and provide price signals to incentivise performance.[4]

The current capacity refund mechanism requires Market Participants (Generators) who have been paid for capacity (through Capacity Credits) to pay refunds if that capacity is not made reliably available to the market. The current capacity refund mechanism requires capacity refunds to be made if accredited capacity presented to market is less than (temperature adjusted) accredited capacity:

- as a result of (unplanned) Forced Outages; or
- where a Market Participant presents to Market less capacity than is required, accounting for Reserve Capacity Obligations, Forced Outages and the Capacity made available to the Market in each trading interval

Specifically the capacity refund mechanism requires a Capacity Credit holder to make repayments to the IMO if the capacity is not presented[5]. The refund is currently set on a time based schedule within the Market Rules and weighted to times when high demands are more likely when reserves may be low and the potential risk to reliability highest. The weighting is achieved by setting the refund to a multiple of the payment that the capacity provider will receive over the period of reduced capacity. The refund creates a financial incentive for capacity providers, without an approved outage, to ensure capacity is made reliably available during times when the potential threat the system reliability is highest.

The refund regime provides for Market Participants to perform controllable maintenance at "acceptable" times, as a Market Participant may apply to System Management to undertake a Planned Outage. Planned Outages can include on the day Opportunistic Maintenance (clause 3.19.11 of the Market Rules). During a Planned Outage the capacity provider is exempt from exposure to capacity refunds. A number of criteria must be met prior to System Management's approval of the Planned Outage or Opportunistic Maintenance (outlined in clause 3.19.6 of the Market Rules). Additionally, System Management may reject a Planned Outage at any time where they consider there will be a risk to system security or system reliability (clause 3.19.5).

A consequence of exempting participants with in-service Facilities from exposure to refunds, in the case where they have not received outage approval, the behaviour that the refund is most likely to influence is:

- the reliability of plant in service and expecting to generate to its resource plan; and
- the cost and effort exerted to return plant to service from a forced outage.

This is an important feature of the design, as it means refunds are (implicitly) directed at influencing plant reliability and maintenance performance, not the amount of capacity available to the Market per se.

[4] To extend the contract analogy further, the refunds are a commercial mechanism rather strict terms of delivery that could be breach of contract in other contexts.
[5] The current structure of the Market Rules requires the IMO to pay this refund amount to Market Customers proportional to their IRCR

3. ISSUES AND POTENTIAL FOR IMPROVEMENT

3.1 Introduction

The intent of an effective capacity refund mechanism can be described as to:

- Incentivise **long term maintenance activity** which will minimise future risk to system security and system reliability; and
- 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.

To be of any value the parties exposed to a price signal such as a capacity refund should be capable of responding to it. In addition if a signal is to be economically efficient it needs to be capable of being used by participants to weigh up their internal (private) costs and benefits and to make decisions that have a net benefit to the market as a whole (public benefit).[6]

The current capacity refund mechanism creates incentives for capacity providers to manage their long term decision making processes around appropriate maintenance schedules by clearly defining the periods where the greatest potential system need for capacity at peak times occurs (during the Hot Season). However, as will be discussed further below, not all hours or days within periods of greatest *potential risk* to system security and reliability will have the same *actual* level of risk. Furthermore the times of (relatively) lower risk in peak periods (e.g. mild summer days) offer opportunity for short term maintenance to reinforce reliability for peak conditions.

Additionally, due to the exposure of participants to refunds through Resource Plan shortfalls the current refund regime may create an imbalance in the exposure to refunds for participants with generators with differing utilisation rates. For instance a base load generator will be exposed to refunds in practically every interval of the year while a peaking generator will only be exposed to refunds when dispatched.

3.2 ***Refund Rate v Reserve under the status quo***

As the current regime includes different levels of incentive for different times, it is useful to review how well the refunds aligned with actual conditions: in particular to assess if the incentive created by the refund was strongest when reserve was low and weakest when it was high. The next two plots provide different views of the actual reserve and refund factor over the 2009 calendar year.

[6] Where a price is simply recovering a cost it should be applied in a way that does not create unintended distortions

Figure 1 Cal 2009 Refund Factor v Reserve

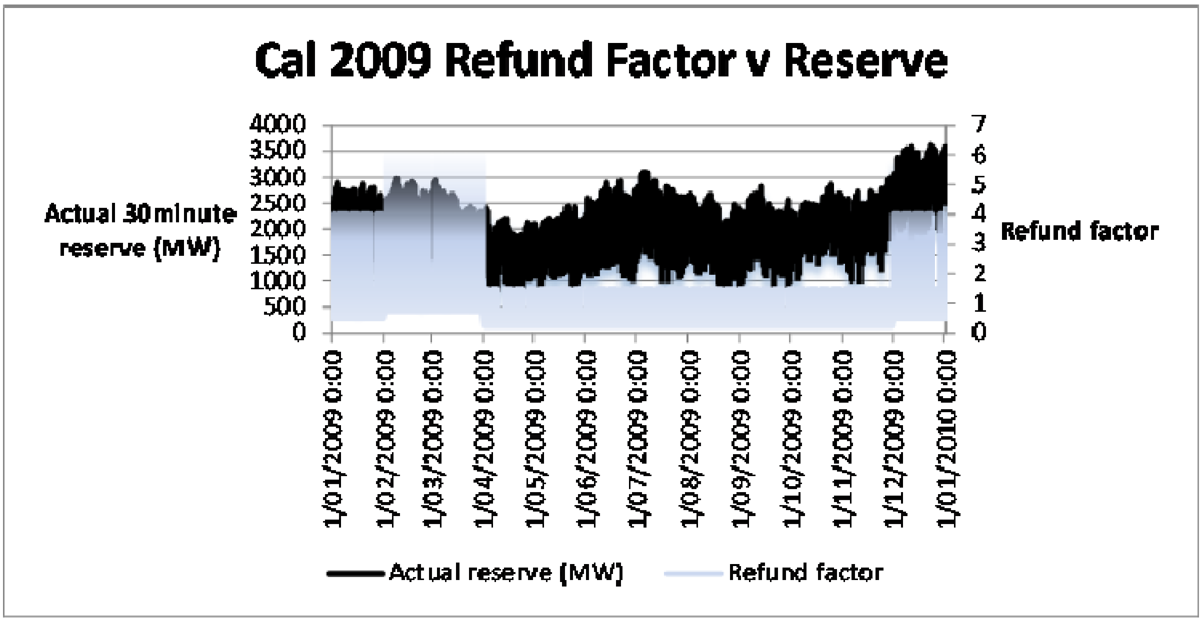
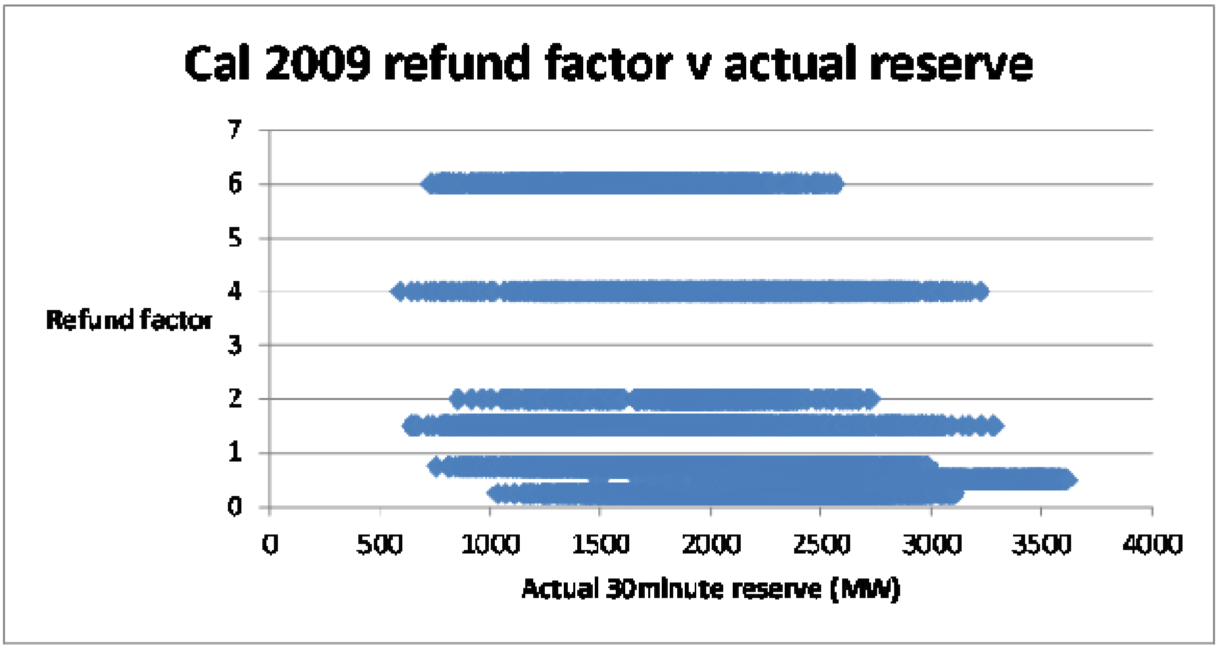


Figure 1 shows actual reserve in solid base plot (as the data covers the entire year only the envelope of maximum and minimum values is readily seen). Figure 2 shows the range of refunds for different reserves across the year. The highest refund rate of 6 applied some of the times of low reserve (as is intended), but factors of 4 and 1.5 also applied for instances of low reserve observed during the year (seen by reading the different levels at the left hand end of the range of reserves). At the low refund end, the highest reserve (3600MW) occurred when the second lowest refund level applied (0.5). The highest reserve occurred when the lowest refund factor (0.25) applied was 3100MW, 1.6 times the largest generating contingency less reserve than the maximum reserve.

Figure 2 Cal 2009 Refund Factor v Actual Reserve



Overall, the current profile and exposure to refunds creates clear long term signals that align with the possible extreme conditions – for example the refund is highest in day light hours in summer and weakest when high reserve is most likely. This can be seen from the broad shape of Figure 2 showing lower refund for higher reserve in general (slight negative correlation evident). However, there are many exceptions that suggest there may be scope for amendment.

4. POTENTIAL SOLUTIONS

Short term risk to reliability of supply can be measured by the Loss of Load Probability (LoLP). However, if refunds were based only on LoLP, refunds would be likely to fall to *very low levels* for reserve that was more than a relatively low margin above the largest unit, but would also lead to very high refunds *well in excess* of the current maximum level that applies in peak periods of summer. This would change the risk exposure and prudential risks in the market and should only be contemplated if it is clearly a net benefit – this not expected. It would also require acceptance that long-term incentives relating to maintenance programs was entirely reliant on short term risk.

Two broad forms of amended arrangement designed to address both short and long term objectives are discussed below. These are:

1. A dynamic refund rate based on the reserve available in any particular interval; and/or
2. A refund rate based on a dynamic reserve calculation overlaid with longer term factors.

Ultimately it is assumed that a regime based on a dynamic calculation of the refund rate and actual reserve with a cap on the maximum refund (potentially set at the same level as the current regime) is a pragmatic translation of the current regime. In conjunction with changes to the exposure to refunds described below this will provide a refinement that creates incentives for both short and long term scheduling of maintenance effort and more equitable treatment of different forms of capacity.

4.1 Basic reserve related refund

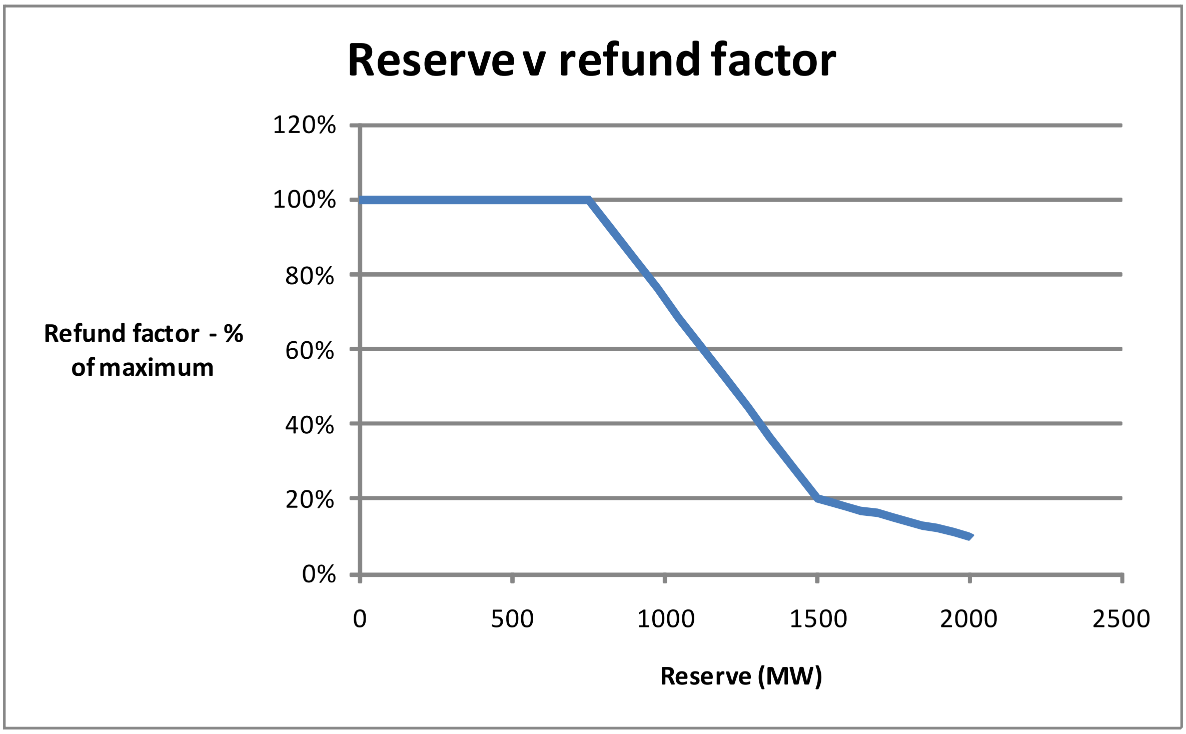
The first alternative is a simple regime that is responsive to prevailing conditions and would:

- Involve a refund rate determined from a series of breakpoints on a reserve versus refund factor relationship;
- The refund factor would be capped – the cap will limit prudential and commercial risks to participants;
- Include a lower minimum floor level to apply once reserve rises to more than a nominated factor above the minimum capacity requirement; and
- A further breakpoint at a higher level of reserve with a very low level of refund (possibly 0).

Compared to a purely short term LoLP based approach the resulting refunds will be far flatter and show a lower refund under lower reserve but higher under moderate to low reserves (for example n the range of 750MW -1500MW at peak times on hot days).

Figure 3 illustrates the relationship using potential breakpoints broadly based on the minimum reserve requirement.

Figure 3 Reserve v Refund Factor



4.2 Combination actual and annual forecast reserve

Another approach to the balance between long and short term activity would see an annual factor based on a measure of annual reserve level applied to the simple dynamically calculated interval factor such that in years with lower reserve the annual factor would lift all refund rates reflecting the higher value of capacity.

This is a more sophisticated approach designed to be more responsive to both long and short term conditions. There are two broad approaches that the annual factor could be based on:

1. historical outages/availability; or
2. forecasted outages/availability

Of the two approaches to setting the annual factor under such a scheme an assessment of likely actual reserve (forecast method) appears more robust as the reason for poor performance in a previous year may have been because of intensive maintenance (planned or forced) that will see good performance in the year in question. However, it is also notable that reduced performance in any year will see lower system wide reserve on more occasions under all conditions.

The basic reserve refund concept is backward sloping and thus longer time with lower reserve will automatically result in a higher refund rate. On this basis the combination alternative has not been pursued.

4.3 Combination forecast and actual reserve related refund

More complex versions which sit between the two methods outlined in sections 4.1 and 4.2 of this paper could see the refund set on the basis of combination of forecast reserve and actual on a more granular level. For example it would be possible to set an “importance” factor for each month where this factor would be a reflection of the relative risks shortage of capacity in that month poses to system security and reliability. The maximum reserve capacity multiplier would then be scaled in each month depending on the “importance” of the month.

Clearly there would be opportunities to adjust the factors to change the percentage of ex ante and ex post and the relationship with forecast and actual reserve and also to change the cap and floor levels. While such an arrangement would provide a more sophisticated approach it would also be more complex. On balance that complexity does not seem warranted at present in light of the improvements that can be achieved from a simpler option.

5. IMO PROPOSED SOLUTION

The IMO considers that, on balance, the basic reserve related refund approach will provide an appropriate mix of long and short term incentives. This method is responsive to prevailing conditions and creates incentives for appropriately timed maintenance. The profile can be structured so the probability of the peak refund not applying at anytime during the year is low and as a result delivers an incentive to undertake maintenance for all peak periods and reduces the risk that a participant may choose to risk avoiding exposure and not pursue an adequate maintenance regime. In years with surplus capacity the hours of exposure to the higher rate will be less and conversely will be higher in years with low reserve.

However, it should be noted that in any realistic scenario there will always be significant exposure to the capped factor.

To assist participants to assess the risk of exposure to refunds the IMO would publish forecasts of the likely reserve over a long horizon and the potential refund rate that a market generator would be exposed to in those situations. The forecasts would likely use the MT PASA for long term projections, the ST PASA for a more granular short term indication of likely refund rates, and finally, the day ahead forecasts to help participants make real time maintenance decisions.

5.1 Defining the magnitude and profile of the dynamic regime

This section considers the design of a basic dynamic refund *v* reserve arrangement in more detail. Design of a refund arrangement can be divided into consideration of three issues:

- The profile of refund or how well the relative refund under different conditions aligns with the incentive that the design is attempting to create. This is about the relativity of net payment for capacity under different conditions;
- The magnitude of refunds within the profile; and
- Exposure of participants to refund.

This next sections deal with how the first two of these dot points could be defined under the proposed methodology while section 6 of this paper deals with exposure.

5.2 Cumulative Refund Cap

The IMO considers that there is no need to change the current cap on cumulative refunds that can be imposed in a period under the Market Rules, for example when commissioning of a new unit runs late.

However, if the cumulative refund limit were to be retained at its current level then the financial consequence of a delay in commissioning of a new unit may be less. This is because the actual reserve during the delay period would most likely not be at the maximum foreshadowed in the current regime at all times and the refund would be lower at those times. This would depend on how severe the resultant loss of aggregate capacity was and for the reasons outlined earlier mean that the refund factor would be higher more often than if the plant did commission on time counteracting the lower refund factor to some extent.

5.3 Analysis: Status Quo Compared to Dynamic Mechanism

Analysis of refunds under the existing design and also under an illustrative setting for the "Basic Reserve Related Refund" is presented below. The analysis has been conducted for the 2008 and 2009 calendar years.

The results show that while there were marked differences between the results for the two years it is notable that taken over the longer term the cumulative refunds across the market were similar under the two approaches (with the profile set as described in section 5.4). These effects are shown in

Figure 4 through to 10. In Figure 6 the effect of different monthly refund base capacity payments is evident and results in some spread of refund rates for the same reserve.

Figure 4 Comparison of cumulative total refund: calendar 2008

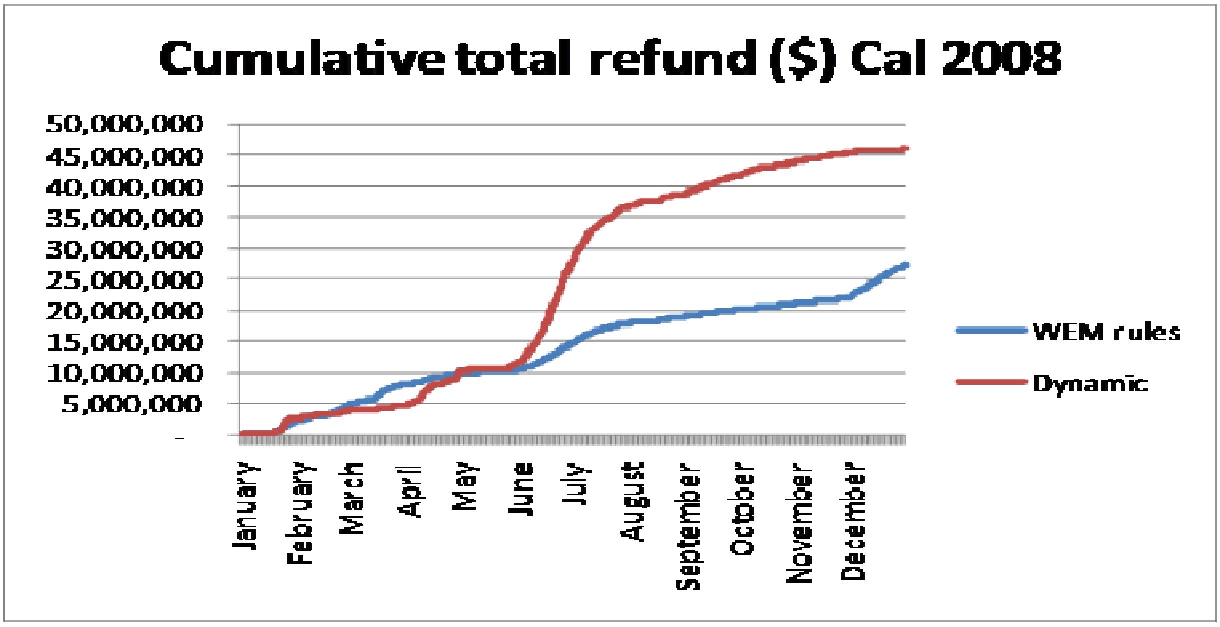


Figure 5 Refund rate versus reserve in calendar 2008: WEM rules

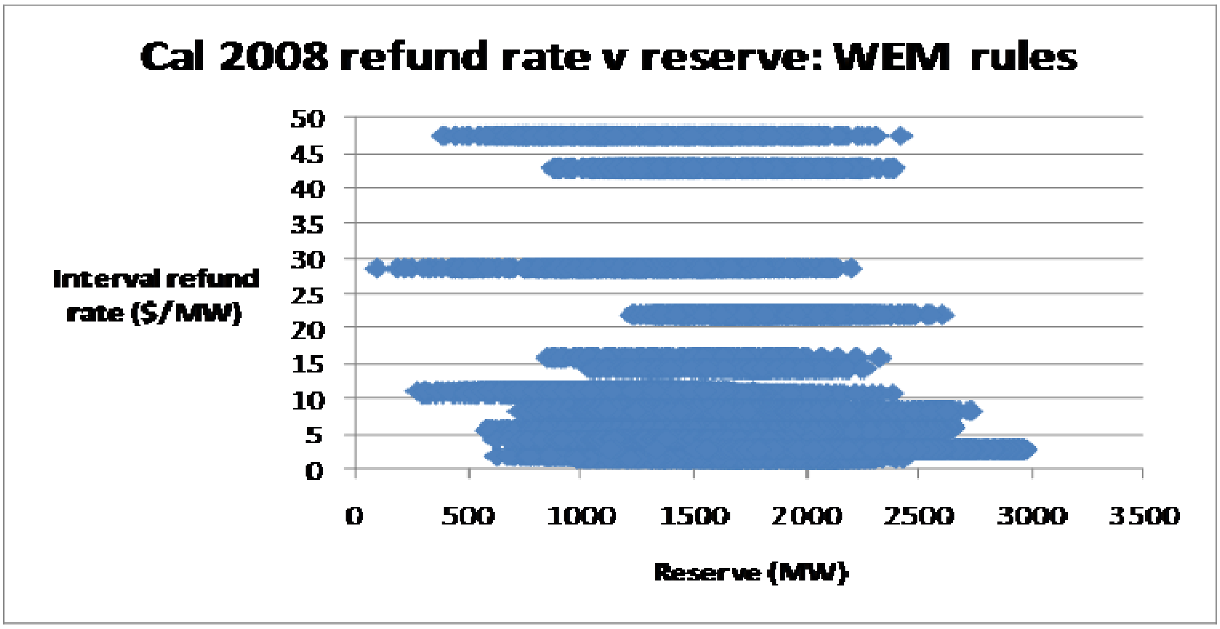


Figure 6 Refund rate versus reserve in calendar 2008: Dynamic settings

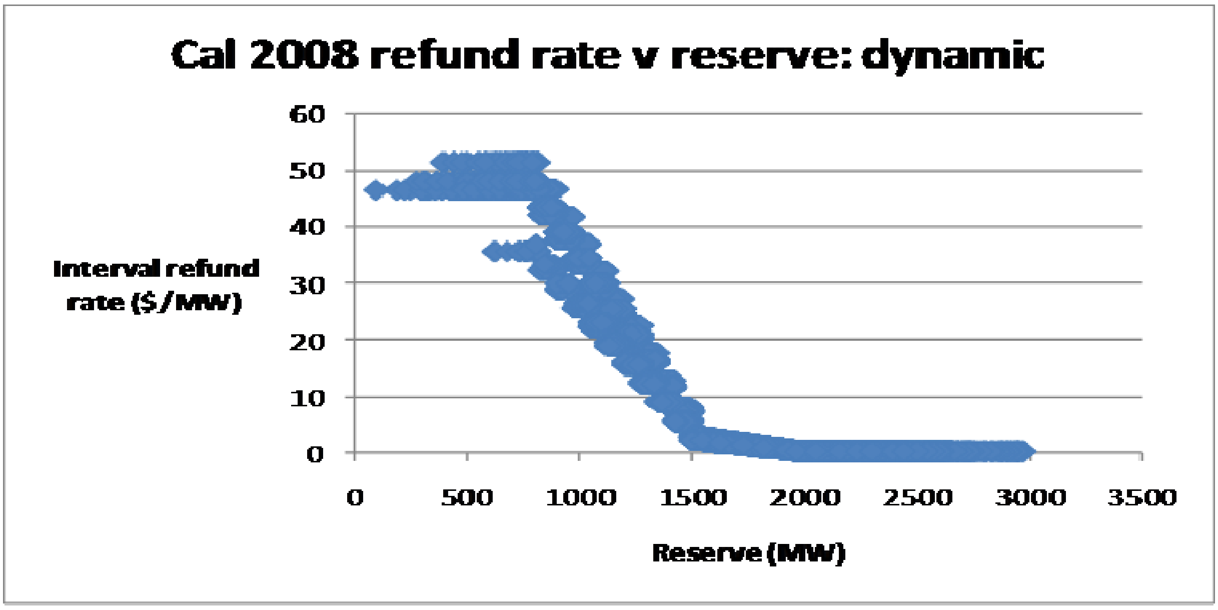


Figure 7 Comparison of cumulative refunds: calendar 2009

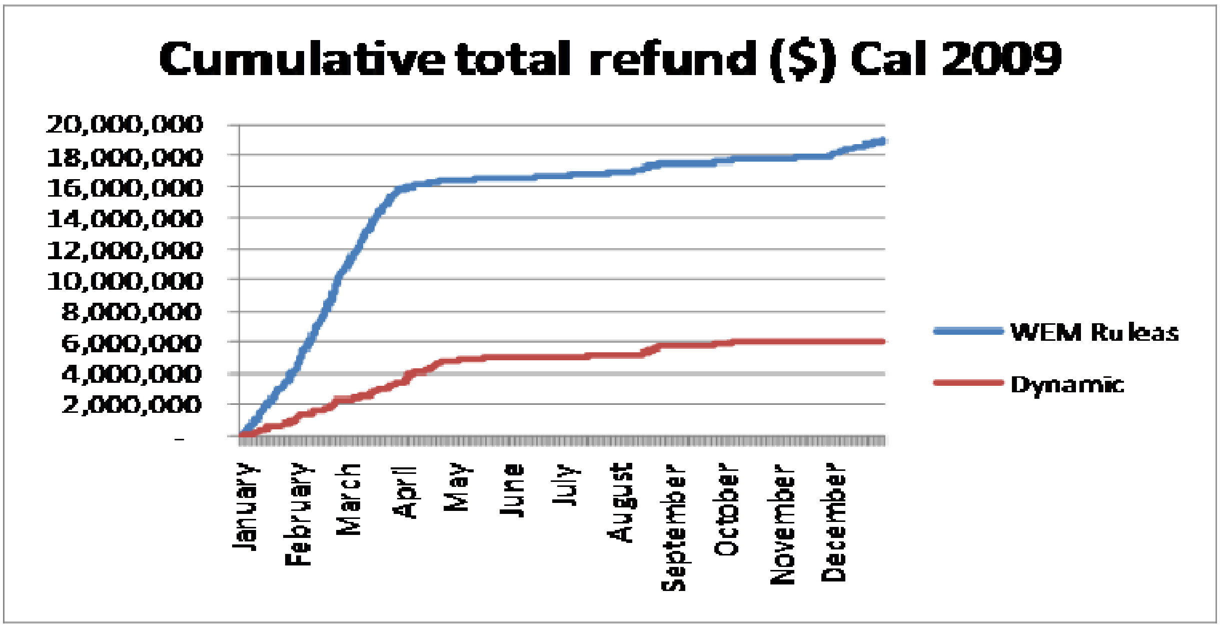


Figure 8 Refund rate versus reserve in calendar 2009: WEM rules

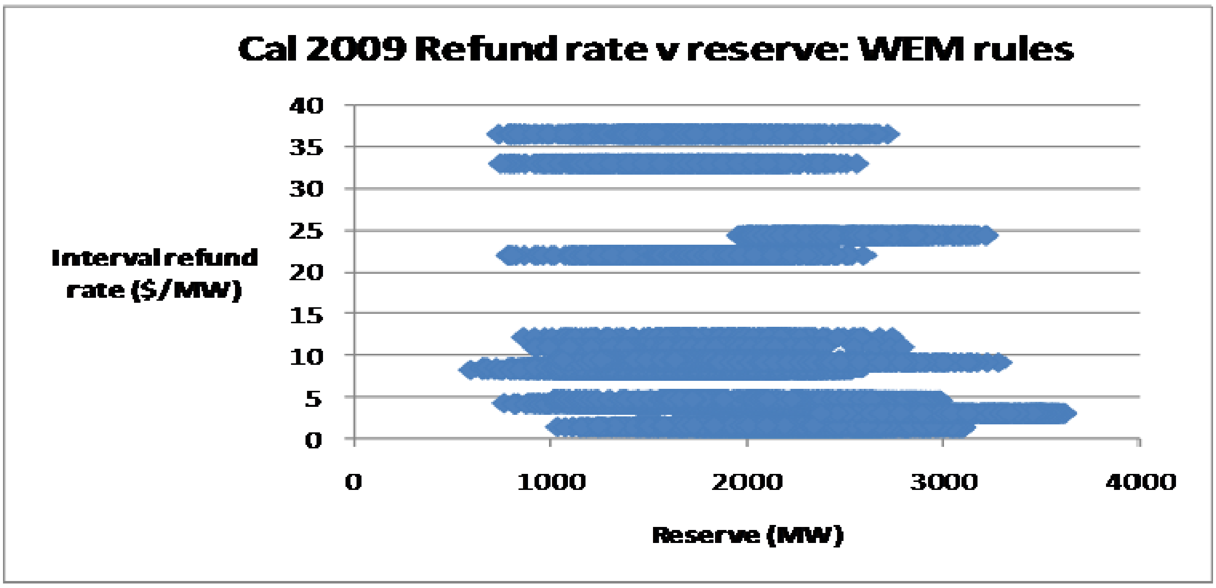


Figure 9 Refund rate versus reserve in calendar 2009: dynamic settings

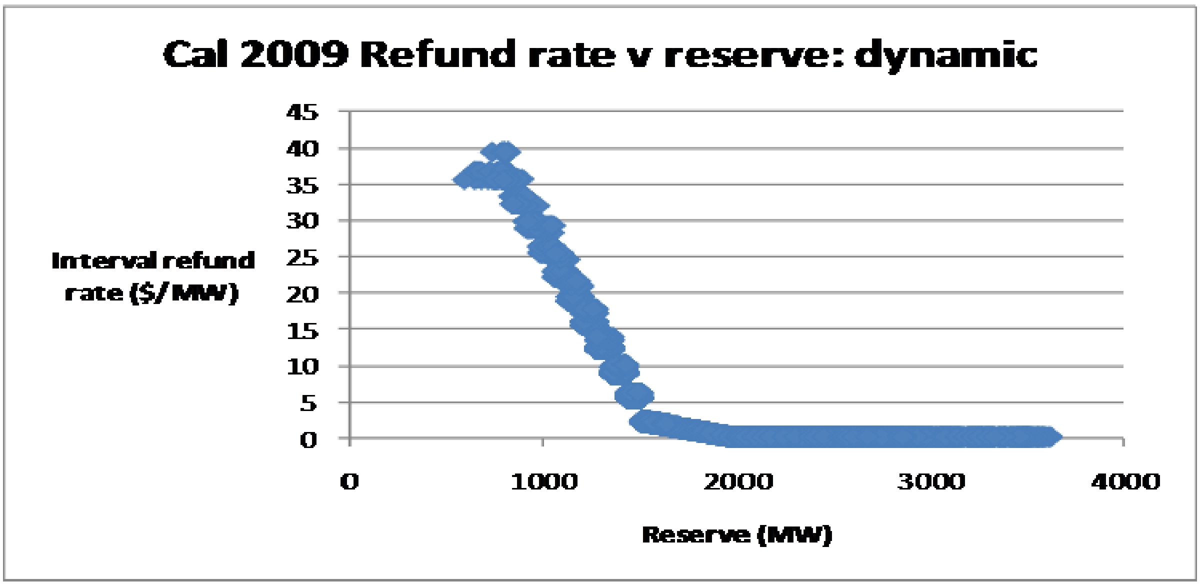


Figure 4 and Figure 7 show that across the year refunds can be higher or lower under the dynamic regime compared to the current WEM rules. Interestingly, over the two years studied the current refund rules were introduced the total refund is approximately the same.

The key point is that under the "Basic Reserve Related Refund" regime the refund rate ($/MW) is a function of reserve and thus value at the time.

5.4 IMO Proposed Solution

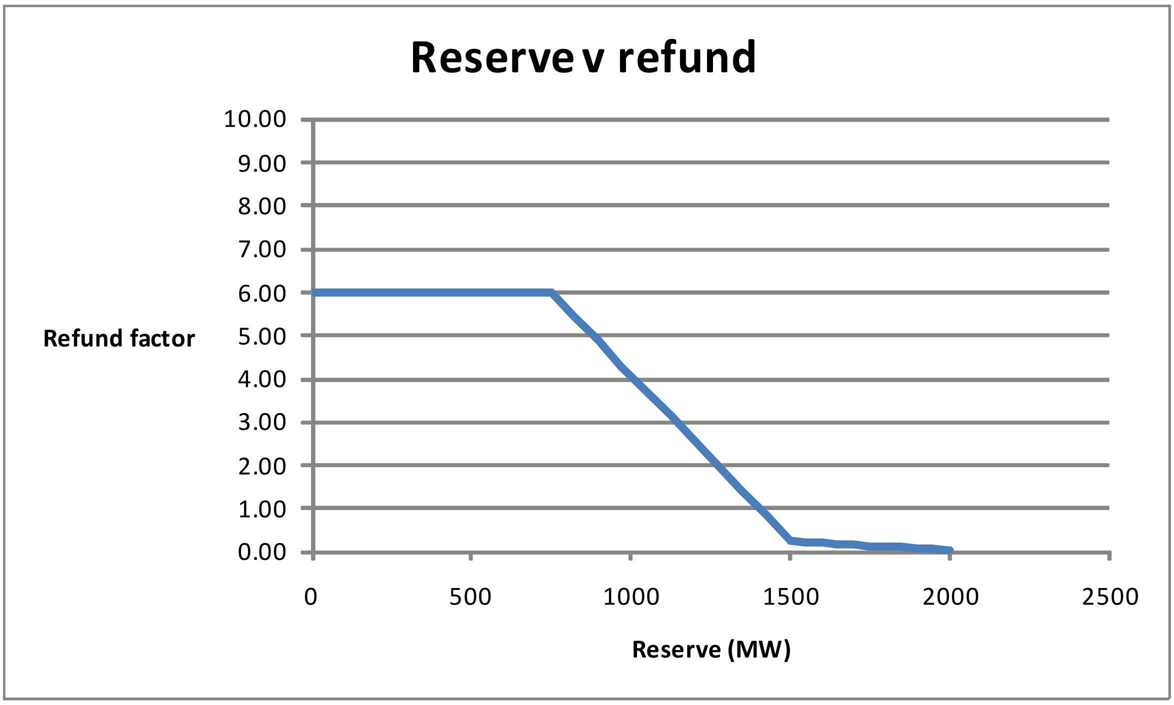
The IMO proposes that the maximum refund factor remain at the maximum value of 6. As noted analysis of the 2008 and 2009 calendar years shows that the cumulative refund amounts under the Market rules and the proposed methodology are similar. The IMO considers that as the design is aiming to produce a pragmatic balance between long and short term incentives a different level of maximum refund factor may not necessarily yield a more efficient or effective result although there is an element of choice about the level adopted. The current defined maximum level of 6 is yielding a level of refunds that is established in the Market and as noted delivers similar to outcomes over a year.

The IMO proposes to set the profile of the refund regime so that:

- The capped refund factor that would apply whenever reserve was below a nominated percentage of the minimum capacity reserve is to linked the required minimum reserve used by System Management in outage planning, say 2*min reserve ~ 750MW;
- the lower minimum floor level to apply once reserve rises to more than a nominated factor above the minimum capacity requirement be set equal to 4* min reserve ~ 1500 MW; and
- the final break point be set such that the refund factor is set to zero when the reserve is greater than 6 * min reserve ~ 2000MW.

Figure 4 illustrates the relationship using the breakpoints noted above.

Figure 10 Reserve v Refund



6 EXPOSURE TO REFUNDS

The sections above have considered amendment to the refund rate. This section considers the exposure to the refunds in two respects.

The first is that, as noted earlier there is an imbalance in the exposure to refunds that depends on the utilisation of the facility in question – the lower the utilisation the lower the risk of exposure.

The second relates to the mechanism for identifying the conditions under which refunds should be imposed. The Market Rules require the payment of a refund where a Market Participant presents to Market less capacity than is required, accounting for Reserve Capacity Obligations, Forced Outages and the Capacity made available to the Market in each trading interval. This shortfall in capacity is captured in the Net STEM Shortfall calculation in the Market Rules. Analysis of the 2008-09 and 2009-10 Reserve Capacity Years indicates that historically the Net STEM Shortfall refunds, as a proportion of total refunds, were 5.1% and 6.5% respectively (see Figure 11 Forced Outage v Net STEM Shortfall Refund). It is clear that the bulk of the refunds by participants are made due to forced outages. The Net STEM Shortfall refunds only represent a small proportion of the refunds but in practice is not technology neutral. This is because resources with low operating costs are more likely to be dispatched at any given time and thus more exposed to risk of refund due to what may be normal variations in operation of their plant whereas other low utilisation technologies are only subject to refund on the basis of a more controlled test.

Adjusting the figures to remove the impact of the late entry of the Griffin Bluewaters 1 facility in the 2008-2009 Reserve Capacity Year does yield slightly results; though does not exhibit an inconsistent trend. The contribution of the Net-STEM shortfall in the 2008-09 and 2009-10 Capacity Years are 9.1% and 6.5% of total refunds. Monthly breakdowns are exhibited in Figures 13 and 14. Figure 15 shows the relative cumulative contributions from both the Net-STEM shortfall and Forced Outage refunds. Adjusting for the effects of the Griffin Bluewaters late entry drastically changes the quantum of the refunds that were paid to the market in the 2008-2009 Reserve Capacity Year and bring its into line with the following Capacity year where no late entry of facilities occurred.

Figure 11 Forced Outage v Net STEM Shortfall Refund

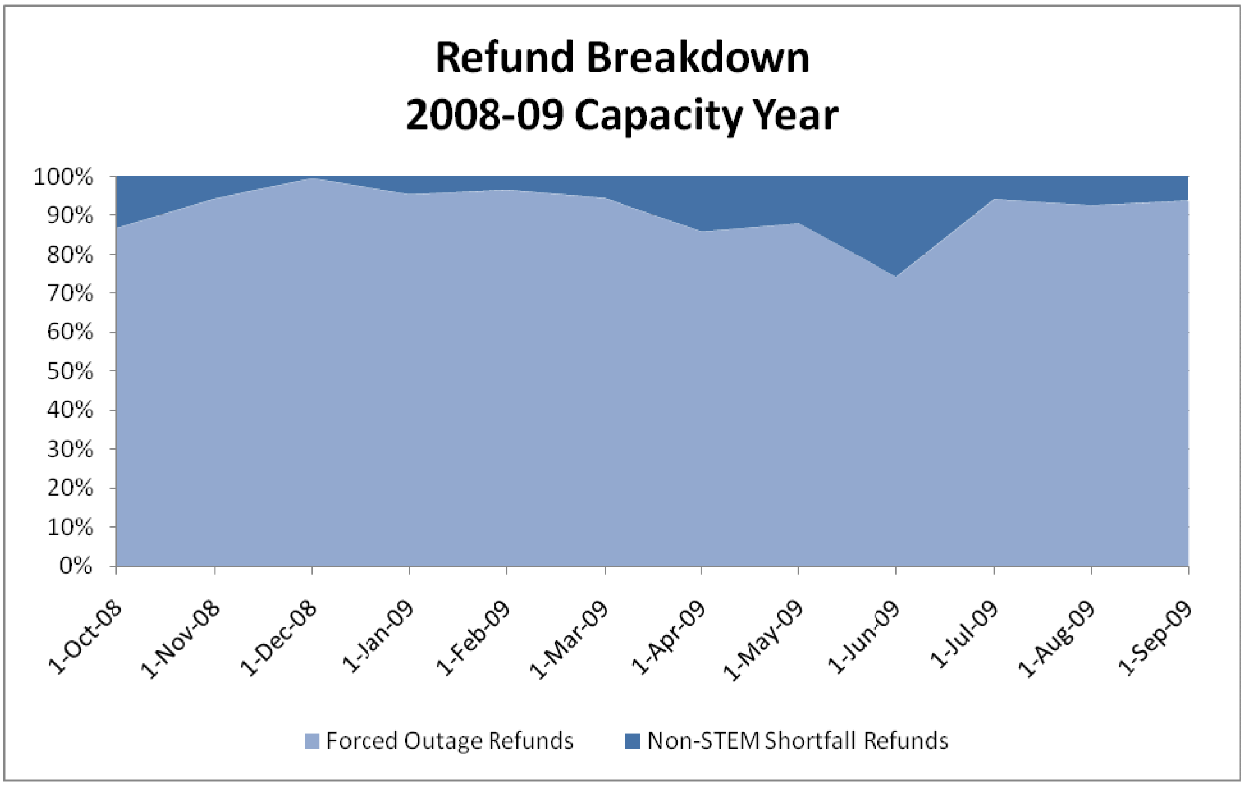


Figure 12 Forced Outage v Net STEM Shortfall Refund

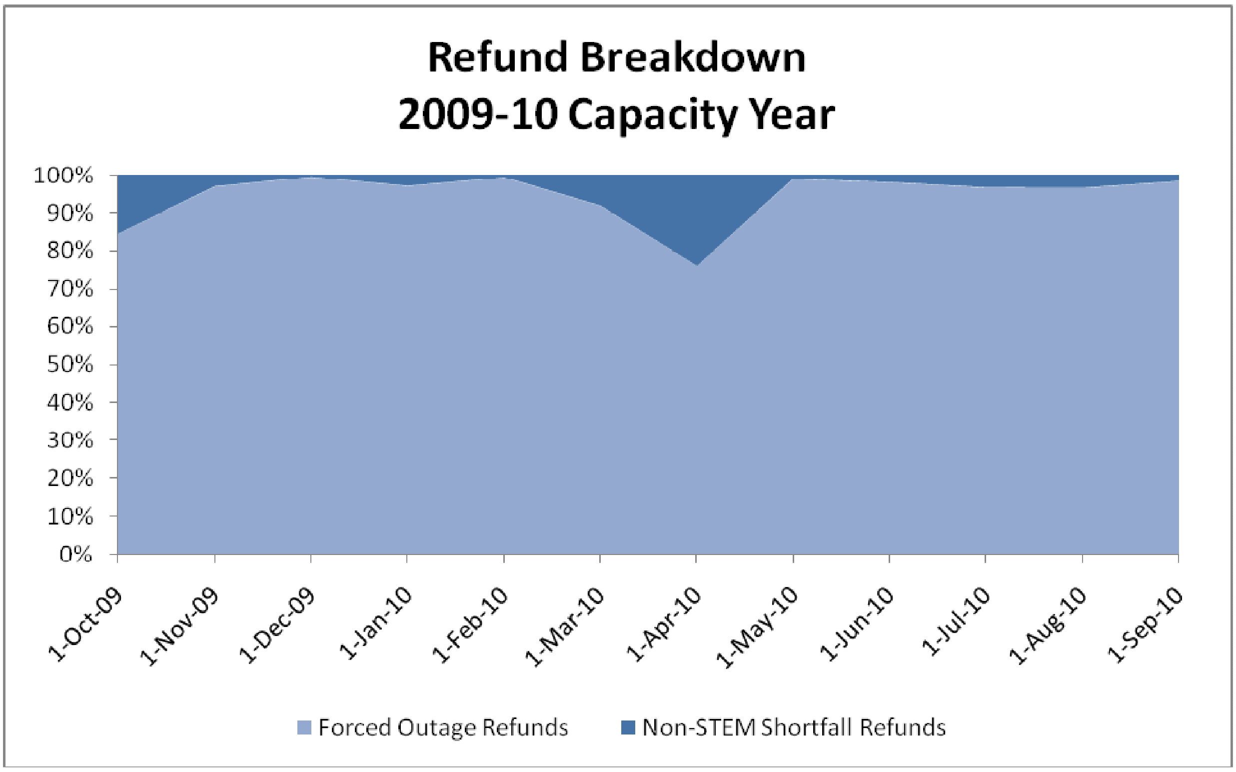


Figure 13 Forced Outage v Net STEM Shortfall Refund (Griffin Adjusted)

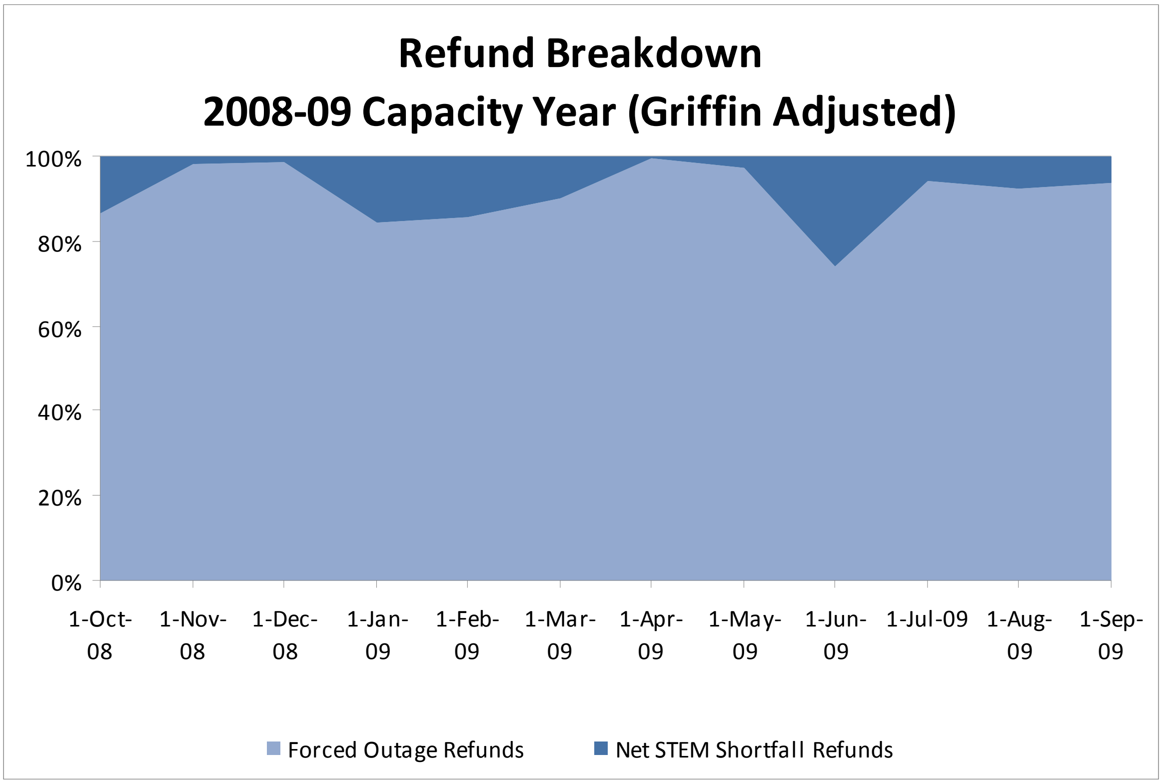


Figure 14 Forced Outage v Net STEM Shortfall Refund (Griffin Adjusted)

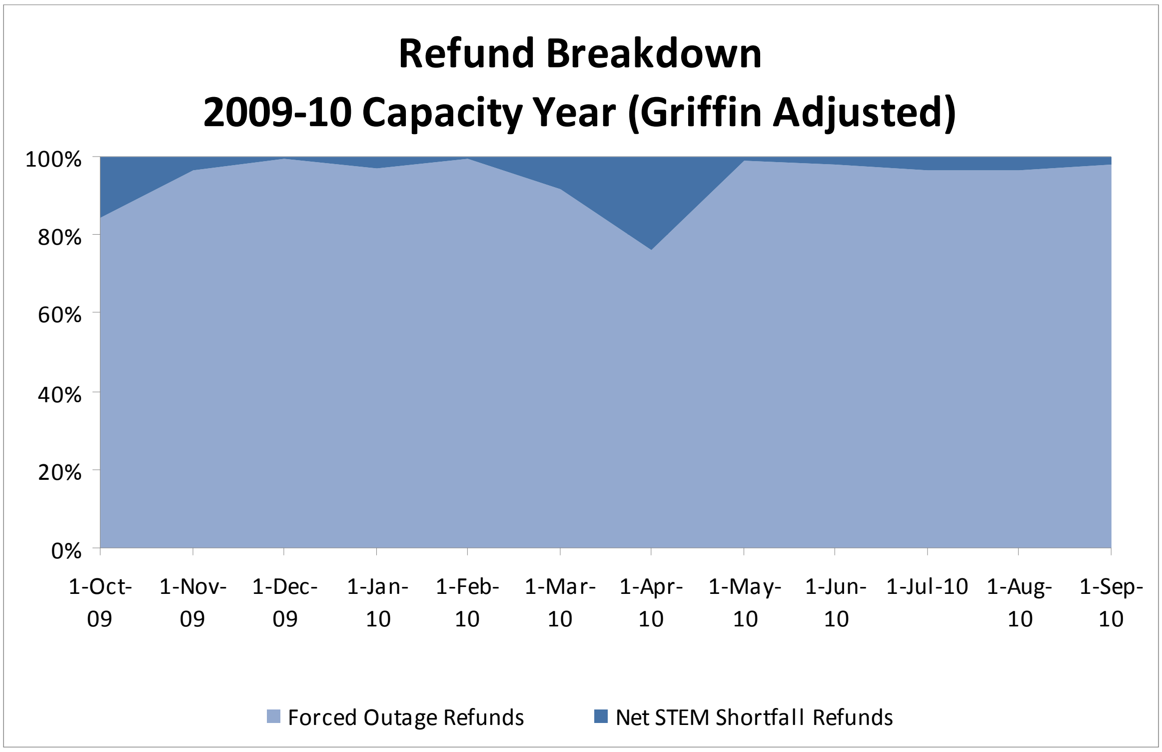
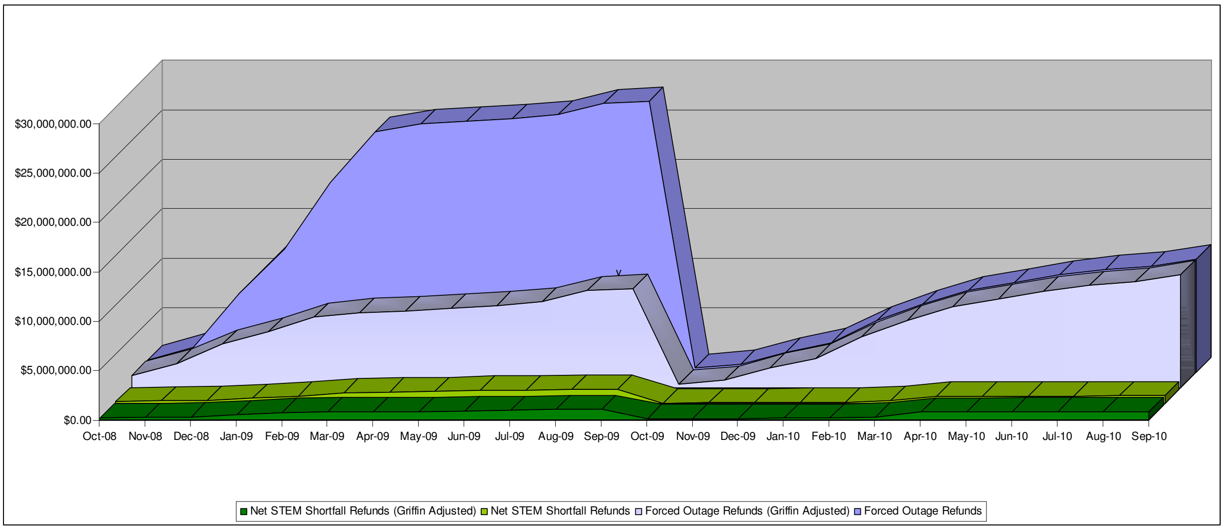


Figure 15 Cumulative Forced Outage and Net-STEM Shortfall Refunds (Per Capacity Year) - Normal and Griffin Bluewaters Adjusted



In reviewing exposure it is useful to note that exposure is a matter of policy rather than analysis and the following principles and mechanisms are proposed for the future:

- As far as practicable all capacity providers should be treated equally;
- All holders of accredited capacity should be required to declare the level of capacity being presented to market each day.
    - The declared amount should only be less than the accredited capacity if System Management has approved a planned outage (see below) plus any amount declared as a forced outage.
    - Approval should be reviewed/confirmed on a daily basis prior to the declaration.
    - The declaration can be part of the STEM submission process but should be a separate and formal declaration on behalf of the business.
- Refunds should only be imposed as a result of a declared Forced Outage or a failure to pass an “Operational Test”.
    - The “Operational Test” should be designed to confirm available capacity when there is a reason to believe it may not be available and is a consequence of moving from an automatic exposure regime to a compliance and surveillance regime. Provisions for the conduct of an Operational Test should not create an unnecessary burden on System Management as the test is essentially a commercial and compliance measure rather than a real time dispatch mechanism;
    - To that end failure to follow a resource plan for a short period should not automatically result in exposure to a refund. The reason for this is that it is within good industry practice for generating units to exhibit some variability in output in the short term. Generation businesses should be expected to seek to

operate each unit in the most efficient manner to meet a target output – in the WEM the resource plan. Variation for minor operational fluctuations is not a definitive indication that the unit would not pass a test of the same sort that a unit that is available but not operating at the time would.

- Clearly failure to reach or maintain full resource plan level of operation is an indication the unit MAY not pass such a test.
- The Operational Test would be conducted either
  - in real time by System Management; or
  - Ex-post by the IMO.

  Each of the above options has differing pros and cons, however a threshold for testing would need to be established and would be considered in the detailed design of rule amendments including that there will be an interaction between calling for a test and emerging changes to arrangements for balancing and ancillary services and the resultant implications for System Management control room activities.
- More surveillance resources will be required for this to work:
  - this may be in the form of an automated system for system management and the requirement for system management to call such tests in specific situations; or
  - more staff and/or IT systems for the IMO to monitor the resource plan deviations of market participants and co-ordinate the testing with SM.

Further refinements may also be possible within the general principle in respect of provisions for opportunistic maintenance and the notice period for approval of maintenance outages ex post. The IMO proposes that, if time permits, this area be developed further as part of the rule change process needed to implement amendments arising from this proposal.

6.1 IMO Proposed solution

The IMO proposes that Net STEM Shortfalls be removed from the Market Rules as a basis for imposing Capacity Refunds.

Further that Capacity Refunds should only be imposed as a result of a declared Forced Outage or a failure to pass an "Operational Test" as outlined in the previous section.

7 DISTRIBUTION OF RESERVE CAPACITY REFUNDS

This section reviews the arrangements for the distribution of Reserve Capacity Refunds received by the IMO and looks at the sources of funding of Supplementary Reserve Capacity (SRC) and proposes an amendment, including the formation of a fund available to be used in the event the procurement of SRC is required in response to a shortfall in capacity in the Wholesale Electricity Market.

7.1 Current Arrangements

Reserve Capacity Refunds are currently collected by the IMO under two circumstances:

- if a Market Participant lodges notice of a forced outage with System Management. Forced outages attract a refund, per trading interval, of the amount that would have been paid by the IMO for the provision of the capacity (capacity payment) multiplied by the refund factor defined in the refund table (Market Rule 4.26.1) for which an amendment has been proposed in paragraph 5.4 above; and

- where a Market Participant presents to Market less capacity than is required, accounting for Reserve Capacity Obligations, Forced Outages and the Capacity made available to the Market in each trading interval - this type of deficiency is termed a Net STEM Shortfall which the IMO is proposing be removed from the Market Rules as a basis for imposing Capacity Refunds .

The sum of these payments over a trading month represents the total amount collected relating to Reserve Capacity Refunds. Reserve Capacity Refunds are distributed to Market Customers consistent with the principle that they are responsible for payment for the capacity "service". Reserve Capacity Refunds reflect the degree to which the service of providing capacity was not delivered.

The market settlement arrangements also include that:

- If the IMO purchases SRC Market Customers shoulder the costs as an unbudgeted expense proportionate to their share of the Shared Reserve Capacity Cost; and

- Under certain circumstances the IMO may also withhold security deposits from accredited new entrant capacity that does not meet the required performance measures specified in the rules. Withheld security is distributed to Market Customers in the month in which it is forfeited in accordance with the peak demand calculation used to determine Market Customer obligations – viz. the IRCR

The current arrangements results in the following issues:

7.2 Refund Distribution Issues

1. Market Customers are unable to budget for their share of the distribution of refund payments due to the volatility around when Reserve Capacity Refund events, such as forced outages, occur.

2. Refunds are distributed to Market Customers regardless of any bilateral contracts for capacity that are in place. This presumes that the capacity payment is factored into the agreed bilateral contract price between Market Customers and accurately reflected in payments to Market Generators. Therefore any risk associated with contract prices not reflecting the prevailing capacity price (appropriately) will be borne by the contracting parties in accordance with the contract.

- For example: if a Market Generator accepts a contracted fixed price but the Reserve Capacity Price rises and Market Customer receives refunds at a higher rate than it is paying the Generator, then Market Generator is "leaving money on the table" as the market is valuing capacity higher than it is being paid: and vice versa.

Security deposit issues

1. Security deposits held by the IMO until such a time that the SRC risk associated with the respective facility ceases to exist. They are then allocated to Market Customers in the same trading month assuming where there was no requirement to fund SRC. The security deposits are then distributed on the basis of the Market Participants contribution to the Shared Reserve Capacity Cost. This is consistent with the basis for Market Customers obligation to fund capacity.

SRC Related Issues

1. In the event that an SRC event arises and funding is required, Market Customers are exposed to uncertain and lumpy cash flow requirements. This is unhelpful for budgeting and management of tariff settings for Market Customers where there can be multiple lagging cash flow effects around recouping the costs of any unbudgeted SRC payments.

2. The collection of Reserve Capacity Refunds and distribution to Market Customers may not align with times where an SRC event occurs and payment for the service is required and this misalignment may be seen as my lead to windfall gains or losses if new participants enter the market or others leave.

7.3 Opportunity for refinement

This section discusses a number of options for refinement in the light of the preceding observations within the broad design of the Reserve Capacity Mechanism and the concept of Reserve Capacity Refunds including:

- Aligning the methodologies to allocate Capacity Refunds and the allocation for withheld security deposits. There is also scope to look to adjust the timelines around the determination of the IRCR at a later date. Currently the IRCR is calculated using data from three months previous. This lagging effect could potentially be improved to exhibit only a one month lag.

- Creation of a fund to be held by the IMO and used to purchase SRC to remove the lumpiness in the payment required to the Market.

7.4 Mechanisms considered

Several mechanisms have been considered to address the issues listed above.

Creation of a Market SRC fund to be held by the IMO and used for funding the procurement of SRC.

Several approaches and methodologies could be employed to create a Market SRC Fund to meet at least some of the costs of any SRC procured by the IMO and thus reduce the size of calls to fund SRC.

- Approach 1 – Single SRC Fund (Dynamic Refund Distribution)

  - This would involve the creation of an on-going Market SRC Fund. The Fund would be empty at its creation and have a maximum level which would be set by the Market Rules.

  - The fund would initially be topped up by directing refunds that are currently distributed to Market Customers on a monthly basis. This would continue until the Fund reached the required level probably over a number of months;

  - Once the Fund reached the maximum level, the IMO would cease allocating refunds to the fund.

  - In the event that the IMO is required to procure SRC, the Fund would provide the initial funds with which to pay for the SRC.

  - If the Fund is partially used or depleted, then the IMO would allocate refunds to the Fund until it reaches the maximum level.

  While this approach will reduce the probability and risk of a call for funds to meet an SRC purchase there will be an unavoidable misalignment of the obligation to pay for the SRC at the time it is required and contributions to the Fund at an earlier time. For example a new entrant Market Customer could reap the benefits of the SRC fund but not directly contribute to it.

  However, this approach also means refunds will continue as now once the Fund is at its maximum level.

- Approach 2 – Cyclic Market SRC Fund

  - This approach also involves the creation of a single fund which would endure over multiple capacity years but be notionally emptied each year.

  - This fund would be empty at its creation and have a maximum level which would be set by the Market Rules.

  - The fund would initially be topped up by allocating refunds that are currently distributed to Market Customers on a monthly basis. This would continue until the fund reached the required maximum level.

  - Once the fund reached a maximum level, the IMO would notionally return the contributions to the Market Customers that contributed to it while at the same time requiring contributions to refill the fund. Continuing Market Customers with the same level of peak demand would face equal and opposite refunds and contributions. Only Market Customers with changing peak requirements would see any difference.

- If the need for SRC arises, then the will IMO utilise the fund to acquire SRC and procure any additional monies to cover any shortfall.

- Similarly if SRC was required refunds to existing Market Customers would be directed to refilling the fund in the first instance

This approach brings the allocation of obligations to fund SRC and entitlement to refunds closer but does not fully align the provision of the capacity “service” the obligation to pay for the capacity as those Market Customers who will be obligated to pay for the capacity service for any given year. This is also the case where those Market Customers who enter the Market reap the benefits of the SRC fund where they had not contributed to the creation of the fund.

While Approach two is potentially more equitable than Approach 1, there are potential practical issues with the implementation that make it the less attractive option. The cyclic fund may have unwanted settlement effects as refunds that are held in the fund would remain there for a period of 12 months (before they leave the cyclic fund). Their release would most likely coincide with the third settlement adjustment for a trading month. This may result in greater transfers of monies at this third adjustment period with no ability for re-course if implemented under the existing settlement arrangements. As such, settlement modifications would need to be made to accommodate this approach.

In each of the approaches refunds received by the IMO would in the first instance be used to build the SRC fund up to its maximum level (SRC Fund Cap). There seems no practical alternative to setting a maximum size of any SRC fund that is established and then allocating refunds over and above this amount to Market Participants. As Market Customers either directly or indirectly (though bilateral contracts) pay the entire capacity price it is appropriate to distribute “surplus” refunds to Market Customers (and inappropriate to allocate to other parties).

Each of the approaches for an SRC fund, however, would reduce the potential for lumpy calls for additional funds in the event SRC is purchased. Note however that once the fund is at its maximum level capacity refunds received by the IMO would be returned to Market Customers, albeit possibly using a different methodology to that used at present.

7.5 Proposed amendments

On balance the following amendments are recommended in relation to the application of funds received by the IMO as capacity refunds:

1. Create a SRC Fund with a cap equal to the SRC Fund Cap (level to be decided – for example 50MW * Maximum Reserve Capacity Price);

2. Apply refunds received in a month to the SRC fund until the balance in the fund reaches SRC Fund Cap;

3. Interest received by the IMO in respect of the SRC fund to be added to the fund until the balance in the fund reaches SRC Fund Cap;

This package of amendments will reduce the risk and size of calls for funds to pay for SRC. It will also align the refunds more closely with the obligation to pay for capacity and hence be more cost reflective and thus more accurately reward demand side management initiatives by Market Customers. The IMO proposes that Approach 1 be used as it yields the desired outcomes, while avoiding the complication of the Cyclic Market SRC Fund in used Approach 2.

Alternatives to account for capacity obligations and refunds on a year by year basis including clearing the fund each year and utilising more complicated smoothing of refund streams have not been proposed. This is a judgement call based on the increased complexity for relatively little gain and a presumption that beyond the reduction in risk and size of calls on Market Customers to fund SRC purchases, participants should be responsible for (and prefer to) manage volatility of revenues. It is, however, clearly a matter for participants to debate.

8 RECOMMENDATION

That IMO recommends that the RDIWG:

- **Discuss** amendment of the capacity refund regime and endorse dynamically calculated refund factor based on actual reserve and a series of breakpoints as described above in section 5.45.1;

- **Discuss** removal of Net STEM shortfall as the basis for imposing refunds subject to its replacement with “Operational Test” (described in section 7.5) as a basis for refunds;

- **Discuss** the creation of a SRC Fund and endorse the allocation of refunds to that fund as described in section 7.4; and

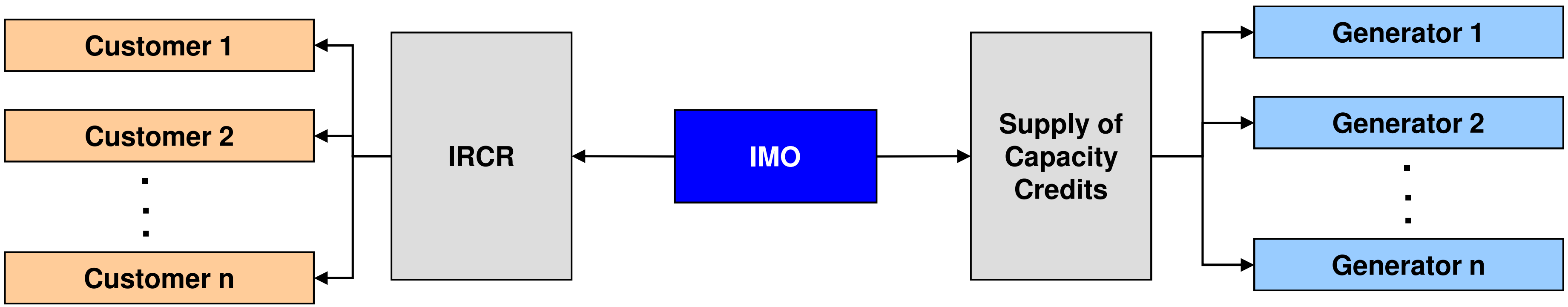
- **Discuss** the allocation of refunds to Market Customers (after accounting for allocation to the proposed SRC Fund), interest on the SRC Fund and withheld security deposits on the basis of peak demand obligations using the principles for allocation of withheld security deposits within the current Market Rules.

Capacity Refunds in a Bilateral Market

March 2011

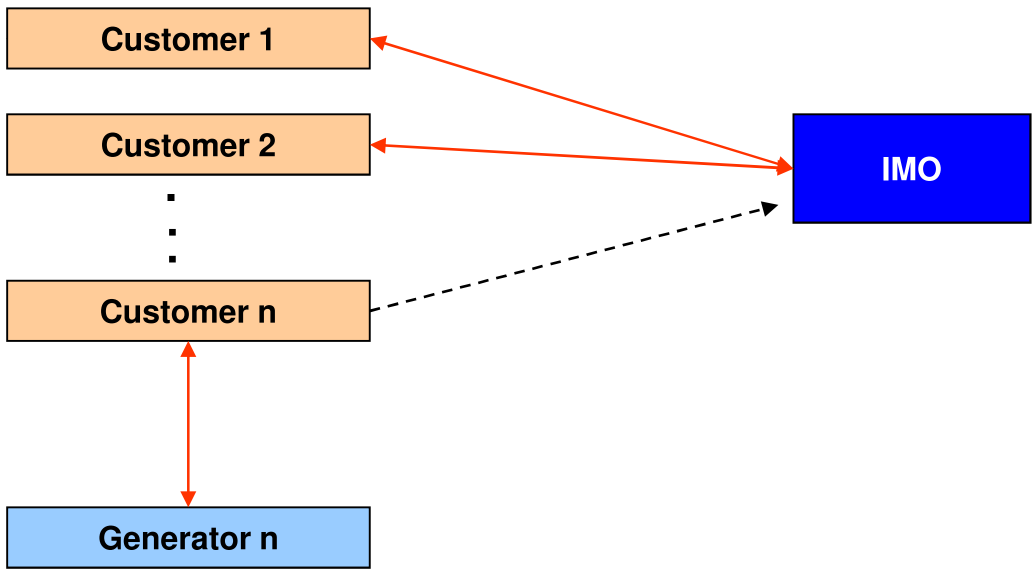
The IMO has a primary function as the 'Central Banker' in the market

Capacity Credits can be considered the 'currency' of the market. The central banker (IMO) is responsible for the 'money supply' in the market, through its oversight of generation capacity. It is also responsible for the liquidity requirements of the retailers, via the IRCR.



The IMO – Customer relationship

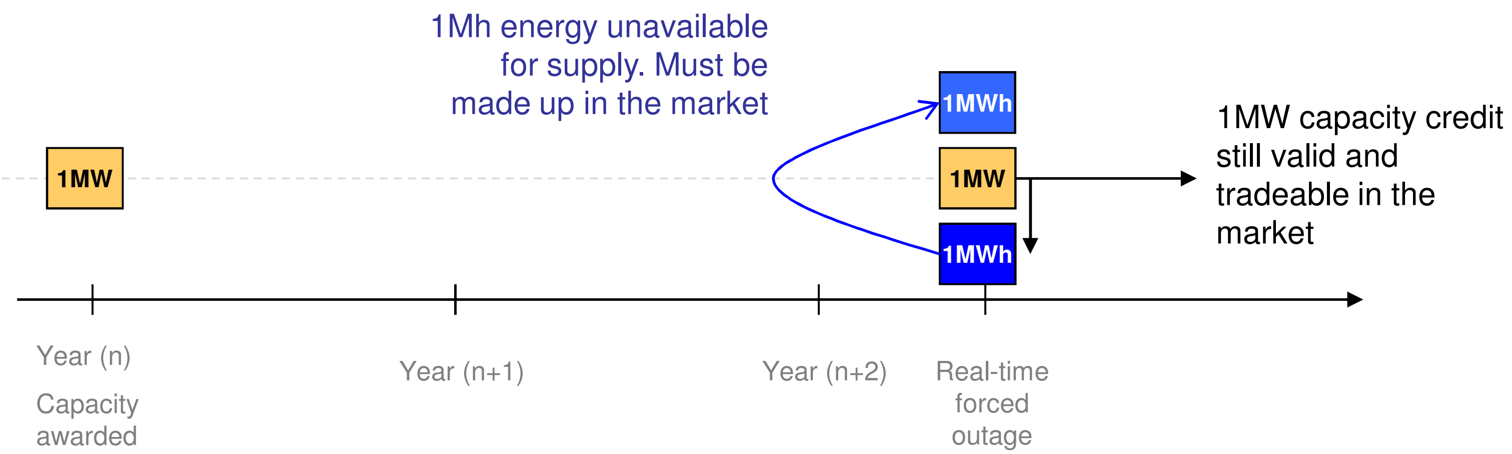
The IMO requires customers to maintain adequate liquidity – that is, acquire enough capacity credits to meet its proportion of the market's IRCR. Customers can do this in 2 ways. They may acquire capacity credits directly from generators, or they may acquire capacity credits from the IMO (or they may choose a mixture of both).



The Nexus between Capacity and Energy

Capacity is a concept that refers to the ability to produce energy. Capacity credits are granted well in advance of the actual requirement to produce energy in real time. If a facility is unable to produce energy in real time (i.e. it is unavailable), this is an instantaneous issue (i.e. the capacity still exists and may be available in the next interval). In fact, the capacity credit for that interval, issued years prior, is still valid; is still tradeable in the market; and can still be used by a customer to meet IRCR.

So Capacity Refunds are not actually related to the capacity per se… it is an incentive to be able to provide energy in real time, and by extension, related to the condition of the facility.



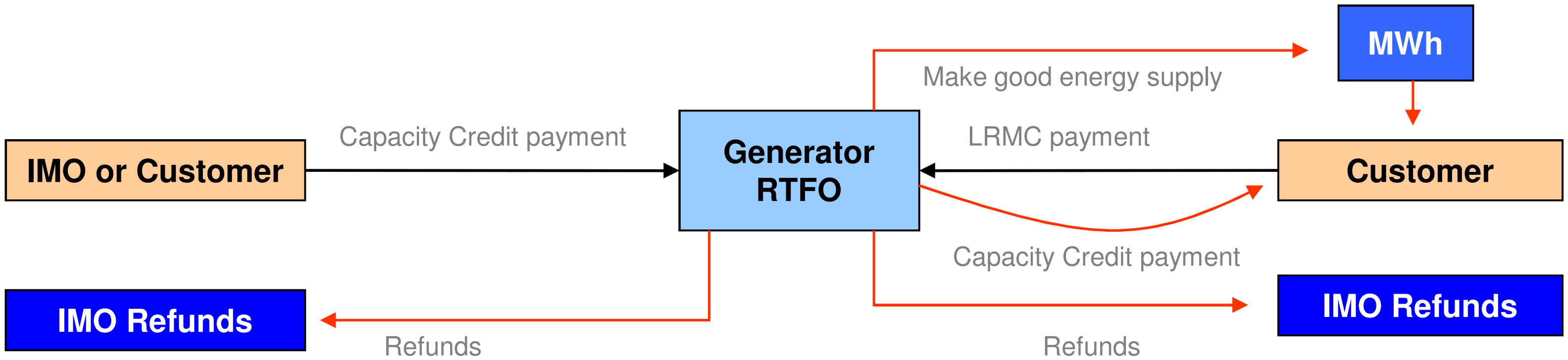
The Bilateral Contract energy relationship versus the capacity only relationship

When a generator is unable to supply energy in real time, under the bilateral contracted scenario, they must make good their bilateral energy commitment in the market. The valid capacity credit is still supplied to the customer. In return, it receives its LRMC contracted price. However the generator must also pay the IMO refunds – in essence, 'making good' on its real-time supply obligation twice.

The capacity only generator receives its (commercially sustainable) capacity credit payment, but pays refunds to the IMO to 'make good' its real-time supply failure. It has no obligation to source new energy, unless it has a Resource Plan from a STEM sale, and then, there is little difference in the price of procuring 'make good' energy from the price received in STEM.

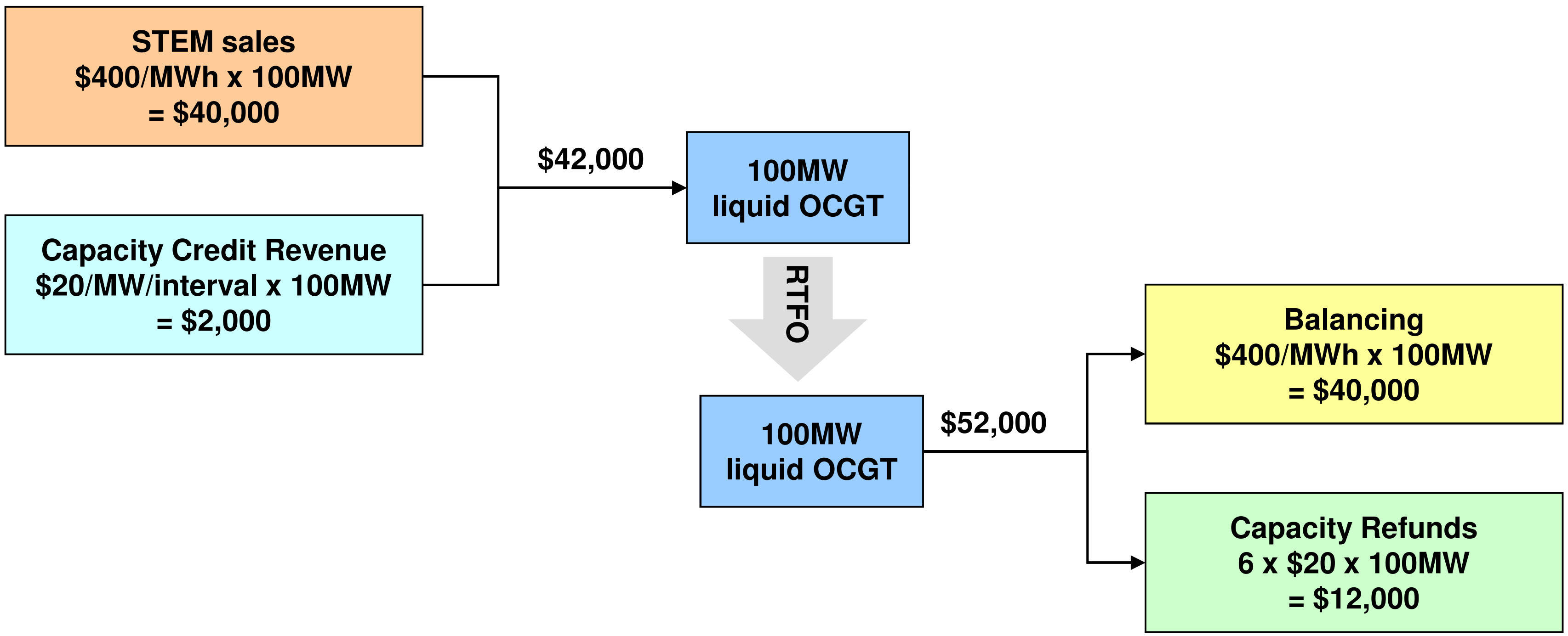
The WEM is better suited to capacity only generators. Bilaterally contracted generators must 'make good' twice, once with their contracted counterparties, and once with the IMO (from whom they derive no revenue and have no agreement). Our market is around 90% bilaterally contracted.

Capacity only generator RTFO **Bilaterally contracted generator RTFO**



In detail – the Capacity only relationship

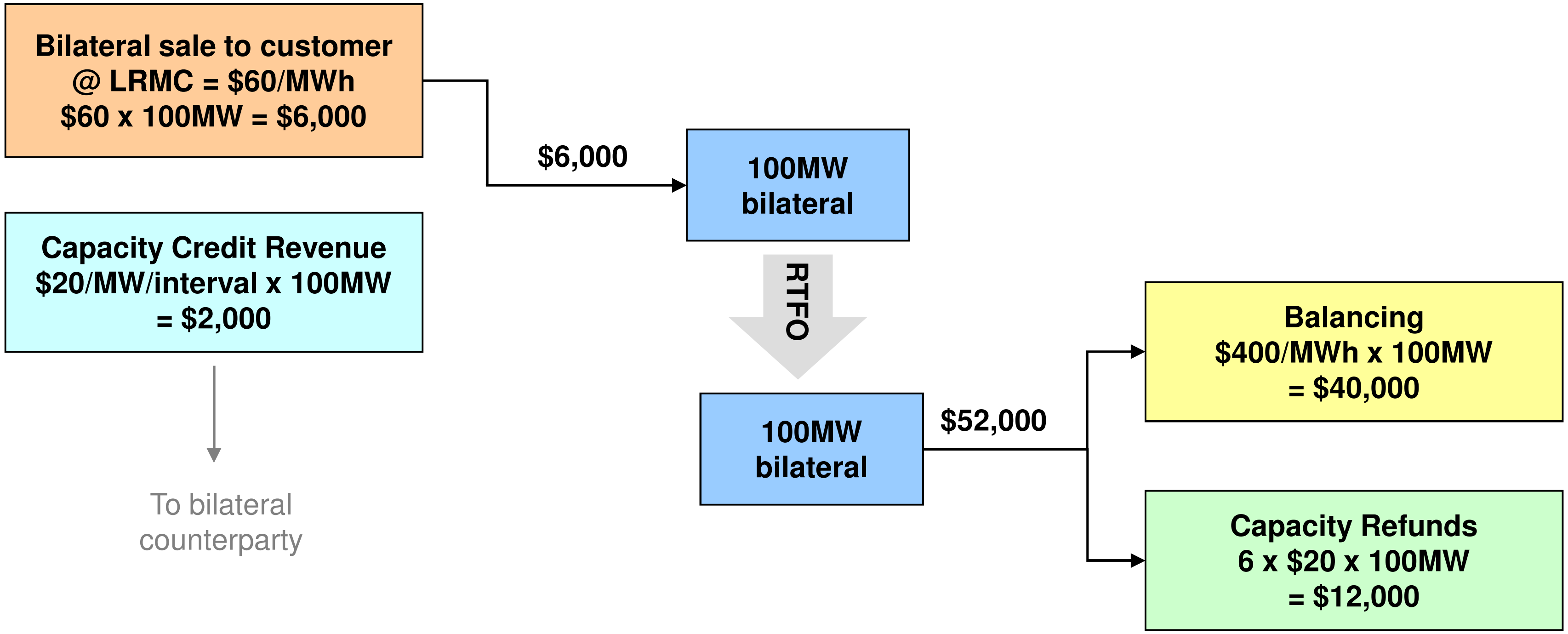
Consider the revenue effects of a RTFO on a generator that is financed on capacity only (i.e. the liquid OCGT as contemplated in the MRCP setting) during a period with a 6 x refund multiple.



The net position is $42,000 - $52,000 = -$10,000. This is equivalent to a x5 capacity refund multiple

In detail – the Bilateral relationship (capacity plus energy)

Consider the revenue effects of a RTFO on a generator that is financed on a bilateral contract, selling capacity and energy at its forecast LRMC, during a period with a 6 x refund multiple.



The net position is $6,000 - $52,000 = -$46,000. This is equivalent to a x23 capacity refund multiple

Baseload and Mid-merit, or 'energy producing' generation pays the vast majority of capacity refunds… But Peakers are the last line of defence before load shedding occurs. They need to be available when called

Even though energy producing generators face energy costs that are much higher than their own costs if they are unavailable, they are the only ones that really contribute to capacity refunds.

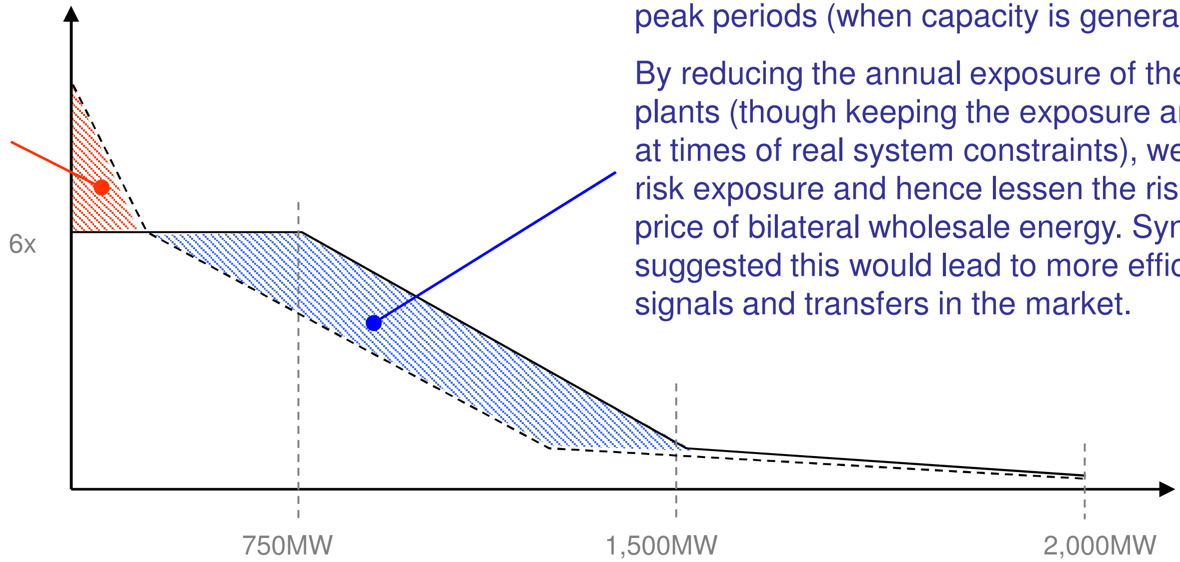
Consider the IMO dynamic refund profile:

Energy producing generators are incentivised to be available and adopt good maintenance practices by their energy supply obligations. Bilaterally contracted supply prices will mostly be significantly lower than energy balancing or STEM prices during peak periods (when capacity is generally tight).

By reducing the annual exposure of these types of plants (though keeping the exposure and incentives at times of real system constraints), we lessen the risk exposure and hence lessen the risk weighted price of bilateral wholesale energy. Synergy has suggested this would lead to more efficient prices, signals and transfers in the market.

It has been suggested that in order to incentivise peakers adequately, there must be higher refunds at the times of peak demand (or lowest spare capacity), as this is when peakers operate.

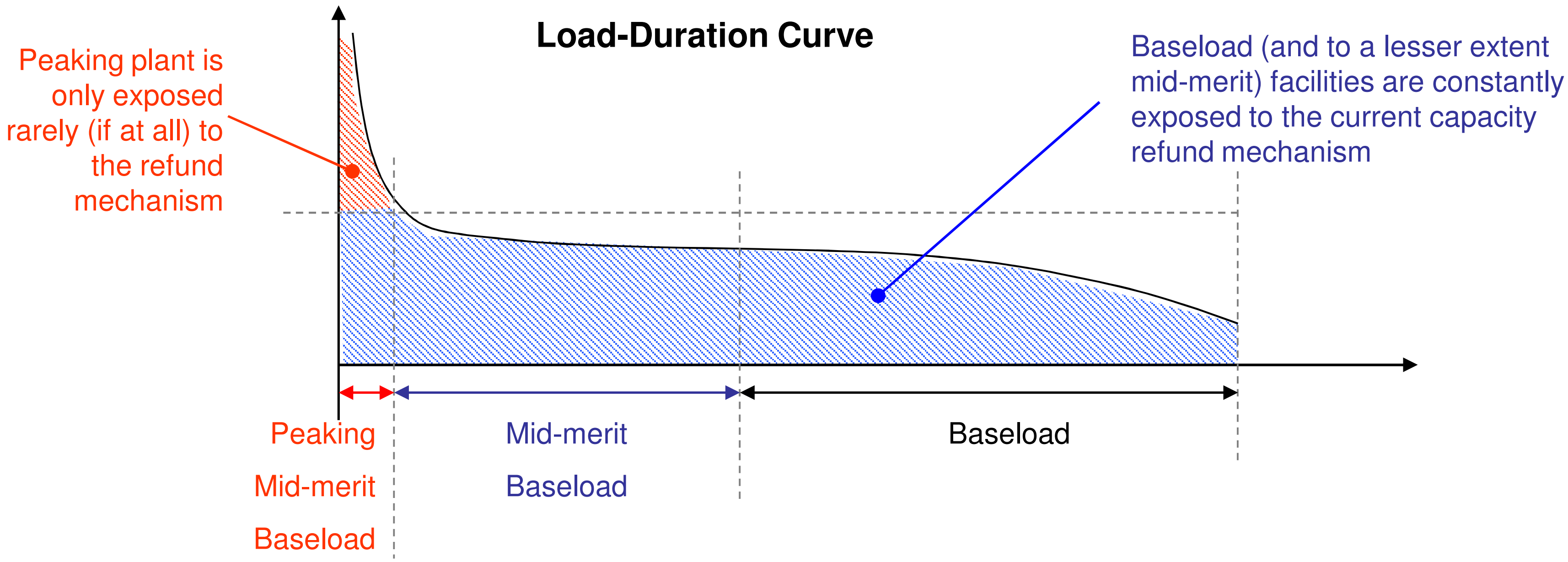
However, energy producers are also operating at this time and the higher refunds will again lead to higher risk-weighted energy prices than is efficient in the market



The Problem: How to incentivise efficient availability of all capacity types using a single mechanism?

The answer is… we don't. It is recognised that DSM is different in that it is only called very sparingly (if at all) each year. Intermittent generation cannot be scheduled. Each has a variant of the capacity allocation or refund mechanism applied to it which take these factors into account.

Let us look at the issues of scheduled generation, including baseload, mid-merit and peaking plant.

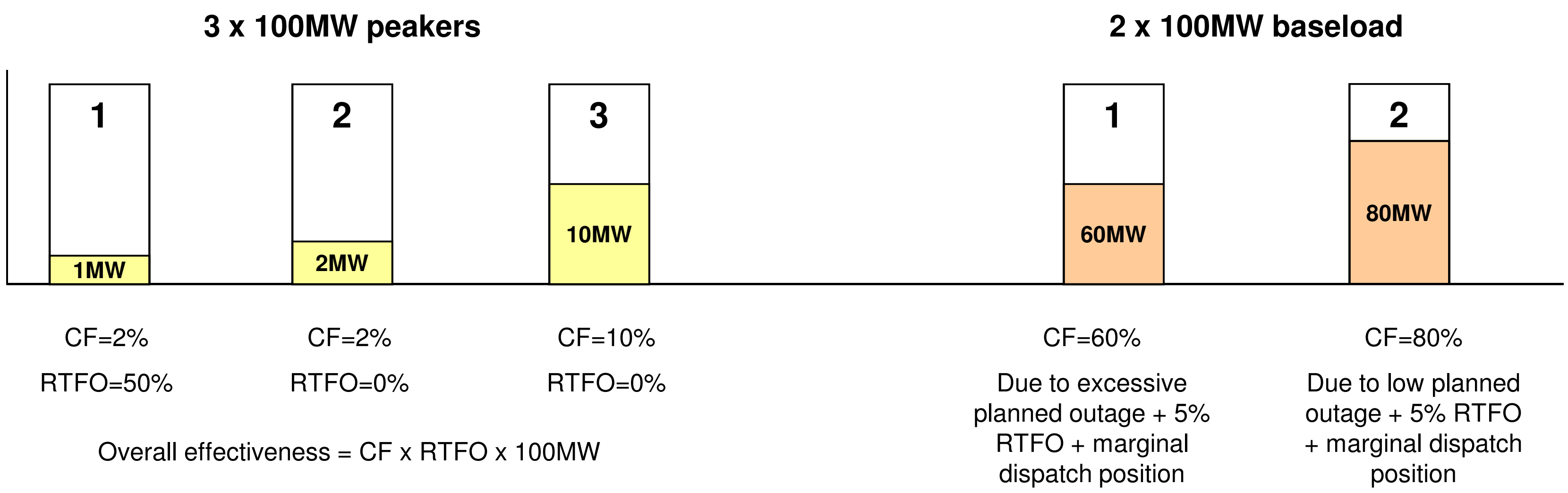


The problem of differentiating by facility type is obvious.

Additionally, the capacity refund mechanism should both reward consistent provision of energy to the market <u>and</u> penalize unavailability

Generation facilities should have their asset values impacted by the capacity refund mechanism… that is, the market should ascribe less value to those facilities that are less reliable in comparison with similar types of facilities that are more reliable. It is near impossible to compare the reliability of a baseload facility with a peaking facility given their completely different operating duties. However, similar facilities should be able to be differentiated based on reliability.

Consider the comparisons below: It is easy to see which facilities the market would value most

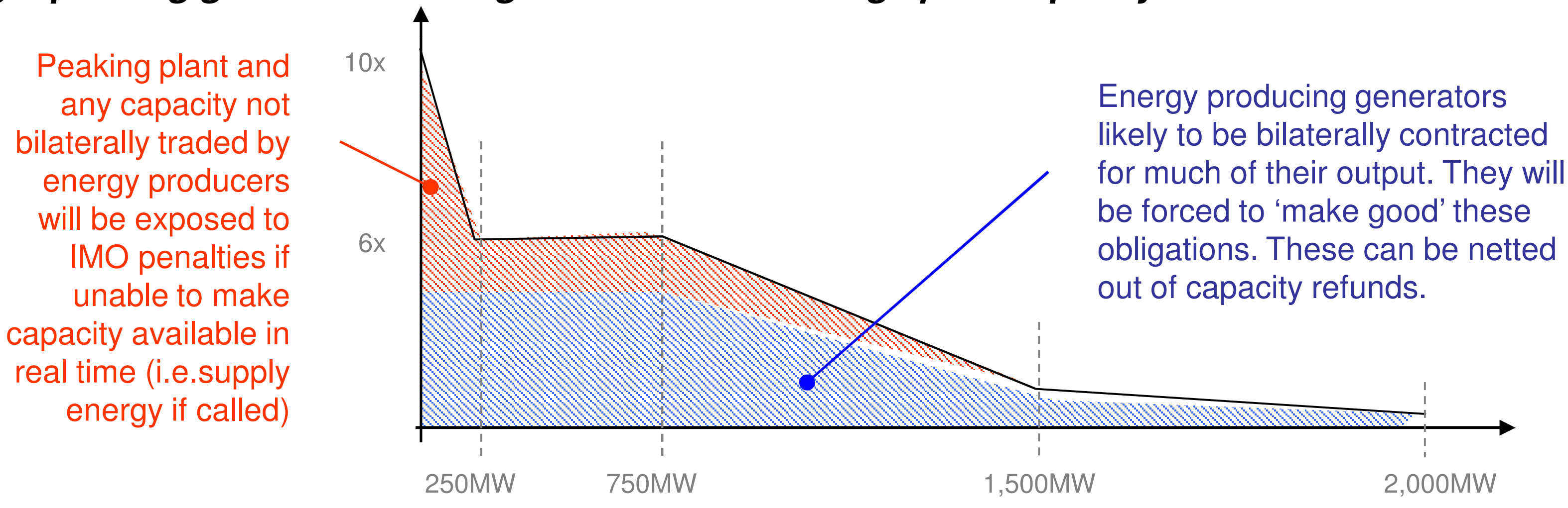


How can we apply the refund mechanism so it increases the availability incentive for all plant, without introducing inefficient increases in wholesale energy prices as a mitigant to risk?

A dynamic solution, which would incorporate the bilateral nature of our hybrid market, would be to net out bilateral and STEM nominations from refunds

The bilaterally contracted generator is obligated to 'make good' the customer with regard to the supply of energy in real-time. They must enter the market to procure the energy they agreed to make available in bilateral contracts.

A dynamic solution would result in an ability to apply a refund profile that has a higher maximum refund factor (as advocated by Synergy), that will not adversely impact energy producing generators (except for their uncontracted energy); not unnecessarily drive up wholesale energy charges; but will target peaking generators during times of diminishing spare capacity.



However, such a methodology would eliminate virtually all capacity refunds, given the quantity of energy supplied in the bilateral and STEM markets. It also would not address the disincentive for some plant to make their capacity available (i.e. excessive planned outage)

A simple proxy to achieve a dynamic outcome, which differentiates facilities by type, as well as performance within similar types, would be to apply a rolling capacity factor (RCF) overlay to capacity refunds.

It is easy to determine a rolling capacity factor for each facility (the average level of output per interval divided by the allocated capacity credits)[1]. The inverse of this capacity factor might be the multiple applied to the capacity refund profile in any interval that refunds are incurred.

Facility : 100MW OCGT with RCF = 2%

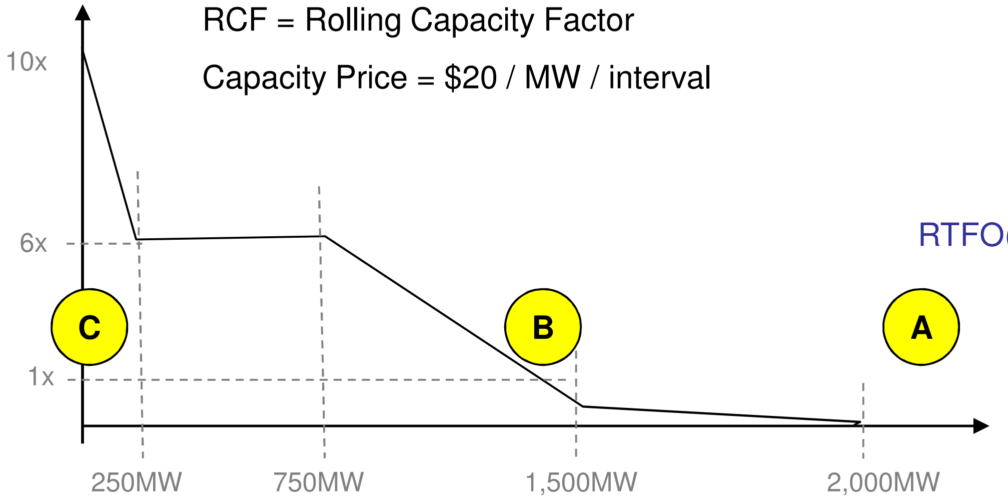
Facility 2 : 100MW OCGT with RCF = 10%

Facility 3: 100MW Baseload coal with RCF = 60%

Facility 4: 100MW Baseload co-gen with RCF = 85%

RCF = Rolling Capacity Factor

Capacity Price = $20 / MW / interval



Consider the effects on each facility of a RTFO at A, B and C

RTFO(A): No impact on the market

RTFO(B):
F1 = not running (no exposure)
F2 = not running (no exposure)
F3 = (0.4 x 1) x $20 x 100MW = $800
F4 = (0.15 x1) x $20 x 100MW = $300

RTFO(C):
F1 = (0.98 x 10) x $20 x 100MW = $19,600
F2 = (0.9 x 10) x $20 x 100MW = $18,000
F3 = (0.4 x 10) x $20 x 100MW = $8,000
F4 = (0.15 x10) x $20 x 100MW = $3,000

New facilities or those returning from major outage would have CF=0% and a high exposure – commensurate with inherent unreliability after such events

RDIWG Action Points

Legend:

Shaded	Shaded action points are actions that have been completed since the last RDIWG meeting (contained in table 2).
Unshaded	Unshaded action points are still being progressed (contained in table 1).
Missing	Action items missing in sequence have been completed from previous meetings and subsequently removed from log.

Table 1: Outstanding

#	Action	Responsibility	Meeting arising	Status/Progress
19	The IMO to investigate with System Management whether wind generation forecasts could be provided to participants at the same time as load forecasts.	IMO	3	
42	The IMO to offer site presentations to Working Group members and invite Working Group members to participate in the presentations.	IMO	5	Underway.
43	The IMO to confirm the accounting advice it has received previously that its expenditure on the Market Evolution Program can all be capitalised.	IMO	6	Underway. A hard copy will be tabled at the meeting.
51	The IMO to arrange a workshop in early 2011 with the Bureau of Meteorology (BoM) and RDIWG members, to discuss options for the enhancement of BoM forecasts and the wider usage of forecasts by	IMO	6	

#	Action	Responsibility	Meeting arising	Status/Progress
	Market Participants.			
52	The IMO and System Management to discuss System Management's dispatch system and whether it is able to accommodate future enhancements.	IMO and SM	6	Underway.
68	The IMO to update the scenario to include summation information.	IMO	9	The Project Team is developing a model for MPs to use.
70	The IMO to provide an additional scenario(s) to include plant commitment and decommitment.	IMO	9	The Project Team is developing a model for MPs to use.
72	The IMO to review its practice of publishing draft minutes on website before made final.	IMO	9	
83	Mr Dykstra to review the SRC rule change within 1 week of meeting 10 and inform the IMO whether he supported the SRC fund proposal or not.	Mr Dykstra	10	
84	IMO to update the design principles underpinning the Balancing and LFAS proposals, as agreed at the meeting.	IMO	10	
85	IMO to write to participants requesting whether the specific balancing model can be distributed.	IMO	10	

Table 2: Completed since last meeting

#	Action	Responsibility	Meeting arising	Status/Progress
82	The IMO to amend the minutes of Meeting No. 9 to reflect the points raised by the RDIWG and publish on the website as final.	IMO	10	Completed.