Rules Development Implementation Working Group (RDIWG)

Meeting No. 10: (Revised) Agenda

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

Date: Tuesday, 15 March 2011

Time: 9.30am – 2.00pm

1. Previous meeting's minutes
2. Reserve Capacity Refunds
3. Balancing Market Proposal:
    a. Updated Balancing Design Details;
    b. Scenarios/Modelling - update; and
    c. Cost Benefit Analysis
    d. System Management "simpler options" paper.
4. Project Timeframes and Milestones – verbal update
5. Response to Submissions
6. General Business
7. Outstanding Action items
8. Next meeting date and time: Tuesday, 5 April 2011 (9.30am – 2.00pm)

Independent Market Operator

Rules Development Implementation Working Group

Minutes

Meeting No.	9
Location:	IMO Board Room Level 3, Governor Stirling Building, 197 St Georges Terrace, Perth
Date:	Tuesday 22 February 2011
Time:	Commencing at 9.34am to 2.06pm

Attendees	
Troy Forward	IMO (Proxy Chair)
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
Paul Hynch	Office of Energy
Chris Brown	ERA
Jacinda Papps	Minutes
Ben Williams	Presenter
Jim Truesdale	Presenter
Greg Thorpe	Presenter
Preston Davies	Presenter
Ashley Milkop	Presenter
Cameron Parrotte	Observer
Douglas Birnie	Observer
William Street	Observer
Apologies	
Allan Dawson	IMO

Item	Subject	Action
1.	**WELCOME AND APOLOGIES / ATTENDANCE** The Chair opened the 9th meeting of the Rules Development Implementation Working Group (RDIWG) at 9.34am.	

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	An apology was noted from Mr Allan Dawson.	
2.	**PREVIOUS MEETING'S MINUTES** The minutes of RDIWG Meeting No. 8, held on 1 February 2011, were circulated prior to the meeting. Members did not make any requests for change. *Action Point: The IMO to publish the minutes of Meeting No.8 on the website as final.*	**IMO**
3.	**BALANCING MARKET PROPOSAL** The Chair proposed to review the design paper, work through the scenario, discuss the submissions received on the design and then discuss the Cost Benefit Analysis. **<u>Updated Design Paper</u>** Mr Ben Williams noted the amendments to each of the 12 proposed stages of the Balancing Market proposal since the RDIWG had last reviewed the paper. The following points were noted: <u>Box 1: Bilateral Submission/STEM/NCP</u> Members were not certain of the origin, or the rationale, behind the suggestion that Market Customers would be unable to either over- or under-state their demand, noting that the current Market Rules only prohibit the overstatement of demand. Members questioned whether there was any technical reason for the change as opposed to one of philosophy and considered that such changes should be kept to a minimum so as to focus on the proposal on the core problems it is trying to address. In response, it was noted that the change was to ensure that we come out of the STEM with the most accurate day ahead position possible. The following benefits of the proposed amendment were noted: • consistency and certainty; and • if the market has contractual arrangements that are physically feasible a day ahead, then commitment decisions are more feasible. System Management noted the more accurate a position there is from STEM the better it is for it as there is already a reasonable amount of variability to deal with i.e. wind generation. *Action Point: The IMO to review the decision to prohibit Market Customers from either over- or under-stating their demand. When doing so, the IMO to discuss the issue with System Management in greater detail to assess how critical the proposed amendment is.* A member presented the RDIWG with a document which illustrated the lack of liquidity in the STEM. A copy of the document is available with the meeting papers on the website: www.imowa.com.au/RDIWG. It was questioned whether the group was getting distracted from its	

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	main focus and questioned whether the STEM issue should be parked to be resolved at a later date. A member noted that the objective of the Market Evolution Program was to develop an effective competitive market for Balancing energy, with broader participation in Balancing, where the Balancing prices reflect efficient costs. *Action Point: The IMO to further discuss the STEM operational issues with Andrew Sutherland and John Rhodes.* <u>Box 2: Resource Plans</u> System Management noted that the limits for overshooting would need to be discussed and suggested that the design team capitalise on its tolerance work. Members discussed the reference to Resource Plans being approved by System Management and how this proposal integrates with the 1 minute profile and 6MW per minute ramp rates required in the Power System Operation Procedures (PSOPs). It was noted that validation could be simple (i.e. IT solution) or complex (i.e. a System Management operator validating each Resource Plan). The Chair suggested that a simple solution was more appropriate. <u>Box 4: IPP Offers/Bids and Verve Energy PSC</u> *Action Point: The IMO to discuss the formation of the Verve Energy Load Following Ancillary Service (LFAS) Portfolio Supply Curve (PSC) with Andrew Everett.* <u>Box 6: Market Forecast</u> Members discussed the proposal for forecasts being provided for the expected balancing price if the Relevant Dispatch Quantity is +/- 1%. It was noted that this band intuitively seemed too small. It was agreed that the detail of this would be discussed in detail at a later stage. <u>Box 8: Gate Closure</u> System Management noted that Gate Closure needs to be resolved. The Chair acknowledged this. <u>Box 10: Pricing</u> It was noted that this section contained the most change from the previous iteration of the design paper. Members discussed the proposal to use SCADA to derive the Energy Relevant Dispatch Quantity, noting that the final quantities would be settled on meter data. **<u>Scenarios</u>** Mr Jim Truesdale presented the scenario that had been circulated to the RDIWG. The following points were discussed/noted: <u>Page 9 of 117:</u> It was noted that currently the expected Verve Energy quantities are not loss adjusted. It was agreed that this would be discussed in detail	

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	at a later stage. In response to a question from System Management it was noted that the timing of the preparation of the initial Verve Energy dispatch plan would be around 4pm, this is to work with the timing of gas nominations. <u>Page 11 of 117:</u> *Action Point: The IMO to update the scenario to include summation information.* <u>Page 12 of 117:</u> There was significant discussion regarding the marginal price outcome as presented in the scenario. A member noted that the outcome presented more of an optimised competitive dispatch rather than what his interpretation of what Balancing was. *Action Point: The IMO to meet with Mr Dykstra to discuss the marginal price outcome in the scenario in greater detail.* *Action Point: The IMO to provide an additional scenario(s) to include plant commitment and decommitment.* <u>Page 15 of 117:</u> It was agreed that further discussion would be required at some stage regarding the frequency and value of the market update cycle. <u>Page 19 of 117:</u> It was recognised that System Management would need to develop the appropriate tools to facilitate dispatch and that System Management and the IMO would work together on this. It was noted that, for equipment that is not AGC capable, dispatch instructions would need to be electronic (i.e. SMS, email or via SMMITS). **<u>Summary of submissions</u>** The Chair explained the process that the IMO undertook in assessing the submissions received from members on the Balancing market proposal, noting the time constraints that both members and the IMO were under. It was noted that the IMO intends to follow up individually with each submitter. Members considered that it would be valuable to see the content of all the submissions. *Action Point: The IMO to circulate a collated copy of all the submissions received on the Balancing Market Proposal to members*. *Action Point: The IMO to review its practice of publishing draft minutes on website before made final.* The RDIWG did not discuss the summary of submissions further. The RDIWG agreed to provide additional comments to the IMO on the Balancing proposal, taking into consideration the meeting discussion	

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	and the submissions already received. *Action Point: Members to provide additional comments to the IMO on the Balancing proposal by 5pm, 4 March 2011.* Members noted discomfort with the IMO's aim to get RDIWG endorsement of the proposal at the 15 March 2011 meeting. **<u>Preliminary Cost Benefit Analysis</u>** Mr Preston Davies circulated a presentation regarding the Cost Benefit Analysis, a copy of this is available with the meeting papers on the website: www.imowa.com.au/RDIWG. The following points were noted/discussed: • While the study horizon is 5 - 7 years, it was noted that any investment influenced during that period would span 20 - 30 years. • Correlation between Collgar and the current wind farms is required, noting that ROAM and SKM have both done some work on this. • Prices are in real terms. • A member understood why transfers are not taken into account in the analysis, but noted that these still need to be outlined in general terms. • A member noted the ongoing costs but questioned what the magnitude of the upfront costs would be. It was noted that work on this is still underway. *Action Point: When undertaking the Cost Benefit Analysis Sapere is to draw on work of ROAM/SKM/ACIL Tasman and MMA (if appropriate).* *Action Point: Sapere to provide members with its volume and modelling assumptions for the Cost Benefit Analysis.* *Action Point: Members to provide comments on the Cost Benefit Analysis paper by 5pm, 4 March 2011.* **<u>Summary</u>** The Chair requested each member's overall thoughts on the balancing work and progress to date.. Comments included: • concern around the complexity, the ambitious timeframes, whether the benefits would outweigh the costs and whether there were simpler ways of achieving the outcomes sought; • concern that the benefits would be largely captured by Market Generators but Market Customers were bearing substantial proportion of the cost; • support for a competitive balancing outcome, concern about the potential costs versus benefits and the timeframes but acknowledgement that the overnight load issue had kicked off the work (and would start to be solved by it); • acknowledgement of the need to think about the longer term, that there was a need to make competitive balancing work, that the	

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	work had to continue and be made consistent with broader strategic workstreams (eg around the Verve/Synergy generator/retailer only constraints) • generally positive support for the proposal although some detail needed to be worked through (eg around gate closure/windows) and that the work needed to continue; • acknowledgement that the proposal seemed complex but had to be, that it would lead to more transparency and complexity but needed to be pushed forward; • acknowledgement that this was work asked for by the industry but concern that the work may have lost its way and that it was too early to make decisions; • interest in gaining an understanding of the level of competition that will result from the hybrid design and proposed changes; • support for the direction of the work but could do with another industry workshop to help people understand it; • optimism about the proposal, that it had nearly arrived at a workable solution, that it was well considered and could be made to work; • supportive of the work, noting some concern of the resourcing implications for Verve and System Management, comment that the proposal was looking "pretty close" One member requested a description of the assumptions being used in the cost benefit analysis. The Chair thanked members for their comments.	
4.	**PROJECT TIMEFRAMES/MILESTONES** Mr Douglas Birnie outlined the background to the development of the project timeframes and milestones. The following points were noted/discussed: • Following RDIWG endorsement the proposal will be presented to the MAC and then the IMO Board; • The Minister has been kept informed of the process and its outcomes, however is not required to sign off the design. The Minister will need to approve any rule changes that are protected provisions; • The timelines are conditional upon the RDIWG, MAC, IMO Board and Rule Change processes. *Action Point: Members to provide additional comments on the project timelines and milestones by 5pm, 4 March 2011.*	
5.	**RESERVE CAPACITY REFUNDS** Mr Greg Thorpe presented the updated Reserve Capacity Refunds paper, noting the amendments to the previous iteration. *Action Point: The IMO to show all incremental changes to papers in tracked changes.* There was discussion on the validity of the use of history to set the	

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	refund shape and exposure. A member suggested that Forced Outage rates from plant manufacturers could be used instead. In response, it was noted that historical information provides a benchmark and that there are a number of other arbitrary benchmarks that could be used. It was noted that there is no clear methodology for this across the world, and that there will always be an arbitrary factor in setting a refund shape and exposure. Opinion was divided on the proposal, at one end of the scale it was noted that it presented significant additional risk to participants. However, the contra opinion was that the proposal does not sufficiently reflect the concept of scarcity. The new proposal for the SRC fund was discussed, the following points were raised: • Would Market Customers be able to opt in or out? • Should refunds be distributed to Market Customers in their entirety if SRC is not called? Should generators be entitled to a proportion of the refunds back if, for example, they attain a better that 3% Forced Outage rate? Is the current allocation methodology (via IRCR) correct? *Action Point: The IMO to remove late entry of Griffin Energy in the quantitative analysis in the refunds paper.* *Action Point: The IMO to consider whether refunds could be discussed prior to Balancing at the 15 March 2011 meeting.* *Action point: Members to provide additional comments on the refunds paper by 5pm, 4 March 2011.*	
6.	**GENERAL BUSINESS** There was no general business raised.	
7.	**OUTSTANDING ACTION POINTS** The RDIWG did not discuss the outstanding action points.	
8.	**NEXT MEETING** Meeting No. 10 will be held on Tuesday 15 March 2011 (9.30am-2.00pm).	
9.	**CLOSED:** The Chair thanked members for the debate and their hard work during the meeting and declared the meeting closed at 2.06pm.	

Agenda Item 2: Discussion Paper - Review of Capacity Cost Refunds

1. BACKGROUND

At the 22 February 2011 meeting the IMO presented, and the RDIWG discussed a further paper on the dynamic refund methodology along with a proposal to establish a funding pool for reserve capacity. It was agreed that the IMO was to remove late entry of Griffin Energy in the quantitative analysis in the refunds paper. Members were asked to provide further comment on the paper by 4 March. These comments indicated support for a move to a dynamic regime and some support for establishment of the fund. However there were contrasting views on the levels of refunds and to whom withheld security deposits should be paid.

Given the range of views on many of the refund proposal aspects, the IMO notes that if progress is to be made, it is going to be important to identify where progress could be made and/or where the industry might prefer no change or for the IMO Board to make a decision despite sharply different views among the industry. Otherwise there is a risk of ongoing work (and associated costs) that fails to reach any resolution.

If the desire is to have any changes in place before the next summer peak period, then decisions will also need to be made within the next two RDIWG meetings.

The issues underpinning the reserve capacity refund proposal include:

i. Creation of a dynamically calculated refund regime and the level of refunds;

ii. Replacement of the Net-STEM Shortfall refund requirement with a compliance regime incorporating an Operational Test; and

iii. Creation of the Market SRC Fund..

These are discussed in turn below along with IMO's suggestions for progressing the issue. The IMO is keen for the RDIWG to consider each of the issues in turn and, if they are uncomfortable with the RDIWG's suggestions, then suggesting alternative courses of action.

Dynamic refund regime and level of refunds

The IMO notes that there appears to be general support for the implementation of a dynamically calculated refund regime, but there is still much disagreement on some of the key aspects of the proposal. The IMO proposes to set the profile of the refund regime so that:

- A maximum (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.

Concerns from Market Participants include the shape and slope of the curve; the breakpoints on the curve and particularly the maximum refund factor. Some Market Participants (representing generators) argue the latter it is far too high. Synergy as the largest retailer argues that it is too low.

In the IMO's view is that refund levels (both shape and level) in a capacity market design are unavoidably a matter of choice. But the proposal nevertheless reflects the current incentives around the provision of reserve capacity overall. Changing these levels could have far reaching consequences i.e. by changing the overall "net value" of reserve capacity. The IMO considers if no coherent case can be made for changing these values then no change would be the most justifiable outcome.

Removal of Net-STEM Shortfall Refund and Introduction of the Operational Test

Currently, 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 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. Historic analysis indicates that the Net-STEM Shortfall refunds, as a proportion of total refunds, has been typically 5.8%.

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 total refunds but in practice is not technology neutral and is significant driver of behaviour at the margin. 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 in practice only subject to refund on the basis of a more controlled test.

The IMO proposes that the removal of the NET-STEM shortfall and introduction of a test in the form of the Operational Test for all technologies would provide a more technology neutral measure of capacity provision while also achieving other benefits to the market such as simplification of market settlement. The following principles and mechanisms are proposed in removing the Net-STEM Shortfall Calculation and supporting the introduction the Operational Test:

- 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 where:
    - 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; and
    - 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 proposed principles underlying the Operational Test include:

- The "Operational Test" would 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 based on dispatch.
- 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 and any relevant balancing instructions. Variation for minor operational fluctuations is not a definitive indication that a 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 requested ex-post by the IMO.
- A threshold for testing would need to be established and would be considered in the detailed design of rule amendments including the 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.

It is clear that an increase in 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.

The IMO also notes that electricity markets generally must deal with the possibility that generators will not comply with dispatch instructions (including implicit instructions within resource plans) in order to assure safe and secure operation of the power system. The IMO believes this requirement is well understood within the generation sector and that in practice the threat of compliance action is a very powerful backstop incentive for compliance and very few compliance actions are needed in other markets where measures such as the non STEM shortfall do not apply.

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.

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

1.1. Introduction of Market SRC Fund

Market Customers are currently subject to unpredictable calls to fund any Supplementary Reserve Capacity (SRC) that is required under the Market Rules. Because SRC is required only rarely, it is not practicable for Market Customers to budget for SRC.

The RDIWG considered several approaches and methodologies that could be utilised to create a Market SRC Fund to meet at least some of the costs of SRC and thus reduce the size of unbudgeted calls to fund SRC. The different approaches are described in the RDIWG paper of 22 February 2011, which notes the preferred approach.

The general design of the preferred on-going Market SRC Fund is described below:

- 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 maximum level, probably over a number of months;
- Once the Fund reached the maximum level, the IMO would cease allocating refunds to the fund and distribute the refunds to Market Customers in accordance with the current methodology in the Market Rules.
- 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 again allocate refunds to the Fund until it reaches the maximum level.

While there is the possibility that a new entrant Market Customer could reap the benefits of a SRC fund but not directly contribute to it, this is seen as temporal as future refunds that would be needed to top up the fund after the call would be directed away from the new entrant Market Customer and into the Market SRC Fund.

There seems no practical alternative to setting a maximum size of any SRC fund 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). While the IMO notes the views of some generator representatives for having such refunds paid back to generators, the IMO considers this would fundamentally alter the intent and purpose of refunds in the first place – and consequently would go well beyond the scope of the current review in the refund methodology itself.

Market generators have submitted that there is a case for withheld security deposits to be allocated to generators. The allocation of withheld deposits was not intended to be altered by consideration of the creation of a fund to reduce the volatility of calls on Market Customers to meet SRC costs. The IMO does not consider the arguments to widen the scope of changes to change the allocation have been made and considers that the issue is more complex than suggested by the submissions but notes generators would be entitled to make such a proposal in the future.

The IMO proposes that the RDIWG approve, in principle, the design of the Market SRC Fund, (noting that there will be additional technical and settlement details that will be need to be considered as part of the Rule Change Process) with surplus refunds continuing to be paid to Market Customers.

2. RECOMMENDATIONS

The IMO recommends that the RDIWG:

- **discuss** each of the three issues outlined in this note and the attached paper namely:

i. Creation of a dynamically calculated refund regime and the level of refunds;

ii. Replacement of the Net-STEM Shortfall refund requirement with a compliance regime incorporating an Operational Test; and

iii. Creation of the Market SRC Fund to receive first call on capacity refunds and be the first source of funding for SRC.

- **decide** for each of the three issues above whether they either:

a) reflect a reasonable compromise between the various views and are worth progressing as they are now into the rule change process where the details can be further considered; or

b) justify further work (and if so identifying that work) that might secure a better design option and a greater level of support; or

c) are not worth progressing further.

Independent Market Operator

Review of Capacity Cost Refunds

Date: 15 March 2011

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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

- o 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;
- o 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;
- o 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;
- o If a security deposit is withheld it is distributed to Market Customers in a similar ratio to the obligation to fund capacity payments;
- o 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;
- o 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.

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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

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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

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Figure 1 Cal 2009 Refund Factor v Reserve

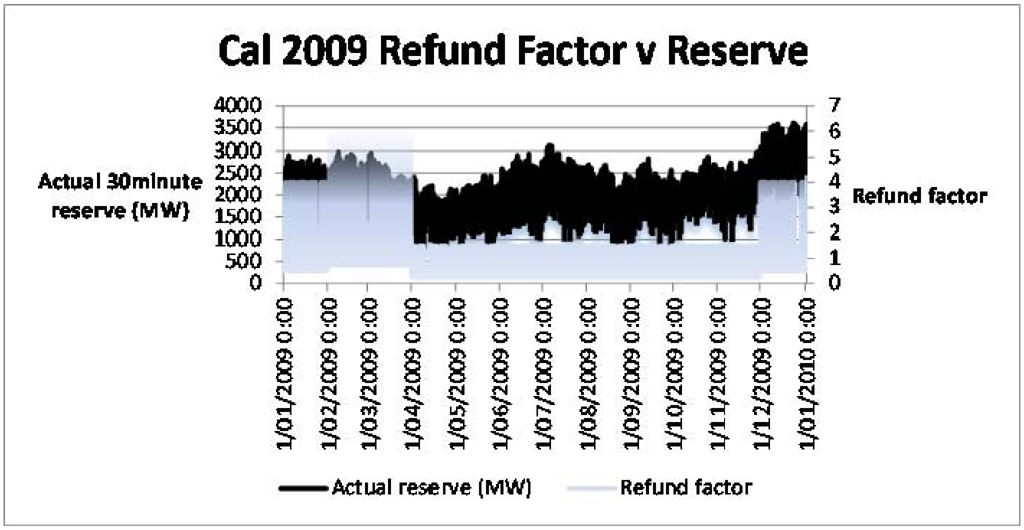
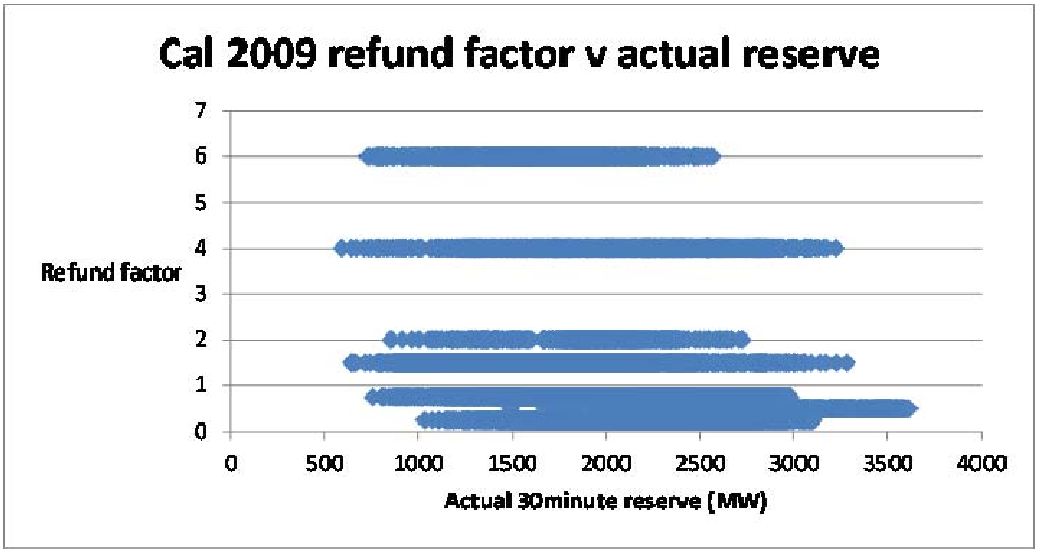


Figure 1 shows actual reserve in solid base plot (as the data covers the entire year only the envelope of maximum and minimum values is readily seen). Figure 2 shows the range of refunds for different reserves across the year. The highest refund rate of 6 applied some of the times of low reserve (as 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.

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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.

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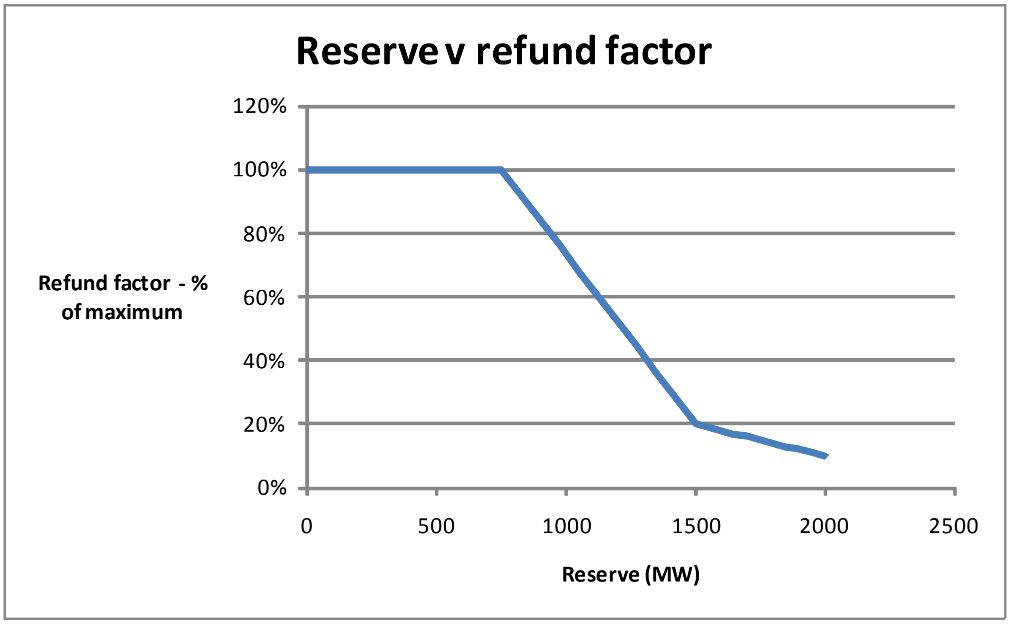
Figure 3 Reserve v Refund Factor



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 <u>profile</u> 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 <u>magnitude</u> of refunds within the profile; and
- <u>Exposure</u> 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.

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Figure 4 Comparison of cumulative total refund: calendar 2008

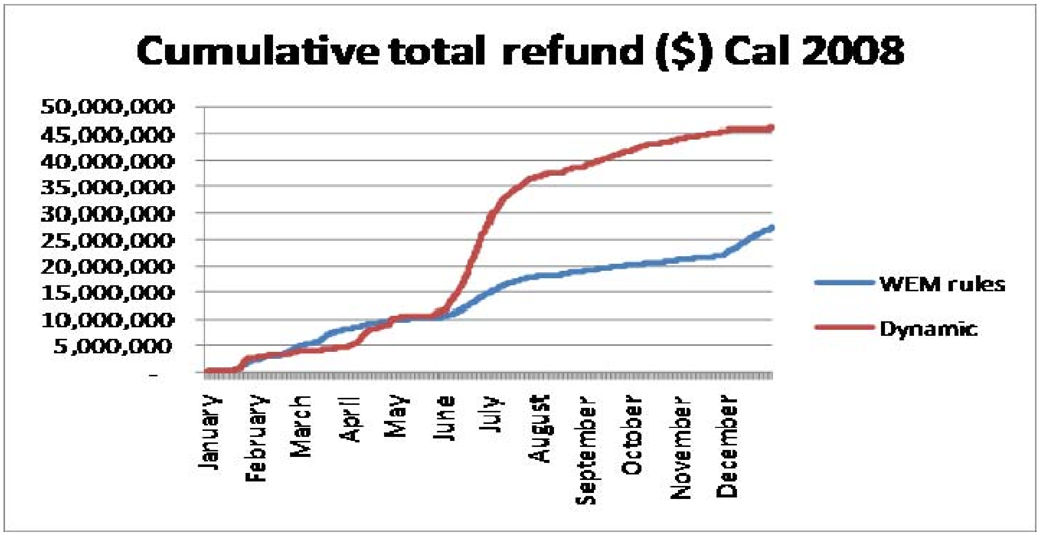

Figure 5 Refund rate versus reserve in calendar 2008: WEM rules

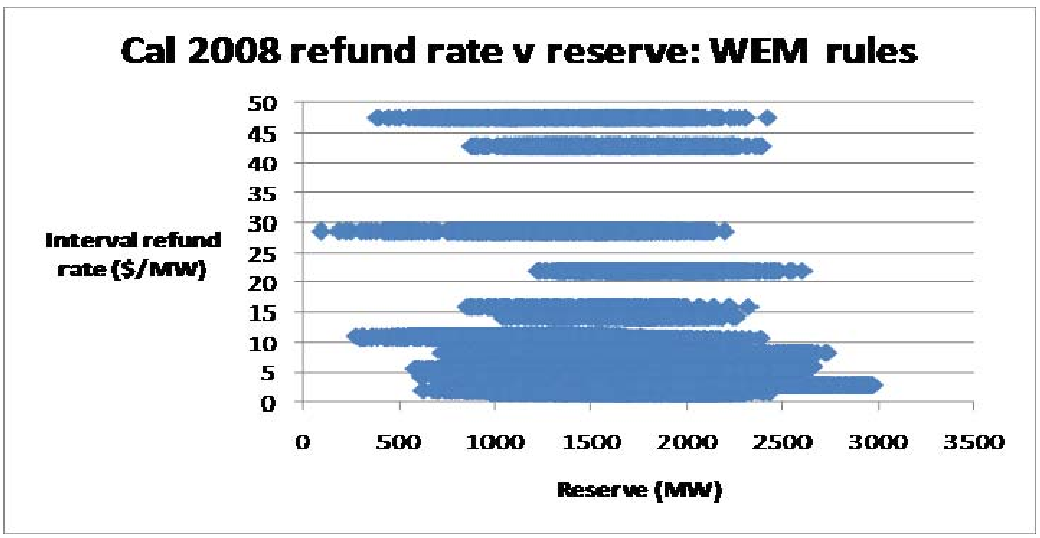

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Figure 6 Refund rate versus reserve in calendar 2008: Dynamic settings

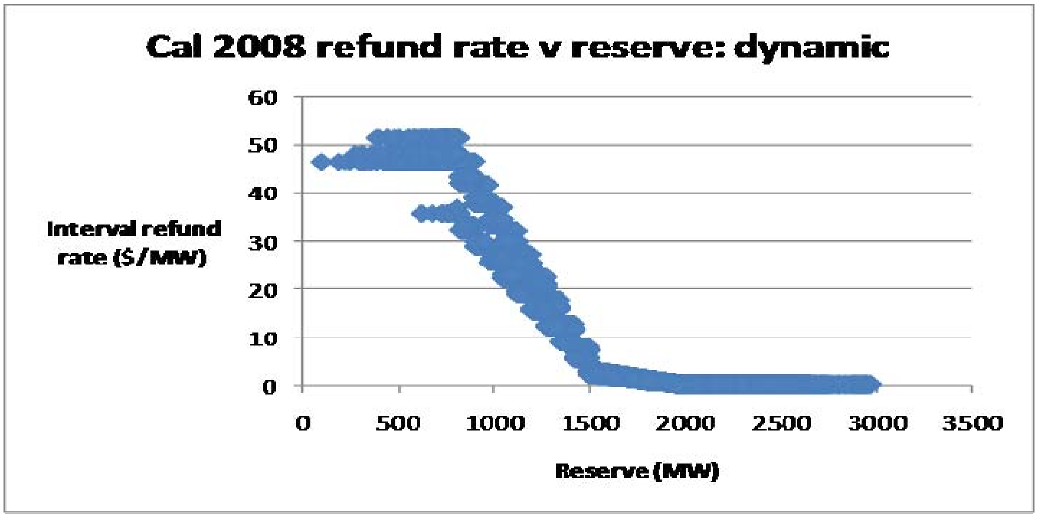

Figure 7 Comparison of cumulative refunds: calendar 2009

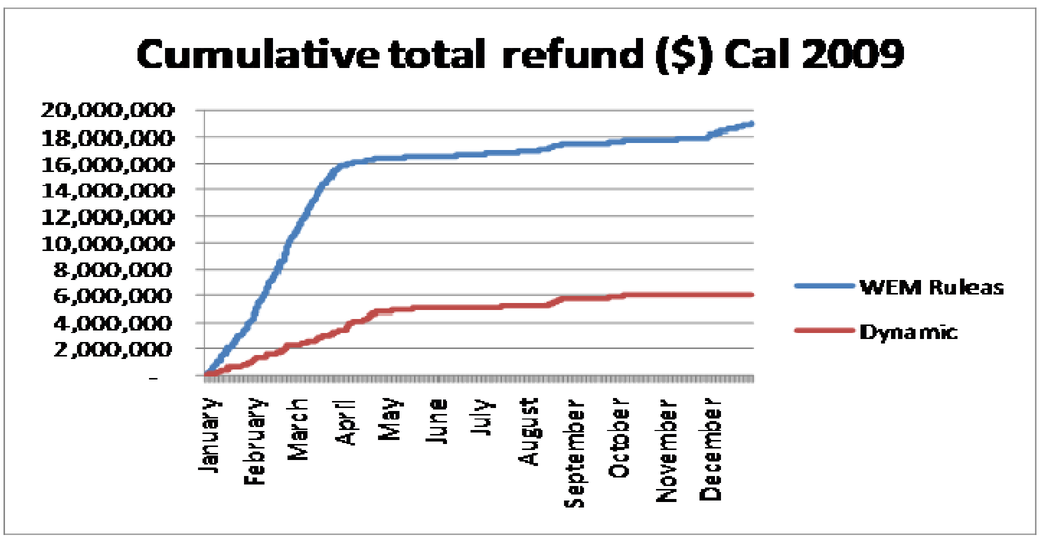

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Figure 8 Refund rate versus reserve in calendar 2009: WEM rules

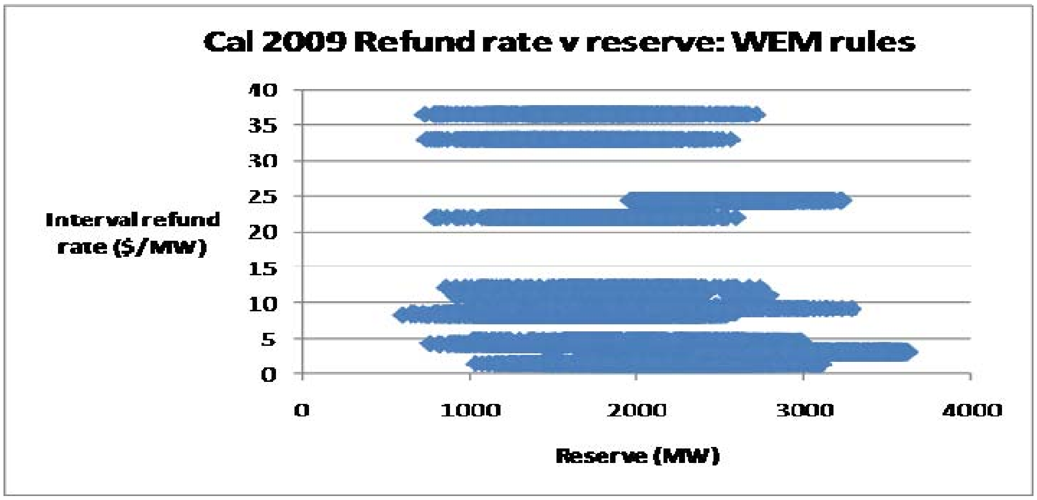

Figure 9 Refund rate versus reserve in calendar 2009: dynamic settings

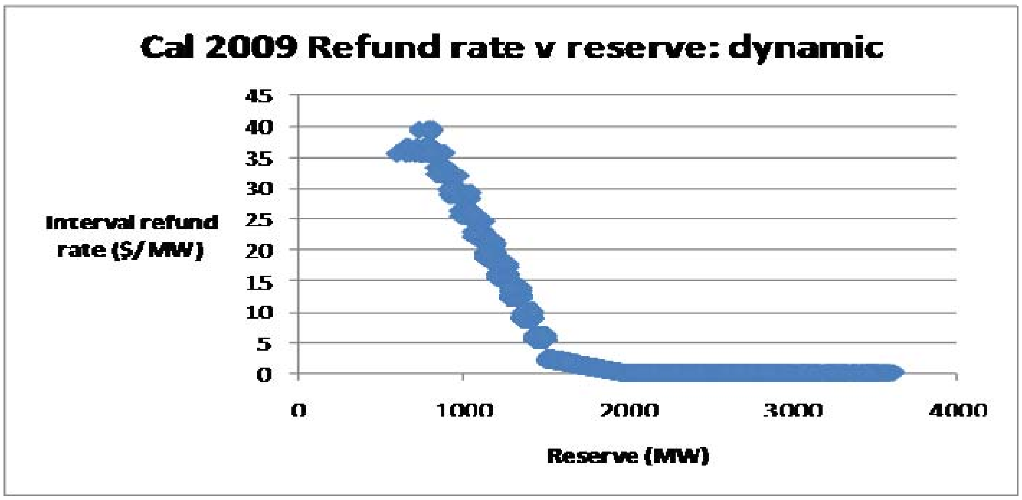

Figure 4 and Figure 7 show that across the year refunds can be higher or lower under the dynamic regime compared to the current WEM rules. Interestingly, over the two years studied the current refund rules were introduced the total refund is approximately the same.

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.

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5.4 *IMO Proposed Solution*

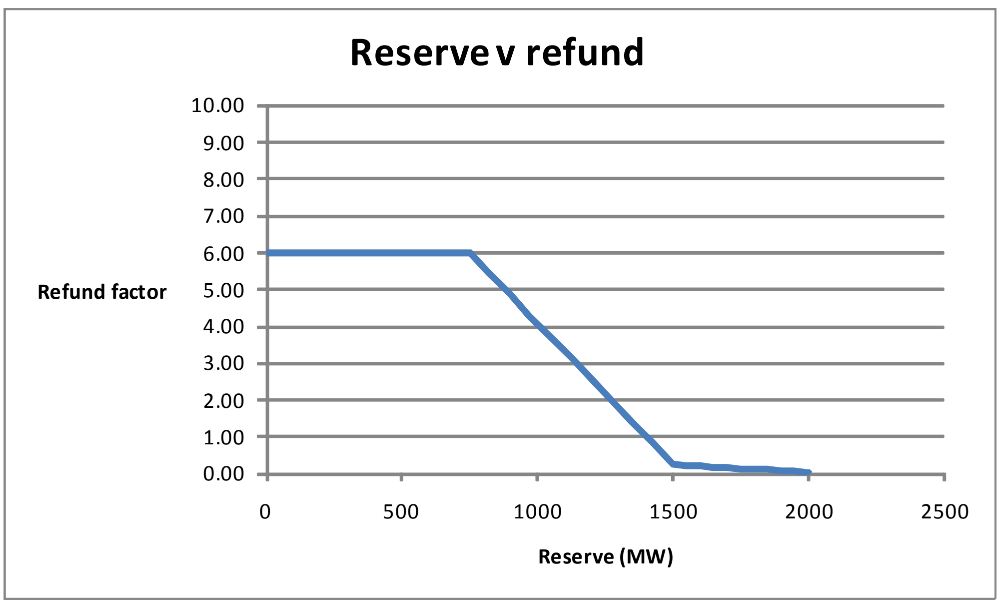
The IMO proposes that the maximum refund factor remain at the maximum value of 6. As noted analysis of the 2008 and 2009 calendar years shows that the cumulative refund amounts under the Market rules and the proposed methodology are similar. The IMO considers that as the design is aiming to produce a 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



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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, a s 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.

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Deleted: Figure 11 Forced Outage v Net STEM Shortfall Refund

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 Capcity Year and bring its into line with the following Capacity year where no late entry of facilities occurred.

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Figure 11 Forced Outage v Net STEM Shortfall Refund

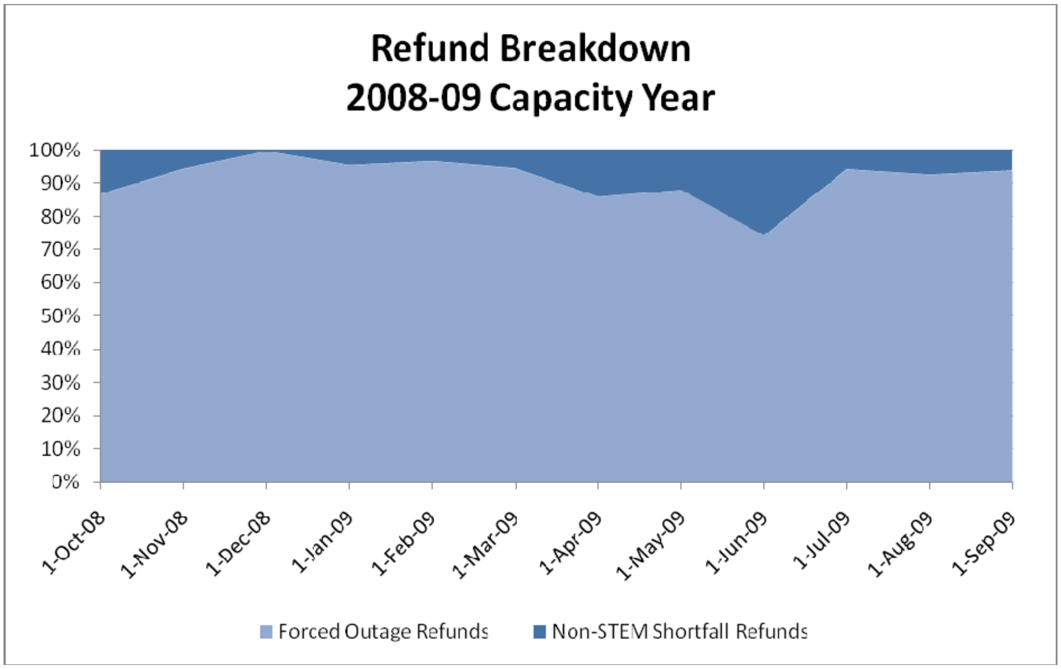

Figure 12 Forced Outage v Net STEM Shortfall Refund

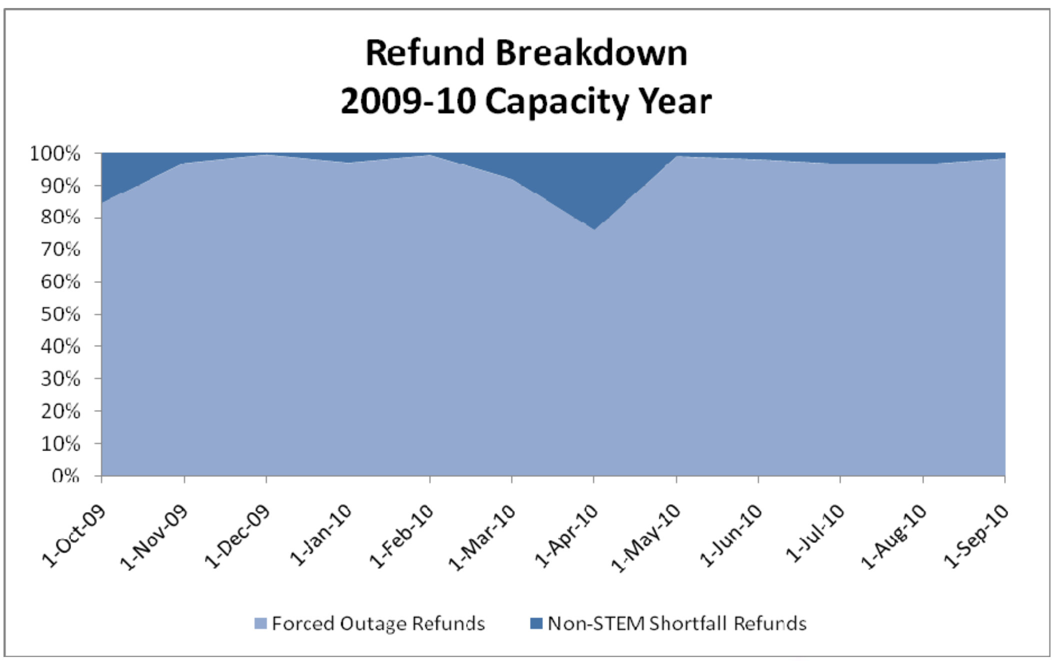

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Figure 13 Forced Outage v Net STEM Shortfall Refund (Griffin Adjusted)

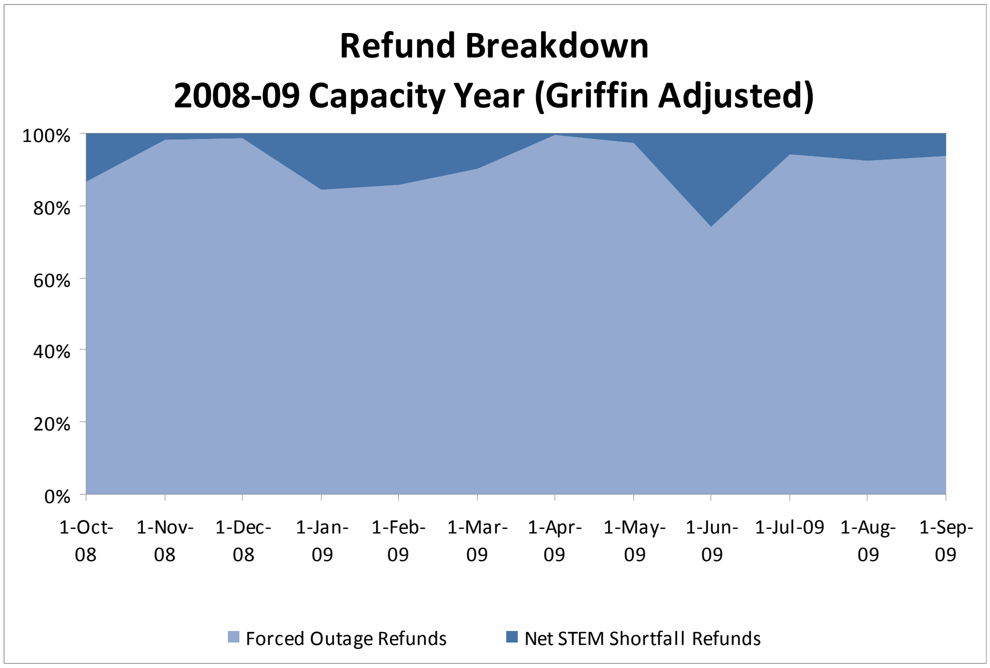

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Figure 14 Forced Outage v Net STEM Shortfall Refund (Griffin Adjusted)

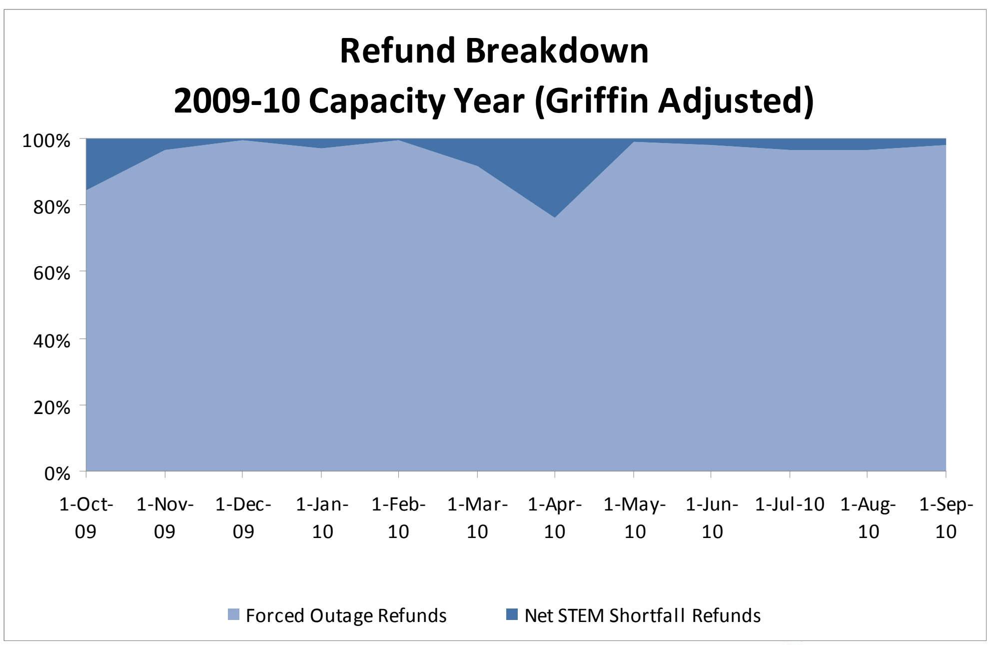
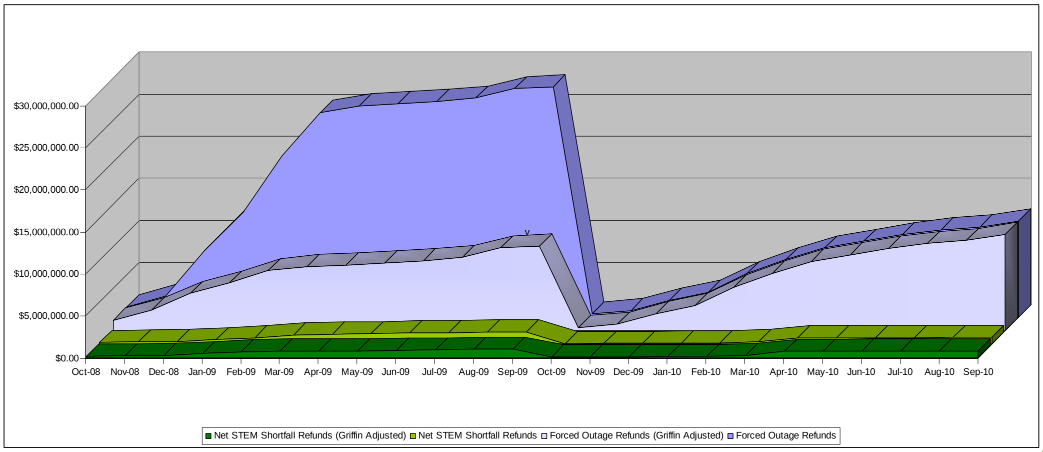


Figure 15 Cumulative Forced Outage and Net-STEM Shortfall Refunds (Per Capacity Year) - Normal and Griffin Bluewaters Adjusted



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

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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.

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7.1 Current Arrangements

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

- o 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

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- o 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.

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- 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 Particiapts 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.

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- o 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.

- o 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;

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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.

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Agenda Item 3a: Balancing and LFAS Proposals – Further principles

1. Purpose

This paper attempts to step back from the detail of the balancing and LFAS proposal and allow RDIWG members to assess some relevant principles. It presents:

a) A brief explanation of what is assumed by "retention and evolution of the current hybrid design";

b) The further design principles that underpin the balancing/ LFAS market proposal.

In doing so it draws on the relevant rules and past MAC and RDIWG decisions.

The papers also includes:

a) A brief update on the balancing/ LFAS design work-stream;

b) The current version of the detailed balancing/LFAS design document (the "12 boxes document").

2. Rules and past decisions underpinning the Detailed Balancing/ LFAS Design

Appendix 1 sets out the key rules and past decisions that have influenced/guided the development of the balancing and LFAS proposals. They are attached to this paper as they influence the remaining content.

3. Retention and evolution of current hybrid design

For the purpose of the balancing market design, retention of the fundamental WEM design is 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:

d) IPPs operating their facilities in accordance with resource plans (subject to dispatch by SM – net dispatch); and

e) Verve Energy as default provider of balancing and ancillary services on a portfolio basis.

f) Continuance of the SM / Verve Energy relationship (portfolio based, gross dispatch).

4. Further Design Principles underpinning the Balancing and LFAS Market Proposals

The proposal is based on a number of further design principles as listed below. These principles have been identified during the design process but are critical to the overall concept.

1. Providing opportunities for all Market Participants to participate in balancing where that makes economic sense.	Consistent with Market Objective (b) and RDIWG Terms of Reference (1)
2. Enabling price-based dispatch of resources for balancing/rebalancing through simple offers/ bids/ flexibility to manage resources efficiently.	Consistent with Market Objective (a)
3. Ensuring that the balancing price and payments for balancing 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)

4. Update on Design Work Stream

The current version of the "12 boxes" design document is attached as Appendix 1. There have been few changes to this document since the version presented to the 22 February RDIWG meeting. The IMO's focus has been on meeting with members, and in some instances staff within their organisations, to discuss the proposal and issues raised in their earlier submissions. Further to these discussions, a simple model is also being developed to enable members to gain insights into the workings of the balancing market forecasting cycle (resource plans, offers/bids, demand/ wind forecasts and forecast balancing prices and generator quantities). Discussions are also ongoing with System Management.

The IMO has now received and circulated the latest submissions from members on the version of the 12 boxes paper as presented at the previous RDIWG meeting. Those submissions relating to the balancing proposal have been attached as Agenda Item 7 to this paper along with the IMO's initial responses. The IMO is currently working through these submissions and will be circulating responses to members on Friday 11 March.

5. RECOMMENDATIONS

It is recommended that the RDIWG:

1) **Discuss** the design principles.

2) **Note** that IMO responses to the latest member submissions on the balancing proposal will be circulated on Friday 11 March.

Appendix 1: Market objectives and Key Decisions

The Market Objectives:

The objectives of the market are:

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

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

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

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

e) to encourage the taking of measures to manage the amount of electricity.

The IMO must not make Amending Rules unless it is satisfied that the Market Rules, as proposed to be amended or replaced, are consistent with the Wholesale Market Objectives. (Market Rules 2.4.2)

MAC Decisions to date

Subject	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*

Subject	Comment
	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 Decisions to date

Meeting since August, the RDIWG has made the following decisions in relation to balancing:

Principle	Comment
Clean 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 clean 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.*

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.

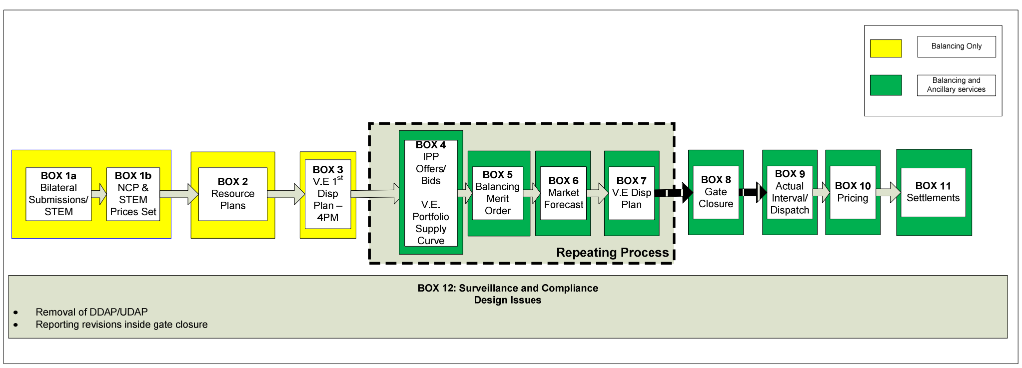
Sections 1 and 2 provide a high level overview (see figure 1). Section 3 provides additional detail of the proposed design in 12 stages.

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).

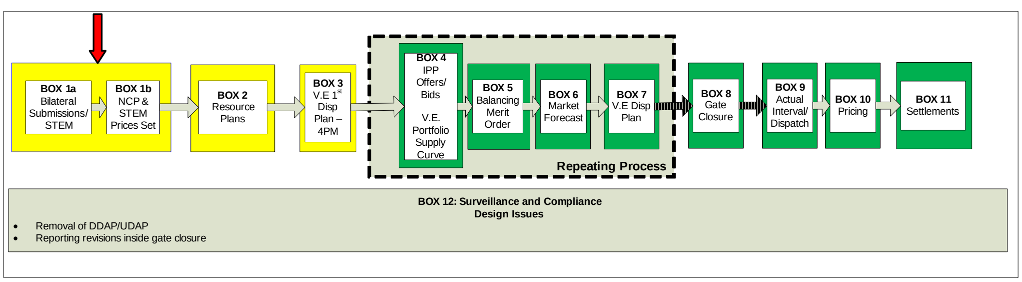
3. DETAILED DESIGN

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)

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Market Customers will be required to provide accurate day ahead nominations in their STEM Submissions:¶
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They should neither over or understate their demand.

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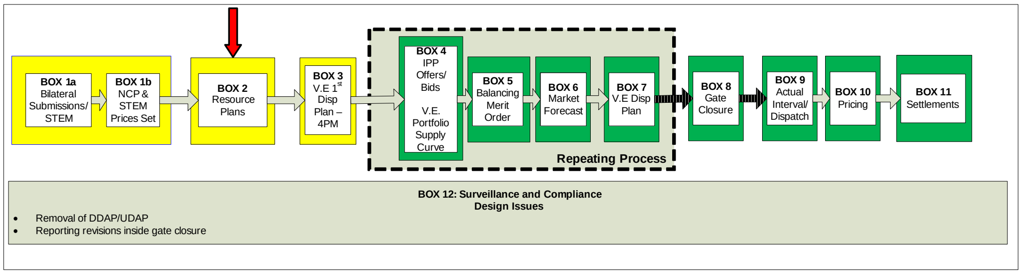
Independent Market Operator

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.

- o 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.

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

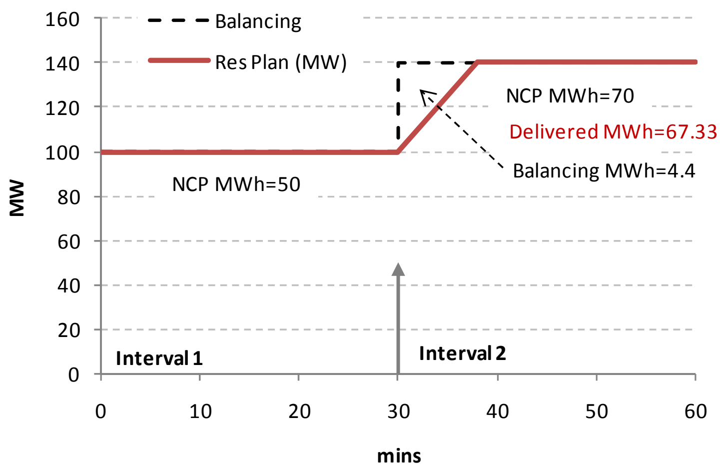
- RPs in each interval from each Market Participant must match the energy (MWh) in the corresponding NCP except when the NCP changes from one interval to the next.

  - o 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

  - o 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.



- o The above provision is intended to remove the implied need for instantaneous change in dispatch when NCP changes that is required under the status quo. An alternative approach whereby output could rise higher than 70MW and then be reduced for the start of the following interval was considered but is not proposed as it:

    - Unnecessarily complicates the point of reference for System Management to use the Facility to provide Balancing within the interval; and

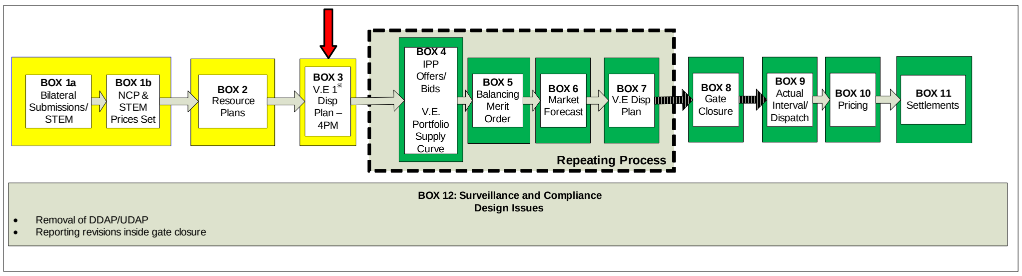
    - Requires multiple adjustments to operating levels and Balancing on other facilities for no other reason than the account for the half hour settlement of the market.

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.

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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

[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.

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).

	Tranche MW Range		Cumulative MW Range[3]	
ID	**From**	**To**	**From**	**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

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.

3 Aggregate MW range added.

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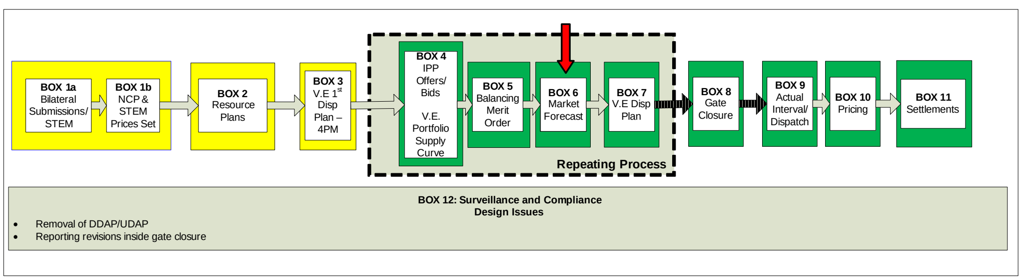
IPP2	0	50	25	75
IPP1	0	25	0	25

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.



3.6.2 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);

- o Expected overall wind/ non scheduled load and curtailment (to all Market Participants)
- o Expected Balancing price (to all Market Participants);
- o Expected balancing price if total generation requirements are +/- 1% from forecast; and
- o Expected Facility Balancing quantities (to relevant Market Participant only) including identification of any security constrained requirements.

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- 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)

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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.

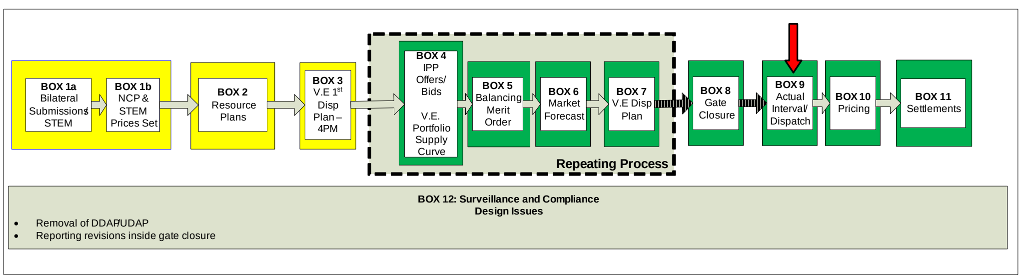
- Normal Facility gate closure requirements may be relaxed if System Management issues a system security advisory indicating a supply shortfall forecast or a supply excess forecast. In these cases Market Participants would be able to increase their offered quantities inside the normal gate closure period 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.

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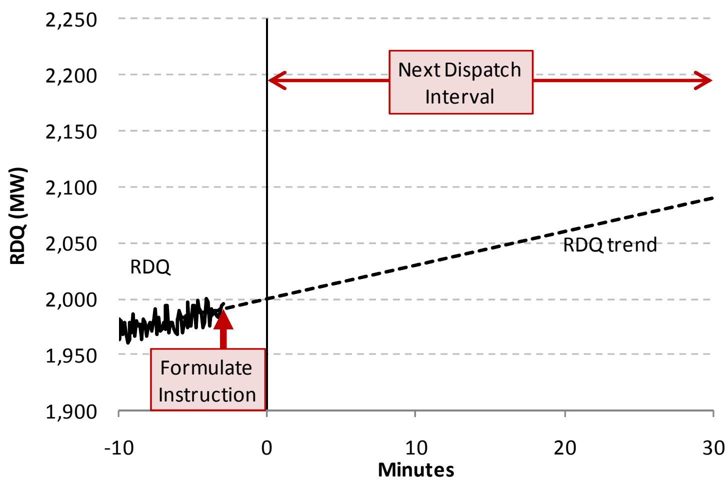
[4] See previous discussion on requirements to provide Ancillary Services.

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.
    - o This quantity is called Relevant Dispatch Quantity (RDQ) for the remainder of this paper.

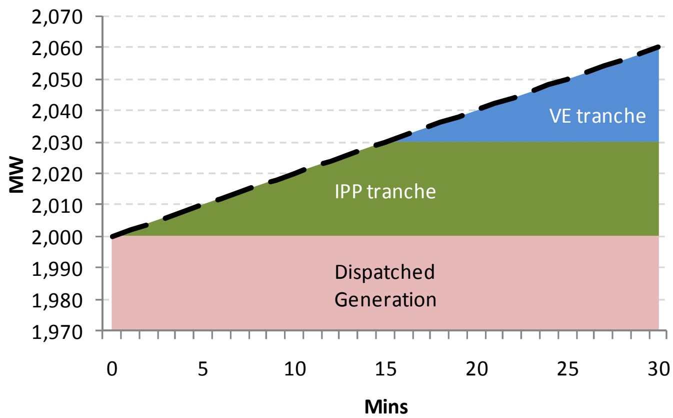


- System Management will formulate Balancing DIs in accordance with the RTBMO so as to meet the expected RDQ with the objective of minimising the cost of dispatch. System Management will need to develop systems to formulate Balancing DIs. Where a Facility is selected for LFAS, AGC capability will be 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:

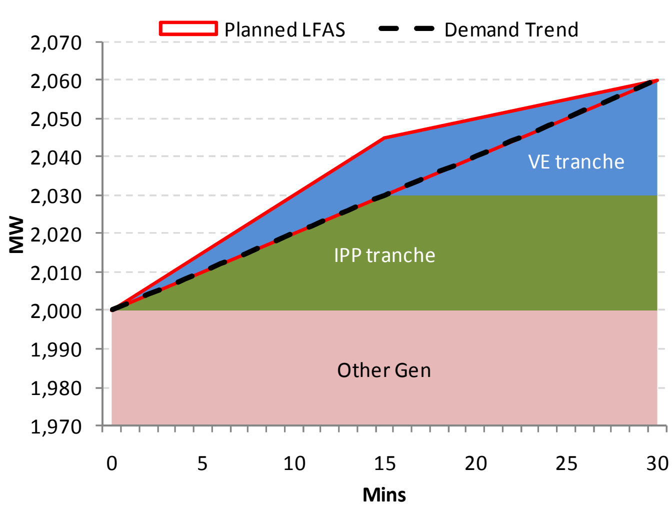


- In the example shown, an IPP Facility Balancing offer is able to be dispatched at less than its specified maximum ramping rate to follow the expected trend in RDQ (the dashed line). This minimises the use of the higher priced Verve tranche.

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.



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.

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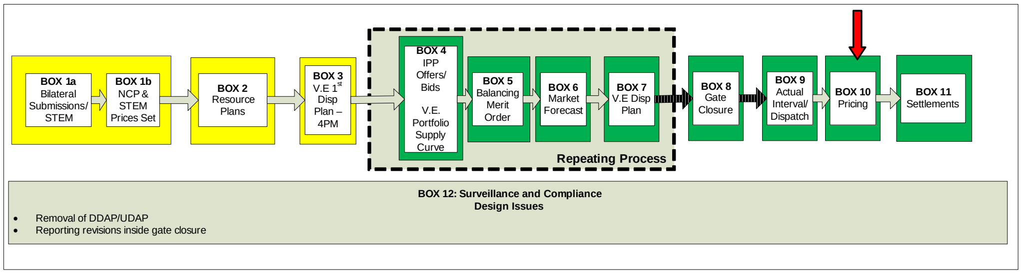
3.10 PRICING (Box 10)

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:

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- 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:

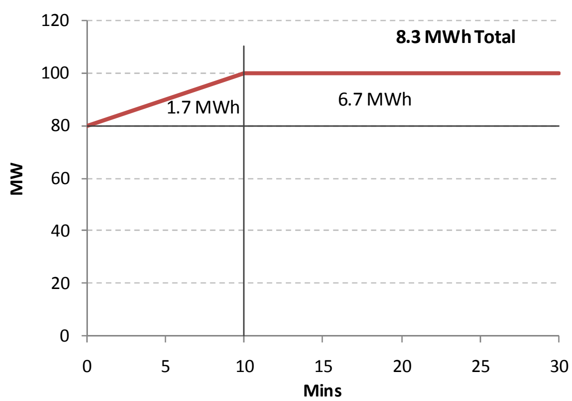
Basic

- 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

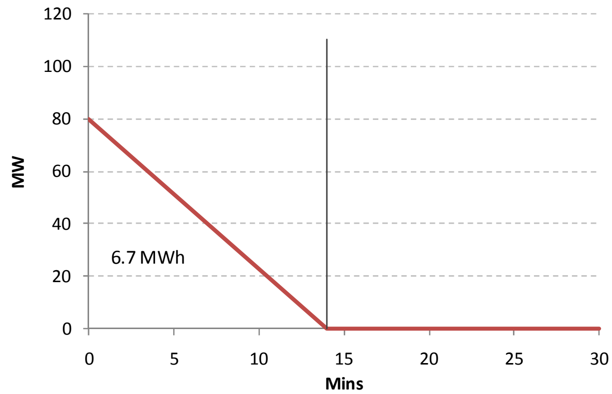
- The maximum amount of energy that the facility could be instructed to generate from the $50 per MWh tranche would be 8.3 MWh as illustrated below:



- 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).

				Cumulative MWh	
Tranche	Min MWh	Max MWh	$/MWh	From	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

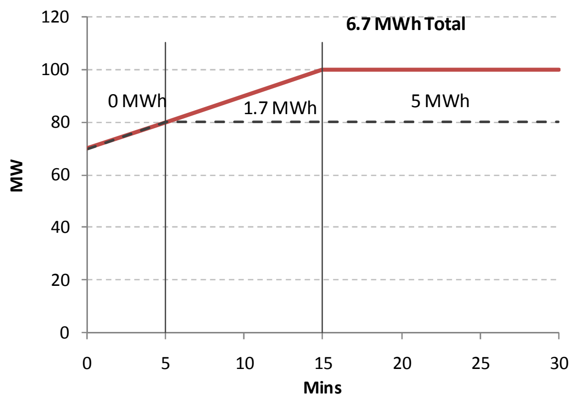
Accounting for ramping within resource plans

- 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).

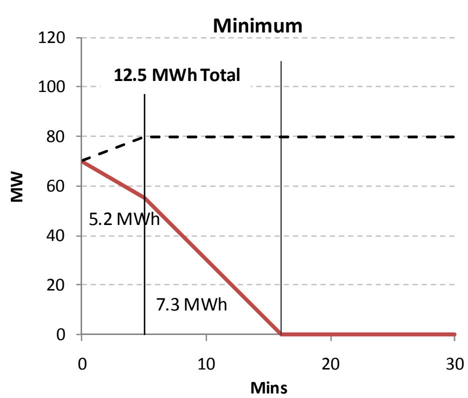
- In practice, the facility's resource plan may include ramping to a new level (refer box 2). For example, assume that in the above scenario, the facility is operating at a resource plan level of 70 MW at the start of the interval and that the resource plan ramps up to 80 MW[5] at 2 MW per minute. As illustrated below, the maximum energy

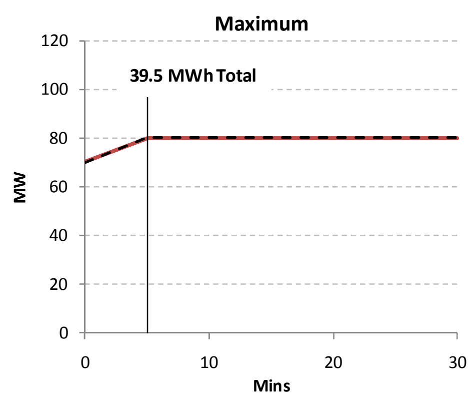
[5] e.g. 40 MWh NCP.

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.





- 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):

				Cum MWh	
Tranche	Min MWh	Max MWh	$/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:

				Cum MWh	
Tranche	Min MWh	Max MWh	$/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.

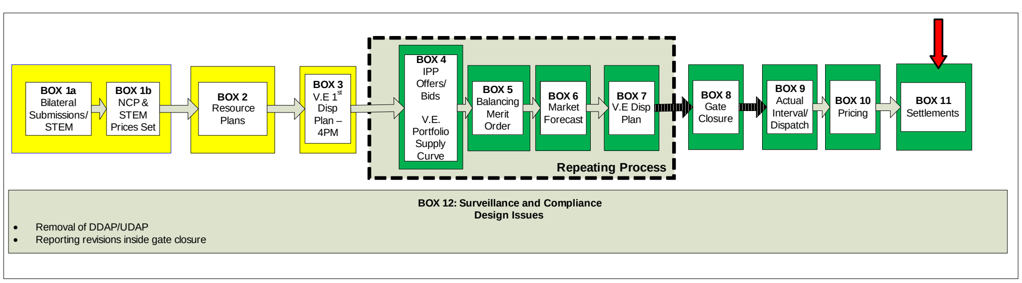
3.10.4 Further work:

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.

[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 $Q_{dispatch}$ * $Price_{Balancing}$ + $Q_{dispatch}$ * ($Price_{Balancing}$ - $Price_{bid}$)

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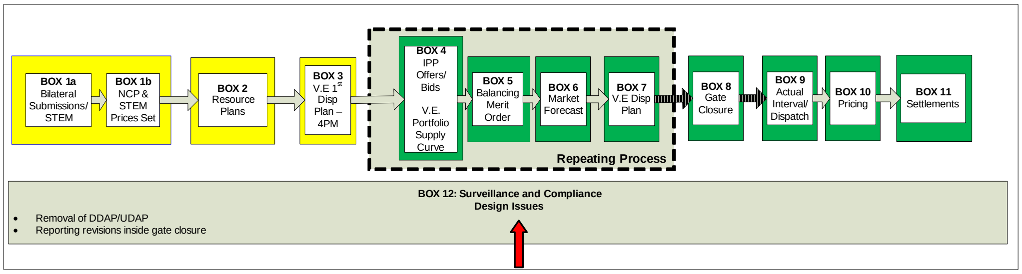


3.12.2 Background:

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.

- 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;

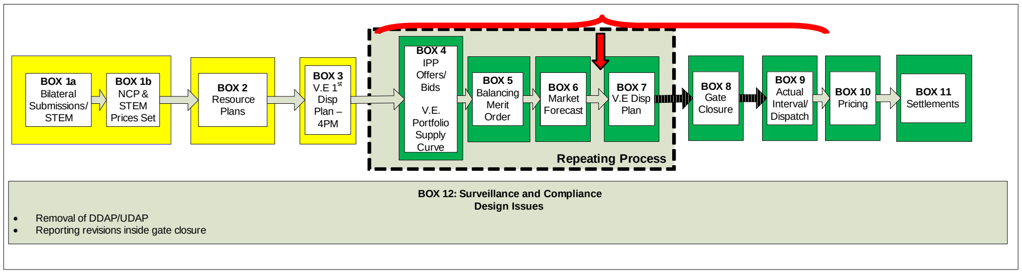
- Compliance with provision of Ancillary Services;

- Level and reason for constrained on/off payments (to assist future development);

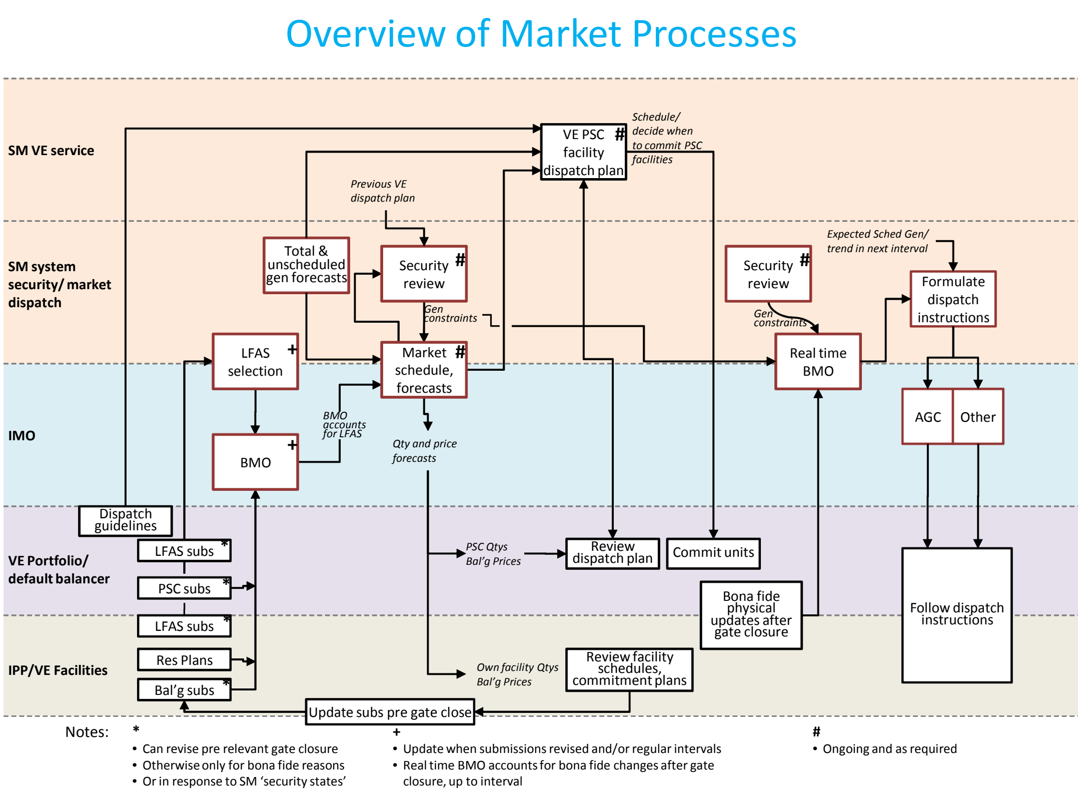
- Ancillary service offer prices; and

- If appropriate - Operational definition of market power and existing requirement for SRMC prices in bids/offers.

APPENDIX A: PROCESS, ROLES AND RESPONSIBILITIES

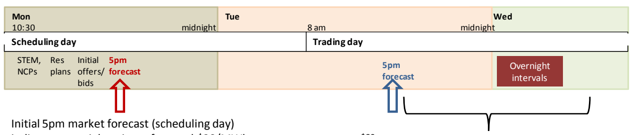


The following diagram illustrates the processes (including where process are repeated over the course of a day) and the roles and responsibilities within the proposed design described in the 12 stages.

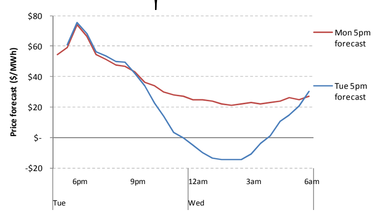


APPENDIX B: OVERNIGHT EXAMPLE

Overnight example



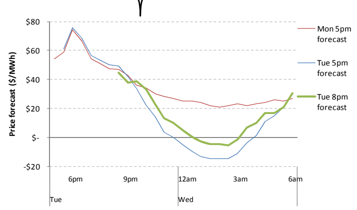
- Initial 5pm market forecast (scheduling day) indicates overnight prices of around $20/MWh
  - Issued 30+ hours ahead of overnight intervals
  - Issued several hours after NCPs established, resource plans submitted
- 5 pm forecast (trading day) indicates lower overnight prices
  - e.g. lower demand/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

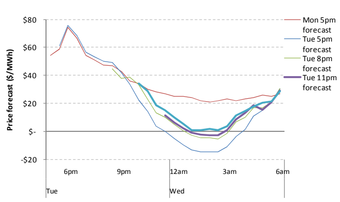


* *Had intermediate price forecasts indicated this trend, participants could have responded earlier given flexibility to revise facility submissions*

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

Agenda Item 3c: Cover Paper MEP Cost Benefit Analysis – Results

1. BACKGROUND

Attached is the Cost Benefit analysis for the balancing proposal undertaken by Sapere Research Group. Kieran Murray, Preston Davies and Ashley Milkop, the consultant's engaged to undertake the cost benefit analysis, will be attending the RDIWG meeting to discuss the results.

As per the RDIWG request, the Cost Benefit Analysis has assessed the benefits and costs of the new balancing proposal versus the status quo. The focus of the cost benefit analysis has been on:

- Identifying the categories of costs and benefits that should be assessed,
- Forecasting a likely "counter factual" future without the new balancing market,
- Identifying the cost and benefits of the potential switch to the new balancing market,
- Modelling these costs and benefits and the results,
- Modelling the sensitivity of the results to changes in the assumptions/different scenarios.

The team have drawn on published date and the data members of the RDIWG have been able to provide.

The team would welcome feedback on the results of the analysis.

2. RECOMMENDATIONS

It is recommended that the RDIWG:

- **Discuss** the attached draft "high level" cost benefit analysis on the balancing proposal;
- **Provide** any further feedback to the team undertaking the Cost Benefit Analysis, by Friday 25 March.

Introducing Competition to Balancing Services

A high level cost-benefit analysis

Kieran Murray

March 2011

About Sapere Research Group Limited

Sapere Research Group is one of the largest expert consulting firms in Australasia and a leader in provision of independent economic, forensic accounting and public policy services. Sapere provides independent expert testimony, strategic advisory services, data analytics and other advice to Australasia's private sector corporate clients, major law firms, government agencies, and regulatory bodies.

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Executive Summary

This report summarises our assessment of the costs and benefits of a proposal to introduce competition into the provision of balancing services in the South West Interconnected System Wholesale Electricity Market (WEM). The results of this study are intended to inform a recommendation by the Rules Development Implementation Working Group around whether to proceed with the proposal.

Scope and method of study

The study is focussed on economic effects- changes to the level of real resources available to the economy. Economy-wide effects, as opposed to individual effects on particular parties, are estimated. Factors that do not result in changes to resources (and associated economic welfare), such as price effects and wealth transfers are excluded. The methods employed involved modelling, desk-based analysis and consultation with industry stakeholders.

The analysis supports proceeding with the proposal

We quantified a small number of direct benefits (as opposed to benefits that are indirect or more diffuse or less sure) and compared these benefits with the costs of the proposal. This analysis shows that the economic welfare of society would be improved as a result of the proposal. That is, the benefits of the proposal outweigh the costs. The net benefits to the economy range from $16.8m in the high (optimistic) scenario, to $ 2.1m in the low (pessimistic) scenario. The ratio of benefits to costs is 2.07 in the high scenario and 1.09 in the low scenario. Doing nothing would mean foregoing the net benefits available from the proposal.

Summary results

	High	Medium	Low
Total benefits	$32.48 m	$27.92 m	$24.92 m
Total costs	$15.72 m	$19.27 m	$22.83 m
Net benefits	$16.76 m	$8.65 m	$2.09 m
Benefit-cost ratio	**2.07**	**1.45**	**1.09**

The positive results are robust to changes in parameters and assumptions

Changes to key parameter values and assumptions did not alter the essential conclusion that benefits outweigh costs. The net benefits associated with the proposal were relatively insensitive to changes in the costs of inputs, a range of additional scenarios around cost and benefit levels, the discount rate used in the analysis and the time period used in the study. Only when the study period was substantially truncated (from a period of seven years to three) or when the discount rate was more than quadrupled (from 8% to over 33%) did the proposal result in net disbenefit (i.e. a benefit-cost ratio below one in value).

Some effects not able to be quantified, but still important

The results mentioned relate solely to those effects that we could quantify. There are other effects that are also relevant, but are either not able to be quantified or would not be captured by the timeframe for the study. These effects include incentives to investment, confidence levels, longer-term transitional impacts and price signalling impacts.

Our assessment is that these non-quantifiable effects are as important as the quantifiable impacts. In terms of scale, they may be more significant. The impact of the non-quantifiable effects is to provide further support for the proposal, though we cannot accurately state the magnitude of non-quantifiable benefits.

The proposal is efficiency enhancing and consistent with wider WEM objectives

In summary, we estimate that there are clear efficiency-enhancing effects associated with the proposal in terms of:

- Productive efficiency- least-cost production of electricity.
- Allocative efficiency- resources devoted to generation most suitable for balancing.
- Dynamic efficiency-producing appropriate signals around investment and encouraging innovation.

These effects support the WEM objectives.

Table of Contents

1 Introduction

1.1 Background

In August 2010, the Rules Development Implementation Working Group (RDIWG) was established by the Market Advisory Committee (MAC) of the South West Interconnected System Wholesale Electricity Market (WEM). Recently, the RDIWG agreed to conduct further analysis of a proposal that would open up the provision of balancing to competition in a way that recognises the role of Verve Energy as the default balancer for the time being. The analysis will consider operating impacts and the costs and benefits of the proposal. The work is to be finalised by early May 2011.

1.2 Purpose of report

The major purpose of this report is to provide an assessment of the benefits and costs of allowing market participants in the WEM to provide balancing services in a competitive market for balancing services. We use the assessment technique of cost-benefit analysis (CBA).

CBA is valued by decision-makers as it produces a clear understanding of the resource (economic) costs and benefits of particular proposals (i.e. whether society will be better off from the proposal). In addition, the results of CBAs are readily comparable across a range of policy and industry areas, enabling comparison (and prioritisation) of initiatives in a manner that is consistent and coherent.

1.3 Lessons from CBA of electricity market reforms

Internationally, there has been a substantial amount of restructuring across electricity markets in recent decades and this has been accompanied by a significant amount of research into the costs and benefits of both proposals ex ante, and implemented changes ex post. This is not the appropriate place for a lengthy review of this body of work. However, some high level points may be made.

A useful summary of US electricity industry cost benefit assessments was completed in 2006 by the Electric Energy Market Competition Task Force.[1] This review

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[1] The Electric Energy Market Competition Task Force (2006) Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy.

considered thirty individual assessments undertaken between 2000-2005. Some general conclusions were drawn from the review. A number of these conclusions could be viewed as pertinent to the techniques employed in the CBA:

- Assessments often overemphasised the benefits with little discussion of the costs of restructuring proposals.
- Models are gross simplifications of the complexity of the electricity market and make simple and at times misleading assumptions about market behaviour.
- There are often data limitations necessitating assumptions, which can drive the result of the modelling. Sensitivity analysis of assumptions made is important.

Other conclusions warn the user of the results of the analysis against assuming that all the relevant information can be incorporated in this type of analysis:

- Many of the most significant benefits, which are often the motivation for changes, are difficult to quantify and therefore left out of the assessments. Maintaining system reliability and facilitating lowest cost electricity production were highlighted as key amongst these.
- Assessments often do not consider the distribution of costs and benefits across society, whereas in reality this may form an important component of the decision.

The decision criteria therefore should in most cases be broader than the quantified information available from the CBA.

In 2002, a NECA paper assessing the options for capacity mechanisms in the National Electricity Market notes the need for criteria other than the broad efficiency objective in the National Electricity Code to be considered.[2] The assessment criteria adopted for that study included:

- Consistency with market and NEC objectives.
- Effect on participants' risk profiles and prudential requirements.
- Economic efficiency implications.
- Form, extent, incidence and equity of charges and payments.
- Relative merits of market-based solutions versus central intervention.

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[2] Travis Consulting (August 2002) Capacity Mechanisms: The Options, prepared for NECA. These criteria are drawn from Putnam, Hayes and Bartlett Asia Pacific (1999) Capacity Mechanisms in the National Electricity Market: A discussion paper prepared for NECA.

- Simplicity and transparency.
- Transition arrangements, including the impact on incumbent revenue and expenditure.
- Long-term viability, in particular incentives for future investment.
- Stakeholder confidence in the market.

The Nordic electricity markets were progressively liberalised through the 1990s and are now integrated through Nord Pool at the wholesale level, while progress is ongoing at the retail level. As part of integrating the retail markets, the integration of balancing services is required.[3] A long list of guidelines was suggested for establishing an integrated market. Although this problem is slightly different to that facing Western Australia some of the guidelines may be relevant:

- Balancing service selection should be market oriented and economically efficient, contributing to operational security at least cost.
- Markets should promote effective competition, not create unjustified technical barriers to trade or unnecessary barriers to entry, not aggravate market power and be non-discriminatory.
- Changes to market rules should be made through a clear and transparent process and enforced in a clear manner.
- In order to avoid the misuse of market power incentives should be created by the structure of the market to encourage participation by generation and load.

Our reading of the experience with CBA of electricity market reforms elsewhere is that we must be mindful of the technical details of CBA and that not all of the key motivational factors for market reforms are conducive to quantification through a CBA. We also observe that the vast majority of studies we located were completed after market reforms had been implemented. This suggests that it may be more difficult to apply quantification techniques before reform is implemented because these techniques require the proponents of reform to be specific about the intended changes and expected benefits. The work of the RDIWG is therefore unusually (in a positive sense) rigorous in its approach.

[3] NordREG Towards Harmonised Nordic Balancing Services Common Principles for Cost Allocation and Settlement, Report 3/2008.

1.4 WEM Objectives

The relevant motivating factors for WEM are determined by reference to the objectives established in the Electricity Industry Act 2004:

- To promote economically efficient, safe and reliable production and supply of electricity and related services in the South West inter-connected system (SWIS).
- To encourage competition among generators and retailers in the SWIS, including by facilitating efficient entry of new competitors.
- To avoid discrimination 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.
- To minimise the long-term cost of electricity supplied to customers from the SWIS.
- To encourage measures to manage the amount of electricity used and when it is used.

It is not possible to achieve these objectives with a single initiative. For example, measures to facilitate entry of new competitors could include establishing regulatory certainty through clear rule change processes, eliminating unnecessary technical requirements, ensuring non-discriminatory access to markets, and enhancing transparency around market operations and pricing. The multi-faceted nature of the solution to such problems should not mean that measures cannot be implemented independently of each other.

In the case of the objective to reduce the long-term cost of electricity supplied to consumers, economists generally accept that opening markets to new participants would reduce long-term costs by introducing competitive pressures around current offering strategies and longer-term investment decisions. To minimise supply costs it is also necessary to maintain a high level of stakeholder confidence in the operation of the market, as risks are priced into decisions by investors. Incremental change is a valid way of maintaining this confidence while progressing toward the desired outcome of an open, competitive market.

A long-term perspective needs to be taken on the evolution of the market toward increasing competition and lowering costs. The introduction of competition for supply of balancing services should be seen in the context of this larger objective and valued as an initial step to this goal, in addition to its own measured net benefit.

1.5 Structure

This report is structured as follows:

- Section 2 describes the proposal in more detail.
- Section 3 outlines the nature of costs and benefits relevant to this analysis
- Section 4 sets out the baseline case against which the costs and benefits will be compared.
- Section 5 details the estimated effects of the balancing market proposal and explains the basis of those estimates, including caveats and assumptions.
- Section 6 discusses the likely net effect of the proposal.
- Section 7 concludes with summary comments and recommendations.

Background material around the analytical approach and its key components is included as an appendix.

2 Proposal under consideration

This section outlines the basic features of the proposal to introduce competition into provision of balancing services. The final design of the market, and indeed whether or not to proceed, is still under consideration. Therefore we describe the features in a somewhat generic manner; refinement will be possible once further details become clear. This section also contains a problem statement which sets out our understanding of the rationale for the proposal.

2.1 Problem statement

The MAC established the RDIWG (involving representatives from across the industry) to assess problems in specified areas and identify solutions. The problems most relevant to this analysis are:[4]

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.

[4] See: "Wholesale Electricity Market- Next Steps. Market Evolution Program: Summary" for a full list of the identified problems/issues. Available at: http://www.imowa.com.au/mep-overview

3. The calculation of MCAP (Marginal Cost Administered Price) and the role of UDAP and DDAP (respectively Upward and Downward Deviation Administered Price) 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.

In addition, there are issues associated with the Short-Term Electricity Market (STEM) in terms of its ability to provide incentives to participate, including a lack of transparency, timing issues and the single pass design, and rigidity of requirements for resource plans to match STEM outcomes. Barriers to participation render the STEM less effective as a means of price discovery. Furthermore, the transparency and cost issues are exacerbated by having a default balancer that is unable to provide facility-based submissions, meaning delays in the discovery of important prices, and little opportunity to mitigate the effect of those prices.

2.2 Proposal under consideration

In keeping with the current design of the wider wholesale market, a hybrid (simple portfolio/facility) arrangement is suggested for the proposed balancing market.[5]

2.2.1 STEM/ resource plans/ dispatch plan

- The bilateral submissions and STEM process would operate as now.
- IPPs would submit resource plans as now.
- System Management would prepare the initial Verve dispatch plan as now (taking account of resource plans, wind/ demand forecasts and Verve guidelines).
- A balancing price forecast would be prepared using STEM supply curves (assuming all IPPs in the curve and Verve are available for dispatch), resource plans and the latest operational load and wind forecasts. i.e. in effect, treat the participant balancing submissions (described in section 2.2.2) as revised offers following the market forecast.

[5] This description is as set out in the IMO Paper "Balancing Support" dated 23 November 2010.

2.2.2 Balancing submissions

- Late in the afternoon, Market Participants would make balancing price submissions.
- IPP balancing submissions would be by facility:
    - Offers/ bids relative to facility resource plans (or gross offers for a facility not in service)
    - All IPPs would submit balancing prices, with prices reflecting willingness to participate in normal balancing or otherwise.
    - Half-hourly price-quantity submissions would be desirable to maximise flexibility to participate.
- Verve's submission would be by portfolio for each trading interval:
    - Verve would submit its full supply curve (as it does now for its STEM supply curve submission). Initially, the existing STEM submission could be used if that would enable quicker implementation.

2.2.3 Balancing merit order

- The Balancing Merit Order (BMO) would be prepared on a gross basis.

2.2.4 Scheduling and dispatch

- IPPs would operate to resource plans unless dispatched off plan by System Management (as now).
- System Management would schedule Verve facilities 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). This would involve:
    - Determining when a balancing dispatch instruction is necessary (e.g. by observing when the frequency regulation/ load approaches limits or is expected to).
    - Monitoring the Verve loss adjusted quantity in real time.
    - Dispatching any IPP quantities (or separately offered Verve facilities) at break points specified in the balancing merit order. IPPs will need to manage constraints extending beyond a trading interval through

their offers and bids rather than expecting inter-temporal trade-offs to be made by the IMO, in preparing the merit order, or System Management, in formulating dispatch instructions.

- o Dispatching Verve facilities, in accordance with the Verve guidelines, until an IPP offer or bid break point in the merit order is reached (or a standalone Verve facility). This will at times involve trade-offs in selecting which Verve facilities to dispatch around IPP break points given inter-temporal factors, although similar to the current situation.

2.2.5 Balancing settlements

- System Management would advise the IMO of any IPP quantities it has dispatched (to identify the marginal quantity, establish the marginal price, identify any out of merit dispatch and establish authorised deviations).
- IPPs that were dispatched above their resource plans by System Management (authorised) would receive the marginal balancing price (or out of merit payment if necessary).
- IPPs that were dispatched below their resource plans by System Management (authorised) would pay the marginal balancing price (or an out of merit payment if necessary).
- Verve would be paid/ pay on the same basis for quantities above/ below its NCP.
- 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.

(Note: there may have been some further amendments to the above since the undertaking of the analysis)

3 Taxonomy of costs and benefits

This section sets out the range of costs and benefits considered in this analysis. It is not exhaustive, but rather reflects the practical nature of the undertaking. In relation to benefits, we have focussed on a small number of that have direct effects, as opposed to impacts that are indirect, more diffuse or less sure. On the costs side, there is slightly more certainty, particularly in relation to timing as costs tend to be incurred upfront and generally have a finite life.

Table 1 Taxonomy of major costs and benefits

Effect	Components/drivers	How expressed	Evidence source/strength
Costs			
Personnel	• Staffing requirements for extended trading periods, additional relationship management and altered duties • Training associated with new arrangements and systems	FTEs/time converted to marginal (additional) expenditure in dollar value terms	Market participants, System Management, IMO.
Systems- assets	• IT requirements to manage in-house trading and forecasting requirements • IT requirements in terms of the interface between participants and IMO	Additional (or re-configured) hardware and software needs converted to marginal (additional) expenditure in dollar value terms	Market participants, System Management, IMO.
Systems- processes	• Monitoring costs (e.g. fuel positions of IPPs; Supervision and awareness costs for System Management (SM)) • Additional preparation of manuals and/or instructions • Associated rule changes • Changes to dispatch costs for default balancer and SM	Additional time costs expressed in net (i.e. total cost minus any offsetting benefits) terms converted to marginal expenditure in dollar value terms	Market participants, System Management, IMO.

Benefits			
Prices	• Removal of DDAP and UDAP and other distortions • Submission of STEM submissions versus Resource Plans • IPP tranches lying between relevant quantity and the balanced market position (i.e. MCAP is not cost-reflective)	Impacts on behaviour from the removal of distortions to the balancing price (i.e. what a “clean price” means for balancing)	IMO
Efficiency	• Dispatch of Verve plant for “everyday” balancing requirements when other (IPP) plant could have been dispatched at lower cost • Dispatch of Verve plant for “extreme” balancing requirements when other (IPP) plant could have been dispatched at lower cost. Also, IPPs and retailers face volatility in MCAP – a business risk • Gate closure that is closer to actual trading (i.e. greater plant availability) • Participants can operate plant more efficiently through the balancing market rather than keeping to counter-productive resource plans (i.e. more flexibility)	Resource cost savings from dispatch of less expensive plant in dollar value terms Avoided costs as a result of flexibility.	Market participants, IMO
Investment	• Appropriate signals determine: o Nature of investment (i.e. type of	Additional investment in dollar terms	Market participants

	plant) best suited to market situation o Quantum of investment (i.e. degree of security/comfort in WEM)	Altered investment New entrants	

3.1 Additional benefits

The table above only contains the effects that are able to be estimated in a quantifiable sense (albeit with some imprecision). There are also a range of other effects that are important, but less amenable to quantification and/or do not result in purely economic outcomes (e.g. financial transfers, which are distributional effects rather than resource costs). These effects are important because they influence behaviour and therefore indirectly affect outcomes that matter. Some of these effects provide softer support for the numbers, in terms of confidence that the proposal will provide a net benefit.

We see the following instrumental benefits arising that have not been quantified.

3.1.1 Transitional advantages

This form of benefit is largely unseen. The benefits arise from the contribution of a competitive balancing market towards preparedness for further WEM evolution. That is, a balancing market provides opportunities for participants to undertake activities that may be beneficial in future. The behaviour changes likely to arise from participation in a balancing market represent a step along the path towards a liberalised and efficient electricity market. In other words, a balancing market provides impetus. The adjustments now may result in avoidance of some of the costs of transition in the future. The proposal is complementary to wider market change objectives and may ultimately pay additional dividends in the future.

3.1.2 Increased confidence

Competitive provision of balancing services may also result in greater confidence levels. Confidence is a necessary, but not sufficient, condition for innovation, which has significant payoffs in the longer term as it is a key driver of dynamic efficiency. The more flexible security processes and automated software that result from the proposal are likely to produce savings that are not immediately quantifiable but that assist in an operational sense. In addition, the central clearing nature inherent in the design of a balancing market should alleviate impediments to participant-to-participant balancing support contracts associated with credit risk, because the IMO will have a prudential role. Participants may also have more confidence about bidding into the STEM knowing that they can resort to a balancing market if need be. While there is a possibility that the proposed balancing market effectively replaces the STEM, it is also possible that they will be complementary in nature. That is, the balancing market results in better all-round operation of the WEM (including the STEM).

3.1.3 Better risk allocation

On the back of increased confidence comes a greater willingness to bear risk. At present the risk-reward calculus is skewed towards safer and more familiar avenues (i.e. bilateral contract arrangements). The enhanced transparency resulting from the proposal may alter those decisions. In discussing the merits of competitive markets for electricity balancing, the European Regulators Group for Electricity and Gas states:

" …transparency concerning market rules, price formation, and market participation will also facilitate the functioning of the market by allowing market parties to make informed decisions and minimise risk concerning investment and operation."[6]

One such decision concerns the choice between renovating existing plant and the purchase of new plant. Where new plant is more amenable to participation in the balancing market and is more efficient in terms of electricity output for given inputs than the existing plant then wider dynamic efficiency benefits accrue from a balancing market than would otherwise be the case, as the market alters these investment decisions in favour of more "balancing capable" capacity. The prospect of stranded costs/assets may also be reduced as result of the balancing market proposal.

6 ERGEG Guidelines of Good Practice for Electricity Balancing Markets Integration, Ref: E05-ESO-06-08 7 June 2006, European Regulators Group for Electricity and Gas. Available at: www.energy-regulators.eu/

4 The baseline

To model the benefits of the proposal, we studied the balancing outcomes since 2008, reviewed the papers presented to the RDIWG, and talked to participants about their experiences with balancing. We used the data obtained from these investigations to forecast balancing costs.

Because of some of the distortions involved with the current balancing regime it is difficult to estimate the actual economic costs of balancing at present. Some of those distortions are:

- IPP offers used in determining MCAP.
- Irregularities with the relevant quantity process.
- Verve portfolio-based (rather than facility-based) bidding.

There are a number of ways we can estimate the financial cost of balancing and the economic advantages of opening it up to competition.

Of note is that balancing volumes and overall costs have decreased since 2008. Taking a detailed look at the data reveals several main conclusions:

- First, the supply cushion (or gap between available capacity and actual load) is the main driver of balancing costs. The cushion has widened somewhat between 2008 and the present, which, in turn, has caused balancing costs to decrease.
- Second, while intermittent generation has been a factor in some extreme balancing events, overall it is not a significant causal factor of balancing requirements. That being said, the addition of the Collgar windfarm will increase the contribution of intermittent generation to balancing volumes.
- Third, there is evidence that, as a result of some legacy gas contracts coming up for renewal, the STEM price is likely to rise over the time period studied. This will, in turn, cause balancing costs to increase.
- Fourth, the IMO's statement of opportunities provides information on how it believes that load will increase over the next years. Contrary to possible expectations, we do not believe that load increases will cause balancing volumes to increase. Load increase will have an effect only through its influence on energy prices.

In the following section on forecasts we present estimates of how we believe the STEM price will evolve over the next few years.

Establishing forecasts is important for two reasons. The first is to model the effect on balancing volumes of the new Collgar windfarm. This matters if we are to establish a fair view of what will happen going forward. The second is to work out a way of scaling the results for future years. The STEM forecast is the means by which we have done this.

There is one aspect that we have not incorporated into the forecasts, which might present an upside to the results. We have noted the significant effect of the supply cushion on the balancing costs. If the supply cushion were to diminish then we would expect to see higher STEM prices and, as a consequence, higher benefits. To the extent that the global financial crisis depressed electricity demand and subsequently new capacity investment in the WA market for a period, the speed of the recovery from this event, may reduce this supply cushion and hence increase the balancing price.

4.1 Modelling approach

This section sets out the components of, and general approach to the modelling we have undertaken. It contains short descriptions of the process, inputs and reference to assumptions. The overarching principles governing our modelling effort (and the overall project) are as follows.

- *Internal consistency*- avoiding (or minimising) any contradictions or inconsistencies in the assumptions invoked or parameters used (e.g. alignment of factors such as participation rates, timing of costs and benefits and what constitutes an economic impact) as well as checking any conclusions are consistent with the supporting analysis.
- *External validity*- in essence, ensuring the results of the study are able to be understood (i.e. accessible and transparent), accepted and reproduced by outside parties if needed.
- *Efficiency*- rather than reinvent the wheel, we look to build on existing material and look to avoid re-litigating past decisions; sticking to our brief.
- *Objectivity*- we do not bring any strong prior beliefs or positions into the analysis and let the data do as much of the talking as possible, without setting out to find a particular outcome (or set of outcomes).

4.1.1 Process

We have drawn on a number of data sources, studies and meetings with market participants to establish a model to capture the benefits of the balancing proposal. We are interested in how the proposal would lead to a change in the physical dispatch of electricity and the related overall costs, rather than any changes to prices or changes to an individual participant's cost or revenue structure. For that reason, we have not considered the implications of the paper on Balancing Price Formation which was presented to the RDIWG on 2 November 2011, as it mainly deals with questions of wealth transfer rather than physical dispatch.

4.1.2 Inputs

We have had access to a wide range of data supplied by the IMO, including SCADA data, and bid and offer data. We have also had available the detailed data on the benefits identified in the paper on Balancing Support presented to the RDIWG on 23 November 2010. The Statement of Opportunities details the load forecasts which we have employed for estimating STEM forecasts. And we have used information from the Verve Margin Review to establish a price curve for the market, which we have used for forecasting purposes.[7]

4.1.3 Assumptions

Specific assumptions are set out in detail in the relevant sections that follow.

4.2 Forecasts

We have built up a model to analyse balancing as it takes place in the WEM. Using data from the beginning of 2007, we have worked out the main drivers of balancing in volume terms and evaluated why MCAP deviates from the STEM price.

DDAP (the downwards deviation administered price) and UDAP (the upwards deviation administered price) do not feature in this analysis. Although these prices are relevant to the extent that they cause penalties to IPPs, they are not incurred by all participants who deviate from plans and are therefore an unnecessary complication.

Time periods are defined as the year to 30 September, consistent with the Statement of Opportunities. So, 2007/08 is the year from 1 October 2007 to 30 September 2008.

Estimating forecasts of balancing costs is not a straightforward process. Figure 1 shows that balancing costs (expressed in MCAP) have declined significantly since 2008, while Figure 2 illustrates the relativity between balancing up and balancing down over the same period.

[7] A list of information sources used is included as an appendix.

Figure 1 Costs of balancing

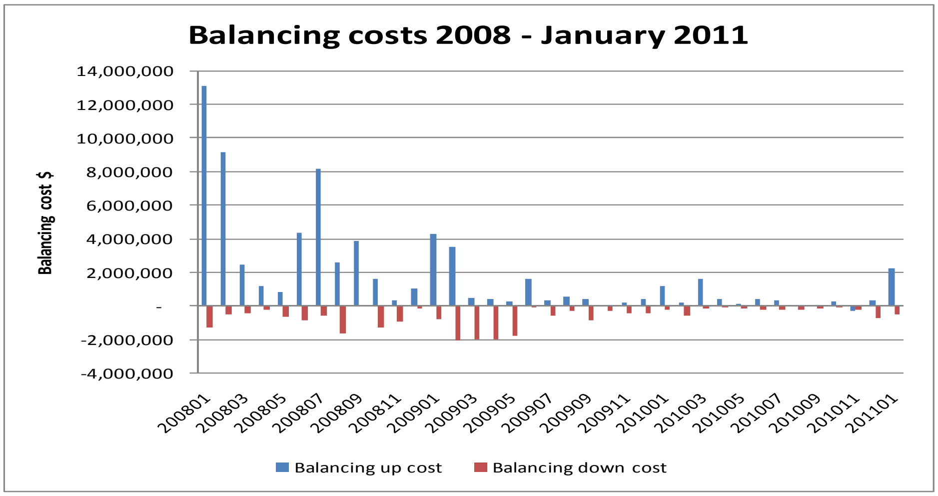
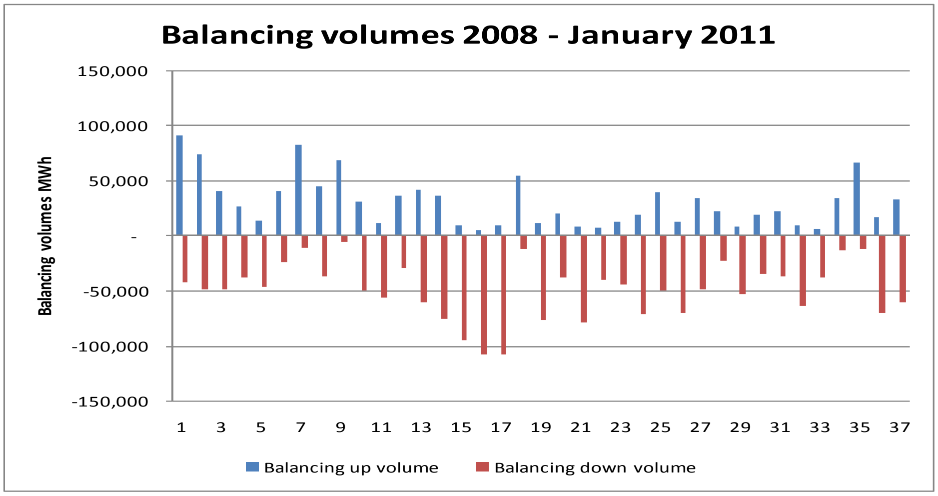


Figure 2 Balancing volumes



Our examination of the data shows that the distortions giving rise to balancing requirements i.e. forecasting inaccuracies, over/under submission have diminished over the past two years, which has reduced somewhat the need for balancing. At the same time there has been an increase in the "supply cushion" which explains the decreasing average STEM price, a result of increased availability of options for balancing.

The time frame we have looked at, since the beginning of 2008, has seen two moderately sized windfarms in operation: Emu Downs and Walkaway. However, intermittent generation has not been a major contributor to balancing requirements. There may have been trading periods where intermittent generation had a significant marginal effect, but it is not a significant contributor to overall balancing volumes. Total installed intermittent capacity is currently around 190MW with approved capacity credits of 77MW. This means that, over a half hour, the contribution to balancing of intermittent generation ranges from around minus 56MWh to plus 40 MWh at the extremes. These variations are dwarfed when compared with overall balancing requirements of +/-300MWh within half hour trading periods.

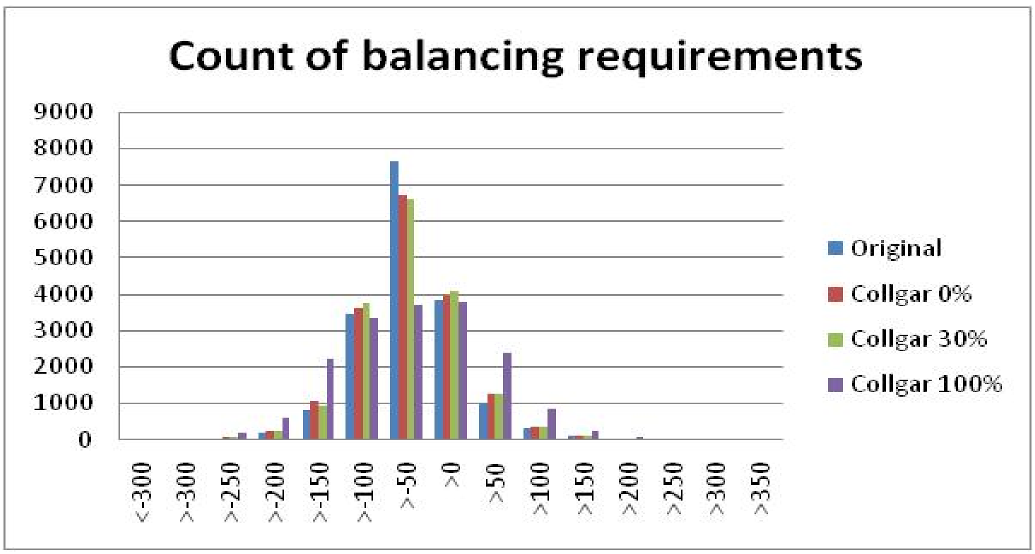
Within our time frame there will be a number of changes to the composition of the generating fleet in the WEM. These will have an effect both on the amount of balancing required and the availability of generation to assist with balancing. The other major change that can be expected is an increase in the cost of gas to generators as contracts come up for renewal.

We have established a model for predicting the balancing costs for the next five years.[8] We have made a number of assumptions in building this model:

- The Collgar wind farm will become fully operational in April 2012 at its stated capacity. Its operating characteristics will be similar to the existing wind farms and the capacity credits awarded to it accurately reflect its average output. The outputs of Walkaway and Emu Downs are correlated at around 40%. In this analysis we have assumed a correlation of 30% between the future Collgar farm and the existing farms.
-
-
- Figure 3 shows the effect of different correlations on balancing volumes. As can be expected, the higher the correlation, the more volatile the balancing requirements – as peaks and troughs in production are exacerbated.

[8] A description of the process for producing balancing forecast with the addition of Collgar is included as an appendix.

Figure 3 Collgar correlation and balancing requirements



- As annual consumption increases the need for balancing does not. We have not observed a strong link between increasing load and increasing balancing requirements.
- The contract gas price faced by participants will rise to $6/GJ by 2014.[9]
- Aside from the generation changes outlined in the Verve margin report there will be no other new plant and no further plant decommissioned.

[9] We note that there are some differing views on the forecast accuracy of this assumption. We have looked at the sensitivity of the results to the gas price and do not believe that it is a significant factor.

- The expected growth scenarios from the 2010 Statement of Opportunities are used for estimating load growth.

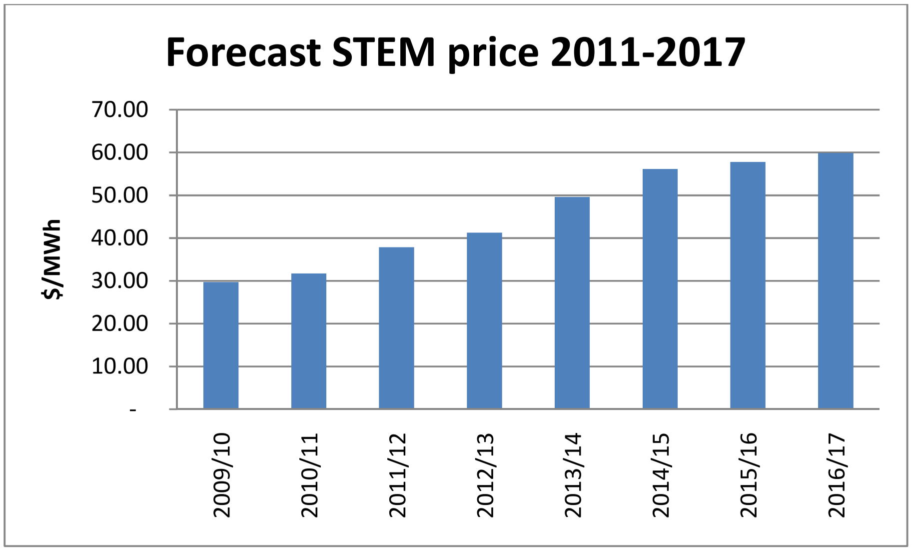
Figure 4 shows the estimated evolution of the weighted average STEM price. Between 2010/11 and 2014/15 there are price and volume increases, but after 2014/15 the increases are confined to volumes. This forecast has been derived by:

- Deriving a price curve for 2009/2010 by averaging the STEM price for a number of load forecast ranges at 100MW intervals (observed supply curve).
- Establishing a supply curve based on the SRMC of plant as tabled in the Verve margin review paper[10] (theoretical supply curve).
- Fitting the observed price curve to the theoretical supply curve by applying smoothed weightings at 100MW intervals.
- Calculating a future theoretical supply curve for 2014/15 by using the Verve margin calculation information and assuming a contract gas price of $6/GJ.
- Applying the weightings established in 3 to the supply curve to establish an estimated price curve for 2014/15.
- Establishing load forecasts for next five years by taking total load forecast and distributing it across 100MW bands consistent with load distribution for 2009/10
- Extrapolating increases between 2009/10 and 2014/15 by taking a straight line between estimated price/quantity points.

The results are demonstrated in Figure 4 below:

Figure 4 STEM price-path forecast

[10] 2010 Margin Peak and Margin Offpeak Review, Final report to IMO, SKM-MMA, 17 November 2010

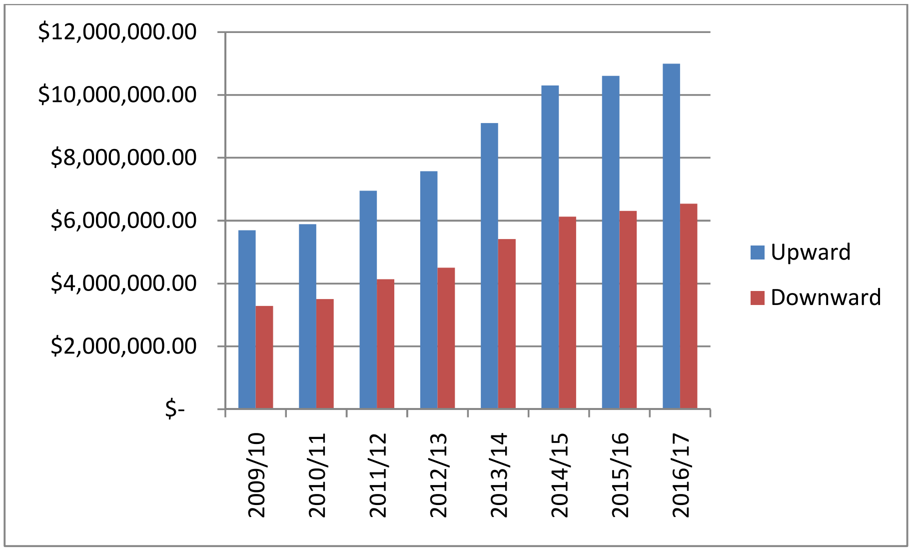


Given our assumptions, we are able to estimate the effect on balancing costs (see Figure 5).

We reiterate that we have not included the effect of UDAP or DDAP in these calculations. In addition, 2009/10 and 2010/11 have been included for illustration only.

These forecasts provide the basis for assessing what the impacts (both costs and benefits) of a balancing market might be. That is, they essentially provide the baseline counterfactual against which we look to measure the net effect of the balancing proposal in the next section.

Figure 5 Balancing costs forecast


$12,000,000.00
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2009/10
2010/11
2011/12
2012/13
2013/14
2014/15
2015/16
2016/17
Upward
Downward

5 Impacts of proposal

This section identifies and discusses the costs and benefits associated with the proposal, focussing on the direct and tangible impacts firstly, before commenting on impacts that are less quantifiable and not able to be captured with any precision in this study (e.g. longer-term and/or qualitative impacts).

With reference to Table 1, the cost categories are essentially the same as those in the table. On the benefits side there are essentially two categories where direct, quantifiable benefits can be obtained. The first category is so-called availability benefits, made up of the following:

- IPP STEM offers not currently dispatched.
- Changes to bidding behaviour from compressed timeframes.
- Increased availability of generation following outages.

The second category includes the costs avoided as a result of not having to curtail baseload generation.

5.1 Costs

As shown in Table 1 above, the main cost categories relate to personnel and systems changes. The costs included are those specifically attributable to the balancing proposal itself. In the case of common or shared costs, where the costs are highly aggregated, we have used a top-down allocation approach, where a percentage of the shared or common costs are attributed to the proposal. Where costs would have been incurred in the absence of the proposal (e.g. expenditure on systems upgrades that would have taken place regardless of the balancing market proposal) then these costs have been excluded.

Discussions with stakeholders were use to make appropriate judgements on the quantum of costs included in the analysis. Given the evolving nature of the proposal design, these costs are still largely indicative. For this reason, we present cost ranges, rather than point estimates.

General assumptions used to determine the costs of the proposal are as follows:[11]

[11] Additional, more specific assumptions relating to particular estimates are detailed in the subsequent sections concerning the particular cost estimates.

- Stakeholders will undertake the necessary investment to allow participation in the balancing market regardless of their (expected) actual degree of participation (i.e. cost estimates are not adjusted to assumed participation levels).
- The prices associated with key inputs (e.g. labour and capital) reflect the scarcity of such inputs (i.e. costs assume availability of inputs).
- The price of labour remains unchanged over the study period (i.e. we have not inflated the estimated salary costs over time).
- With the exception of System Management, no explicit labour productivity adjustment has been assumed.[12]
- There is some degree of uniformity in requirements between stakeholders (i.e. cost estimates for participants can be applied to others, in a broad sense).
- A seven-year project life.
- Full implementation and set-up for all participants will be completed within two (calendar) years of approval.
- A discount rate of 8% applies.

5.1.1 Total costs

Table 2 shows the total estimated costs associated with the balancing market proposal for "high" **($28.34million**) and 'low**" ($19.45 million**) cost scenarios respectively. The figures indicate the relatively intensive upfront commitment associated with the proposal - see the broad cost profile in Figure 6 below. The "high cost" scenario estimate of total costs is therefore around 45% higher than the "low cost" scenario.

Set-up and implementation costs represent around 45% of total (undiscounted) costs in the "high cost' scenario and around 47% of total (undiscounted) costs in the "low cost" scenario.

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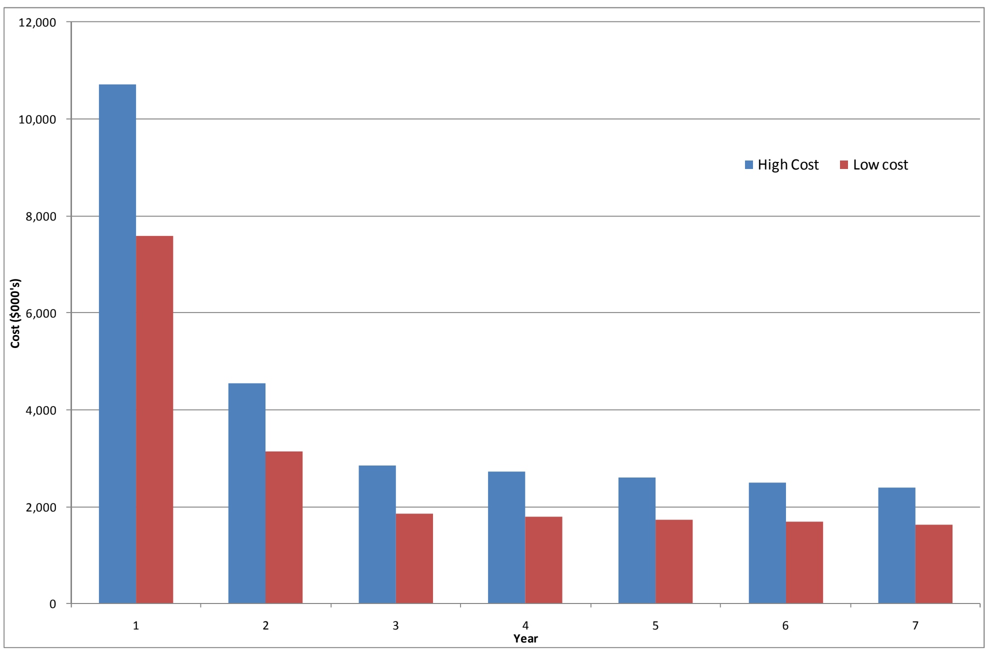
[12] This so-called productivity adjustment is predicated on assumed labour-saving and/or labour-enhancing properties from automation of processes. In the case of System Management we have applied a 10% per year cost reduction factor (to the ongoing personnel required) in order to account for this possibility. This is essentially arbitrary but not inconsistent with discussions around likely effects.

Table 2 Total cost (undiscounted)		
Description	**Costs -$ (High)**	**Costs -$ (Low)**
Set-up and implementation	$12.70 m (over two years)	$9.15 m (over two years)
Ongoing	$15.64 m (over five years)	$10.30 m (over five years)
TOTAL	**$28.34 m**	**$19.45 m**

Figure 6 Cost profile



The major difference between the two cost scenarios is that the "low cost" scenario assumes that costs for System Management are 50% below those associated with the "high cost" scenario.[13] In addition, costs for the remaining stakeholders are reduced (from "high cost" scenario levels) by the same proportion as indicated by

[13] The costings we received from System Management were expressed as "orders of magnitude" with an error bound of up to 50%.

IMO costs. That is, the IMO identified that their actual costs related to balancing ranged between 90% and 70% of MEP costs. The lower bound of this range is around 78% of the upper bound and thus, costs were scaled down by that percentage. For example, costs of $100 in the "high cost" scenario would be $77.78 in the "low cost" scenario. In effect, we assumed the interval identified by the IMO as appropriate for all other participants, in the absence of available evidence to the contrary.

For both scenarios we have assumed that only one third of ongoing labour costs are incurred in the first year and half in the second year. This assumption allows for the time required to set-up, test and then implement required systems changes. Thus, there is some degree of overlap in terms of the two-year and five-year separation between "one off" and ongoing costs highlighted in the table.

While not reported in detail here, we also derived a "medium" scenario. This scenario assumes the midpoint for IMO costs (80%) and a scaling factor for all other participants costs (excluding System Management) of around 89%. In relation to System Management we have assumed that costs are 25% below the "high" scenario. This scenario is used more extensively in subsequent sections.

5.1.2 Cost detail

Table 3 below presents the costs in more detail. It shows that, in relation to the "one-off" costs associated with set-up and implementation, system assets are the predominant cost category. As expected, the labour component of set-up and implementation costs is relatively minor, but total ongoing labour costs are significant (across a longer time period).[14]

[14] The key assumptions used for labour costs are that a trader/analyst is paid a salary of $100k and a system operator/engineer is paid a salary of $95k. Factoring in overheads of 50% results in cost figures of $150k and $142.5k respectively.

Table 3 Further cost details (undiscounted)		
Description	**High cost, $ (% of total)**	**Low cost, $ (% of total)**
Personnel- ongoing	$15.64 m (55%)	$10.30 m (53%)
Personnel- set-up and implementation	$1.43 m (5%)	$1.14 m (6%)
Systems- assets	$7.05 m (25%)	$5.26 m (27%)
Systems- processes	$4.22 m (15%)	$2.75 m (14%)
TOTAL	**$28.34 m**	**$19.45 m**

5.2 Direct benefits[15]

We have drawn on the paper on Balancing Support[16] presented to the RDIWG on 23 November 2010 in this section. We assess the overall economic benefits, not the effects on individual participants. While some of the extreme events that have taken place recently (such as on 10/11 January) may have had significant effects on individual participants, if these costs are offset by equal benefits to other parties then they have no relevance to an assessment of changes to resources available to the economy and therefore cannot be included in the analysis. We have not quantified the benefits to parties of reduced volatility; however, we have addressed this point in the qualitative benefits.

We discuss in turn the following direct benefits from the new balancing market:

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

(ii) A marginal increase in the bidding of capacity given that compressed time frames allow participants to recast their bids based on new information.

(iii) The return of capacity from outages.

[15] A description of the process of estimating benefits relating to all relevant categories in included as an appendix.

[16] Balancing Support, IMO paper, 23 November 2010

(iv) Fewer curtailments of base load generation.

5.2.1 IPP offers to STEM available for balancing

The benefits estimated in this section result from improved scheduling of generation. Currently, because IPPs are excluded from balancing except for system security or to ensure dispatch in the merit order before distillates, there are occasions where inefficient costs are incurred. For instance, Verve generation is dispatched when cheaper IPP generation was available on the STEM curve. Similarly, Verve generation was curtailed when it would have been cheaper to curtail a more expensive IPP generator.

This possible benefit is contingent on the assumption that IPPs are willing to generate or be curtailed as signalled in their STEM offers.

From our discussions with IPPs we have established that there is interest in taking part in balancing were the opportunity to become available.

The difficulty lies in assessing how much IPP generation becomes available for balancing and whether it will displace Verve generation appropriately in the merit order. With such uncertainty in mind, we have taken a conservative approach to estimating the benefits.

The Balancing Support paper captures a number of the benefits that are available. That paper looked at what current STEM offers by IPPs would have been accepted had system management been able to dispatch them. It estimated for the year 2009/10 that there were potentially $2.7m of savings to be made. We estimate that with the advent of the Collgar wind farm that the total savings/benefits are **$3.08m in 2011/12**. We believe that $3.08m is a reasonable estimate of the economic advantages related solely to IPPs that were available to the STEM and are now available for balancing.

We consider this estimate is likely to increase over the next few years given that:

(i) There is greater availability of fast start plant than during the period analysed.

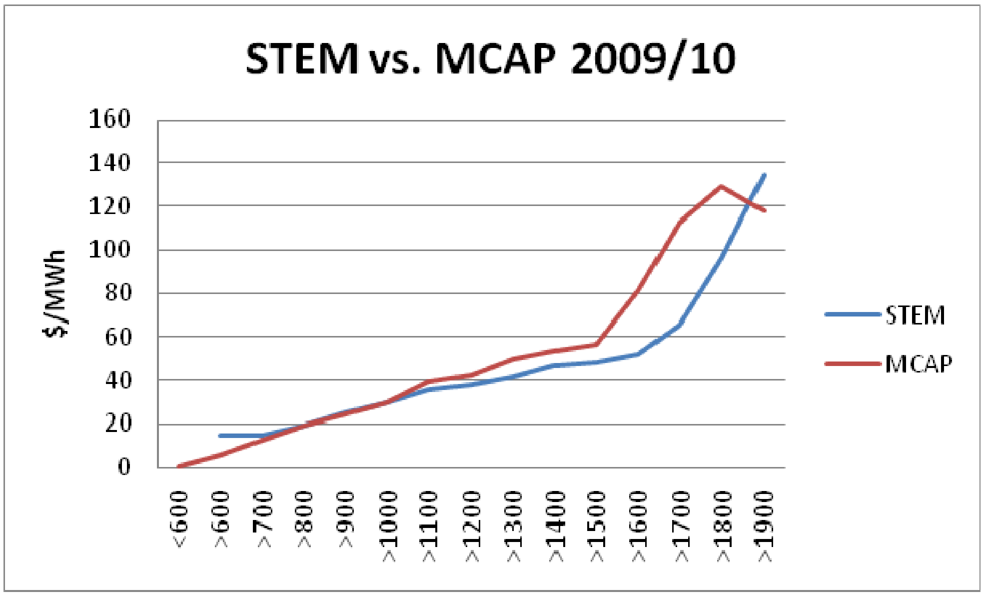
(ii) As the supply curve increases with gas price rises, the benefit in absolute terms will also rise.

There are other benefits that are not captured in this analysis of IPP offers, which we now discuss.

5.2.2 Reactions to more recent information

Most bidders, because of the type of plant they have, take into consideration inter-temporal factors when formulating bids. Baseload generation with slow start-up times will often be bid in to the market at prices significantly less than SRMC to ensure that it is not curtailed during low demand periods. Likewise, there are many occasions where schedulers prefer not to have plant that is only part-dispatched and will price it high to ensure that it is not dispatched at all. The effect of this is that the STEM offer curve can only be considered an accurate signal of intentions to generate or to be curtailed at the margins of the load forecast. This can perhaps best be illustrated by comparing the MCAP and STEM curves for 2009/10 at different load intervals (see Figure 7).

Figure 7 STEM and MCAP comparison 2009/10



As the figure illustrates, even though MCAP is calculated using the same offer information as the STEM, there is a significant difference between the two price curves[17]. The reason for this is that participants form expectations as to the load forecast and bid accordingly. If load is high then more generation is made available. The reverse is also true.

[17] Readers will note that there is an anomaly at the upper end of the load range. There are fewer observations at this load range so it is more vulnerable to distortions.

Dispatchers have to take into account minimum operating ranges for plant. Traders will know based on their observations of historic load levels and of other plant outages whether their plant is likely to be dispatched. This has an effect on how generation is bid into the market. It can have the effect of both under and over-bidding (in price terms) to ensure that the outcome that the trader wants is achieved. Once plant reaches its minimum operating range there is more of an expectation that bids will lie close to the SRMC, however, there is a certain degree of distortion once balancing exceeds relatively small bounds.

Figure 8 illustrates the nature of IPP bidding as it stands. This chart is for 2009/10 and shows how, on average, the majority of IPP generation is offered in at price caps. If even a fraction of this generation can be made available to be cleared at dispatchable prices then the benefits are potentially significant.

Figure 8 – IPP STEM submissions 2009/10

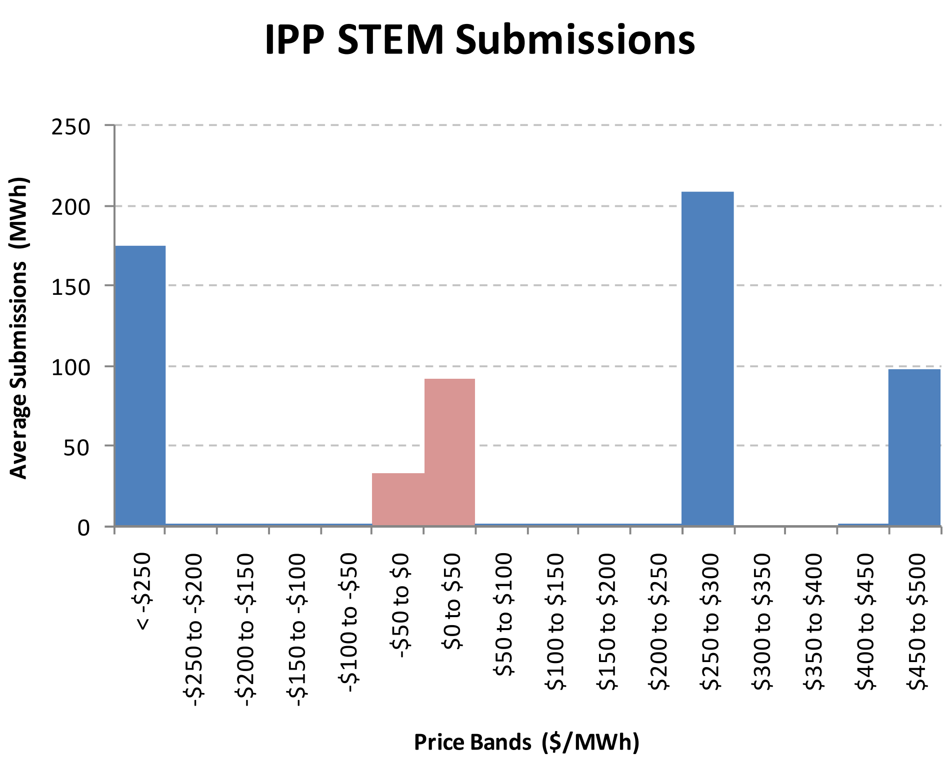
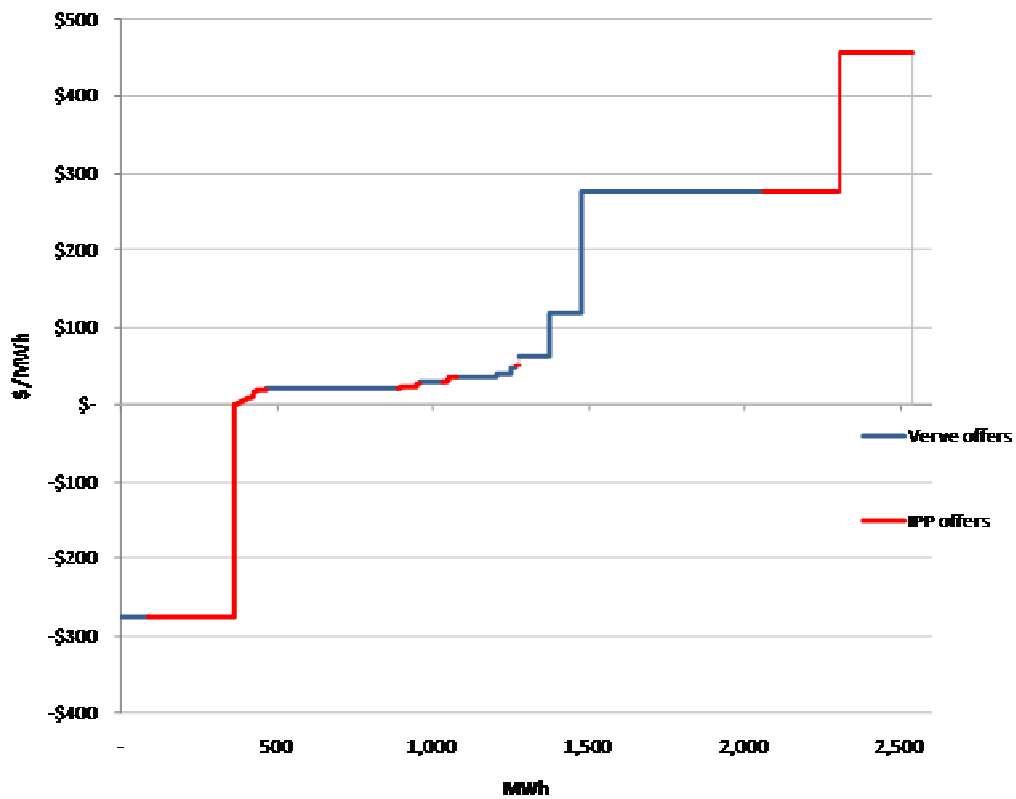


Figure 9 shows for a single trading period what the STEM price curve looks like. As can be seen there is some IPP generation that is priced closed to the clearing price ($26/MWh) but the bulk of generation has been priced at the extremes. This high/low priced generation might be rebid in a balancing market to be brought into the merit order, which could result in fewer extreme deviations.

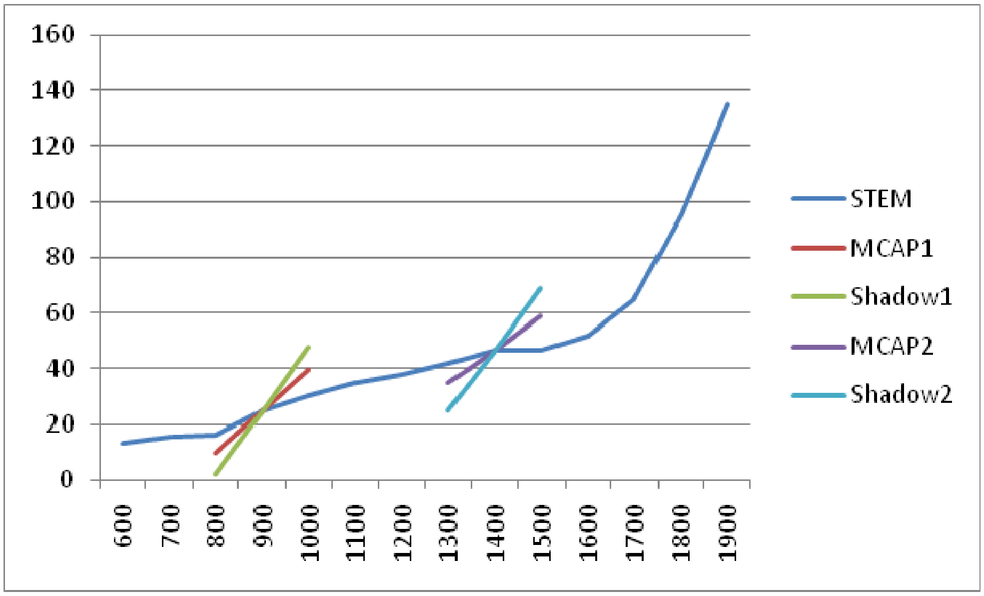
Figure 9 – Offers for 7 February 2010 at 5pm



Another factor which causes offers to chase load is that participants with a limited stock of fuel will look to maximise revenue throughout the whole day rather than treat each trading period equally. Generation that is available for one trading period might not be available for another if fuel is limited. The obvious consequence of this is that plant is bid in for the higher price periods at dispatchable prices and during lower price periods is bid in at higher cost. This factor also contributes to distortions in the balancing outcomes that are observed presently.

Conceptually, what is happening is shown in Figure 8. For each load forecast there is an MCAP deviation curve that represents the willingness of participants to move from their current levels of production based on their previous day submissions. However, there is also a shadow MCAP deviation curve that represents the reality that only Verve resources are used for balancing, leaving out other, possibly in-merit, production. The Balancing Support paper itemises the advantages that accrue when moving from the shadow deviation curve to the MCAP curve. We have captured the benefits that are potentially available when the MCAP curve approaches the STEM curve.

Figure 8 Conceptualisation of MCAP-STEM divergence



It is important not to overstate these benefits as there will always be a degree of uncertainty even with a two-hour window before dispatch. Furthermore, in cases where balancing is driven by a plant outage then it is possible to overstate the benefits considerably if we assume that plant is still available for balancing.

We have used three techniques to estimate the range of value associated with this benefit, and combined this with information from market participants to derive “high”, “medium” and “low” scenarios.

The first approach involved modelling the availability of conceptual generation. A number of combinations of price and quantity were tested on 2009/10 data, both for upwards and downwards balancing. Consider the following example. Generator X has 100MW capacity and a SRMC of $80. If the STEM price is less than $80/MWh then we assume that generator X can deliver 50MWh for the next trading period when MCAP exceeds $80/MWh. If the STEM price was already greater than $80/MWh we assume that generator X is fully dispatched and there is no residual for balancing. Generator X’s contribution is capped at the maximum of 50MWh or the actual balancing requirement. The benefit we calculate is as follows:

*Benefit = [Total generation at X (MWh) * (MCAP-80)] / 2*[18]

From Table 4 below, we estimate the total advantage of this particular combination at $0.33m. Note that some of these benefits might be added together if there were two types of available stations. However, our modelling approach does not make it possible to separate the results and as there would be a risk of double counting if we added the benefits, we have excluded this source of benefit from our estimates. Our "low" scenario (below) involves taking 50MWh of generation at $60 for up balancing and $20 for down balancing. This results in **$0.59m** in estimated benefits if a balancing market had been in place in 2009/10.

Table 4 shows the benefits that would be available with different load amounts and with different sized facilities. Note that the benefits are potentially cumulative across different generation size scenarios; however, there is a risk of double counting. More analysis would be needed to try to add up these benefits. However, we believe that this analysis does establish that the benefit exists if the right plant is available.

Based on our exchanges with participants regarding some specific events and by observing available generation in some extreme balancing situations we believe this to result in a figure that is too low.

A second method involves estimating the surplus that is available if the MCAP curve graphed above were to tend towards the STEM price curve. Such an approach yields a theoretical **$2.12m** of benefits; $0.38m of balancing down benefits and the balance of $1.74m of balancing up benefits. Because of the distortions involved in the current calculation of MCAP and because the STEM is formed on uncertain information it is important to show care in calculating the possible benefits[19]. This forms our "high" benefit scenario.

We have also been able to test these numbers against some information provided to us by market participants. We believe from this information that it is safe to assume

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[18] The result is divided by two as we do not know at what demand level the MCAP offer was accepted. While essentially arbitrary this adjustment was undertaken in order to avoid overstating the possible benefits.

[19] These distortions were detailed in the paper on Balancing price formation (IMO paper, 2 November 2010) which showed the impact on MCAP of relevant quantity inconsistencies. By adjusting MCAP to remove resource plan shortfalls with no corresponding STEM submission, which reduces MCAP by an average of $2.80 (see figure 11 in that paper), we found that the potential benefits rose to $3.1m. Because of a number of other uncertainties in MCAP and the STEM, however, we have preferred to take a lower number.

around **$1.5m** in benefits from greater availability of plant. This is our “medium” scenario.

Table 4 Benefits from behavioural responses to more timely load information ($m)[20]

$/MWh	**10 MWh**		**25MWh**		**50MWh**		**100 MWh**		**150 MWh**		**200 MWh**	
MCAP strike price	Up	Down	Up	Down	Up	Down	Up	Down	Up	Down	Up	Down
$100 up; $60 down	.05	.01	.12	.03	.24	.05	.43	.07	.58	.07	.63	.07
$90 up; $50 down	.06	.02	.14	.04	.27	.07	.49	.10	.65	.10	.71	.11
$80 up; $40 down	.07	.01	.17	.03	.33	.06	.59	.08	.78	.09	.85	.09
$70 up; $30 down;	.09	.02	.21	.05	.41	.08	.71	.12	.93	.13	1.01	.13
$60 up; $20 down	.11	.05	.26	.05	.50	.09	.86	.13	1.11	.14	1.21	.15
$50 up; $10 down	.10	.05	.23	.11	.44	.19	.75	.24	.97	.25	1.07	.25

[20] To understand this table, consider for example the top left box, which shows a benefit of 0.05 (or $50,000). This is the effect of 10MWh of generation being available constantly if the balancing price rises above $100/MWh. If the STEM price is already above $100/MWh then it is assumed that this generation would already have been dispatched. Conversely, the box to its immediate right, which shows .01 (or $10,000) is the estimated advantage if there is a facility that is able to curtail production by 10MWh if the price falls below $60/MWh.

5.2.3 Early plant return following outages

Another quantifiable benefit of availability is from early return to production following outages. At present because of the early gate closure for trading, there is less generation made available for dispatch than there might otherwise be. There are two reasons for this. One is that a cautious participant may not want to schedule plant that is due to come back to service but with some uncertainty. This is because that participant can incur DDAP penalties if that plant is not ready to generate. The second concerns situations where plant does become available earlier than expected for dispatch. This generation would be available for balancing, even if not available for dispatch. We estimate that around 108GWh of cheaper generation might be dispatched, which would displace more expensive generation. We estimate that the saving would amount to $13.33/MWh (at 2009/10 prices) and that the total savings for 2011/12 would be around **$1.55m** when scaled up.

This estimate is based on 1500MW of IPP generation available for three extra days in the year. The $13.33/MWh is an estimate of the displacement of more expensive generation. It is accepted that these numbers are averaged at quite a high level, however discussions with participants regarding some specific events give us comfort as to the magnitudes.

5.2.4 Reduction in cycling costs

The final quantifiable benefit is that it is less likely that baseload generation will have to be curtailed. We understand that the costs of having to cycle a thermal generator are around $40k per event.[21] We have estimated that with a more efficient balancing system there will be five fewer curtailment events compared with the alternative, or a saving of **$0.2m** per annum.

5.2.5 Summary of direct benefits

Table 5 contains benefits estimates across categories and years. These benefits range from **$35.10 million** in the low scenario to **$45.74 million** in the high scenario. It is important to note that, in order to account for set-up and implementation requirements this stream of benefits is for the years 2011/12- 2016/17 only.

[21] See The Cost of Cycling Coal Fired Power Plants, Steven A. Lefton, Power Plant O&M and Asset Optimisation, 2006.

Table 5 Benefit summary (undiscounted)

	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Availability benefits ($m)							
Use of current IPP offers in STEM	2.89	3.08	3.19	3.31	3.42	3.42	3.42
Further IPP generation available from more timely information	0.61	.064	0.66	0.68	0.70	0.70	0.70
Further IPP generation available from early outage return	1.50	1.55	1.61	1.66	1.72	1.72	1.72
Sub-total availability benefits	**5.00**	**5.27**	**5.46**	**5.65**	**5.84**	**5.84**	**5.84**
Cost saving from avoiding cycling plant	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Total quantifiable benefits- low scenario	**5.20**	**5.47**	**5.66**	**5.85**	**6.04**	**6.04**	**6.04**
Total quantifiable benefits- medium scenario	**5.83**	**6.13**	**6.34**	**6.55**	**6.77**	**6.77**	**6.77**
Total quantifiable benefits- high scenario	**6.79**	**7.13**	**7.37**	**7.62**	**7.87**	**7.87**	**7.87**

Note: The benefit figures for 2010/11 are illustrative only. No benefits actually accrue while set-up takes place (so the 2010/11 numbers are not used further in the analysis).

6 Net effects

Having separately considered the costs and benefits in the section above, we now turn to the integration of such impacts. Reiterating, the period for the analysis is seven years. However, to allow for the set-up, implementation and testing requirements discussed previously, the comparison is essentially between seven years of cost and six years of benefit; i.e. we have assumed no benefits accrue at all in the first year while set up is taking place.

6.1 Summary results

Table 6 presents summary results comparing the discounted costs and benefits for those categories of benefit where quantification is possible. The scenarios presented are as follows:

- *High*: low cost and high benefit
- *Medium*: medium cost and medium benefit
- *Low*: high cost and low benefit

All of the scenarios result in a positive benefit-cost ratio (BCR). That is, there is a net benefit to society from the proposal. Even the most pessimistic scenario results in benefits that outweigh costs. Conversely the most optimistic scenario results in benefits that are around twice the costs of the proposal. While there is some risk comparing proposals in terms of subject matter, the calculation of (monetised) benefit-cost ratios does allow these estimates to be compared with alternative investments including "doing nothing".

It is important to keep in mind that these results do not include indirect or qualitative benefits.

Table 6 Summary results for quantifiable categories

	High	Medium	Low
Total benefits	$32.48 m	$27.92 m	$24.92 m
Total costs	$15.72 m	$19.27 m	$22.83 m
Net benefits	$16.76 m	$8.65 m	$2.09 m
Benefit-cost ratio	**2.07**	**1.45**	**1.09**

6.2 Sensitivity analysis

In addition to the summary results shown above, this section considers the impacts of adjusting key assumptions and testing alternative scenarios. While there are myriad factors that can potentially be altered, we focus our attention on the following:

- Combinations of (already modelled) cost and benefit scenarios
- Alternative parameters (e.g. study period, discount rate)
- Alternative cost and benefit intervals

6.2.1 Different scenarios

In addition to the three scenarios presented in Table 6, there are six further permutations (using the existing modelled parameters):

1. High cost, high benefit
2. High cost, medium benefit
3. Medium cost, low benefit
4. Medium cost, high benefit
5. Low cost, low benefit
6. Low cost, medium benefit

As might be expected, altering the relative scenarios does not materially affect the BCR (i.e. by definition, they are bounded by 2.07 and 1.09), but does give a clearer sense for possible values for both costs and benefits.

Table 7 Alternative cost and benefit scenarios

	1	2	3	4	5	6
Total benefits	$32.48 m	$27.92 m	$24.92 m	$32.48 m	$24.92 m	$27.92 m
Total costs	$22.83 m	$22.83 m	$19.27 m	$19.27 m	$15.72 m	$15.72 m
Net benefits	$9.65 m	$5.09 m	$5.65 m	$13.21 m	$9.21 m	$12.21 m
Benefit-cost ratio	**1.42**	**1.22**	**1.29**	**1.69**	**1.59**	**1.78**

6.2.2 Alternative parameter values

We now consider the effect of alterations to the time period under study, the discount rate applied and cost/availability of labour.[22] We examine the effects of such changes with reference to the "medium" scenario above.

Table 8 shows the effect on net benefits and the BCR from different discount rates, relative to the "medium" scenario. A higher discount rate means we place less value on benefits (and costs) incurred in the future than we do at present, while the opposite is also true.

Given the benefits increase over time while the costs decrease, we would expect some asymmetry in the BCR as the discount rate gets higher. While this is true, the figures show that, in general the BCR is relatively insensitive to changes in the discount rate. Only at a discount rate greater than around 33.5% would the BCR reduce to below "break even" (i.e. costs exceed benefits).[23]

Table 8 Alternative discount rates

	Original scenario	Very low disc. rate	Moderately low disc.rate	Moderately high disc. rate	Very high disc. rate
Discount rate	8%	2%	5%	11%	20%
Net benefits	$8.65m	$13.40m	$10.80m	$6.87m	$3.07m
Benefit-cost ratio	**1.45**	**1.59**	**1.52**	**1.38**	**1.21**

Table 9 shows the effect of altering the time period for the analysis (again relative to the original "medium" scenario). With a severely truncated study period of three years the costs significantly outweigh the benefits (a BCR of 0.75, and net disbenefits of 3.36m). A moderately truncated study period of five years

[22] While the scenario analysis implicitly includes changes to labour cost, it does so in a general sense (i.e. all other input costs changes as well). Here we are focussing specifically on labour cost changes, holding all other costs constant. By changing cost, we are indirectly accounting for scarcity.

[23] A discount rate of 33.5% would indicate that the value of a dollar in one year is around one third less than the value of receiving that dollar today. Such a discount rate is outside reasonable bounds for this type of analysis.

substantially reduces the net benefit from almost $9m to almost $3m, but still has a positive BCR of 1.17. In terms of interactive effects, with the truncated study period of five years and a discount rate of 20%, the proposal is just above "break even", with a BCR of 1.01 and net benefits of just $183,000.

Table 9 Alternative study periods

	Original scenario	Heavily truncated time period	Moderately truncated time period
Study period	7 years	3 years	5 years
Total benefits	$27.92m	$10.29m	$19.71m
Total costs	$19.27m	$13.65m	$16.78m
Net benefits	$8.65m	-$3.36m	$2.93m
Benefit-cost ratio	**1.45**	**0.75**	**1.17**

Table 10 indicates that if labour costs were to increase by a quarter (and all other costs were to remain the same) then the net benefit of the proposal reduces from $8.65m to $7.30m and the BCR from 1.45 to 1.35. Combining the effect of a shorter time period of five years and an increase in labour costs of 25%, results in the net benefit dropping to just $2m and the BCR to 1.11. With a truncated study period of five years, a labour cost premium of 25% (to reflect scarcity) and a discount rate of 17%, the proposal "breaks even" with a BCR of 1 and net benefits of $19,000.

Table 10 Increased labour costs and a truncated study period

	Original scenario	Labour costs increase by 25%	Moderately truncated time period
Study period	7 years	7 years	5 years
Total benefits	$27.92m	$27.92m	$19.71m
Total costs	$19.27m	$20.63m	$17.71m
Net benefits	$8.65m	$7.30m	$2.00m
Benefit-cost ratio	**1.45**	**1.35**	**1.11**

6.2.3 Alternative cost intervals

We have not specifically modelled changes to the intervals of costs and benefits. The reason for this is that the ratio of benefits to costs is unlikely to be affected in any material sense by altering the intervals in a symmetric manner (i.e. increasing both the interval of costs and benefits by the same percentage amount) and the impacts of asymmetric changes were discussed in the broad scenario analysis above. We are happy to include such analysis if this is seen as worthwhile.

6.2.4 Summary

Overall, the results are relatively robust to changes in key assumptions and parameters, both individually and in combinations. The vast majority of changes still result in net benefit to society. Time period is the factor where there is most sensitivity. Truncating the time period to five years results in a BCR that is similar in magnitude to the "low" scenario contained in Table 6.

6.3 Other effects

As mentioned in section 3 above, the impacts of the balancing proposal are not restricted solely to the quantifiable impacts we have summarised. There are additional benefits that are either not amenable to quantification (e.g. effects on confidence) or that occur outside the relevant study period (e.g. longer-term effects on investment incentives). In addition, there are other effects that have been raised by participants- the most obvious being so-called "clean price" impacts.

We have not modelled the potential benefits in terms of investment incentives, confidence and "clean price" impacts, but discuss each of these possible effects below. While our discussion considers the effects individually, we wish to note that there are likely to be strong interactive effects. That is, the effects mentioned are best thought of as complements rather than substitutes.

Overall, our assessment is that these other effects are likely to be positive for the basic results derived above. While there may be some unquantifiable costs associated with transitioning to the new balancing market, we assess these to be relatively minor, and outweighed by the potential addition to the benefits associated with the proposal, even if these cannot be enumerated with any precision in this study.

6.3.1 Investment incentives

Creating appropriate investment incentives for new generating capacity has been a key motivating factor in electricity market liberalisation initiatives the world over. Experience with reforms in the 1990's suggested that competitive wholesale markets could and would mobilise adequate (or more than adequate) investment in new generating capacity.[24] On its own, a proposal to introduce competition to balancing would not be likely to significantly influence investment decisions. Stakeholder discussions confirmed this view, with other factors such as reserve capacity mechanisms having greater influence.

Nevertheless, the proposal is unlikely to have no effect at all on investment incentives. As part of a wider package involving privatisation of state-owned enterprises, vertical and horizontal restructuring to facilitate competition and mitigate self-dealing and cross-subsidisation problems, good wholesale market designs that facilitate efficient competition among existing generators, competitive entry of new generators, and retail competition (at least for industrial customers), the balancing proposal is likely to support the investment incentives that accompany successful reform programmes (Joskow, 2008).

Using values for the capital cost from a recent AEMO report, multiplied by the installed capacity in the SWIS, we derive a crude estimate of the replacement value of current installed capacity of around $13.5 billion.[25] For illustrative purposes only, a small change in this large number would result in estimated effects that are considerably greater than the quantified effects summarised above. A 0.5% increase in the overall value of investment totals some $67.5m. We cannot claim these as benefits attributable directly to the balancing proposal, but do make the point that potential (positive) impacts on investment incentives do have the potential to add significantly to the net benefit estimates we have derived.

The scale of investment is not the only relevant dimension in this discussion. The composition of investment is likely to matter as well. All else equal, a balancing market is likely to influence the type of plant that generators will look to invest in, going forward. We would expect that generators would face stronger incentives to invest in "balancing-capable" plant than if there was no opportunity to participate in balancing provision. To the extent that such plant is more suitable to overall market operation (e.g. flexibility, better ramp rates and minimum loads), there are likely to

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[24] Joskow P (2008) "Lessons Learned from Electricity Market Liberalization." The Energy Journal, v29, special issue #2, pp.9-42.

[25] ACIL Tasman Pty Ltd (2010) "Preparation of Energy Market Modelling Data for the Energy White Paper- Supply Assumptions Report."Report for AEMO/DRET. Available at: www.aemo.com.au/planning/0400-0019.pdf

be efficiency impacts.[26] We are not able to capture these to any extent in this analysis, but again it is important to observe the possibility of their existence.

6.3.2 "Clean price" impacts and confidence

RDIWG participants have previously considered work examining the inherent distortions to the price relating to balancing. That work estimated that the "cost" of such distortions amounted to approximately $8m per annum.[27] These price effects characterise wealth transfers (as opposed to changes in real resources available to the economy) and their removal cannot be counted as economic benefits as such, they may have important behavioural impacts that are relevant.

In the case of "extreme" events such as plant tripping, the presence of the distortions exacerbates the resulting balancing impacts. In effect, the MCAP adjustment is artificially more significant than might otherwise be the case. Again, these effects are essentially transfers between parties with a net economic effect of zero, but the party on the "wrong" side of the transfer may be left questioning the stability of the operation of balancing. This uncertainty may apply more generally to participation in the WEM and ultimately have economic impacts in the form of reduced confidence and concomitantly lower levels of commitment to investment as a result.

We stress that no allowance has been made in our benefit estimates for such an occurrence being avoided as a result of the balancing proposal. The possible impacts on confidence, which were referred to indirectly by some market participants, of the balancing proposal might also increase the quantified benefits over time. We caution that the impacts are likely to manifest in the form of increased investment so should not be counted twice.

Finally, we wish to mention the role that consistency with the WEM objectives might play. As mentioned previously, the success of reform processes relies on a package of (interdependent) measures, rather than a single initiative. The WEM objectives provide a quasi measure of success in that they set out what is looking to be achieved. The balancing proposal supports the competition-driven aspects of the WEM objectives, as well as the efficiency aspects of the objectives. Joskow (2008)

[26] Joskow (2008) refers to the application of high-powered incentives created by competitive wholesale electricity networks leading to lower generator operating costs and improved availability. We have captured only the latter in our quantified benefit estimates.

[27] See "Balancing price Formation" paper at http://www.imowa.com.au/f139,963182/Combined_RDIWG_Mtg_5_Papers.pdf

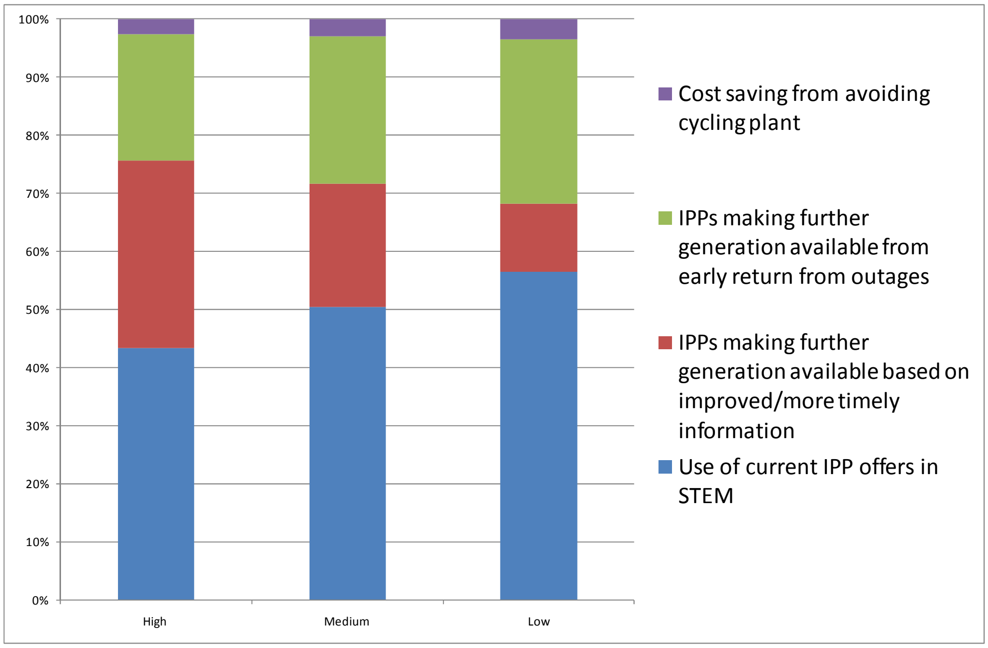
considers that voluntary transparent organised spot markets for energy and ancillary services (day-ahead and real-time balancing) that accommodate bilateral contracts and self-scheduling of generation if suppliers choose are basic design features that contribute (along with allocation of scarce transmission capacity) to success. This is consistent with the high-level market objectives and thus should be mutually reinforcing in terms of confidence levels.

There are likely to be transitional benefits from the balancing proposal (e.g. by adapting systems, processes and people now, it becomes easier and less costly to do so in future) but there may also be transitional costs (e.g. getting "up to speed" may take longer than anticipated). Neither of these effects can be enumerated with any degree of precision.

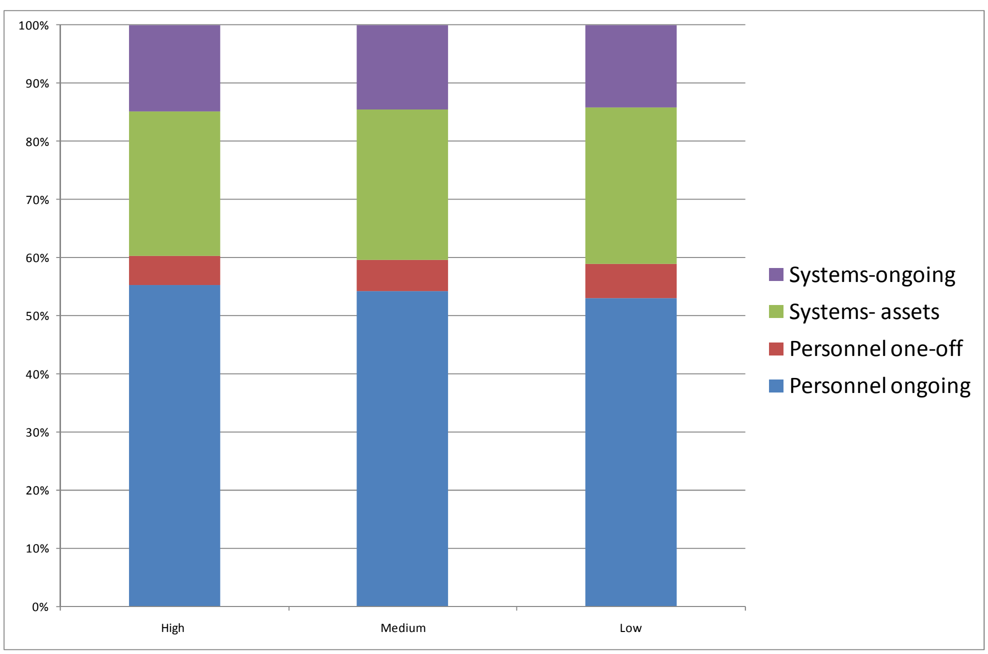
7 Conclusions

We draw the following conclusions from this work:

- Conducting a CBA specifically for competition in balancing is not a straightforward or trivial exercise, but important guidelines do exist in respect of competitive impacts in electricity markets more generally.
- CBA is the "right" method of assessment given the well-established principles and techniques embodied in the economic cost-benefit approach. That is, considering impacts economic welfare overall provides more useful information than individual party impacts, which may involve wealth transfers (as opposed changes to real resources available in the economy).
- Under reasonable assumptions, the introduction of competition/creating a balancing market will result in net benefits to society, i.e. an increase in economic welfare.
- The net benefits are estimated to range from $16.8m (at the upper end) to $2.1m (at the lower end). These figures translate into benefit-cost ratios of 2.07 (the benefits are around 107% greater than the costs) and 1.09 (the benefits are around 9% greater than the costs) respectively.
- The positive benefit-cost result is robust to alternative scenarios and a wide variety of changes to key parameters. Only more "extreme" changes such as reducing the study timeframe to three years, or increasing the discount rate to around 34% would result in a benefit-cost ratio below the break even value of one.
- The biggest contribution to benefits across all scenarios, comes from IPP offers in STEM that are currently not able to be routinely dispatched but would be dispatched under the proposal:



- The majority of costs, across the study timeframe of seven years, is explained by ongoing personnel across all scenarios, with one-off systems changes the second biggest contributor to costs:

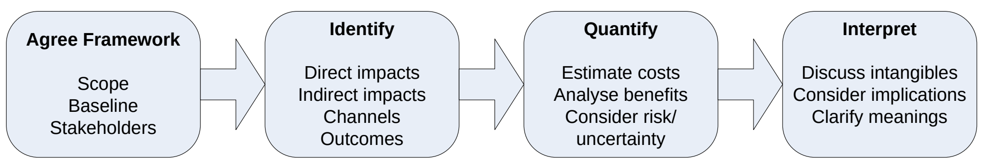


- This assessment is not just about the quantifiable impacts. Other non-quantifiable effects accrue to the proposal:
    - increased levels of confidence in the wider market (through reductions in distortions as well as proposals that are consistent with the WEM objectives);
    - improved incentives to invest (altering the level and type of investment undertaken); and
    - benefits in the form of lowered (or avoided) costs through easing the wider transitional burden towards a well-functioning market.
- These other effects cannot be included in the quantified analysis, but we assess their impact as being supportive of the positive overall contribution of the proposal.
- In sum, we estimate that there are clear efficiency-enhancing effects associated with the proposal in terms of:
    - productive efficiency- least-cost production of electricity;
    - allocative efficiency- resources devoted to generation most suitable for balancing; and
    - dynamic efficiency-producing appropriate signals around investment and encouraging innovation.

Appendix A- CBA methodology

Anatomy of a CBA

The basic analytical framework for a CBA is shown below. The aim should be to work systematically through the various steps sequentially to better highlight the basis, linkages and scale of impacts being measured. Often CBAs conflate steps two and three. We recommend these steps be separated to aid understanding, remove ambiguity and highlight the thinking that underpins the various analytical steps. In other words, we see merit in avoiding "black-box" types of analysis where the derivation of the estimated effects is difficult to understand and subsequently reproduce, replicate elsewhere, question or modify.



The framework is amenable (but not limited) to a quantitative analysis, that allows for alternative options to be compared in a consistent way. It consists of the following:

- A baseline scenario — the baseline case would represent a scenario in which no intervention would be pursued.
- Problem definition — what is the nature of the problem (including consideration of where and upon whom the effects of the problem fall)? This involves clear identification of linkages, channels through which impacts are felt, and the specific outcomes being sought.
- Option identification — a set of alternative options should be considered and developed alongside a well articulated rationale for intervention.
- Impact assessment — the benefits and costs of each option should be assessed relative to the baseline scenario (that is, it should show the net change of the option), including distributional and equity considerations.
- Interpretation — explanations of what the numbers , concepts and estimation procedures mean are crucial in terms of understanding what conclusions can (and importantly cannot) be drawn from the analysis.

Each of these points is considered in greater detail below.

Baseline scenario

The baseline, or 'business-as-usual' (BAU), case establishes the scenario in which no intervention is pursued. It provides the benchmark to assess the efficiency and effectiveness of different options.

Notably, the BAU should not depict a stagnant market. Rather, the BAU should reflect the dynamics of the WEM generally, as well as the impacts of major initiatives around the volume and composition of known investments.

Ideally, the baseline would reflect on the variables listed in the table below. However in the interests of tractability, a much smaller list of variables will be utilised.

Table 2.1: Variables considered in the BAU

Category	Variable
Economic	Household construction
	Age of household stock
Demographic	Population
	Number (and composition) of households
Energy	Energy consumption
	Electricity prices
	Investment in generation (and transmission)
Other	Weather patterns

Appropriate lifespan

'Time' is likely to be a key factor in determining the success of any change proposal. Furthermore, it is the nature of many investments that:

- most costs are borne up front; and
- benefits are accrued for a (potentially significant) period of time thereafter.

(Additionally, some maintenance and operating costs may be incurred over the life of the investment, however these are likely to be minor.)

Consequently, it is important that the analysis defines both how long a policy will induce new investment, and for how long those benefits will accrue.

In making this determination, the assessment should be realistic about the lifetime of the policy. For instance — when is it likely that a policy would be replaced? Is there a natural limit on the policy life? It is not unreasonable to limit the life of a policy of this nature to a period of 5-10 years.

Noticeably, benefits are likely to continue for a period that extends substantially beyond this. It would be appropriate to assume a benefits stream that lasts as long as any asset. This could be as long as 25 years.

Once the asset has expired, no further benefits or costs will be accrued. Although it is likely to be replaced by a like asset, the decision to reinvest is outside that of the policy.

Discount rate

Related to the above discussion is the choice of a relevant discount factor.

A discount factor allows for the comparison between streams of costs and benefits that occur at different points in time. The choice of the discount factor is especially important for the issues at hand here, because of the disjointed nature of costs and benefits. A discount factor too low is likely to over state the benefits of the proposal, while a discount factor too high, will do the reverse.

Standard public policy analysis suggests a discount rate of 10 per cent for investments of this nature. This is a default rate, meaning that alternative rates might be used if arguments can be mounted to that effect. Because of the sensitivity of the results to this factor however, it may be informative to present a range of results using a different rates (such as 5, 7 and 12 per cent).

Problem definition

Before any options (or action) are considered, it is important to crystallise precisely the problem at hand. The rationale for intervention should be grounded in overcoming a market failure, and this rationale should be clearly articulated. Moreover, appropriately identifying and defining the problem will help to guard against proposals that only act to treat symptoms, and should minimise any unintentional outcomes.

Option identification

In light of the problem definition above, the next step of the analysis is to define a set of options that may address the defined problem. It is often useful to identify a range of potential solutions. Given the work done previously by the RDIWG to determine the most viable alternative approach, we have restricted our focus to a single option.

Impact assessment

At the heart of the analysis is the impact assessment. The impact assessment considers all of the benefits and costs that are incurred as a result of the proposal/s being pursued. Note that the exercise being conducted here is different to making a business case, which considers the investment proposition from a financial (accounting) perspective. What is required is an economic perspective — it is important that the assessment be holistic in its approach and assesses the impact economy-wide. That is, an economic lens requires the CBA to be resource-based (focus on the effects (costs and benefits) on resources available to society) rather than merely financially-based.

The 'impact' should be assessed relative to the baseline scenario — that is, it should show the **net** change of the option.

Identification of costs and benefits

The analysis should attempt to identify costs and benefits incurred to the fullest extent possible. Where practical, benefits and costs should be quantified to allow for a more malleable comparison.

Non-quantifiable impacts

It will not be possible to quantify all benefits and costs. This may, for example, be due to data limitations.

Non-quantifiable impacts are still important, and are noted in the analysis along with an indication of the magnitude of those impacts and how they might impact on the assessment.

Avoid double counting

The analysis should be cautious of, and avoid, double counting of benefits and costs.

Unintended consequences

While the analysis may attempt to be holistic and identify all costs and benefits, there may be some unintended consequences that arise from the proposal.

Some unintended consequences may be identifiable as risks. There may be, for instance, uncertainty about the behaviour of market participants (i.e. will they participate fully and is the way they participate likely to be subject to strategic/gaming behaviour?). To a degree, these risks can be accounted for through a sensitivity analysis and highlighted as key assumptions to the assessment. However, others may simply not be included in the analysis.

Describe option features

Finally, having identified the net impact of the proposed option, the options need to be compared in a useful and meaningful way. This comparison can be conducted with the use of two key metrics:

- Benefit-cost ratio (BCR) — the BCR reports the ratio of benefits to costs. A BCR greater than unity implies that benefits exceed costs; and a BCR less than unity implies the reverse. Benefits and costs used to calculate the BCR are presented as the discounted sum.
- Net Present Value (NPV) — the NPV reports the net impact of the option on the economy (compared to the do-nothing BAU scenario). The streams of benefits and costs are discounted and reported in present value terms, and the NPV is calculated by subtracting the present value of costs from the present value of benefits.

Note that the BCR can be a very useful tool, especially when the benefits (or costs) of each option are the same — and only costs (or benefits) differ. For example, if different balancing options produced the same level of benefits, and what varied between each option were the costs, then the option with the greatest BCR (i.e. lower costs) would present the more obvious case to be pursued.

These two metrics will provide some assistance in making a recommendation. Excluding non-quantifiable impacts, only those options with a BCR greater than 1 (that is, an NPV greater than zero) should be considered as desirable solutions.

Sensitivity analysis

A sensitivity analysis should support the assessment — especially where the degree of uncertainty is high.

A useful tool for testing the sensitivity of the BCR and NPV to the various assumptions made is a 'breakeven analysis.' Under the breakeven analysis, key variables are individually increased (for costs) or decreased (for benefits) until the BCR is reduced to unity. (This is the same as having an NPV of zero.). The analysis shows the degree to which it is necessary for costs to rise, or benefits to fall, before the option breaks even.

Appendix B- Forecast and benefits estimation methodology

Balancing forecasts with addition of Collgar

A. *for 0% correlation*

1. Work out variations from average production in MWh for existing wind farms
2. Assume that same distribution exists for Collgar
3. Scale the variations up to Collgar's average production
4. Enumerate the number of times that Collgar causes balancing to go vary in bands of 50MW
5. Apply variations to balancing distribution

B. *for 100% correlation*

1. Multiply existing variations of wind from average by scaling factor to get Collgar production

C. *for 30% correlation*

1. Scale intermittent generation to Collgar average (i.e. capacity credit number) and reduce to 30%. Distribute the remaining 70% randomly across trading periods.

Calculating benefits from displacement of generation

A. *Method 1: Model specific generators*

1. Assume that MCAP price represents at least Verve's SRMC
2. Assume that there is a short start station with a SRMC of $x/MWh and production aMW
3. Assume that if STEM is less than x and if MCAP greater than x then that station was willing to be dispatched
4. Assume balancing up volume to be m
5. Assume all capabilities to be expressed in half hour quantities
6. Calculate advantage by taking the sum of (MCAP-x)*[min(m,a)]/2 (where division by two is because the advantage on average is that the supply curve is a straight line)
7. Run different scenarios by varying a and x
8. Note: no allowance made for the fact that sometimes balancing up caused in some cases by outages which mean also that less generation available for balancing

B. *Estimate advantage from MCAP approaching STEM*

1. Develop a grid for load (100MWh bands) and balancing (50MWh bands) pairs

2. For each pair calculate the expected STEM price on forecast load, the expected STEM price on revised load, and the expected MCAP on revised load
3. Count the number of occurrences of each pair
4. Calculate the surplus by estimating the area below each change in circumstances; then calculate the difference.

Issues: how much of the curve to assume; how steep to make benefits.

Calculating availability following outage benefits

1. Calculate a reasonable number of trading periods of additional availability
2. Calculate a reasonable estimate of displacement cost advantage/MWh

Scaling the benefits

1. Use change in slope of STEM price curve to scale advantages

Calculating cycling plant costs (avoided)

1. Estimate the number of times plant has to be cycled
2. Use international standard to estimate cost per occasion

Appendix C- Information sources

Statement of Opportunities, IMO document, July 2010

- Load forecasts
- List of current generating assets
- Planned generation

Balancing Support, IMO paper, 23 November 2010

- Raw data showing by trading period the advantage from IPPs' STEM offers being used for balancing for 2009/2010

2010 Margin Peak and Margin Offpeak Review, Final report to IMO, SKM-MMA, 17 November 2010

- Properties of existing generators table

IMO website (by trading period)

- STEM and MCAP
- Balancing volumes
- Load forecast

Other information

- SCADA data for all generators for 2009-2010

Other documents consulted:

Valuing the Capacity of intermittent Generation in the South-West Interconnected System of Western Australia, MMA Confidential Report to the IMO, 29 January 2010

Scenarios for Modelling Renewable Generation in the SWIS, ROAM report to the IMO, 25 August 2010

Economic Evaluation of Cycling Plants, Siemens Reference Power Plants, H. Emberger, Dr D. Hoffman, C. Kolik, 2007

The Cost of Cycling Coal Fired Power Plants, Steven A. Lefton, Power Plant O&M and Asset Optimisation, 2006

Development of balancing in the Internal Electricity Market in Europe, K Verhaegen, L. Meeus, and R. Belmans, Electrotechnical Department ESAT-ELECTA, 2006

Gas prices in Western Australia – Review of inputs to the WA Wholesale Energy Market, ACIL Tasman, prepared for the IMO, May 2010

Balancing price formation, IMO paper, 2 November 2010

COMPETITIVE BALANCING – ARE THERE SIMPLER LOWER COST OPTIONS THAT ACHIEVE MOST OF THE BENEFITS?

Whilst System Management's primary concern is system security and does not see prices it does observe market outcomes for balancing which would appear to be inefficient:

1) Short term commitment of additional Verve generator(s) due to substantial changes in Verve dispatch plan due to load coming in faster, load larger than forecast, wind output less than forecast, loss of a generator, etc when there is spare capacity on inservice IPP generators.
2) Decommitment of "base load" Verve generator(s), generally overnight, when IPP base load generators are not at minimum.
3) Decommitment of "base load" Verve generator(s) overnight which is really only required for a few hours (1-5am), when wind farm output could be curtailed.
4) IPP resource plans with large MW changes at intervals thus requiring large ramp rates to comply with RPs. This requires substantial movement of Verve balancing plant in order to counteract the IPP fast movements. This is exacerbated when multiple IPP movements and/or when these movements are not consistent with the load pattern (ie large upward movement when load is flat or decreasing).

System Management recognises the merit in the '12 Boxes' competitive balancing proposal (effectively optimised dispatch) developed by the RDI design group. However, System Management is concerned over the extent of the changes required to implement (thus cost impacts, risks to BAU, etc) and would like to see consideration of simpler, less costly competitive balancing proposals which address, at least to a reasonable extent, the existing balancing inefficiencies presently witnessed by System Management. Two simpler proposals are outlined in the following diagrams, utilising the same 12 boxes proposed by the RDI design group for ease of comparison. A summary of these 2 potentially simpler proposals is:

Proposal 1: Market Participant participation in balancing utilising existing Balancing Prices. Balancing Merit Order generated by combining existing one off gate closure IPP balancing peak on/off inc/decs prices with new Verve Portfolio Supply Curve. System Management would develop Verve dispatch plan for next day based on Verve Load Profile (ie Load forecast – wind forecast – IPP RPs). If actual load/wind substantially different to forecast or generator substantially deviates from plan (which would now require Verve to modify its dispatch plan), System Management would utilise BMO to determine which unit to dispatch (via Balancing Instruction) to make up the difference. Thus in terms of system changes IMO would need to generate BMO and SM would need to have system to be able to determine required Balancing Instructions (BIs) based on projected/actual load/wind resulting in deviations to Verve's Load Profile. SM could continue to issue BIs as it does now (ie verbally or AGC and email).

Proposal 2: Market Participant participation in balancing utilising new Balancing Tranch Prices. This is the same as Proposal 1 but here the balancing incs/decs bids are changed so they can be provided in tranches (minimum changes would be one upwards deviation price, one downwards deviation price to minimum output and second downward deviation price from minimum to off), but still one off gate closure. System changes required as per above but IPPs and IMO would also need to change balancing biding interface/proforma.

A simple example is shown in the following sheets to illustrate that if there is no change in the load/wind forecast (and generation output) then no review of the balancing merit is required. Another example is shown where load is projected to be higher than forecast for 3 hours and BMO is utilised and an IPP dispatched to cover this expected additional load.

Notes:
1) LFAS has been excluded from these proposals for simplicity of presentation only but could be added in (but increases complexity).
2) An option is shown to potentially improve the present overnight load issue of decommitment of baseload power stations.
3) The attached will have issues and has not been worked through in depth but hopefully shows there are feasible, simpler alternatives available.

ALL MP PARTICIPATION IN BALANCING USING EXISTING BALANCING PRICES

GENERAL NOTES:
Dispatch Support Tool = DST
Balancing Merit Order = BMO
BOX 9: DI becomes BI (Balancing Instruction)
NOTE 1: Verve Load Profile (VLP) = MW Output in each interval determined from forecast load minus forecast wind minus IPP resource plan.
NOTE 2 : An extension of this to minimise overnight load issue, is for BMO and DST to be used where defined (IMO/SM approved) Verve "base load" plant is on Verve Dispatch Plan to be de-committed overnight and returned the next day. IPPs would only be reduced to minimum if balancing price was less than Verve Portfolio Supply Curve prices.
Conditional Bids: Allow IPPs to nominate time available (eg due to fuel limitations) for balancing

BOX 1a
Design details:
- STEM remain the same

BOX 2
Design Issues:
- To change to DI format
- To be described as
  - -MW target
  - -Ramp rate
  - -start time
- Verve stand alone and IPP to provide RPs
- Still required to resemble NCP, however can differ when NCP changes across hh

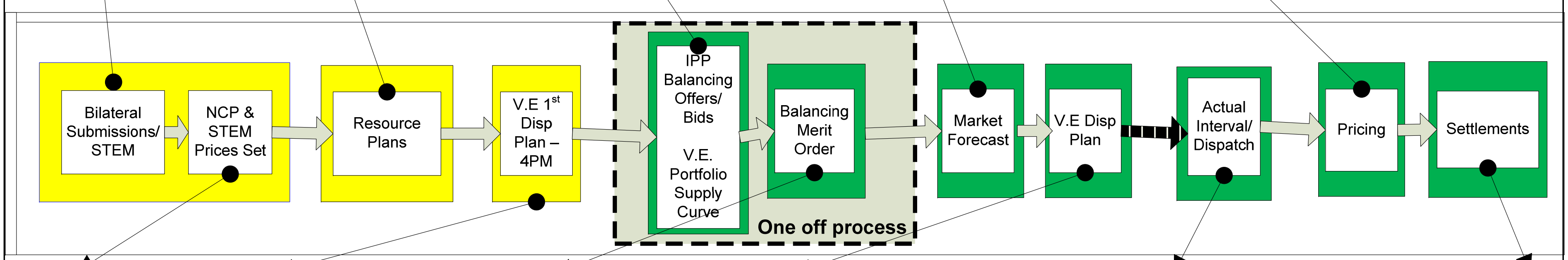
BOX 4
Design details:
- IPPs to provide balancing peak on/off inc/dec prices
- V.E. to provide portfolio supply curve
- Intermittent generation (wind) to provide decs only (CLs incs only).

BOX 6
Design Details:
- Will provide expected Balancing info to participants when significant change to Verve Load Profile (Note 1) due to combination of wind forecast, load forecast or forecast generator output changes (eg generator trip).
- Including quantity and $
- Will need to include constraints on generation identified by SM

BOX 10
Design Details:
- All deviations from NCP to pay/be paid the Balancing Price
- Ex post based pricing
- Will use Energy Equivalent Real Time BMO to determine ex-post prices

Balancing Proposal Summary

NOTE: Summary Only



BOX1b
Design details:
- To remain the same

BOX3
Design details:
- No Change – prepared by SM for V.E to prepare PSC and determine initial gas requirements .
  - -allow SM to use any relevant info to allow for accurate Disp Plan
- Delay rules requirement for 12pm Dispatch plan to 4pm (approx)

BOX 5
Design details:
- IMO to construct BMO from IPP balancing on/off peak inc/dec prices and PSC
- SM to either provide wind farm forecasts or sense check wind quantities provided by participants

GATE CLOSURE 5PM TBC

BOX 7
Design Details:
- Will be updated on an ongoing basis by SM using V.E. guidelines in response to scheduled IPP quantities including expected balancing

BOX 9
Design Details:
- SM to balance using Verve portfolio providing Verve Load Profile not significantly different from forecast at scheduling day STEM.
- Where significant change in VLP (say >25 MW/hr in half hour interval) SM to enter difference into Dispatch Support Tool (ie MW, start & finish time). Note 2.
- DST then determines, using BMO and recommit standing data cost, what is to be dispatched. Assuming retain 'manual' issuing of Balancing Instruction, would need logic built into DST to limit number of BI's. DST would also consider commitment / de-commitment times.
- SM to issues BIs as:
  - -MW target
  - -Ramp rate
  - -start time
- BIs will be issued through Verbal / web /SCADA / AGC means (details to be developed)
- Protocols will be developed for SM intervention

BOX 11
Design Details:
- DDAP/ UDAP removal
- Constrained on/off

BOX 12: Surveillance and Compliance
Design Details
- Removal of DDAP/UDAP- will need to report on diffs to NCP in an interval.
- Reporting revisions inside gate closure

Largely existing process

Largely new processes

ALL MP PARTICIPATION IN BALANCING USING NEW MULTIPLE TRANCH BALANCING BIDS

GENERAL NOTES:
Dispatch Support Tool = DST
Balancing Merit Order = BMO
BOX 9: DI becomes BI (Balancing Instruction)
NOTE 1: Verve Load Profile = MW Output in each interval determined from forecast load minus forecast wind minus IPP resource plan.
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Conditional Bids: Allow IPPs to nominate time available (eg due to fuel limitations) for balancing.

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Design details:
- STEM remain the same

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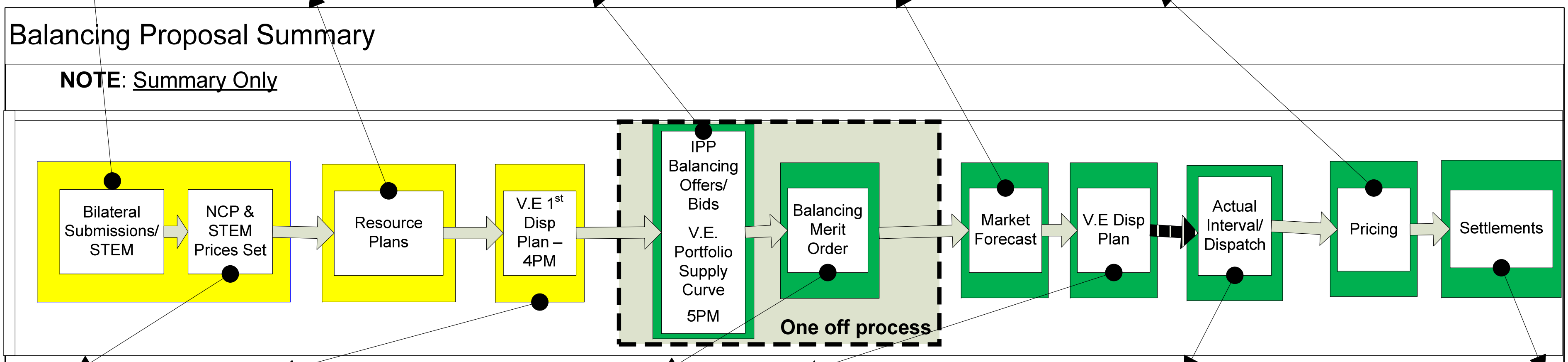
Design Issues:
- To change to DI format
- To be described as
  - -MW target
  - -Ramp rate
  - -start time
- Verve stand alone and IPP to provide RPs
- Still required to resemble NCP, however can differ when NCP changes across hh

BOX 4
Design details:
- IPPs to provide balancing incs/decs as MW target with $/MW associated with each tranche (to be determined but would be at least one upwards to maximum, one downwards to minimum and second downwards to off) for each interval
- Incs and decs to cover entire Capacity of Facility
- Intermittent generation (wind) to provide decs only (CLs incs only).

BOX 6
Design Details:
- Will provide expected Balancing info to participants when significant change to Verve Load Profile (Note 1) due to combination of wind forecast, load forecast or forecast generator output changes (eg generator trip).
- Including quantity and $
- Will need to include constraints on generation identified by SM

BOX 10
Design Details:
- All deviations from NCP to pay/be paid the Balancing Price
- Ex post based pricing
- Will use Energy Equivalent Real Time BMO to determine ex-post prices



BOX1b
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BOX3
Design details:
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- Delay rules requirement for 12pm Dispatch plan to 4pm (approx)

BOX 5
Design details:
- IMO to construct BMO from balancing incs/decs and PSC
- SM to either provide wind farm forecasts or sense check wind quantities provided by participants

GATE CLOSURE 5PM TBC

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- Will be updated on an ongoing basis by SM using V.E. guidelines in response to scheduled IPP quantities including expected balancing

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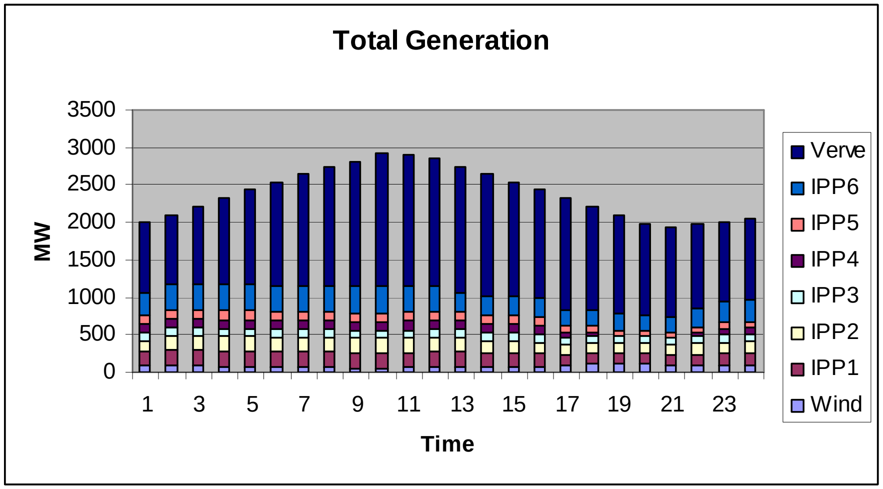
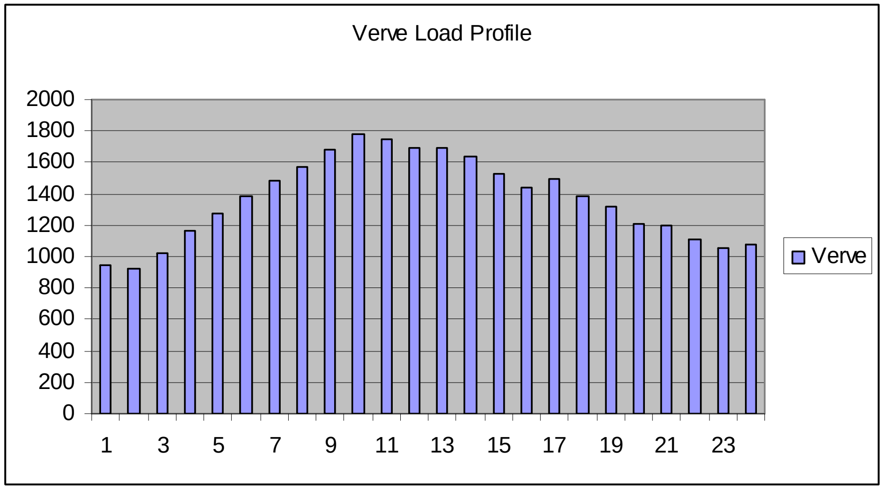
- DDAP/ UDAP removal
- Constrained on/off

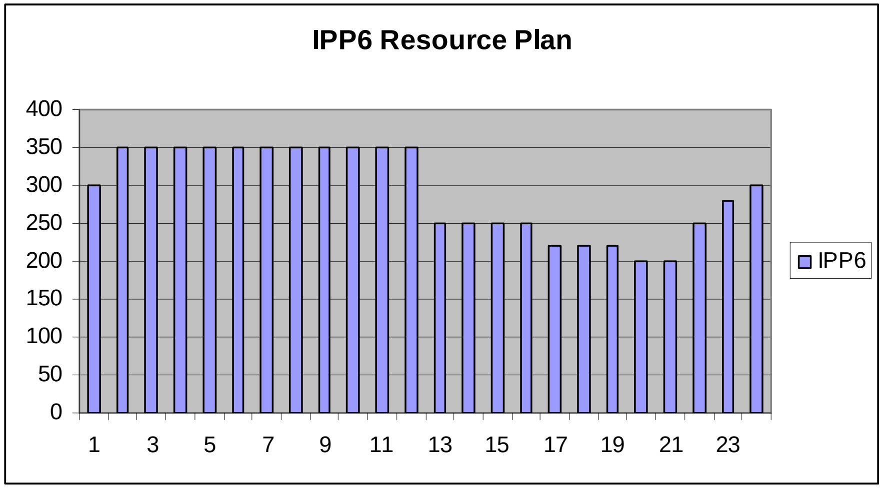
BOX 12: Surveillance and Compliance
Design Details
- Removal of DDAP/UDAP- will need to report on diffs to NCP in an interval.
- Reporting revisions inside gate closure

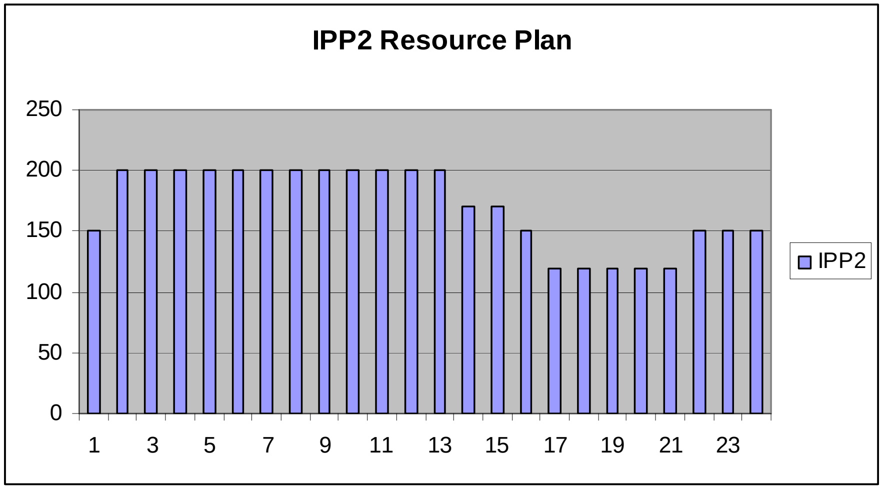
Largely existing process
Largely new processes

EXAMPLE 1: Actual Load and Wind as per forecast thus no change to Verve Load Profile hence no requirement to dispatch IPPs for balancing



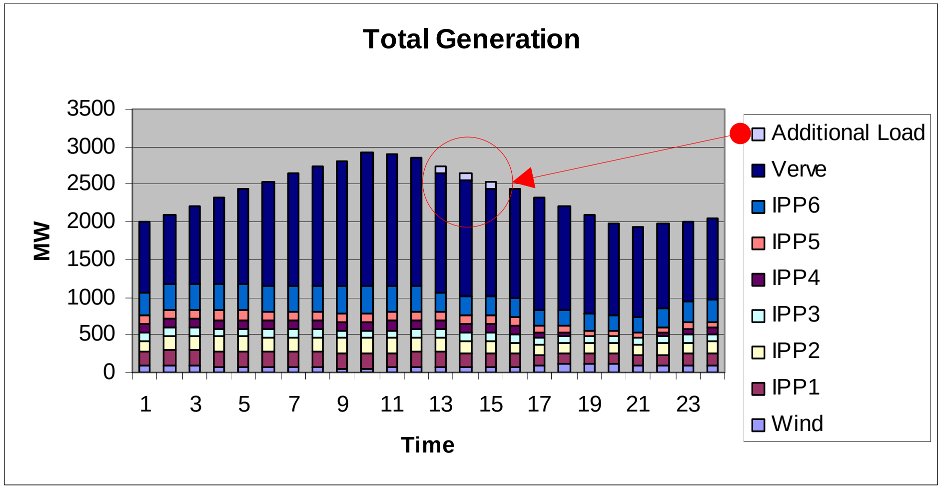


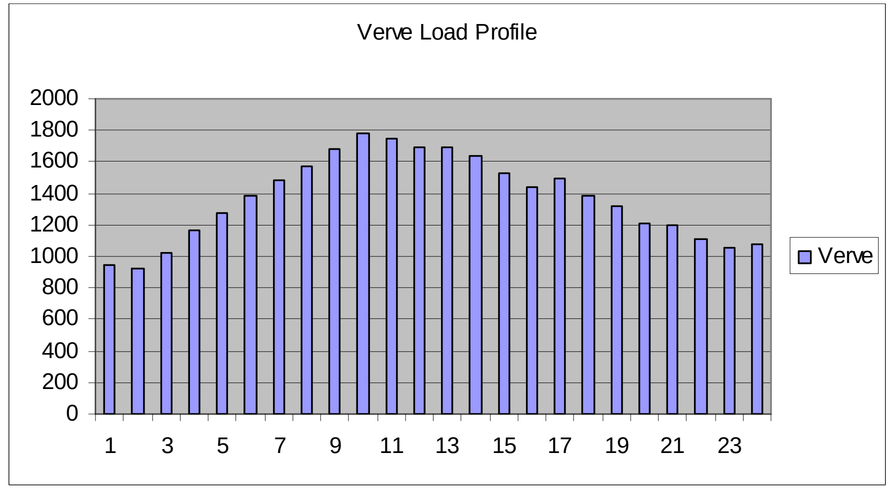


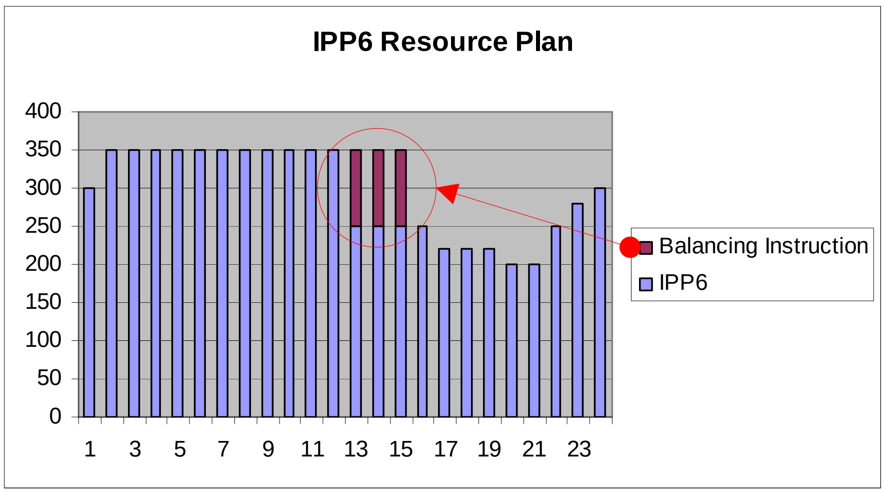


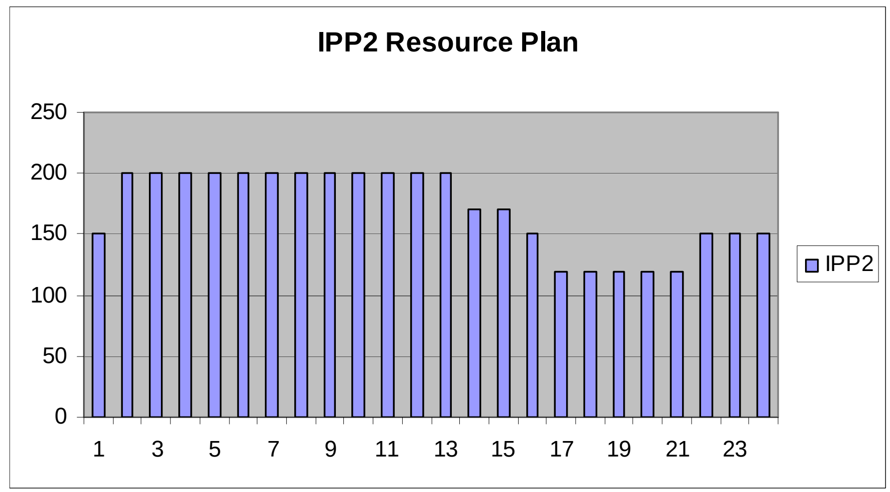
Actuals as per forecast thus no need to issue Balancing Instructions

EXAMPLE 2: Actual Load higher than forecast thus need to use Balancing Merit Order to determine unit(s) to be dispatched up









Here controller and/or load forecasting tool identifies load will be 100MW higher over hours #13-19 than forecast.
Assume here that IPP6 has lowest upwards deviation price of IPPs and Verve PSC over hours #13-15
Dispatch Support Tool would identify IPP6 is the most appropriate unit to dispatch up above resource plan. SM would issue BI for 100MW above RP to IPP6 for hours #13-19.

RDIWG submissions on Papers Presented at Meeting 9 – 22 February 2011 and the IMO's responses

Stakeholder	Balancing Design - Comments	IMO's Response
LGP	In general I perceive it to be progressing well and I have only one significant issue, which is to request a reality check on the appropriateness of calculating the Balancing Prices on the basis of what Facilities *could have done*, rather than what they actually did. It seems to be that only price submissions that could reasonably be called have a legitimate role in forming the Balancing Price. I perceive the Resource Plan to represent a MWh figure against which a facility is to be assessed and that, following the listed principles in 3.11.1, a Market Transaction occurs when its actual output doesn't match it, be it either a purchase from or a sale to the Balancing Market. Insofar as there are purchases from Balancing, then there will also be sales, and the selling parties would have bid genuine prices. Having said this, though, this approach could lead to a lack of depth and chunky prices and could 'disconnect' from the STEM prices that I was previously expressing as being undesirable.	The pricing methodology is based on what offers and bids *should* (not *could*) have been dispatched in accordance with the BMO. This approach to pricing, common in electricity markets[1], reflects the fact that balancing is coordinated through the dispatch of MW based offers/ bids to follow the expected MW trend during each half hour whereas pricing is calculated on a half hourly MWh and $/MWh basis. Dispatch relies on estimates that must be made to formulate instructions prior to the start of an interval. Some difference between dispatch and pricing will be inevitable because of the different time scales for dispatch and pricing The constrained on/off arrangements ensure that where the price of a facility offer or bid that was dispatched by SM is different to the half hourly marginal balancing price, the participant is kept whole.
	On this theme, I'd also request review of the appropriateness of the treatment of windfarms, requiring a forecast of what they expect to output over relevant intervals. This seems to me to be subjective and burdensome, even when the prices are genuine. I wonder if it would be better to require a windfarm to be remunerated along the lines the proposed Enablement Price proposed for Ancillary Services; in effect the Wind Farm would be paid A dollar amount to switch off and the market would be spared administration of the estimates. Delving into the minutiae, I would make the following observations: • I perceive the paper to presume that the LFAS resets and Balancing Merit Order resets would occur at different times and at different frequencies. If this is the intention, I'd have thought that they should be aligned.	Forecasting the output of wind farms, as for demand, is a fundamental market requirement anyway – not one that arises because of the balancing proposal per se. The proposal is that wind generators will be required to submit a bid price at which they are prepared to be dispatched down. Forecast wind quantities would be included in the BMO and the RTBMO at their submitted bid price. This provides the wind farm certainty as to pricing outcomes – it will only be dispatched down if the market price falls to its bid price ensuring commercial certainty[2]. An enablement fee approach would require the wind farm to internalise the risk of being dispatched down at an uncertain balancing price.

[1] In principle, the WEM balancing price calculation currently uses this method – calculating a marginal price (MCAP) from the STEM supply curve. The STEM supply curve is like a BMO except that at present it includes IPP capacity that is not able to be dispatched.

[2] Noting also that constrained-off payments will apply if the wind farm is dispatched down by SM but the final balancing price ends up higher than the wind farms bid price.

	• I perceive the paper to presume that Verve and the IPPs will have different Gate Closures; if this is the intention, I'd have thought that they should be aligned. • I support the notion of Verve being able to nominate Stand-alone Facilities, but I wonder if they will utilise this feature as I perceive they would seek maximum flexibility at all times and that within their portfolio approach they could internally quarantine plant in their Dispatch Guidelines. I mention this only from the perspective of reducing the complexity if Verve won't use it. • System Management's role in rejecting Resource Plans – it seems to me that this isn't feasible at the submission stage (via WEMS) and that this would have to be done when the participant submitted the one-minute plan in accordance with the PSOP. Perhaps this aspect of the PSOP needs to be brought into the Rules? • Please clarify the last dot-point in section 3.9.3 regarding Verve switching to liquids; why wouldn't this be picked up in a routine resubmission?	Final details of the timing of submissions, resubmissions and reassignment of ancillary service duty will be chosen to align with the broader balancing market design and design of software support and processes used by System Management
Verve	Verve Energy considers that the main issues yet to be resolved are: • Balancing Bid/offer gate closure - clearly the views of System Management are of importance here	 Agreed. The IMO is working through these issues with System Management. IPP flexibility though is also important for reasons noted above and there is a trade-off between the desire for certainty versus flexibility to optimise the use of constrained resources/ timing of facility-based decisions. In any event, System Management will retain authority to ensure that security requirements can be met.
	• Verve Energy rebidding arrangements - what is determined in relation to gate closure will have a significant bearing on the outcome. It remains Verve Energy's fundamental position that the rebidding arrangements should be the same for all participants. I am yet to witness a plausible rationale why that should not be the case	While flexibility is important, the need for facility based resubmission flexibility is driven by different requirements to portfolio based flexibility as noted above.
	• LFAS - it needs to be determined whether the complexity of overlaying LFAS over balancing, with attendant difficulties and cost, will outweigh the benefits that will accrue (which may be minimal)	Noted
	• page 40 of 117 - Form of bids and offers 4th bullet point: Would a wind generator not opting to participate in balancing still have the	The proposal is that wind generators will be required to submit a bid <u>price</u> at which they are prepared to be

	option of not running even when the wind is blowing and avoid paying the market for the wind farm to generate? Effectively this will make the option to participate in balancing to be of no value – why offer into balancing when the option to curtail could be exercised later in real time on forecast balancing prices being below the wind generator or its bilateral counter party price threshold? •	dispatched down. Forecast wind quantities would be included in the BMO and the RTBMO at their submitted bid price in the same way that forecast quantities are included in the preparation of schedules by SM now. This provides the wind farm certainty as to pricing outcomes but does not oblige a wind farm to pre-determine balancing volumes – it will only be dispatched down if the market price falls to its bid price ensuring commercial certainty[3]. An enablement fee approach would require the wind farm to internalise the risk of being dispatched down at an uncertain balancing price.
	• page 41 of 117 - Ancillary Service offers: Further detail is needed on how a Verve Energy portfolio supply curve (PSC) for LFAS will work, particularly in relation to how it relates to a balancing PSC.	Noted. Under discussion.
	• page 41 of 117 - Resubmissions: I would observe that this is not yet resolved and the final arrangement will need to be determined when the gate closure issue is resolved.	Agreed. Gate closure is a relevant consideration.
	• page 43 of 117 - Verve Standalone Facilities: The intent is clearly that facilities formally removed from the portfolio will be a permanent. To what extent will this be reversible should System Management subsequently determine that such removal has created a security issue?	The one month trial option should enable such assessments. System Management will retain the authority to intervene for system security purposes, should that be necessary, in any event.
	• pages 40 to 43 - LFAS discussion:	
	- Could capacity be withheld from the STEM to be offered into LFAS or would LFAS be offered after not being cleared in the STEM and therefore of lower opportunity cost value? Would this also apply to the default provider? Or would an energy-first-LFAS-after approach result in higher LFAS cost than otherwise in that the left over capacities are high cost facilities resulting in higher total cost of generation?	The issue is unclear but LFAS operates much as balancing and is incremental to resource plans. Hence capacity not cleared in STEM could be offered to balancing/ ancillary services. Rebalancing and coincident (approximation to co-optimisation) will lead to optimized cost.
	- Would Verve Energy LFAS portfolio supply curve be required to be large enough to cover System Management's expectation of total LFAS required? If not how would Verve Energy balance supply be priced?	Verve will continue to be the default provider of LFAS and as such a minimum aggregate quantity of LFAS would need to be offered (price / quantity pairs in increasing price order)

[3] Noting also that constrained-off payments will apply if the wind farm is dispatched down by SM but the final balancing price ends up higher than the wind farms bid price.

	- Would selected LFAS offers be paid bid prices or would there also be a clearing price or two clearing prices (one upward and one downward) for each Trading Interval applicable to all accepted offers and the default supplier? - Would an up only offer selected, once moved up in real time, be liable to be moved down to the starting point and vice versa for the down only offer? - Would the facility providing the LFAS be returned to its Resource Plan level once it is no longer providing LFAS or balancing service? The balancing dispatch system will thus have to take this into consideration. (Similarly a balancing offer accepted and dispatched from a facility will be returned to its Resource Plan level when no longer providing balancing service.) - A worked example incorporating LFAS in balancing over a period covering several Trading Intervals would be useful • page 54 of 117 2nd bullet point - Outstanding Issues: The arrangements around Verve liquid versus IPP non-liquid dispatch need to be further considered and resolved to ensure that the inefficient dispatch that currently occurs around this issue does not continue. A key element governing the outcome here is Verve Energy rebidding arrangements.	It is proposed that there be separate up and down marginal LFAS prices. Initially, LFAS may need to procured on a symmetrical basis in which case up and down prices would be the same. To the extent raise and lower services are needed in the same half hour, depending on LFAS offers, this could happen. Yes subject to offers and bids. Agreed. Noted.
Synergy	***(i) Net dispatch arrangement*** Synergy notes that the updated design paper goes beyond simple competitive balancing by including a net dispatch capability. By allowing market generators to adjust their resource plans, by either selling more or replacing expected supply from other market generators, extends the design beyond what would reasonably be expected of a competitive balancing arrangement delivering instead a <u>net dispatch arrangement</u>. This is mentioned here because at the July 2010 MAC meeting members decided not to progress the market design into the realm of a net or a gross dispatch design and instead elected to limit the changes to incremental elements by allowing IPPs to participate in the provision of the balancing service.	By necessity the proposal is a net dispatch arrangement in respect of IPPs. Retention of the current hybrid market design means that IPPs will continue to be subject to facility based net dispatch (with increased balancing opportunities) and Verve will continue to be subject to portfolio based gross dispatch and mandatory default balancer role. The intent of the proposal[4] is to extend the current design, which unavoidably involves a degree of complexity given inherent constraints in the current design. However, the proposal falls well short of the options for net dispatch

[4] "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.

	Although Synergy recognises the improvements in efficiency resulting from a more flexible dispatch design, ie a net dispatch, it notes that such changes also come at a cost, and cost without corresponding benefits was a concern expressed by the MAC in July 2010. Therefore, in order to progress this design, the market needs to be confident that the inclusion of net dispatch increases the marginal cost-benefit beyond that attained from IPP participation in the balancing service. In Synergy's view, this inclusion needs to have its costs and benefits separately identified such that the market, in the light of updated information, can reconsider its July 2010 decision. ***(ii) Clean balancing price curve the priority*** Following the July 2010 MAC decision on a way forward, Synergy expressed a view that the priority component of any improvement to balancing would be a move away from the STEM based process of setting MCAP to a clean balancing price curve. A clean balancing price curve, in Synergy's view, constitutes a price derived from the cost of the generator providing the balancing service. Such a change was seen as a way to reduce Verve's cost exposure (annually $10 million) whilst removing unrelated STEM offers from the balancing price curve. Synergy's comment on the updated design is that by combining several components – a clean balancing price curve, a competitive balancing arrangement, a hybrid net dispatch option and a competitive LFAS arrangement - creates implementation interdependency which could delay market benefits resulting from an early start of a clean balancing price curve whilst waiting for all components to be developed. In expressing the above views, Synergy is not commenting upon the merits of the updated design itself, but simply wishes to raise concern that the current process is moving away from the incremental (evolutionally) approach agreed in July 2010 and moving closer to a revolutionary approach. Now, this last comment is an overstatement of the size of the change in approach currently being adopted compared to what may have been expected in July 2010, but the market needs to remember what it originally intended to happen and why, before it can comfortably move forward. ***(iii) All balancing bids at SMRC***	(option B) and gross dispatch (option C) considered last year. Both of these options would have been a fundamental departure from the current hybrid design. For example, under option B (net dispatch), Verve and IPPs would both have participated on an identical facility by facility basis, with resource plans required for all facilities and offers/bids relative to these resource plans. In addition to such a fundamental design change, market systems and processes, including System Management capabilities, would be significantly different than under the proposal. A clean price is part of a package of measures[5]. While it is an important element, a clean price will not achieve competitive balancing. Implementing a clean balancing by itself would require significant time to progress through the rule change process and involve significant changes to market systems that would not be part of, and inevitably delay, implementing the proposal (and achieving the benefits, including addressing overnight concerns). Note that Verve's exposure depends on the extent to which it is required to balance down or up (there are multiple effects, not just IPP STEM offers). The historical analysis was for a period in which Verve was systematically tending to balance downwards, in turn depending on the extent to which overall nominations are accurate. The proposal is somewhat complicated by the constraints of the current market design but is incremental rather than revolutionary. The proposal is subject to a full cost benefit assessment.

[5] For example, RDIWG Minutes, 30 September 2010.

	Synergy understands that similar to the STEM, participation in competitive balancing will be compulsory. Synergy agrees with this design parameter thereby avoiding an incomplete balancing dispatch merit order. Synergy still retains a concern that like the STEM, even a compulsory participation in balancing will not of itself deliver SRMC outcomes by all players or at all times. Synergy therefore suggests that the market look at the practicality of requiring SRMC for balancing participation. ***(iv) Flexibility for Market Customers*** With reference to the updated design section 3.1.2 of the Competitive Balancing Proposal, Synergy notes that there had been no prior debate or paper presented setting out the rationale for what amounts to a significant change in how a Market Customer can participate in the market and how such a change would better achieve the market objectives. Currently, it is at a Market Customer's discretion as to whether it actually makes a STEM submission. Making it mandatory, as indicated in section 3.1.2, immediately reduces choice for Market Customers while simultaneously imposing processing costs for no apparent gain to the Market Customer. Synergy has difficulty understanding how this proposal could satisfy any economic efficiency criteria. It is also opportune to reflect as to why the market effectively prohibited Market Customers from overstating their demand, through the collection action of rules 6.7.3 and 6.7.4, but never sought to impose any reciprocal requirements with regard to understating demand. In Synergy's view, this asymmetrical approach is quite proper and recognises that a Market Customer's load is inherently uncertain on the day and, through the action of growth and churn, over time which exposes it to an unknown level of balancing. Synergy contents that forcing a Market Customer not to understate its position in the STEM, especially where loads are characterised as being temperature sensitive, is removing a valid strategy for managing load variability risk faced by Market Customers. Further, Synergy remains to be convinced that the STEM delivers efficient prices. Taken together, the requirement for a Market Customer to make a STEM submission and to ensure that its forecast position is not understated will likely result in less efficient outcomes for the market. This is because Market Customers will face higher costs (inefficient STEM prices) and increased balancing exposure (disallowed from taking a conservative position on forecast load resulting in increased occurrences of selling into the balancing market).	Participation in STEM is a *one shot* exercise with submissions constrained by the need to avoid infeasible or inefficient contract positions/ facility resource plans. The balancing proposal provides flexibility to manage resources/ facilities through resubmissions. This has been removed from the paper pending consideration in light of discussion at the last RDIWG meeting.

	Another point to note is that by imposing these requirements on Market Customers may act to increase barriers to entry for new Market Customers and weaken competition in the longer term. A new entrant may be cautious about entering into significant bilateral contracts and given inefficient prices in the STEM may legitimately seek access to significant balancing market energy while it establishes it supply portfolio. To remove access to balancing energy increases a new entrant's risk profile for no offsetting gain resulting making it less economic to enter the market. ***(v) Will IPPs participate at sufficient level to justify the change?***	
	Synergy would also like to raise the question whether there is a sufficient number of Market Generators operating in the WEM to justify the level of change being proposed. This change may be premature particularly given it requires Market Generators to invest in updated nomination systems. ***(vi) Inter temporal difference in benefit capture***	In the short term, flexibility available to IPPs to update submissions will enable them to better match the timing/use of resources to market requirements. This is particularly important for facilities with energy/ fuel constraints. This can also be expected to drive longer term decision making with flexibility becoming more valuable.
	The Competitive Balancing Design presented to the RDIWG, represented by Boxes 1a to Box 11 in the design schematic, effectively states that no changes will occur in the bilateral nomination, STEM and Resource Plans processes nor in the creation of Verve Energy's 4pm dispatch plant by System Management. The design changes start from the new multiple gate process allowing Verve and generators to submit incs/decs balancing offers to take advantage of forecast new balancing prices. These offers are designed to allow generators to trade around their net contract/resource plan positions so as to improve their economic outcomes. In contrast, Market Customers are locked out of this process (being restricted to Box 1a); they are unable to respond to these changing price signals to optimise their positions. This means Market Customers, unlike generators, will be unable to capture any immediate benefits arising from the implementation of this competitive balancing proposal. However, Synergy does acknowledge that in the longer term efficient balancing prices will reduce generator costs which will manifest in the next round of bilateral contracting. In Synergy's view, the benefits for Market Customers lie mostly in the future, while the benefits to generators will accrue immediately the proposal is implemented. This inter temporal difference in benefit realisation suggests that it is both reasonable and appropriate to review the funding of the market's competitive balancing	Noted.

	implementation costs. Currently, recovery of market costs are split evenly between generation and consumption. In this case however, Synergy suggests there is sufficient reason, as outlined above, to consider an amended cost allocation that would result in Market Customers funding a much lower amount. To this end, Synergy suggests a cost allocation of 25% to Market Customers with the residual to Market Generators.	

Stakeholder	Cost Benefit Analysis - Comments	Sapere's Response
LGP	• [Need to fix the reference to the Dongara wind farm – presumably Walkaway]	Has been corrected thanks.
	• Section 2.3. I take the point about seeking benefits that alter the aggregate economic resource levels, but would advocate express comment on the benefits to Verve (especially) and IPPs in general (so that they don't get envious of Verve ☺) because the Government has demanded action to remove the disadvantages to which Verve is subject. We should therefore remain alert to ticking that particular box.	The Cost Benefit Analysis has deliberately focused on the overall costs and benefits as opposed to individual firm impacts.
	• I agree with Corey's comment that the assumptions need to be integrated with the consultant reports submitted to the REG WG and the Energy Price Limits process, and that justification should be provided where that work is superseded. In particular, the stated gas price seems to be very optimistic and the lack of correlation of Collgar with the other windfarms might need to be reconsidered.	The main use of the price forecast was for scaling the future results. As load increases, the energy clearing price will be set at a steeper point on the supply curve based on our information. It is the slope that is important for scaling the results, not the actual weighted average price. The main factors that influence the slope are load (as it increases the average clearing point moves along the supply curve to the right) and changes to the market generation portfolio (additions to the generation portfolio of base load can serve to flatten the supply curve). The input prices are important but the results are not highly sensitive to the gas price change.
	• I understand the report to say that the stated forecast STEM increases are linked to gas price evolution. I perceive that coal pricing should also be an important factor and that it would mitigate the extent of the increase. (Apart from that, the stated increases are scary and ought not be released into the public domain until more robustly confirmed.)	The approach we have used to try to forecast STEM prices uses a range of information. We established theoretical supply curves for 2009/10 and 2014/15 based on information from the Verve margin review. We then reviewed those supply curves and reweighted them based on actual information observed in 2009/10. The price forecasts that LGP refer to were not reweighted. This is a matter of judgement. There are a number of variables that will have an impact on price: new generation units added; old generation units closed down; total load; load duration; generation mix (base load, fast start; wind); cost of inputs; regulation; customer contracts; legacy supply contracts. We determined after further consideration that the first method that we used did not take sufficient account of the actual results in 2009/10 and decided to reweight the forecasts. As mentioned in the answer to question 3, we have been careful in the way we have used the results so as to take into account only the economic effects and to ignore the price effects except insofar as they have a real,

	• Section 3.2. I perceive that an important benefit of the proposed change is that it will improve continuity between the STEM Clearing Price and MCAP. This is important because it will allow IPPs to unwind sub-optimal NCPs; that is, allow them to bid at the optimistic side of their SMRC scenario-range, and if it results in an unviable outcome, unwind it in balancing with minimal price risk. At the moment there is often a big disconnect between STEM and MCAP, with system contingencies causing MCAP to blow out because plant has to be committed grudgingly – that is, running plant for a few hours at even the price limits would still under-recover costs while simultaneously punishing the market. In recent weeks on a 5MW quantity, this disconnect has run at around $20,000 per week. • This might not be the proper venue for this comment, but the comments on improved load forecasting and its expected continued improvement are interesting; I'd welcome further comment on this.	physical effect. This benefit is implicit in our analysis. We agree that giving participants an opportunity to "re-balance" will encourage better outcomes as more information becomes available. We have avoided building in any assumptions regarding forecasting improvements. We noted that the balancing volumes have decreased substantially since the beginning of 2008 but accept that there are likely to be a number of reasons for this.
Verve	• page 73 of 117: What is considered 'everyday' balancing and what is considered 'extreme' balancing and why the difference? • page 76 of 117: How are balancing up and balancing down defined: in terms of Verve Energy Authorised Deviation Quantity or the difference between Operational Load and Scheduled System Load, or otherwise" • page 77 of 117 second paragraph: Is the range of the balancing contribution to balancing of intermittent generation determined from the installed capacity and the approved capacity credits? • page 77 of 117 on model assumptions: What is the correlation between the Dongara and Emu Downs wind farms? Is it correlation between the minute by minute outputs or half-hourly Trading Interval average outputs? • page 77 of 117 2nd para: I'm not sure I agree that intermittent generation has not been a major contributor to balancing requirements. Wind generation has been a significant contributor to	There is no set definition, but we would describe balancing which was due to intermittent generation fluctuations and to forecast inaccuracies was everyday balancing; prolonged balancing caused by unforeseen events such as outages could be described as extreme. The difference between operational and scheduled system load. Yes It is around 40%. This is based on half-hour trading average output. We agree that intermittent generation has been a big factor during some trading periods. However, we have not been able to identify a strong overall correlation between intermittent generation and balancing requirements. Our

	the downturn of Verve Energy base load plant overnight and this is expected to exacerbate with increasing wind penetration.	modeling of the status quo assumes a small increase in overall balancing volumes with Collgar and models the effect of additional balancing during the low load periods during the night.
	• page 77 of 117 item 3: $6/GJ by 2014 seems on the low side to me.	As noted above it is the slope that is important for scaling the results, not the actual weighted average price. The main factors that influence the slope are load (as it increases the average clearing point moves along the supply curve to the right) and changes to the market generation portfolio (additions to the generation portfolio of base load can serve to flatten the supply curve). The input prices are important but the results are not highly sensitive to the gas price change.
	• page 78 of 117: Is balancing cost a transfer between Market Participants or a cost or benefit to the market, eventually flowing to the end users?	A change in the balancing price – in itself - is simply a wealth transfer between those buying the balancing and selling the balancing. Any economic impacts accrue from the signalling impacts of the price – in terms of changing future behaviours around balancing. In this instance, however, he CBA was not able to quantify any benefits from the change in the balancing pricing methodology by itself without a move to competition.
	• page 80 of 117 1st para: the amount quoted for shut down and start up of thermal plant is primarily associated with fuel oil cost, not wear and tear of machinery.	This is a difficult item to model. We have tried to capture the wear and tear only as some of the other costs are captured in energy offers. The study we have used suggests that the capital costs range from between $5,000 and $100,000 per event. These costs depend on the age and type of plant.
	• page 81 of 117 bullet point: Not sure that is correct. Why would Verve Energy have fewer resources? Plant retirements are not contemplated in the timeframe being considered here.	This comment has been removed from the final draft. The point was regarding Verve's relative share of capacity rather than an absolute number.
	• page 82 of 117 2nd bullet point: "...more flexible security processes". It is unclear what this means	There are two things that we were attempting to capture: one was that System Management would be able to make calls on a wider range of facilities as a rule rather than as an exception; and two: that automated processes would assist with security.
	• page 82 of 117 4th bullet point: This doesn't quite capture the issue.	Agree this was a placeholder for more reflection.

	The current problem is that MCAP, which incorporates IPP pricing, is not cost reflective in the situation where pricing would dictate that an IPP should move in balancing but a Verve plant is dispatched instead.	
Synergy	Synergy notes that the cost benefit analysis report presented at the RDIWG of 22 February was a partly finished draft with minimal quantitative information about the costs and benefits of introducing a competitive balancing regime. Accordingly, it is not possible, at this stage, to draw any solid conclusions about the distribution of costs and benefits among Market Participants and the nature and level of benefits that will flow to customers. However, Synergy offers the following comments about the report: ***(i) Removal of DDAP and UDAP - likely to occur irrespective competitive balancing decision*** Table 1 lists the benefits expected to flow from implementing competitive balancing. Removal of DDAP and UDAP is cited as a benefit. Synergy has observed that there is strong support from most MAC members to remove these penalties and concludes that their removal will occur irrespective of whether competitive balancing proceeds. Therefore Synergy questions whether it is appropriate to include the removal DDAP and UDAP in Table 1 which infers the realisation of this benefit is dependent on the implementation of competitive balancing.	While such options are obviously possible our brief is to compare the current proposal with the status quo.
	(ii) Recognise the temporal distribution of benefits Competitive balancing will likely drive efficiency gains in both the short and long terms. The report makes a clear distinction between immediate implementation and on-going costs, in Synergy's view it is equally important to identify benefits on a similar temporal basis. This is because usually greater value is placed on near term benefits as they typically have a higher likelihood of being realised while a greater risk attaches to benefits to be realised in the long term. Clearly the latter should be discounted accordingly or only be included in the report as a qualitative benefit. In this regard, Synergy sees any benefits that may arise in respect of future "investment" decisions as sitting in the long term category. ***(iii) Identify why balancing costs are forecast to increase rapidly***	We believe that the revised report addresses this point. Longer term investment type benefits are noted qualitatively.

	Charts presented in the draft report show forecast business-as-usual balancing prices and costs to 2015/16 increasing at an average annual rate of about 25%/annum. The underlying factors driving this must be explained so readers will be able to draw conclusions about how this price and cost profile may change as a result of the introduction of competitive balancing.	Agree – see the revised results and the appendix.
	(iv) Decision matrix - identify incremental cost benefits	
	Synergy views the proposal before the RDIWG as comprising four separate and distinct outcomes being: 1. Clean balancing price curve; 2. Competitive balancing arrangement 3. Net dispatch option; and 4. Competitive procurement of load following ancillary services. In Synergy's view, the minimum outcome from the proposal will be the Clean Balancing Price Curve which can be delivered at low cost and minimal impact on most Market Participants. Thereafter, it is a matter of judgement as to whether the incremental benefits of moving to steps 2 and/or 3 can be justified. To provide part of the necessary information to facilitate this decision Synergy recommends that the incremental cost benefits be presented in a matrix so that decision makers can clearly see the relative merit or otherwise of selecting one outcome or combination of outcomes over another. A stylised example of the cost benefit matrix is presented below.	It is obviously possible to think of the proposal this way but we were asked to model the proposal against the status quo. We would note, however, that it was not possible to identify any quantifiable benefits from the 'clean balancing price" in the analysis: the benefits are all derived from the increase in competition in the provision of balancing. Hence the cost benefit analysis would not support an argument that the balancing price change should be delivered first on a net benefit basis.

Stylised incremental cost and benefits of Competitive Balancing– NPV 2010 $M

Case	Cost	Benefit	Net Benefit	C/B Ratio
Base - Clean Balancing Price	2	12	10	6
Competitive Balancing	5	10	5	2
Hybrid Net Dispatch	3	10	7	3

Total	**10**	**32**	**22**	

(v) No requirement to bid competitively reduces potential benefits

Synergy notes that although generator participation in competitive balancing is proposed to be compulsory, there is a risk, as has proved to be the case with the STEM, that some balancing bids may not reflect short run marginal costs, indicating an unwillingness of generators to move from Resource Plans. Synergy views that there is real potential for this to occur and therefore strongly believes that the cost benefit report should include scenarios around differing active generator participation rates to understand the sensitivity of the benefits to participation rates. If balancing incs/decs bids are similar to that posted in the STEM, which arguably are not reflective of marginal costs, then competitive balancing could turn out to be a premature investment for the market.

We have provided “low”, “medium” and “high” scenarios because of a number of uncertainties. Participation is one of these uncertainties.

(vi) Use existing pricing assumptions accepted by the market

In Synergy’s view there is merit in key commodity price and other major assumptions being drawn from recently completed expert reports that have been used as input into other market processes such as for determining Energy Price Limits.

Agree. See also the comments about the impact of such pricing on the results. They are an input but not a critical influence on the results.

Stakeholder	Implementation Timelines - Comments	IMO's Response
Synergy	Synergy has concern that achieving the current implementation timeframe will be difficult. Setting a timeline is important but the market needs to be realistic if slippage is unavoidable. Synergy is particularly concerned about System Management's response given that their systems will be the most impacted and so they are mostly likely to be the cause of any delay. Synergy would be concerned if the IMO felt it was locked into an end date which could only be achieved by a rushed implementation delivering likely errors and unforeseen impacts that may detract from efficiency rather than improve it.	The IMO is working with System Management and both parties agreed to revise the implementation date for the new balancing and LFAS markets to April next year. Determining the right timeframe requires an assessment of the risks of rushing versus the risk (and costs) of delay. The IMO considers the current timeframes are reasonable from a cost/efficiency/practicality point of view .
Verve	Other issues page 28 of 117 - Timing of proposed changes: I don't see the advantage of delaying identification of timing concerns until the formal Rule Change process. Any concerns should be identified and resolved as they arise. With that intent, Verve Energy raised timing concerns in its previous comments. Implementation timing - clearly the date of implementation will be governed by the ability of participants to adapt IT systems to suit. System Management and Verve Energy are two incumbents that are most affected by this and it will not be possible to implement the necessary changes until design details are largely finalised. Given that it is likely that the proposed implementation date may be delayed, consideration should be given to whether a Rule Change to achieve a 'clean' MCAP should proceed separately. This would realise a significant portion of the anticipated benefits and would go a long way to achieving the 'quick, cheap fix' that many participants are calling for.	See above. The issue of whether the balancing price should be dealt with separately was discussed by the RDIWG and there was acknowledgement of the IMO view that they should not be progressed separately. The IMO also notes that the cost benefit analysis was not able to identify any quantifiable benefits from resolving the balancing pricing issues – the benefits identified all accrue from the introduction of competition in the provision of balancing.

Stakeholder	Reserve Capacity Refunds - Comments	IMO's Response
LGP	<u>Dynamically Calculated Refunds</u> I support this concept and the proposed: • retention of the Maximum Refund Factor of 6; • the cap on cumulative refunds; • the broad form of the Refund Factor as a function of Reserve with provision for significant exposure to the Maximum refund Factor; That said, the complexity inherent in the final phase of the Refund Factor Function after the second break-point seems to me to be unwarranted, and I'd prefer to see the function instead linearly progress to zero. I support the notion of the IMO publishing forecasts akin to the PASAs as a guide to preferred times for planned outages. While I have no objection to the proposal to NOT develop a combined 'forecast annual' and dynamic factors, I would support the (unstated) proposition that generators should have some sort of safe haven in which they are free to plan major maintenance without fear of being pinged by some or other very unlikely contingency in the middle of it. <u>Removal of Net STEM Shortfall</u> I support removal of Resource Plan non-compliance as an automatic trigger for refunds, and replacement by an Operational Test. <u>Creation of an SRC Fund</u> I support creating an SRC Fund and funding it from Capacity Refunds and Security Deposits. <u>Allocation of Refund Monies to SRC and Market Customers</u> I perceive the proposed method to be reasonable, and also have no objection to the cyclic method. That said, I perceive that under the current Rules, Capacity Refund monies are un-forecastable windfalls that don't really represent anything material in the general functioning of the	The IMO considers that developing a curve that presents intermediary values for capacity will more adequately balance incentives for generators to exhibit the correct short term and long term behaviors. The breakpoints are largely arbitrary and the IMO will look at the quantum of the breakpoints in any rule change that is progressed as a result of the decisions by the RDIWG, however, in the absence of convincing argument to the contrary the IMO also considers that there is merit in retaining a similar level of exposure and prudential risk to the current arrangements. Other aspects of the Reserve Capacity Mechanism that may require fine tuning as a result of the transition to a more dynamic refund regime. One of those areas is the rules around System Managements outage planning processes. This is because there may be a need to provide greater flexibility in the outage planning process to reflect the dynamically calculated value of refunds which may not be aligned with a seasonal planning process. The IMO will add to the section related to the presentation of capacity to the market at an SRMC cost basis.

	market. Consequently, unless SRC is called, I perceive that default by a Capacity provider does not of itself create injury to capacity purchasers (being parties bearing an IRCR liability).That said, I perceive that default by a baseload or mid-merit unit drives the price curve to higher prices and there is an argument, touched on by Shane at the last meeting, for compensating the buyers of that energy (the defaulting generator plus me!!! J) On that theme, I have no objection to "treating all capacity equally", but I would support recognition that the baseload and mid-merit plants make more of a contribution to producing low cost energy and should not be disadvantaged through longer exposure to refunds. [However, hypothetically, if 185MW coal-burners are off during a Tropical Cyclone, I'd like to see them back on real quick……… ☺] Just one other thing, on the theme of the baseload generators, I suggest including in section 2.1 a dot-point detailing that generators are obligated to offer to STEM at their SRMC, which to my mind is the substance underpinning the delivery of the capacity – as a Retailer, Capacity is presumed and ignored…….. but profitability hinges on daily STEM and Balancing outcomes. The corollary of this is that, rascal that I may be, I would rather have a capacity shortfall and customers turned off than have to buy energy from a peaker burning diesel fuel.	
Verve	The multiplier-reserve margin relationship and the quantum of the refund appear to require more refinement. Some considerations: i Current clause 4.26.1 Refund Table multipliers consist of 7 discrete values with the maximum multiplier at 6 and the minimum multiplier at 0.25 or 7 discrete values in the range of 5.75. (The limited number of discrete values could contribute to the lack of relationship in the refund factor- reserve charts in the review paper.) The choice is arbitrary and we might choose to move away from discrete values to a continuous relationship between multiplier and reserve margin ii The basis for the maximum multiplier of 6 in current clause 4.26.1 Refund Table and the other six discrete values are not clear. They were established via a rule change after marker start but appear arbitrary in nature. A new "negotiated" set of parameters could be appropriate in the	The proposed dynamic refund calculation methodology only has a single discrete value of 6 when the level of capacity in the market drops below the defined level of 2*Reserve Margin (approximately 750MW). All other multipliers are based on a sliding scale with infinitely numerous points between 6 and 0, dependent of the level of reserve in any given interval. The maximum refund multiplier is largely arbitrarily defined. That said, the current maximum factor is a risk factor that Market Participants are familiar with and has also been used to set appropriate prudential requirements in the Market. Changing this factor could result in significant wealth transfers between Market Participants which would need an economic justification.

	current market circumstance taking into consideration the move from season-time of the day-type of day to reserve margin iii To give weight to the low reserve margin but to avoid penalising generators, the multiplier over the reserve margin distribution should average to 1.0 multiplier. It may be helpful to organise a workshop to canvass and appropriately resolve this aspect. With the Reserve Capacity Price reduced when the accepted Reserve Capacity Credit exceeds the Reserve Capacity Target, the Market Generators receive a lower sum for their capacities. When some of these Reserve Capacity Credits are not provided, such as when a planned generator is not built, the Market Generators will have earned less than what they would have. As a way of compensating the Reserve Capacity Credit Participants, the Reserve Capacity Security forfeited could be argued to be more appropriately distributed to those Reserve Capacity Credit Market Participants. On page 105 of 117 under the section "Security deposit issues" the last sentence suggests that distributing the forfeited Reserve Capacity Security to Market Customers is consistent with the basis for Market Customers obligation to fund capacity. This needs thinking through. Through Reserve Capacity Refunds, the Market Customers would have already received back the Reserve Capacity Credit payments made. Distributing the forfeited security to Market Customers could be over-refunding.	At this stage, there does not appear to be a strong economic rationale for changing it. Unfortunately there is no supporting evidence to substantiate that this would yield a better balance in incentivising short-term and long-term generator behavior. This argument is not supported as risk to reliability of supply is highly asymmetric. Generators are protected in the sense that an average multiplier of 1.0 would achieve by the annual cap on refunds The price of capacity credits is a much broader issue than that being dealt with here. Security provided by new entrant Capacity Credit holders is in place to provide a construction incentive to ensure the timely delivery of capacity to the required specification as accredited in the Reserve Capacity Certification process and is in effect a risk weighted contribution to the future SRC costs (ideally the expected value of forfeited refunds over time should match expected SRC costs due to construction delays). The philosophical view of who is potentially disadvantaged by a non delivery of this capacity has historically lay on the side of Market Customers who bear an IRCR cost and potentially the SRC Cost.
System Management	1. The IMO proposes that Net STEM Shortfalls be removed from the Market Rules as a basis for imposing Capacity Refunds. The net stem shortfall calculation is made up of 2 components being The equation SF(p,d,t) = RCOQ(p,d,t) - A(p,d,t) + Max(0,	The current regime automatically penalises generators for what can be on occasion, despite best intentions and good industry practice, invariable deviations from resource plan which result in what can be considered to be highly punitive payments to the market. This mechanism is also biased against certain technologies that face a greater exposure due to the nature of their operation. The requirement to present the capacity is not

	B(p,d,t) – C(p,d,t)) has two components. The component RCOQ(p,d,t) - A(p,d,t) quantifies the amount of capacity that should have been made available but was not, while Max(0, Min(B(p,d,t) – C(p,d,t))) quantifies the amount by which metered schedules fall short of scheduled quantities. The fact that this is small may show that the incentive to make the available capacity to the STEM is working A basic foundation of the market is that capacity payments obligate the participant to offer all its capacity into the market, unless on outage or providing ancillary services By removing the net stem shortfall this incentive is removed. Another mechanism would be required to maintain this incentive I would not support the removal in its current form 2. The operational test regime This imposes a further compliance obligation on System Management in real time as "a reason to believe it may not be available" could occur at anytime 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; I think this needs to be more clearly defined before we can support this I trust these will be incorporated into your combined response	being removed, just merely replaced with a compliance focused regime. True, but this ignores the negative impacts of the current mechanism. Agree that particular incentive is removed however other commercial incentives remain and the compliance and testing regime is the be strengthened In practise, this test would be similar to the current Reserve Capacity testing regime that is long developed in the Market Rules, is well understood by Market Participants and is embedded in the operational practises of some Market Participants. The test could also be conducted, in theory, ex-post, again in a similar methodology to the Reserve Capacity testing regime, where generator performance would be critiqued based on historical meter/SCADA data.
Synergy	Synergy understands the proposal as presented comprised three main elements with a fourth being added during the discussion. 1. Substitute a sliding scale refund factor for fixed	

	refund factors set out in the Refund Table of clause 4.26.1 of the Market Rules; 2. Remove the liability for refunds for shortfalls in capacity presented to the market for other than forced outages; 3. Create an SRC fund into which refunds are initially paid with any surplus refunded through one of two options; and 4. The final disposition of the refunds as to whether they should continue to be paid to retailers, as they are now, or exclusively paid to generators, or paid to generators on the achievement of an arbitrary forced outage level. ***(i) Sliding Scale Refund Factor*** Synergy understands that the refund arrangements form an integral part of the Reserve Capacity Mechanism (RCM) which itself can be considered as representing a contract for performance between customers and the market, with the latter represented by the IMO. The refund arrangements create the financial incentive for generators to maximise the availability of their capacity to the market (i.e. customers) when it is most valuable. Currently, the value indicator for lack of availability is embodied in the Refund Table in clause 4.26.1 of the Market Rules which sets out the fixed refund factors applicable across the year. Synergy notes that the fixed refund factors represent an approximation of when capacity it is likely to be more valuable and when it is likely to be less valuable. Synergy agrees that a dynamic refund factor mechanism, one that takes into account actual reserve levels at any point in time, would better reflect the relative value to customers of the scarcity of capacity. A dynamic refund factor mechanism also provides a better basis for generators when planning short-term outages. That is, a dynamic refund factor mechanism better signals the real time value of capacity which generators can take into account in deciding to take or defer a forced outage. In theory, this should lead to capacity availability responding to real time relative scarcity signals, rather than their annualised approximation as embodied in the current Refund Table.	The shape of the curve used in the dynamic refund regime aims should also aim to provide a balance between incentivising long and short term planning behaviour of generators. The issues raised by Synergy about the detail of the profile around critical min threshold are substantive– but these relate to short term signals and the aim of this design was to balance short and long term. Theory would say only that long term can be measured by the sum of short term and expect rational responses and risks. There are 2 problems with this. A capacity market with a minimum reserve margin is by definition not prepared to consider a price based risk – so the principle espoused/implied by Synergy in their response is a non starter. Secondly, the theory stated above is very narrow and presumes the only factor in decision making is the expected long term revenue risk. This is not supported by commercial decision making processes which once these are taken into account give a different answer. Put another way the theory presumes a purely spot pricing approach gives the same answer as a risk managed approach and the evidence is that it does not. For example market with energy only spot prices and voluntary hedge contracting see high levels of voluntary risk management and vertical integration

	If it is desirable to further explore a dynamic refund factor mechanism concept, then the pivotal issue is how its shape should be determined. Synergy has concerns that the shape presented in the proposal does not adequately represent the relative scarcity of capacity to customers. As the reserve margin declines, it is unequivocal that customers face a higher risk of non-supply and therefore place a higher value on capacity being available. This should be clearly signalled to generators through the refund factor shape; to do otherwise is to forego the use of a scarcity signal as a basis for decision-making by generators and embed an avoidable inefficiency in the market. In regard to the shape of the refund factor, the IMO may wish to consider: (i) It to rise very sharply (possibly asymptotically) as the reserve margin falls below a critical minimum threshold of MW reaching a zenith of 20 times at a zero reserve margin; (ii) In theory the factor should be uncapped (reflecting the value customers have on have supply available) but in practice it needs to be capped to limit investor risk; (iii) The critical minimum threshold to be determined by reference to rule clauses 4.5.9(a) and 3.10 (i.e. this represents the minimum level of margin required to operate the system reliability and maintain system security). Linking the critical minimum threshold to these security values overcomes the inherent problem of selecting a fixed threshold in a system experiencing growth; (iv) A zero value factor should be set at a reasonable level compliant with a shorter term planning horizon and not the same criteria established for major outage planned years in advance; (v) Synergy therefore suggests the market could consider a zero factor commencing at maximum of 1,000 MW	

	but likely at a lower value; (vi) It to take the form of a straight line[6] joining the minimum threshold defined under (iii) and the maximum threshold defined under (iv/v); and (vii) Capacity available from Demand Side Management Programmes (certified to provide 454 MW in 2012/13) should be excluded when determining the reserve margin threshold values as the nature of such capacity means it has limited scope (available hours) to replace the energy lost on account of forced outages. The rationale underlying Synergy's observations are: (i) It should clearly signal the value customers place on having a minimum reserve margin available and as it falls below the critical minimum level generators should be highly incentivised to defer maintenance or accelerate the return of plant from unauthorised outages to absolutely minimise the risk of customers suffering a loss of supply; (ii) It should be such that most of the refunds are incurred when the reserve margin is between the critical minimum and maximum thresholds and little, if any, incurred when the reserve margin falls below the critical minimum threshold; (iii) It should deliver the minimum possible refunds consistent with customers facing the minimum possible risk of loss of supply as ultimately refunds costs are passed through to customers; and (iv) It should be capped.	Arguably the proposal achieves all of these points and also provides a degree of comfort about longer term incentives and balances prudential risk in the market
	(ii) Remove Net STEM Shortfall triggered refund Synergy understands that the net STEM shortfall refund is designed to incentivise capacity providers to make their capacity available to the level credited, authorised outages excepted. The obligation to make credited capacity available to the market is a fundamental cornerstone of the Reserve Capacity Mechanism.	Under the current refund regime, certain technology types are exposed differently than others dependent on their operation patterns and interaction in the Market. The removal of the automatic refund generated by the Net-STEM Shortfall is aiming to provide a more equitable regime where technology types are not discriminated on the basis on their technology type and frequency of operation.

[6] Synergy would also consider two line segments such that the lower segment had a reduced gradient and the high segment had a steeper gradient reflecting the differing levels of reserve capacity scarcity.

	Synergy also understands that concern has been expressed that the net STEM shortfall mechanism results in an "imbalance" in the risk exposure faced by capacity providers. Higher capacity factor capacity providers (typically generators with low SRMC) incur a higher exposure than lower capacity factor capacity providers (typically peaking generators or DSM with high SRMC). Synergy recognises that this observation can be made but is reluctant to acknowledge it as a "concern". In Synergy's view, the potential for differential exposure is merely an outcome of the characteristics of the different technologies from which capacity can be sourced. The market has paid for and expects capacity to be fully available; the fact that high capacity generators are typically dispatched to their accredited capacity levels, reflecting their lower levels of SRMC, is an appropriate economic outcome. The fact that such generators may face a net STEM shortfall penalty is also reasonable as it incentivises the return of derated capacity thus ensuring that the market returns to its most efficient point of production as quickly as possible. Synergy understands the proposal to be considered is that the net STEM shortfall be replaced with an "Operational Test". In other words, it is proposed that an automatic compliance incentive mechanism that targets the most efficient production of energy, is to be replaced with a manual oversight system that will likely impose higher costs on Market Participants as a result of its monitoring and other operational requirements. Further, it is unclear to Synergy how this proposal would better achieve the goal of maximising the capacity available to the market so that the market operates at its most efficient point thus minimising costs across the market as a whole. At this stage, until there is a better understanding of the Operational Test proposals and its associated likely increase in costs to be funded by Market Participants, Synergy believes that the case for moving from an automatic compliance mechanism is not strong. In Synergy's view, it is difficult to accept a proposal that would likely weaken the incentive to return derated capacity to service, on account of the net STEM shortfall being deleted, and likely impose additional costs on the market.	There would be additional processes that would need to be developed with a move from an automatic refund regime to a manual compliance regime. The aim of replacing the automatic refund regime imposed by the Net-STEM shortfall calculation is to alleviate, what could be considered as, a highly punitive outcome for inadvertent deviations from resource plans by generators – the current provisions presume that variations in operational capability for plant operating at efficient levels is indicative of failure to provide capacity and this is not always the case. The move to a more compliance based regime would reduce some costs but increase others . The IMO notes that there are pros and cons in implementing this proposal and the RDIWG should consider these when deciding whether to progress this scope of work. The IMO notes the concerns regarding the inclusion of additional information regarding the introduction of an Operational Test. As the design is still at a conceptual stage, there is still further detail to be developed once the general principle has been endorsed by the RDIWG.

	(iii) Create SRC Fund and distribute surplus Synergy acknowledges that it is the IMO's prerogative to initiate an SRC process if and when it forms the view, on the information before it at the time, that the market will be short of capacity. Accordingly, it is difficult to budget for SRC costs and equally difficult to pass to customers such unpredictable costs as customers, quite reasonably, believe that they have met their capacity obligations through IRCR charges. Synergy, therefore supports the creation of an SRC Fund for the purpose of retaining capacity refunds which can be used as the first source from which an SRC event would be funded. Issues that the IMO may wish to consider prior to creating the framework to support an SRC Fund are: (i) What is an appropriate target level or target range for the quantity of funds to be retained? Synergy suggests that a target range is probably more appropriate reflecting periods of lower and higher risk of an SRC process being required. The floor and ceiling limits of the range would reflect values agreed by the MAC with the target for any year set by the IMO one or two years in advance of the start of the relevant capacity year reflecting the IMO's assessment of the relative risk of an SRC process being required, possibly based on, among other data, the Statement of Opportunities current when the decision was made. (ii) Whether Market Participants can elect not to participate and elect to have their due refunds paid to themselves as opposed to the fund. Synergy suggests that elective choice would reduce the benefit of establishing the fund (i.e avoiding cost shock from an SRC event) and would favour a non-elective requirement to participate which would also avoid making the mechanism more complex; (iii) Once refunds paid to the fund exceed the target level any excess would be distributed to Market Participants. If the non-elective requirement is adopted then procedural equity would suggest that refunds are returned to the Market Participants who otherwise would have received those refunds but for the advent of the SRC fund. In this regard, Synergy	To preserve the simplicity of the design, the IMO considers any application of the fund would need to apply to all Market Customers. The IMO notes that there may be complex settlement implications associated with the implementation of a cyclic fund that would possible require a re-write of the settlement timelines to accommodate the lagging effect of return the refunds required by a cyclic implementation of the fund.

	favours Approach 2 (Cyclic Market SRC Fund) as presented to the RDIWG (in agenda item 3) at its 22 February meeting. ***(vi) Allocate refunds to Market Generators as opposed to Market Customers*** Recently it was suggested that it was timely to review the distribution of Reserve Capacity Credit refunds. Currently, the Market Rules provide that refunds are paid to Market Customers in proportion to their IRCRs. At issue is whether such payments should be distributed to Market Generators and not Market Customers, as is currently the case. Such an amendment, if it proceeds, would be significant and requires careful consideration. This is because it would change one of the fundamental market tenants: that generators are paid by the market (i.e. customers) to be available and are required pay refunds when they are not - planned outages excepted. There is an elegant economic balance about this: customers pay for a service and when it's not provided, they are reimbursed their payments. Further, paying refunds to generators for failing to meet capacity obligations, as opposed to customers who initially funded the capacity credits, would remove a key driver for generators to maximise plant availability. In effect, the market would be signalling that failure to meet capacity obligations were of no consequence and it falls on customers to bear the cost. The potential logical extension of this proposal (through the process of non-discrimination against different technologies) to Demand Side Management programs may change the preparedness of customers to drop load if ultimately they were the beneficiaries of the refunds. Another fundamental tenant of the market is that there is no Force Majeuré – this has not changed since market start. Generators seeking to invest in the market typically manage the forced outage risk by including a cost premium in energy off-take agreements. That is, through such agreements, customers already pay for forced outages. To proceed with a proposal that would see generators receiving forced outage refunds would in effect result in	The IMO agrees that any such change that involves the allocation of refunds to Capacity Credit holders (Market Generators) would be a fundamental change to the design of the refund mechanism and would require careful consideration. The IMO notes that the current design of the Market SRC Fund does not seek to make changes to the fundamental concept that refunds are allocated to Market Customers. The intention here is to withhold refunds to supplement the Market SRC Fund (in essence socialising the processes of allocating fund for the purpose of procuring SRC, which would have normally been undertaken internally by Market Customers). The distribution of refunds would continue as per the current market design, once the Market SRC Fund has reached the maximum level.

	customers paying twice for non-performance; once in the PPA price and once via non return of the refund. This would be an untenable situation, one that would, in contract terms, amount to a "change in law" and result in unproductive energy contract renegotiations to recover PPA embedded forced outage premiums. Synergy notes that discussions on this topic invariably point to the magnitude of the refunds, as opposed to the concept of the refund itself given that it is well understood that Force Majeuré is not part of the market design, as being the key factor giving rise to concern. In that regard, Synergy notes that the high cost of refunds reflects the high Reserve Capacity Price, rather than any change in underlying forced outage rates. In fact, over the five years ending with the 2012/13 capacity year, the Reserve Capacity Price increased at an annual average rate of 17.4% per annum to be $186,001/MW. Synergy therefore suggests effort should be directed to addressing the high Reserve Capacity Price and its high rate of growth rather than deconstructing one of the fundamental tenants on which the market design is based.	

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.
66	The IMO to review the decision to prohibit Market Customers from either over- or under-stating their demand. When doing so, the IMO to discuss the issue with System Management in greater detail to assess how critical the proposed amendment is.	IMO	9	Proposal to revert to the status quo.
67	The IMO to further discuss the STEM operational issues with Andrew Sutherland and John Rhodes.	IMO	9	Done
68	The IMO to update the scenario to include summation information.	IMO	9	The Project Team is developing a model for MPs to use.
69	The IMO to meet with Mr Dykstra to discuss the marginal price outcome in the scenario in greater detail.	IMO	9	Done
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	
74	When undertaking the Cost Benefit Analysis Sapere is to draw on work of ROAM/SKM/ACIL Tasman and MMA (if appropriate).	Sapere	9	Done
75	Sapere to provide members with its volume and modelling assumptions for the Cost Benefit Analysis.	Sapere	9	Included in final report and appendix.
78	The IMO to show all incremental changes to papers in tracked changes.	IMO	9	Done
79	The IMO to remove late entry of Griffin Energy in the quantitative analysis in the refunds paper.	IMO	9	Done

Table 2: Completed since last meeting

#	Action	Responsibility	Meeting arising	Status/Progress
65	The IMO to publish the minutes of Meeting No.8 on the website as final.	IMO	9	Completed.
71	The IMO to circulate a collated copy of all the submissions received on the Balancing Market Proposal to members.	IMO	9	Completed. Circulated 22 February 2011.
46	The IMO to undertake a high level cost/benefit analysis for the proposed Balancing provision solution.	IMO	6	Completed.
73	Members to provide additional comments to the IMO on the Balancing proposal by 5pm, 4 March 2011.	Members	9	Completed.
76	Members to provide comments on the Cost Benefit Analysis by 5pm, 4 March 2011.	Members	9	Completed.
77	Members to provide additional comments on the project timelines and milestones by 5pm, 4 March 2011.	Members	9	Completed.
80	The IMO to consider whether refunds could be discussed prior to Balancing at the 15 March 2011 meeting.	IMO	9	Completed.
81	Members to provide additional comments on the refunds paper by 5pm, 4 March 2011.	Members	9	Completed.