Rules Development Implementation Working Group (RDIWG)

Meeting No. 9: Agenda

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

Date: Tuesday, 22 February 2011

Time: 9.30am – 2.00pm

1. Previous meeting's minutes
2. Balancing Market Proposal:
   a. Scenarios;
   b. Updated design paper; and
   c. Preliminary Cost Benefit Analysis.
3. Reserve Capacity Refunds
4. Project Timeframes and Milestones (for information only, as requested at the 1 February 2011 meeting)
5. General Business
6. Outstanding Action items
7. Next meeting date and time: Tuesday, 15 March 2011 (9.30am – 2.00pm)

Independent Market Operator

Rules Development Implementation Working Group

Minutes

Meeting No.	8
Location:	IMO Board Room Level 3, Governor Stirling Building, 197 St Georges Terrace, Perth
Date:	Tuesday 1 February 2011
Time:	Commencing at 9.30am to 2.00pm

Attendees	
Allan Dawson	IMO (Chair)
Troy Forward	IMO
John Rhodes	Market Customer
Corey Dykstra	Market Customer
Steve Gould	Market Customer
Geoff Gaston	Market Customer
Andrew Everett	Market Generator
Shane Cremin	Market Generator
Andrew Sutherland	Market Generator
Phil Kelloway	System Management (from 9.55am)
Paul Hynch	Office of Energy
Chris Brown	ERA
Jacinda Papps	Minutes
Ben Williams	Presenter
Jim Truesdale	Presenter
Greg Thorpe	Presenter
Douglas Birnie	Observer
Will Street	Observer
Richard Anderson	Observer
Adam Lourey	Observer

Item	Subject	Action
1.	**WELCOME AND APOLOGIES / ATTENDANCE** The Chair opened the 8th meeting of the Rules Development Implementation Working Group (RDIWG) at 9.30am. The Chair outlined that he had received a request to delay the meeting due to the volume and late circulation of papers. The Chair noted that he had decided to proceed due to the format of the	

Item	Subject	Action
	meeting. The Chair invited the Program Manager to explain the papers and the context for the meeting. The Program Manager noted that the intent of circulating all the papers was simply to provide members with an update on the various streams of work underway exploring the Balancing Market proposal. It was noted that the aim for today's meeting is to go through the Balancing Market design details, stage by stage, in order to explain the proposal and answer questions. The aim for the discussion is to centre in on what elements of the Balancing Market design need further work and/or greater consideration. The Chair noted that the Market Evolution Program (MEP) will be time onerous for RDIWG members in the coming three to four months and recommended members arrange internal teams to work through the detail. Members noted that these will often be teams of just one or two and that this work is additional to core operational work. The IMO committed to providing documentation as early as possible and offered to provide internal briefings as often as required. The Chair noted that the IMO received negative feedback in its stakeholder survey for not taking action on Balancing and refunds sooner and that the IMO is trying to deliver on its stakeholder expectations. In addition, there was an expectation from the survey that the business as usual/operational work would carry on to the same level. The Chair noted that it is on this basis that the IMO has been resourced to undertake the MEP. *Action Point: The IMO to add an agenda item for the next MAC meeting to discuss the work coming out of the MEP and operational rule changes.*	**IMO**
2.	**PREVIOUS MEETING'S MINUTES** The minutes of RDIWG Meeting No. 7, held on 14 December 2010, 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. on the website as final.* *Action Point: The IMO confirm how the 100 MW of Load Following aligns with the requirements modelled in the ROAM report.*	**IMO** **IMO**
3.	**BALANCING MARKET PROPOSAL: DESIGN DETAILS** Mr Ben Williams presented the Balancing Market proposed design in 12 stages; each of these stages was discussed in detail. The following high level issues/areas for further consideration were identified as needing further reflection and/or discussion: • Bilateral Submissions/STEM and Net Contract Positions: Use of STEM and changes to Resource Plans; • Resource Plans: Ramp rates and MW overshoot; • How the proposed Balancing Market and Load Following	

Item	Subject	Action
	Ancillary Services Market will interact; • Verve Energy Portfolio Supply Curve (PSC), the timing of the development of the PSC and the ability for Verve Energy to nominate standalone Facilities; • Market Forecasts: Whether high and low forecasts should be provided and the number and timing of market forecasts; and • Pricing: How constrained on/off payments should be allocated and use of generation data versus sent out data. Additionally, the RDIWG requested that the IMO develop a number of pricing scenarios to present at the next RDIWG meeting. *Action Point: The IMO to work with Andrew Sutherland to discuss the issue relating to "Use of STEM and changes to Resource Plans".* *Action Point: The IMO to review each of the issues raised and prepare the scenarios requested for the next RDIWG meeting.* *Action Point: Members to provide the IMO with additional comments on the Balancing Market proposal by 10 February 2011.* *Action Point: The IMO to convert the table on page 23 (of 75) to the energy equivalent Balancing Merit Order and circulate to the RDIWG.* *Action Point: The IMO to circulate a word version of the Balancing Market proposal paper to the RDIWG.*	 **IMO** **IMO** **Members** **IMO** **IMO**
4.	**BALANCING MARKET PROPOSAL: HIGH LEVEL BUSINESS REQUIREMENTS, SYSTEM IMPACTS, INITIAL RULE CHANGE IMPACTS AND PROCESS MAPS** It was noted that the additional information presented was for information only.	
5.	**UPDATE ON RESERVE CAPACITY REFUNDS** It was noted that the IMO is currently undertaking the quantitative analysis that the RDIWG requested, this is to assess the outcomes of the proposed dynamic mechanism using past data. It is anticipated that this information will be presented at the next RDIWG meeting.	
6.	**GENERAL BUSINESS** The RDIWG discussed the workshop scheduled for 23 February 2011. It was agreed that this was too early for this workshop to be held. *Action Point: The IMO to postpone the 23 February 2011 workshop.* A member requested whether a project plan is available. *Action Point: The IMO to include the project plan in future RDIWG meeting papers.* The RDIWG discussed what the appropriate level of detail it requires prior to making a recommendation to the MAC. The following was noted:	 **IMO** **IMO**

Item	Subject	Action
	• The RDIWG is getting close to understanding the operational impacts associated with the proposal and more examples/scenarios will assist this understanding. • A member noted that a fundamental design has been settled on and only a small amount of additional detail (specifically around Ancillary Services) is required. • A member noted that the Cost Benefit Analysis would be required prior to making a recommendation to the MAC. In response, it was noted that the work on this has commenced and will be made available as soon as it is ready for circulation.	
7.	**OUTSTANDING ACTION POINTS** The RDIWG did not discuss the outstanding action points.	
8.	**ADDITIONAL 2011 MEETING DATES** The RDIWG noted the proposed additional meeting dates.	
8.	**NEXT MEETING** Meeting No. 9 will be held on Tuesday 22 February 2011 (9.30am-2.00pm).	
9.	**CLOSED:** The Chair thanked members for their hard work during the meeting and declared the meeting closed at 1.40pm.	

Agenda Item 2a: Balancing Market Proposal, MEP Scenarios Cover Paper

1. BACKGROUND

A presentation detailing a worked scenario of the proposed balancing market for a "typical" interval was circulated to Working Group members on 11 February 2011.

The presentation details the expected behaviours for a typical interval under the balancing mechanism proposed at the last RDIWG meeting. In particular the presentation covers the expected bids/offers of an IPP and how these will be incorporated with the Verve Energy Portfolio Supply curve (PSC) in the determination of the Balancing Merit Order (BMO). It goes on to present how the Market forecasts may influence an IPP to alter their bids/offers and how this will affect the BMO and forecasted price.

This presentation has been prepared as an introduction to the concepts presented at the last RDIWG meeting and will be supplemented by further presentations detailing increasingly complex concepts and scenarios, including:

- Dispatch and Pricing outcomes of the typical interval;
- Multiple interval scenarios;
- System security scenarios; and
- Commitment/de-commitment of a facility through the balancing market.

An updated version was circulated to Working Group members on 15 February 2011. This updated scenario builds upon the information presented in the previous presentation to show how the Balancing Merit Order will be translated into Dispatch Instructions leading into an interval. The presentation also shows how, following the formulation of Dispatch Instructions, the differences between actual load and forecasted load would be accounted for through Load Following Ancillary Services. Finally the slides show how, after dispatch, the price for the interval would be calculated using the ex-post methodology.

The updated presentation is attached as Appendix 1 to this paper.

2. RECOMMENDATIONS

It is recommended that the RDIWG:

- **Note** that the scenario presentation will be worked through at the meeting.

Market Scenarios

- These notes are intended to illustrate how the proposed market arrangements will operate (as a supplement to the *12 boxes* design document)
- They provide an end to end overview of the mechanics of and interactions between balancing submissions, BMO formation, market forecasts, dispatch, pricing and settlement
- Stylised examples are used to support explanations
- The initial focus is on the mechanics from a day ahead leading to a single trading interval

Market Scenario Intro

After STEM:

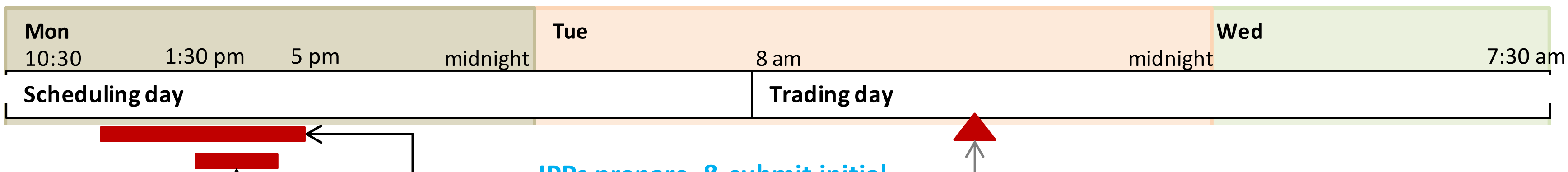
- **MPs review NCPs/own load commitments & prepare/ submit facility resource plans (as now)**

Assume 2 IPPs : Focus on one trading interval

- IPP1: 100 MW facility, submits 80 MW resource plan (flat profile)
- IPP2: 200 MW facility, submits 150 MW resource plan (flat profile)

Market Scenario Intro

Following facility resource plan submissions:



IPPs prepare & submit initial balancing submissions

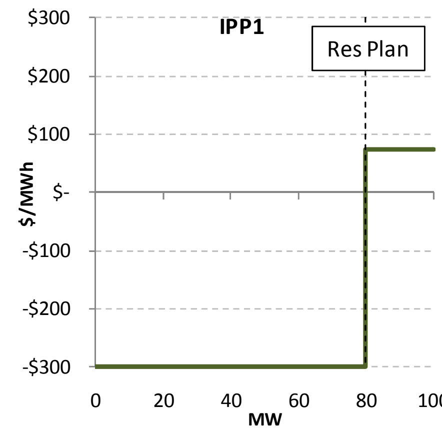
e.g . for selected trading interval

SM prepares initial VE dispatch plan:

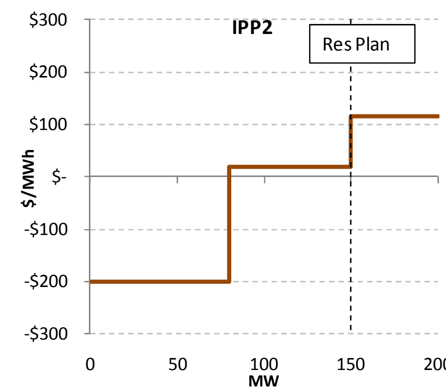
- To meet expected VE quantities (rest of scheduling day through trading day)
  - i.e. loss adjusted demand less forecast wind generation less resource plans*
- Assesses fuel requirements/ facility commitments over scheduling horizon
- Provides Dispatch Plan to VE for review (e.g. fuel requirements/ facility commitments etc)

* *For rest of current scheduling day, would also take into account latest forecast of IPP balancing dispatch*

IPP1 Submission (Res Plan = 80 MW flat)		
Parameter	MW	$/MWh
Offer (Up) 1	20	$75
Bid (Down) 1	80	-$300
Facility Capacity	100	
	Up	Down
Max MW/min	2	5



IPP2 Submission (Res Plan = 150 MW flat)		
Parameter	MW	$/MWh
Offer (Up) 1	50	$115
Bid (Down) 1	70	$20
Bid (Down) 2	80	-$200
Facility Capacity	200	
	Up	Down
Max MW/min	3	3



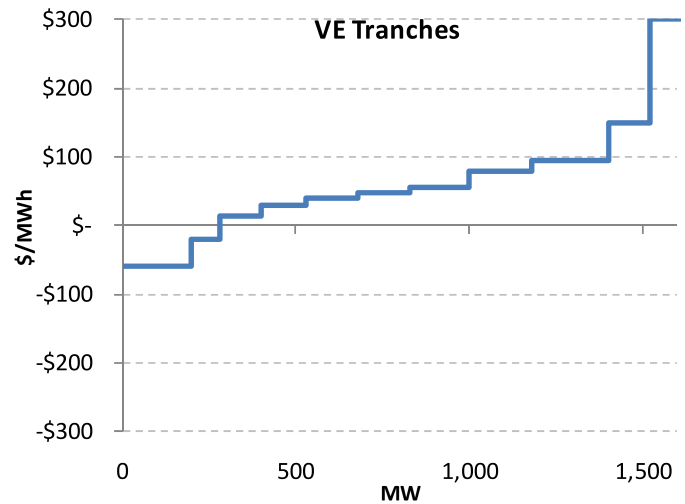
Market Scenario Intro

Following Initial VE Dispatch Plan:

VE prepares/ submits portfolio supply curve

- e.g . for selected trading interval

VE Tranches	MW	$/MWh
VEPSC11	120	$300
VEPSC10	120	$150
VEPSC9	220	$95
VEPSC8	180	$80
VEPSC7	170	$55
VEPSC6	150	$48
VEPSC5	150	$40
VEPSC4	130	$30
VEPSC3	120	$15
VEPSC2	80	-$20
VEPSC1	200	-$60



Market Scenario Intro

Following Initial Balancing Submissions:

Mon				Tue			Wed	
10:30	1:30 pm	5 pm	midnight		8 am	midnight		7:30 am

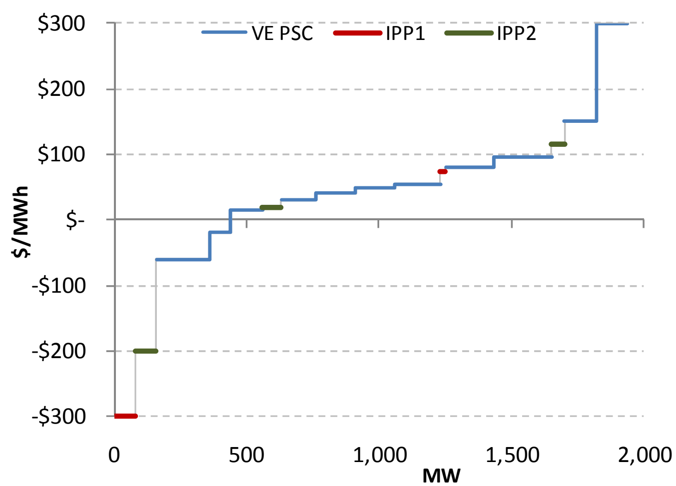
Scheduling day | Trading day

Establish Market Balancing Merit Orders (BMO) for each trading interval

e.g. IPP1 should be dispatched above its resource plan (i.e. IPP1 offer 1) before VE portfolio is dispatched above 1,000 MW (i.e. before VEPSC8 tranche).

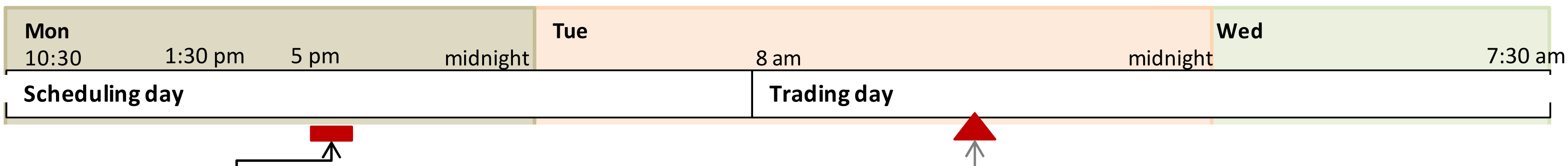
e.g . Market BMO for selected trading interval

BMO	Tranche MW range		Max MW/min		
Tranches	From	To	Up	Down	$/MWh
VEPSC11	1520	1,640			$300
VEPSC10	1400	1,520			$150
IPP2 Offer 1	150	200	3	3	$115
VEPSC9	1180	1,400			$95
VEPSC8	1000	1,180			$80
IPP1 Offer 1	80	100	2	5	$75
VEPSC7	830	1,000			$55
VEPSC6	680	830			$48
VEPSC5	530	680			$40
VEPSC4	400	530			$30
IPP2 Bid 1	80	150	3	3	$20
VEPSC3	280	400			$15
VEPSC2	200	280			-$20
VEPSC1	0	200			-$60
IPP2 Bid 2	0	80	3	3	-$200
IPP1 Bid 1	0	80	2	5	-$300



Market Scenario Intro

Following Initial BMO:



Prepare and publish market forecasts:

e.g . For market BMO for selected trading interval*:

- Total generation forecast = forecast "Relevant Dispatch Quantity" (RDQ)
- Assume forecast RDQ = 1,450 MW (avg for interval)
- Expect all tranches below VEPSC 9 to be dispatched and VEPSC9 to be marginal tranche (partly dispatched by 70 MW)

**Ignore ramp rates for now*

RDQ (MW)		BMO	Tranche MW range		Max MW/min		
From	To	Tranches	From	To	Up	Down	$/MWh
1,820	1,940	VEPSC11	1520	1,640			$300
1,700	1,820	VEPSC10	1400	1,520			$150
1,650	1,700	IPP2 Offer 1	150	200	3	3	$115
1,430	1,650	VEPSC9	1180	1,400			$95
1,250	1,430	VEPSC8	1000	1,180			$80
1,230	1,250	IPP1 Offer 1	80	100	2	5	$75
1,060	1,230	VEPSC7	830	1,000			$55
910	1,060	VEPSC6	680	830			$48
760	910	VEPSC5	530	680			$40
630	760	VEPSC4	400	530			$30
560	630	IPP2 Bid 1	80	150	3	3	$20
440	560	VEPSC3	280	400			$15
360	440	VEPSC2	200	280			-$20
160	360	VEPSC1	0	200			-$60
80	160	IPP2 Bid 2	0	80	3	3	-$200
0	80	IPP1 Bid 1	0	80	2	5	-$300

Forecast balancing price = $95/MWh

- Publish to <u>all</u> MPs

Expected VE generation = 1,200 MW

- ∑ VE tranches below VEPSC9 + 20 MW of VEPSC9 tranche (= RDQ)

Expected IPP1 generation = 100 MW

- ∑ IPP1 offer/bids below VEPSC9
- = Res Plan + Offer 1

Expected IPP2 generation = 80 MW

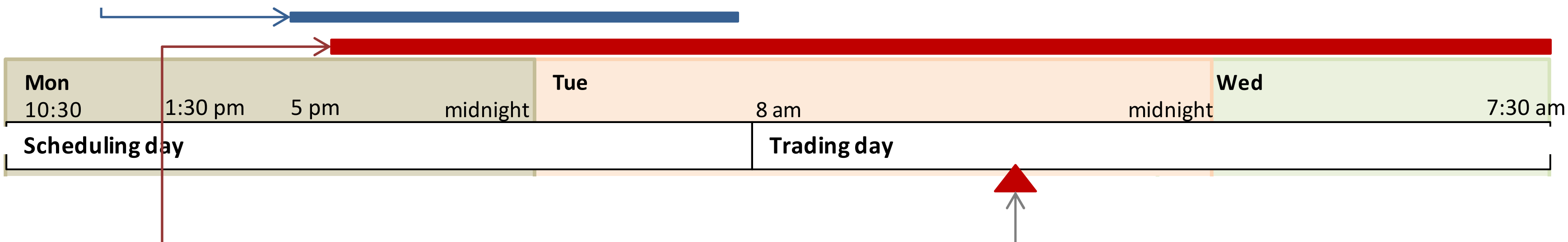
- ∑ IPP2 bids below VEPSC9
- = Res Plan

Publish forecast quantities to <u>relevant</u> MPs only

Market Scenario Intro

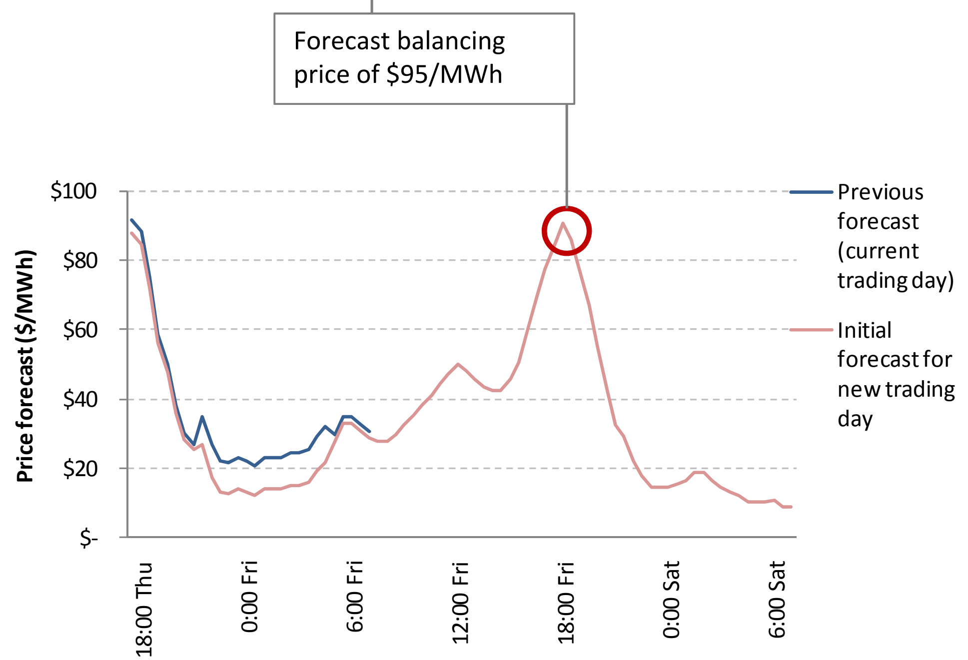
Market Forecast Horizon will extend to:

- End of current trading day (if issued prior to initial balancing submissions/ BMO)



- End of next trading day (once initial balancing submissions/ BMO available)

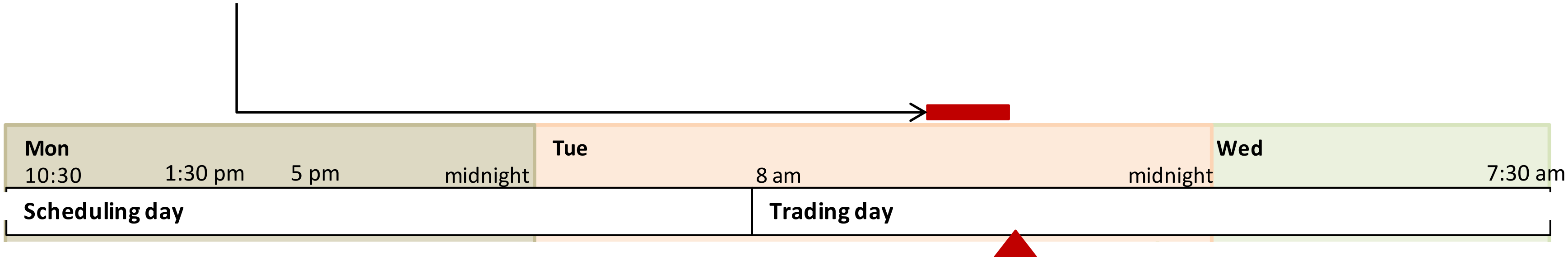
- New forecasts will be issued at regular intervals reflecting forecast generation requirements and any revisions to balancing submissions (for commercial reasons or plant conditions)



Market Scenario Intro

Revision of Facility Balancing Submissions

- **Able to revise submissions until gate closure ahead of relevant dispatch interval**



Suppose IPP2 revises its submissions in response to market forecasts. e.g.

- Market forecasts indicate overnight prices lower than expected (e.g. increased wind) and that its bid will be dispatched down for balancing down
  - which it indicated by its bid price that it is prepared to do by
- Able to shift fuel savings to higher price intervals

  (or it may to see how overnight dispatch unfolds and then revise submission)

So assume IPP1 reduces its offer1 price to $50 in peak intervals

- Reflecting lower opportunity cost than initially indicated

IPP2 Submission (Res Plan = 150 MW flat)		
Parameter	**MW**	**$/MWh**
Offer (Up) 1	50	$50
Bid (Down) 1	70	$20
Bid (Down) 2	80	-$200
Facility Capacity	200	
	Up	**Down**
Max MW/min	3	3

Market Scenario Intro

Market Update Cycle

Mon				Tue		Wed	
10:30	1:30 pm	5 pm	midnight	8 am	midnight		7:30 am
Scheduling day				Trading day			

Assume no other changes to balancing submissions:

- Market BMO would be revised accordingly
- Assume forecast generation requirement for relevant interval is unchanged (1,450 MW)

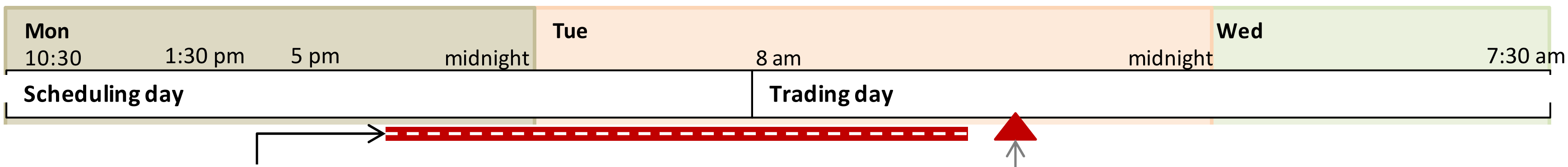
IPP2 offer 1 now sits lower down in the BMO:

- Forecast IPP2 generation increases by 50 MW (IPP2 offer 1) from 150 MW to 200 MW
- Forecast VE portfolio generation reduces by 50 MW
- The VEPSC8 is expected to be the marginal tranche (instead of VE PSC9)
- Forecast balancing price reduces from $95 to $80 per MWh

RDQ (MW)		BMO	Tranche MW range		Max MW/min		
From	To	Tranches	From	To	Up	Down	$/MWh
1,820	1,940	VEPSC11	1520	1,640			$300
1,700	1,820	VEPSC10	1400	1,520			$150
1,480	1,700	VEPSC9	1180	1,400			$95
1,300	1,480	VEPSC8	1000	1,180			$80
1,280	1,300	IPP1 Offer 1	80	100	2	5	$75
1,110	1,280	VEPSC7	830	1,000			$55
1,060	1,110	IPP2 Offer 1	150	200	3	3	$50
910	1,060	VEPSC6	680	830			$48
760	910	VEPSC5	530	680			$40
630	760	VEPSC4	400	530			$30
560	630	IPP2 Bid 1	80	150	3	3	$20
440	560	VEPSC3	280	400			$15
360	440	VEPSC2	200	280			-$20
160	360	VEPSC1	0	200			-$60
80	160	IPP2 Bid 2	0	80	3	3	-$200
0	80	IPP1 Bid 1	0	80	2	5	-$300

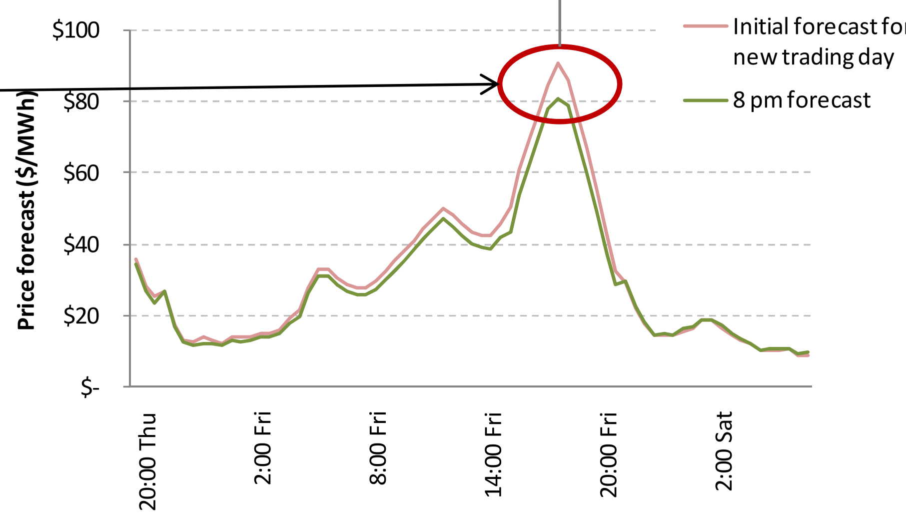
Market Scenario Intro

Revised Market Forecasts



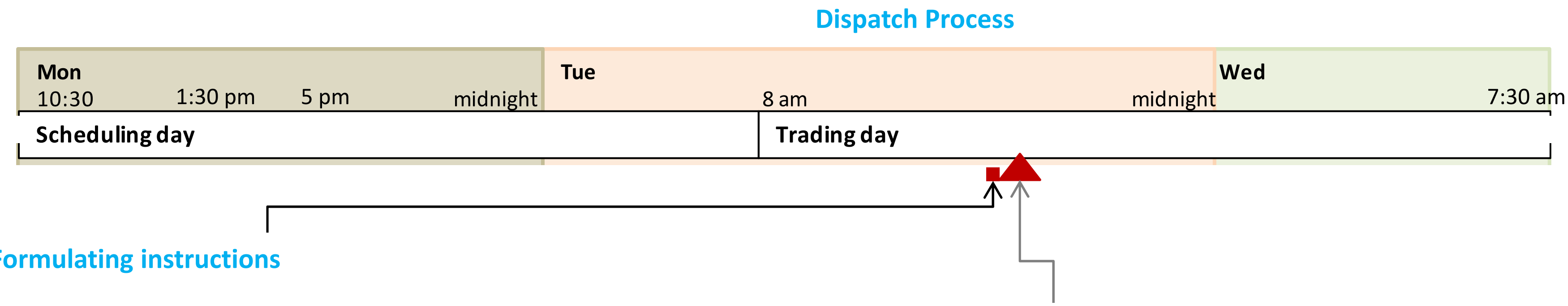
Revised market forecasts issued to MPs:

- Reflecting revised submissions
  - e.g. for selected interval, IPP2 now expected to be dispatched ahead of VE PSC, reducing balancing price to $80
- Of course, changes in demand/ wind forecasts will also affect market forecasts
  - e.g. for current example, for 50 MW increase in forecast RDQ, expect VEPSC9 tranche to be dispatched and balancing price back to $95/MWh



<u>Multi-interval scenarios, including commitment decisions, are discussed later.</u>

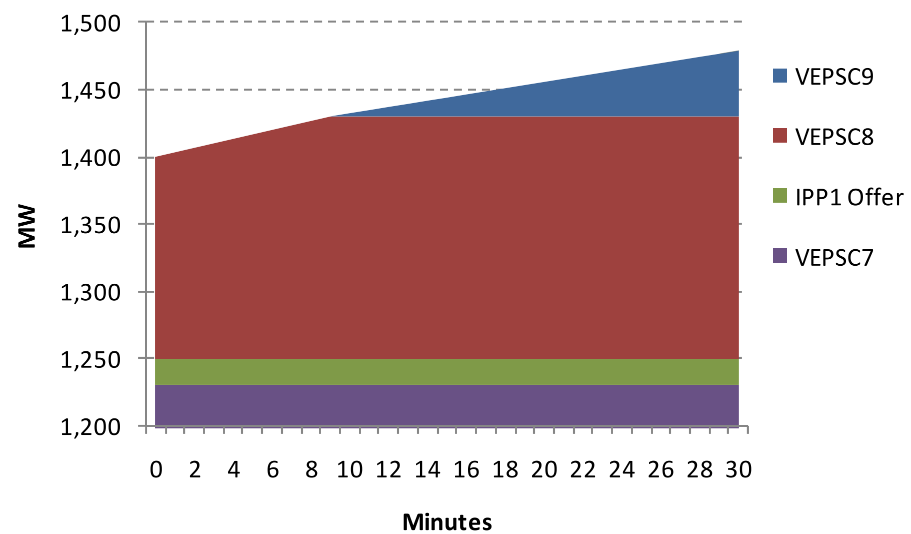
Market Scenario Intro



Formulating instructions

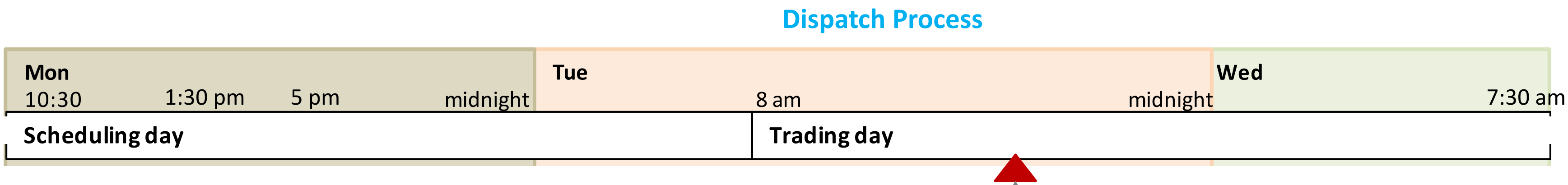
Approaching a dispatch interval, SM will estimate the trend in RDQ (total generation demand) through the interval and, using a dispatch support tool, will formulate dispatch instructions for the interval in the form of MW targets and ramp rates

- e.g. assume the RT BMO is the same as market BMO in the original example
- SM estimates the RDQ will trend from 1,400 MW to 1,500 MW during the interval
- assume the same RTBMO in the previous interval (to simplify start of interval generation)
- dispatch instructions would be issued to VE to ramp portfolio generation to meet the expected trend in RDQ



- in this example, only VE tranches need to be dispatched
- SM would decide which VE facilities to instruct (in accordance with VE guidelines and the Dispatch Plan) to meet aggregate RT BMO requirements

Market Scenario Intro



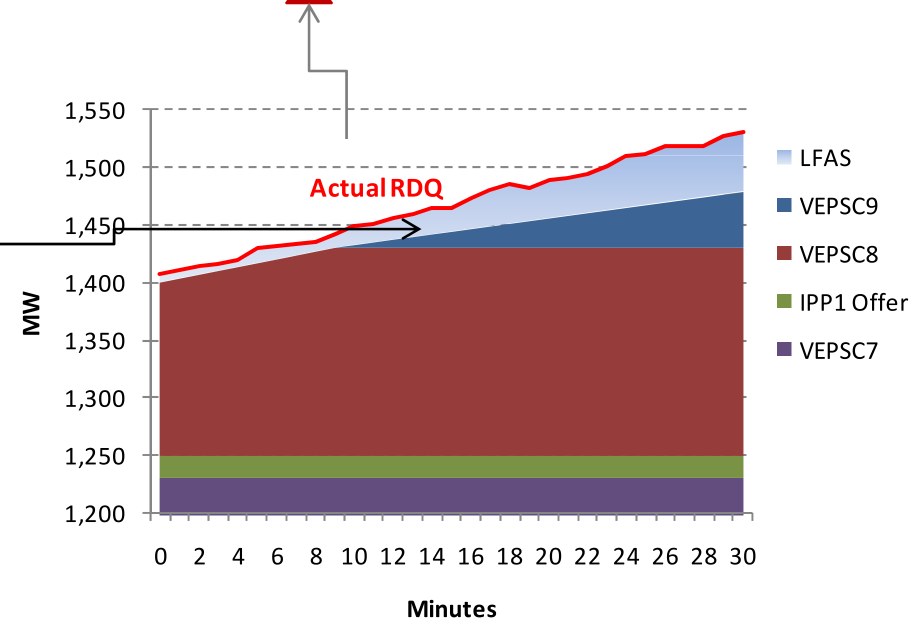
Practical issues:

Actual generation requirements (RDQ) during an interval will inevitably differ from estimated trends

- as illustrated, LFAS typically compensates for this
- however, if LFAS service approaches upper or lower limits, SM may need to reissue dispatch instructions during an interval

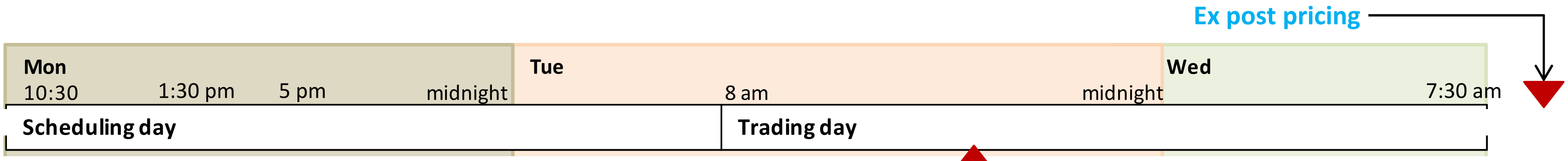
Actual generation will vary from instructed levels

- e.g. generator governor response to system frequency
- actual ramping responses, delays etc



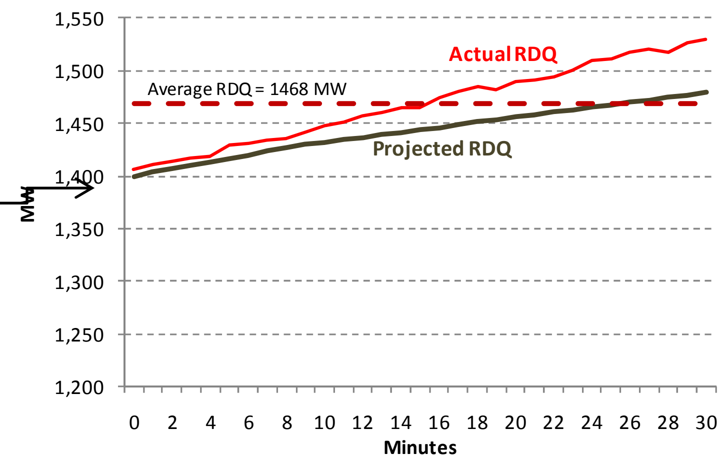
<u>Ex post pricing arrangements and constrained on/off settlements compensate for such uncertainties within the dispatch process</u>

Market Scenario Intro



Balancing price will be calculated from actual RDQ energy (ERDQ) in an interval and amounts final of energy in BMO tranches which could have been dispatched

- e.g. for original example, suppose the average RDQ was 1,468 MW (ERDQ = 734 MWh)



- using simplifying assumption that RTBMO is same from one interval to the next, amounts of energy that could have been dispatched from each RT BMO tranche are:

RT BMO Tranches	Max MWh	Cum MWh From	Cum MWh To	Price $/MWh
VEPSC11	60	897	957	$300
VEPSC10	60	837	897	$150
IPP2 Offer 1	12.4	825	837	$115
VEPSC9	110	715	825	$95
VEPSC8	90	625	715	$80
IPP1 Offer 1	10	615	625	$75
VEPSC7	85	530	615	$55
VEPSC6	75	455	530	$48
VEPSC5	75	380	455	$40
VEPSC4	65	315	380	$30
IPP2 Bid 1	35	280	315	$20
VEPSC3	60	220	280	$15
VEPSC2	40	180	220	-$20
VEPSC1	100	80	180	-$60
IPP2 Bid 2	40	40	80	-$200
IPP1 Bid 1	40	0	40	-$300

- The marginal tranche would have been VEPSC8
    - i.e. ERDQ of 734 MWh falls within this band
- So price is $95 per MWh

Agenda Item 2b: Updates on Balancing Design Details

1. BACKGROUND

At the 1 February 2011 meeting the IMO presented, and the RDIWG discussed, the key aspects of the "New Balancing Market proposal – design details" paper. It was agreed that:

- The IMO would develop scenarios detailing the operation of the proposed Balancing mechanism;
- RDIWG members would provide the IMO with comments on the Balancing design details paper; and
- The IMO would incorporate the comments into the Balancing market design details paper and present the adjusted paper at the 22 February 2011 RDIWG meeting;

Appendix 1A provides a table summarising the issues, questions and comments raised at the RDIWG meeting along with the IMOs preliminary responses to those comments.

Additionally, the IMO received comments on the Balancing design details paper from the following RDIWG members:

- System Management;
- Verve Energy;
- Alinta;
- ERM;
- Synergy; and
- Perth Energy.

In total the submissions received comprised of approximately 150 individual comments, concerns or issues with the Balancing design details paper. Due to the large number of the comments received, the IMO is not able to respond to each comment individually in this paper. However the IMO has summarised the comments into 17 key points. These points and the IMOs preliminary responses to each can be found in appendix 1B.

Due to the short timeframe required for RDIWG members to provide responses to the IMO, many of the submission received are in not in a format appropriate to be published. As such the IMO proposes to work individually with the submitting RDIWG member to work through their comments prior to the March 15 2011 RDIWG meeting.

Appendix 2 presents an updated version of the "New Balancing Market proposal – design details" paper. The paper has been updated to include changes resulting from RDIWG members' issues, questions and comments. Additions to the paper presented to the RDIWG on 1 February 2011 are marked in underlined while deletions are marked with ~~strikethrough~~. For completeness a clean copy will also be emailed to RDIWG members.

2. RECOMMENDATIONS

The IMO recommends that the RDIWG:

- **Discuss** the high level overview of key processes relating to the operation of the proposed Balancing market;
- **Endorse** the IMO response strategy for working through RDIWG member's submissions individually with the members who made the submissions;
- **Agree** to provide the IMO with any further comments on the updated Balancing design details paper prior to 28 February 2011; and
- **Note** the IMO will incorporate member's comments into a final design details paper to be presented and discussed at the 15 March 2011 RDIWG meeting with the aim for the RDIWG to endorse the design be sent to MAC.

APPENDIX 1A: RESPONSES TO COMMENTS RAISED AT 1 FEBRUARY 2011 RDIWG MEETING

Clause/Issue	Submitter	Comment/Change Requested	IMO's response
Use of STEM and ability choose to buy from Balancing.	RDIWG discussion	In response to the IMOs suggestion that there will be no changes to the current STEM and NCP processes, a member noted that the current STEM process "forced" any Load which the corresponding generators could not meet to be cleared in STEM. This member would prefer the ability to set this load aside to be settled at the Balancing price.	The IMO committed to looking into this issue to see if it was possible for a generator to set aside a Load to be cleared in Balancing as opposed to STEM – the worked example of the findings can be found in Appendix 3. In summary the IMO found that a Generator is required to buy any shortfall from their net bilateral position from the STEM. The IMO considers that that the STEM is a contract settling mechanism with the premise that, other than for system security issues, there is a physically viable implemental plan locked in a day ahead. Therefore the IMO contends that there is no reason to change the current operation of the STEM in this regard. A change to allow an optional Balancing quantity would have two main impacts: 1. there is a greater amount of overall load which System Management would be required to balance the system for; and 2. if retailers wished they could choose to ignore the STEM altogether and instead choose to operate in a more "real time" market, the IMO sees this as a fundamental departure from the day ahead market design, which presumes accurate day ahead nominations. Furthermore the IMO proposes that the ability for Market Customers to understate their demand should also be removed from the Market Rules.

Clause/Issue	Submitter	Comment/Change Requested	IMO's response
Requirement for the Resource Plan to indicate a MW target for the end of the interval equal to double the MWh amount implied in Net Contract Position (NCP) + Self Supplied Load (SSL).	RDIWG Discussion	The IMO proposed that the form of Resource Plans be amended such that when the NCP + SSL amounts needing to be generated changed from one interval to the next, participants would structure their Resource Plans such that their generators would ramp from the start of an interval to a MW target twice the MWhs indicated in NCP + SSL. Resource Plans would thus comprise self dispatch instructions consistent with the form of System Management dispatch instructions for Balancing purposes. Facility Balancing submissions are also in the form of MW, relative to Resource Plan levels, and ramp rates. The RDIWG indicated that it was uncomfortable with the fact that this would require them to be exposed to Balancing for any shortfall (surplus) due to ramping up (down) to the target MW level for the interval.	The IMO proposes to amend its design so that if participants wish they may ramp up (down) to a target MW level above (below) the load implied by twice their NCP + SSL MWh in the first interval that requires change to output so that on average the MWhs over the interval is equal to the MWhs required by NCP + SSL. However the IMOs design proposal will still require participants to conform to the new Resource Plan format indicated in the last design details paper. This format requires Resource Plans to be formulated so that there is only one linear ramp rate from the start of an interval plus a fixed MW target for the rest of the interval. This will mean that while the ability of participants to minimise their exposure to Balancing by "overshooting" or "undershooting" their MWh implied target, there may still be some exposure to the Balancing price – for more information on this please refer to section 3.2.3 of the design details paper which has been amended to incorporate the change.
How the proposed Balancing and Load Following Ancillary Service (LFAS) market will interact?	RDIWG discussion	The RDIWG wished for the IMO to further expand upon its proposal for a joint Balancing and LFAS market.	The Balancing design details paper has been updated to incorporate more details on the proposal for the LFAS market – the majority of the proposed LFAS market design details can be found in section 3.4 – Balancing offers/bids and Verve Energy Portfolio Supply Curve and Load Following Ancillary Service offers (Box 4). The IMO considers that the principles provided for the LFAS market design are at a sufficient level of detail to endorse the concept of joint implementation with the Balancing design. As such the two work streams should be developed in parallel through the rule change process– this is a departure from the time frames indicate at the last RDIWG meeting[1].

[1] At the last RDIWG meeting the IMO proposed that the LFAS market be developed at a two month lag to the Balancing market.

Clause/Issue	Submitter	Comment/Change Requested	IMO's response
			The IMO notes that a number of details in regards to the LFAS market are subject to decisions being made in regards to the Balancing market design, for example gate closure and Verve Energy re-nominations.
Verve Energy's Portfolio Supply Curve (PSC) submissions	RDIWG Discussions	The RDIWG requested more information in regards to how and when Verve Energy would be eligible to submit, and in particular resubmit, its PSC	The IMO has amended the design paper to clarify that the original verve PSC will be submitted at the same time as the first IPP bids and offers. For Verve Energy's PSC to be as accurate as possible (and hence reduce the need to re-submit the PSC at a later date) it is required that this will occur after System Management has an ability to incorporate updated forecasts and IPPs Resource plans, and also after Verve Energy has made its gas nominations. It is assumed that the PSC (and first IPP bids/offers) will be required by 5PM. Additionally, the IMO considers that Verve Energy will be eligible to resubmit the PSC once before the start of the trading day This ability to re-submit the PSC has been included to allow Verve Energy to update assumptions that were made when submitting the original PSC the day before, subject to a gate closure period of [4 to 6 hours]. The IMO understands that there may be perceptions of Verve Energy having additional flexibility but notes that Verve Energy is required to make SRMC based submissions, has a considerably longer gate closure period than IPPs and will continue to be the default balancer, having to respond to uncertain Balancing requirements. The IMO proposes that Verve Energy would be required to incorporate any physical changes (other than actual facility Forced outages) into this updated PSC.
Clarification around Verve Energy "standalone" facilities.	RDIWG Discussion	The RDIWG requested more information in regards to the process for Verve Energy to nominate standalone Facilities from its portfolio.	The IMO has updated the design details paper to specify that Verve Energy will be entitled to split out any Facility it chooses from its portfolio, subject to System Management approval (on the basis of capability/ systems being in place and/or system security). The IMO notes that removing a facility from the portfolio will

Clause/Issue	Submitter	Comment/Change Requested	IMO's response
			increase Verve Energy's participation in ongoing Balancing decisions (which are currently undertaken by System Management on behalf of Verve Energy). As such the IMO considers that it is appropriate for Verve Energy to have the ability to trial a facility as a standalone facility. The design paper has been further updated to specify that Verve energy will have the ability to "split out" a facility on a trial basis for one month prior to formal removal from the portfolio. Verve Energy will be required to seek System Management approval for standalone status of a facility at least one week prior to the facility being split out on either a trial or permanent basis.
Market Forecasts	RDIWG Discussion	Whether high and Low forecasts should be provided and the number and timing of Market forecasts.	The IMO has updated the design details paper to clarify that market forecasts will be provided (at least initially) on a two hourly basis. With a review into the adequacy of the market forecast to be completed after two years Additionally the paper also clarifies that market price forecasts will include high and low demand sensitivities for +/- 1% of the forecast RDQ. This will provide better information to participants regarding expected market prices and their scheduled Balancing quantities/ likelihood of being dispatched
Pricing	RDIWG discussion	How should constrained on/off payments be allocated?	The IMO has updated the design details paper to show that constrained on/off payments will be allocated to Market Customers proportional to their energy use in the interval the payment was made. The rationale for this allocation is that it can be argued that there are two types of constrained/on off situations. 1. local security / out of merit dispatch; and 2. within half hour effects. Ideally both of these effects would be captured directly in the marginal price. However, in regards to point 1 the WEM does

Clause/Issue	Submitter	Comment/Change Requested	IMO's response
			not have locational marginal prices, but theoretically the "local" price within a constrained area would be the price of the offer or bid constrained or off. If that were so, then generators and customers within the affected area would receive/ pay the local marginal price. Instead, under the design, the generators will receive/pay constrained on/off costs (to keep them whole in terms of offers/ bids dispatched by System Management). Ideally, the next best thing to the theoretical ideal of local customers paying a locational marginal price would be to allocate/ recover constrained on/off costs to/from customers within the affected area. At present such costs are allocated/ recovered from all market customers so it is proposed to retain the same approach. In relation to point 2 within half hour effects would ideally be reflected in the marginal Balancing price although that would require a much shorter dispatch and pricing interval and is impractical. Allocating within half hour costs to Market Customers (as now for pay as bid dispatch) therefore makes sense. The alternative of creating an uplift component to the Balancing price would be a significant change, especially if within half hour effects were to be treated differently
Pricing	RDIWG discussion	On what data should pricing be based on?	The IMO has updated the design details paper to clarify that prices will be set the day following the trading day and will be based on the average MWhs sent out over an interval as measured by System Managements SCADA systems. While prices will be set based on the SCADA system, final Balancing quantities will still be settled based on the current arrangements in the market rules for example SCADA for Verve Energy Facilities and Meters for IPP Facilities.

APPENDIX 1B: Responses to key points raised by RDIWG members in submissions on the Balancing Design Details Paper

Issue	Comment/Change Requested	IMO's response
Cost/ benefit analysis and incremental benefits	A number of the submissions received expressed a desire to see the cost benefit analysis of the proposed Balancing market. Further the submissions questioned the incremental benefits associated with implementing the entire Balancing market proposal compared to the majority of the benefits being captured for a low proportion of the cost, for example, by implementing a clean Balancing price.	A working draft of the high level cost benefit analysis is being presented to the RDIWG as part of the 22 February 2011 meeting papers. This work is aimed at assessing the merits of the balancing proposal with the status quo. Work undertaken over the past few months by the IMO consultants working to the RDIWG assessed a number of variations on the current design for trying to secure a cleaner balancing price and more competition in balancing. The option being assessed now is the only option that appears likely to achieve this without fundamentally changing the current design or, alternatively, effectively reverting to the status quo. Some of the currently suggested "simpler" options would in the IMO's view simply largely replicate the outcomes of the status quo that would lead to little or no real competition and no improvement in transparency. Additionally the minutes from of the RDIWG meeting 3 (30 September 2010) state: "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."
Verve PSC submissions, re-submissions and the formulation of the Verve Dispatch Plan	A number of the submissions refer to Verve Energy's ability to submit (and re-submit) it's PSC. There were no submissions which recommended against Verve Energy having the ability to re-submit its PSC. With a number suggesting that Verve energy should be able to re-submit up to the same gate closure as IPPs. There were also a number of issues raised about the Verve Energy Dispatch Plan (the service	Please see the IMO response to issue: "Verve Energy's PSC submissions" in Appendix 1A for the IMOs rationale in relation to Verve Energy's ability to re-submit. In regards to the Verve Energy Dispatch Plan, the IMO notes that the ability for re-submission by Verve Energy resolves a number of issues, and the IMO will continue to work with Verve Energy and System Management on any outstanding issues.

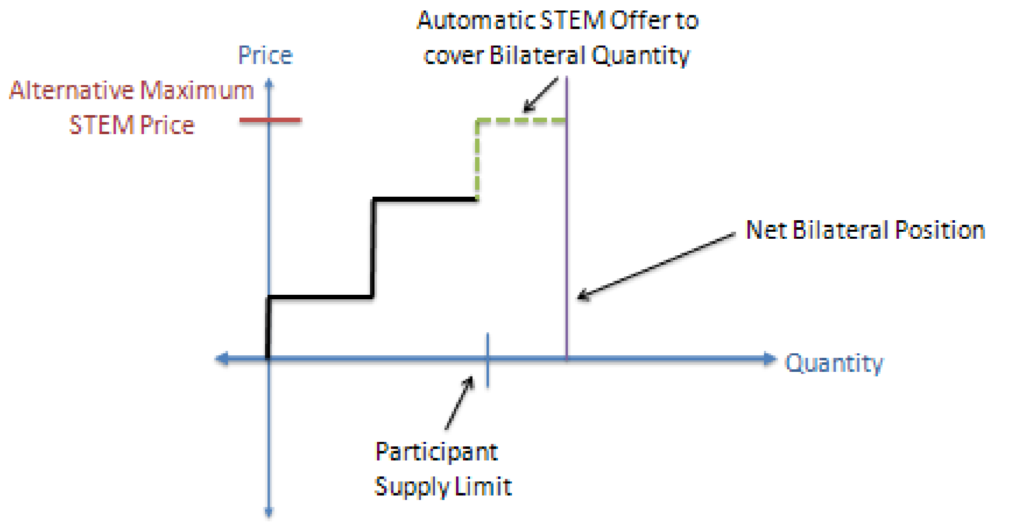
Issue	Comment/Change Requested	IMO's response
	System Management provides for Verve Energy).	
The proposal for Verve Energy to move towards Facility only bidding.	There were a number of proposals both for and against the ability for Verve energy to be "required" to move towards Facility based bidding.	The IMO considers that voluntary incentives work best. The proposed market design provides such voluntary incentives without *requiring* Verve Energy to move to Facility based participation. As such, the IMO has amended the paper to remove the concept that further work into a pathway for Verve to participate in Balancing on a Facility basis is required.
More details on the Balancing and LFAS Markets.	There were a number of questions raised around the operation of the LFAS Market and how it would interact with the proposed Balancing market.	Please see the IMO response to issue "How the proposed Balancing and LFAS market will interact?" in Appendix 1A.
Timing of proposed changes and implementation risks	There were a number of questions regarding the expected timing of the Balancing and LFAS market implementation. There were also a number of submissions that contained concerns that either the IMO, System Management or Market Participants would not be able to meet the timeframes being proposed by the IMO for implementation of the Balancing and LFAS Markets.	The IMO notes that in regards to the expected implementation of the Balancing and LFAS markets the IMO has provided Market Participants with a detailed draft implementation plan at the 1 February 2011 RDIWG meeting. This implementation plan specified that the IMO is aiming for a market trial at the beginning of December 2011 and commencement of a Balancing market at the beginning of April 2012. The IMO also notes as stipulated in appendix 1A it is now proposed to implement the LFAS market along the same timeframe. In regards to risks associated with the implementation of the Balancing and LFAS markets, the IMO is confident that it can deliver the changes in the timeframes proposed in the implementation plan. However the IMO also notes that should other Rule Participants have concerns that they will not be able to implement the required changes that there is a process as part of the Rule Change Process which specifically allows people to specify these concerns. If the IMO deemed it appropriate at the time the IMO could extend the implementation date of any rule change.
The impacts of proposed changes for Market Customers	A number of submissions raised concerns that the IMO had not provided any indication of the benefits, costs and impacts the proposed design would have on Market Customers	The IMO is committed to providing detailed scenario analysis for Market Participants, including a workshop which has been scheduled on 16 March 2011 at which any interested parties may attend and ask specific questions. The IMO is also willing to arrange individualised meetings with interested stakeholders to work through any questions they may have about the new Balancing market. The IMO also notes that in the WEM the Balancing service covers contractual mismatches, with inaccurate demand forecasts being a

Issue	Comment/Change Requested	IMO's response
		significant determinant of Balancing. To the extent that Balancing can be delivered more efficiently and cost effectively, Market Customers will benefit from that. The IMO contends that the proposed Balancing market will deliver a competitive Balancing market which will ultimately deliver economically efficient outcomes for retailers.
IPP bids/offers, Gate Closure and re-submission of bids/offers	Most Submissions made comments as to either the: • Process for IPPs to adjust their bids/offers; • Need for IPPs to have flexibility in providing bids/offers; and/or • The need for a rolling gate closure	The IMO notes that the RDIWG recommended that the IMO pursue a Balancing market design which allowed for simple facility based bidding for IPPs. This recommendation was made in the context of IPPs requiring flexibility to re-nominate their incs and decs for different intervals across the day to respond to changing market conditions and manage constrained fuel supplies/ commitment decisions. The IMO notes that it has issued a number of papers outlining the benefits which are associated with IPPs having flexibility to adjust bids and offers, these benefits range from the increases in cost reflectivity in the Balancing price through to making commitment/de-commitment decisions possible through the Balancing market. The IMO contends that the remaining issue to be resolved in respect to gate closure is the timing of the rolling gate closure. The IMO is currently working on scenarios with System Management to help determine an appropriate gate closure period.
Market Mechanics	A number of submissions indicated that additional information on the mechanics of a real time market would be beneficial.	The IMO has delivered a worked scenario on how the market is proposed to work in a typical trading interval, and is committed to providing ongoing examples involving more complex scenarios. The IMO has also provided public and private workshops on the operation of the proposed Balancing market and will continue to offer ongoing support and training opportunities for interested stakeholders.
Inter-temporal effects	Concerns around how inter-temporal effects will be accounted for in the Balancing market design for example, start up times	The IMO notes that IPPs will need to account for and manage inter-temporal effects in constructing and updating their offers/bids. System Management will continue to manage the commitment of facilities within Verve Energy's portfolio consistent with the Verve Energy Dispatch Plan and "guidelines".
STEM Operation	Questions were raised regarding whether it is appropriate for generators to be forced to buy	For a detailed response to the requirement for generators to buy from the STEM please refer to the response to issue "Requirement for Resource

Issue	Comment/Change Requested	IMO's response
	from STEM when their Net Bilateral Position is negative, especially when this is not a requirement for retailers as they are able to understate their demand.	Plan to indicate a MW target for the end of the interval equal to double the MWh amount implied in NCP + Self Supplied Load (SSL)" in Appendix 1A. In regards to a retailer being able to effectively "choose" to buy from Balancing the IMO notes that it has amended the design paper to incorporate a requirement on Market Customers to not understate their demand
Clarification on individual issues and recommended grammatical changes	A number of individual clarifications on different clauses were requested. A number of grammatical changes were also recommended	The IMO notes that it will respond to each of these issues on an individual basis.
Pricing	Clarification around different aspects of the proposed pricing process was requested.	Please refer to the response to issue "Pricing" in Appendix 1A.
Timing of events and responsibilities of IMO, System Management and/or Market Participants	Clarity in regards to responsibilities and timing of many of the different events was requested.	The IMO notes that the RDIWG was provided with process maps detailing the roles and responsibilities of different rule participants, as well as indicative times for each of these processes. These process maps will be continually updated and provided to the RDIWG on a periodical basis. Responses to individual queries will be provided to the relevant Rule participant as part of the IMOs response strategy outlined in the cover paper above.
Resource Plans	General agreement for the proposed Resource plan format was provided. However clarity around the "linear" ramp rates was requested. The definition of "appropriate ramp rates" was also asked to be better defined	The IMO notes that the design details paper has been amended to clarify that 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 IMO has amended the design details paper to better explain the concept – the document now states: "System Management will accept/reject Resource Plans in response to system security concerns caused by Resource Plans. The design paper also specifies that the conditions and actions System Management can/will take in such system security scenarios will be defined in the Market Rules, Market Procedures and the Power System Operation Procedures. As such System Managements powers in accepting/rejecting will be subject to the Rule change and Procedure change processes."
Balancing Merit Order	A number of questions were raised regarding how	RDIWG members have been provided with a scenario detailing how bids

Issue	Comment/Change Requested	IMO's response
(BMO) and Real Time BMO (RTBMO) construction	the BMO and RTBMO would be constructed.	and offers will be converted into the BMO. This scenario is to be explained by the IMO at today's meeting. The IMO will provide further scenarios to RDIWG members, one of which will detail how changes will be incorporated into the RTBMO.
Dispatch (including system security provisions)	The dispatch processes and also the situations and powers that will be provided to System Management in system security situations were questioned.	The IMO notes that RDIWG members have been provided with a scenario detailing the expected operation of a single trading interval, including an example of how dispatch decisions will be made. Further the IMO will endeavour to provide further worked before the March 15 2010 RDIWG meeting. Additionally the IMO is currently developing scenarios with System Management to assess practical requirements from System Management's perspective, including system security issues. In any event though, the overarching wide authority for System Management to manage the security of operation of the SWIS will be maintained.
Compliance regime	More details on the compliance regime need to be provided	The IMO has committed to conduct a review of the likely compliance requirements. The IMO will provide the outcomes of this review to the RDIWG when it has been completed.
Curtailable, Dispatchable and Interruptible Loads	How will CLs be handled in the Balancing Market	The incremental benefit of including CLs in the Balancing market design needs to be compared to the cost of inclusion.

APPENDIX 3: Example of Automatic STEM offer for Market Generator



In the above figure the Market Generators Supply Curve is short of the Net Bilateral position. In this instance, an additional offer is automatically generated which extend the supply curve to the Net Bilateral Position (Appendix 6(c)). This offer is priced at the Alternative Maximum STEM Price, which means that a Market Generator that is short on its bilateral position is forced into a STEM exposure.

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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.

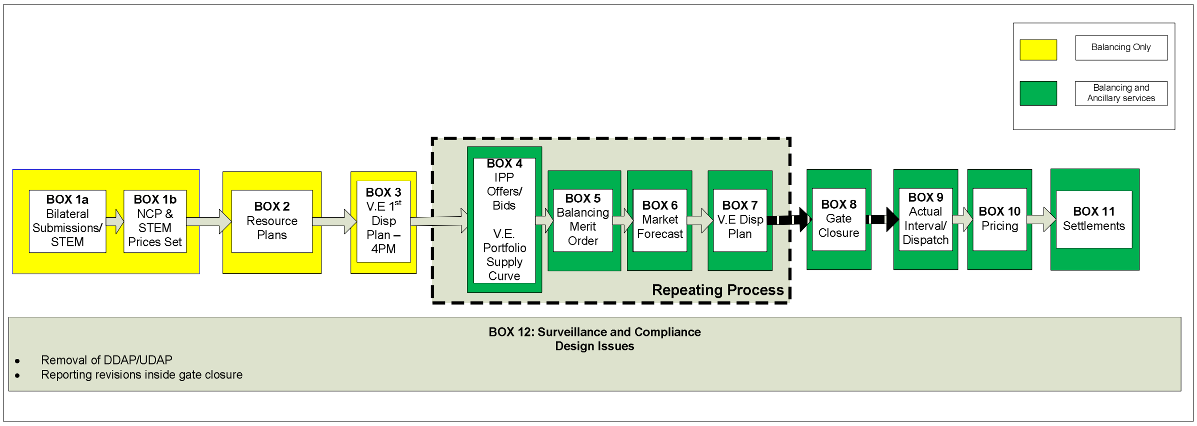
Sections 1 and 2 provide a high level overview (see figure 1). Section 3 provides additional detail of the proposed design in 12 stages.

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).

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- 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).

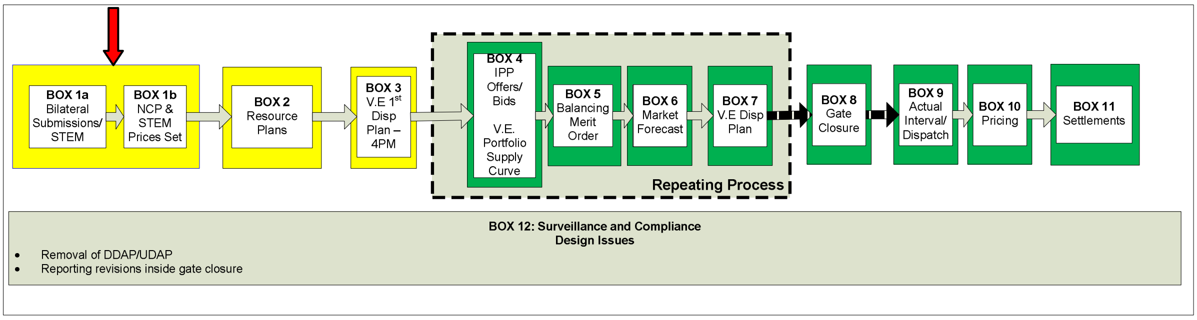
3. DETAILED DESIGN

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 for Generators.

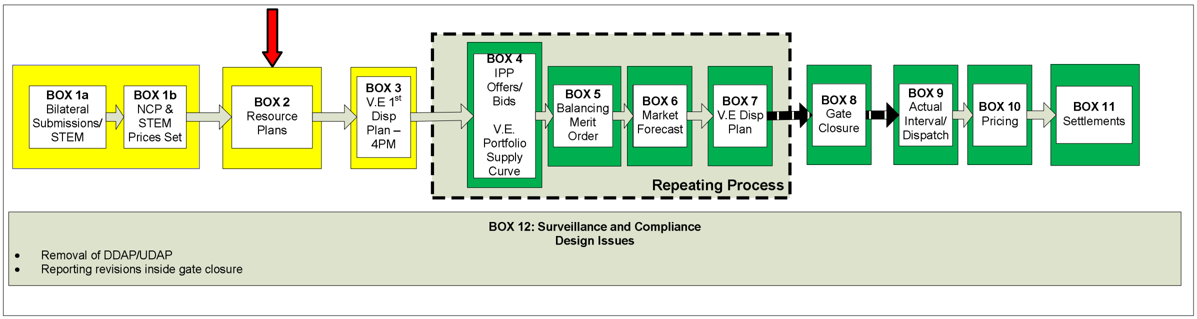
- Market Customers will be required to provide accurate day ahead nominations in their STEM Submissions:

    - They should neither over or understate their demand.

3.2 RESOURCE PLANS (Box 2)

3.2.1 Purpose:

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



3.2.2 Background:

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

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

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

3.2.3 Proposal:

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

- For each dispatch interval, RPs are to specify a MW target (sent out) with a specified ramp rate from a specified time:
    - This will make the format of the implied self dispatch instructions through RPs consistent with the form of System Management dispatch instructions for Balancing in any interval (subject to development of necessary dispatch support tools).
    - Facilities operating to a RP will thus ramp up or down linearly in an interval and will be operating at a nominated level by the end of the interval.

- The linear ramp rates must be realistic estimates of how the participant will dispatch the facility to meet the target level specified, accepting that for practical reasons a facility may not be able to ramp continuously at a uniform rate. However, the specified ramp rate should reflect the time the participant expects to take, from the start of the interval, to ramp to the specified target MW level.

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

- System Management will accept/reject RPs in response to ~~inappropriate ramp rates at inappropriate times~~system security concerns caused by RPs.

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

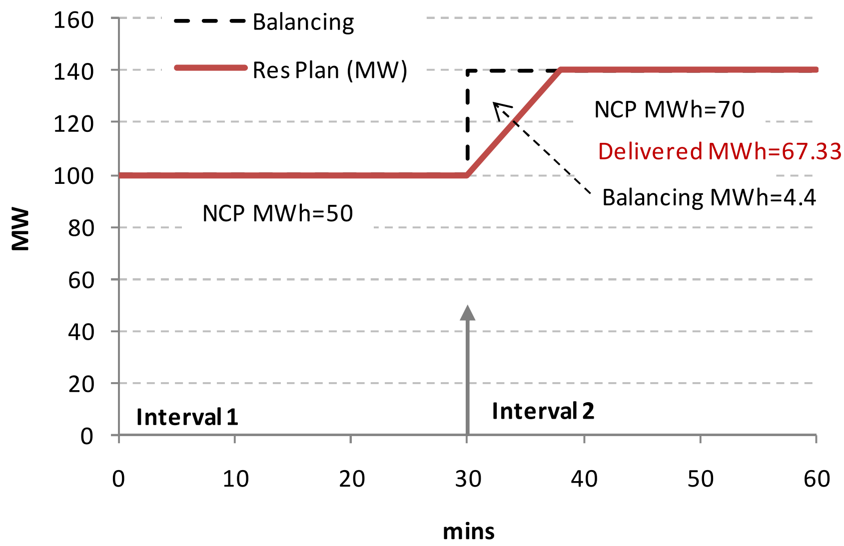
- RPs in each interval from each Market Participant must match the energy (MWh) in the corresponding NCP except when the NCP changes from one interval to the next.

    - When NCP changes from one interval to the next a RP may indicate more or less energy than the relevant NCP, this may ~~reult~~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 ~~providing that the MW dispatch level by the end of the interval aligns with the MW level that would have been required to match the NCP for that interval. This is illustrated in the following example.~~

    - 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.



- 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

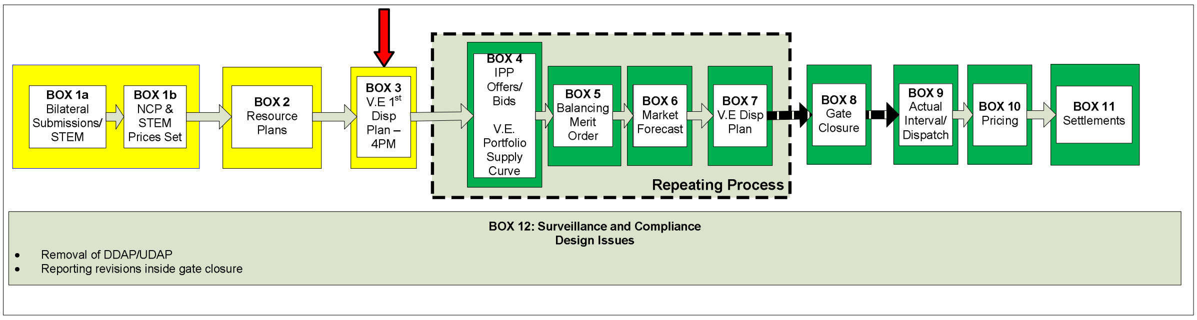
  - Requires multiple adjustments to operating levels and Balancing on other facilities for no other reason than the account for the half hour settlement of the market.

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:

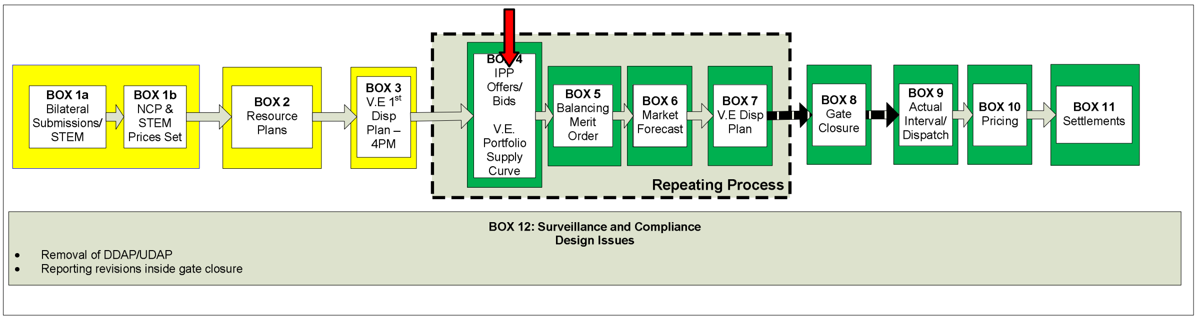
- The Market Rules will require System Management to provide dispatch plans in accordance with the Verve Dispatch Guidelines. As a minimum System Management must provide Verve an initial dispatch plan before Verve is required to submit Balancing offers/bids.

- 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 ~~providers~~ 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.

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 ~~yet to be defined set gate closure times~~the beginning of the trading day (say 8 am) and/or when ~~material/ demonstrable changes to the assumptions~~a Facility within the PSC experiences a demonstrable physical outage to one of the Facilities within ~~underpinning~~ the Portfolio Supply Curve ~~that effect the tranches submitted (further work required to define conditions and compliance implications)~~.
- 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.

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

~~3.4.3 Further work:~~

- ~~Conditions such as the notice period and any opportunity Verve should have to take a Facility back into its portfolio require further work (lack of flexibility may be a barrier to transfer and too much flexibility will add to the operation burden of System Management and IMO software);~~

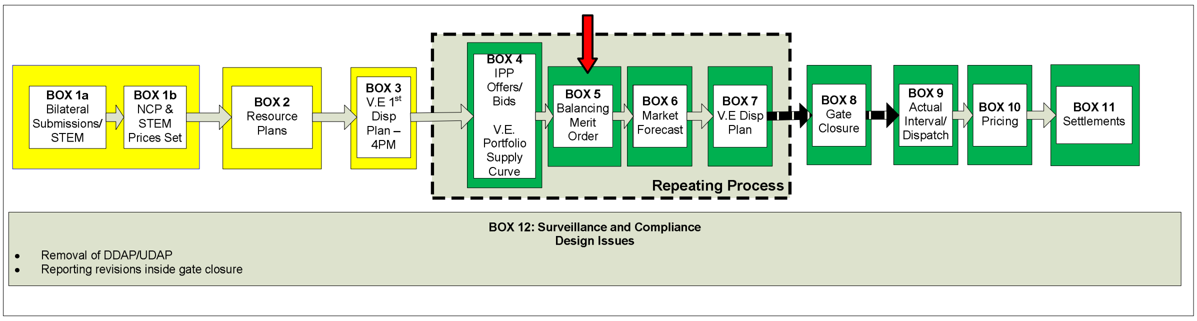
- ~~What conditions should Verve be eligible to renominate it’s Portfolio Supply Curve; and~~

- ~~To ensure that the most competitive outcomes are achieved, define a pathway for Verve to participate in the Balancing market on a Facility only basis.~~

3.5 BALANCING MERIT ORDER (Box 5)

3.5.1 Purpose:

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



3.5.2 Proposal:

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

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

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

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

- Offers or bids with identical prices will be identified/linked in the BMO/ RTBMO. Their treatment in forecasting and dispatch is discussed later.

- Note that it will not be practical to identify Verve liquids facilities specifically within the BMO/RTBMO unless Verve submits them for Balancing on a Facility basis. i.e. quantity/price pairs within Verve's Portfolio Supply Curve are not linked to individual facilities. Discussed further in relation to dispatch.

3.5.3 Further work:

- Review impact on mechanics of Intermittent Loads in the BMO.

- Incorporating curtailable, dispatchable and interruptible load into the BMO.

3.5.4 Example:

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

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

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

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

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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.

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).

	MW Range	
ID	**From**	**To**
VE PSC	1,610	2,060
IPP2	100	150
VE PSC	1,410	1,610
IPP1	40	50
VE PSC	1,030	1,410
IPP2	50	100
VE PSC	950	1,030
IPP1	25	40
VE PSC	560	950
Wind1 Down	50	0
VE PSC	360	560
VE PSC	0	360
IPP2	0	50
IPP1	0	25

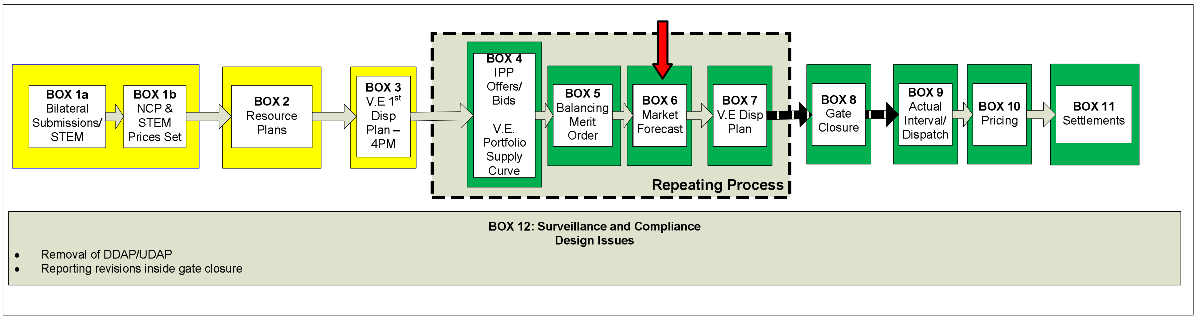
2 Resource plans will be in the form of ramp rate and MW target as discussed earlier. This is ignored here for simplicity but will need to be accounted for in formulating dispatch instructions.

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);

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

    - Expected Balancing price (to all Market Participants);

    - Expected balancing price if RDQ is +/- 1%; and

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

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

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

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

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

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

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

Appendix A includes an overview of the above processes.

3.6.3 Further Work:

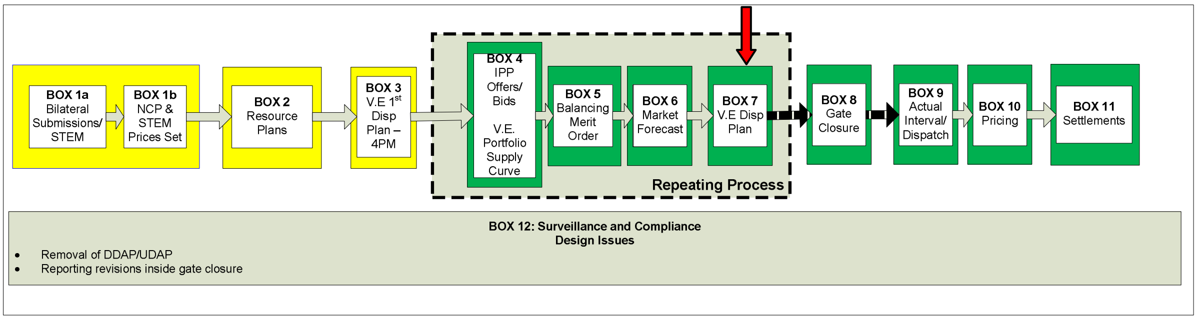
- ~~Should high/low forecasts be provided so that IPPs can see if they are close to a price collapse?~~

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

3.7 VERVE ENERGY DISPATCH PLAN (Box 7)

3.7.1 Purpose:

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

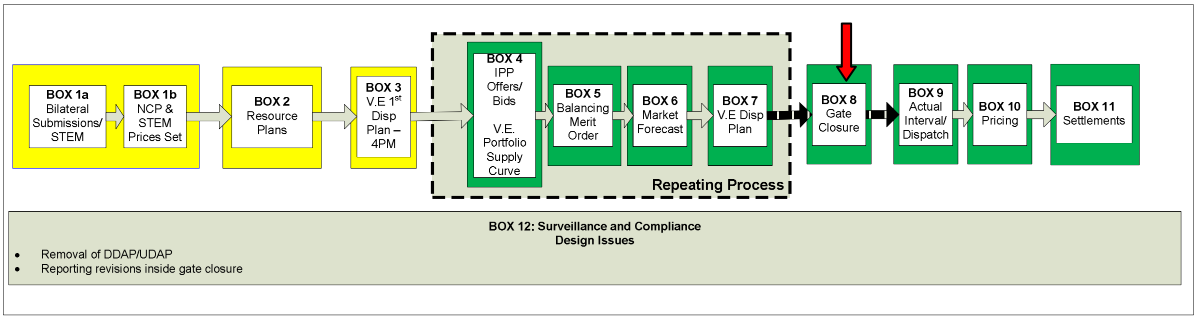


The Verve dispatch plan is prepared by System Management as a service to Verve within the hybrid design and reviewed as needed. In updating the Verve dispatch plan, System Management is in effect undertaking a review and revisions to Balancing bids/offers for facilities within the Verve Portfolio Supply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

3.8 GATE CLOSURE (Box 8)

3.8.1 Purpose:

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



3.8.2 Proposal:

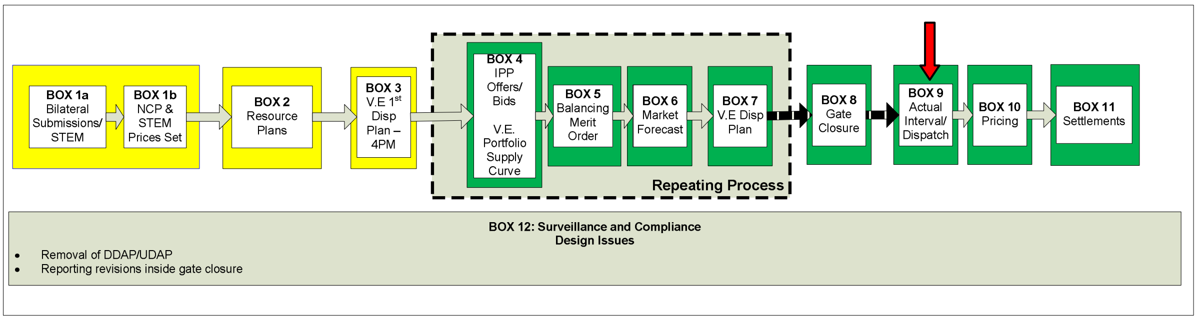
- At fixed gate closure times and/ or when a major change in circumstances occurs, such as a Facility failure or having to switch a Facility from gas to liquids Verve may update its portfolio supply curve.
- Up to a normal rolling gate closure, say 2 hours, ahead of dispatch intervals IPPs (and Verve for standalone facilities) may resubmit Facility bids and offers for Balancing/Ancillary Services relative to their Resource Plan.
- Normal Facility gate closure requirements may be relaxed if System Management issues a system security advisory indicating a supply shortfall forecast or a supply excess forecast. In these cases Market Participants would be able to increase their offered quantities inside the normal gate closure period in response to a System Management supply shortfall advisory. Market Participants would be able to increase bid quantities (e.g. to effect a de-commitment) within the normal gate closure if System Management has issued a supply excess advisory notice.

- Once normal gate closure has occurred, changes to the BMO/RTBMO will still be required (eg 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 ~~GATE CLOSURE~~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 Services3. The load following Ancillary Service tracks the instantaneous difference between demand, including losses, and all other production. This principle is unchanged from the status quo.

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

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

3.9.3 Proposal:

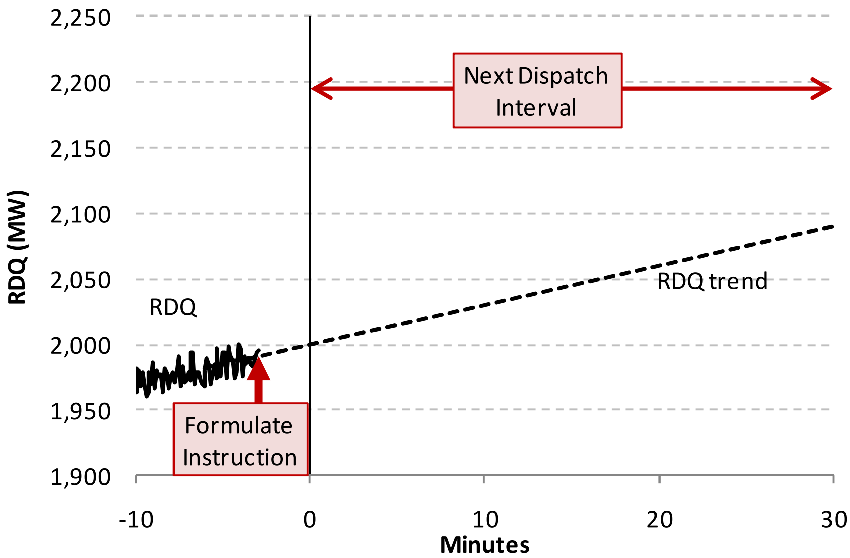
- System Management will use the RTBMO to formulate Balancing DIs.

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

- If the facilities providing LFAS are to change, relevant LFAS providers would be instructed to enable/disable the service and System Management would bring the relevant facilities into/out of the AGC system.

- Prior to a dispatch interval, System Management will estimate the underlying MW trend in total generation requirements during the next dispatch interval.

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



- 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:

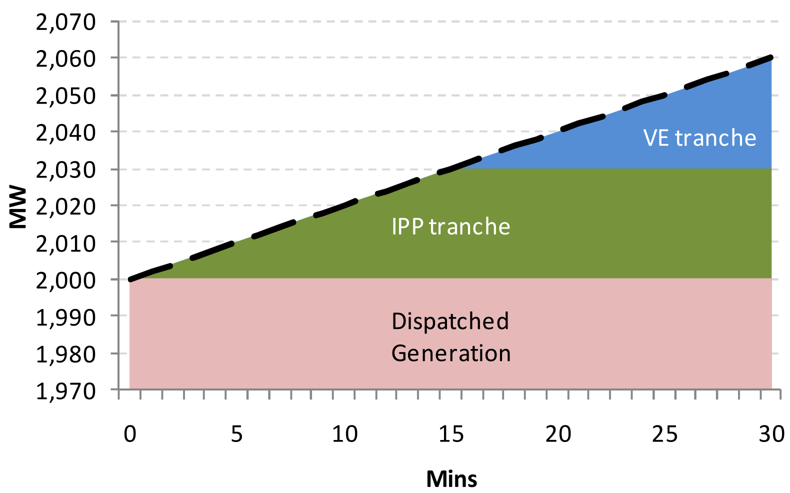
    - For an IPP or Verve standalone Facility, an instruction is relative to RP (assumed to be zero if no Resource Plan submitted).

- 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:

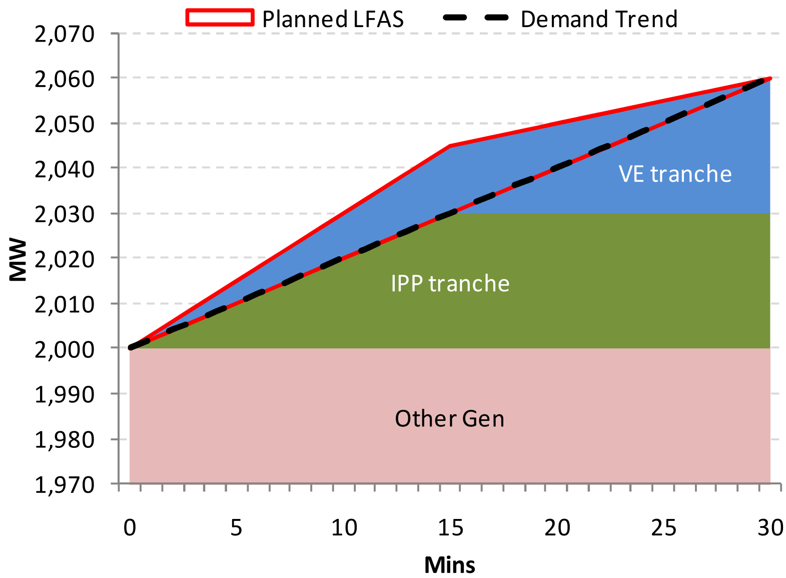


- In the example shown, an IPP Facility Balancing offer is able to be dispatched at less than its specified maximum ramping rate to follow the expected trend in RDQ (the dashed line). This minimises the use of the higher priced Verve tranche.

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:

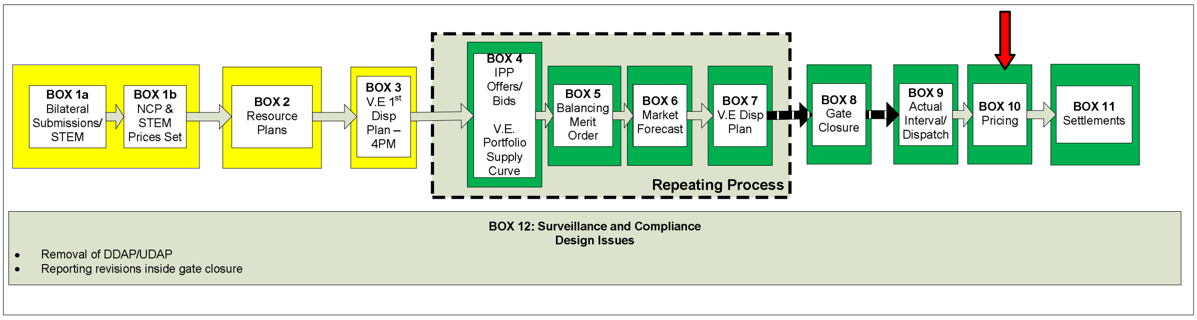
- As noted above, System Management will require decision support software that incorporates the above rules with the total generation forecasts and the RTBMO. For example, to manage the potential of multiple tranches being dispatched in an interval, including one ramping down while another ramps up, 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 is could be considered further but is problematic given that the Verve Portfolio Supply Curve is not Facility specific.

3.10 PRICING (Box 10)

3.10.1 Purpose:

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



Balancing Price:

Objective: balancing price to reflect the marginal price of resources dispatched by ~~SM~~System Management to provide actual balancing from IPP and any Verve facility prices and Verve PSC prices.
~~Objective: Balancing price to reflect price of resources dispatched by System Management to provide actual Balancing from IPP and any Verve Facility prices and Verve Portfolio Supply Curve 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.

- ~~The Balancing price is to be calculated ex post based on the intersection of the Energy Relevant Dispatch Quantity (ERDQ) and the RTBMO expressed in form of tranches of Balancing energy (Energy Equivalent RTMBO) available for dispatch in half hour.~~

- ~~The amount of energy able to have been dispatched in a particular interval will be determined with reference to its maximum ramp rate and actual MW (SCADA) at the start of the interval.~~

~~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 ~~Further work~~Details:

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

- The methodology involves calculating the amounts of energy that could have been generated in merit order from each tranche in the RTBMO, and in the case of unscheduled supply what was actually generated, to satisfy the ERDQ.

- The balancing price will be set the day following the trading day at the price of the marginal tranche in the above calculation.

Example:

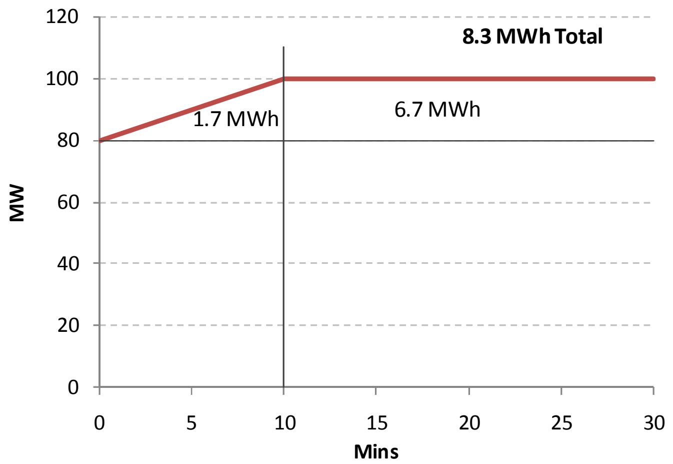
Basic

- For each facility based tranche in the RTBMO, the maximum and minimum amounts of energy that could have been dispatched in the interval will be calculated. This will take into account the amount of generation from the relevant facility at the start of the trading interval and the maximum ramping rate of the facility.

- For example, consider a 100 MW facility that is operating at its resource plan level of 80 MW at the start of an interval. Suppose the balancing submissions for that facility were as follows:

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

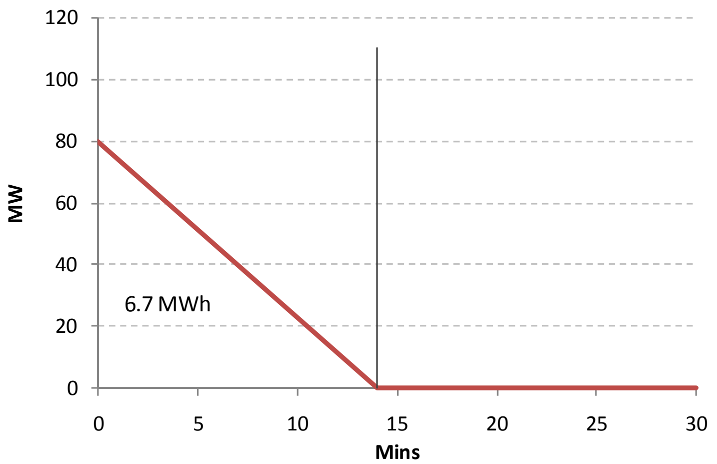
- The maximum amount of energy that the facility could be instructed to generate from the $50 per MWh tranche would be 8.3 MWh as illustrated below:



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

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

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



- These calculations would be carried out for each facility based tranche in the RTBMO.
- For each Verve portfolio tranche, the maximum and minimum amounts of energy that could have been dispatched would be the maximum quantity offered and zero (no ramp rate constraints).
- The dispatchable quantities would then be sorted in price order (as in the RTBMO) to establish the balancing price with reference to the ERDQ. For example, as in the stylised example below. If the ERDQ was anywhere between 540 and 548.3 MWh, the balancing price would be $50 per MWh (set by the shaded IPP offer 1).

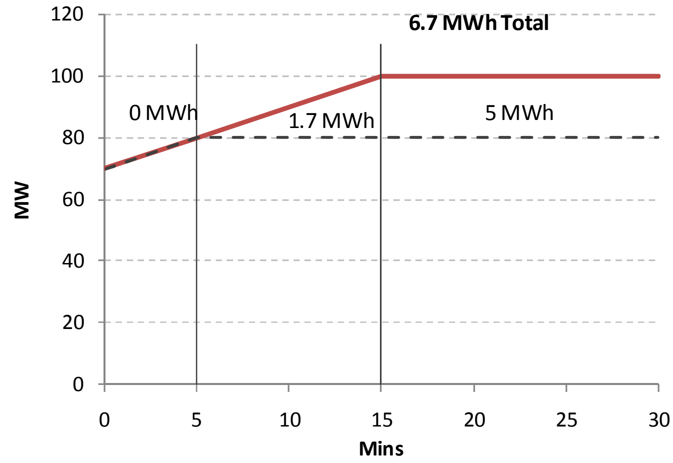
Tranche	Min MWh	Max MWh	$/MWh	Cum MWh From	Cum MWh To
VEPSC3	0	200	$275	548.3	748.3
IPP offer 1	0	8.3	$50	540.0	548.3
VEPSC2	0	300	$40	240.0	540.0
VEPSC1	0	200	-$50	40.0	240.0
IPP bid 1	6.7	40.0	-$275	6.7	40.0

Accounting for ramping within resource plans

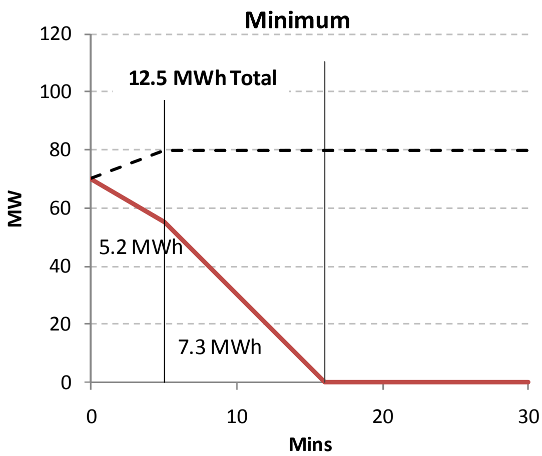
- In the above example, the IPP is operating at the resource plan level at the start of the interval and has a fixed resource plan throughout the interval (i.e. no change in resource plan level (NCP / own load) from the previous interval).
- In practice, the facility's resource plan may include ramping to a new level (refer box 2). For example, assume that in the above scenario, the facility is operating at a resource plan level of 70 MW at the start of the interval and that the resource plan ramps up to 80 MW[4] at 2 MW per minute. As illustrated below, the maximum energy

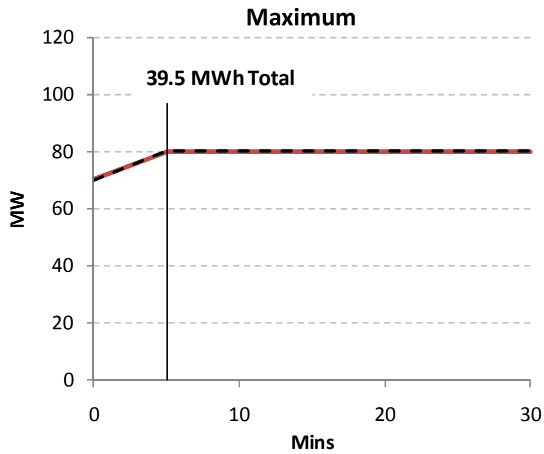
[4] e.g. 40 MWh NCP.

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):

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

Unscheduled generation

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

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

Constrained on/off

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

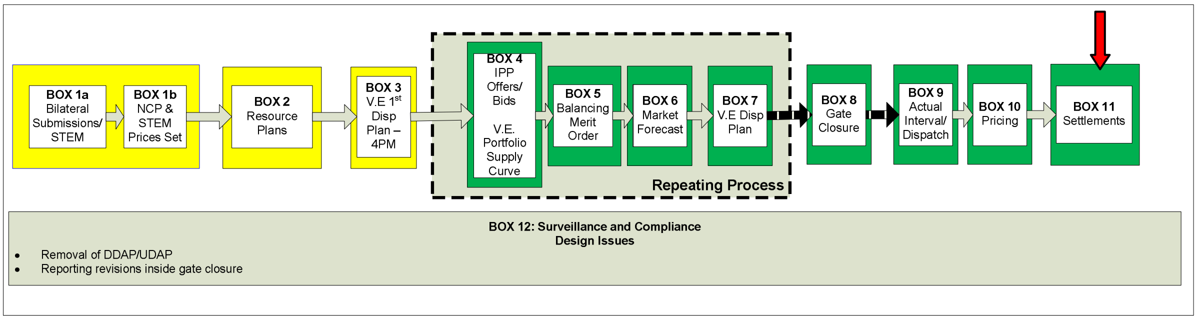
3.10.4 Further work:

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. An Market Participant that was dispatched down below its Resource Plan by System Management 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 $20 per MWh and the Market Participant's bid price negative $15 per MWh, the IPP would have paid negative $20 per MWh (i.e. received $20/MWh) but expected to have paid negative $15 per MWh (i.e. receive $15 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[5] (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.

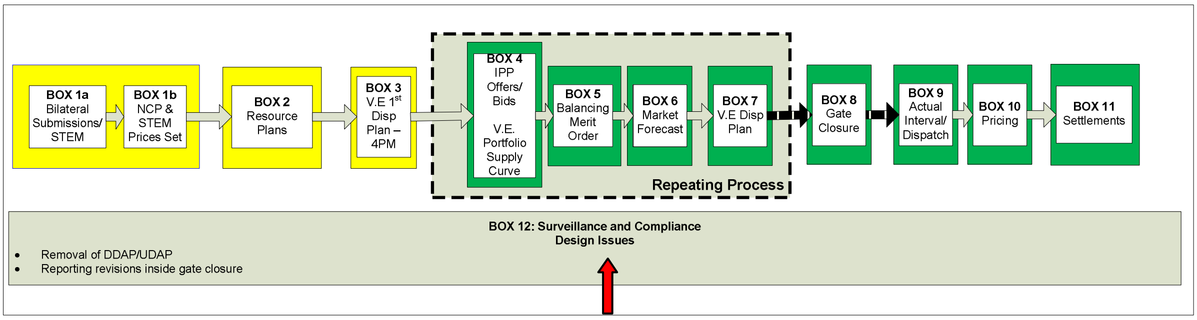
- Constrained on/off payments will be allocated to Market Customers proportional to their energy use in the interval the payment was made.

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.

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



3.12.2 Background:

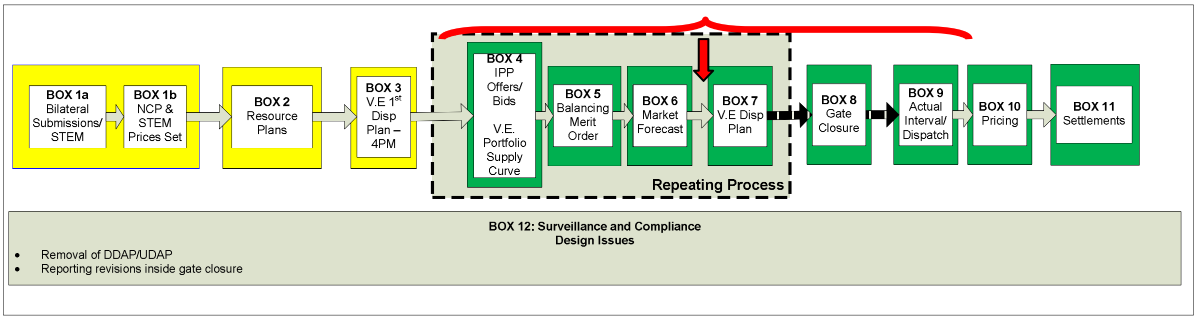
Market power can have a positive or negative impact on market outcomes. The ability to exercise market power detrimentally to the objective of the market is common in many electricity markets. On the other hand the threat or actual exercise of temporary of market power can be a key incentive for competitors 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.

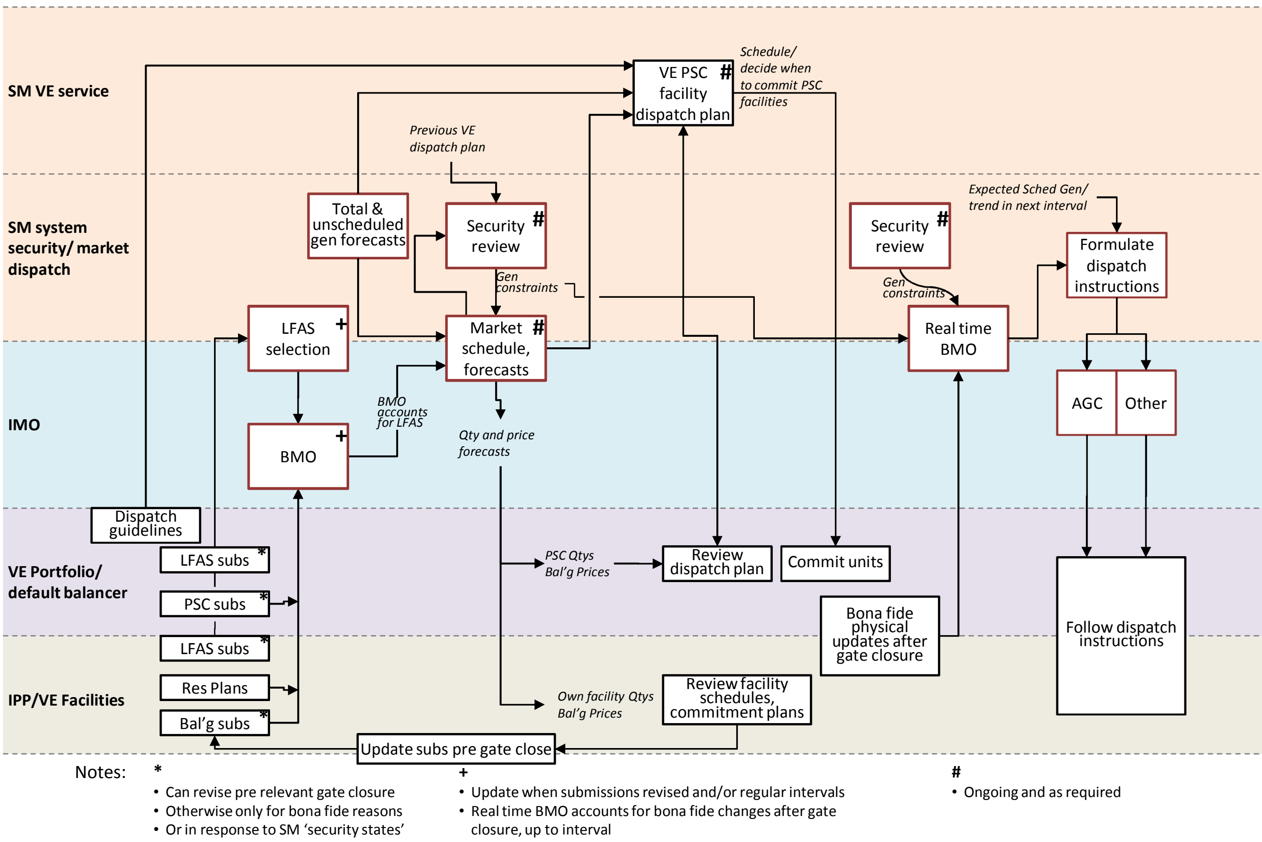
- Compliance with formation of Resource Plans given that UDAP and DDAP penalties are proposed to be removed and the requirement is to be relaxed when NCP changes;
- Surveillance of the basis for renominations – given the proposal to allow renominations under some circumstances such as following material 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



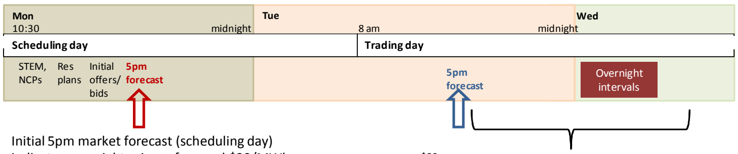
The following diagram illustrates the processes (including where process are repeated over the course of a day) and the roles and responsibilities within the proposed design described in the 12 stages.

Overview of Market Processes

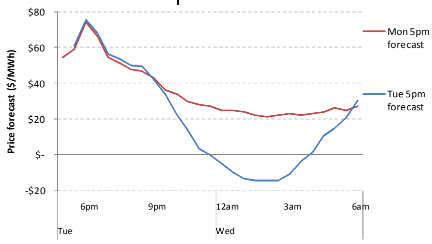


APPENDIX B: OVERNIGHT EXAMPLE

Overnight example

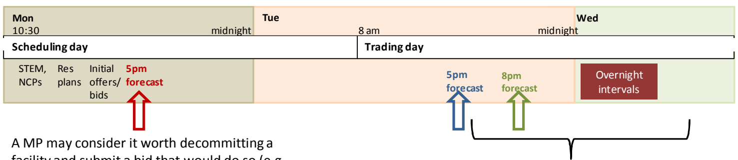


- Initial 5pm market forecast (scheduling day) indicates overnight prices of around $20/MWh
  - Issued 30+ hours ahead of overnight intervals
  - Issued several hours after NCPs established, resource plans submitted
- 5 pm forecast (trading day) indicates lower overnight prices
  - e.g. lower demand/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

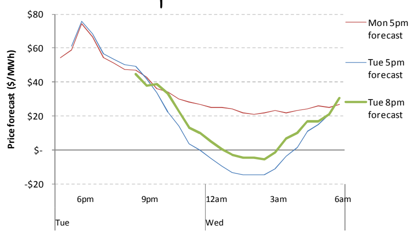


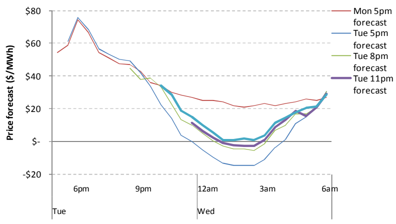
Had intermediate price forecasts indicated this trend, participants could have responded earlier given flexibility to revise facility submissions

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 2c: Cover Paper MEP Cost Benefit Analysis – Progress to date

1. BACKGROUND

As RDIWG members are now well aware, work has commenced on the "high level" cost benefit analysis focusing on the balancing proposal.

Attached is the draft analysis as it stands on Wednesday 16 February 2011. Preston Davies and Ashley Milkop, the consultant's engaged to undertake the cost benefit analysis, will be attending the RDIWG meeting to discuss the work to date.

The focus of the cost benefit work 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 market,

using the data members of the RDIWG have been able to provide so far for which the team is particularly grateful given the time and other constraints.

The team would welcome feedback on the material to date and will be in Perth until Thursday, 24 February 2011 to secure any further data on likely benefits and costs.

The focus will then turn to finalising the remaining parts of the report and calculating the likely cost benefit ranges and assessing their sensitivities to key assumptions. The aim is to have the paper back for the 15 March 2011 RDIWG meeting.

2. RECOMMENDATIONS

It is recommended that the RDIWG:

- **Note** the attached draft "high level" cost benefit analysis on the balancing proposal, as it stands at Wednesday 16 February 2011;
- **Advise** of any issues or concerns with the material so far presented;
- **Provide** any further relevant information to the team undertaking the cost benefit analysis, noting they are in Perth until Thursday, 24 February 2011;
- **Request** additional meetings with the team undertaking the cost benefit analysis, if required; and
- **Note** the intention to bring the high level cost benefit analysis - with its results – back to the 15 March 2011 RDIWG meeting.

sapere research group

Introducing Competition to Balancing Services

A “high level” cost-benefit analysis

Kieran Murray

Working draft as at 18 February 2011

Confidential

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Executive Summary

[To come]

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1 Classifying 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 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 (i.e. costs are 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 • HR-related shared costs	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 • Other shared costs	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 face volatility in MCAP – a business risk • Gate closure that is closer to actual trading intervals (i.e. greater plant availability) • Participants can operate plant more efficiently, resorting to 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:
	  ○ Nature of investment (i.e. type of plant) best suited to market situation
	  ○ Quantum of investment (i.e. degree of security/comfort in WEM)
		Additional investment in dollar terms
		
		Altered investment
		
		New entrants
			Market participants

1.1 Additional benefits

[To come]

2 The baseline

This section contains our assessment of the "business as usual" scenario against which we compare the effects of the proposal. It starts with an overview of the volume and cost of balancing in the recent past. It then considers the likely volume and cost of balancing in the period 2010-2017 given a range of assumptions. We also identify and discuss the key drivers of balancing requirements and what they mean for the forecasts. Finally, we identify the extent of possible IPP participation in future balancing requirements given the current set of rules and policy (i.e. that IPPs are only actually called upon in emergency type situations).

2.1 Modelling approach

[To be finalised- describe process, inputs and assumptions].

- Amounts expressed in 2010 dollars
- 2010 is calendar year
- 2009/10 is capacity year ended 30 September 2010

Drivers of balancing requirements:

- Embedded generation
- Intermittent generation
- Load forecast inaccuracy
- Deviations from resource plans from STEM submitters
- Deviations from resource plans from non-STEM submitters

Drivers of balancing costs:

- Balancing volume required
- Available generation (supply cushion)
- Verve portfolio curve
- IPP and Verve STEM submissions

2.2 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) have been ignored in this analysis. Although they 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.

Where years coincide with the forecasts in the statement of opportunities – where the end date is the 30th of September – they are specified as such, e.g. the 2008 capacity year is stated as 2007/08.

Estimating forecasts of balancing costs is not a straightforward process. Looking back at previous years shows that balancing costs (expressed in MCAP) have declined significantly since 2008.

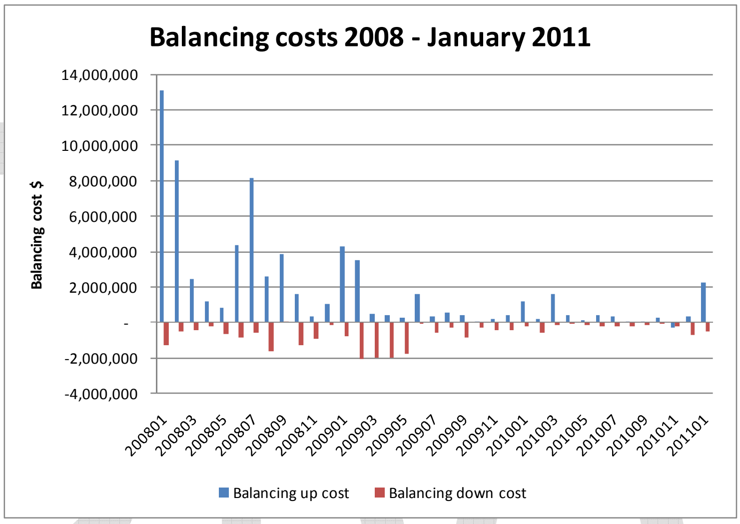
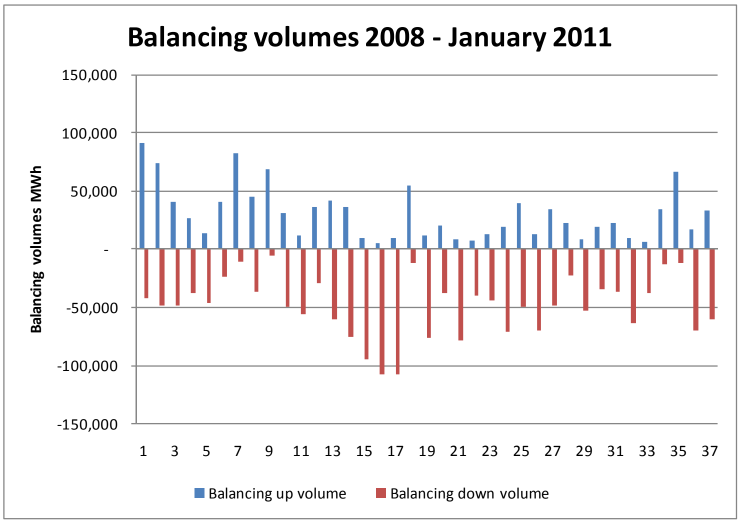


Chart 1a: balancing volumes



Analysis of the information shows that load forecasting has improved over the past two years, which has reduced somewhat the need for balancing. At the same time there has been an increase in excess supply which likely both decreased the average STEM price and increased the available options for balancing.

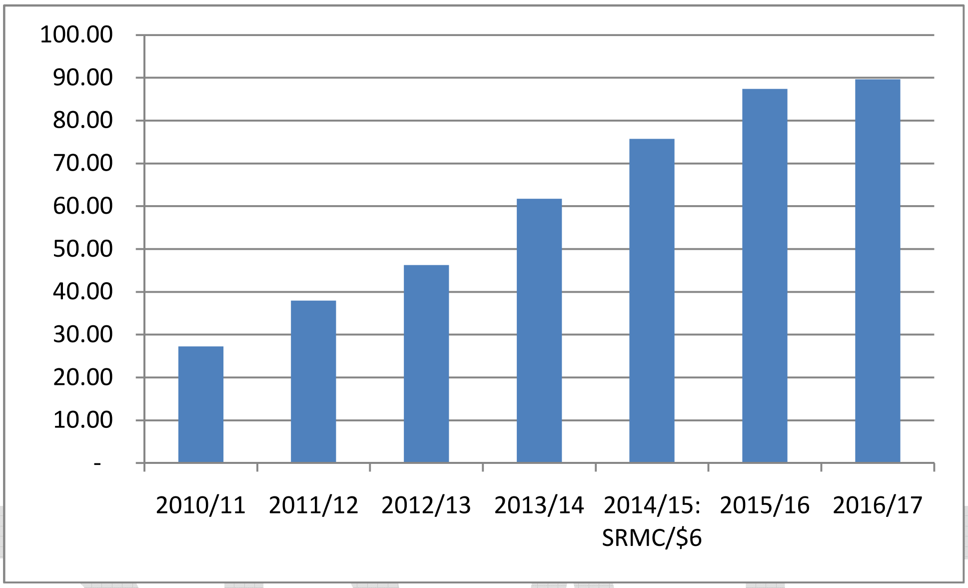
The time frame we have looked at (since the beginning of 2008) has seen two moderately sized windfarms in operations: Emu Downs and Dongara. However, intermittent generation has not been a major contributor to balancing requirements. There may be trading periods where intermittent generation has a significant marginal effect, however 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 -56MWh to +40MWh at the extremes. These variations are dwarfed when compared with overall balancing requirements of +/-300MWh within half hour trading periods.

Within the time frame for this analysis there will be a number of changes to the composition of the generating fleet in the WEM. These changes 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.

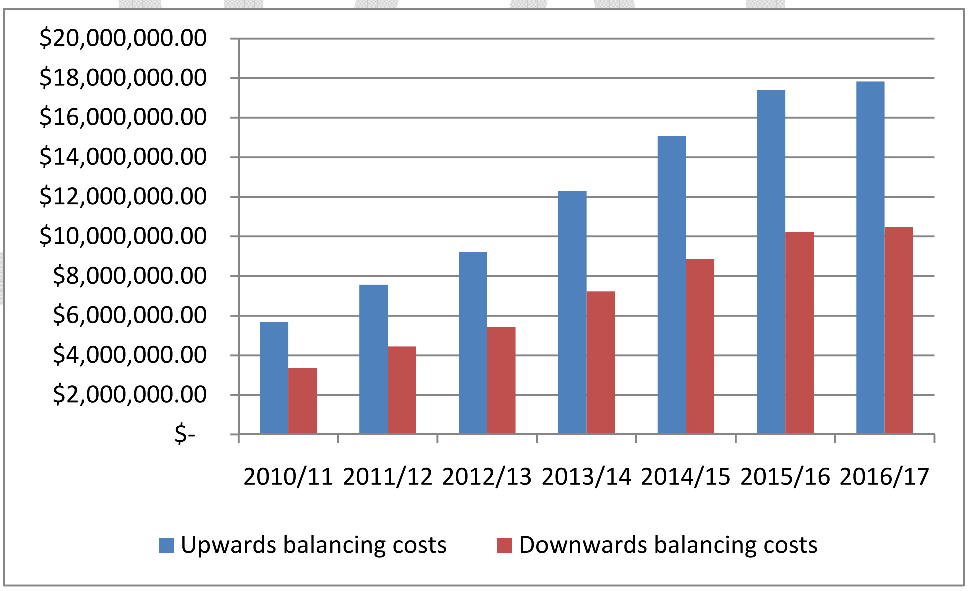
We have established a model for predicting the balancing costs for the next five years. We have made a number of assumptions in devising this model:

1. 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 is average output. Although the outputs of Dongara and Emu Downs are correlated at around 40% we have assumed no correlation between Collgar and the other stations.
2. That as annual consumption increases the need for balancing does not. We have not observed a strong link between increasing load and increasing balancing requirements. We consider that, even if there is a link, it will be offset by improved forecasting.
3. That the gas price faced by participants will rise to $6/GJ by 2014.
4. That, aside from the generation changes outlined in the SKM report, there will be no other new plant and no further plant decommissioned.
5. We have taken the expected growth scenarios from the 2010 Statement of Opportunities for estimating load growth.

Based on these assumptions we forecast that the STEM price will evolve as follows:



Given these assumptions, the effect on balancing costs will be as follows:



Note that we have not included the effect of UDAP or DDAP in these assumptions.

2.3 Quantifying the benefits

We have drawn in this section on the paper on Balancing Support presented to the RDIWG on 23 November 2010. It is important to note here that we are assessing 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) have had significant effects on individual participants, if these costs are offset by equal benefits to other parties then they cannot be considered as altering aggregate economic resource levels in any way. It might be possible to determine quantitative benefits to parties of reduced volatility, however, we have addressed this point in the qualitative benefits at this stage.

There are three main quantifiable benefits that we have identified.

The first of these is an 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 is a number of occasions where Verve generation is dispatched when cheaper IPP generation was available, or where Verve generation was curtailed when it would have been cheaper to curtail a more expensive IPP generator. The possible benefit is contingent on a number of variable factors:

1. That IPPs are able and willing to participate in balancing;
2. That the IPP bids to the STEM are an accurate portrayal of their willingness to generate and of their cost structures.

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

To test the benefits outlined in the balancing support paper we have taken a modelling approach. We have modelled the impact of introducing two generators. The first is a fast start generator which can supply 100MW at a price greater than $90/MWh and zero otherwise. The second will supply 300MW at $20/MWh and is willing to be curtailed quickly at prices less than $15/MWh. Their availability for balancing is based on their dispatch positions from the STEM. If the first generator is fully dispatched in the STEM then it is not available for balancing upwards. It is the reverse for the second, which is available for balancing downwards only if it is dispatched in the STEM.

[Further modelling is underway, but we have largely been able to replicate much of the analysis and findings. We can test the sensitivity of the results by changing the thresholds and the generator sizes.]

The $X.Xm worth of advantages are likely to increase over the next few years for two reasons. The first is that there is greater availability of fast start plant than during the period analysed. The second is that, as the supply curve increases with gas price rises, the advantages in absolute terms will also rise (even if the relative advantages do not.)

There are also some caveats to keep in mind: (e.g. IPPs overstating their SRMCs in STEM offers, whether plant can be scheduled quickly). However, we believe that the $X.Xm is a reasonable estimate of the economic advantages related solely to IPP that would have been available to the STEM now being available to balancing.

The second quantifiable benefit is that it is less likely that baseload generation will have to be curtailed. We understand that the costs of having to stop a thermal generator (coal plant or CCGT) are significant, amounting to around $40,000 a time in wear and tear of machinery. These costs are only partially reflected in the balancing support paper.

The third quantifiable benefit is the increased availability of plant for generation. 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. Also, if plant does become available earlier than expected for dispatch, the participant cannot schedule it if the gate closure has already passed. That generation would, however, be available for balancing. We estimate that the advantage can be estimated at around half a day's worth of generation per plant.

[Further detail to be added to paper:

- Downwards and upwards balancing costs (MCAP only) for past four years .
- Supply curve graphs using current information regarding SRMC; historical supply curves using STEM and MCAP data have also been developed.
- Intermittent generation data showing the distribution of intermittent generation and how I've modelled Collgar.]

3 Impacts of proposal

3.1 Costs

As shown in Table 1 above, the main cost categories relate to personnel and systems changes. The costs represented here are those specifically attributable to the balancing proposal itself. Thus, in the case of common or shared costs, where the costs are highly aggregated, we have sort to apply a percentage of those costs to the proposal on a reasonable basis. Where costs would have been incurred anyway (i.e. even in the absence of the proposal, expenditure on systems upgrades would have take place) then these costs have been excluded.

The costings detailed below are first approximations and are subject to (potentially substantial) adjustment and refinement as further detail around the balancing market proposal is confirmed. They show that, as expected the majority of costs (around 54%) are incurred in the set-up/implementation phase of around two years.

Annual figures for the remaining ongoing costs for the other five years in the project life total around $2.3m per annum.

[Note these costs are subject to revision and do not include all participants costs at this stage].

Table 2 Cost details (undiscounted)

Description	Costs -$000's
Set-up and implementation	$
Ongoing	$

3.2 Direct benefits

The main component of direct benefit is the avoided costs of dispatching more costly Verve plant when IPP plant is available for dispatch.[1] While arguments could be mounted on both sides of the equation (i.e. that the actual benefits estimated over or under states the true level of benefit) we have been able to replicate the process and confirm the order of magnitude of avoided cost benefits estimated previously.[2] We have augmented this estimate by factoring in the likely avoided costs associated with more extreme events, such as plants tripping. These events occur much less frequently, but provide an "upside" analogue to the avoided costs of curtailment which is the subject of the previous analysis. To be clear, a balancing market will not reduce or avoid the incidence of plant outages, but it will reduce the (economic) costs associated with such events. We describe the factors in more detail below.

Points for further discussion:

- As Verve operates relatively less generating capacity it has fewer resources to provide balancing and must schedule "inappropriate" plant to cover balancing

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[1] The assumption used in this analysis is that IPP plant is available if signalled as such in STEM submissions (i.e. they are able to source fuel and dispatch if required). This assumption is challengeable and is discussed further in subsequent parts of the report.

[2] See IMO "Balancing Support" paper dated 23 November 2010 on IMO website.

requirements. At times it must curtail baseload generation at an economic cost. This can only be estimated imprecisely.

- IPPs have equipment that can be used to cover balancing requirements that is cheaper than Verve resources [current estimates could over or under state true advantage- further modelling underway- important factors include Verve's costs in relation to their supply-curve and IPPs submissions in relation to their SRMC].
- There are possible savings through more flexible security processes and from the automated software that has been brought in.
- Gas price rise (is it relevant for our purposes?). Only to the extent that if IPPs have more efficient equipment (some of it is newer, then the differential between IPP and Verve will be greater. IPPs face volatile MCAP prices that present a business risk. This volatility will increase as gas prices rise. As seen on 10/11 January.
- Clean price versus MCAP price (see RDIWG paper from 2/11/2010) – relevant quantity issues. Currently MCAP is based on "relevant quantity" meaning that even if specific Verve plant is used or curtailed then the cost isn't reflected.
- At the moment the full costs of curtailing plant are not recognised in MCAP. Also, because prices are pay as bid, there is no incentive for IPPs to submit sensible prices as they are unlikely to be dispatched. It seems that they put in high bids/low offers to get compensated for the few times that they're called on. Means that participants can make decisions based on MCAP instead of being forced into paying a high DDAP, which is inconsistent with marginal cost pricing. I.e. participants will look to keep inefficient plant on instead of shutting it down and incurring MCAP.
- If gate closure closer to actual trading then participants face more certainty as to what plant is available. Could mean greater plant availability. Advantages of certainty.
- Clearer investment signals, despite balancing not being a major driver of investment decisions currently.
- Participants can operate plant more efficiently, resorting to balancing market rather than keeping to counter-productive resource plans.

3.3 Sensitivity analysis

[Initial numbers to be subject to changes in assumptions. Discuss caveats, risks, etc]

Agenda Item 3: Updates on Review of Capacity Cost Refunds

1. BACKGROUND

At the 14 December 2010 meeting the RDIWG discussed the key aspects of the “Review of Capacity Cost Refunds” paper. It was agreed that:

- In principle, the amendment of the capacity refund regime to a dynamically calculated refund factor based on actual reserve and a series of breakpoints;;
- Further work on the maximum refund factor was required, including analysis of refunds versus Forced Outage rates versus deviations;
- The IMO would expand the Reserve Capacity refunds paper to cover the use of a consolidated fund for refunds for the purposes of Supplementary Reserve Capacity.

The attached paper addresses these issues with additional discussion in regard of the maximum refund factor and details of a proposed solution in regard of the dynamically calculated refund regime. The proposal for the removal of the Net STEM Shortfall refunds is also described. The approaches considered by the IMO in regard of the creation of a consolidated fund for the purposes of Supplementary Reserve Capacity; and a methodology for the allocation of refunds to supplement the fund, are detailed and an proposed solution is put forward to the working group.

2. RECOMMENDATIONS

The IMO recommends that the RDIWG:

- **Discuss** the recommendations made in the updated Review of Capacity Cost Refunds Paper (22 February 2011), these are:

- **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 **Error! Reference source not found.Error! Reference source not found.**;

- **Discuss** removal of Net STEM shortfall as the basis for imposing refunds subject to its replacement with "Operational Test" (described in section **Error! Reference source not found.**) 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 **Error! Reference source not found.**; 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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Contents

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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;
  - Energy provided by accredited capacity is traded under:
    - bilateral contracts and a day ahead short term market that provides a mechanism for participants to increase or decrease level of contracts, and
    - on-the-day balancing of variations in supply or demand from day ahead net contract positions.

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

2.2 The RCM and Reserve Capacity Refunds

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

[3] See clause 4.26 of the Market Rules.

mechanism within the "contract". They are commercial in nature and provide price signals to incentivise performance.[4]

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

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

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

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

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

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

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

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

3. ISSUES AND POTENTIAL FOR IMPROVEMENT

3.1 Introduction

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

- incentivise **long term maintenance activity** which will minimise future risk to system security and system reliability; and
- Incentivise **short term behaviours** to ensure day to day operation and maintenance activities are directed to maximising reliability at time of greatest value, generally when actual reserves are lowest.

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

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

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

3.2 Refund Rate v Reserve under the status quo

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

Figure 1 Cal 2009 Refund Factor v Reserve

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

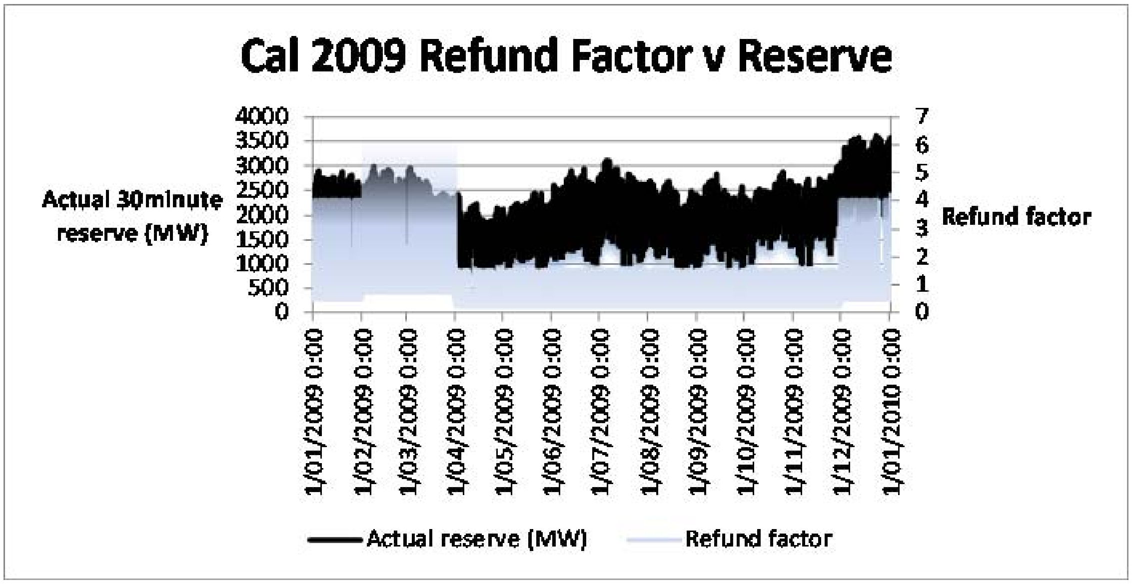
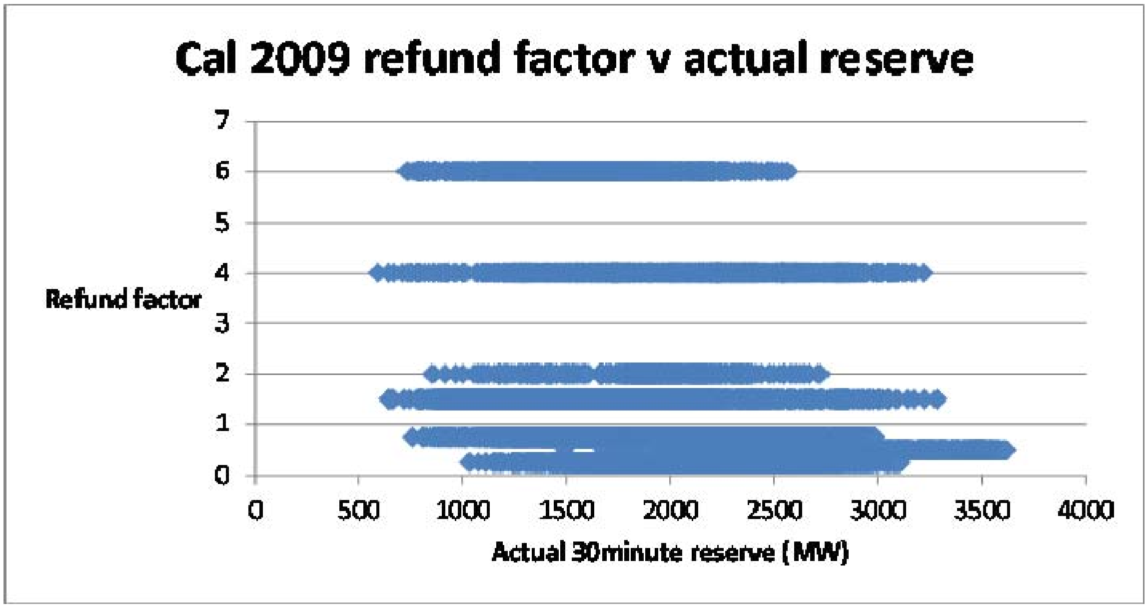


Figure 1 shows actual reserve in solid base plot (as the data covers the entire year only the envelope of maximum and minimum values is readily seen). Figure 2 shows the range of refunds for different reserves across the year. The highest refund rate of 6 applied some of the times of low reserve (as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

Figure 2 Cal 2009 Refund Factor v Actual Reserve



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

4. POTENTIAL SOLUTIONS

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

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

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

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

4.1 Basic reserve related refund

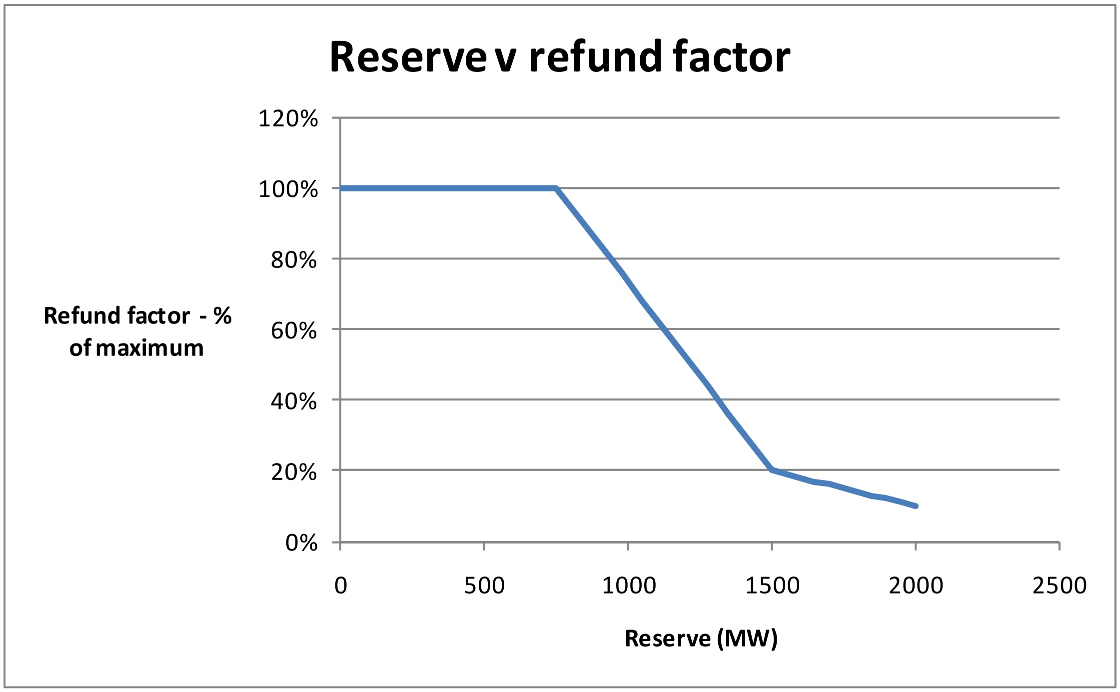
The first alternative is a simple regime that is responsive to prevailing conditions and would:

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

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

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

Figure 3 Reserve v Refund Factor



4.2 Combination actual and annual forecast reserve

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

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

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

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

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

4.3 Combination forecast and actual reserve related refund

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

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

5. IMO PROPOSED SOLUTION

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

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

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

5.1 Defining the magnitude and profile of the dynamic regime

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

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

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

5.2 Cumulative Refund Cap

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

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

5.3 Analysis: Status Quo Compared to Dynamic Mechanism

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

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

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

Figure 4 Comparison of cumulative total refund: calendar 2008

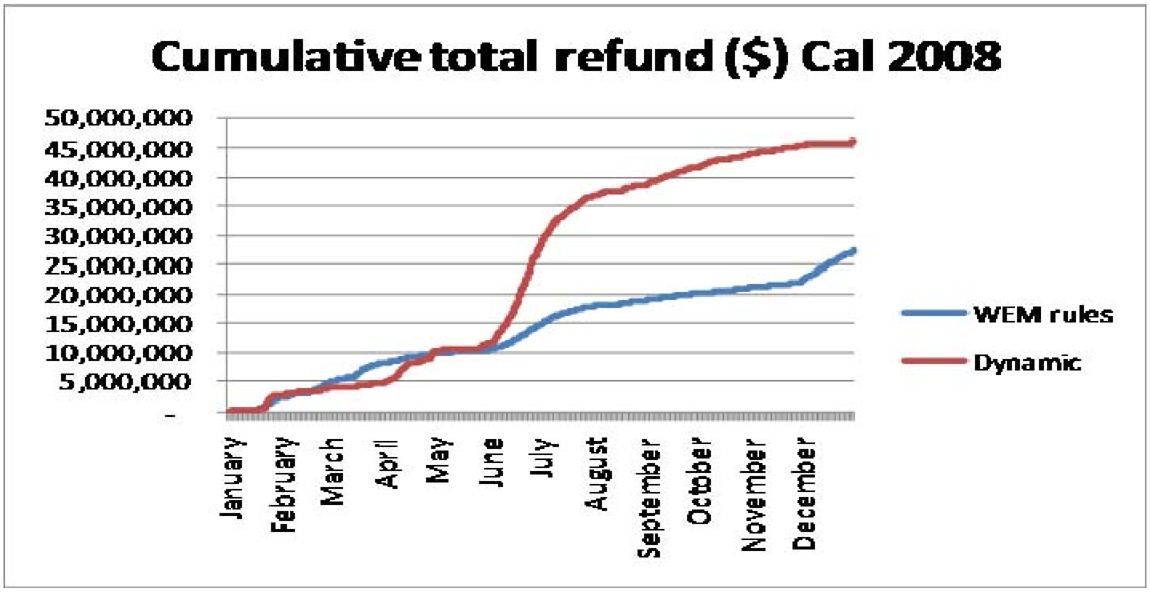


Figure 5 Refund rate versus reserve in calendar 2008: WEM rules

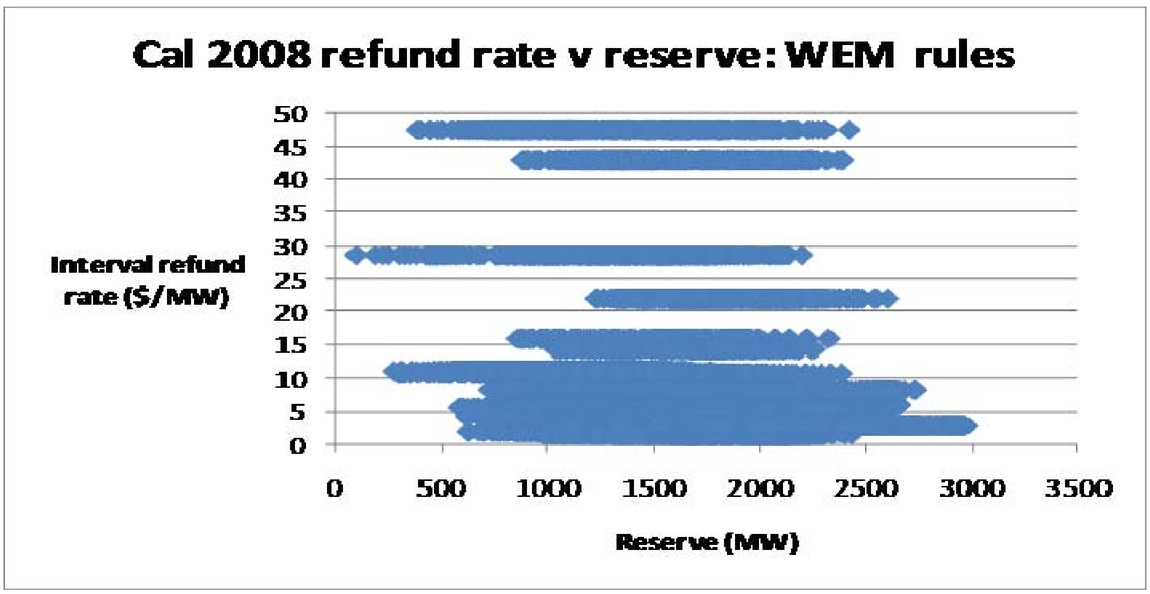


Figure 6 Refund rate versus reserve in calendar 2008: Dynamic settings

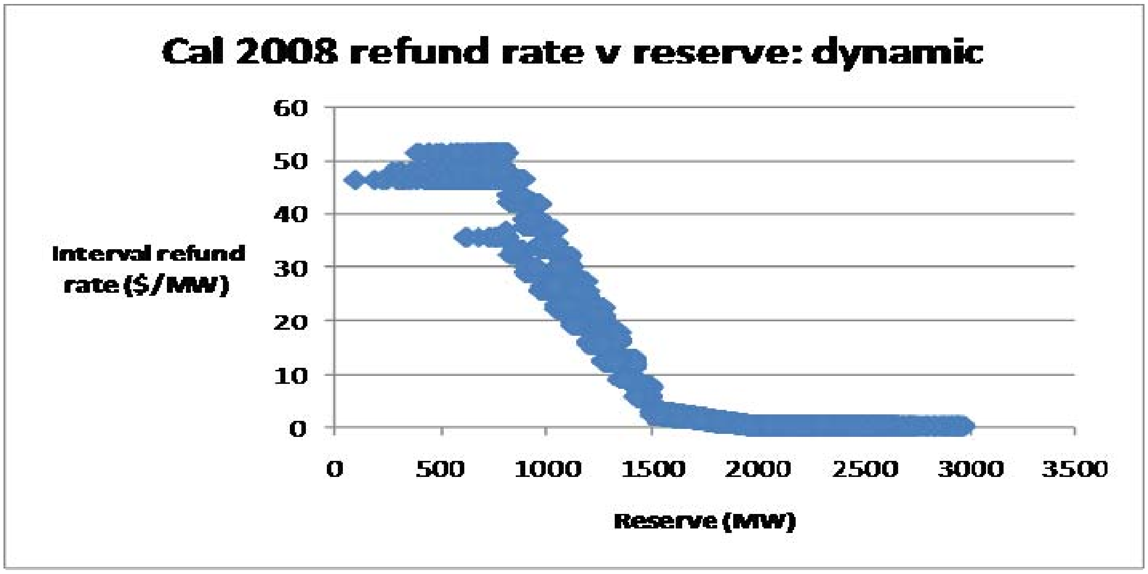


Figure 7 Comparison of cumulative refunds: calendar 2009

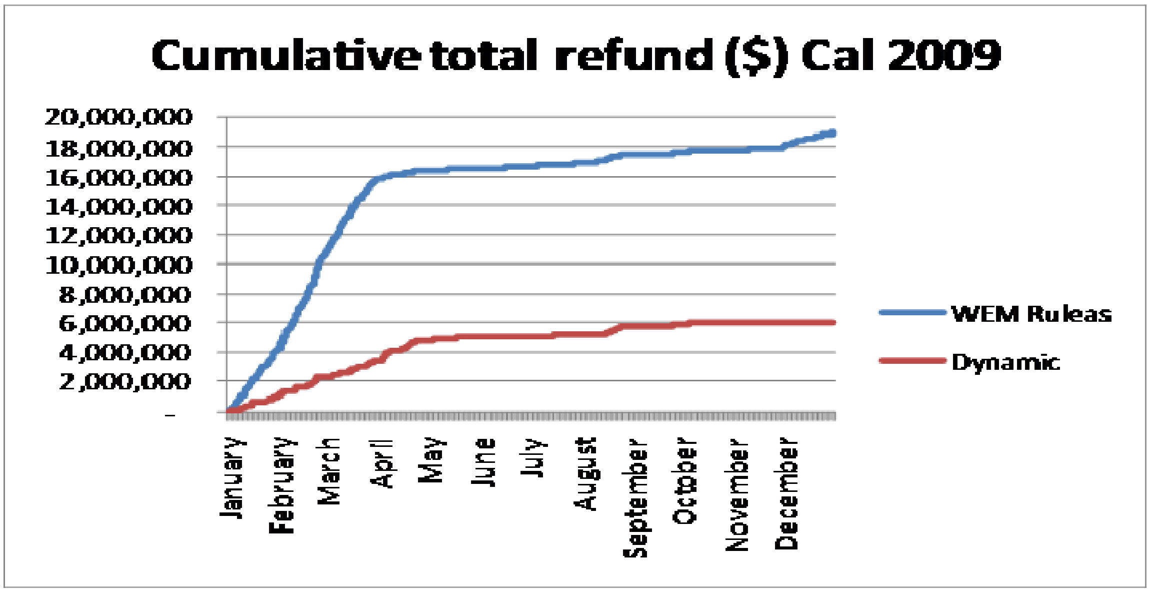


Figure 8 Refund rate versus reserve in calendar 2009: WEM rules

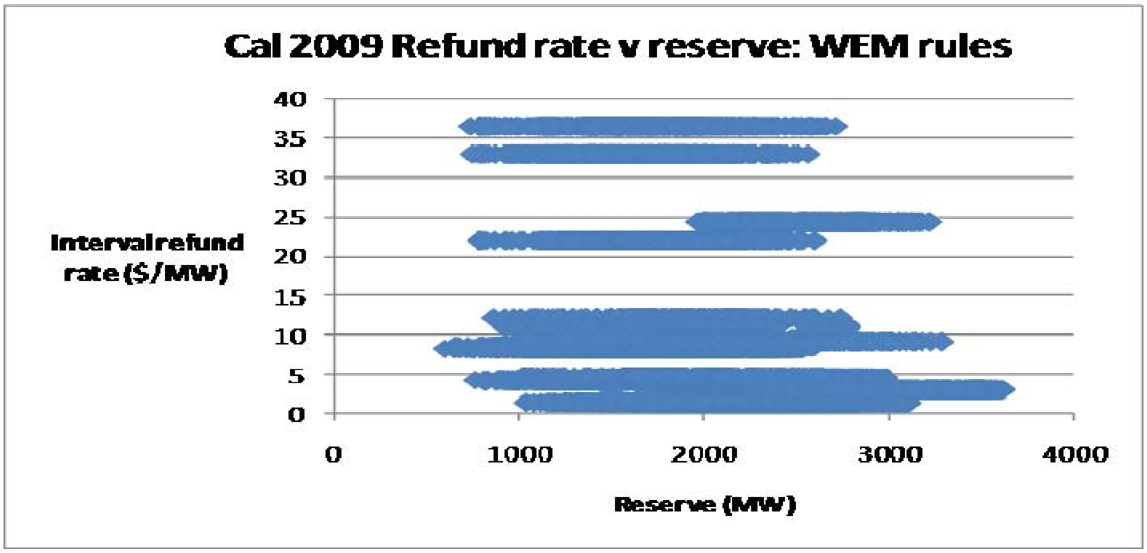


Figure 9 Refund rate versus reserve in calendar 2009: dynamic settings

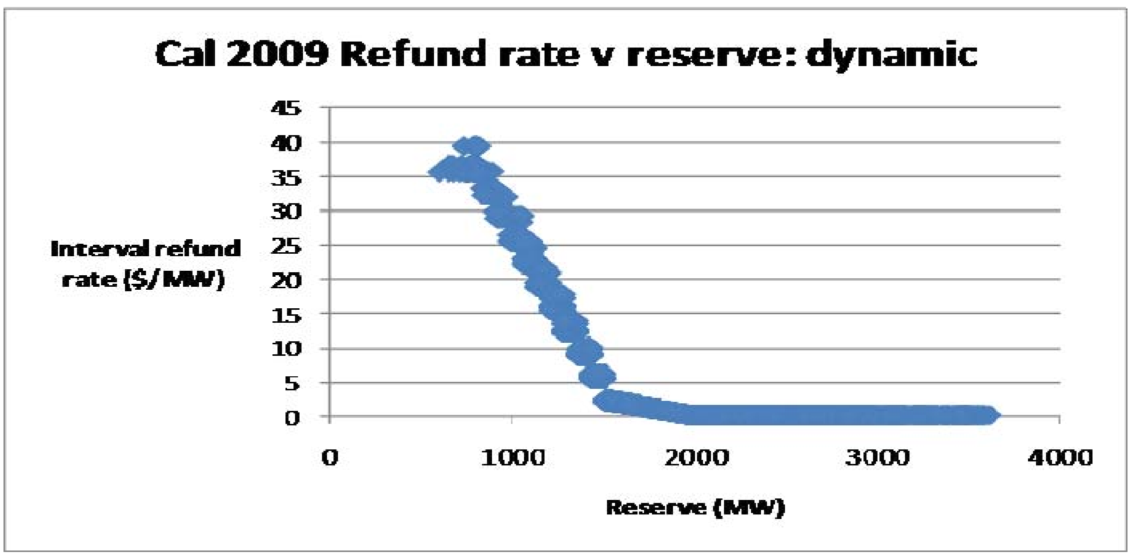


Figure 4 and Figure 7 show that across the year refunds can be higher or lower under the dynamic regime compared to the current WEM rules. Interestingly, over the two years studied the current refund rules were introduced the total refund is approximately the same.

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

5.4 IMO Proposed Solution

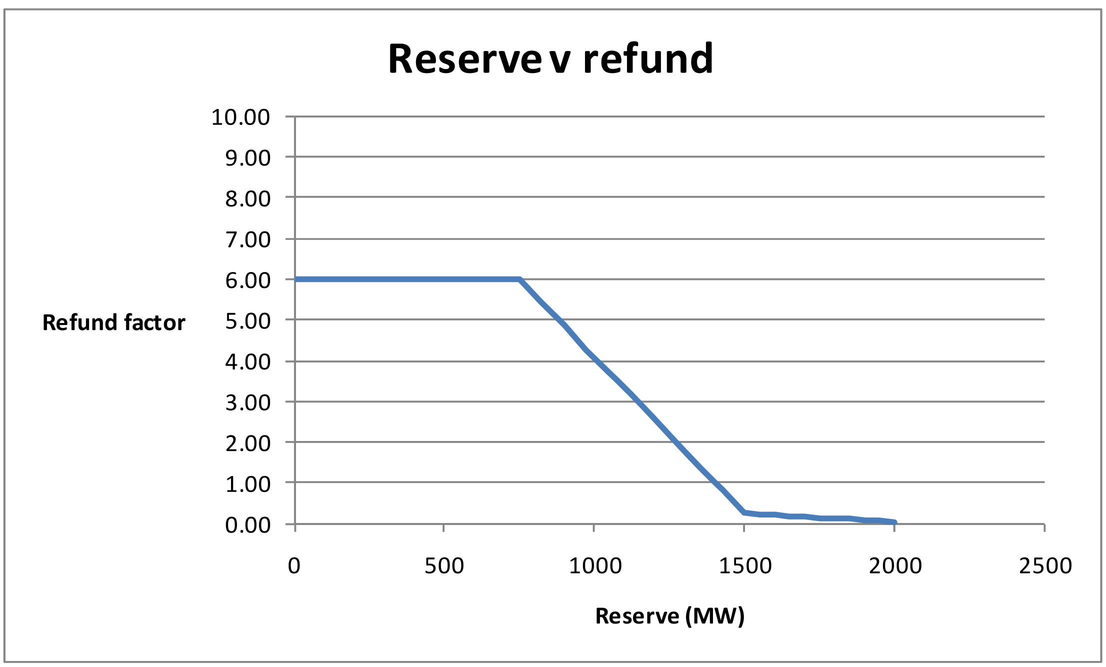
The IMO proposes that the maximum refund factor remain at the maximum value of 6. As noted analysis of the 2008 and 2009 calendar years shows that the cumulative refund amounts under the Market rules and the proposed methodology are similar. The IMO considers that as the design is aiming to produce a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

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

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

Figure 4 illustrates the relationship using the breakpoints noted above.

Figure 10 Reserve v Refund



6 EXPOSURE TO REFUNDS

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

The first is that, 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.

Figure 11 Forced Outage v Net STEM Shortfall Refund

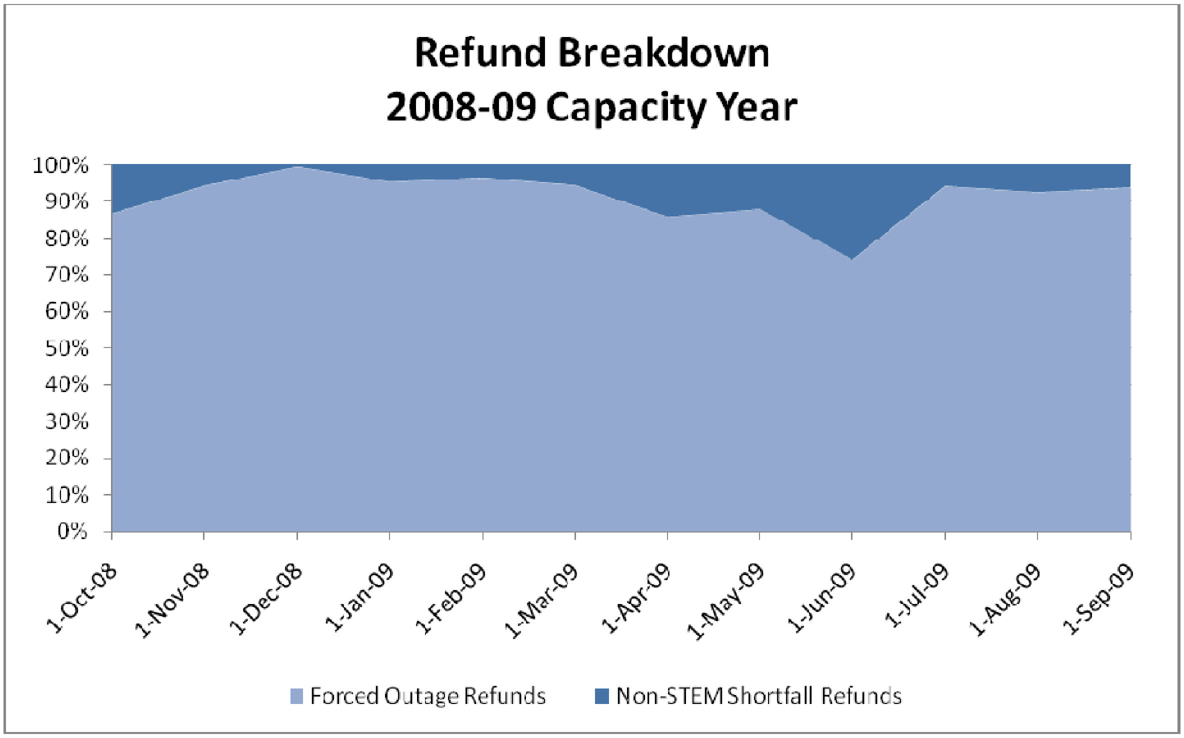
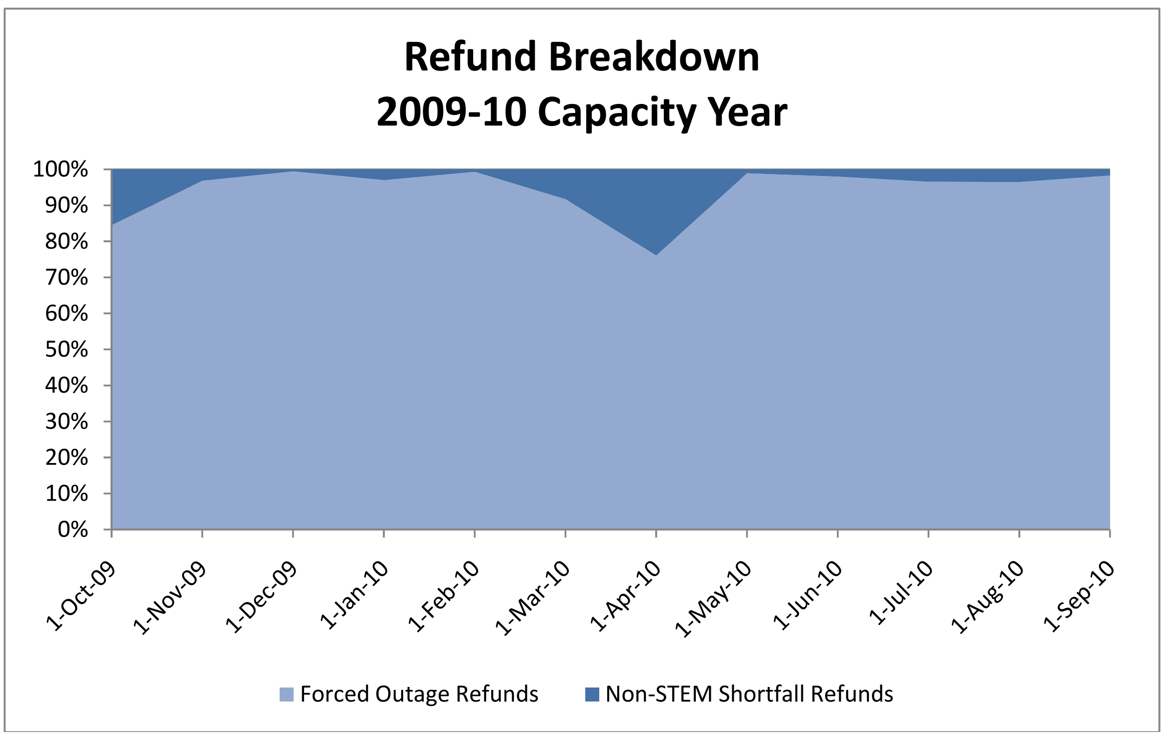


Figure 12 Forced Outage v Net STEM Shortfall Refund



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

- As far as practicable all capacity providers should be treated equally;
- All holders of accredited capacity should be required to declare the level of capacity being presented to market each day.
    - The declared amount should only be less than the accredited capacity if System Management has approved a planned outage (see below) plus any amount declared as a forced outage.
    - Approval should be reviewed/confirmed on a daily basis prior to the declaration.
    - The declaration can be part of the STEM submission process but should be a separate and formal declaration on behalf of the business.
- Refunds should only be imposed as a result of a declared Forced Outage or a failure to pass an "Operational Test".
    - The "Operational Test" should be designed to confirm available capacity when there is a reason to believe it may not be available and is a consequence of moving from an automatic exposure regime to a compliance and surveillance regime. Provisions for the conduct of an Operational Test should not create an unnecessary burden on System Management as the test is essentially a commercial and compliance measure rather than a real time dispatch mechanism;
    - To that end failure to follow a resource plan for a short period should not automatically result in exposure to a refund. The reason for this is that it is within good industry practice for generating units to exhibit some variability in output in the short term. Generation businesses should be expected to seek to operate each unit in the most efficient manner to meet a target output – in the WEM the resource plan. Variation for minor operational fluctuations is not a definitive indication that the unit would not pass a test of the same sort that a unit that is available but not operating at the time would.
    - Clearly failure to reach or maintain full resource plan level of operation is an indication the unit MAY not pass such a test.
    - The Operational Test would be conducted either
        - in real time by System Management; or
        - Ex-post by the IMO.

      Each of the above options has differing pros and cons, however a threshold for testing would need to be established and would be considered in the detailed design of rule amendments including that there will be an interaction between calling for a test and emerging changes to arrangements for balancing and ancillary services and the resultant implications for System Management control room activities.

- o More surveillance resources will be required for this to work:
  - this may be in the form of an automated system for system management and the requirement for system management to call such tests in specific situations; or
  - more staff and/or IT systems for the IMO to monitor the resource plan deviations of market participants and co-ordinate the testing with SM.

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

6.1 IMO Proposed solution

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

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

7 DISTRIBUTION OF RESERVE CAPACITY REFUNDS

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

7.1 Current Arrangements

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

- 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

- 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.

    - 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:

- o 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.

- o 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)

    - o 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.

    - o 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;

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

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

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

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

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

- Approach 2 – Cyclic Market SRC Fund
  - This approach also involves the creation of a single fund which would endure over multiple capacity years but be notionally emptied each year.
  - This fund would be empty at its creation and have a maximum level which would be set by the Market Rules.
  - The fund would initially be topped up by allocating refunds that are currently distributed to Market Customers on a monthly basis. This would continue until the fund reached the required maximum level.
  - Once the fund reached a maximum level, the IMO would notionally return the contributions to the Market Customers that contributed to it while at the same time requiring contributions to refill the fund. Continuing Market Customers with the same level of peak demand would face equal and opposite refunds and contributions. Only Market Customers with changing peak requirements would see any difference.
  - If the need for SRC arises, then the will IMO utilise the fund to acquire SRC and procure any additional monies to cover any shortfall.
  - Similarly if SRC was required refunds to existing Market Customers would be directed to refilling the fund in the first instance

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

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

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

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

7.5 Proposed amendments

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

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

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

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

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

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

8 RECOMMENDATION

That IMO recommends that the RDIWG:

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

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

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

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

Agenda Item 4: Cover Paper MEP Timeframes and Milestones

1. BACKGROUND

At the 1 February 2011 RDIWG meeting members requested to see the key timeframes and milestones for the Market Evolution Program (MEP). Attached are the currently proposed timeframes and milestones requested by the IMO Board at its meeting in January 2011. Several assumptions were made when setting the timeframes and milestones and these remain conditional upon the RDIWG, MAC, IMO Board and Rule Change processes.

Key drivers behind the timeframes include:

- a desire by the Minister for Energy, Board and IMO Management to see real progress given the efforts and expenditures involved, and
- recent Market Participant feedback about the time it has already taken to look into these issues.

The overall timelines were signalled in the MEP site visits during December 2010 and January 2011.

At its January 2011 meeting, the IMO Board also asked for a set of summary milestones and objectives for the MEP, noting that all the milestones were conditional upon the RDIWG, MAC, IMO Board and Rule Change processes. The following summary milestones and objectives have been suggested to the IMO Board:

1. A new Balancing market in trial from 1 December 2011 and fully operational from 1 April 2012 that:

    (i) Ensures the most economically efficient balancing options are used to provide balancing services – whether it be IPP generation, demand side management or Verve generation; and

    (ii) Ensures the State-owned Generator – Verve Energy – can be increasingly treated like other Market Participants over time even though it remains as the default balancer;

2. A new Reserve Capacity refund methodology fully operational from 1 December 2011 that:

    (i) Continues to incentivise a efficient long term maintenance regime for generation units to support the reliable delivery of energy; and

    (ii) Provides a refund regime that better reflects actual market conditions;

3. A new Load Following Ancillary Service market in trial from 1 February 2012 and fully operational from 1 April 2012 that:

   (i) Ensures the most economically efficient options are used to provide load following ancillary services – whether it be IPP generation, demand side management or Verve generation; and

   (ii) Ensures the State owned Generator – Verve – can be increasingly treated like other Market Participants over time even though it remains as the default provider of ancillary services;

4. A more adaptable IT system with a longer life in place from 1 July 2012 that:

   (i) Enables the MEP changes to be rolled out successfully, on time and on or under budget; amd

   (ii) Allows the market to continue to operate and evolve for another 3-5 years without further substantial I T investment and/or until more fundamental reforms are rolled out.

2. IT FORUM

The IMO provided an update on the IT roadmap work to key Market Participant IT staff at the recent IT Forum. Concerns were expressed about the timeframes for the balancing work in particular. This seemed in contrast to the feedback received from Market Participants in the most recent IMO survey indicating concerns with the lack of progress and timeliness in delivering solutions for issues like balancing.

3. RECOMMENDATIONS

It is recommended that the RDIWG:

- **Discuss** the attached timeframes and milestones for the MEP; and
- **Discuss** the above summary key milestones and objectives requested by the IMO Board at its January 2011 meeting.

Market Evolution Program - Milestones and Timelines as at February 2011

Design Area	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12
MEP Prep																		
Concept Design																		
Process design/mapping																		
Rules Development																		
Operations																		
Systems Development [Matt Pember]		Standalone Environment Complete	• Release Timeline Reduction documentation complete • Requirements and design for Test Harness Automation Tool complete • Testing of Oracle 11G (WEMS starts)	Oracle 11G (WEMS) Testing complete. Implementation into production.			Construction and testing of Test Harness Automation Tool complete				Balancing functionality incorporated into Test Harness							80% Automated Coverage of Test Harness complete
Balancing Market																		
Concept Design	Internal workshop to confirm outstanding issues	Papers to RDIWG 1 Feb and 22 Feb	Final Paper to RDIWG in early March and then MAC confirming design (April MAC)	Paper presented to the April MAC meeting (due 30 March 2011) (Ben/Jim via Jacinda)														
Process design / mapping	Draft available	Finalised for op/rule/ system development																
Rules Development			Commencement of drafting (Caroline, with assistance from Ben/Jim/Troy and Jacinda)			* Rules Released for first round of consultation (Jacinda's replacement) * Minister informed of Rule Change Proposal (if protected provisions are amended) (Jacinda's replacement)		First Round of submissions close	* Rules released for second round of consultation (in Draft Rule Change Report) (early sept)	Second round of submissions close	* Final Rule Change Report released * Final Rule Change report sent to Minister for approval (if protected provision)	Minister's Approval for Fiinal Rule Change.		Rule Change Commences (Operational on 1st Feb)				
Operations												Infrastructure Changes - Redundant Web Application Servers						
Systems Development [Steve Black]		• Fortran (MCAP) development complete • Engine Spike development complete		• Rules Engine development commences • Requirements for Screens / Web Services and System Management Interface complete	Requirements for MCAP Recalc and Settlements Update complete		Development for Fortran (Price), MCAP Recalc, Pricing UDAP / DDAP, and Settlements Update complete	System Management Interface and Settlements Update development complete	• UAT for MCAP Recalc, and Settlements Update complete • Screens / Web Services development complete	• Fortran (STEM) development complete • System Management Interface, Pricing UDAP / DDAP, and Settlements Update UAT complete • Requirements for MPI Phase 4 & 5 complete	• Screens / Web Services UAT complete • Retirement of Rules Engine complete	• Retirement of Fortran; Confirmation that new operations and systems are consistent with final rules **• Market Trial of Balancing System**				**Implementation of Balancing System and Pricing UDAP / DDAP**		
System Management																		
Communications		Industry Workshop on Market Proposal																
Reserve Capacity Refunds																		
Concept Design		Paper to RDIWG by 22 Feb (Will/Greg)	Updated Paper to RDIWG in March (Will/Greg)	Signed off EARLY April - by RDIWG Paper presented to MAC (OUT OF SESSION OR AT A SPECIAL MEETING) (Will/Greg via Jacinda's replacement)														
Process design/mapping																		
Rules Development				Commencement of drafting (Caroline, with assistance from Ben/Greg/Troy and Jacinda)	* Rules Released for first round of consultation (Jacinda's replacement). Rules need to be formally submitted early May to meet 1 December deadline. * Minister informed of Rule Change Proposal (if protected provisions are amended) (Jacinda's replacement)		First Round of submissions close	* Rules released for second round of consultation (in Draft Rule Change Report)	Second round of submissions close	* Final Rule Change Report released * Final Rule Change report sent to Minister for approval (if protected provision)	Minister's Approval for Fiinal Rule Change.	Rule Change Commences (1 Dec)						
Operations																		
Systems Development [Matt Pember]				Settlements Update requirements complete			Settlements Update development complete		Settlements Update UAT complete		Confirmation that operations and systems are consistent with the final rules.	**Implementation of Reserve Capacity Refunds System**						
Communications																		

Market Evolution Program - Milestones and Timelines as at February 2011

Ancillary Services																		
Concept Design		Paper on balancing to incorporate principles for ancillary services			Paper on ancillary services proposal to RDIWG for sign off-May	Paper presented to the June MAC (papers due 25 May 2011) (Ben / Jim via Jacinda's replacement)												
Process design/mapping																		
Rules Development					Commencement of drafting (Caroline, with assistance from Ben/Greg/Troy and Jacinda)			* Rules Released for first round of consultation * Minister informed of Rule Change Proposal (if protected provisions are amended)		First Round of submissions close	* Rules released for second round of consultation (in Draft Rule Change Report)	Second round of submissions close	* Final Rule Change Report released * Final Rule Change report sent to Minister for approval (if protected provision)	Minister's Approval for Fiinal Rule Change.	Rule Change Commences			
Operations																		
Systems Development [Matt Pember]							Requirements for Rules Engine Spike, Screens / Web Services, and System Management Interface complete				Development for Rules Engine Spike, Screens / Web Services, and System Management Interface complete		UAT for Rules Engine Spike, Screens / Web Services, and System Management Interface complete	• **Market Trial of Load Following Ancillary Services**	Confirmation that operations and systems are consistent with final rules	**Implementation of Ancillary Services System**		
System Management																		
Communications																		
Compliance																		
Concept Design																		
Process design/mapping																		
Rules Development																		
Operations																		
Systems Development [Matt Pember]						Requirements for Balancing Compliance Report complete		Development of Balancing Compliance Report complete		Requirements for Market compliance tools complete		Development of market compliance tools complete		Development of market compliance tools complete. Testing commences				• UAT for Compliance Tools Complete • **Implementation of Compliance**
Communications																		
Registration																		
Concept Design																		
Process design/mapping																		
Rules Development																		
Operations																		
Systems Development	Business Requirements complete [Hari Babu Madala] ✔			Development for MPI Security, User Admin, and File Exchange complete [Matt Pember]		• Development for MPR Rego prework, MPI Phase 2, and Curtailable Loads complete [Matt Pember] • UAT for MPI Security, User Admin, and File Exchange complete [Matt Pember]			• UAT for MPR Rego prework, MPI Phase 2, and Curtailable Loads complete [Hari Babu Madala] • Requirements for Gentailer Nominations complete [Hari Babu Madala] • **Implementation of Registration System** [Hari Babu Madala]		Development for Gentailer Nominations complete * [Hari Babu Madala]	• UAT for Gentailer Nominations complete * [Hari Babu Madala]	*** If progressed by RDIWG ***		**Implementation of Gentailer Nominations** * [Hari Babu Madala]			
Communications																		
Other IT Roadmap items																		
Ex Post Fuel [John M]		UAT complete		**Implementation**														
MPI Phase 3 (Pt 1 & 2 - D/W & ERA) [Hari]		Functional Test complete	UAT complete	**Implementation**														
MPI Phase 3 (Pt 3 - Reporting Services) [Hari]																Development complete		• UAT Complete • **Implementation**
MPI Phase 3 (Pt 4 - IMO Tools) [Hari]																Development complete		• UAT Complete • **Implementation**
Settlements Web Services [Matt P]				Development complete		• UAT Complete • **Implementation**												
NTDL [John M]		UAT complete		**Implementation**														
Metering Update [Matt P]	** Implementation likely to be before Dec 11 [Martin M]						Requirements complete				Development complete	• UAT Complete • **Implementation ****						
Credit Limits [Matt P]		Requirements complete		Development complete		UAT complete			**Implementation**									
Intermittent Loads [Matt P]													Requirements complete			Development complete		• UAT Complete • **Implementation**
Reserve Capacity Security [Matt P]													Requirements complete			Development complete		• UAT Complete • **Implementation**
MRCP Price Setting [Matt P]													Requirements complete			Development complete		• UAT Complete • **Implementation**
FTP File validation [Matt P]	Requirements complete ✔			Development complete		UAT complete	**Implementation**											
Market Summary Reports [Steve B]													Requirements complete			Development complete		• UAT Complete • **Implementation**
Monitoring [Martin M]																		
Communications	• MEP onsite Presentations cont ✔ • MEP Watch ✔	• MEP Watch • IT User Group Forum	• General Information Session • MEP Watch	• MEP onsite Presentations • MEP Watch • IT User Group Forum • Market Operation Stakeholder Forum	• MEP Watch	• General Information Session • MEP Watch • IT User Group Forum	• MEP Watch	• MEP Watch • IT User Group Forum • Market Operation Stakeholder Forum	• General Information Session • MEP Watch	• MEP onsite Presentations • MEP Watch • IT User Group Forum	• MEP Watch	• General Information Session • MEP Watch • IT User Group Forum • Market Operation Stakeholder Forum	• MEP Watch	• MEP Watch • IT User Group Forum	• General Information Session • MEP onsite Presentations • MEP Watch	• MEP Watch • IT User Group Forum	• MEP Watch	• General Information Session • MEP Watch • IT User Group Forum
Finances				Budget and revenue filing						Strategic Asset Plan lodged								

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
11	The IMO to discuss with System Management its requirements for actual wind speed data and progress a Rule Change Proposal to ensure the provision of this data (if appropriate).	IMO/SM	2	Underway. Discussed with System Management 11 November 2010. System Management is summarizing the potential requirements for this. Once complete, an assessment will be made as to whether a Rule Change Proposal is necessary.
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.

#	Action	Responsibility	Meeting arising	Status/Progress
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. Will be available at the 15 March 2011 meeting.
46	The IMO to undertake a high level cost/benefit analysis for the proposed Balancing provision solution.	IMO	6	Preliminary analysis on today's agenda.
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 Market Participants.	IMO	6	
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.
61	The IMO to convert the table on page 23 (of 75) to the energy equivalent Balancing Merit Order and circulate to the RDIWG.	IMO	8	Underway. The IMO has included a simplified version of this in the new pricing section (using only one IPP instead of two).
64	The IMO to include the project plan in future RDIWG meeting papers.	IMO	8	Included in today's meeting papers.

Table 2: Completed since last meeting

#	Action	Responsibility	Meeting arising	Status/Progress
54	The IMO to expand the Reserve Capacity refunds paper to cover the use of a consolidated fund for refunds for the purposes of Supplementary Reserve Capacity.	IMO	7	Complete. Paper on today's agenda.
55	The IMO to add an agenda item for the next MAC meeting to discuss the work coming out of the MEP and operational rule changes.	IMO	8	Completed. Discussed at the 9 February 2011 MAC meeting.

#	Action	Responsibility	Meeting arising	Status/Progress
56	The IMO to publish the minutes of Meeting No. on the website as final.	IMO	8	Completed.
57	The IMO confirm how the 100 MW of Load Following aligns with the requirements modelled in the ROAM report.	IMO	8	The ROAM report assumed a base Load Following requirement of 72 MW (without Collgar), with an additional 28.8 MW required with Collgar fully commissioned. This totals 100.8 MW. It should be noted that the current Load Following requirement (set in the 2010 Ancillary Services report[1]) is 60 MW (without Collgar). Therefore, the base of 72 MW (assumed by ROAM) may be too high.
58	The IMO to work with Andrew Sutherland to discuss the issue relating to "Use of STEM and changes to Resource Plans".	IMO	8	Completed.
59	The IMO to review each of the issues raised and prepare the scenarios requested for the next RDIWG meeting.	IMO	8	Completed. Paper on today's agenda.
60	Members to provide the IMO with additional comments on the Balancing Market proposal by 10 February 2011.	IMO	8	Completed. Comments received from: • Alinta; • ERM; • Perth Energy; • System Management;

[1] Available: http://www.imowa.com.au/ancillary-services-annual-reports

#	Action	Responsibility	Meeting arising	Status/Progress
				• Synergy; and • Verve Energy.
62	The IMO to circulate a word version of the Balancing Market proposal paper to the RDIWG.	IMO	8	Completed. Circulated 16 February 2011.
63	The IMO to postpone the 23 February 2011 workshop.	IMO	8	Completed.