INDEPENDENT
MARKET
OPERATOR

# Final Rule Change Report: Changes to the Reserve Capacity Price and the Dynamic Reserve Capacity Refund Regime (RC_2013_20)

## Standard Rule Change Process

15 April 2015

## Executive summary

The Reserve Capacity Mechanism (RCM) Working Group (RCMWG) was established in February 2012 to assess the issues highlighted by The Lantau Group in its report 'Review of RCM: Issues and Recommendations'[1]. This report was commissioned by the IMO Board to analyse the effectiveness and efficiency of the RCM.

The RCMWG considered a number of work-streams including issues in relation to the:

(a) poor responsiveness of the administered Reserve Capacity Price (RCP) formula to changing market conditions which results in inefficient signals for investment in or deferment of new capacity;

(b) weak alignment of the refund factors to prevailing power system conditions which results in inefficient valuing of capacity available to the market when system reserve is low; and

(c) current distribution of Capacity Cost Refund revenue to Market Customers which results in an inefficient value transfer from Market Generators to Market Customers. The current mechanism fails to account for the fact that an 'expected refund cost' is not currently included in the Maximum RCP and the administered RCP formula (which together determine the price of Capacity Credits). Therefore, if the quality of service remains unaffected for Market Customers such that they receive the full benefit of the capacity product they paid for, distributing the refund revenue to Market Customers represents an inefficient value transfer that does not lead to any economic benefit in the overall market.

**Proposed amendments**

The IMO developed this Rule Change Proposal to progress the proposed amendments discussed at the RCMWG, which seek to:

(a) change the administered RCP formula such that the downward adjustment to the RCP is accelerated with increasing levels of excess capacity thereby sending stronger signals for the need for capacity;

(b) align the determination of refund factors to the prevailing spare capacity in any given Trading Interval while retaining the maximum and minimum refund factor values thereby improving the value placed on capacity available to the market when system reserve is low; and

(c) recycle the Capacity Cost Refund revenue to capacity providers instead of capacity users in the form of rebates based on a combination of availability and dispatch in the previous 30-day period thereby minimising the inefficient value transfer in the market.

Although not unanimously agreed, the RCMWG members generally supported the amendments proposed in this Rule Change Proposal.

[1] Available at: http://www.imowa.com.au/home/electricity/market-advisory-committee/mac-working-groups/inactive---reserve-capacity-mechanism-working-group.

## Consultation

A concept paper exploring the proposed changes to the RCP formula and the introduction of a dynamic Reserve Capacity refund regime was presented at the Market Advisory Committee (MAC) meeting held on 9 October 2013. Some MAC members requested further information on the economic justifications underpinning the proposed recycling regime for Capacity Cost Refund revenue. Incorporating the suggestions received at the 9 October 2013 MAC meeting, the IMO presented a pre Rule Change Proposal at the 11 December 2013 MAC meeting. At this meeting, the MAC agreed to submit the proposal into the formal rule change process. The IMO formally submitted the Rule Change Proposal into the Standard Rule Change Process and published the Rule Change Notice on 10 January 2014.

The first submission period was held between 13 January and 24 February 2014. Submissions were received from Alinta Energy, Bluewaters Power, Community Electricity, EnerNOC, ERM Power, Perth Energy and Synergy.

Bluewaters Power, Community Electricity, EnerNOC and ERM Power supported the Rule Change Proposal in its entirety. Alinta Energy, Perth Energy and Synergy requested deferral of the Rule Change Proposal in light of the impending outcomes from the State Government's Electricity Market Review (EMR).

The following table provides a summary of the views expressed in submissions received during the first submission period.

| Proposal | Supported | Not Supported |
|---|---|---|
| **Proposed RCP Formula** | Bluewaters Power – suggested a steeper slope than -3.75 because the current excess capacity situation has significantly diluted the investment signal | Alinta Energy – considered that the suggested values for the RCP parameters were not based on detailed analyses and also noted that if the proposal continues, a price floor should be introduced to reduce investment uncertainty |
| | Synergy – provided in principle support but suggested the introduction of a price floor (70 percent of MRCP) due to increased investment uncertainty | Perth Energy – considered that the proposal introduces further price volatility and reduces stability of investment |
| | ERM Power – suggested a steeper slope to better reflect market conditions and incentivise bilateral contracting | |
| | Community Electricity | |
| | EnerNOC | |

| Proposal | Supported | Not Supported |
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| **Dynamic Reserve Capacity Refund Factors** | Bluewaters Power – suggested earlier implementation due to positive impacts of the associated behavioural changes | Alinta Energy – noted increased uncertainty of refund exposure and the interaction with RC_2013_09[2] which is expected to increase the risk of refund exposure when Outages are in excess of the exempt Planned Outage cap |
| | Synergy – provided in principle support but noted interaction with RC_2013_09[2] which is expected to increase the risk of refund exposure when Outages are in excess of the exempt Planned Outage cap | |
| | Community Electricity | |
| | EnerNOC | |
| | ERM Power | |
| | Perth Energy | |
| **Recycling of Capacity Cost Refund Revenue to Capacity Providers** | Alinta Energy – provided in principle support but suggested removing the eligibility criterion because inefficient outcomes may occur as a result of peaking generators bidding at low prices to enable dispatch | Perth Energy – noted that generators are already compensated for providing energy and where energy is not being provided customers should be refunded |
| | Bluewaters Power – suggested earlier implementation due to positive impacts of the behavioural changes | Synergy – considered that the proposal will not lead to increased availability of capacity and would result in an unjustified transfer in costs to tax payers |
| | Community Electricity – suggested that refund revenue should only be distributed to generators producing energy in the Trading Interval | |
| | EnerNOC | |
| | ERM Power | |

The second submission period was held between 1 April and 1 May 2014. Submissions were received from Alinta Energy, Community Electricity, Merredin Energy and Synergy.

Alinta Energy and Synergy reiterated their view that the Rule Change Proposal should be deferred until after the outcomes of the EMR are published. Merredin Energy also supported the views raised by other submitters in the first submission period in relation to deferring the Rule Change Proposal in light of the EMR. However, Community Electricity reiterated its

[2] The Rule Change Proposal: Incentives to Improve Availability of Scheduled Generators has since been rejected by the Minister on the basis that the costs associated with the proposed changes may not be recovered in light of the EMR. Further information is available at: http://www.imowa.com.au/RC_2013_09.

support for the Rule Change Proposal and further supported progressing the Rule Change Proposal in parallel with the EMR.

The following table provides a summary of the views expressed in submissions received during the second submission period.

| Proposal | Supported | Not Supported |
|---|---|---|
| **Proposed RCP Formula** | Synergy – provided in principle support but reiterated its suggestion of a price floor (70 percent of MRCP) due to increased investment uncertainty | Alinta Energy – reiterated its suggestion of a price floor due to increased investment uncertainty |
| | | Merredin Energy – suggested introducing a price floor and reducing the slope gradient to reduce price volatility and investment uncertainty |
| **Dynamic Reserve Capacity Refund Factors** | | Alinta Energy – noted increased uncertainty of refund exposure which may result in inefficient plant maintenance to the detriment of power system security |
| **Recycling of Capacity Cost Refund Revenue to Capacity Providers** | Alinta Energy – provided in principle support but suggested removing the eligibility criterion because inefficient resource allocation may occur as a result of peaking generators bidding at below-cost prices to enable dispatch | |

Following the close of the second submission period, the IMO extended the timeframe for publishing this Final Rule Change Report until 30 April 2015 to allow the IMO to consider the outcomes of the EMR and any potential impacts on this Rule Change Proposal.

On 18 March 2015, the IMO received a letter from the Minister requesting that the IMO resume the 2014 Reserve Capacity Cycle, which had been deferred by 12 months under a Ministerial Direction received on 29 April 2014, and expedite the progression of this Rule Change Proposal to provide certainty to applicants for the 2014 Reserve Capacity Cycle. Due to the significant period of time that had passed since the second round of consultation, on 23 March 2015, the IMO published a 'call for further submissions' to allow stakeholders to make submissions on any new substantive issues.

The further submission period was held between 23 March and 2 April 2015. During the further submission period, the IMO received submissions from Alinta Energy and Perth Energy. Alinta Energy stated that it considered the proposed changes to the RCP formula represents a suitable solution for the current market issues and that the proposed changes are well aligned with the EMR's broader objectives. Perth Energy reiterated views expressed in its submission in the first submission period and noted that this Rule Change Proposal may be inconsistent with the outcomes of 'Phase 2' of the EMR.

### Assessment against the Wholesale Market Objectives

The IMO considers that the proposed amendments better achieve Wholesale Market Objectives (a), (b), (c) and (d) and are consistent with Wholesale Market Objective (e).

### Practicality and cost of implementation

The IMO expects to incur costs of approximately $480,000 to develop and test the modifications to its IT and settlement systems to implement the proposed amendments. The majority of this cost is expected to be incurred in the 2015/16 financial year and can be accommodated within the IMO's existing budget. The remaining costs will be incurred in the 2016/17 financial year and will therefore need to be included in the IMO's fourth Allowable Revenue submission.

In the first submission period, Bluewaters Power and ERM Power noted that modifications will be required to their business systems but the costs were not expected to be material. In the second and further submission periods, no Market Participant indicated any costs or issues with the practicality of implementing the proposed amendments.

The proposed Amending Rules affecting the name change from Maximum Reserve Capacity Price to Benchmark Reserve Capacity Price and the new RCP adjustment formula are proposed to commence on 1 May 2015[3] to apply from the 2014 Reserve Capacity Cycle (for the 2016/17 Capacity Year) onwards. It should be noted that the 2014 Reserve Capacity Cycle was deferred by 12 months as a result of a Ministerial Direction received by the IMO on 29 April 2014[4].

The IMO notes that clause 4.1.19 and section 4.16 of the Market Rules are Protected Provisions requiring the Amending Rules in this Rule Change Proposal to be approved by the Minister. In accordance with clause 2.8.4 of the Market Rules, the Minister has 20 Business Days from receipt of this Final Rule Change Report to make a decision on the proposed Amending Rules. However, if the Minister wishes to approve the Rule Change Proposal, this approval should occur by 30 April 2015 to allow the Amending Rules to commence on 1 May 2015.

### The IMO's decision

The IMO's decision is to accept the Rule Change Proposal as modified following the first, second and further submission periods.

### Next steps

The IMO proposes to stage the commencement of the proposed Amending Rules set out in this Rule Change Proposal in order for them to apply from the 2014 Reserve Capacity Cycle (as deferred) onwards, as follows:

- **At 8:00 AM on 1 May 2015**: The amendments that replace the name of the Maximum Reserve Capacity Price with Benchmark Reserve Capacity Price and the adjustments to the RCP formula are proposed to commence on 1 May 2015 for the beginning of the 2014 Reserve Capacity Cycle. This includes the amendments to clauses 2.26.1, 2.26.2, 2.26.3, 4.1.19, 4.3.1, 4.13.2, 4.16.1, 4.16.2, 4.16.3, 4.16.5,

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[3] This is the date that applications open for the certification of Reserve Capacity for the 2014 Reserve Capacity Cycle.

[4] Information on the Ministerial Direction and the Reserve Capacity Timetable for the 2014 Reserve Capacity Cycle is available at: http://www.imowa.com.au/home/electricity/reserve-capacity/reserve-capacity-timetable-overview.

4.16.6, 4.16.7, 4.16.8, 4.18.2, 4.22.2, 4.28C.9, 4.29.1, 10.5.1, the definitions of Reserve Capacity Price and Maximum Reserve Capacity Price in the Glossary of the Market Rules. This also includes the new definition of Benchmark Reserve Capacity Price in the Glossary of the Market Rules.

- **At 8:00 AM on 1 October 2016**: The amendments relating to the application of the dynamic Reserve Capacity refund factors and the recycling of Capacity Cost Refund revenue are proposed to commence on 1 October 2016 to become applicable from when Reserve Capacity Obligations start applying for the 2014 Reserve Capacity Cycle. This includes amendments to clauses 1.4.1, 4.26.1, 4.26.1A, 4.26.3, 4.26.3A, 4.26.4, 4.28.4, 4.28A.1, 4.29.3, 9.7.1 and the definitions of Balancing Forecast, Maximum Participant Generation Refund, Off-Peak Trading Interval Rate, Peak Trading Interval Rate and Refund Table, in the Glossary of the Market Rules. This also includes the new clauses 4.26.6, 4.26.7 and the new definitions of Facility Capacity Rebate, Maximum Participant Demand Side Programme Refund, Participant Capacity Rebate and Trading Interval Refund Rate in the Glossary of the Market Rules.

# Contents

# 1. Rule change process and timetable

On 10 January 2014, the IMO submitted a Rule Change Proposal to:

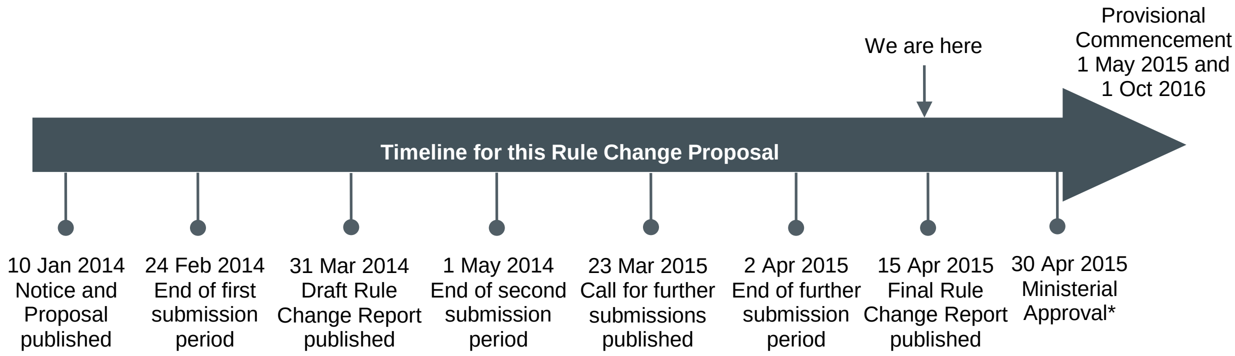
- amend clauses 1.4.1, 2.26.1, 2.26.2, 2.26.3, 4.1.19, 4.3.1, 4.13.2, 4.16.1, 4.16.2, 4.16.3, 4.16.5, 4.16.6, 4.16.7, 4.16.8, 4.18.2, 4.22.2, 4.26.1, 4.26.1A, 4.26.3, 4.26.3A, 4.26.4, 4.28.4, 4.28A.1, 4.28C.9, 4.29.1, 4.29.3, 9.7.1, 10.5.1 and the Glossary of the Wholesale Electricity Market (WEM) Rules (Market Rules); and

- propose new clauses 4.26.6 and 4.26.7 of the Market Rules,

to make changes to the Reserve Capacity Price (RCP) formula and introduce a dynamic Reserve Capacity Refunds regime.

This proposal is being processed using the Standard Rule Change Process, described in section 2.7 of the Market Rules.

The key dates in processing this Rule Change Proposal are:




** In accordance with clause 2.8.4 of the Market Rules, the Minister has 20 Business Days from receipt of the Final Rule Change Report to make a decision on the proposed Amending Rules. However, if the Minister wishes to approve the Rule Change Proposal for it to apply to the 2014 Reserve Capacity Cycle, the IMO considers that the latest date for Ministerial approval is 30 April 2015.*

In accordance with clause 2.5.10 of the Market Rules, the IMO has extended the timeframes for this Rule Change Proposal as follows:

- The timeframe for publishing the Draft Rule Change Report was extended by four Business Days to allow sufficient time for the IMO to consider the submissions received during the first submission period in detail, as published in the Extension Notice on 25 March 2014.

- The timeframe for publishing this Final Rule Change Report was extended by 230 Business Days for the IMO Board to consider in detail the issues raised in submissions received during the second submission period and consider the outcomes of the State Government's Electricity Market Review (EMR) and any potential impacts on this Rule Change Proposal, as published in the Extension Notices on 19 May 2014, 23 May 2014 and 19 December 2014.

The IMO was due to publish this Final Rule Change Report on 30 April 2015, but has expedited the report in response to a letter from the Minister received on 18 March 2015 requesting that the IMO bring forward its consideration to provide greater certainty for Market Participants with regard to the 2014 Reserve Capacity Cycle.

The IMO notes that, in order for the proposed changes in this Rule Change Proposal to apply for the 2014 Reserve Capacity Cycle, the proposed Amending Rules would need to be approved by the Minister prior to, and commence on 1 May 2015 as this is the date applications open for the certification of Reserve Capacity.

# 2. Proposed amendments

## 2.1 The Rule Change Proposal

In February 2012, the Reserve Capacity Mechanism (RCM) Working Group (RCMWG) was formed to explore issues and propose improvements to the design and performance of the RCM. The RCMWG considered a number of work-streams including issues in relation to the:

- poor responsiveness of the administered RCP formula to changing market conditions which results in inefficient signals for investment in or deferment of new capacity;
- weak alignment of the refund factors to prevailing power system conditions which results in inefficient valuing of capacity available to the market when system reserve is low; and
- current distribution of Capacity Cost Refund revenue to Market Customers which results in an inefficient value transfer from Market Generators to Market Customers. The current mechanism fails to account for the fact that an 'expected refund cost' is not currently included in the Maximum RCP (MRCP) and RCP (which determine the price of Capacity Credits). Therefore, if the quality of service remains unaffected for Market Customers implying that they receive the full benefit of the capacity product they paid for, distributing the refund revenue to Market Customers represents an inefficient value transfer that does not lead to any economic benefit in the overall market.

Based on the considerations in the RCMWG, the IMO developed this Rule Change Proposal to progress the following amendments to the Market Rules.

**1. Changes to the Reserve Capacity Price formula**

To address the issue of the current persistent excess capacity in the market, the IMO proposed to improve the responsiveness of the RCP to changing market conditions such that stronger price signals could be delivered for investment in or deferral of new capacity.

Specifically, the IMO proposed to implement the following amendments to the RCP formula (applicable if no Reserve Capacity Auction was run for the Reserve Capacity Cycle) outlined in clause 4.29.1 of the Market Rules:

- the ability for the RCP to rise above the MRCP such that the RCP is 110 percent of the MRCP when 97 percent of the Reserve Capacity Requirement (RCR) has been fulfilled; and

- a steeper slope function of -3.75 replacing the current -1 slope embedded into the ‘excess capacity adjustment’ component of the RCP formula such that the rate of downward adjustment is accelerated as excess capacity increases.

The IMO considered that the proposed amendments to the RCP formula in clause 4.29.1 of the Market Rules would achieve a more balanced RCM where the RCP would be lower than under the current formula for levels of excess capacity above approximately seven percent, while enhancing the investment incentives necessary to assure capacity adequacy as excess capacity declines. The increased responsiveness of the RCP formula resulting from the steeper slope and the ability to exceed the MRCP would create stronger commercial and behavioural incentives for investors in capacity.

**2. The applicable ceiling price in a Reserve Capacity Auction**

The IMO considered that to maintain consistency with the maximum price applicable when no Reserve Capacity Auction is held, the proposed uplift of the RCP to 110 percent of the MRCP (as outlined under issue 1) should also be reflected in the maximum price that will apply if a Reserve Capacity Auction is held for the Reserve Capacity Cycle.

Accordingly, the IMO proposed to amend clauses 2.26.3, 4.18.2 and the definition of Reserve Capacity Price in the Glossary of the Market Rules.

**3. Renaming the Maximum RCP to the Benchmark RCP**

Following the five-yearly MRCP review completed in 2011, the RCMWG members agreed that the MRCP has become more representative of a benchmark price that signals the expected rather than the maximum price for providing Reserve Capacity. For this reason, the IMO proposed to replace all references to the ‘Maximum’ RCP with the ‘Benchmark’ RCP in the Market Rules. This proposed amendment affects clauses 2.26.1, 2.26.2, 2.26.3, 4.1.19, 4.3.1, 4.13.2, 4.16.1, 4.16.2, 4.16.3, 4.16.5, 4.16.6, 4.16.7, 4.16.8, 4.18.2, 4.22.2, 4.28C.9, 4.29.1, 10.5.1, the definition of Maximum Reserve Capacity Price (proposed to be replaced by Benchmark Reserve Capacity Price) and the definition of Reserve Capacity Price in the Glossary of the Market Rules.

**4. Dynamic Reserve Capacity refund factors**

To address the issue of the weak alignment between the value of capacity available to the market and the prevalent power system conditions, the IMO proposed to implement a dynamic refund mechanism whereby refund factors are determined on the basis of the available spare capacity in any Trading Interval. The IMO noted that a dynamic refund mechanism would improve the valuing of capacity available to the market when spare capacity in the system is running low. However, in adopting dynamic refund factors, RCMWG members emphasised the need to retain a maximum and minimum refund factor to provide certainty of the potential financial exposure to Market Participants.

Based on the considerations of the RCMWG, the IMO proposed to replace the Refund Table in clause 4.26.1 of the Market Rules with a formula for determining the applicable refund factor. It was proposed that the refund factor be determined as a function of the spare capacity in a given Trading Interval where the spare capacity is calculated as the sum of the capacity available from different types of Facilities taking into account Outages and system load in that interval.

The formula is proposed to work such that:

- a maximum refund factor of six applies when the spare capacity in a Trading Interval is 750 MW or below;
- a minimum refund factor of 0.25 applies when the spare capacity in a Trading Interval exceeds 1500 MW; and
- the minimum refund factor scales up from 0.25 towards one depending on the level of availability of a Facility over the previous 90-day period up to and including that Trading Interval.

These proposed amendments affect clauses 1.4.1, 4.26.1, 4.28A.1, the definition of Refund Table (proposed to be deleted) and the definition of Maximum Participant Generation Refund in the Glossary of the Market Rules.

**5. The applicable refund rate for Demand Side Programmes**

To maintain consistency with supply-side capacity resources, the IMO considered that the magnitude of Capacity Cost Refunds for Demand Side Programmes (DSP) should be reflective of that faced by generators. As such, the IMO proposed to link the proposed DSP Capacity Cost Refund formula in clause 4.26.3A to the Refund Table in clause 4.26.1 of the Market Rules.

The proposed amendments to the Refund Table in clause 4.26.1 of the Market Rules as outlined under issue 4 require further amendments to the calculation of the Demand Side Programme Capacity Cost Refund in clause 4.26.3A of the Market Rules. The definitions of Off-Peak Trading Interval Rate and Peak Trading Interval Rate were no longer required and therefore were proposed to be replaced by the new proposed definition of Trading Interval Refund Rate in the Glossary of the Market Rules. This proposed amendment also required the deletion of references to Off-Peak Trading Interval Rate and Peak Trading Interval Rate in clauses 4.26.1A, 4.26.3 and, 4.26.3A of the Market Rules.

**6. Recycling of Capacity Cost Refund revenue**

The RCMWG members considered the issues presented by The Lantau Group in relation to the inefficient value transfers created under the current mechanism where Capacity Cost Refund revenue is distributed to Market Customers in proportion to their Individual Reserve Capacity Requirement. The Lantau Group highlighted that the distribution of refund revenue to Market Customers constitutes a value loss from Market Generators because under the current mechanism, the price of a Capacity Credit that Market Customers pay (as determined by the MRCP and the administered RCP formula) does not account for an 'expected refund cost' to protect against the risk of unplanned supply interruptions. As a result, if the quality of service to end-users remains unaffected, the refund revenue to Market Customers amounts to an uncertain revenue stream with no long-term benefits. Ultimately, the inefficient value transfer from Market Generators to Market Customers would need to be offset by higher energy costs or higher capacity prices.

Although not unanimously accepted, the RCMWG agreed to propose a recycling regime such that the collected Capacity Cost Refund revenue is re-distributed to Scheduled Generators and DSPs rather than Market Customers in the form of participant capacity rebates. Eligibility for rebates was proposed to be based on an assessment of actual dispatch of a Facility in the previous 30-day (1,440 Trading Intervals) rolling period.

Rebates for a Trading Interval were proposed to be allocated to Facilities based on their share of available Capacity Credits in that Trading Interval. It should be noted that Intermittent Generators would not be eligible for rebates because under clauses 4.26.1 and 4.26.1A of the Market Rules, Intermittent Generators that are in Commercial Operation and have operated at their Required Level are not liable for Capacity Cost Refunds. Given this arrangement where the risk of exposure to refunds is minimal, the IMO considers that it is appropriate to exclude them from eligibility for a reward.

The IMO proposed amendments to clauses 4.26.4, 4.28.4, 4.29.3, 9.7.1 and introduced new clauses 4.26.6 and 4.26.7 and the definitions of Facility Capacity Rebate and Participant Capacity Rebate in the Glossary of the Market Rules to give effect to the recycling regime.

### 7. Publication of Spare Capacity

At the 11 December 2013 Market Advisory Committee (MAC) meeting, in response to a request by MAC members, the IMO committed to explore the possibility of publishing a forecast of spare capacity based on the information currently publically available under the Market Rules. The IMO considered that the following information currently available under the Market Rules or expected to become available under proposed Amending Rules in other Rule Change Proposals should be used for forecasting spare capacity in any given Trading Interval:

- the Load Forecast for a Trading Day provided by System Management, as defined in the Glossary of the Market Rules;
- for each Scheduled and Non-Scheduled Generator, the Available Capacity as provided and updated in the Balancing Submissions for the Trading Intervals in the Balancing Horizon;
- for each DSP, the aggregate expected minimum consumption of its Associated Loads as provided under clause 2.29.5B(c) of the Market Rules; and
- for each DSP, the aggregate consumption data provided under the proposed Amending Rule 7.6.10 as contained in RC_2013_10.

Finally, the IMO considered that forecast spare capacity for a Trading Interval should be published together with the Balancing Forecast information. The IMO therefore proposed to amend the definition of Balancing Forecast in the Glossary of the Market Rules to include a forecast of the spare capacity for a Trading Interval.

### 8. Accounting for Capacity Credits covered by a Special Price Arrangement in DSP Capacity Cost Refunds

Clause 4.26.3(a) of the Market Rules currently limits the Generation Capacity Cost Refund for a Market Participant in a Trading Month such that the total Generation Capacity Cost Refund for the Market Participant over the relevant Capacity Year cannot exceed the Maximum Participant Generation Refund defined in the Refund Table in clause 4.26.1[5] of the Market Rules. The Maximum Participant Generation Refund is calculated as the total Capacity Credit payment to the Market Participant in the relevant Capacity Year (excluding

5 Note that the proposed amendments to clause 4.26.1 of the Market Rules as outlined in section 8 of this report include placing the definition of Maximum Participant Generation Refund in the Glossary of the Market Rules.

payments in relation to DSPs), assuming the IMO acquires all of the relevant Capacity Credits and the cost of each Capacity Credit so acquired is determined in accordance with clauses 4.28.2(b), (c) and (d) of the Market Rules (as applicable). This ensures that any Capacity Credits covered by a Special Price Arrangement are accounted for appropriately.

For DSPs, a corresponding limit on the Demand Side Programme Capacity Cost Refund is prescribed in clause 4.26.3A(a) of the Market Rules. However, this calculation assumes that all of the relevant Capacity Credits are acquired by the IMO at the Monthly RCP and fails to account for Capacity Credits covered by a Special Price Arrangement.

The IMO therefore proposed the new definition of Maximum Participant Demand Side Programme Refund to maintain consistency with the existing definition of Maximum Participant Generation Refund in the Glossary of the Market Rules and to appropriately account for Capacity Credits covered by a Special Price Arrangement. Additionally, the IMO proposed to amend clause 4.26.3A(a) of the Market Rules to include the new definition of Maximum Participant Demand Side Programme Refund.

Full details of the Rule Change Proposal are available at: http://www.imowa.com.au/RC_2013_20.

### 2.2 The IMO's initial assessment of the Rule Change Proposal

The IMO decided to proceed with the Rule Change Proposal on the basis that section 4 of the Rule Change Proposal indicated that the proposed amendments would better achieve the Wholesale Market Objectives. In particular, the Rule Change Proposal indicated that it would better achieve Wholesale Market Objectives (a), (b), (c) and (d).

The IMO therefore considered that Rule Participants should be given an opportunity to provide submissions on the proposal.

### 2.3 Protected Provisions, Reviewable Decisions and civil penalties

The IMO notes that clause 4.1.19 and the clauses in section 4.16 of the Market Rules are Protected Provisions under clause 2.8.13 of the Market Rules. Under clause 2.8.3 of the Market Rules, amendments to a Protected Provision require the Amending Rules in this Rule Change Proposal to be approved by the Minister.

The IMO has engaged with the Public Utilities Office to progress these amendments.

The IMO notes that this Rule Change Proposal does not include any proposed changes to clauses of the Market Rules that are Reviewable Decisions or civil penalty provisions.

## 3. Consultation

### 3.1 The Market Advisory Committee

A concept paper exploring the proposed changes to the RCP and the introduction of a dynamic Reserve Capacity refund regime was presented at the MAC meeting held on

9 October 2013[6]. The concept paper elaborated on the recommendations for the minimum refund factor (between 0.25 and one) to apply to a Facility depending on the level of its availability over the previous 90-day period. Further recommendations were also presented on the recycling of Capacity Cost Refund revenue to capacity providers that have met the eligibility criterion of generating (or reducing consumption in response to a Dispatch Instruction in the case of DSPs) a non-zero MW quantity in any one Trading Interval in the previous 30-day period.

The IMO presented a pre Rule Change Proposal which incorporated the feedback previously received from MAC members at the 11 December 2013 MAC meeting. At this meeting, MAC members agreed to submit the proposal into the Standard Rule Change Process. Some members sought clarifications on the definition of 'spare capacity' in a Trading Interval which was provided in detail at the meeting. Members also queried whether the IMO could publish the forecast of spare capacity by Trading Interval to facilitate commercial decision-making. The IMO committed to explore the possibility of publication of spare capacity information by Trading Interval. The IMO outlined the proposed amendments in relation to publishing forecast spare capacity in the Draft Rule Change report which was published on 31 March 2014.

Further details are available in the MAC meeting minutes available at: http://www.imowa.com.au/MAC.

## 3.2 Submissions received during the first submission period

The first submission period for this Rule Change Proposal was held between 13 January and 24 February 2014. Submissions were received from Alinta Energy, Bluewaters Power, Community Electricity, EnerNOC, ERM Power, Perth Energy and Synergy.

Bluewaters Power, Community Electricity, EnerNOC and ERM Power supported the Rule Change Proposal in its entirety. Alinta Energy, Perth Energy and Synergy requested deferral of the Rule Change Proposal in light of the impending outcomes from the EMR.

The table below provides a summary of the views expressed in the submissions received in the first submission period.

| Proposal | Supported | Not Supported |
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| **Proposed RCP Formula** | Bluewaters Power – suggested a steeper slope than -3.75 because the current excess capacity situation has significantly diluted the investment signal | Alinta Energy – considered that the suggested values for the RCP parameters were not based on detailed analyses and also noted that if the proposal continues, a price floor should be introduced to reduce investment uncertainty |
| | Synergy – provided in principle support but suggested the introduction of a price floor (70 percent of MRCP) due to increased investment uncertainty | Perth Energy – considered that the proposal introduces further price volatility and reduces stability of investment |

[6] CP_2013_06 is available on page 66 of the meeting papers of the MAC meeting no.65: http://www.imowa.com.au/governance/market-advisory-committee-(mac)/2013/mac-65.

| Proposal | Supported | Not Supported |
|---|---|---|
| | ERM Power – suggested a steeper slope to better reflect market conditions and incentivise bilateral contracting | |
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| **Dynamic Reserve Capacity Refund Factors** | Bluewaters Power – suggested earlier implementation due to positive impacts of the associated behavioural changes | Alinta Energy – noted increased uncertainty of refund exposure and the interaction with RC_2013_09[7] which is expected to increase the risk of refund exposure when Outages are in excess of the exempt Planned Outage cap |
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| | ERM Power | |
| | Perth Energy | |
| **Recycling of Capacity Cost Refund Revenue to Capacity Providers** | Alinta Energy – provided in principle support but suggested removing the eligibility criterion because inefficient outcomes may occur as a result of peaking generators bidding at low prices to enable dispatch | Perth Energy – noted that generators are already compensated for providing energy and where energy is not being provided customers should be refunded |
| | Bluewaters Power – suggested earlier implementation due to positive impacts of the behavioural changes | Synergy – considered that the proposal will not lead to increased availability of capacity and would result in an unjustified transfer in costs to tax payers |
| | Community Electricity – suggested that refund revenue should only be distributed to generators producing energy in the Trading Interval | |
| | EnerNOC | |
| | ERM Power | |

[7] The Rule Change Proposal: Incentives to Improve Availability of Scheduled Generators has since been rejected by the Minister on the basis that the costs associated with the proposed changes may not be recovered in light of the EMR. Further information is available at: http://www.imowa.com.au/RC_2013_09.

## 3.3 The IMO's response to submissions received during the first submission period

The IMO's response to submissions received during the first submission period is detailed in Appendix 1 of the Draft Rule Change Report available at: http://www.imowa.com.au/RC_2013_20.

## 3.4 Additional amendments following the first submission period

Following the first submission period, the IMO made the following additional amendments to the proposed Amending Rules:

- for the purpose of publishing the forecast spare capacity available from DSPs in a Trading Interval, the IMO proposed to change the timing of the provision of DSP consumption data by System Management to the IMO by introducing the proposed new clause 7.6.10A and deleting clause 7.13.1(eH)[8] of the Market Rules;
- for the purpose of providing detail on the calculation of forecast spare capacity in the Market Procedure for Balancing Market Forecasts, the IMO proposed to include the forecast spare capacity for a Trading Interval in the definition of Balancing Forecast in the Glossary of the Market Rules;
- to account for Capacity Credits covered by a Special Price Arrangement which were inadvertently excluded from the current calculation of Demand Side Programme Capacity Cost Refund in the Market Rules, the IMO proposed a new definition of Maximum Participant Demand Side Programme Refund in the Glossary and amendments to clause 4.26.3A(a) of the Market Rules;
- the IMO proposed further amendments to the proposed new clause 4.26.6(b)(i) of the Market Rules to account for a DSP's reduction in consumption in response to a Dispatch Instruction, which was overlooked in the proposed Amending Rules presented in the Rule Change Proposal; and
- the IMO proposed other minor changes to the proposed Amending Rules to improve the overall integrity of the Market Rules.

The amendments the IMO to the proposed Amending Rules following the first submission period are detailed in Appendix 2 of the Draft Rule Change Report available at: http://www.imowa.com.au/RC_2013_20.

## 3.5 Submissions received during the second submission period

The second submission period was held between 1 April and 1 May 2014. Submissions were received from Alinta Energy, Community Electricity, Merredin Energy and Synergy.

Alinta Energy and Synergy reiterated that the Rule Change Proposal should be deferred until after the outcomes of the EMR are known. Merredin Energy also supported the views raised by other submitters in the first submission period in relation to deferring the Rule Change Proposal in light of the EMR. However, Community Electricity reiterated its support for the Rule Change Proposal and further supported progressing the Rule Change Proposal in parallel with the EMR.

[8] As contained in the proposed Amending Rules in RC_2013_10.

The following table provides a summary of the views expressed in submissions received during the second submission period.

| Proposal | Supported | Not Supported |
|---|---|---|
| **Proposed RCP Formula** | Synergy – provided in principle support but reiterated its suggestion of a floor price (70% of MRCP) due to increased investment uncertainty | Alinta Energy – reiterated its suggestion of a price floor due to increased investment uncertainty |
| | | Merredin Energy – suggested introducing a price floor and reducing the slope gradient to reduce price volatility and investment uncertainty |
| **Dynamic Reserve Capacity Refund Factors** | | Alinta Energy – noted increased uncertainty of refund exposure which may result in inefficient plant maintenance to the detriment of power system security |
| **Recycling of Capacity Cost Refund Revenue to Capacity Providers** | Alinta Energy – provided in principle support but suggested removing the eligibility criterion because inefficient resource allocation may occur as a result of peaking generators bidding at below-cost prices to enable dispatch | |

A copy of all submissions in full received during the second submission period is available at: http://www.imowa.com.au/RC_2013_20.

## 3.6 The IMO's response to submissions received during the second submission period

The IMO's response to each of the issues identified during the second submission period is presented in Appendix A of this Final Rule Change Report.

## 3.7 Additional amendments following the second submission period

Following the close of the second submission period, the Minister rejected the Rule Change Proposals:

- Incentives to Improve Availability of Scheduled Generators (RC_2013_09); and
- Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10),

on the basis that the cost to implement the amendments may not be recovered in light of the possible reforms arising from the EMR.

The IMO therefore made further amendments to the proposed Amending Rules contained in the Draft Rule Change Report to remove the drafting reflecting the changes in the two rejected Rule Change Proposals.

The IMO also took the opportunity to make minor grammatical changes to improve the integrity of the Market Rules.

The amendments the IMO to the proposed Amending Rules following the second submission period are detailed in section 5 of the call for further submissions, available at: http://www.imowa.com.au/RC_2013_20.

### 3.8 Submissions received during the further submission period

Following the close of the second submission period, the IMO extended the timeframe for publishing this Final Rule Change Report until 30 April 2015 to allow the IMO to consider the outcomes of the EMR and any potential impacts on this Rule Change Proposal.

On 18 March 2015, the IMO received a letter from the Minister requesting that the IMO resume the 2014 Reserve Capacity Cycle, which had been deferred by 12 months under a Ministerial Direction received on 29 April 2014, and expedite the progression of this Rule Change Proposal to provide certainty to applicants for the 2014 Reserve Capacity Cycle. Due to the significant period of time that had passed since the second round of consultation, on 23 March 2015, the IMO published a 'call for further submissions' to allow stakeholders to make submissions on any new substantive issues.

The further submission period was held between 23 March and 2 April 2015. During the further submission period, the IMO received submissions from Alinta Energy and Perth Energy.

Alinta Energy noted that the EMR had established a clear case for change to the current RCM and stated that it considers that the IMO's proposed changes to the RCP formula are well aligned with the broader objectives of the EMR. Alinta Energy considers that the proposed changes represent a suitable solution for the current market issues and would ensure that an appropriate amount of appropriately priced capacity will be available.

The IMO requested that only new and substantive issues be raised in the further submission period. In particular, this was because the IMO's response to submissions provided in the second submission period had not yet been published. Alinta Energy and Perth Energy reiterated the following views from previous submissions:

- Alinta Energy reiterated its recommendation that the IMO expressly include in the Market Rules a price floor. Alinta Energy noted that, while it understood that there is a natural price floor in the proposed RCP formula, making it explicit in the Market Rules would enhance the transparency of the calculation of the RCP and would facilitate this understanding for new entrants.

- Perth Energy reiterated views expressed in its submission in the first submission period and provided some further observations to support its view on the appropriateness of the proposed recycling of Capacity Cost Refund revenue to capacity providers. In particular, Perth Energy cited a recent example of where Balancing Prices reached the price cap due to a high number of Forced Outages and noted that Market Customers did not receive the capacity paid for and should have been compensated.

- Perth Energy also noted that it considered that this Rule Change Proposal may be inconsistent with the outcomes of phase 2 of the EMR.

A copy of all submissions in full received during the further submission period is available at: http://www.imowa.com.au/RC_2013_20.

### 3.9 The IMO's response to submissions received during the further submission period

The IMO has responded to Alinta Energy's suggestion of an explicit price floor in issues 4 and 5 of the IMO's response to submissions received in the second submission period, provided at Appendix A of this Final Rule Change Report.

The IMO responded to Perth Energy's view that refunds should be provided to Market Customers rather to Market Generators in issue 17 of the IMO's response to submissions received in the first submission period, provided at Appendix 1 of the Draft Rule Change Report available at: http://www.imowa.com.au/RC_2013_20.

The IMO has also responded to concerns raised about the potential for the proposed amendments in this Rule Change Proposal to be affected by the outcomes of the EMR in both the Draft Rule Change Report and this Final Rule Change Report.

### 3.10 Public forums and workshops

No public forums or workshops were held specifically in relation to the Rule Change Proposal.

## 4. The IMO's draft assessment

The IMO's draft assessment, against clauses 2.4.2 and 2.4.3 of the Market Rules, and analysis of the Rule Change Proposal can be viewed in the Draft Rule Change Report, available at: http://www.imowa.com.au/RC_2013_20.

## 5. The IMO's proposed decision

The IMO's proposed decision was to accept the Rule Change Proposal as modified following the first submission period.

The wording of the relevant Amending Rules was presented in section 7 of the Draft Rule Change Report.

The IMO made its proposed decision on the basis that the proposed Amending Rules:

- better achieved Wholesale Market Objectives (a), (b), (c) and (d);
- were consistent with Wholesale Market Objective (e); and
- had the general support of the RCMWG, MAC and submissions received during the first submission period.

# 6. The IMO's final assessment

In preparing its Final Rule Change Report, the IMO must assess the Rule Change Proposal in light of clauses 2.4.2 and 2.4.3 of the Market Rules.

Clause 2.4.2 of the Market Rules outlines that the IMO "must not make Amending Rules unless it is satisfied that the Market Rules, as proposed to be amended or replaced, are consistent with the Wholesale Market Objectives". Additionally, clause 2.4.3 of the Market Rules states, when deciding whether to make Amending Rules, the IMO must have regard to the following:

- any applicable policy direction from the Minister regarding the development of the market;
- the practicality and cost of implementing the proposal;
- the views expressed in submissions and by the MAC; and
- any technical studies that the IMO considers necessary to assist in assessing the Rule Change Proposal.

The IMO notes that there has not been any applicable policy direction from the Minister in respect of this Rule Change nor has it commissioned a technical review in respect of this Rule Change Proposal. A summary of the views expressed in submissions and by the MAC is available in section 3 of this Final Rule Change Report.

Details of the additional amendments to the proposed Amending Rules presented in the call for further submission are presented in section 6.1 below. The IMO's assessment of the Rule Change Proposal, inclusive of the further amendments made following the first, second and further submission periods, is outlined in the following sub-sections.

## 6.1 Additional amendments to the Amending Rules

Following the further submission period, the IMO has made the further amendments to:

- clause 4.26.1 of the Market Rules to clarify the calculation of the dynamic refund factors, including:
  - ensuring that the dynamic refund factor cannot be negative; and
  - clarifying that the spare capacity of a Non-Scheduled Generator will always be zero, as the Facility will always produce its maximum quantity, unless dispatched down because of a network constraint; and
- clause 4.26.6 of the Market Rules to:
  - differentiate the Capacity Cost Refund (a value for a Market Participant for a Trading Month) from the market-wide pool of refunds for a Trading Interval (proposed to be introduced as the 'total available refunds'); and
  - correct cross-references.

## 6.2 Assessment against the Wholesale Market Objectives

The IMO considers that the Market Rules as a whole, if amended as presented in section 8 of this Final Rule Change Report, will allow the Market Rules to better achieve Wholesale Market Objectives (a), (b), (c) and (d). Additionally, the IMO also considers that the proposed amendments are consistent with Wholesale Market Objective (e).

The Wholesale Market Objectives are:

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

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

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

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

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

A detailed assessment against the Wholesale Market Objectives is outlined in the following table.

| Proposed Amendments | Benefits | Wholesale Market Objective Assessment |
|---|---|---|
| **MRCP name change** | The proposed amendments will encourage competition in the market by improving the clarity of the Market Rules and helping to eliminate any misconceptions about the operation of the RCM and the opportunity it offers to new entrants. | Better achieves Wholesale Market Objective (b). |
| **Proposed RCP formula** | The proposed amendments will:<br>• improve the responsiveness of the RCP to changing market conditions thereby promoting economic efficiency;<br>• facilitate efficient entry of new competitors by supporting an appropriate level of new investment in capacity; and<br>• minimise the long-term cost of electricity supply by reducing the cost of excess capacity borne by Market Participants. | Better achieves Wholesale Market Objectives (a), (b) and (d). |

| Proposed Amendments | Benefits | Wholesale Market Objective Assessment |
|---|---|---|
| **Applicable maximum price in the Reserve Capacity Auction** | The proposed amendments will ensure that capacity submitted into the Reserve Capacity Auction is valued at the same maximum price that applies to capacity not subject to the auction, thereby avoiding discrimination between capacities procured from different sources. | Better achieves Wholesale Market Objective (c). |
| **Dynamic Reserve Capacity refund factors** | The proposed amendments will:<br>• improve incentives for efficient scheduling of plant maintenance thereby promoting economically efficient and reliable supply of electricity;<br>• avoid discrimination against Facilities with high utilisation factors by aligning refund factors with prevalent system conditions; and<br>• ensure consistent application of refund rates for both demand-side and supply-side capacity resources thereby avoiding discrimination between different capacity sources. | Better achieves Wholesale Market Objectives (a) and (c). |
| **Accounting for DSP Capacity Credits covered by Special Price Arrangements** | The proposed amendments will ensure consistent application of the limit on refunds between generators and DSPs thereby avoiding discrimination between generators and DSPs. | Better achieves Wholesale Market Objective (c). |
| **Recycling of Capacity Cost Refund revenue** | The proposed amendments will:<br>• improve incentives for Market Generators to provide capacity at times of greatest system need thereby promoting efficient and reliable supply of electricity in peak periods;<br>• reduce value loss in the RCM by redistributing the Capacity Cost Refund revenue to Market Generators instead of Market Customers thereby promoting economic efficiency;<br>• encourage competition between capacity providers by rewarding better availability performance;<br>• avoid discrimination against Facilities with different utilisation factors by recycling refund revenue | Better achieves Wholesale Market Objectives (a), (b), (c) and (d). |

| Proposed Amendments | Benefits | Wholesale Market Objective Assessment |
|---|---|---|
| | based on a combination of availability and dispatch in the previous 30-day period;<br>• minimise the long-term cost of electricity by reducing the risk of price spikes (through incentives to increase availability) in the event of unforeseen supply interruptions; and<br>• minimise the long-term cost of electricity by reducing the administrative costs of the IMO and System Management incurred with respect to Reserve Capacity Testing. | |

## 6.3 Practicality and cost of implementation

### *6.3.1 Practicality*

The proposed Amending Rules affecting the name change from Maximum Reserve Capacity Price to Benchmark Reserve Capacity Price and the new RCP adjustment formula are proposed to commence on 1 May 2015 to become applicable from the 2014 Reserve Capacity Cycle (as deferred[9]) onwards. The remaining proposed Amending Rules relate to the 2014 Reserve Capacity Cycle but are not required to commence, for operational purposes, until 1 October 2016.

The IMO notes that clause 4.1.19 and section 4.16 of the Market Rules are Protected Provisions requiring the Amending Rules in this Rule Change Proposal to be approved by the Minister. In accordance with clause 2.8.4 of the Market Rules, the Minister has 20 Business Days from receipt of this Final Rule Change Report to make a decision on the proposed Amending Rules. However, if the Minister wishes to approve the Rule Change Proposal, this approval should occur by 30 April 2015 to allow the Amending Rules to commence on 1 May 2015.

The IMO notes that two Market Participants, ERM Power and Bluewaters Power noted in their submissions in the first submission period that the proposed amendments will take between one and three months to implement. Bluewaters Power and EnerNOC also noted that the proposed changes will have some effect on operational and investment decisions. As the proposed Amending Rules relate to the 2016/17 Capacity Year, the IMO considers that sufficient implementation time is available.

No other issues were identified with the practicality of implementation of the proposed changes through the consultation process.

[9] Information on the Ministerial Direction and the Reserve Capacity Timetable for the 2014 Reserve Capacity Cycle is available at: http://www.imowa.com.au/home/electricity/reserve-capacity/reserve-capacity-timetable-overview.

The IMO notes that amendments will be required to the following associated Market Procedures if Amending Rules in this Rule Change Proposal are made:

- Market Procedures: Maximum Reserve Capacity Price[10] and Reserve Capacity Security to reflect the name change of the defined term Maximum Reserve Capacity Price to Benchmark Reserve Capacity Price; and
- Market Procedure: Balancing Market Forecasts to include detail in relation to the publication of forecast spare capacity by Trading Interval.

#### *6.3.2 Cost*

The IMO expects to incur costs of approximately $480,000 to develop and test the modifications to its IT and settlement systems to implement the proposed amendments. The majority of this cost is expected to be incurred in the 2015/16 Financial Year and can be accommodated within the IMO's existing budget. The remaining costs to be incurred in the 2016/17 Financial Year and will therefore need to be included in the IMO's fourth Allowable Revenue submission.

In the first submission period, Bluewaters Power and ERM Power noted that modifications will be required to their business systems but the costs were not expected to be material. In the second and further submission periods, no Market Participant indicated any costs to be incurred in implementing the proposed amendments.

## 7. The IMO's decision

Based on the matters set out in this report, the IMO's decision is to accept the Rule Change Proposal as modified following the first, second and further submission periods.

### 7.1 Reasons for the decision

The IMO has made its decision on the basis that the proposed Amending Rules in the Rule Change Proposal:

- better achieve Wholesale Market Objectives (a), (b), (c) and (d);
- are consistent with Wholesale Market Objective (e);
- have the general support of the RCMWG and MAC;
- have the full support of the majority of submissions and in-principle support for certain proposals in other submissions received during the first submission period;
- have the full support of one submission and in-principle support for certain proposals in other submissions received during the second submission period;
- raised no new issues in the further submission period; and

[10] It should be noted that the Rule Change Proposal: Reduced Frequency of the Review of the Energy Price Limits and the Maximum Reserve Capacity Price (RC_2014_05) proposes to remove the requirement for the Market Procedure: MRCP. Further information is available at: www.imowa.com.au/RC_2014_05.

- appear consistent with Phase 2 of the EMR announced on 24 March 2015, in particular, with respect to the RCM reforms aimed at reducing excess capacity and the associated cost.

Additional detail outlining the analysis behind the IMO decision is outlined in section 6 of this Final Rule Change Report.

# 8. Amending Rules

## 8.1 Commencement

The IMO proposes to stage the commencement of the proposed Amending Rules set out in this Rule Change Proposal in order for them to become applicable from the 2014 Reserve Capacity Cycle (as deferred) onwards, as follows:

- **At 8:00 AM on 1 May 2015**: The amendments that replace the name of the Maximum Reserve Capacity Price with Benchmark Reserve Capacity Price and the adjustments to the RCP formula are proposed to commence on 1 May 2015 for the beginning of the 2014 Reserve Capacity Cycle. This includes the amendments to clauses 2.26.1, 2.26.2, 2.26.3, 4.1.19, 4.3.1, 4.13.2, 4.16.1, 4.16.2, 4.16.3, 4.16.5, 4.16.6, 4.16.7, 4.16.8, 4.18.2, 4.22.2, 4.28C.9, 4.29.1, 10.5.1, the definitions of Reserve Capacity Price and Maximum Reserve Capacity Price in the Glossary of the Market Rules. This also includes the new definition of Benchmark Reserve Capacity Price in the Glossary of the Market Rules.
- **At 8:00 AM on 1 October 2016**: The amendments relating to the application of the dynamic Reserve Capacity refund factors and the recycling of Capacity Cost Refund revenue are proposed to commence on 1 October 2016 to become applicable from when Reserve Capacity Obligations start applying for the 2014 Reserve Capacity Cycle. This includes amendments to clauses 1.4.1, 4.26.1, 4.26.1A, 4.26.3, 4.26.3A, 4.26.4, 4.28.4, 4.28A.1, 4.29.3, 9.7.1 and the definitions of Balancing Forecast, Maximum Participant Generation Refund, Off-Peak Trading Interval Rate, Peak Trading Interval Rate and Refund Table, in the Glossary of the Market Rules. This also includes the new clauses 4.26.6, 4.26.7 and the new definitions of Facility Capacity Rebate, Maximum Participant Demand Side Programme Refund, Participant Capacity Rebate and Trading Interval Refund Rate in the Glossary of the Market Rules.

## 8.2 Amending Rules

This section includes the proposed Amending Rules for this Rule Change Proposal, as amended following the first, second and further submission periods. The changes are shown with reference to the current Market Rules (as at 1 November 2014).

The proposed Amending Rules contained in the call for further submissions published on 23 March 2015, removed references to changes to the Market Rules that were proposed to be included in other Rule Change Proposals but which have subsequently not been progressed[11]. The differences between the Amending Rules presented in this section and the call for further submissions are shown in Appendix B of this Final Rule Change Report. The

[11] The amendments from the Draft Rule Change Report are detailed in section 5 of the call for further submissions available at: www.imowa.com.au/RC_2013_20.

differences between the Amending Rules in the Draft Rule Change Report and the call for further submissions are provided in section 5 of the call for further submissions.

The proposed Amending Rules as presented in the Rule Change Proposal and amended following the first, second and further submission periods are as follows (~~deleted text~~, <u>added text</u>):

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...



...

1.4.1. In these Market Rules, unless the contrary intention appears:

...

(r) (**Headings and comments**): headings and comments appearing in boxes in these Market Rules ~~(other than the Refund Table in clause 4.26)~~ are for convenience only and do not affect the interpretation of these Market Rules.

...

# ~~Maximum and Minimum~~ <u>Administered</u> Prices and Loss Factors

### 2.26. Economic Regulation Authority Approval of ~~Maximum and Minimum~~ <u>Administered</u> Prices

2.26.1. Where the IMO has proposed a revised value for the ~~Maximum~~<u>Benchmark</u> Reserve Capacity Price in accordance with ~~clause~~ <u>section</u> 4.16 or a change in the value of one or more Energy Price Limits in accordance with ~~clause~~ <u>section</u> 6.20, the Economic Regulation Authority must:

…

(b) make a decision as to whether or not to approve the revised value for the ~~Maximum~~<u>Benchmark</u> Reserve Capacity Price or any value comprising the Energy Price Limits;

(c) in making its decision, only consider:

i. whether the proposed revised value for the ~~Maximum~~<u>Benchmark</u> Reserve Capacity Price or Energy Price Limit proposed by the IMO reasonably reflects the application of the method and guiding principles described in ~~clauses~~ section 4.16 or 6.20 (as applicable);

...

2.26.2. Where the Economic Regulation Authority rejects a revised ~~Maximum~~Benchmark Reserve Capacity Price or the Energy Price Limits submitted by the IMO it must give reasons and may direct the IMO to carry out all or part of the review process under ~~clause~~ section 4.16 or 6.20 (as applicable) again in accordance with any directions or recommendations of the Economic Regulation Authority.

2.26.3. The Economic Regulation Authority must review the methodology for setting the ~~Maximum~~Benchmark Reserve Capacity Price and the Energy Price Limits not later than the fifth anniversary of the first Reserve Capacity Cycle and, subsequently, not later than the fifth anniversary of the completion of the preceding review under this clause 2.26.3. A review must examine:

…

(d) historical Reserve Capacity Offers and the proportion of Reserve Capacity Offers with prices equal to the ~~Maximum~~Benchmark Reserve Capacity Price, in the case of Reserve Capacity Cycles up to and including 2013;

(dA) historical Reserve Capacity Offers and the proportion of Reserve Capacity Offers with prices equal to 110 percent of the Benchmark Reserve Capacity Price, in the case of Reserve Capacity Cycles from 2014 onwards;

…

(f) the appropriateness of the parameters and methodology in ~~clauses~~ section 4.16 and the Market Procedure referred to in clause 4.16.3 for recalculating the ~~Maximum~~Benchmark Reserve Capacity Price;

…

…

4.1.19. The IMO must commence a review of the ~~Maximum~~Benchmark Reserve Capacity Price as required by clause 4.16.3 with the objective of completing the review, including consideration of public submissions in relation to that review, so as to allow a reasonable time for the Economic Regulation Authority to approve any proposed change in value and for that value to be implemented prior to the date and time specified in clause 4.1.4 that relates to the following Reserve Capacity Cycle.

…

4.3.1. A Request for Expression of Interest for a Reserve Capacity Cycle must include the following information:

...

(c) for each of the three previous Reserve Capacity Cycles (if applicable):

...

v. the ~~Maximum~~Benchmark Reserve Capacity Price;

...

(f) the then current ~~Maximum~~Benchmark Reserve Capacity Price;

...

4.13.2. For the purposes of this section ~~clause~~ 4.13 the amount of Reserve Capacity Security is:

(a) at the time and date referred to in clause 4.1.13, ~~twenty-five~~ 25 percent of the ~~Maximum~~Benchmark Reserve Capacity Price included in the most recently issued Request for Expressions of Interest at the time the Certified Reserve Capacity is assigned, expressed in $/MW per year, multiplied by an amount equal to:

…

(b) at the time and date referred to in clause 4.1.21, ~~twenty-five~~ 25 percent of the ~~Maximum~~Benchmark Reserve Capacity Price included in the most recently issued Request for Expressions of Interest at the time the Certified Reserve Capacity is assigned, expressed in $/MW per year, multiplied by an amount equal to the total number of Capacity Credits assigned to the Facility under clause 4.20.5A.

...

## 4.16. The ~~Maximum~~Benchmark Reserve Capacity Price

4.16.1. For all Reserve Capacity Cycles, the IMO must publish a ~~Maximum~~Benchmark Reserve Capacity Price as determined in accordance with this clause 4.16 prior to the time specified in clause 4.1.4.

4.16.2. The ~~Maximum~~Benchmark Reserve Capacity Price to apply for the first Reserve Capacity Cycle is $150,000 per MW per year.

4.16.3. The IMO must develop a Market Procedure documenting the methodology it uses and the process it follows in determining the ~~Maximum~~Benchmark Reserve Capacity Price, and:

…

(b) the IMO must follow the documented Market Procedure to annually review the value of the ~~Maximum~~Benchmark Reserve Capacity Price in accordance with this clause 4.16 and in accordance with the timing requirements specified in clause 4.1.19.

...

4.16.5. The IMO must propose a revised value for the ~~Maximum~~Benchmark Reserve Capacity Price using the methodology described in the Market Procedure referred to in clause 4.16.3.

4.16.6. The IMO must prepare a draft report describing how it has arrived at a proposed revised value for the ~~Maximum~~Benchmark Reserve Capacity Price under clause 4.16.5. The IMO must publish the report on the Market Web-Site and advertise the report in newspapers widely distributed in Western Australia and request submissions from all sectors of the Western Australia energy industry, including end-users.

4.16.7. After considering ~~of~~ the submissions on the draft report described in clause 4.16.6, the IMO must propose a final revised value for the ~~Maximum~~Benchmark Reserve Capacity Price and publish that value and its final report, including submissions received on the draft report, on the Market Web-Site.

4.16.8. A proposed revised value for the ~~Maximum~~Benchmark Reserve Capacity Price becomes the ~~Maximum~~Benchmark Reserve Capacity Price after the IMO has posted a notice on the Market Web Site of the new value of the ~~Maximum~~Benchmark Reserve Capacity Price with effect from the date and time specified in the IMO's notice.

...

4.18.2. Each Reserve Capacity Price-Quantity Pair must comprise:

…

(b) an offer price in units of dollars per MW per year expressed to a precision of $0.01/MW between zero and 110 percent of the ~~Maximum~~Benchmark Reserve Capacity Price;

...

…

4.22.2. If a Market Participant nominates to have Capacity Credits covered by a Long Term Special Price Arrangement, it must at the same time nominate:

(a) a level of coverage, in MW and to a precision of 0.005 MW, subject to the limits that:

…

ii. if the Capacity Credits are provided by a Facility which has previously provided Capacity Credits, the number of Capacity Credits covered by the arrangement is not to exceed the lesser of:

…

the increase in the number of Capacity Credits provided by the Facility, whether acquired by the IMO or traded bilaterally, since the previous Reserve Capacity Cycle~~.~~,

~~W~~where the Long Term Special Price Arrangement is conditional on evidence being provided to the IMO prior to that Long Term Special Price Arrangement taking effect that capital costs in excess of 10~~%~~ percent of the ~~Maximum~~Benchmark Reserve Capacity Price have been incurred on average with respect to the provision of each Capacity Credit covered by the arrangement; and

...

> **Note:** The IMO has proposed to amend the alignment of the drafting of the last section in this clause to ensure that it applies for each sub-clause in 4.22.2(a), rather than only sub-clause 4.22.2(a)(ii).

...

4.26.1. If a Market Participant holding Capacity Credits associated with a ~~generation system~~Facility fails to comply with its Reserve Capacity Obligations applicable to any given Trading Interval then the Market Participant must pay a refund to the IMO calculated in accordance with the following provisions.

(a) The refund factor RF(f,t) for a Facility f in a Trading Interval t is the lesser of:

i. six; and

ii. the greater of RF_dynamic(t) and RF_floor(f,t).

(b) The dynamic refund factor RF_dynamic(t) in a Trading Interval t is equal to:

$$11.75 - \left(\frac{5.75}{750}\right) \times \mathrm{Spare(t)}$$

where $\mathrm{Spare(t)}$ in a Trading Interval t is equal to the sum of the quantities calculated as follows:

i. for each Scheduled Generator for which a Market Participant holds Capacity Credits, the greater of zero and:

1. the MW quantity of Capacity Credits; less

2. the MW quantity of Outage provided under clause 7.13.1A(b); less

3. the Sent Out Metered Schedule multiplied by two so as to be a MW quantity;

> **Note**: The IMO intends to propose amendments to clause 7.13.1A(b) to receive Outage data as measured at 15 degrees and 41 degrees Celsius in the Rule Change Proposal: Administrative Improvements to the Outage Process (RC_2014_03). Clause 4.26.1(b)(i)(2) will be proposed to be further amended in RC_2014_03 to refer to the Outage data measured at 41 degrees Celsius.

ii. for each Non-Scheduled Generator is zero; and

iii. for each Demand Side Programme within the periods specified in clause 4.10.1(f)(vi) and for which a Market Participant holds Capacity Credits, the greater of zero and:

1. the Demand Side Programme Load multiplied by two so as to be a MW quantity; less

2. the sum of the minimum consumption of each Load in MW provided under clause 2.29.5B(c) for the Facility's Associated Loads.

(c) Subject to clause 4.26.1(d), the minimum refund factor RF_floor(f,t) in a Trading Interval t is equal to:

$$1 - 0.75 \times \mathrm{Dispatchable(f,t)}$$

where $\mathrm{Dispatchable(f,t)}$ for a Facility f in a Trading Interval t, over the 4,320 previous Trading Intervals pt prior to and including that Trading Interval, is determined as:

$$1 - \left(\frac{\sum_{\mathrm{pt}\in\mathrm{PT}} \mathrm{FO(f,pt)}}{\sum_{\mathrm{pt}\in\mathrm{PT}} \mathrm{Cap(f,pt)}}\right)$$

where:

i. $\mathrm{PT}$ is the set of 4,320 Trading Intervals immediately prior to and including the Trading Interval t and $\mathrm{pt}$ is a Trading Interval within that set;

ii. $\mathrm{FO(f,pt)}$ is the quantity of Forced Outage in the Trading Interval $\mathrm{pt}$, determined in accordance with clause 3.21.6(b); and

iii. $\mathrm{Cap(f,pt)}$ is the capacity for the Facility in the Trading Interval $\mathrm{pt}$, given by:

1. the number of Capacity Credits held by the Facility in the Trading Interval $\mathrm{pt}$ if the Facility holds Capacity Credits and had its Certified Reserve Capacity assigned using the methodology described in clause 4.11.1(a); or

2. the Sent Out Capacity of the Facility as recorded in Standing Data (Appendix 1(b)(iii) if the Facility is a Scheduled Generator and Appendix 1(e)(iiiA) if the Facility is a Non-Scheduled Generator) in the Trading Interval $\mathrm{pt}$ otherwise.

(d) For a Facility to which clause 4.26.1A(a)(ii)(2), 4.26.1A(a)(ii)(3), 4.26.1A(a)(ii)(4) or 4.26.1A(a)(ii)(5) applies or for which a non-zero value is determined under clause 4.26.1A(a)(ii)(6), RF_floor(f,t) in a Trading Interval t is equal to one.

(e) The Trading Interval Refund Rate for a Facility f in a Trading Interval t is equal to:

$$\mathrm{RF(f,t)} \times \mathrm{Y}$$

where:

i. for a Non-Scheduled Generator, Y equals zero if the IMO has determined that the Non-Scheduled Generator is in Commercial Operation under clause 4.13.10B and one of the following applies:

1. the Non-Scheduled Generator has operated at a level equivalent to its Required Level, adjusted to 100 percent of the level of Capacity Credits currently held, in at least two Trading Intervals; or

2. the Market Participant has provided the IMO with a report under clause 4.13.10C specifying that the Facility can operate at a level equivalent to its Required Level, adjusted to 100 percent of the level of Capacity Credits currently held; and

ii. for a Non-Scheduled Generator to which clause 4.26.1(e)(i) does not apply and for all other Facilities, Y is determined by dividing the Monthly Reserve Capacity Price (calculated in accordance with clause 4.29.1) by the number of Trading Intervals in the relevant Trading Month.

**~~REFUND TABLE~~**

| **~~Dates~~** | **~~1 April to 1 October~~** | **~~1 October to 1 December~~** | **~~1 December to 1 February~~** | **~~1 February to 1 April~~** |
|---|---|---|---|---|
| ~~Business Days Off-Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)~~ | ~~0.25 x Y~~ | ~~0.25 x Y~~ | ~~0.5 x Y~~ | ~~0.75 x Y~~ |
| ~~Business Days Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)~~ | ~~1.5 x Y~~ | ~~1.5 x Y~~ | ~~4 x Y~~ | ~~6 x Y~~ |
| ~~Non-Business Days Off-Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)~~ | ~~0.25 x Y~~ | ~~0.25 x Y~~ | ~~0.5 x Y~~ | ~~0.75 x Y~~ |
| ~~Non-Business Days Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)~~ | ~~0.75 x Y~~ | ~~0.75 x Y~~ | ~~1.5 x Y~~ | ~~2 x Y~~ |

| | |
|---|---|
| ~~Maximum Participant Generation Refund~~ | ~~The total value of the Capacity Credit payments paid or to be paid under these Market Rules to the relevant Market Participant for the 12 Trading Months commencing at the start of the Trading Day of the previous 1 October (excluding any payments relating to a Demand Side Programme) assuming the IMO acquires all of the Capacity Credits held by the Market Participant (excluding any Capacity Credits held for Demand Side Programmes) and the cost of each Capacity Credit so acquired is determined in accordance with clause 4.28.2(b), (c) and (d) (as applicable).~~ |
| ~~Where:~~<br><br>~~For an Intermittent Generator that has:~~<br><br>~~(a) either:~~<br><br>~~i. operated at a level equivalent to its Required Level, adjusted to 100 percent of the level of Capacity Credits currently held, in at least two Trading Intervals; or~~<br><br>~~ii. provided the IMO with a report under clause 4.13.10C, where this report specifies that the Facility can operate at a level equivalent to its Required Level, adjusted to 100 percent of the level of Capacity Credits currently held; and~~<br><br>~~(b) is, following a request to the IMO by a Market Participant, considered by the IMO to be in Commercial Operation:~~<br><br>~~Y equals 0~~<br><br>~~For all other facilities: Y is determined by dividing the Monthly Reserve Capacity Price (calculated in accordance with clause 4.29.1) by the number of Trading Intervals in the relevant Trading Month.~~ | |

4.26.1A. The IMO must calculate the Reserve Capacity Deficit refund for each Facility ("**Facility Reserve Capacity Deficit Refund**") for each Trading Month m as the lesser of:

(a) the sum over all Trading Intervals t in Trading Month m of the product of:

i. the ~~Off-Peak Trading Interval Rate or Peak~~ Trading Interval Refund Rate ~~determined in accordance with the Refund Table~~ applicable to the Facility in Trading Interval t; and

ii. the Reserve Capacity Deficit in Trading Interval t,

where the Reserve Capacity Deficit for a Facility is equal to whichever of the following applies:

~~iii.~~1. if the Facility is required to have submitted a Forced Outage under clause 3.21.4, the Forced Outage in that Trading Interval measured in MW; ~~or~~

~~iv.~~2. if the Facility is an Intermittent Generator which is not considered by the IMO to have been in Commercial Operation for the purposes of clause 4.26.1(e), the number of Capacity Credits associated with the relevant Intermittent Generator; ~~or~~

~~ivA.~~3. if the Facility is an Intermittent Generator which is considered by the IMO to have been in Commercial Operation for the purposes of clause 4.26.1(e), but for which Y does not equal zero ~~in the Refund Table~~ in clause 4.26.1(e), the minimum of:

~~1.~~i. RL- (2 x $Max_2$); or

~~2.~~ii. RL – A

where;

…

where this value will be applied for the purposes of this clause for the relevant Trading Month; ~~or~~

~~v.~~4. if, from the Trading Day commencing on 30 November of Year 3 for Reserve Capacity Cycles up to and including 2009 or 1 October of Year 3 for Reserve Capacity Cycles from 2010 onwards, the Facility is undergoing an approved Commissioning Test and, for the purposes of permission sought under clause 3.21A.2, is a new generating system referred to in clause 3.21A.2(b), the number of Capacity Credits associated with the relevant Facility; ~~or~~

~~vi.~~5. if, from the Trading Day commencing on 30 November of Year 3 for Reserve Capacity Cycles up to and including 2009 or 1 October of Year 3 for Reserve Capacity Cycles from 2010 onwards, the Facility is not yet undergoing an approved Commissioning Test and, for the purposes of permission sought under clause 3.21A.2, is a new generating system referred to in clause 3.21A.2(b), the number of Capacity Credits associated with the relevant Facility; or

~~vii.~~6. if the Facility is a Demand Side Programme:

max(0, RCOQ - max(0, (RD – MinLoad)))

where:

RCOQ is the Reserve Capacity Obligation Quantity determined for the Facility under clause 4.12.4

RD is the Relevant Demand for the Facility determined in accordance with clause 4.26.2CA; and

MinLoad is the sum of the minimum load MW quantities provided under clause 2.29.5B(c) for the Facility's Associated Loads; and

…

…

4.26.3. The Generation Capacity Cost Refund for Trading Month m in Capacity Year y for a Market Participant p holding Capacity Credits associated with a generation system is the lesser of:

(a) the Maximum Participant Generation Refund determined for Market Participant p and Capacity Year y ~~Trading Month m in accordance with the Refund Table,~~ less all Generation Capacity Cost Refunds applicable to Market Participant p in previous Trading Months falling in ~~the same~~ Capacity Year y ~~as Trading Month m~~; and

(b) the Generation Reserve Capacity Deficit Refund for Market Participant p and Trading Month m, plus the sum over all Trading Intervals t in Trading Month m of the Net STEM Refund,

where the Net STEM Refund is the product of:

i. the ~~Off-Peak Trading Interval Rate or Peak~~ Trading Interval Refund Rate ~~determined in accordance with the Refund Table~~ applicable to Facility f in Trading Interval t; and

ii. the Net STEM Shortfall for Market Participant p in Trading Interval t.

4.26.3A. The Demand Side Programme Capacity Cost Refund for Trading Month m in Capacity Year y for a Market Participant p holding Capacity Credits associated with a Demand Side Programme is equal to the lesser of:

(a) ~~twelve times the Monthly Reserve Capacity Price for Trading Month m multiplied by the number of Capacity Credits associated with the Facility,~~ the Maximum Participant Demand Side Programme Refund determined for Market Participant p and Capacity Year y less all Demand Side Programme Capacity Cost Refunds applicable to ~~that Facility~~ Market Participant p in previous Trading Months falling in ~~the same~~ Capacity Year y~~as Trading Month m~~; and

(b) the sum of:

i. the sum over all Trading Intervals t in Trading Month m of:

12 x Monthly Reserve Capacity Price x S / (2 x H)

~~W~~where:

S is the Capacity Shortfall in MW determined in accordance with clause 4.26.2D in any Trading Interval; and

H is the maximum number of hours per Trading Day that the Facility ~~was certified to be~~ is available to provide Reserve

Capacity in accordance with clause 4.10.1(f)~~(ii)~~; and

…

4.26.4. ~~The IMO must apply any revenue generated from the application of clause 4.26.2E to Market Customers in accordance with clause 4.28.4.~~For each Market Participant holding Capacity Credits associated with a Scheduled Generator or a Demand Side Programme, the IMO must determine the amount of the rebate ("**Participant Capacity Rebate**") to be applied for Trading Month m as the sum of all Facility Capacity Rebates determined in accordance with clause 4.26.6.

...

4.26.6. The Facility Capacity Rebate for Facility f, being a Scheduled Generator or a Demand Side Programme for which a Market Participant holds Capacity Credits, is the sum over all Trading Intervals t in Trading Month m of:

$$\frac{\mathrm{CC(f,t)} \times \mathrm{E(f,t)}}{\sum_{\mathrm{f \in F}}(\mathrm{CC(f,t)} \times \mathrm{E(f,t)})} \times \mathrm{TAR(t)}$$

where:

(a) $\mathrm{TAR(t)}$ is the total available refunds for the Trading Interval t and equals the sum of:

i. the sum for all Facilities of, for each Facility, the product of the Trading Interval Refund for Trading Interval t determined under clause 4.26.1A(a)(i) and the Reserve Capacity Deficit for Trading Interval t under clause 4.26.1A(a)(ii); and

ii. the sum for all Demand Side Programmes of, for each Demand Side Programme:

12 x Monthly Reserve Capacity Price x S / (2 x H)

where:

1. S is the Capacity Shortfall in MW determined in accordance with clause 4.26.2D in any Trading Interval; and

2. H is the maximum number of hours per Trading Day that the Facility is available to provide Reserve Capacity in accordance with clause 4.10.1(f)(ii); and

iii. the sum for all Market Participants of the Net STEM Refund determined under clause 4.26.3(b);

(b) $\mathrm{F}$ is the set of Facilities, being Scheduled Generators or Demand Side Programmes for which Market Participants hold Capacity Credits, in Trading Interval t and $\mathrm{f}$ is a Facility within that set;

(c) $\mathrm{CC(f,t)}$ which equals:

i. for a Scheduled Generator, the MW value of Capacity Credits less the MW quantity of Outage as provided under clause 7.13.1A(b); and

ii. for a Demand Side Programme, the Demand Side Programme Load multiplied by two so as to be a MW quantity less the sum of the minimum consumption of each Load in MW provided under clause 2.29.5B(c) for the Facility's Associated Loads; and

(d) $E(f,t)$ which is the eligibility of the Facility f in Trading Interval t, where eligibility is equal to:

i. one if, subject to clause 4.26.7, Facility f was dispatched and generated (for a Scheduled Generator) or dispatched and reduced (for a Demand Side Programme) a non-zero MW quantity in any one of the 1,440 Trading Intervals prior to and including Trading Interval t; or

ii. zero otherwise.

**Note**: The IMO intends to propose amendments to clause 7.13.1A(b) to receive Outage data as measured at 15 degrees and 41 degrees Celsius in the Rule Change Proposal: Administrative Improvements to the Outage Process (RC_2014_03). Clause 4.26.6(a)(i) will be proposed to be further amended in RC_2014_03 to refer to the Outage data measured at 41 degrees Celsius.

4.26.7. For the purposes of clause 4.26.6(b)(i), a Facility is deemed to have generated a non-zero MW quantity if it meets the requirements for a Reserve Capacity Test specified in clause 4.25.1(a) in any one Trading Interval of the 1,440 Trading Intervals prior to and including Trading Interval t.

...

4.28.4. For each Trading Month, the IMO must calculate a Shared Reserve Capacity Cost being the sum of:

(a) the cost defined under clause 4.28.1(b); and

(~~aA~~b) the net payments to be made by the IMO under Supplementary Capacity Contracts less any amount drawn under a Reserve Capacity Security by the IMO and distributed in accordance with clause 4.13.11A(a); less

~~(b) the Capacity Cost Refunds for that Trading Month; less~~

(~~bA~~c) the Intermittent Load Refunds for that Trading Month; less

(~~c~~d) any amount drawn under a Reserve Capacity Security by the IMO and distributed in accordance with clause 4.13.11A(b)

and the IMO must allocate this total cost to Market Customers in proportion to each Market Customer's Individual Reserve Capacity Requirement.

...

4.28A.1. The IMO must determine for each Intermittent Load registered to Market Participant p the amount of the refund ("~~Intermittent Load Refund~~**Intermittent Load Refund**") to be applied for each Trading Month m in respect of that Intermittent Load as the sum over all Trading Intervals t of Trading Day d in the Trading Month m of the product of:

(a) the applicable value of Y for Scheduled Generators as specified ~~in the Refund Table described~~ in clause 4.26.1(e)(ii) is that which applies for Scheduled Generators; and

…

...

4.28C.9. The amount for the purposes of clauses 4.28C.8 and 4.28C.12 is ~~twenty-five~~ 25 percent of the ~~Maximum~~Benchmark Reserve Capacity Price included in the most recent Request for Expressions of Interest at the time and date associated with ~~either~~ clause 4.28C.8 or 4.28C.12, as applicable, multiplied by an amount equal to the Early Certified Reserve Capacity assigned to the Facility.

...

4.29.1. The Monthly Reserve Capacity Price for a Reserve Capacity Cycle to apply during the period specified in clause 4.1.29 is to equal:

(a) if a Reserve Capacity Auction ~~was~~ is run for the Reserve Capacity Cycle, the Reserve Capacity Price for the Reserve Capacity Cycle divided by 12; or

(b) if no Reserve Capacity Auction ~~was~~ is run ~~for the Reserve Capacity Cycle~~:

i. for a Reserve Capacity Cycle prior to 1 October 2008, 85% of the ~~Maximum~~Benchmark Reserve Capacity Price for the Reserve Capacity Cycle divided by 12;

ii. for a Reserve Capacity Cycle ~~from 1 October 2008~~ up to and including the 2013 Reserve Capacity Cycle, 85% of the ~~Maximum~~Benchmark Reserve Capacity Price for the Reserve Capacity Cycle multiplied by the ~~E~~excess ~~C~~capacity ~~A~~adjustment and divided by 12 where the excess capacity adjustment is equal to the minimum of~~;~~

1. one; and

2. the Reserve Capacity Requirement for the Reserve Capacity Cycle divided by the total number of Capacity Credits assigned by the IMO in accordance with clause 4.20.5A for the Reserve Capacity Cycle; and

~~(c)~~ the ~~Excess Capacity Adjustment is equal to the minimum of:~~

~~i. one, and~~

~~ii. the Reserve Capacity Requirement for the Reserve Capacity Cycle divided by the total number of Capacity Credits assigned by the IMO in accordance with clause 4.20.5A for the Reserve Capacity Cycle.~~

iii. for a Reserve Capacity Cycle from the 2014 Reserve Capacity Cycle onwards, the value calculated as below and divided by 12:

$$\mathrm{MIN}\{\left(\frac{\mathrm{BRCP}\times 1.1}{1-((\mathrm{surplus}+0.03)\times -3.75)}\right), \mathrm{BRCP}\times 1.1\}$$

where:

1. BRCP is the Benchmark Reserve Capacity Price determined in accordance with clause 4.16; and

2. surplus is the amount of excess capacity calculated as:

   i. the total number of Capacity Credits assigned by the IMO in accordance with clause 4.20.5A for the Reserve Capacity Cycle; less

   ii. the Reserve Capacity Requirement for the Reserve Capacity Cycle,

   divided by the Reserve Capacity Requirement for the Reserve Capacity Cycle.

4.29.3. The IMO must prepare and provide the following information to the Settlement Systems in time for settlement of Trading Month m:

...

(d) subject to clause 4.29.4, for each Market Participant p and for Trading Month m:

...

v. the Individual Reserve Capacity Requirement for each Market Customer for that Trading Month; ~~and~~

vi. the total Capacity Cost Refund to be paid by the Market Participant to the IMO; and

vii. the total Participant Capacity Rebate to be paid to the Market Participant by the IMO;

...

...

9.7.1. The Reserve Capacity settlement amount for Market Participant p for Trading Month m is:

RCSA(p,m) =

Monthly Reserve Capacity Price(m) × (CC_NSPA(p,m)
– Sum(q∈ P,CC_ANSPA(p,q,m)))
+ Sum(a ∈ A, Monthly Special Price(p,m,a) × (CC_SPA(p,m,a)
– Sum(q∈ P,CC_ASPA(p,q,m,a))))

- Capacity Cost Refund(p,m)
- Intermittent Load Refund(p,m)
+ Participant Capacity Rebate(p,m)
+ Supplementary Capacity Payment(p,m)
- Targeted Reserve Capacity Cost(m) × Shortfall Share(p,m)
- Shared Reserve Capacity Cost(m) × Capacity Share(p,m)
+ LF_Capacity_Cost(m) × Capacity Share(p,m)

Where:

...

LF_Capacity_Cost(m) is the total Load Following Service capacity payment cost for Trading Month m as specified in clause 9.9.2(q)~~.~~; and

Participant Capacity Rebate(p,m) is the Participant Capacity Rebate payable to the Market Participant p for Trading Month m, as calculated in accordance with clause 4.26.4.

...

10.5.1. The IMO must set the class of confidentiality status for the following information under clause 10.2.1~~,~~ as Public, and the IMO must make each item of information available from the Market Web Site after that item of information becomes available to the IMO:

...

(e) details of bid, offer and clearing price limits as approved by the Economic Regulation Authority including:

i. the ~~Maximum~~Benchmark Reserve Capacity Price;

…

...

...

# 11 Glossary

...

**Balancing Forecast**: Means a forecast, determined by the IMO in accordance with the Balancing Forecast Market Procedure, for a Trading Interval, of the following:

(a) the Relevant Dispatch Quantity for the Trading Interval;

(b) the aggregate output of all Non-Scheduled Generators which are Balancing Facilities for the Trading Interval;~~ and~~

(c) the Balancing Price for the Trading Interval; and~~.~~

(d) the spare capacity for the Trading Interval.

...

**Benchmark Reserve Capacity Price**: In respect of a Reserve Capacity Cycle, the price in clause 4.16.2 as revised in accordance with clause 4.16.

...

**Facility Capacity Rebate**: For a Scheduled Generator or a Demand Side Programme, the rebate determined for a Trading Month m, as calculated in accordance with clause 4.26.6.

…

**Maximum Participant Demand Side Programme Refund:** The total amount of the Capacity Credit payments paid or to be paid under these Market Rules to a Market Participant in relation to its Demand Side Programmes and in relation to a Capacity Year assuming that:

(a) the IMO acquires all of the Capacity Credits held by the Market Participant in relation to its Demand Side Programmes; and

(b) the cost of each Capacity Credit so acquired is determined in accordance with clause 4.28.2(b), 4.28.2(c) and 4.28.2(d) (as applicable).

...

**Maximum Participant Generation Refund:** ~~Has the meaning given in clause 4.26.1.~~The total amount of the Capacity Credit payments paid or to be paid under these Market Rules to a Market Participant in relation to its generating Facilities and in relation to a Capacity Year assuming that:

(a) the IMO acquires all of the Capacity Credits held by the Market Participant in relation to its generating Facilities; and

(b) the cost of each Capacity Credit so acquired is determined in accordance with clause 4.28.2(b), 4.28.2(c) and 4.28.2(d) (as applicable).

...

~~**Maximum Reserve Capacity Price**: In respect of a given Reserve Capacity Cycle, the price in clause 4.16.2 as revised in accordance with clause 4.16.~~

...

~~**Off-Peak Trading Interval Rate**: A Trading Interval occurring between 10 PM and 8 AM.~~

...

**Participant Capacity Rebate**: For a Market Participant holding Capacity Credits associated with a Scheduled Generator or a Demand Side Programme, the rebate determined for a Trading Month m, as calculated in accordance with clause 4.26.4.

...

~~**Peak Trading Interval Rate**: A Trading Interval occurring between 8 AM and 10 PM.~~

...

~~**Refund Table**: The table titled "Refund Table" and set out in Chapter 4.~~

...

**Reserve Capacity Price**: In respect of a Reserve Capacity Cycle, the price for Reserve Capacity determined in accordance with clause 4.29.1 and multiplied by 12, where this price is expressed in units of dollars per megawatt per year and has a value between zero and 110 percent of the ~~Maximum~~Benchmark Reserve Capacity Price.

...

**Trading Interval Refund Rate**: The refund rate applicable in a Trading Interval, and in respect of a Facility, as calculated in accordance with clause 4.26.1(e).

…

## Appendix A. The IMO's response to submissions received during the second submission period

| No. | Submitter | Comment/Change Requested | IMO's Response |
|---|---|---|---|
| **Potential Impact of the Government's Electricity Market Review** | | | |
| 1. | Alinta Energy | The State Government is currently undertaking a review of the design and functions of the WEM which includes a review of a design of the capacity mechanism. It is preferable that issues such as the responsiveness of the capacity mechanism to market conditions are considered as part of this more holistic review of the market design. This will ensure that significant changes in the direction that the market is developing towards are not made in quick succession given the associated implementation costs and investment uncertainty this would create. On this basis Alinta recommends that the progression of this rule change should be deferred until after the findings of the State Governments review are published.<br><br>While the IMO cannot cease the rule change process it can reject the proposal and progress it at a later time once the outcomes of the review are available. Alternatively the IMO could extend the timeframe for making its final decision out to allow time for the review to be completed and a clear outline of the future direction of the market to be available. Alinta Energy suggests that the IMO further investigates these options to determine an approach which can ensure that:<br><br>• the reviews findings can be appropriately taken into account so as to avoid changes in quick succession thereby reducing investor uncertainty; and<br><br>• uncertainty as to how the RCP will be determined in future years is not unnecessarily created i.e. this may necessitate rejecting the changes at this time rather than leaving the proposal awaiting the IMO's final decision for a | In 2012, the RCMWG expended a significant amount of time and effort on deliberations with respect to proposals including this Rule Change Proposal with a view to addressing the issue of excess capacity in the RCM (see Appendix E for the papers discussed at the RCMWG). Following the RCMWG, the IMO progressed this Rule Change Proposal to ensure that the problems identified were addressed as soon as practicable.<br><br>The IMO extended the timeframe for publishing this Final Rule Change Report in order to consider the outcomes of the EMR.<br><br>The IMO notes that Phase 2 of the EMR was announced on 24 March 2015. Reforms to the RCM are to be further investigated under the 'WEM Improvements' work stream of Phase 2. This project "addresses the manner in which the capacity price and volume is determined… to reduce the amount of surplus generation capacity in the market and its associated cost"[12]. The IMO considers that the proposed amendments in this Rule Change Proposal directly address this objective and therefore should be progressed. |

[12] Further information about Phase 2 of the EMR is available at: http://www.finance.wa.gov.au/cms/Public_Utilities_Office/Electricity_Market_Review/Electricity_Market_Review_-_Phase_2.aspx.

| | | | |
|---|---|---|---|
| | | number of years. | |
| | Merredin Energy | Merredin Energy supports the proposal by Alinta Energy, Perth Energy and Synergy to defer the Rule Change Proposal in light of the State Government's Electricity Market Review and other concerns identified in the submission. Delaying the RCP rule change will provide additional time for policy makers to consider and develop appropriate solutions to the concerns raised.<br><br>While there is uncertainty over the extent to which market power would be used to game the RCP [as discussed under point 1 in the submission], we propose that IMO defer the introduction of the new methodology until the Government's WEM review is completed. The WEM review is providing an opportunity for market participants to examine further the implications of the new formula as well as other options with regard making the capacity pricing regime more efficient.<br><br>Possible enhancements to the capacity market could include:<br>• establishing a RCP floor;<br>• developing appropriate protections for independent market participants against market power gaming; and<br>• reviewing MRCP components and the applicability of the 3.75 RCP parameter. | |
| | Synergy | Synergy understands that the role and functioning of the RCM will form a significant part of the Electricity Market Review, and as such, Synergy considers that it is inappropriate to continue with this proposal in the face of further significant review.<br><br>Synergy notes that the RCM is a complex administrative mechanism and changing too many aspects of such a mechanism, or changing the aspects too frequently creates significant regulatory uncertainty and investment risk. As such, Synergy suggests that the prudent approach of deferring this work would be the most appropriate outcome under the current | |

| | | | |
|---|---|---|---|
| | | circumstances.<br>The IMO has indicated that under clauses 2.4 – 2.8 of the Market Rules, it must make a decision to either accept or reject a Rule Change Proposal at each stage of the process, and that it does not have the discretion to cease the progress of a proposal once it has been submitted into the rule change process. Noting this, Synergy highlights that the IMO is able to extend the timeframes for each step of a Rule Change Process. As such, Synergy suggests that the IMO could defer its final decision until the outcomes of the Electricity Market Review are published.<br>There is precedence for this approach, the IMO significantly extended the time to make a decision on "RC_2010_08: Removal of DDAP uplift when less than facility minimum generation" while the Rules Development Implementation Working Group (and latterly the Market Evolution Programme) undertook its review of UDAP and DDAP (among other things). The draft decision for RC_2010_08 was eventually extended for just under two years following an assessment of the expected costs and benefits of the proposal in which the IMO "identified that while there would be financial benefits to Independent Power Producers associated with the changes these are likely to be negated by the costs of implementation of the Amending Rules when spread over a two year period". | |
| **Cost Benefit Assessment** | | | |
| 2. | Synergy | Synergy considers that regulatory change should occur when it can be shown to offer overall net benefit. In order to assess net benefit every substantive regulatory policy change should be subject of a cost benefit assessment.<br>This proposal is a substantive change, may incur implementation costs of up to $440,000 and does not include any supporting evidence that the changes will result in overall net benefit to the market. Consistent with best practice | The IMO has provided more detail on the financial impact of excess capacity in Appendix D of this report. The analysis shows that if the proposed RCP formula was applied since the 2010/11 Capacity Year, there would be overall cost savings in the market even if excess capacity existed. For example, there would have been a saving of $8million in the 2010/11 Capacity Year followed by $7million in the 2011/12 Capacity Year.<br>Additionally, various papers presented at the RCMWG by |

| | | | |
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| | | regulation, Synergy considers it appropriate for the IMO to provide evidence that the benefits of this proposal outweigh the cost. This is especially relevant for this proposal given the potential benefits may only accrue over a short period of time (or even not at all) as a result of the Electricity Market Review and the recent Ministerial direction to defer the 2014 Reserve Capacity Cycle. | The Lantau Group provide further detail on the cost and benefit implications of the overall package of the proposed amendments (see Appendix E for papers discussed at the RCMWG). The IMO also provided its qualitative assessment of the costs and benefits in the Rule Change Proposal and the Draft Rule Change Report. |
| | Alinta Energy | The costs of approximately $285,000 - $440,000 for implementation of the proposed changes are significant and any associated benefits may only accrue over a short period of time (or potentially not at all) depending on the outcomes of the Electricity Market Review and given the recent Ministerial direction with respect to the 2014 Reserve Capacity Cycle. As raised at the March 2014 Market Advisory Committee meeting the IMO needs to demonstrate that the benefits to the market associated with the proposed changes over the potentially short time period during which they may apply will outweigh the estimated costs of implementation.<br><br>Alinta Energy requests that the IMO completes this detailed cost-benefit assessment and presents it to industry for consultation prior to making its final decision. | |
| 3. | Merredin Energy | The IMO expects generation investors to make long term decisions to commit to building capacity yet is taking short term, reactive actions which seem to contravene Wholesale Market Objectives (a) and (d). In particular, Wholesale Market Objective (d) is focused on minimising the long term cost of electricity supply; it is not a short term objective. | The IMO notes that it is unable to quantify the costs that would be incurred by Market Participants in implementing these changes although two submissions received in the first submission period indicated these costs would be minimal.<br><br>The IMO does not consider that the proposed RCP formula represents a short-term reactive action because:<br><br>• it has been developed after detailed analysis of the long-term trends that have existed in the RCM which indicated that the overall mechanism worked well but required refinements to deliver economic efficiency, thereby supporting Wholesale Market Objective (a); and |

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| | | | • the analysis presented in Appendix D of this report indicates that the proposed RCP formula would result in overall cost savings in the market in the future Capacity Years, thereby supporting Wholesale Market Objective (d). |
| **Price Floor in the proposed RCP formula** | | | |
| 4. | Alinta Energy | Alinta continues to not support the progression of the proposed changes to the RCP formula. However, if the IMO determines to continue to progress the proposed changes a price floor should be incorporated into the formula. This will ensure symmetry with the inclusion of a price ceiling and provide greater certainty to investors as to the minimum price their investment may receive from Capacity Credits if traded through the IMO.<br><br>Price ceilings are a widely recognised option to limit the risk that a price exceeds acceptable levels; thereby providing greater cost certainty. The mirror instrument is a price floor which ensures a minimum price is received. Fundamentally the introduction of a price floor and ceiling within a market is intended to truncate the possible range of prices and hence reduce price volatility. Investment certainty is an important consideration in any market which may warrant the introduction of a price floor. Alinta considers that this is particularly relevant to investment in power generation assets which involve long-term investment horizons. | Two common approaches used in capacity markets around the world include:<br><br>• procuring a preset quantity through an auction, thereby discovering the price such as the ISO-New England Forward Capacity Auction; or<br>• using an administered price thereby determining the quantity that enters the market such as the RCM.<br><br>In both approaches, the main challenge is to send the appropriate signal to potential investors without forcing inefficient windfall gains or losses on any one stakeholder group. In quantity-based approaches, a downward sloping demand curve is used to discover the appropriate price to be paid for the required amount of capacity to enter the market. Vertical demand curves have also been used with little success because of the consequent zero-infinity problem of pricing electricity such that when excess capacity exists, price of an incremental MW of capacity falls to zero and when shortfall occurs, the price reaches infinity.<br><br>If a price floor is guaranteed so that the price does not fall to zero with excess supply, then excess capacity continues to persist in the market at unnecessary costs to customers. ISO-New England faced this challenge over seven capacity auctions when significant excess supply persistently cleared in the market at the price floor. In 2013, the Federal Energy Regulatory Commission approved the removal of the price floor beginning with the eighth capacity auction by the order |
| | Synergy | Synergy recognises that this proposal seeks to make the RCP more responsive to the capacity balance – a concept that Synergy supports in principle. However, with greater responsiveness comes greater volatility (an unavoidable result of using price to ration supply). Due to this increased volatility risk Synergy again requests that the IMO specifically considers the inclusion of a price floor in order to limit the extent to which the administered capacity price can be adjusted downward. | |

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| | | This will ensure alignment with the inclusion of a price ceiling and provide greater investment certainty regarding the minimum price an investment may receive from Capacity Credits (if traded through the IMO).<br><br>Synergy considers that without a price floor there is significant investment uncertainty as to the minimum level of income a generator could assume under all market conditions (i.e. in times of either excess or a shortage of capacity). Synergy considers that the risk of a price potentially adjusting to zero (while very unlikely) is an unacceptable risk for any rational investor to take. Synergy considers that future investors need the assurance of a minimum funding flow necessary to secure financial close (i.e. meet lending criteria). Reducing investment uncertainty is an important rationale for the adoption of price floors. Generation investment involves long term horizons and price floors give investors the certainty needed regarding the minimum return on an investment. Without this assurance the level of market risk is higher which may result in difficulty being experienced in attracting future investors to the WEM.<br><br>As such Synergy strongly reiterates its position that the IMO specifically considers the inclusion of a price floor in order to limit the extent to which the administered capacity price can be adjusted downward. Synergy considers that a specific level for the floor should be consulted on, but a level of 70% of the MRCP is suggested as being a reasonable level which balances the objective of achieving a low enough price to ensure there is no residual investment signal with providing a floor price that caps potential downside thus reducing investment risk in the market. A market with a lower investment risk profile ultimately translates into reduced costs for end use consumers. | 138 FERC ¶ 61238[13]. This has already corrected the investment signals such that no further capacity is cleared in the auction when the requirement is fulfilled.<br><br>In price-based approaches such as the RCM, the downward sloping administered price curve approximates customer demand for capacity. Similar to the previous approach, if the price does not adjust downward sufficiently in order to offer price stability to investors, excess capacity will continue to be supplied into the market at an unnecessary cost to customers.<br><br>To assess Synergy's proposal of establishing a price floor of 70 percent of the BRCP and Merredin Energy's proposed price floor of 90 percent of the BRCP, the IMO has calculated the corresponding levels of excess capacity at which the suggested price floors will apply. The analysis shows that a 70 percent price floor corresponds to 12 percent and a 90 percent price floor corresponds to three percent excess capacity in the market. Details are provided in Appendix C of this Report.<br><br>The IMO considers that in the current environment where excess capacity is already at 11 percent of the RCR for the 2015/16 Capacity Year, the inclusion of a price floor at any level will not be of any benefit to the market and will only further dilute the signal for deferring investment in capacity at higher levels of excess capacity. |
| | Merredin | We recommend leaving the price elasticity of excess supply | |

13 See page 8 of http://www.ferc.gov/CalendarFiles/20130826142258-Staff%20Paper.pdf.

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| | Energy | unchanged at 1-to-1, or revising it well down from the proposed 3.75 parameter, to around 2, accompanied by a price floor.<br><br>Given that the maximum RCP could only be 110% of the MRCP, there is every rationale to limit the minimum to 90% of MRCP using a 2x parameter, and 1x parameter for any higher excess capacity. For instance, if excess capacity is 10%, then the first 5% would lead to a 10% fall in RCP, plus the additional 5% leading to a further 5% fall in RCP, totalling 15% fall. This price fall quantum would be more than sufficient to deter the bravest investor from participating in new Capacity Credit certification for the Capacity Year in question. To require a more volatile outcome (such as a 39% drop in this case) is to fail totally to understand the true nature of project financing in this infrastructure market. There is no gain for anyone, least of all consumers, for a RCP regime that could so easily lead investors to breach of project finance covenants. | |
| 5. | Alinta Energy | The introduction of a price floor could be argued to potentially result in surpluses of capacity occurring in the WEM due to the distortionary impacts of price controls in allocating resources. Likewise the introduction of a price ceiling could be argued to potentially result in shortages of capacity occurring. Nonetheless the IMO's draft decision suggests it is reasonable and appropriate to put a ceiling on the RCP. Alinta assumes this is the case because should a shortage of capacity occur there is already a mechanism provided under the rules for procuring additional capacity, aka Supplementary Reserve Capacity. Alinta however does not consider that the rationale for not including a price floor has been sufficiently investigated. | The IMO notes that allowing the RCP to rise up to 110 percent of the BRCP ensures that Market Customers are incentivised to seek Bilateral Contracts with capacity providers to hedge their risk of being exposed to a higher capacity price when capacity is in short supply. If the ceiling price is removed, then the capacity price could reach infinity when capacity is in short supply.<br><br>Additionally, where the Reserve Capacity Requirement in a Reserve Capacity Cycle is not met with the available quantity of Certified Reserve Capacity, the IMO holds a Reserve Capacity Auction. A ceiling price (equal to 110 percent of the BRCP) is imposed on the Reserve Capacity Offers submitted into the auction to equally ensure that the price for incremental capacity does not reach infinity when capacity is in short supply. |

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| 6. | Alinta Energy | To avoid excess capacity occurring in the WEM any price floor would need to be set so as to discourage the introduction of the market's cheapest form of capacity. In the WEM, Demand Side Management (DSM) would likely be the lowest fixed cost capacity to enter the market and so the floor would need to be set so as to discourage the entry of DSM. Using this rationale as the basis to set a price floor would result in a low value being adopted (potentially close to zero). Setting the price floor at this low level though would not however provide any form of investment certainty for capacity developers. A trade-off against allocative efficiency would need to be made to provide greater investment certainty in the WEM. | As previously noted, a price floor is not desirable or appropriate in the current environment where there is an excess of supply as it artificially inflates the capacity price thereby diluting the signal for deferment of investment in new capacity.<br><br>It should be noted however that the IMO also considers that if a price floor were to be introduced, setting it at a level to discourage the entry of DSM in accordance with Alinta Energy's suggestion would be inconsistent with Wholesale Market Objective (c).<br><br>Additionally, the IMO considers that the fixed costs of providing DSM cannot be generalised. There are cases where substantial capital investment may be required to invest in standby generation, communication and control requirements for dispatch etc. |
| 7. | Alinta Energy | Attracting investment from private-sector participants that are of a scale and capitalisation sufficient to facilitate long-term stability and investment is one the stated objectives of the current Electricity Market Review. [To the extent that there is any uncertainty as to whether this stated objective of the Electricity Market Review has any relevance in considering the current Rule Change Proposals being progressed Alinta Energy recommends that the Public Utilities Offices advice on this matter should be requested.]<br><br>Likewise the concept of providing investment certainty is embodied within Wholesale Market Objective (b), i.e. investment certainty would be required to facilitate the entry of new competitors. Consistent with these objectives providing greater investment certainty should be a key consideration in making the IMO's determination with respect to this proposal. On this basis Alinta requests that the IMO incorporates an appropriate price floor into the RCP formula that will provide greater investment certainty. | The IMO notes that no submission was received from the Public Utilities Office in the consultation period in relation to any interdependencies between the Electricity Market Review objectives and this Rule Change Proposal.<br><br>Wholesale Market Objective (b) is aimed at encouraging competition among generators and retailers, including by facilitating efficient entry of new competitors. The IMO considers that with respect to the operation of the RCM, this objective is achieved by creating the appropriate signals for capacity to enter or exit the market in response to changing market conditions. As noted in Alinta Energy's submission, where there is short supply of capacity, the proposed RCP formula will operate such that Market Customers will seek Bilateral Contracts for capacity, thereby providing greater investment certainty to capacity providers. |

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| 8. | Alinta Energy | As an aside the introduction of a capacity price floor would be consistent with the arrangements that are currently in place in PJM, NYISO and ISO-NE. Alinta however acknowledges that the arrangements in these capacity markets were initiated due to market power concerns with respect to net buyers offering their generation at low prices so as to influence auction outcomes. It is unclear whether it would be necessary to introduce a capacity price floor into the auction process at this time, particularly given it may result in lower cost technologies not clearing in the auction and therefore missing out on a capacity payment, and, in some cases it may not be counted towards satisfying the relevant retailer's capacity obligation. Alinta suggests that this is not an important consideration at this time given the lack of auctions that have been held since the markets inception. | The IMO notes Alinta Energy's observation that other capacity markets introduced price floors to address market power concerns. However, the IMO is not aware of net buyers offering below cost generation in the WEM and therefore does not consider a price floor necessary at this stage for the reasons previously stated.<br><br>Also as previously noted, the capacity price floor in ISO-NE has been removed beginning with the eighth capacity auction. PJM and NYISO have also recently undertaken reviews of their capacity markets to assess the efficacy of various components. |
| **Gaming the RCP** | | | |
| 9. | Merredin Energy | To understand the severity of the gaming potential and the market power being granted to the largest participants, the IMO should consider the following example.<br><br>At present, the SWIS comprises 5,683MW of assigned capacity (IMO SOO 2013). The Reserve Capacity Requirement is 5,119MW, with surplus capacity of 564MW (11%).<br><br>Synergy/Verve accounts for about 3,000MW of generation capacity once Kwinana Stage C is decommissioned in late 2015. At the 2015-16 RCP of $120k/MW, this equates to total annual capacity revenue of $360m for Synergy. By withholding supply temporarily, through periodic mothballing of capacity for instance, Synergy (or another large generator) could use the Lantau formula to game the RCP in its favour.<br><br>Synergy could, say, reduce 10% of its capacity through mothballing of the 300MW Kemerton GTs on the relatively | The IMO notes that Synergy, the dominant Market Participant, is a net buyer of Capacity Credits in the RCM. This implies that as it retires more capacity, as suggested in Merredin Energy's example, its risk of being exposed to a higher administered RCP to cover its Individual Reserve Capacity Requirement also increases. This strengthens the incentives for Synergy to seek Bilateral Contracts with other capacity providers to hedge its risk in the market.<br><br>It should be noted that the RCM is predicated on the existence of Bilateral Contracts between participants as a risk management instrument. The proposed RCP formula provides for the symmetry of risk between Market Customers and Market Generators. Where a generator decides not to participate in the RCM, the level of excess capacity decreases resulting in a substantial increase in the administered RCP, which in turn creates an incentive for retailers to procure capacity through Bilateral Contracts (with potentially lower |

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| | | plausible excuse of high gas costs. The total surplus capacity in the market would reduce by 6 percentage points, from 11% to 5%. As a result, the RCP would increase by 22% (being 6% x 3.75). This 22% price increase equates to a new RCP of $146k/MW under the proposed formula. Under this scenario, Synergy's total capacity revenue would be $394m (ie, its reduced capacity of 2,700MW x $146k). This represents a net increase of $34m in annual capacity revenues.<br><br>Should Synergy wish to increase its capacity revenue therefore, it could do so by simply mothballing capacity temporarily.<br><br>This potential arises from the steep 3.75 price slope, as the price effect (+22%) more than offsets the quantity effect (-10%) in this example. Even greater super profits could be potentially made by also temporarily mothballing the 230MW Cockburn CCGT and other power stations.<br><br>The ability of a dominant market participant to artificially restrain supply to earn highly predictable (formula based) super profits is being offered by IMO in this administered-price framework.<br><br>We question why the IMO is supporting an arrangement that will provide dominant participants with such easy gaming powers at the expense of smaller participants and more critically consumers. | capacity prices) rather than being exposed to higher costs by procuring capacity through the IMO.<br><br>Additionally, displacement of old plant with new capacity is a desired outcome in economically efficient markets. |
| **MRCP and its components** | | | |
| 10. | Merredin Energy | Merredin Energy is a strong supporter of the Capacity Credit regime. The WEM is dominated by Synergy and a small number of other participants. Given the composition of the market, it remains appropriate for the WEM to have a capacity market with stable policy and price frameworks. The Reserve Capacity Price should represent an economically efficient price and lead to the efficient deployment of capital and provide an | The IMO notes that the RCP adjustment formula in clause 4.29.1 of the Market Rules has not previously been amended. Price volatility in the RCM in the past has resulted from changes to the input components (such as transmission costs) of the MRCP and not the RCP formula itself. Following a review of the MRCP in 2011, the price calculated under the revised formula for the 2014/15, 2015/16 and 2016/17 |

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| | | efficient and appropriate financial return to generators, consistent with the market objectives. The constant modification of the RCP methodology and process has caused this infrastructure market to be seen as high risk to investors and financiers. This has led to higher funding costs and potentially inefficient outcomes, contrary the Wholesale Market Objectives. The proposed change to adopting the Lantau formula is introducing further uncertainties to an increasing risk environment. We therefore suggest the IMO delays the introduction of the proposed RCP changes | Capacity Years have been relatively stable. |
| 11. | Merredin Energy | The application of a 3.75 slope means the RCP will be incredibly sensitive to changes in peak demand assumptions – which is IMO's domain and outside the control of generators.<br>Demand forecasting is inherently difficult. We have seen material year-on-year changes in forecast peak demand. For example, the 2012 SOO estimated 2013 peak demand at 4,164MW (based on 50% PoE). The following year when the IMO published the 2013 SOO, the same peak demand forecast had been revised to 3,735MW, representing a 10.3% fall.<br>Under the Lantau formula, all else being equal, a 10.3% change in forecast demand will reduce the RCP by a massive 39%. IMO is not accountable for its performance in demand forecasting. All the price risks as a result of wrong forecasts are borne by generators, excessively. Price variation of such magnitude would inevitably cause investors to breach debt coverage covenants in standard project finance arrangements. Such predictable risk could only lead to two possible outcomes: 1) investors refusing to invest, or 2) cost of capital going up to incorporate such volatility. | The IMO notes that forecasts are by nature, uncertain. However, the IMO strives to continuously improve the quality of its forecasts. For example, the IMO has undertaken detailed analyses on the impact of distributed solar PV generation and energy efficiency on demand. The preparation of the Statement of Opportunities (SOO) requires the IMO to collect and use information provided by Market Participants. The IMO also conducts stakeholder consultations where possible to ensure information transparency[14].<br>The IMO notes that it is required under the Market Rules to undertake reviews of the Planning Criterion and the processes by which it forecasts SWIS peak demand once every five years. The most recent reviews of the Planning Criterion and demand forecasting processes were completed in 2012, following the Rule Change Proposal: 5-Yearly Review of the Planning Criterion (RC_2012_21) which was progressed to reduce the reserve margin outlined in clause 4.5.9(a)(i) of the Market Rules from 8.2 to 7.6 percent. Additionally, the IMO has adopted the recommendations outlined in the final report of the review of SWIS demand forecasting processes for the 2013 SOO[15]. |

[14] For the 2013 SOO, the IMO held workshops with stakeholders on demand forecasting assumptions. More information is available at: http://www.imowa.com.au/reserve-capacity/electricity-statement-of-opportunities-(esoo).

[15] More information on these reviews is available at http://www.imowa.com.au/home/electricity/reserve-capacity/reserve-capacity-reviews/reserve-capacity-reviews-overview.

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| | | We seriously question whether this is an outcome intended or desired by IMO, market customers and generators. If not, we recommend leaving the price elasticity of excess supply unchanged at 1-to-1, or revising it well down from the proposed 3.75 parameter, to around 2, accompanied by a price floor. | Further, the IMO notes that variation in the RCP occurring as a result of changes to the Reserve Capacity Requirement does not represent a weakness of the RCP formula itself. The IMO notes that where demand has decreased as determined through the SOO, it is logical that less capacity is required and therefore it is appropriate that the administered RCP formula signals to the market that investment in new capacity is not required. |
| 12. | Merredin Energy | The 3.75 parameter used to calculate the RCP will increase the volatility of revenues for generators. If adopted, we argue that the MRCP asset beta used to derive the WACC should be adjusted significantly. For the IMO or its adviser PwC to ignore the impact of this increased volatility of revenue seems highly inappropriate. | The IMO considers that any issues with the components of the MRCP should be raised during the annual MRCP determination process. The next five-yearly review of the MRCP methodology is scheduled to commence in 2015. The IMO encourages Market Participants to actively participate in the respective processes and discussions. |
| | | The increased RCP volatility will have implications for debt as noted above. The cost of debt will increase materially and lenders will need to ensure greater coverage ratios. This will mean projects have to carry less debt than otherwise. This is a real world commercial issue. Investors will be compelled to refinance a project if covenants are breached, with the cost of refinancing and debt contribution adding inexorably to cost per MW built and maintained, leading to pre-emptive under-investment in the generation market. In times of capacity need this under-investment will have serious economy wide impact should brown-outs or black-outs result.<br><br>We argue that the adoption of the Lantau formula should at least result in an immediate reduction in the Debt Ratio from 40% to 30% for MRCP calculation purposes. | The IMO also notes that more detail on the appropriateness of the equity beta and PwC's views are provided in the final report for the determination of the MRCP for 2016/17 Capacity Year[16]. Briefly, in response to issues related to merchant risk of generation investment in the RCM, PwC noted that "*firms receiving 10 years of contracted revenue under the Reserve Capacity Mechanism will have cash-flow characteristics closer to baseload than intermediate/peaking generators"* and "*...considers that the systematic risk characteristics of a business whose capacity is procured by the IMO will be closer to that of a baseload generator than an intermittent/peaking generator.*" Based on these observations, the IMO does not consider that the cost of debt is expected to increase materially as a result of the proposed amendments to the RCP formula.<br><br>The IMO has submitted the Rule Change Proposal: Reduced Frequency of Determining the Energy Price Limits and Maximum Reserve Capacity Price (RC_2014_05)[17] to lengthen |

[16] Available at: http://www.imowa.com.au/docs/default-source/Reserve-Capacity/mrcp/2014_mrcp_final_report.pdf?sfvrsn=0.
[17] Available at: www.imowa.com.au/RC_2014_05.

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| | | | the review period for the MRCP from the current annual determination to every five years, as recommended by the Economic Regulation Authority in its 'Review of methodology for setting the Maximum Reserve Capacity Price and Energy Price Limits'[18]. This should also provide greater long-term certainty to investors. |
| **DSM Participation** | | | |
| 13. | Merredin Energy | DSM has been the most inefficient feature of the capacity market, especially in periods like now when there is significant excess capacity as calculated by IMO. We are at a loss as to why IMO is willing to force $60-70m of additional "capacity" cost per year onto retailers and ultimately consumers.<br><br>Adopting the Lantau formula should be effected hand-in-hand with the exclusion of DSM from the capacity market, to provide a true supply-demand position of generation capacity as defined in the Market Rules and as subjected to the Rules governing the Balancing Energy market dispatch. It is unfair and unreasonable for IMO to treat DSM preferentially while imposing additional punitive outcomes on genuine capacity investors. | The IMO considers that entry of any new capacity, irrespective of its source, would be economically inefficient in the current scenario when excess capacity is already 11 percent of the RCR.<br><br>The IMO also notes that exclusion of any type of capacity from the RCM is inconsistent with Wholesale Market Objective (c).<br><br>Further, the IMO notes that proposed changes that create a level-playing field between demand-side and supply-side capacity resources (RC_2013_10)[19] which was subsequently rejected on the basis that the costs may not be recovered in light of the EMR. However, this area may be considered further as part of Phase 2 of the EMR. |
| **Commencement of the proposed RCP formula** | | | |
| 14. | Merredin Energy | In light of the above points, we consider it highly inappropriate for the IMO to apply the new RCP calculations from 2016-17, without resetting the MRCP components and dealing appropriately with DSM. We would argue IMO should:<br><br>Re-calibrate the MRCP for the 2016-17 MRCP based on revising the Asset Beta and Debt Ratio, and clarifying the Rules surrounding DSM dispatch to make it consistent with all generation capacity; or | The IMO does not consider it necessary to reset the MRCP components in order to implement the proposed amendments in this Rule Change Proposal. Please refer to responses to specific issues under number 1 and 12. |

[18] Available at: http://www.erawa.com.au/energy-markets/electricity-markets/review-of-methodology-for-setting-the-maximum-reserve-capacity-price-and-energy-price-limits.
[19] Available at: www.imowa.com.au/RC_2013_10.

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| | | Delay the implementation of the Lantau formula until such re-calibration and Rules clarification are done | |
| **Dynamic Reserve Capacity refund factors** | | | |
| 15. | Alinta Energy | Alinta continues to not support the introduction of dynamic refund mechanism on the basis that it creates greater uncertainty as to the refund rate that will apply at any time. In particular under the dynamic refund mechanism it is not possible to be 100% certain of the amount of spare capacity in the market in advance and so this will mean that there will be a level of uncertainty as to the exact financial exposure of a generator to refunds in any one trading interval. | As noted in the Draft Rule Change Report and reiterated in this Final Rule Change Report, the IMO considers that the publication of the forecast spare capacity in a Trading Interval will be additional information to that already available to Market Generators to better inform their risk management strategies.<br>The IMO acknowledges that a forecast cannot provide complete certainty. However, in accordance with the principles outlined in clause 7A.3.20 of the Market Rules, the IMO will provide the latest information, to the extent reasonably practicable, for Market Generators to inform their Balancing Submissions. |

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| 16. | Alinta Energy | It is important that in making its decision as to whether to introduce a dynamic refund mechanism that the IMO is fully aware of the potential implications of the proposed changes in a broader sense. Introducing greater uncertainty into the Market Rules will not come without cost. Some of these costs may however not be immediately obvious as they will not be demonstrated within the STEM and Balancing markets. The real impact of the uncertainty associated with the proposed changes will likely play out within the bilateral market where it is possible that the uncertainty will drive generators to apply a higher risk premium when pricing so as to account for the worst case financial exposure of the generator to refunds.<br><br>There will also be other potential implications associated with the proposed changes which the IMO should be aware of in making its decision. For example when a generator experiences a Forced Outage it will likely undertake a cost-benefit assessment so as to identify what approach should be adopted to rectify the issue and get the plant back online. If the refund rate is low the generator may determine to undertake a more permanent fix, whereas if the refund rate is high they are likely to simply complete a quick fix to reduce the magnitude of the refunds they will need to make. Under a dynamic refund mechanism the exact financial exposure of the generator to refunds will be largely unknown and so it is likely that they will need to assume the full level of exposure. This may result in more quick fixes to facilities occurring so as to reduce their immediate exposure to refunds. This may in the long-run be to the detriment of system security. | As noted in the Draft Rule Change Report, the IMO considers that the proposed dynamic refund mechanism itself does not change the current likelihood of exposure to refunds for existing Market Generators. However, it is expected that Market Generators will take into account various incentives proposed, including the proposed dynamic refund mechanism, in their commercial decision-making, thereby increasing the overall efficiency of the market. The IMO considers that the dynamic refund mechanism strengthens the incentive for Market Generators to maximise their availability while taking into account their potential exposure to refunds.<br><br>In response to Alinta Energy's suggestion that the introduction of a dynamic refund mechanism may be to the detriment of power system security, the IMO does not consider this to be a potential outcome of the proposed amendments. Additionally, the IMO notes that System Management has not indicated any issues related to power system security are expected as a result of the dynamic refund mechanism. |
| **Recycling of Capacity Cost Refund revenue** | | | |
| 17. | Alinta Energy | As noted previously Alinta remains generally supportive of the IMO's proposal to recycle capacity refunds to available generators. However Alinta considers that the IMO has not identified all of the potential inefficiencies that could be created | As noted in the Draft Rule Change Report, a Market Generator's decision to become available for dispatch at any time is a commercial decision based on its assessment of its operating costs and risk exposure. |

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| | | by requiring a facility to have generated electricity during any one Trading Interval in the past 30-day period<br>The proposed new "eligibility criteria" for generators to receive capacity refunds will create an incentive for some peaking generation to run at non-peak times so as to be entitled to refunds. As noted previously this will be a commercial decision for generators based on whether they consider the likely capacity refund income will be greater than the costs that they incur in ensuring a non-zero level of generation occur during the relevant time period.<br>This behaviour will have implications for the mix of generation running in the WEM during any relevant Trading Intervals. While as the IMO illustrates there may be a downward pricing impact from peaking generation bidding into the market at low prices to ensure they are dispatched (and therefore satisfy the eligibility criteria for the rebate pool) this behaviour will not be without broader consequences.<br>Bidding a generator at a level below its cost stack simply to be dispatched and meet the eligibility criteria is not necessarily a good use of resources from a broader economic perspective as those factors of production used for generating electricity (i.e. fuel supply) have alternative uses in many cases. Bidding a generator below cost will also potentially result in naturally cheaper facilities being displaced in the economic merit order.<br>The WEM design should not create perverse incentives for behaviour that will distort the normal economic allocation of resources without having good reason for doing so. In this case truly least cost resources may not be used to meet the WEM's energy requirements in some trading intervals and it's unclear that this distortion is warranted. While the behavioural implications will overlap with those currently created by the capacity testing regime (i.e. there are already incentives to bid in a similar manner so as to allow self-testing for capacity | The IMO also does not consider that any perverse outcomes are created by a peaking generator bidding into the energy market to be dispatched (so as to satisfy the eligibility for receiving recycled refunds). The IMO considers that this is an appropriate and intended outcome because more capacity will be available at cheaper rates to be dispatched; thereby putting a downward pressure on prevailing energy prices. The relevant Market Generator may decide it is beneficial to be dispatched taking into account the likely energy price and potential available refunds. Further, the IMO does not consider that there is any detrimental effect on the overall mix of generation dispatched in the energy market by the participation of peaking generators at lower costs. |

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| | | purposes) this will be a potentially more frequent behaviour.<br>To date the IMO's consideration of this issue has simply focused on the impact on energy market prices rather than taking a broader consideration of the impacts on resource allocation and whether the distortionary impacts are indeed warranted. While this might be appropriate given the specific rule making test that is required to be applied by the IMO, Alinta suggests it is prudent that the IMO also identifies and considers the broader implications of its regulatory changes. | |

# Appendix B. Further amendments to the Amending Rules

The IMO has made further amendments to the proposed Amending Rules following the further submission period. These changes are as follows (~~deleted text~~, <u>added text</u>):

4.26.1. If a Market Participant holding Capacity Credits associated with a Facility fails to comply with its Reserve Capacity Obligations applicable to any given Trading Interval then the Market Participant must pay a refund to the IMO calculated in accordance with the following provisions.

…

(b) The dynamic refund factor RF_dynamic(t) in a Trading Interval t is equal to:

$$11.75 - (\frac{5.75}{750}) \times \mathrm{Spare(t)}$$

where $\mathrm{Spare(t)}$ in a Trading Interval t is equal to the sum of the quantities calculated as follows:

i. for each Scheduled Generator for which a Market Participant holds Capacity Credits<u>, the greater of zero and</u>:

1. the MW quantity of Capacity Credits; less

2. the MW quantity of Outage provided under clause 7.13.1A(b); less

3. the Sent Out Metered Schedule multiplied by two so as to be a MW quantity;

ii. for each Non-Scheduled Generator <u>is zero; and</u>~~that received a Dispatch Instruction to decrease its output under clause 7.6.1C and for which a Market Participant holds Capacity Credits:~~

~~1. the estimate of the maximum quantity of sent out energy which would have been generated had a Dispatch Instruction not been issued, as provided by System Management in accordance with clause 7.13.1(eF), multiplied by two so as to be a MW quantity; less~~

~~2. the Sent Out Metered Schedule multiplied by two so as to be a MW quantity; and~~

iii. for each Demand Side Programme within the periods specified in clause 4.10.1(f)(vi) and for which a Market Participant holds Capacity Credits<u>, the greater of zero and</u>:

1. the Demand Side Programme Load multiplied by two so as to be a MW quantity; less

2. the sum of the minimum consumption of each Load in MW provided under clause 2.29.5B(c) for the Facility's Associated Loads.

(c) Subject to clause 4.26.1(d), the minimum refund factor RF_floor(f,t) in a Trading Interval t is equal to:

$$1 - 0.75 \times \mathrm{Dispatchable(f,t)}$$

where $\mathrm{Dispatchable(f,t)}$ for a Facility f in a Trading Interval t~~, over the 4,320 Trading Intervals prior to and including that Trading Interval,~~ is determined as:

$$\cancel{1 - (\frac{\sum \mathrm{FO(f,pt)}}{\sum \mathrm{Cap(f,pt)}})}\ 1 - (\frac{\sum_{\mathrm{pt} \in \mathrm{PT}} \mathrm{FO(f,pt)}}{\sum_{\mathrm{pt} \in \mathrm{PT}} \mathrm{Cap(f,pt)}})$$

where:

i. PT is the set of 4,320 Trading Intervals immediately prior to and including the Trading Interval t and pt is a Trading Interval within that set;

ii. $\mathrm{FO(f,pt)}$ is the quantity of Forced Outage in the Trading Interval pt determined in accordance with clause 3.21.6(b); and

iii. $\mathrm{Cap(f,pt)}$ is the capacity for the Facility in the Trading Interval pt, given by:

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

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

(d) For a Facility to which clause 4.26.1A(a)(ii)(2), 4.26.1A(a)(ii)(3), 4.26.1A(a)(ii)(4) or 4.26.1A(a)(ii)(5) applies or for which a non-zero value is determined under clause 4.26.1A(a)(ii)(6), RF_floor(f,t) in a Trading Interval t is equal to one.

…

…

4.26.3A. The Demand Side Programme Capacity Cost Refund for Trading Month m in Capacity Year y for a Market Participant p holding Capacity Credits associated with a Demand Side Programme is equal to the lesser of:

…

(b) the sum of:

i. the sum over all Trading Intervals t in Trading Month m of:

12 x Monthly Reserve Capacity Price x S / (2 x H)

where:

1. S is the Capacity Shortfall in MW determined in accordance with clause 4.26.2D in any Trading Interval; and

2. H is the maximum number of hours per Trading Day that the Facility is available to provide Reserve Capacity in accordance with clause 4.10.1(f)~~(ii)~~; and

…

…

4.26.6. The Facility Capacity Rebate for Facility f, being a Scheduled Generator or a Demand Side Programme for which a Market Participant holds Capacity Credits, is the sum over all Trading Intervals t in Trading Month m of:

$$\frac{\mathrm{CC(f,t)} \times \mathrm{E(f,t)}}{\underline{\sum_{\mathrm{f}\in\mathrm{F}}(\mathrm{CC(f,t)} \times \mathrm{E(f,t)})}\cancel{\sum_{\mathrm{f=1}}^{\mathrm{F}}\mathrm{CC(f,t)} \times \mathrm{E(f,t)}}} \times \sum \cancel{\mathrm{CCR(t)}}\,\underline{\mathrm{TAR(t)}}$$

where:

~~$\sum \mathrm{CCR(t)}$ is the sum over all Market Participants of the Capacity Cost Refund for Trading Interval t; and~~

(a) $\mathrm{TAR(t)}$ is the total available refunds for the Trading Interval t and equals the sum of:

i. the sum for all Facilities of, for each Facility, the product of the Trading Interval Refund Rate for Trading Interval t determined under clause 4.26.1A(a)(i) and the Reserve Capacity Deficit for Trading Interval t under clause 4.26.1A(a)(ii); and

ii. the sum for all Demand Side Programmes of, for each Demand Side Programme:

12 x Monthly Reserve Capacity Price x S / (2 x H)

where:

1. S is the Capacity Shortfall in MW determined in accordance with clause 4.26.2D in any Trading Interval; and

2. H is the maximum number of hours per Trading Day that the Facility is available to provide Reserve Capacity in accordance with clause 4.10.1(f); and

~~$\sum_{\mathrm{f=1}}^{\mathrm{F}}\mathrm{CC(f,t)} \times \mathrm{E(f,t)}$ is the sum, over all Facilities F, being Scheduled Generators or Demand Side Programmes for which Market Participants hold Capacity Credits, in Trading Interval t, of the product of:~~

(b) $\mathrm{F}$ is the set of Facilities, being Scheduled Generators or Demand Side Programmes for which Market Participants hold Capacity Credits, in Trading Interval t and $\mathrm{f}$ is a Facility within that set;

(~~a~~c) $\mathrm{CC(f,t)}$ equals:

…

(~~b~~d) $\mathrm{E(f,t)}$ is the eligibility of the Facility f in Trading Interval t, where eligibility is equal to:

i. one if, subject to clause 4.26.7, Facility f was dispatched and generated (for a Scheduled Generator) or dispatched and reduced (for a Demand Side Programme) a non-zero MW quantity in any one ~~Trading Interval~~ of the 1,440 Trading Intervals prior to and including Trading Interval t; or

…

…

# Appendix C. Levels of excess capacity by RCP value

Table C.1 shows the levels of excess capacity that would exist at different RCP values as calculated using the proposed RCP formula with the BRCP determined for 2014 Reserve Capacity Cycle for the 2016/17 Capacity Year.

**Table C.1: Impact of the proposed RCP formula on the 2014 Reserve Capacity Cycle**

| Percentage excess capacity | 2016/17 BRCP | Proposed RCP formula | RCP as percent of BRCP |
|---|---|---|---|
| -4% | $176,800 | $194,480 | 110% |
| -3% | $176,800 | $194,480 | 110% |
| -2% | $176,800 | $187,451 | 106% |
| -1% | $176,800 | $180,912 | 102% |
| 0% | $176,800 | $174,813 | 99% |
| 1% | $176,800 | $169,113 | 96% |
| 2% | $176,800 | $163,773 | 93% |
| 3% | $176,800 | $158,759 | 90% |
| 4% | $176,800 | $154,044 | 87% |
| 5% | $176,800 | $149,600 | 85% |
| 6% | $176,800 | $145,406 | 82% |
| 7% | $176,800 | $141,440 | 80% |
| 8% | $176,800 | $137,685 | 78% |
| 9% | $176,800 | $134,124 | 76% |
| 10% | $176,800 | $130,743 | 74% |
| 11% | $176,800 | $127,528 | 72% |
| 12% | $176,800 | $124,467 | 70% |
| 13% | $176,800 | $121,550 | 69% |
| 14% | $176,800 | $118,766 | 67% |
| 15% | $176,800 | $116,107 | 66% |
| 16% | $176,800 | $113,565 | 64% |
| 17% | $176,800 | $111,131 | 63% |
| 18% | $176,800 | $108,800 | 62% |
| 19% | $176,800 | $106,564 | 60% |
| 20% | $176,800 | $104,419 | 59% |

Similarly, Table C.2 shows the levels of excess capacity that would exist at different RCP values as calculated using the proposed RCP formula with the BRCP determined for 2015 Reserve Capacity Cycle for the 2017/18 Capacity Year using the ERA approved BRCP and the 2014 SWIS Electricity Demand Outlook.

**Table C.2: Impact of the proposed formula on the 2015 Reserve Capacity Cycle**

| Percentage excess capacity | 2017/18 BRCP | Proposed RCP formula | RCP as percent of BRCP |
|---|---|---|---|
| -4% | $164,800 | $181,280 | 110% |
| -3% | $164,800 | $181,280 | 110% |
| -2% | $164,800 | $174,728 | 106% |
| -1% | $164,800 | $168,633 | 102% |
| 0% | $164,800 | $162,948 | 99% |
| 1% | $164,800 | $157,635 | 96% |
| 2% | $164,800 | $152,657 | 93% |
| 3% | $164,800 | $147,984 | 90% |
| 4% | $164,800 | $143,588 | 87% |
| 5% | $164,800 | $139,446 | 85% |
| 6% | $164,800 | $135,536 | 82% |
| 7% | $164,800 | $131,840 | 80% |
| 8% | $164,800 | $128,340 | 78% |
| 9% | $164,800 | $125,021 | 76% |
| 10% | $164,800 | $121,869 | 74% |
| 11% | $164,800 | $118,872 | 72% |
| 12% | $164,800 | $116,019 | 70% |
| 13% | $164,800 | $113,300 | 69% |
| 14% | $164,800 | $110,705 | 67% |
| 15% | $164,800 | $108,227 | 66% |
| 16% | $164,800 | $105,857 | 64% |
| 17% | $164,800 | $103,589 | 63% |
| 18% | $164,800 | $101,415 | 62% |
| 19% | $164,800 | $99,332 | 60% |
| 20% | $164,800 | $97,332 | 59% |

# Appendix D. Financial impact of excess capacity

The RCM is a price-based capacity market, establishing a price paid for capacity based on the capacity supply-demand position. The price engenders a competitive supply response which determines the amount of capacity that enters the market and is available. The responsiveness of the RCM to the supply-demand position is therefore critical to promote efficient market outcomes.

In the RCM, the price will move upwards if there is too little capacity. If there is too much capacity, the RCM adjusts the price downward.

The administered RCP is calculated as follows[20]:

RCP = Maximum Reserve Capacity Price (MRCP) x 85% x Excess Capacity Adjustment

where

Excess Capacity Adjustment = Reserve Capacity Requirement / (∑ Capacity Credits)

This formula was designed to maintain the total cost of Capacity Credits at a constant level, irrespective of the quantity of excess capacity. The RCP decreases when excess capacity increases.

However, a Market Customer’s exposure to the discounted price will depend on the quantity of capacity that it has contracted bilaterally. If the discount does not flow through to all Capacity Credits, then excess capacity may result in an increase in the total cost of capacity paid by the market. This is explored in Table 1 over the page, which shows the following for the period from 2010/11 to 2015/16:

- the Reserve Capacity Requirement and the Capacity Credits assigned;
- the MRCP and RCP, as well as the RCP that would have applied if there was no excess capacity;
- the percentage of the Reserve Capacity Requirement that has been contracted in each Capacity Year (estimated for the 2013/14 to 2015/16 Capacity Years); and
- an estimate of the increased cost of uncontracted Capacity Credits as a result of excess capacity.

**Table D.1: Estimated financial impact of excess capacity using the current RCP formula**

| Capacity Year | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
|---|---|---|---|---|---|---|
| **Common input parameters** | | | | | | |
| Reserve Capacity Requirement (RCR) | 5,146 | 5,191 | 5,501 | 5,312 | 5,308 | 5,119 |
| MRCP ($) | 173,400 | 164,100 | 238,500 | 240,600 | 163,900 | 157,000 |
| % of RCR bilaterally contracted | 57% | 65% | 68% | 76% | 75% | 74% |

20 This formula applies where no Reserve Capacity Auction is conducted. No Reserve Capacity Auction has occurred since the commencement of the WEM.

| Capacity Year | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
|---|---|---|---|---|---|---|
| **Cost of uncontracted capacity, actual excess** | | | | | | |
| Total Capacity Credits (MW) | 5,258.6 | 5,493.5 | 5,995.6 | 6,086.8 | 5,862.7 | 5,683.3 |
| Excess capacity (MW) | 112.6 | 302.5 | 494.6 | 774.8 | 554.7 | 564.3 |
| Excess capacity (%) | 2.2% | 5.8% | 9.0% | 14.6% | 10.4% | 11.0% |
| RCP ($) | 144,235 | 131,805 | 186,001 | 178,477 | 122,428 | 120,199 |
| Uncontracted Capacity Credits (MW) | 2,316.0 | 2,103.9 | 2,258.4 | 2,049.7 | 1,893.7 | 1,910.0 |
| Cost of uncontracted capacity | $334.1m | $277.3m | $420.1m | $365.8m | $231.8m | $229.6m |
| **Cost of uncontracted capacity, no excess** | | | | | | |
| Total Capacity Credits (MW) | 5,146 | 5,191 | 5,501 | 5,312 | 5,308 | 5,119 |
| RCP ($) | 147,390 | 139,485 | 202,725 | 204,510 | 139,315 | 133,450 |
| Uncontracted Capacity Credits (MW) | 2,203.5 | 1,801.4 | 1,763.8 | 1,274.9 | 1,339.0 | 1,345.7 |
| Cost of uncontracted capacity | $324.8m | $251.3m | $357.6m | $260.7m | $186.5m | $179.6m |
| **Financial impact of excess capacity** | **$9.3m** | **$26.0m** | **$62.5m** | **$105.1m** | **$45.3m** | **$50.0m** |

Table D.1 shows that the estimated financial impact of excess capacity peaks at $105 million in the current 2013/14 Capacity Year. This cost is the result of:

- a peak in the RCP (driven by the inflated transmission cost within the MRCP); and
- a peak quantity of excess capacity,

which both decline in the following years.

Accordingly, the financial impact of excess capacity will decrease over the next two Capacity Years as a result of:

- lower capacity prices, resulting from the implementation of the MRCP review in 2011; and
- a reduction in excess capacity, largely driven by the retirement of the Kwinana C facilities.

These changes alone will result in the financial impact of excess capacity dropping by more than 50 percent from 2013/14 to 2015/16.

The proposed amendments to the RCP formula in this Rule Change Proposal are aimed at improving the responsiveness of the RCP to the capacity supply-demand position and improve incentives in relation to bilateral contracting of capacity.

Table D.2 compares the RCP that would have applied under the proposed formula for the 2010/11 to 2015/16 Capacity Years with the RCP calculated under the current formula. These years are shown in order to display a range of potential outcomes.

**Table D.2: RCP using the current and proposed formulae**

| Capacity Year | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
|---|---|---|---|---|---|---|
| MRCP ($) | 173,400 | 164,100 | 238,500 | 240,600 | 163,900 | 157,000 |
| Excess capacity (%) | 2.2% | 5.8% | 9.0% | 14.6% | 10.4% | 11.0% |
| RCP – current formula ($/MW/yr) | 144,235 | 131,805 | 186,001 | 178,477 | 122,428 | 120,199 |
| RCP – proposed formula ($/MW/yr) | 159,680 | 135,618 | 180,972 | 159,483 | 110,624 | 113,179 |

As shown in Table D.2, the RCP under the proposed formula would be lower from 2012/13 onwards, with excess capacity quantities above seven percent. However, in 2010/11 and 2011/12, where the excess capacity is less than seven percent, the proposed formula would result in a higher RCP. This addresses the concern raised at the RCMWG that the current MRCP is now representative of a benchmark price, reflecting an expected cost of providing Reserve Capacity rather than a maximum. Allowing the RCP to move above the BRCP provides for symmetry of risk for Market Customers during times of both scarce and excess capacity and creates an incentive for a Market Customer to seek Bilateral Contracts for new capacity as the market requires new investment.

Table D.3 shows the financial impact of excess capacity that would result under the proposed formula. As above, the 2010/11 to 2015/16 Capacity Years are shown in order to display a range of potential outcomes.

**Table D.3: Estimated financial impact of excess capacity using the proposed RCP formula**

| Capacity Year | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
|---|---|---|---|---|---|---|
| **Common input parameters** | | | | | | |
| Reserve Capacity Requirement (RCR) | 5,146 | 5,191 | 5,501 | 5,312 | 5,308 | 5,119 |
| MRCP ($) | 173,400 | 164,100 | 238,500 | 240,600 | 163,900 | 157,000 |
| % of RCR bilaterally contracted | 57% | 65% | 68% | 76% | 75% | 74% |
| **Cost of uncontracted capacity, actual excess** | | | | | | |
| Total Capacity Credits (MW) | 5,258.6 | 5,493.5 | 5,995.6 | 6,086.8 | 5,862.7 | 5,683.3 |
| Excess capacity (MW) | 112.5 | 302.5 | 494.6 | 774.8 | 554.7 | 564.3 |

| Capacity Year | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
|---|---|---|---|---|---|---|
| Excess capacity (%) | 2.2% | 5.8% | 9.0% | 14.6% | 10.4% | 11.0% |
| RCP ($) | 159,679 | 135,618 | 180,972 | 159,483 | 110,624 | 113,179 |
| Uncontracted Capacity Credits (MW) | 2,316.0 | 2,103.9 | 2,258.4 | 2,049.7 | 1,893.7 | 1,910.0 |
| Cost of uncontracted capacity | $369.8m | $285.3m | $408.7m | $326.9m | $209.5m | $216.2m |
| **Cost of uncontracted capacity, no excess** | | | | | | |
| Total Capacity Credits (MW) | 5,146 | 5,191 | 5,501 | 5,312 | 5,308 | 5,119 |
| RCP ($) | 171,452 | 162,256 | 235,820 | 237,897 | 162,058 | 155,236 |
| Uncontracted Capacity Credits (MW) | 2,203.5 | 1,801.4 | 1,763.8 | 1,274.9 | 1,339.0 | 1,345.7 |
| Cost of uncontracted capacity | $377.8m | $292.3m | $415.9m | $303.3m | $217.0m | $208.9m |
| **Financial impact of excess capacity** | **-$8.0m** | **-$7.0m** | **-$7.2m** | **$23.6m** | **-$7.5m** | **$7.3m** |

As shown in Table D.3, the application of the proposed formula would have significantly reduced the financial impact of the existence of excess capacity when compared with the impact of excess capacity under the current arrangements, as shown in Table D.1.

Report

Prepared For:

The Reserve Capacity Mechanism Working Group

# RCM Options Discussion for the RCMWG


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# 1. OVERVIEW

In this paper we briefly review the current excess reserve capacity situation and make a connection between the Reserve Capacity Mechanism (RCM) and the recently finalised revisions to the Maximum Reserve Capacity Price (MRCP). We describe options for improving the RCM by tuning the formula that determines the Reserve Capacity Price (RCP) to be more responsive to market conditions, as has been recommended by the IMO Board. We also discuss ways to restrict the supply of capacity credits in order to mitigate excess investment in the WEM, including options that rely more heavily on bilateral contracting and limited (probably IMO-facilitated) trading.

## 1.1. WHAT CAUSES EXCESS RESERVE CAPACITY

We define excess reserve capacity as any reserve capacity that contributes materially less value to the provision of system reliability than what it is being paid. Put differently, if capacity were paid only what it were “worth”, there would be no incentive to sustain any material amount of “excess” reserve capacity. In theory this is a simple definition. In practice, numerous complications must be considered, including the difficulty of measuring the specific value of capacity accurately and in a timely manner. These complications are arguably more challenging in a small, lumpy market like the WEM in which supply and demand can change quickly and there is no recourse to neighbouring markets.

The amount of excess reserve capacity in the WEM at any point in time is the product of a complex mix of supply and demand-side forces:

- On the supply side, investors continuously adjust their investment plans based on their expectations of future conditions. The amount of excess reserve capacity in the WEM is also the product of legacy conditions (such as the pre-global financial crisis economic boom), as well as historical programmes (no longer in force), such as the Displacement Mechanism in the original Vesting Contract and the earlier Schedule 7 requirements that required Western Power Corporation to tender for new capacity; and
- On the demand side, current and projected demand will generally not be the same as the level that was previously expected or projected. Market conditions change all the time. The global financial crisis and subsequent global economic slowdown exemplify disruptive forces that caused demand to be much lower than previously forecast.

The challenge of adjusting supply and demand using a combination of administrative mechanisms and market forces can be analogised to a person walking a dog. Like a person walking a dog, there is the path of the person and the path of the dog. Over time, the person and dog both must get to the same place, just as supply and demand must align reasonably over the longer term to conserve costs while maintaining reliability. But the relative path of each can look very different in the short term. The dog will wander to the left and to the right, and sometimes ahead and sometimes behind. If the leash is too short, the dog fights against the leash. If the leash is too long, the person fights against the dog, or the dog may fall behind or get stuck around a tree.

A well-functioning electricity market has mechanisms (both market-based and administrative) that work a bit like an effective leash. The relationship of supply and demand is, naturally, always in flux, just like the relative position of the person and the dog on a walk. Supply should not outpace demand for too long without becoming unprofitable. Supply should not run behind demand without a strong new investment "signal", else reliability will be compromised. But how long should the leash be? In normal, competitive, markets for most goods and services we generally do not worry about this question. In those cases, the leash is simply Adam Smith's invisible hand. But in the WEM, or any modern electricity market, adequacy, security and reliability do not just happen without mechanisms and signals to manage them. In the WEM, the RCM is the leash. If the RCM does not adjust with sufficient responsiveness and dynamism, the amount of reserve capacity can vary widely, imposing excess costs or reduced reliability.

## 1.2. The RCM as an Administrative Mechanism

The RCM is an administrative mechanism built around the concept of a Reserve Capacity Requirement (RCR), a Maximum Reserve Capacity Price (MRCP) and a Capacity Credit. Capacity Credits are allocated to facilities certified by the IMO in a process which begins around three years prior to the start of the Capacity Year in question. The IMO reviews sources of Capacity Credits to determine whether they can be relied on to provide capacity by the time required. The IMO categorises facilities as either "committed" or "proposed". When undertaking this review, the IMO considers a range of factors, including whether the facility has entered into irrevocable commitments.[1]

Each Market Customer must secure Capacity Credits to meet its Individual Reserve Capacity Requirement (IRCR), which is based on its expected contribution to peak demand. Market Customers can procure Capacity Credits bilaterally from Capacity Credit suppliers. The IMO pays an administered price, the RCP, to anyone with Capacity Credits that have not been traded bilaterally. Stakeholders may find it advantageous to rely on the IMO as the market maker in the event that there are too many Capacity Credits (more than are needed to cover all requirements), or in the event that the transactions cost of dealing with the IMO is less than that associated with contracting bilaterally, or in the event that a bilateral transaction is not able to be reached.

## 1.3. Evaluating Changes to the RCM Against the Market Objectives

The Market Objectives provide guidance for evaluating whether the RCM works effectively and guidance in relation to possible adjustments to the RCM. The Market Objectives are to:

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

1 As provided for in Appendix 3 of the Market Rules.

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

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

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

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

If the RCM attracts or supports more capacity than is required, then it would get lower marks for meeting Market Objective (d). On the other hand, more capacity may be argued, in some instances, to assist the achievement of Market Objective (b) by supporting greater competition in the energy market. Similarly, a failure of the RCM to attract sufficient capacity would also result in a costly failure of the WEM, compromising virtually all of the Market Objectives, except perhaps (e). Clearly, evaluating a specific change to the RCM (or even its current performance) against the Market Objectives involves balancing a number of countervailing forces.

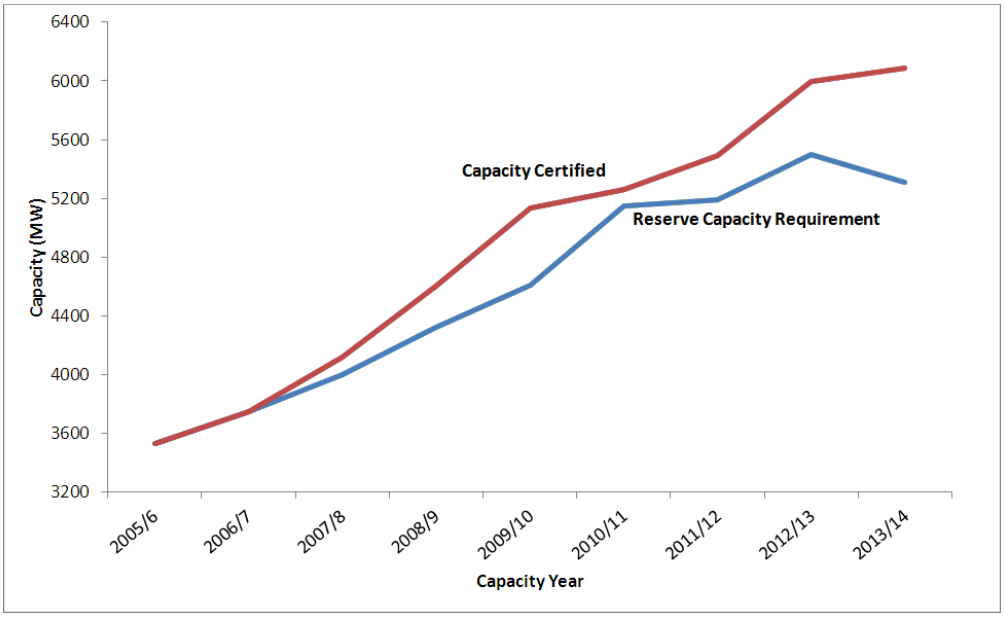
Ultimately, an RCM that supports too much excess reserve capacity implies higher costs due to excess investment. An RCM that fails to support sufficient reserve capacity implies higher cost associated with reduced reliability. The evaluation of the RCM against the Market Objectives requires striking a balance, keeping in mind that the costs associated with reduced reliability can be substantial and highly disruptive compared to the carrying cost of somewhat too much excess reserve capacity.

## 1.4. THE EXCESS RESERVE CAPACITY PROBLEM

Under the RCM, any resource that can establish itself as “committed” and declares itself as intending to trade bilaterally can secure Capacity Credits. Importantly, the RCM does not require facilities that have declared their intent to trade bilaterally to actually do so. By stating an intention to trade bilaterally and becoming a committed facility, a new entrant can enter the WEM and earn the administered RCP without ever entering into a bilateral contract, or necessarily intending to operate at all. As a result, the number of Capacity Credits can decouple (as it has) from the actual reserve requirement.

Historical review suggests that the RCM has produced excess reserve capacity and higher costs for customers. Appendix A reviews the cost of excess reserve capacity in the WEM based on analysis conducted in mid 2011, in which the amount of excess reserve capacity in the WEM was estimated to be around 9 percent in the 2012/2013 capacity year. The historical trend of certified capacity compared to the reserve capacity requirement is shown in Figure 1.

**Figure 1: Historical Trend in Excess Reserve Capacity[2]**

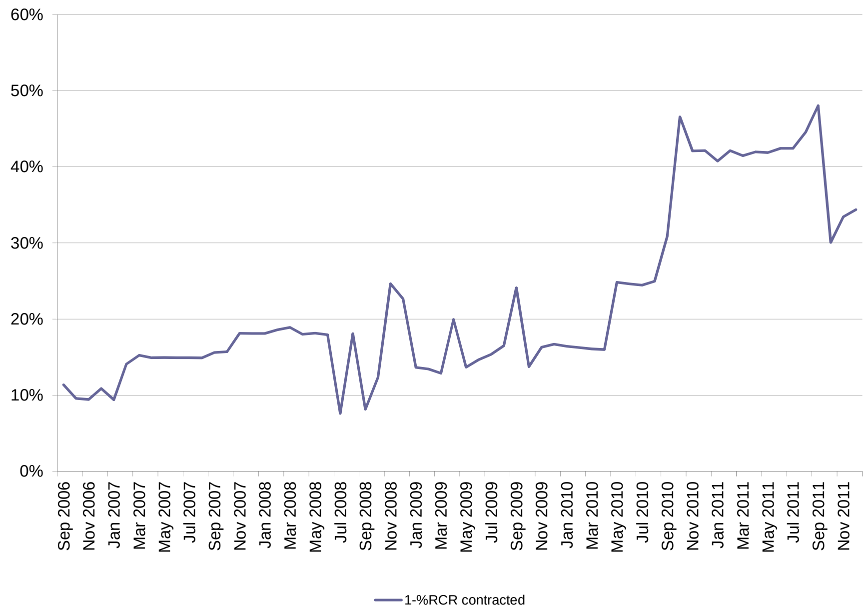



Currently, projected excess reserve capacity has *increased* to 14.6 percent for 2013/2014.[3] Furthermore, since mid-2010, the proportion of Capacity Credits that are purchased by the IMO directly (as opposed to being subject to bilateral trades between retailers and generators) has increased dramatically, as shown in Figure 2.

2 Source: IMO data provided to TLG in mid 2011. The reported trend data were current as at mid 2011.

3 Source: IMO data provided to TLG by the IMO in March 2012. Measured as: (Capacity Credits / Reserve Capacity Target) – 1.

**Figure 2: Uncontracted Reserve Capacity Requirement**[4]




The upward trend in the uncontracted reserve capacity requirement suggests that (1) generators prefer to contract with the IMO or (2) that retailers prefer not to contract with generators. The reason for either preference could be that it is perceived to be easier to deal with the IMO (e.g., lower transactions costs) or that there is a disconnect in the market (e.g., the IMO sets a floor price when the actual economic value of credits is lower).

## 1.5. The Recent Downward Revision to the MRCP

The RCP is a function of the MRCP, which is, in turn, based on the estimated cost of connecting a 160MW gas turbine to the WEM. Recently, the MRCP was revised downward by approximately 32 percent. This revision and the reasons for it are relevant to our interpretation of RCM outcomes.

Revisions to the MRCP are to be expected from time to time as cost estimates or other parameter values change with market conditions. If cost estimates and parameter values change merely to track evolving market conditions, then the MRCP should track the cost of a 160 MW peaking unit. If the MRCP tracks these costs reasonably well, and the 160 MW peaking unit benchmark is a reasonable one, then the changes to the MRCP "should" be neutral with respect to any "incentive" to support or not support more reserve capacity. Put differently, if this year's MRCP is just sufficient to support new entry, and next year the MRCP parameters are revised to reflect the then applicable market conditions such that the MRCP remains, over time, just sufficient to support new entry, then from an investor perspective, the changes in the MRCP are neutral (unbiased).

4 Source: IMO data provided to TLG in March 2012.

But, the more recent changes to the MRCP included significant methodological and definitional adjustments as well. Two methodological changes had the largest impact, by far:

- The basis for the estimate of transmission connection costs was changed; and
- The specification of the generation technology was altered to incorporate inlet cooling.

Together, these changes reduced the MRCP by 23 percent after adjustments for year-on-year changes to input parameters. It is therefore reasonable to consider that historical MRCP values may have been too high.

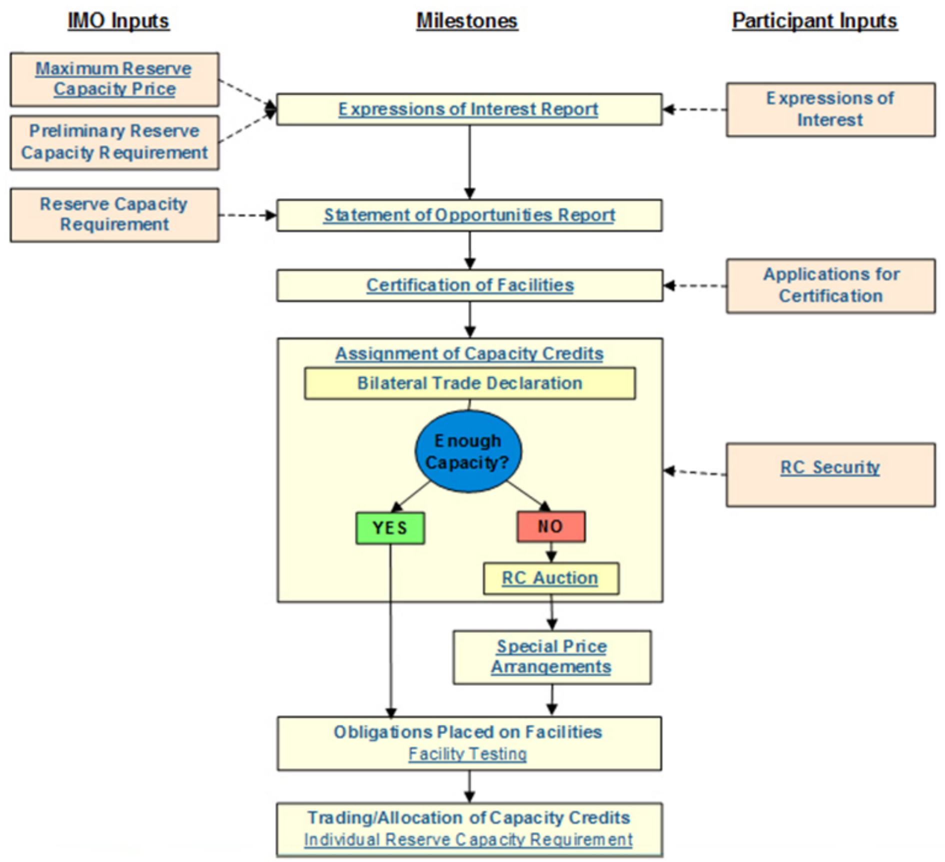
In the extreme, the 23 percent reduction in the MRCP from the previous level implies that the previous MRCP could have been 4 percent higher than the cost of new entry even after being scaled down by 85 percent (the base value of the RCP when administered and before further adjustment for excess reserve capacity). An RCP value that is above the cost of new entry would clearly support investment in the WEM. Changing the RCM adjustment formula to be more responsive to market conditions would certainly reduce the incentive to build capacity that is not yet needed, but so too would reducing the MRCP by changing the methodology upon which it is based.

Over the past year, stakeholders would have been aware of the review of the MRCP, including the signals throughout that review of the likely direction and nature of changes being considered, as well as also being aware of the concurrent RCM review. Stakeholders would also have seen the extent of excess reserve capacity, which obviously represents a standing “red flag”. Growing awareness of these factors correlates with the lowest level of new capacity entry in the WEM since commencement, a factor that possibly highlights the important role of expectations in investor decisions.

## 1.6. The Linkage Between the MRCP and an Effective RCM

The overall RCM process is depicted in Figure 3.

**Figure 3: RCM Process**




If there is not enough reserve capacity in the WEM, a Reserve Capacity Auction is scheduled. Reserve capacity must be available (certified) to be eligible for participation in the auction. So long as the value of the credits is high enough, investors will invest and seek committed status, certification and an allocation of Capacity Credits.

It matters, therefore, how expectations of the RCP compare to the cost of new capacity. If the RCP can be adjusted downward, below the MRCP but never upward, above the MRCP, then the *expected* RCP value is likely to be *less* than the MRCP. Whether having an expected RCP that is below the MRCP is a problem depends on whether the expected RCP is below the cost of new capacity at a time when new capacity is needed. An expected RCP value below the MRCP could lead to a situation in which insufficient capacity over time is actually available to participate in the auction. To date, no auction has been needed. Nevertheless, it bears consideration when evaluating the scope for further adjustments to RCM parameters.

# 2. OPTIONS TO IMPROVE THE RCM

The RCP is an administered price initially set at 85 percent of the MCRP. The RCP is used by the IMO to purchase Capacity Credits that are not traded bilaterally. The RCP is further adjusted downward in the event there is excess capacity.

Currently, the adjustment to the RCP for excess reserve capacity is proportional with respect to the amount of actual supply relative to the amount of targeted supply. For example, if the amount of excess reserve capacity is ten percent, the adjustment constitutes an approximately nine percent reduction[5] in the RCP. This price adjustment reduces the value of a capacity credit, and thus reduces the support available to new capacity investment. If the downward adjustment is great enough, then investors will defer new investment—helping to reduce excess reserve capacity over time as demand grows.

The economic value of excess reserve capacity, however, is not a *linear* function of the amount of excess reserve capacity but is, instead, a much more dynamic. The more excess reserve capacity exists, the more quickly the economic value of incremental excess capacity falls to zero. Clearly, a more dynamically adjusting RCP can send an even sharper signal to investors to defer new investment until market conditions improve. This dynamism is bidirectional. In the extreme, the very short-term market value of a Capacity Credit could tend towards zero during periods of excess reserve capacity and towards virtually unbounded levels during periods in which there is significant looming scarcity of reserve capacity.

## 2.1. ADJUST THE SENSITIVITY OF THE RCP TO EXCESS RESERVE CAPACITY

When too much excess reserve capacity exists, the implication is that the generation investors have seen opportunity to add capacity at a time when the retail sector did not need capacity. The supply and demand imbalance can be caused by an external disruption (and thus would likely be temporary), or it can be caused by a persistent failure of the market to adjust properly. As noted above, the RCM is intended to adjust to support adequate but not excessive amounts of reserve capacity.

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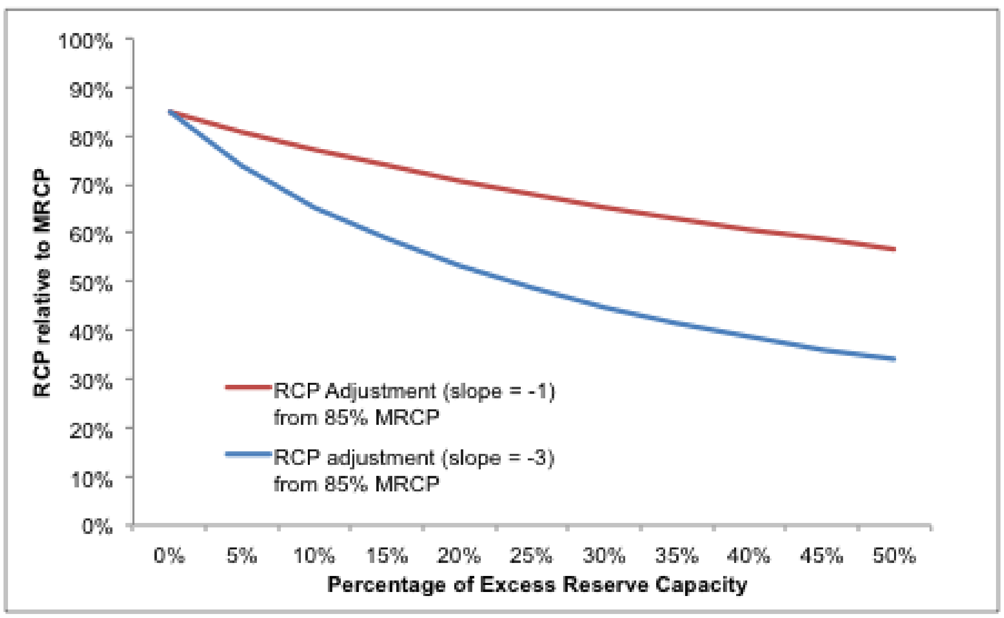
5 For example, if the requirement is 100MW and capacity is 110MW (10 percent excess) then price is multiplied by 100/110, a 9.09 percent reduction.

The fact that the RCM has had persistent excess reserve capacity—while good from the point of view of assuring adequate generation resource availability—indicates strongly and clearly that the RCM does not adjust adequately to the supply and demand for Capacity Credits. A simple solution to this problem is to make the RCP adjustment mechanism more sensitive to market conditions. In the limit, the current administrative adjustment mechanism could be replaced with market-based approach. Though theoretically sound, a number of implementation and risk management challenges would quickly arise. The most important of these involves developing a design that mitigates the inherent price volatility (bounded between zero and infinity) of the market value of a capacity credit as a function of the amount of excess reserve capacity. Such a market-based approach would also be inconsistent with other administrative features of the WEM, and may not work effectively in such a small, lumpy market.

The easier way to adjust the RCP to make it more sensitive to market conditions is to adjust what we call the "slope" factor in the current RCP price-setting formula. Currently the slope is effectively "minus 1"—the RCP is adjusted downward in proportion to the amount of excess reserve capacity. A slope factor of "minus 3" would reduce the value of a Capacity Credit purchase at a faster rate, significantly strengthening the signal to generation investors to defer capacity investment until demand has increased, as shown in Figure 2.

**Figure 4: RCP Adjustment Formula Comparison**




A steeper slope can be implemented straightforwardly within the existing RCM structure and, of course, is readily amenable to periodic review for the purposes of tuning the RCM to deliver efficient outcomes over time. If the slope factor were changed from "minus 1" to "minus 3", the existence of 15 percent excess reserve capacity would result in the RCP being 58.6 percent of the MRCP rather than 73.9 percent, as summarised in Table 1.

**Table 1: RCP as a Percentage of the MRCP (Same starting point)**

| Amount of Excess Reserve Capacity | Based on "-1 slope" | Based on "-3 slope" |
|---|---|---|
| 0% | 85.0% | 85.0% |
| 5% | 81.0% | 73.9% |
| 10% | 77.3% | 65.4% |
| 15% (~current) | 73.9% | 58.6% |
| 20% | 70.8% | 53.1% |
| 25% | 68.0% | 48.6% |
| 30% | 65.4% | 44.7% |
| 35% | 63.0% | 41.5% |
| 40% | 60.7% | 38.6% |
| 45% | 58.6% | 36.2% |
| 50% | 56.7% | 34.0% |

Alternatively, the RCP could be directly linked to the MRCP, rather than continue with the definition of the base RCP as being 85 percent of the MRCP, an adjustment that has unclear origins and no obvious foundational logical support. Eliminating the initial "85 percent adjustment step" would actually reduce the penalty relative to the MRCP for very small amounts of excess reserve capacity, though the increase in risk and the greater penalty for larger amounts of excess reserve capacity would remain strong disincentives to invest in excess reserve capacity, as shown in Table 2.

**Table 2: RCP as a Percentage of the MRCP (Alternative starting point)**

| Amount of Excess Reserve Capacity | Based on "-1 slope" starting at 85 percent of the MRCP | Based on "-3 slope" starting at 100 percent of the MRCP |
|---|---|---|
| 0.0% | 85.0% | 100.0% |
| 5.0% | 81.0% | 87.0% |
| 10.0% | 77.3% | 76.9% |
| 15.0% (~current) | 73.9% | 69.0% |
| 20.0% | 70.8% | 62.5% |

| Amount of Excess Reserve Capacity | Based on "-1 slope" starting at 85 percent of the MRCP | Based on "-3 slope" starting at 100 percent of the MRCP |
|---|---|---|
| 25.0% | 68.0% | 57.1% |
| 30.0% | 65.4% | 52.6% |
| 35.0% | 63.0% | 48.8% |
| 40.0% | 60.7% | 45.5% |
| 45.0% | 58.6% | 42.6% |
| 50.0% | 56.7% | 40.0% |

A feature of the "minus 3" slope in combination with application directly to the MRCP rather than to a value that is equal to 85 percent of the MRCP is that it only slightly reduces the RCP compared to the current formula at the current level of excess reserve capacity, while making investment in *excess* reserve capacity inherently more risky.

## 2.2. Transition Mechanism Application

A change to the RCP formula or RCM mechanism has the potential to disrupt expectations of stakeholder value. In principle, if the disruptions are sufficient, and can be linked to economic detriment, a transition mechanism may be justifiable. The IMO Board has approved a framework for evaluating the appropriateness of transition mechanism application.[6] Having regard to that framework, it seems doubtful that a transition mechanism can be justified. In particular, the amount of excess reserve capacity is widely visible suggesting that it should be difficult to argue that a "right" to long-term compensation has been established for capacity that has no other value except the RCM itself. Investments that are justifiable primarily on the basis of an administrative mechanism rather than an underlying source of fundamental value should necessarily bear risk associated with eventual regulatory reform. Put differently, it is sensible to incentivise stakeholders to think carefully before investing in opportunities that exist primarily because of regulatory imperfections.

That said, if it is determined that a change to the RCP formula justifies consideration of a transition mechanism, several possible transition approaches exist:

- Initiate the steeper slope immediately, but transition via a "floor" price that starts at just five percent below what the current RCP methodology would produce and then reduce the floor price by five percent each year for three years before dropping the floor altogether; or

6 See: Kieran Murray, "Transition Arrangements: Guidelines", Sapere Research Group, May 2011.

- Introducing the steeper slope in a stepwise manner, with the slope moving from -1 to -1.5 in year one; to -2.0 in year two, and to -2.5 in year three and -3.0 in year four; or
- Introduce the refinements as of a projected date such that participants have time to make changes, if appropriate, in anticipation of the future implementation.

Each option mitigates the risk that unneeded additional capacity is added to the WEM. Each also provides time for participants to adjust (and for the market to potentially absorb existing excess reserve capacity).

## 2.3. Institute a Quantity-Based Control Mechanism

We also previously considered the possibility of mitigating the risk of excess reserve capacity by controlling the *number* of Capacity Credits that are made available (supported) by the WEM at any point in time. A change that limits the number of additional Capacity Credit sources that are certified may be seen as protecting existing Capacity Credit suppliers against a reduction in the value of the Capacity Credits they have been awarded. At the same time, by effectively locking in the existing Capacity Credit holders, the lower economic value of Capacity Credits during periods of excess reserve capacity is not able to be passed on to consumers.

To implement a quantity restriction regime, the IMO could be the Capacity Credit gatekeeper through the certification process. If the level of reserve capacity exceeds a specified threshold, the IMO would not certify new capacity until the threshold is again met. This admittedly simplistic approach has the virtue of being easily implemented. If the threshold is exceeded, all certification of new supply sources would cease. Yet, many problems exist for which solutions are neither simple nor clear.

- What happens as conditions change, as they can quite quickly in the lumpy and relatively small WEM?
- If there are multiple projects queuing up for certification, perhaps each with varying degrees of bilateral contract commitments, how should the IMO choose?
- Currently commitment status is partly determined on the basis of irrevocable commitments. Why would facilities enter into irrevocable commitments if becoming "committed" did not assure access to Capacity Credits?
- Would a facility not be declared committed even if it had negotiated a bilateral contract covering all of its potential Capacity Credits?

The process of turning off the capacity certification "spigot" without modifying the RCP effectively puts the mouse on one side and the cheese on the other—a situation that is likely to be unstable and difficult to manage. An auction process could be used to prioritise projects against the quantity that is deemed certifiable at any point in time. But if one considers it reasonable to move to an auction-based approach to resolve such situations, it would almost certainly be even more reasonable to develop incentives that force stakeholders to sort themselves out through the bilateral market. For example, the IMO could propose simply to sell credits to short retailers at a punitively high price while offering to buy from long generators at a very much lower price.

## 2.4. Enhance Bilateral Market Support

An alternative to a pure spigot-control approach involves strengthening incentives for bilateral contracting of Capacity Credits. Bilateral contracts—which are really at the heart of the WA WEM design—could play a more direct role in the RCM, along the following lines:

1. IMO defines an IRCR for each retailer as now;
2. IMO certifies capacity as now (with all the adjustments already recommended re: intermittent supply sources and demand response);
3. Each retailer holds capacity credits equal to, or greater than, its IRCR. It pays for these capacity credits through the contracts it has with the suppliers (i.e. a bilateral approach); and
4. If the retailer does not hold sufficient capacity credits, then it is charged a penalty rate for not meeting the market rules (some penalty greater than the cost of procuring capacity, to act as a deterrent). The penalty revenues fund any supplementary auctions required to support new capacity. And any remaining revenues are returned to customers.

The IMO would probably need to administer a capacity trading platform that allows retailers to trade Capacity Credits to avoid mismatches. This would mean that those retailers with spare capacity credits can trade with those that are short. The IMO would continue to produce the periodic Statement of Opportunities and associated measures and reports that track overall system reserve capacity margins.

Measures to target large loads could include mechanisms to give block loads an incentive to accurately forecast their entry. For example, any new load connecting to the grid greater than a defined size may have to provide a security deposit to the IMO to cover the cost of capacity, procure capacity credits in advance of being allowed to connect or show that they have a binding retail contract which includes the provision of capacity credits from the date that the load actually connects. Intention is to put the onus on the loads to keep players updated about their entry and to pay for the costs of the additions to the system that they cause to occur, even if their entry is delayed.

Under this alternative, the ability for any generator to simply exist and earn capacity credits without a bilateral contract is removed. As a result, generators cannot claim that they will trade bilaterally while counting on the certainty of capacity credit revenue during periods of excess reserve capacity. Effectively, the IMO would no longer be in a position of effectively underwriting the financing of investments that contribute to increasing excess reserve capacity. It thus links the volumes in the market more closely to the aggregate IRCR required.

The risk of the mechanism is that some retailers may be unable to underwrite the bilateral contracts needed to bring in new generation. One of the benefits of the current mechanism is that a generator has some certainty that even if its bilateral counterparty fails, there is a source of revenue in the market. It was argued in the original market design that ensuring a credit-worthy counterparty is essential to new investment in any market and that remains true. There may, therefore, be merit in investigating mechanisms whereby the IMO can stand behind smaller retailers and pick up the capacity payment obligations (passed through to the market generally as now) should those retailers struggle. The capacity itself released by a failing retailer could be traded by the IMO in the market mechanism discussed above.

A move to an enhanced bilateral market based mechanism would involve a material shift in the RCM, and would necessarily involve a significant detailed design and implementation effort. Though we can see merit in the logic of such a rework of the RCM, it is likely to be difficult to justify such an extensive change at this point in time on cost-effectiveness grounds unless the existing administrative pricing mechanism could not be made to work.

# 3. SUMMARY

As currently configured, the RCM is an administrative mechanism. It makes limited use of market-based forces to establish the value of an uncontracted capacity credit. A theoretical *economic* capacity market would prevent this from occurring because supply and demand would be managed through the price mechanism. However, some forward capacity markets elsewhere have run into trouble (and required extensive and on-going redesign or adjustment) because they employed a forward capacity price that was set too close to delivery—at the point where volatility in the value of capacity begins to exhibit an all or nothing (zero or infinity) character. Bilateral agreements struck earlier in the process can mitigate this all-or-nothing pricing risk, and are naturally market-based. However, there is no requirement, currently, in the RCM that bilateral contracts actually be used. Instead, concern for the various “not-my-fault” reasons why a contract may not be entered into have led to a situation in which the clear benefits of bilateral contracting are reduced. Neither side has to make a commitment if it doesn’t want to.

One could promote bilateral contracting through mandatory requirements—not unlike the requirements imposed on “load-serving” entities in some US markets. Alternatively, the price charged by the IMO for capacity credits sold to retailers through the IMO could be increased to the point where bilateral contracting begins to look much more attractive. At the same time, the IMO could maintain a minimum purchase price for uncontracted Capacity Credits from generators, or this feature could be dropped completely (at the risk of greatly increasing investor risk). Such a reduction is already achieved using the RCM mechanism, but the question arises whether the reduction is steep enough to engender the expected response.

Currently, the RCP is adjusted downward in proportion to the amount of excess reserve capacity that exists. A straightforward change would focus on sharpening the administrative price adjustment mechanism to be more responsive to the amount of excess reserve capacity in the WEM. Doing so would reduce the discrepancy between the RCP and the economic value of a capacity credit. By reducing the gap, the risk of unintended consequences, rent-seeking behaviour and other generally value-destroying outcomes is diminished. The risk to be avoided is one in which the adjustments to the RCP are so sufficiently and consistently downward without any chance of an offsetting upward adjustment that the expected value of a Capacity Credit over the life of a capacity investment is not sufficient to support that investment commercially.

# APPENDIX A: COST OF RESERVE CAPACITY

*The analysis described below was conducted in mid-2011, but remains equally, if not even more, relevant today as the amount of excess reserve capacity has increased in percentage terms.*

The 2008 SOO set the Reserve Capacity Target for the 2010/11 Capacity Year at 5,146MW. This was based on a projected Peak Demand (10 percent POE case) of 4,704MW plus a reserve margin. As a result, there was an excess of 2.19 percent[7] of Capacity Credits procured for this year and the RCP was therefore correspondingly reduced by 2.14 percent. The actual RCP paid in the 2010/2011 year was AUD 144,235 per MW per annum. In the following discussion, we consider the economic value of *incremental* capacity in the context of the WEM. The value we derive is meaningful principally as a measure of the value attached to improved reliability and generation adequacy reasonably associated with an investment that increases the amount of capacity in the WEM by one megawatt. While this type of estimate does not indicate the overall cost of excess capacity, it is the value that is most relevant to the evaluation of the workings of the RCM in terms of providing incentives for investment. Investment is always about the *next* increment of capacity.

The reliability standard in WA is based on the 10 percent POE forecast peak demand supplied through the SWIS plus a reserve margin equal to the greater of 8.2 percent of the forecast peak demand and the maximum capacity of the largest unit on the system. Expected energy shortfalls are to be limited to 0.002 percent of annual energy consumption.

This reliability standard defines a target level of capacity based on target reserve margin and expected unserved energy (EUE). The marginal value of capacity, however, relates to the loss-of-load probability (LOLP), rather than the EUE. Why is this? One incremental MW of capacity would allow an additional MW of load to be served whenever there is a loss-of-load situation. Accordingly, the annual LOLP measures the decrease in EUE that would result from an additional MW. Since the value of capacity arises from reducing unserved energy, this economic value is directly related to LOLP.[8]

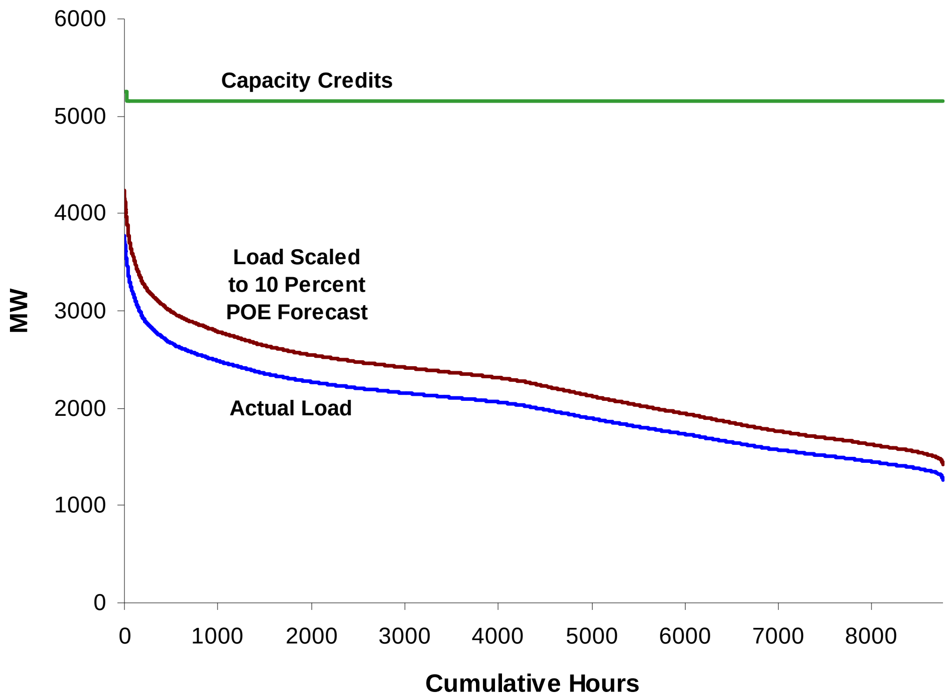
In practice, the LOLP will always exceed the EUE on a fractional or percentage basis. On a percentage basis, the EUE will equal the LOLP (on a percentage basis) times the average share of the total load left unserved during each loss-of-load event. Since the LOLP is small and the average share of load left unserved during each event is small, the EUE equals the product of two small numbers.

7 Source: Maximum reserve capacity price cap calculation on website.

8 Since unserved energy is typically imposed on customers involuntarily (and somewhat arbitrarily), the marginal value equals the LOLP times the average value of lost load (VOLL) for the customers who are curtailed. This relationship was the impetus for the half-hourly capacity price payment in the original England and Wales pool. While this was an elegant mechanism, it was disastrously prone to manipulation. Nonetheless, as a measure of true system value, the calculation – assuming a true declaration of availability – was entirely appropriate.

Figure 5 shows the approximate capacity duration curve and the load duration curve for the 2009/10 capacity year. The capacities are based on the allocated capacity credits. The small peak in the capacity duration curve represents the DSM capacity, in each of the classes. We implicitly assume that DSM can be dispatched perfectly into each of the very top 24 hours that most DSM resources have obligations to be available. Because of planned maintenance needs, the quantity of capacity credits somewhat overstates the actual availability during off-peak periods.

**Figure 5: Load and capacity duration curves for 2009/10**



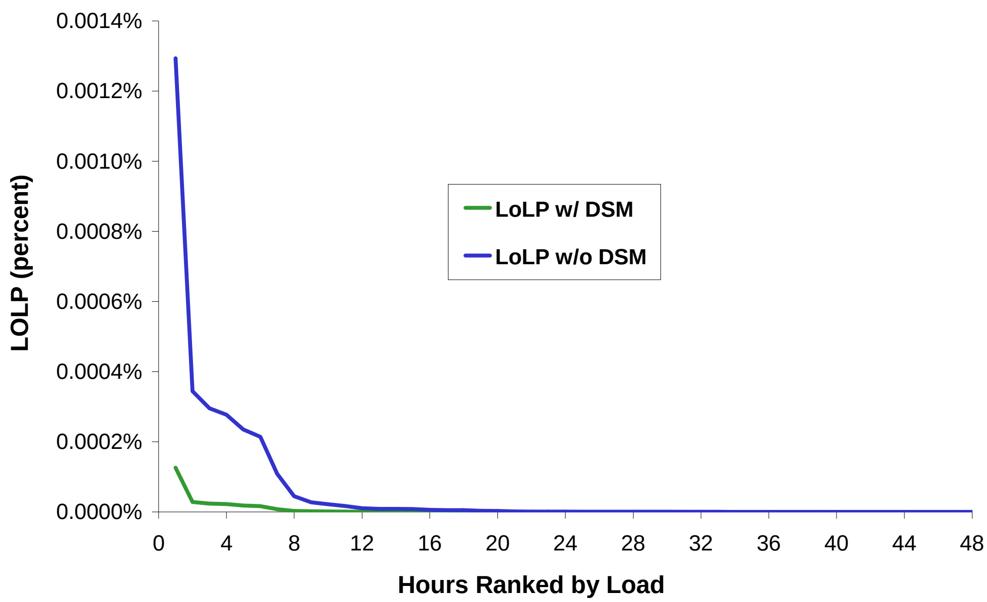

But the quantity of capacity is really only relevant during the extreme peak hours in which the load duration curve hits high loads. Figure 5 presents two different load duration curves – one depicting the actual loads and a second scaled to match the 10 percent POE forecast as of the 2007 forecast. The value of the RCM is clearly concentrated in the approximately top 200 peak hours in which the difference between the load and capacity available is the smallest.

We can calculate the LOLP associated with the supply and demand situation at each point in time. For example, the available capacity of each unit in a given hour ($C_i$) is an uncertain variable, due to the possibility of forced outage. Similarly, the load in that hour (*L)* is subject to forecasting error. The LOLP is the likelihood that *L* exceeds the sum of $C_i$ across all units in the system. A number of different algorithms exist to form this required distribution of load less total capacity and solve for the likelihood that this quantity is positive.

Note that the LOLP is a time-dependent concept. A year ahead, the LOLP in any given hour would necessarily be based on average forced outage rates and load distributions. As we approach real time, our estimates of outage likelihoods and loads become more precise. In the original UK electricity market, the capacity payment paid to any participant was made up of the LOLP estimated a day ahead multiplied by the Value of Lost Load (VOLL). After the fact, LOLPs are either one or zero – that is, load was lost or it wasn't.

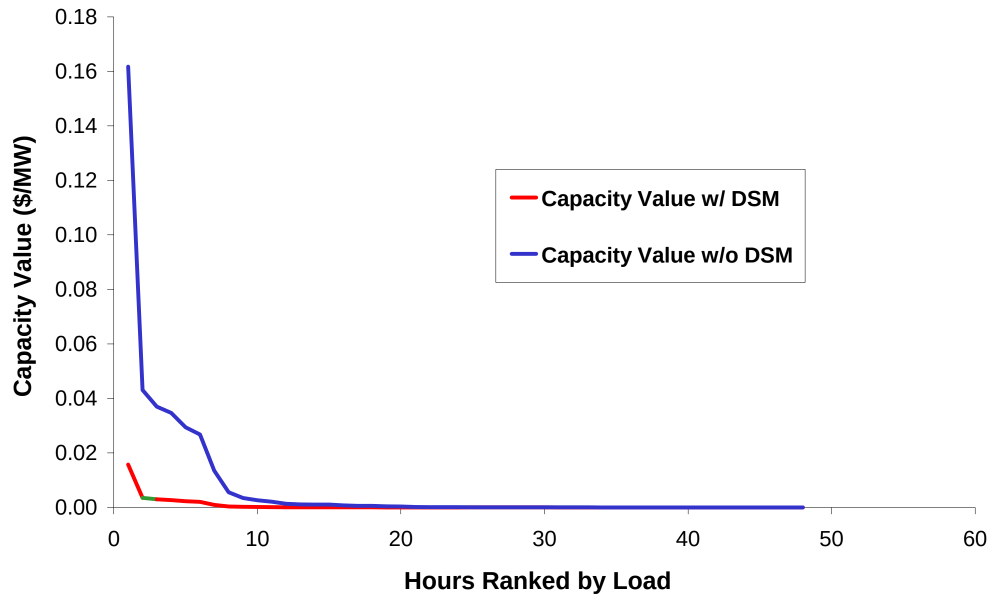
Figure 6 shows LOLPs in the WEM for 2009/10, as derived using the actual hourly loads and assuming average forced outage rates.

**Figure 6: LOLP for 2009/10 capacity year**




If we then assume for illustrative purposes that the value of lost load is AUD12,500/MWh, which is the value of the Market Price Cap in the National Electricity Market covering the eastern states, then the value of the capacity can be shown as in Figure 7.

**Figure 7: Value of capacity using NEM VOLL figures**




Based on these assumptions, the value of *incremental* reserve capacity across the whole year in the WEM is less than AUD1/MW (even without DSM included). The actual price paid in 2009/10 was AUD108,459/MW. This highlights the extent to which customers in WA overpay for capacity *at the margin* based on the actual requirement for reserve capacity in the market, at the margin.[9] Alternatively, it highlights the extent of unnecessary "signal" currently being sent to potential investors, inviting them to develop capacity that is not needed in the market at this time.

Of course, the point of the RCM is to ensure reliability based on what *might* occur, rather than what actually did occur. If we base the analysis on the 10 percent POE forecast[10] of demand from 2007 (the year in which the RCR for the 2009/10 Capacity Year was forecast), then we see a different outcome.

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9 This is not to imply that capacity has no value to consumers. But the value of each *incremental* MW is less. This analysis measures the marginal value, which is extremely low because there are so many excess MW.

10 This has been done simplistically by scaling the top 48 hours of the demand hours in the year by the ratio between the 10 percent POE peak demand and the actual peak demand in 2010 and scaling the rest of the hours in the year so that the total energy matches the high energy demand forecast for the year. As such it almost certainly over-estimates the energy in the year; however, it gives a feel for what the difference of a 10 percent POE versus actual peaks might be.

**Figure 8: LOLP based on 10 percent POE forecast for 2009/10**

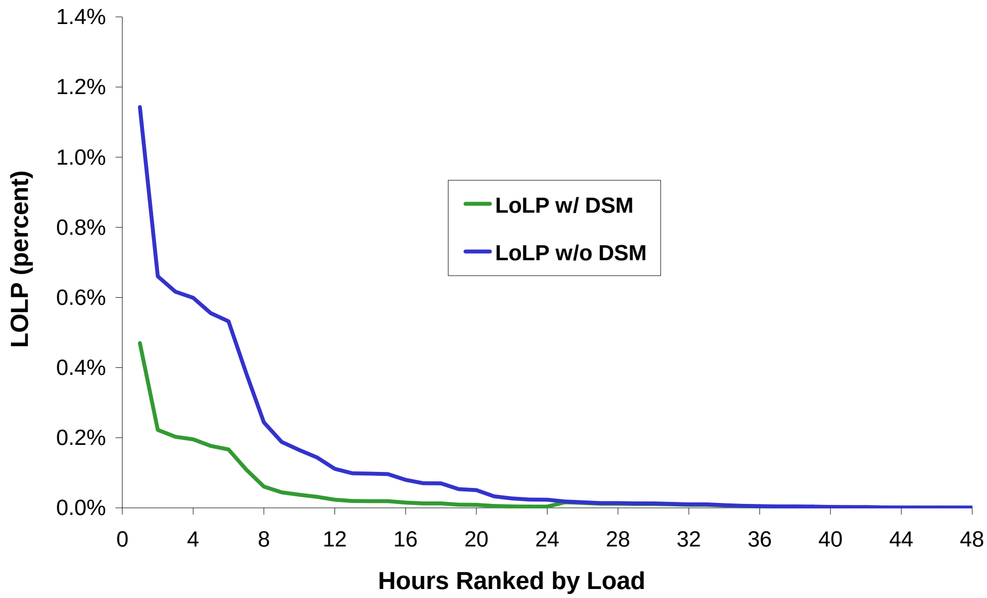
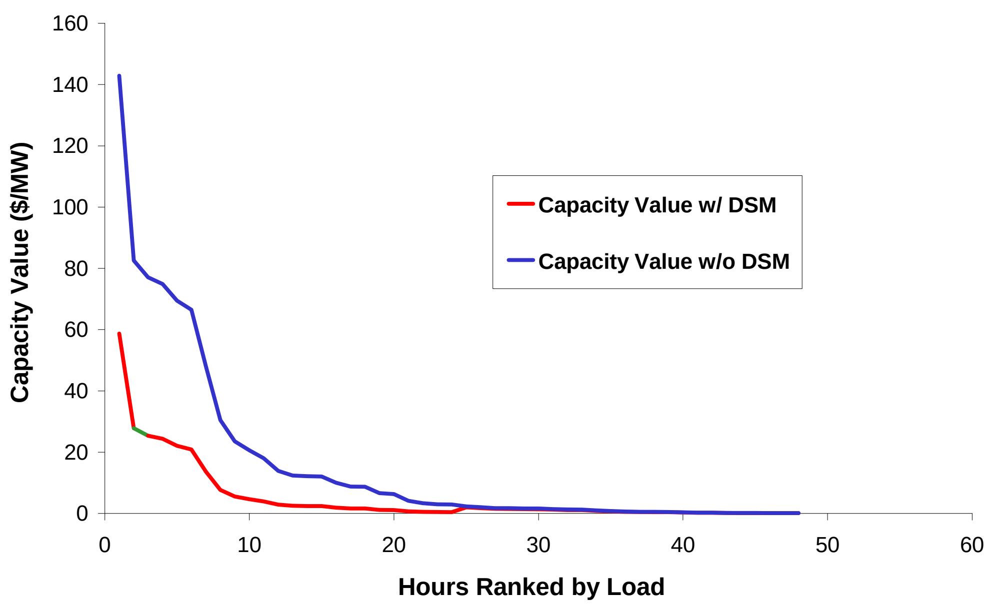



**Figure 9: Value of capacity based on 10 percent POE forecast**




In this instance, the value of incremental reserve capacity over the year is AUD 253/MW with DSM or AUD 780/MW without it. These values are still much lower than the actual cost of reserve capacity in the RCM.

## Independent Market Operator

## Reserve Capacity Mechanism Working Group

# Minutes

| | |
|---|---|
| **Meeting No.** | 2 |
| **Location:** | IMO Boardroom<br>Level 3, 197 St Georges Terrace, Perth |
| **Date:** | Tuesday 27 March 2012 |
| **Time:** | Commencing at 2.00pm – 5.00pm |

| **Attendees** | |
|---|---|
| Allan Dawson | Chair |
| Suzanne Frame | IMO |
| Brendan Clarke | System Management |
| Andrew Sutherland | Market Generator |
| Ben Tan | Market Generator |
| Shane Cremin | Market Generator (Via phone) |
| Brad Huppatz | Market Generator (Verve Energy) |
| Amanda Rudd | Market Customer (Proxy) |
| Patrick Peake | Market Customer |
| Steve Gould | Market Customer |
| Stephen MacLean | Market Customer (Synergy) |
| Andrew Stevens | Market Customer/Generator |
| Jeff Renaud | Demand Side Management |
| Geoff Down | Contestable Customer |
| Justin Payne | Contestable Customer |
| Paul Hynch | Observer (Office of Energy) |
| Wana Yang | Observer (Economic Regulation Authority) |
| **Additional Attendees** | |
| Mike Thomas (The Lantau Group) | Presenter |
| Aditi Varma | Minutes |
| Fiona Edmonds | Observer |
| Jenny Laidlaw | Observer |
| Greg Ruthven | Observer |
| **Apologies** | |
| Corey Dykstra | Market Customer |

| Item | Subject | Action |
|---|---|---|
| 1. | **WELCOME AND APOLOGIES / ATTENDANCE**<br>The Chair opened the second meeting of the Reserve Capacity Mechanism (RCM) Working Group (RCMWG) at 2:05pm.<br><br>The Chair welcomed the members in attendance and noted apologies received from Mr Corey Dykstra prior to the meeting. The Chair acknowledged Ms Amanda Rudd as a proxy for Mr Dykstra and Mr Shane Cremin linked via phone. The Chair also introduced Mr Mike Thomas from The Lantau Group. | |
| 2. | **MINUTES ARISING FROM MEETING 1**<br>The following changes were noted on page 8:<br><br>• Mr Huppatz noted that ~~keeping~~ a discussion on the classification of Outages ~~in the out-of-scope list would limit the amount of attention given to~~ should have been included as a part of the scope of the dynamic refund regime.<br><br>There was discussion among RCMWG members regarding the level of detail required in the recording of minutes. RCMWG members decided that it was important to retain some level of detail relating to the reasoning behind decisions taken and the various topics raised in discussions. | |
| 3. | **ACTIONS ARISING**<br>The Chair noted that all action points from the previous meeting had been completed. | |
| 4. | **PRESENTATION ON RCM OPTIONS DISCUSSION FOR THE RCMWG: MR MIKE THOMAS, THE LANTAU GROUP**<br>The Chair invited Mr Mike Thomas to present his paper on the over-supply of capacity in the Wholesale Electricity Market (WEM).<br>The following points of discussion were noted:<br>• Mr Stephen MacLean queried Mr Thomas's opinion on the consistency of a market-based approach with the administrative features of WEM. Mr Thomas responded that it was important to assess the level of governance in WEM. He also noted that WEM was similar to the Singapore market because of its administrative nature.<br>• Mr Andrew Stevens noted that in the event of excess capacity, retailers are faced with increased costs in the form of an increased Shared Reserve Capacity cost. Discussion ensued amongst RCMWG members over how costs of excess capacity were shared in the market. Mr Thomas concluded that the key point was that the excess reserve capacity had to be paid for in some way by Market Participants.<br>• Mr Thomas commented that the solution to the problem of excess capacity should not be such that it removes today's problem of excess only to create tomorrow's problem of shortage. Mr MacLean noted that the current market design may have the potential for future shortages in reserve capacity. | |

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| | The Chair highlighted that in 2008-09, the market faced shortages and the IMO procured Supplementary Reserve Capacity (SRC).<br>• Mr Thomas talked about the analysis on the indicative value of lost load. He noted that the analysis showed that the difference between the administrative value and the economic value of capacity credits was high. On this point, Mr Huppatz noted that the Planning Criterion is not only based on the probability of exceedence, the market also places high value on unserved energy. Mr Thomas acknowledged that the current analysis did not delve deeper into that issue. However, he noted that the issue around value creation in a few number of hours remained.<br>• On the issue of excess capacity, Mr Sutherland highlighted that it was important for the group to understand the make-up of the capacity surpluses. Mr Stevens and Mr MacLean noted that this was an important question to consider. Mr Thomas observed that in a pure market-based mechanism, it is never possible to know what caused the problem and only the effects are visible. Mr Peake noted that in a market-based scenario, older, inefficient plants might be retired whereas in RCM, older plants continued to produce power. Mr Thomas noted this point. He added that the causes of excess capacity could potentially change in the future and therefore, it would be more useful to think of the problem as active or passive behaviour of participants. Active behaviour is characterized as participants actively making commercial decisions in the market and passive behaviour is characterized as participants' exposure to decisions made by other stakeholders.<br>• Discussion ensued on uncontracted Capacity Credits. Mr Sutherland mentioned that large OCGT plants do not generally rely on the RCM to be built because they have large capital costs. In his opinion, a lot of the uncontracted Capacity Credits present in the market might be supplied by projects with low capital costs or low debt-to-equity ratios. He added that retailers would prefer contracting for the long term to match their capacity requirements. He also observed that there are potentially other hedges working outside of the RCM. Mr MacLean added that retailers are also concerned with volatility in the market and their preference is to hedge their risks by locking in contracts. He added that retailers would prefer to contract to meet their energy requirements and would contract for capacity only if they perceive a discount was being offered on the prevailing Reserve Capacity Price (RCP). However, the RCM offered generators a higher expected price. Mr Peake added that the volatility in the RCP has made participants contract outside the market. Mr Sutherland added that the RCP is a blunt instrument as it tends to attract capacity that can be offered by projects that have low capital costs. Mr MacLean suggested that the Maximum Reserve Capacity Price (MRCP) should be sensitive to the type of capacity that the market needs at a given time. Mr Cremin observed that the market would buy energy if it is needed irrespective of the RCM. He noted that it should only be the peak capacity on which an administrative control might be needed.<br>• Mr Thomas proceeded to talk about the five-yearly MRCP review. He further discussed the corrective action that could be | |

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| | taken to discourage excess capacity. He mentioned that the RCP setting process did not allow for the RCP to adjust enough in response to excess capacity in the market. Mr MacLean queried if the purpose of the adjustment was to only discourage excess capacity or also to act as an administrative method to create an efficient price that could be received in an auction. Mr Thomas responded that the RCP did not have any connection with a reserve capacity auction outcome. Mr Shane Cremin noted that the adjustment mechanism was not only to discourage excess capacity but also to encourage bilateral contracting. Mr Tan observed that a problem with increasing the slope of the sliding scale was that it would perversely incentivise retailers to increase capacity because the book value of a capacity credit may decrease. This implied that the sliding scale would need a floor price to stop a massive injection of capacity in the market. Mr Sutherland argued that the sliding scale would imply that more expensive capacity such as those supplied by coal fired plants or combined cycle plants would get priced out of the market till only DSM capacity was left as the cheapest option.<br>• Mr Thomas proceeded to present his recommendations on the excess capacity adjustment slope. Mr Thomas added that preference should be given to adjusting the RCM in ways that could make it more consistent with market-based outcomes rather than considering a replacement of the current mechanism. Mr MacLean noted that he had been working on an option that would not be a complete overhaul of the market but would still be closer to a market based mechanism. Mr Peake mentioned that it was important to consider that a shortfall of capacity would be less acceptable than excess. Mr Sutherland mentioned that it is difficult to fine-tune the mechanism without knowing the cause and effect. Mr Thomas responded that market mechanisms always work in information asymmetry where exact causes are not known and market players tweak their decisions and then assess the consequences<br>• Mr Thomas also presented a spigot-control mechanism as an alternative solution to the excess capacity issue. The Chair mentioned that a spigot control mechanism creates barriers for new technologies to enter the market. He added that perverse behaviours like not voluntarily decommissioning old plants would be incentivised. Mr Peake added that such a mechanism could also create situations where peaking generators could drive out generators that have low fuel costs. This would then flow to the energy market in terms of higher prices.<br>• Mr Sutherland argued that the same issue existed with the steep sliding scale. If too much excess capacity existed in the market then projects with large capital costs face high entry barriers. He added that low capital cost, high variable cost capacity is affecting the energy prices. Mr Thomas observed that a similar situation exists in Korea. Mr Huppatz and Mr Stevens argued that a steeper discount factor will create a distortion in the capacity market. Mr Sutherland argued that without a cap on the sliding scale, lower capital cost capacity like DSM would persist providing more capacity as long as the price is high enough.<br>• Mr Stevens argued that the most efficient outcome was only | |

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| | possible if the proportion of baseload generation, mid-merit and peaking generation capacity existed in the shape of a pyramid. He argued that a higher percentage of DSM and peaking capacity in the market indicated inefficiencies. The Chair emphasized that the load profile in the SWIS was such that a healthy mix of plants was required. Mr Jeff Renaud added that DSM in WEM is almost at its saturation point. He noted that irrespective of the price, there was only a finite amount of demand response. Discussion ensued on the risks created by the sliding scale. Mr Peake noted that with a steeper sliding scale, risks to a large capital investment are increased but that does not necessarily mean that the technology would face entry barriers. Companies would look for a higher margin before investing in new projects. Mr Thomas noted that changing the risk profile is at the heart of the steep sliding scale. The idea is to discourage excess investment in harder to finance projects as well as undermine investment in easily financed unnecessary projects. Mr Down noted that a variable price will also motivate contestable customers to consider changes to their capacity mix. He added that sustainable technologies will become more important. Mr Thomas acknowledged the importance of this point and added that this alternative adds a little more volatility to the market which will drive both generators and customers in the market to reconsider their positions.<br>• Discussion ensued on the potential magnitude of impact of a shortage in capacity. The Chair reiterated that loss of load is a major cost to the market.<br>• Mr Thomas concluded his presentation with a discussion on active and passive behaviours in the RCM and his recommendations.<br>• The Chair reiterated the IMO Board's view that the RCM has provided benefit to the WEM since 2004. He noted that the WEM started with a shortage of capacity and has dealt with significant economic growth in Western Australia. The Board's perspective was that this mechanism should be adjusted rather than restructured to provide better economic incentives for existing and new capacity.<br>• Mr Sutherland cautioned that the market could potentially become unattractive to investors given the recent MRCP reduction, the impending forecasting methodology review and peak demand reductions. The Chair noted that the RCMWG's advice may be to do nothing. However he observed that some ideas in Mr Thomas's recommendation would appear attractive and should be given adequate consideration.<br>• The Chair concluded the discussion by inviting Mr Thomas to evaluate the concepts of a steeper sliding scale and expected value of capacity for the consideration of the RCMWG at its April meeting. Mr MacLean offered to provide details to the RCMWG on the topic of excess capacity costs to retailers. Mr Sutherland, Mr Payne and Mr Stevens asked if analysis could be provided on the composition of existing excess capacity.<br>• Ms Yang noted that forecasting uncertainty is indispensable and that the last Statement of Opportunities (SOO) had shown a significant reduction in the load forecast. She noted that any discussion on the RCM should adequately consider the | |

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| | reductions introduced by the SOO.<br>*Action Points:*<br>• *The IMO to conduct analysis on the composition of excess capacity in the RCM and provide updates at the April RCMWG meeting.*<br>• *Mr Thomas to conduct further analysis on his recommendations for the RCM and provide updates at the April RCMWG meeting.*<br>• *Mr MacLean to circulate his analysis on costs of excess capacity to the market among RCMWG members.* | **IMO**<br>**Mr Thomas**<br>**Mr MacLean** |
| **5** | **PROPOSED SCHEDULE OF WORK FOR RCMWG**<br>The Chair noted some participants had requested that the timing of the discussion on the alignment of a dynamic reserve capacity refund regime should be brought forward and lengthened to about 5 months. The Chair noted that the IMO will endeavour to accommodate this request. However, he mentioned that the plan for the next RCMWG meeting was already finalised and it would include Dr Tooth's presentation on harmonisation of DSM with generation capacity. He also noted that Mr Thomas would be invited to the next meeting to elaborate his ideas further.<br>*Action Point:*<br>• *The IMO to reissue the proposed work schedule for RCMWG with the changed timing for the discussion on the Dynamic Refund regime.*<br>• *The IMO to invite Mr Thomas to April RCMWG meeting.* | **IMO**<br>**IMO** |
| **6** | **CLOSED**<br>The Chair thanked all members for attending and declared the meeting closed at 5.05 pm. | |

## Independent Market Operator

## Reserve Capacity Mechanism Working Group

# Minutes

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| **Meeting No.** | 3 |
| **Location:** | IMO Boardroom<br>Level 3, 197 St Georges Terrace, Perth |
| **Date:** | Tuesday 17 April 2012 |
| **Time:** | Commencing at 2.00pm – 5.30pm |

| **Attendees** | |
|---|---|
| Allan Dawson | Chair |
| Suzanne Frame | IMO |
| Neil Hay | System Management (Proxy) |
| Andrew Sutherland | Market Generator |
| Brad Huppatz | Market Generator (Verve Energy) |
| Corey Dykstra | Market Customer |
| Patrick Peake | Market Customer |
| Steve Gould | Market Customer |
| Stephen MacLean | Market Customer (Synergy) |
| Andrew Stevens | Market Customer/Generator |
| Jeff Renaud | Demand Side Management |
| Geoff Down | Contestable Customer |
| Justin Payne | Contestable Customer |
| Paul Hynch | Observer (Office of Energy) |
| Wana Yang | Observer (Economic Regulation Authority) |
| **Additional Attendees** | |
| Richard Tooth | Presenter (Sapere Research Group) |
| Mike Thomas | Presenter (The Lantau Group) |
| Aditi Varma | Minutes |
| Fiona Edmonds | Observer |
| Jenny Laidlaw | Observer |
| Greg Ruthven | Observer |
| Aaron Breidenbaugh | Observer (EnerNOC, USA) |
| Ken Schisler | Observer (EnerNOC, USA) |
| Paul Troughton | Observer (EnerNOC) |

| Apologies | |
|---|---|
| Ben Tan | Market Generator |
| Shane Cremin | Market Generator |
| Brendan Clarke | System Management |

| Item | Subject | Action |
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| 1. | **WELCOME AND APOLOGIES / ATTENDANCE**<br>The Chair opened the third meeting of the Reserve Capacity Mechanism (RCM) Working Group (RCMWG) at 2:05pm.<br><br>The Chair welcomed the members in attendance and noted apologies received from Mr Brendan Clarke, Mr Ben Tan and Mr Shane Cremin prior to the meeting. The Chair acknowledged Mr Neil Hay as proxy for Mr Clarke. The Chair also introduced Dr Richard Tooth from Sapere Research Group. The Chair also noted observers from EnerNOC, USA in attendance. | |
| 2. | **MINUTES ARISING FROM MEETING 2**<br>The minutes were accepted as a true and accurate record of the meeting. | |
| 3. | **ACTIONS ARISING**<br>The Chair noted that all action points from the previous meeting had been completed. | |
| 4. | **PRESENTATION: Harmonisation of Demand Side and Supply Side Resources by Dr Richard Tooth, Sapere Research Group**<br>The Chair invited Dr Richard Tooth to present his paper.<br>The following points of discussion were noted:<br>• On the issue of Availability Classes for Demand Side Management (DSM), Mr Jeff Renaud observed that the refund regime for DSM becomes more lenient in higher Availability Classes. However, it is more difficult to recruit customers in higher Availability Classes because of the associated opportunity costs of being available for greater number of hours. He also noted that Demand Side Aggregators (DSA) would generally absorb refunds for non-performance and would not pass those costs on to their customers as it creates disincentives for signing up to a demand management program. With regard to Dr Tooth’s comment that there was potential for some DSM programmes to offer more availability, he observed that there was a range of loads with some being indifferent to providing greater availability and others being opposed because of the costs of potential production shut-downs. He added that a DSA, however, with a portfolio of customer loads would be in a position to mitigate that risk for individual market customers.<br>• Discussion ensued on the order of dispatch of generators and DSM. Some members argued that the value provided by generators and DSM may be different because key variables such as response time to dispatch instructions from System Management for the two was different.<br>• Discussion ensued on when DSM can be dispatched. Mr Neil | |

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| | Hay noted that under the current Availability Classes, System Management would not dispatch DSM if it believes that the peak of summer has not yet been reached. Mr Dykstra observed that this would imply DSM is considered to be the last resort. Mr MacLean queried if this implied that System Management would have different operational guidelines in early summer vis-a-vis late summer. Mr Hay disagreed with this and noted that consideration would be given to System Management's expectation that the peak summer day is yet to occur.<br>• Mr Huppatz observed that this might indicate that DSM could be considered to be more valuable during peak summer (for example, from January to March) than during other months. Mr Geoff Down observed that some level of ~~uncertainty~~ flexibility needs to be factored in dispatch decisions.<br>• Mr Renaud noted that in most markets DSM is used in emergency reliability conditions. He observed that in this case it seemed that the issue was not the dispatch of DSM itself but System Management's confidence level in dispatching DSM when faced with peaky circumstances early in summer. Mr Hay agreed with the statement and noted that if System Management was faced with the option of shedding load versus dispatching DSM, it would always dispatch DSM but it must give adequate consideration to the fact that that option would then be used up and would not be available if a similar circumstance occurred again. Mr Payne noted that the capacity provided by DSM in the market currently might be sufficient to provide some flexibility of dispatch for System Management. However, Mr Dykstra and Mr Stevens argued that dispatch decisions were constrained because of DSM availability limitations. Mr Renaud mentioned that DSM could strive to provide advanced technological tools to System Management for better dispatch decisions. However the issue was more around the prescriptive grid conditions needed to dispatch DSM rather than the actual hours of availability of it.<br>• Mr Breidenbaugh observed that in the US, the issue was not so much the availability duration of DSM but how often and for how long it was dispatched. He added that an important concern for DSM providers was performance measurement over their availability duration as that happened during the peakiest periods. He also observed that in the PJM market, DSM is only dispatched during reserve deficiency situation.<br>• Discussion continued on how DSM participates in the energy market. Members discussed that there is an extra monetary benefit that DSM is able to receive because of savings resulting from lower consumption for the load and the dispatch payment for the DSA. The Chair noted that this was one of the issues being considered in the discussion on harmonisation.<br>• On the issue of fuel availability requirements, members discussed the capacity refund regimes for peaking facilities and DSM facilities. Mr Sutherland noted that a peaking generator would have to bear fixed expenses in the event of capacity refunds whereas a DSA could contractually control this expense by not paying the load that did not perform. Mr Peake noted that there was no economic justification as to why DSM could not be | |

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| | dispatched before a peaking generator if its marginal cost was lower. Mr Renaud noted the mechanism is based on value not cost to which Mr Peake responded that the value of the capacity provided by DSM changes throughout the Capacity Cycle. The Chair noted that this was an issue that is being considered in the discussion on harmonisation. He challenged the group to consider the inclusion of DSM in the balancing market as a potential solution for harmonisation of demand and supply side resources. Mr Breidenbaugh noted that it was important to note that DSM providers lose money if they are dispatched whereas peaking generators make money when they are dispatched. This implied that DSM providers would prefer not to be dispatched at times when the system operator wants them to.<br>• The Chair noted that Dr Tooth had provided a spectrum of options which now need to be mapped on a continuum of pros and cons. He added that the group should consider that these solutions would affect many potential customers in Western Australia who are willing and able to provide curtailment.<br>• Discussion ensued on potential solutions for harmonisation of demand side and supply side. Mr Breidenbaugh noted that changing availability requirements would require that DSAs review their portfolio of customers. However, changing other variables such as minimum hours of duration etc. would create unmanageable risks for DSA's because these variables affect all customers in the same way and little room for adaptability across portfolio is left for the DSA. Mr Renaud cautioned against over-specifying DSM requirements as that would severely limit the entry of DSM into the market.<br>• The discussion concluded with the members agreeing that more work should be conducted on the potential solutions. The Chair noted that the solutions should be debated keeping in mind the right signals need to be provided at the right time. The Chair noted that some of these issues were also being assessed in PJM market. He encouraged members to send their feedback on potential solutions to the IMO. Members requested that information be provided on aspects of different capacity markets and on the dispatch of DSM since market start. Members also requested that the cost-effectiveness of different solutions should be presented.<br>*Action Points:*<br>• *RCMWG Members to provide feedback to the IMO on the proposed solutions for harmonisation of demand and supply side sources*<br>• *The IMO to include information on the cost effectiveness of proposed solutions or harmonisation*<br>• *The IMO to provide information to members on aspects of different capacity markets* | |
| 5 | **PRESENTATION: RCM Review Report-2 by Mr Mike Thomas, The Lantau Group**<br>The Chair invited Mr Thomas to present his paper.<br>The following points of discussion were noted: | |

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| | • On the issue of forecasting uncertainty, Mr Sutherland noted that forecasting error made a significant contribution to over-supply of capacity. Mr MacLean observed that because forecasts inherently have a level of uncertainty, the question to ponder is what protections exist in the market for existing loads to be shielded from the costs of committed loads not becoming available.<br>• There was some discussion on the level of DSM contracted bilaterally in the market. Mr Breidenbaugh noted that if the intent was to encourage bilateral contracting, then DSM might be driven out of the market. Mr Thomas noted that the intent of the proposed solution was not to drive out any particular technology from the market.<br>• <u>On the table detailing factors to which capacity additions could be attributed, Mr Dykstra queried if data could be provided on capacity credits by facility. Further,</u> Mr Dykstra noted that the objective was to make sure that at any time, the right price signal was available to anyone contemplating making capacity available to the market. He noted that the reserve capacity price should be set at the marginal value of a unit of capacity irrespective of the marginal cost associated with that unit of capacity. He added that the price-based solution may not be productive as it is an administrative tool and it might be more useful to consider a spigot control mechanism. Discussion ensued among members on the advantages and disadvantages of a spigot control mechanism vis-a-vis a price-based mechanism. Mr Breidenbaugh observed that most capacity markets have some form of administrative determination of variables such as downward sloping demand curve that ultimately determine the price. He observed that the cost of new entry should be well below the capacity price to encourage new technology. At the same time, it should reduce enough at appropriate times to signal the exit of inefficient technologies.<br>• Discussion ensued among members on bilateral contracting in the market. The Chair noted that the market was quite concentrated on the retailer side. Mr Huppatz observed the reduction in reserve capacity price if a number of uncontracted capacity credits existed in the market. There was some discussion among members on whether the sliding scale of price determination should be reviewed annually. The Chair noted that there is always a lag time between cause and effect in the capacity mechanism.<br>• The Chair concluded the discussion by noting that there may be some merit in the proposal. He observed that there is a balancing act between price incentive and the level of capacity resources. He encouraged members to provide feedback to the IMO on the proposed solution so that it could be developed further.<br><br>*Action Points:*<br><br>• *RCMWG Members to provide feedback to the IMO on the proposed sliding scale determination of Reserve Capacity Price.* | |
| **6** | **CLOSED**<br><br>The Chair thanked all members for attending the meeting and added that the next meeting is tentative based on the development of the two work streams. He also noted that the next work stream on dynamic | |

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| | refund regime would be kick-started in the next meeting. He declared the meeting closed at 5.30 pm. | |

THE LANTAU GROUP
strategy & economic consulting

For Discussion

Prepared For:

RCM Working Group

# RCM Review Report 2 for RCM Working Group

Prepared By:

The Lantau Group (HK) Limited

1902A Tower Two Lippo Centre

89 Queensway, Hong Kong

Date: 10 April 2012

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# 1. OVERVIEW

At the March Reserve Capacity Mechanism Working Group (RCM WG) meeting, a number of issues were raised for further discussion. Ahead of turning to those issues, we summarise three key points from the previous meeting:

- The RCM is an administrative mechanism and, by design, does not adjust as dynamically to market conditions as a pure market-based mechanism would. While that may make the RCM less-than-perfect, it does not necessarily mean the RCM is "broken". The perfect can, as everyone knows, be the enemy of the good. If the RCM works well enough, or relevant RCM parameters are able to be adjusted frequently enough and with sufficient transparency, then the case for changing the RCM becomes weaker. The case for changing the RCM depends on whether the RCM adjusts sufficiently to stop (most) investment that is not needed while supporting (enough) investment that is needed. It also depends on the costs and risks associated with designing and implementing changes that achieve the desired results without costly unintended consequences.
- Currently, there are too many capacity credits in the WEM. Regardless of cause(s), which we consider below, the economic value of capacity credits currently available in the WEM is substantially lower than the RCP value set by the workings of the RCM. The RCP is too high when it creates a continuing "development" signal for capacity credit resources at a time when there is already a significant excess of reserve capacity.
- The results of the MRCP review should not be underestimated in terms of their impact on investment signals in the WEM. The significant reduction in the MRCP drives a flow-through reduction in the RCP, which naturally reduces the commercial attractiveness of potential sources of new capacity credits, all else equal.

In the follow-on discussion, we look at three issues in more detail:

- What has "caused" the excess capacity in the WEM, and how (whether) that matters in thinking about the role of the RCM and scope for changes to it;
- How the RCM and capacity "markets", generally, influence investment decisions by type of resource; and
- Evolution of the RCM, taking into account the MRCP review and other concerns identified.

# 2. CAUSATION

## 2.1. THE RCM AND OTHER DRIVERS

The amount of excess reserve capacity in the WEM arises from a number of sources. Table 1 estimates new capacity entering the WEM by attributed factor.

**Table 1: Capacity additions (MW) by attributed factor[1]**

| | Capacity Year | | | | | | |
|---|---|---|---|---|---|---|---|
| **Attributed Factor** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **Total** |
| Schedule 7 | 536 | | | | | | 536 |
| Displacement tender | | 256 | | | | | 256 |
| MRET | | 1 | 1 | 90 | 5 | 19 | 116 |
| Government policies | | | | | 220 | | 220 |
| Market outcomes | | 331 | 109 | 10 | 112 | | 562 |
| Demand-side resources | 47 | 0 | 71 | 87 | 181 | 45 | 431 |
| Total Capacity Addition | 583 | 587 | 181 | 187 | 518 | 64 | 2120 |
| Excess Reserve Capacity | 278 | 527 | 113 | 302 | 495 | 775 | |

The attributed factors have included:

- Schedule 7 of the Electricity Corporations Act 1994 – which was the requirement by WPC to tender for new capacity through an open and non-discriminatory process should it require new energy or capacity in the SWIS. This was in force until WPC was disaggregated;
- The Displacement Mechanism in the Original Vesting Contracts (dated 2005), which applied to Synergy and commenced after WPC was disaggregated. Under this Mechanism, Synergy was required to Tender for certain volumes of energy and capacity (which could be supplied by new or existing plant) to meet franchise customer volumes;
- The Mandatory Renewable Energy Target – which requires that all retailers supply a certain percentage of their loads from renewable energy sources. This target was set at 9500 GWh across Australia in 2001 and increased in 2009 with an Expanded MRET intended to target 20 percent of electricity to be supplied by renewables by 2020. This has effectively driven a growth in renewable options with the penalty payments of AUD40/MWh from 2001 to 2010 and AUD65/MWh from 2010; and
- Certain policy decisions by the WA Government such as the refurbishment of Muja AB (220 MW).

Schedule 7 and the Displacement Tender accounted for over 780 MW, but affected the WEM from the beginning. Subsequent entry decisions would have been taken with knowledge of the effect or likely effect of those initial policy-driven initiatives. The combination of resources added to the WEM due to market outcomes (essentially, the absence of any other attributed factor) and demand-side resources contributes the vast

1 Source: IMO

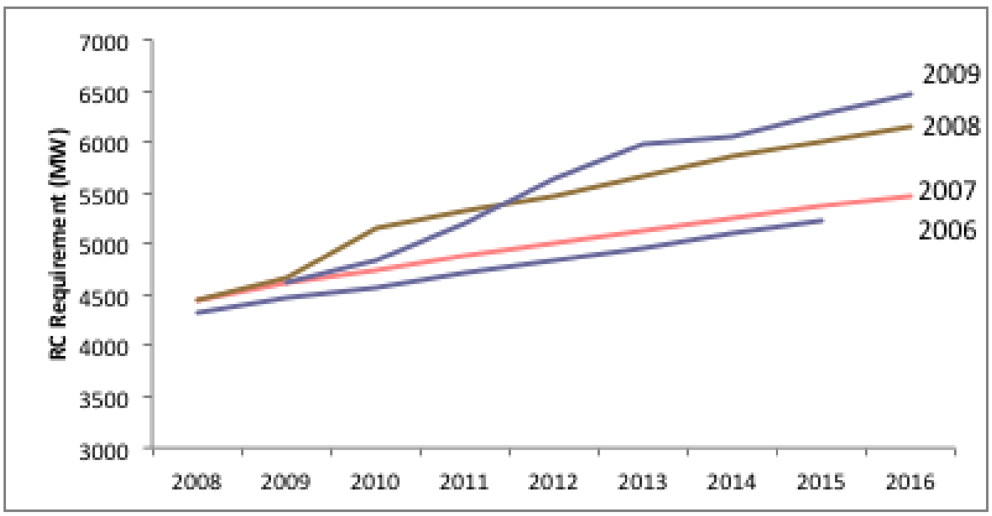
majority of capacity credit sources added to the WEM, accounting for over 960 MW. The MRET scheme accounts for significant renewable resource adoption, principally wind, particularly for the capacity year 2011. It is also clear that public policy also influences investment timing and magnitude, a factor that is important to consider when determining how much risk to expose market stakeholders to with respect to the prospect that excess reserve capacity can be caused by factors originating outside of the WEM.

Looking forward, the RCM is the only mechanism left in the SWIS (other than government direction through Verve) to drive new investment in non-intermittent facilities. Schedule 7 and the Displacement Mechanism no longer exist. The expanded MRET scheme will continue to bring new capacity online, though most of this is likely to be intermittent in nature. Given the lead times for baseload capacity, the RCM needs to guide investor expectations such that future investments are expected to be commercially viable at the same time they are also physically needed in the WEM.

## 2.2. LOAD FORECAST UNCERTAINTY

Load forecasts are inherently uncertain as market conditions can change dramatically over time. From 2006 to 2009, forecasts exhibited considerable timing uncertainty (compare 2008 and 2009), but were generally upward trending, with each subsequent year's outlook suggesting even greater reserve capacity requirement than had been expected previously, as shown in Figure 1.

**Figure 1: Load forecasts: 2006 to 2009**[2]




More recent forecasts indicate a different "trend". Figure 2 shows the extent of change by showing the most recent forecast 2011 (black) compared to 2010 (red) as well as earlier forecasts. The forecast for 2009 is shown for reference, as well. Notably, between 2009 and 2010, virtually no growth was projected.

2 Source: IMO

**Figure 2: Load forecasts: 2009-2011**[3]

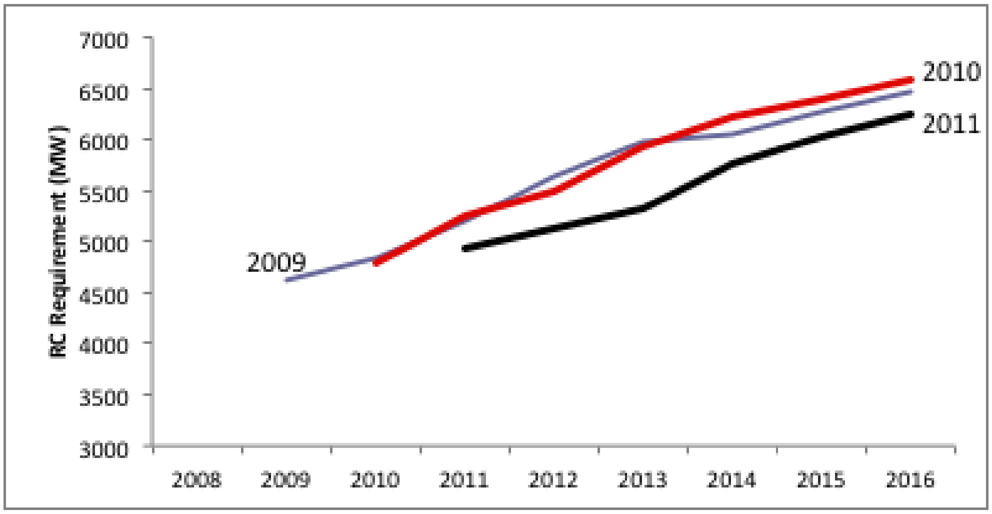



Table 2 summarises the RCR by capacity year over time.

**Table 2: Reserve Capacity Requirement**

| | SOO Publication Year | | | | | |
|---|---|---|---|---|---|---|
| **Capacity Year** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** |
| 2008 | 4322 | 4442 | 4452 | | | |
| 2009 | 4463 | 4609 | 4666 | 4623 | | |
| 2010 | 4581 | 4737 | 5146 | 4836 | 4778 | |
| 2011 | 4721 | 4881 | 5314 | 5191 | 5261 | 4930 |
| 2012 | 4844 | 5009 | 5477 | 5632 | 5501 | 5121 |
| 2013 | 4965 | 5122 | 5674 | 5978 | 5937 | 5312 |
| 2014 | 5102 | 5257 | 5849 | 6049 | 6213 | 5773 |
| 2015 | 5219 | 5361 | 6004 | 6268 | 6392 | 6032 |
| 2016 | | 5470 | 6148 | 6465 | 6597 | 6240 |

By 2011 the RCR for 2013 had been revised downward by 189 MW from what it had been in 2010 for the 2012 capacity year.  The downward revision is particularly stark when considering that the projected estimated of the RCR for 2013 had been 5937 MW in 2010, a value that was revised down to 5312 MW, a downward revision of over 600 MW. Clearly, load uncertainty is a driver of the economic value (and risk) of capacity credits.

The challenge of forecasting lumpy loads in a smaller market is evident in Figure 3, which illustrates the range of uncertainty present in a single forecast.

3 Source: IMO

**Figure 3: The challenge of block load forecasting in the WEM[4]**

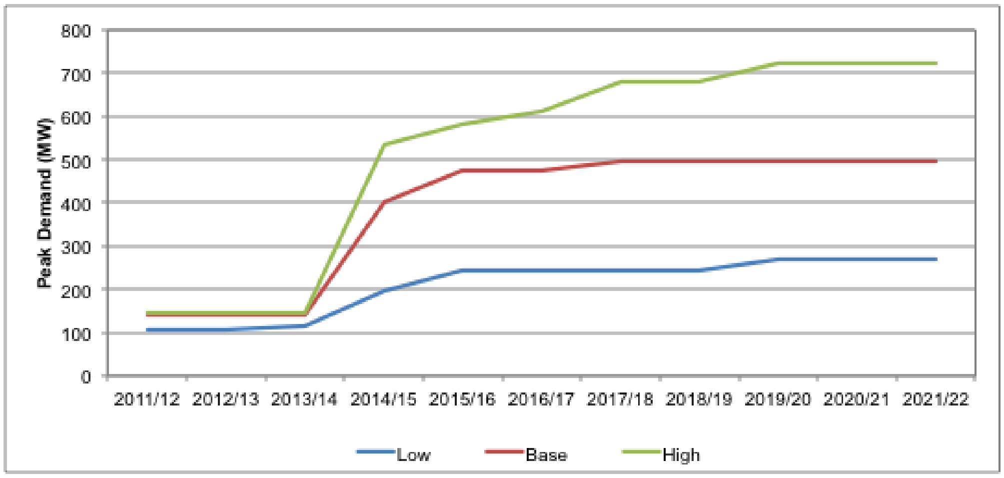
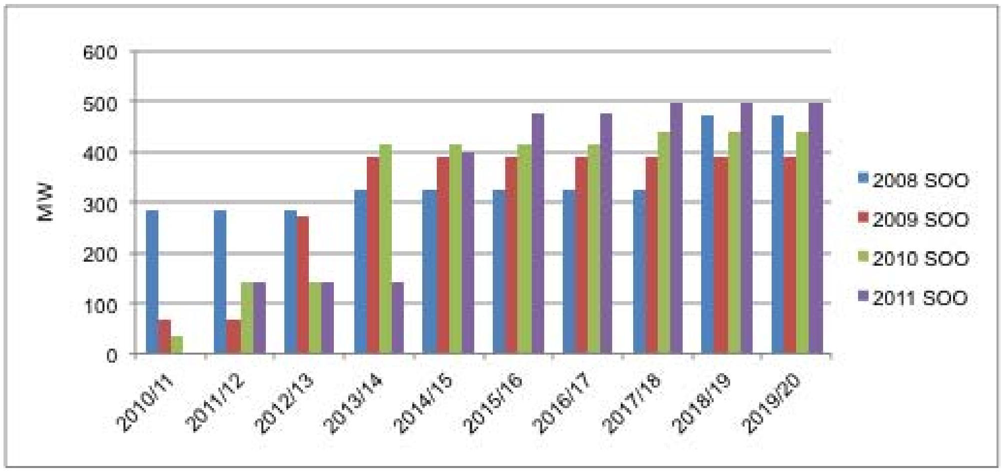



Figure 4 highlights the extent of uncertainty across SOO forecasts with respect to just six potential large loads. Whereas on one side of the equation it is important to establish the committed status of generation projects, it has proven difficult to achieve a similar level of "commitment" for block loads. In other markets, centrally developed forecasts and data are often an important service, but responsibility for interpreting forecasts and forming views of future supply and demand levels remains with the investor. A potentially important question for the RCM is whether or how load forecast uncertainty, which at some point is irreducible, is to be handled. Theoretically it may be possible to improve a forecast, but that is not the issue here. The issue, which does not go away even if a forecast is the very best possible forecast, is that the future is uncertain, and that, in the WEM, the RCR can be influenced significantly by changes in the timing of a very small number of large potential loads.

4 Source: IMO

**Figure 4: Block load forecasting uncertainty across forecasts[5]**




5 Source: IMO (From 2011 Statement of Opportunities)

# 3. HOW THE RCM INFLUENCES CAPACITY INVESTMENT CHOICES

A MW of capacity cannot just be summoned to exist in specific hours. Investment is required. In order to attract and support new investment, the expected value of the RCP must be capable of equalling or exceeding the annual carrying charge (capacity charge) associated with a pure peaking (or peak lopping) resource. The MRCP sets the maximum value for the RCP in the WEM. The MRCP needs to be high enough that the resulting *expected RCP* is able to support new capacity investment when and as that investment is actually required. The other condition is that the expected RCP should be *less than* the level necessary to support new capacity investment at a time when such capacity investment is not needed.

## 3.1. THE VALUE OF PURE CAPACITY

Consider the choice between investing in an incremental MW of a pure peaking resource or an incremental MW from a unit with a lower marginal dispatch cost. Both units would provide exactly the same reliability benefit. In addition, the unit with the lower dispatch cost could displace higher-cost resources. Accordingly, the unit with the lower dispatch cost has a second source of value.

The total value associated with a unit with a lower dispatch cost than a pure peaking unit resource equals the contribution from both sources—that is, the capacity value plus the additional dispatch value. Static equilibrium is a notional point where a power system has a perfectly optimal mix of all different types of capacity. At this point, the total value for either a baseload or a mid-merit technology would just equal the annual carrying cost for the peaking resource (assuming that the peaking resource is an economic addition at the margin). In short, the higher carrying cost of a non-peaking resource is perfectly offset by the dispatch cost savings. This point of optimality gives rise to the following simple "rule":

*Capacity_value + Annual_dispatch_cost_savings = Annual_carrying_cost*

If a power system has the optimal mix of technology to serve expected load, then as load grows, new investment will be needed in each load segment whether it be new peaking capacity, new mid-merit (flexible) capacity or new baseload capacity. When the plant mix is optimal, each type of capacity in the optimal mix would fulfil this equilibrium condition.

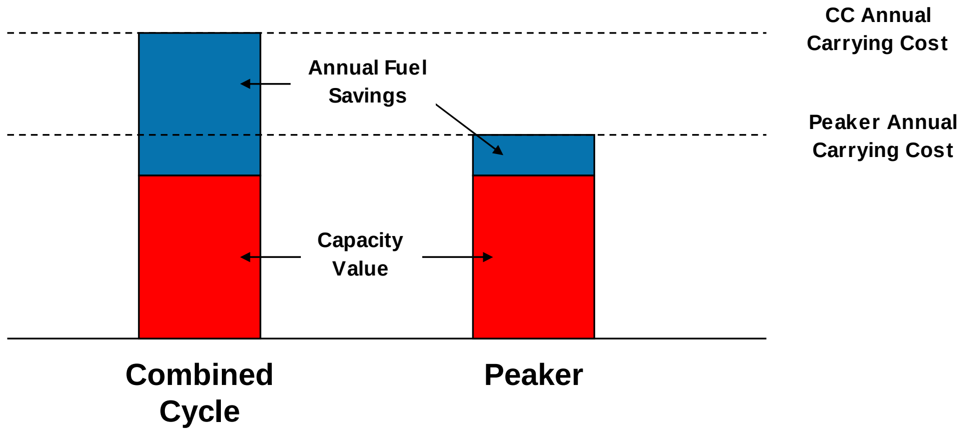



**Figure 5: Optimal Investment by Type**

It is the role of the RCM to produce the “red” portion of Figure 5, which in the WEM corresponds to the reference peaking technology (160 MW open cycle gas turbine). The energy market portion of the WEM then adjudicates whether dispatch cost differentials across different technologies and fuels provide sufficient additional value to tilt the investment decision away from a pure capacity resource and towards something else.

The workings of the RCM need to get the “capacity value” sufficiently right that the WEM neither falls short of capacity nor supports materially excess investment.

## 3.2. THE MRCP REVIEW IN PERSPECTIVE

The changes to the MRCP in the recently concluded review have resulted in an MRCP that reflects an expected value of new capacity—a best estimate of the cost of building a reference peaking resource. The result has been a significant reduction in the MRCP that, as previously discussed, reflects methodological and definitional considerations and not just revisions to parameters to reflect ever-changing market conditions. The review resulted in an overall reduction of approximately 32 percent in the MRCP for the 2014/15 Capacity Year. Of the overall 32 percent reduction, 23 percentage points reflect changes to the MRCP formulation, as summarised in Table 3.

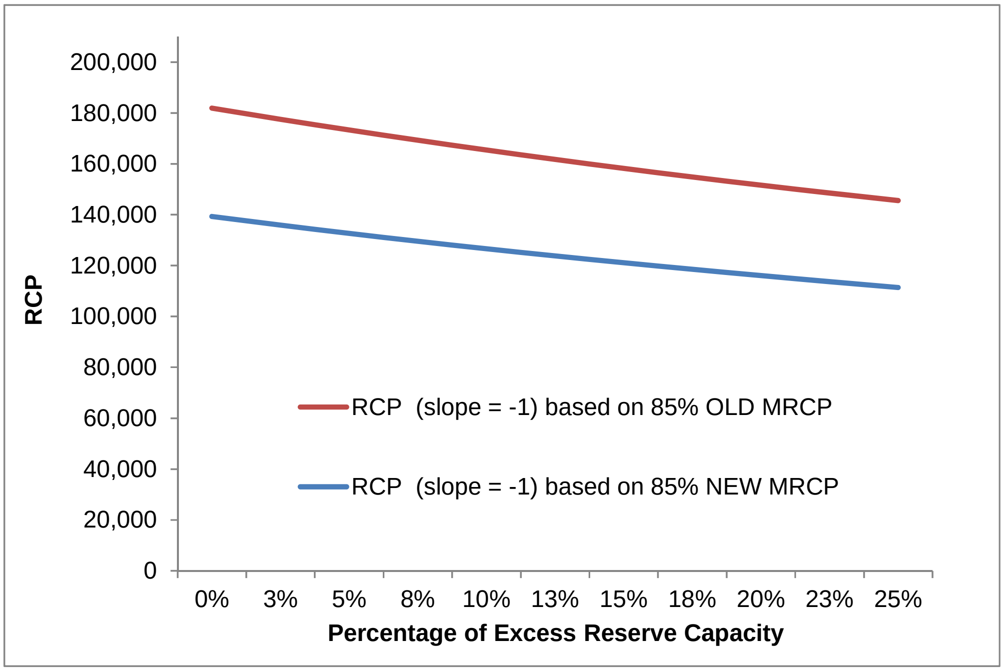
**Table 3: Summary of MRCP review adjustments**[6]

| | | | |
|---|---|---|---|
| MRCP after year-on-year changes | | | $214,100 |
| Methodological and Definitional changes | Amount $ | Amount % | Adjusted Result |
| Inclusion of inlet cooling | -18,800 | -8.80% | 195,300 |
| Revised Transmission Cost methodology | -30,300 | -14.20% | 165,000 |
| Increased fuel allowance (increase from 12 to 14 hours) | 100 | 0.00% | 165,100 |
| Use of average land cost | 1,400 | 0.70% | 166,500 |
| Revised cost escalation/WACC methodology | -6,500 | -3.00% | 160,000 |
| Debt issuance cost included in WACC (relevant portion) | -500 | -0.20% | 159,500 |
| Annual insurance costs included in Fixed O&M | 4,400 | 2.10% | 163,900 |
| **Net change** | **-50,100** | **-23.40%** | **$163,900** |

6 Source: *Final Report: Maximum Reserve Capacity Price for the 2014/15 Capacity Year*, IMO, February 2012.

Figure 6 highlights the impact of the recent MRCP review on the relationship between the RCP and the amount of excess reserve capacity.

**Figure 6; Impact of the MRCP review on the RCP relationship to excess reserve capacity**




In the next section, we discuss the implications of this change and other potential changes that could be made to the RCM to improve its overall responsiveness to market conditions in the WEM.

# 4. OPTIONS AND APPROACHES: FURTHER DISCUSSION

## 4.1. OVERVIEW

The adjustment of the RCP plays two important roles:

- It establishes the risk borne by generators and retailers respectively in relation to the overall level of excess reserve capacity in the WEM. If the RCP adjusts effortlessly and perfectly with market conditions, the risk of excess is borne primarily by capacity resource investors. If the RCP adjusts less perfectly or in a constrained manner, more of the risk is shared by capacity resource users. In addition, if the adjustment is not "perfect" there is greater risk of inefficient outcomes (too much or too little investment). At the same time, pushing more risk to resource investors tends to create more volatility by increasing the sensitivity of investment viability to market conditions.
- It determines the overall economic value created or destroyed by the workings of the RCM insofar as the RCM creates or supports appropriate signals for investment given supply and demand conditions and expectations in each Capacity Year.

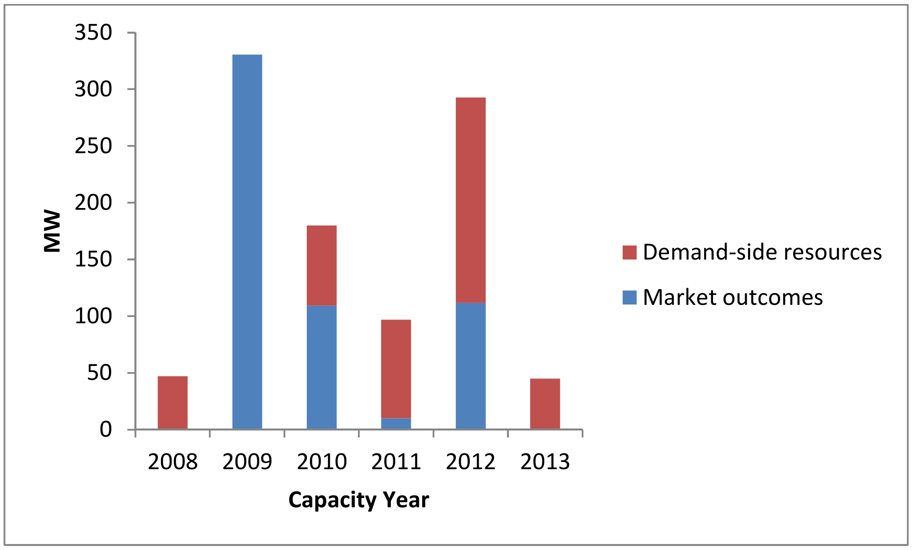
In this section we set out in more detail an approach based on modifying the existing RCP formula. This approach, though not purely market-based, involves changes intended to improve alignment with market conditions.

## 4.2. EVIDENCE THAT THE EXPECTED RCP IS BELOW THE COST OF NEW ENTRY

The significant reduction in the value of a Capacity Credit improves the alignment between the RCM value of a Capacity Credit and what a market-based mechanism would yield. In part due to the impact of the MRCP reduction and probably also due to the uncertainty created for investors as a result of simultaneous reviews of the MRCP and RCM, market-based investment in the WEM has fallen to essentially zero, a situation consistent with fundamental supply and demand conditions.

Figure 7 compares market-based investment and demand resource investment over time, highlighting the fall-off for the 2013 Capacity Year. Additional potential changes to the performance requirements of demand resources (to improve the consistency of treatment between demand resources and supply resources) resulting from the RCM review would likely reduce the overall level of capacity attributable to demand resources as well as reduce the amount of untapped demand resource remaining in the WEM.

**Figure 7: Capacity Credit generating resources most strongly influenced by the RCM**



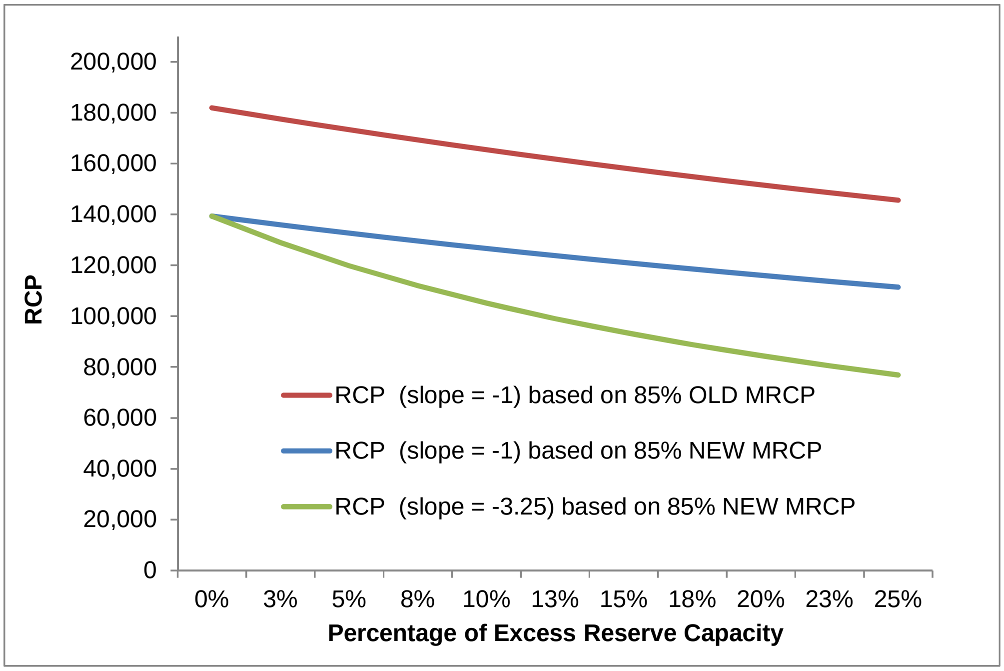

The absence of a clear "build signal" at this time in the WEM is a good thing because it aligns with a fundamentals-based analysis of what "should" be happening in the WEM at this time. However, it would be unwise to assume merely from appearances that all is now fine for the longer-term. At least two important aspects of the RCM pose on-going concerns:

- The RCM is no more sensitive to market conditions than before – the RCP has merely been re-floated downward as a result of the MRCP review; and
- The MRCP value itself, having been reduced, may no longer provide sufficient headroom for the "expected" long-term RCP to support investment.

## 4.3. THE RCP FORMULATION AND THE OPTION OF A STEEPER "SLOPE"

Currently, the slope is "minus 1". The RCP applicable to uncontracted capacity credits is adjusted downward in proportion to the amount of excess reserve capacity. A slope factor of "minus 3.25" (a specific value discussed later) would reduce the value of an uncontracted capacity credit at faster rate, strengthening the signal to generation investors to defer capacity investment until demand has increased, as shown in Figure 8.

**Figure 8: RCP Adjustment Formula Comparison**




The steeper slope would be implemented within the existing RCM structure and, of course, would be amenable to periodic review for the purposes of tuning the RCM to improve efficiency over time. Substantial justification for a steeper slope exists, based on the fact that a market-based valuation of excess reserve capacity would yield values significantly less than what the RCM currently yields, as set out in the Appendix of the TLG report for the March Working Group meeting.

A steeper slope, in combination with the MRCP revision, would significantly alter the value of a Capacity Credit compared to previous Capacity Years. For example, a 15 percent excess reserve capacity would result in the RCP being 57.1 percent of the MRCP given a slope factor of “minus 3.25”, rather than 73.9 percent under the current adjustment formula, as summarised in Table 4.

**Table 4: RCP as a Percentage of the MRCP (starting at 85% of MRCP)**

| Amount of Excess Reserve Capacity | Based on "-1 slope" | Based on "-3.25 slope" |
|---|---|---|
| **0.0%** | 85.0% | 85.0% |
| **2.5%** | 82.9% | 78.6% |
| **5.0%** | 81.0% | 73.1% |
| **7.5%** | 79.1% | 68.3% |
| **10.0%** | 77.3% | 64.2% |
| **12.5%** | 75.6% | 60.4% |
| **15.0%** | 73.9% | 57.1% |
| **17.5%** | 72.3% | 54.2% |
| **20.0%** | 70.8% | 51.5% |
| **22.5%** | 69.4% | 49.1% |
| **25.0%** | 68.0% | 46.9% |

### 4.3.1. The relationship between the RCP and the MRCP

Currently, the RCP for uncontracted capacity credits begins at 85% of the MRCP. Given that the newly revised MRCP is presumed equal to the reasonable cost of capacity, the current formula for setting the RCP (beginning at 85% of the MRCP and going downward, potentially, from there) cannot cover that cost even if the amount of excess reserve capacity reduces substantially.

It would make more sense for the RCP to be directly linked to the MRCP, rather than continue with the definition of the base RCP as being 85 percent of the MRCP, an adjustment that has unclear origins and no obvious foundational logical support. Eliminating the initial "85 percent adjustment step" would reduce the penalty relative to the MRCP for very small amounts of excess reserve capacity, but a steeper slope would offset this impact, by increasing risk, as shown in Figure 9 and Table 5.

**Figure 9: RCP with adjusted starting point and slope**

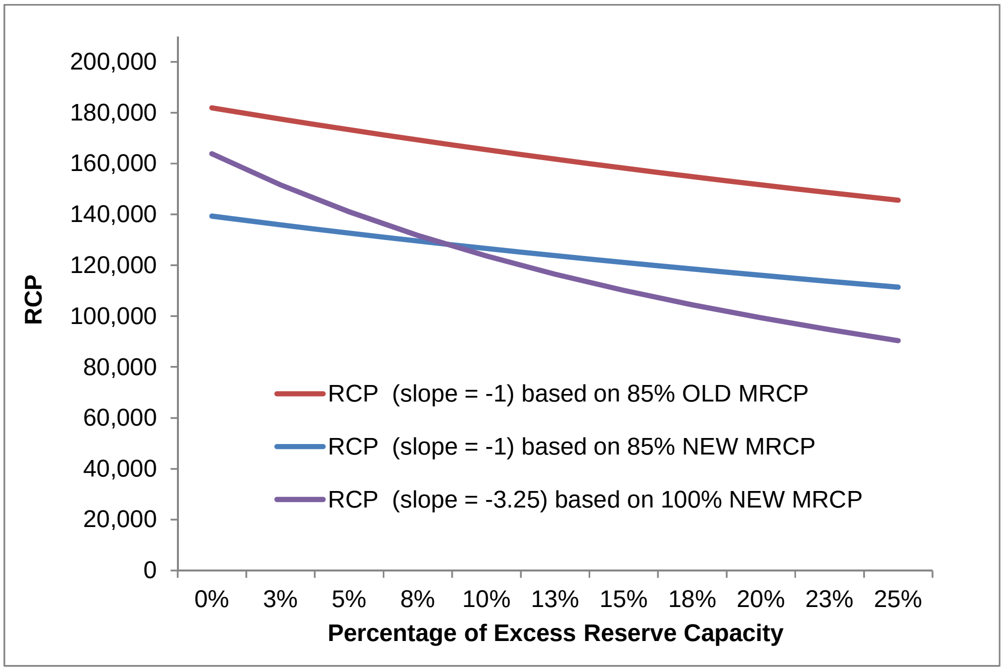



**Table 5: RCP as a Percentage of the MRCP (Alternative starting point)**

| Amount of Excess Reserve Capacity | Based on "-1 slope" starting at 85 percent of the MRCP | Based on "-3.25 slope" starting at 100 percent of the MRCP |
|---|---|---|
| **0.0%** | 85.0% | 100.0% |
| **2.5%** | 82.9% | 92.5% |
| **5.0%** | 81.0% | 86.0% |
| **7.5%** | 79.1% | 80.4% |
| **10.0%** | 77.3% | 75.5% |
| **12.5%** | 75.6% | 71.1% |
| **15.0%** | 73.9% | 67.2% |
| **17.5%** | 72.3% | 63.7% |
| **20.0%** | 70.8% | 60.6% |
| **22.5%** | 69.4% | 57.8% |
| **25.0%** | 68.0% | 55.2% |

The steeper slope and adjusted starting point are attractive in their simplicity and their ability to penalise investment progressively as the amount of excess reserve capacity increases—more in line with what a market-based mechanism would achieve.

### 4.3.2. Picking values

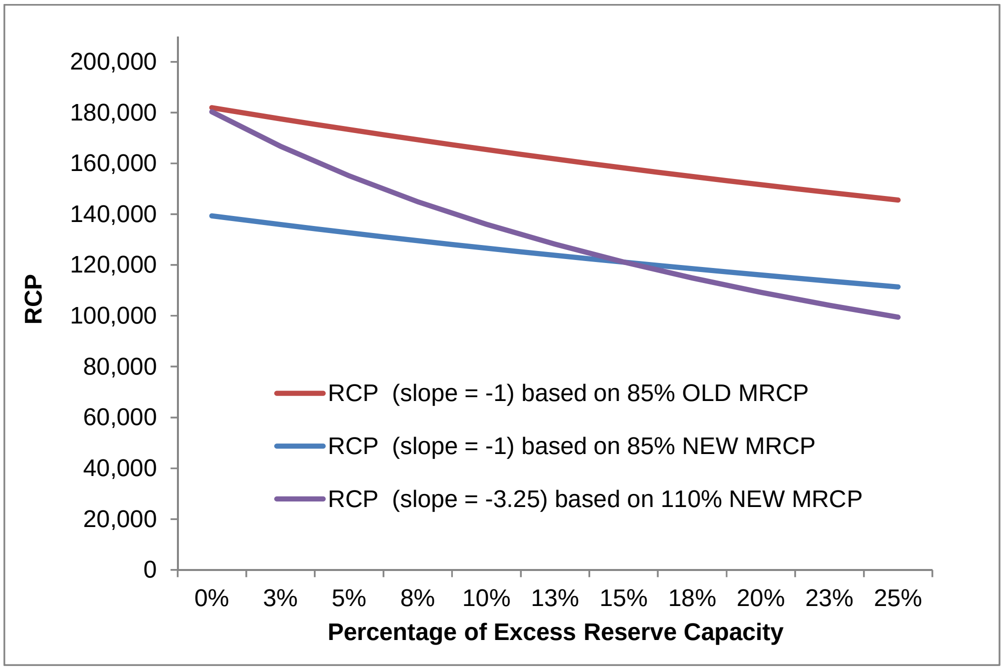
The steeper slope and adjusted starting point result in values for the RCP that are below the revised MRCP and the previous MRCP in all instances. While not a formal reference point, the previous MRCP has the useful quality that it clearly supported investment. The MRCP itself is *supposed* to be able to support investment, but it has not been established that values at varying levels *below* the MRCP will be able to support the amount or type of investment desired in the future. Indeed, the values used to establish the MRCP were drawn from actual costs and technology design choices making it less likely that RCP values *below the MRCP* can support investment in the reference peaking technology to the degree the WEM requires for long-term timely investment support.

The MRCP plays two roles in the RCM. Firstly, it is the maximum value that can be used in an auction when tendering for new capacity. In such instances, the MRCP can be locked-in for ten years. Secondly, the MRCP is the value that sets the maximum for the RCP, an inherently short-term (annual) value. If the annual RCP can fall below the MRCP, but can never rise above it, the *expected* RCP must be less than the MRCP. If the MRCP has been properly estimated, then this RCP<MRCP relationship could pose a serious obstacle for investors in the future.

Consequently, in addition to a steeper slope to make the RCP more market-sensitive, we propose that the RCP be allowed to increase above the MRCP as the amount of excess reserve capacity approaches zero. On the assumption that the WEM will experience, due to its lumpy nature, periodic excess reserve capacity between 0 and 10% under normal conditions, a maximum RCP value of 110% of the MRCP is suggested, as shown in Figure 10.

This 110% value has the additional feature that, when combined with a steeper slope of “minus 3.25” results in a near-term impact on the RCP that is very close to what has occurred already due to the MRCP review. Whether this feature is a net plus or a minus will depend on stakeholder perspectives, but, at minimum, it mitigates the need for a transition mechanism. The other feature of this combination of adjustments is that at zero excess reserve capacity the RCP would be almost the same as the value obtained under the “old” MRCP methodology. Again, while the old value is not a formal reference value (and need not be), it is a data point that is known to have supported vigorous investment interest—the key desirable feature of a true “maximum” annual RCP value.

**Figure 10: Adjusted RCP formula starting at 1.1x the new MRCP**




### 4.3.3. Other Related Issues

The RCM developed the way it has developed in part due to the inability to be certain that a retail load will actually exist. Declaring an intention to bilaterally contract provides an "off-ramp" situation in case the bilateral contract was not forthcoming. The IMO currently provides a put option in the form of the RCP payable for a Capacity Credit to the generation investor. The value of that put option, when it is too high, can support excess investment, but it may also support bilateral transactions between smaller parties by mitigating counterparty concerns.

## 4.4. Summary

The RCM avoids some known complexities and risks of pure auction- or trading-based approaches in relation to the definition of the product being traded, the volatility associated with market-based pricing and counterparty risks. The size of the WEM and the lumpiness of the market would likely be a challenge for a more short-term defined auction product. At the same time, the current RCM parameters can be adjusted to better tailor the investment and value signals to ever-and-often-rapidly changing conditions in the WEM.

# Discussion with the RCM Working Group

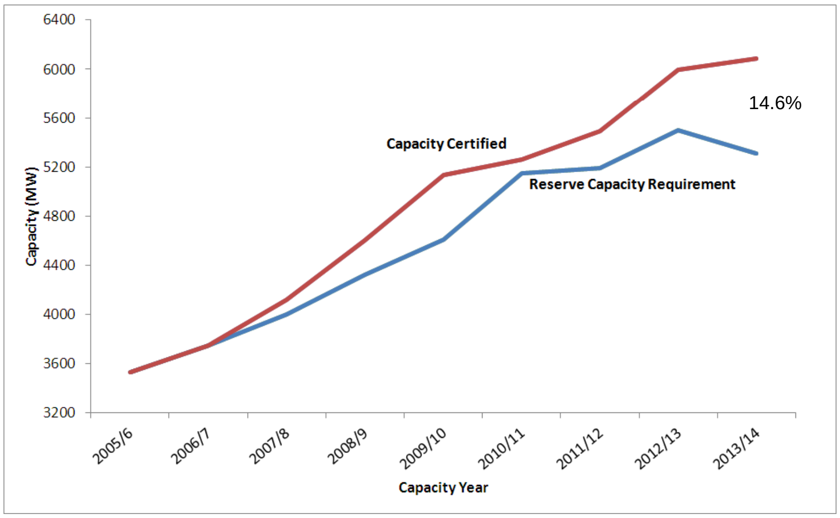
17 April

THE LANTAU GROUP
strategy & economic consulting

## Discussion outline

- CAUSATION
  - THE RCM AND OTHER DRIVERS
  - LOAD FORECAST UNCERTAINTY
- HOW THE RCM INFLUENCES CAPACITY INVESTMENT CHOICES
  - THE VALUE OF PURE CAPACITY
  - THE MRCP REVIEW IN PERSPECTIVE
- FURTHER DISCUSSION
  - COMPLEXITY OF FULL MARKET-BASED APPROACH
  - RCP FORMULA-BASED APPROACH
    - The current RCP formulation and the option of a steeper “slope”
    - The relationship between the RCP and the MRCP
    - Picking values
  - Other Related Issues

## Trend in excess reserve capacity



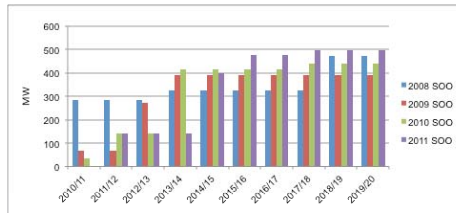



## Many "reasons", but the RCM is always a factor

| | Capacity Year | | | | | | |
|---|---|---|---|---|---|---|---|
| Attributed Factor | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | Total |
| Schedule 7 | 536 | | | | | | 536 |
| Displacement tender | | 256 | | | | | 256 |
| MRET | | 1 | 1 | 90 | 5 | 19 | 116 |
| Government policies | | | | | 220 | | 220 |
| Market outcomes | | 331 | 109 | 10 | 112 | | 562 |
| Demand-side resources | 47 | 0 | 71 | 87 | 181 | 45 | 431 |
| Total Capacity Addition | 583 | 587 | 181 | 187 | 518 | 64 | 2120 |
| Excess Reserve Capacity | 278 | 527 | 113 | 302 | 495 | 775 | |

The specifics are interesting, but the general point that the RCM is a s factor
attracting or supporting investment remains

## Demand uncertainty (1 of 2)

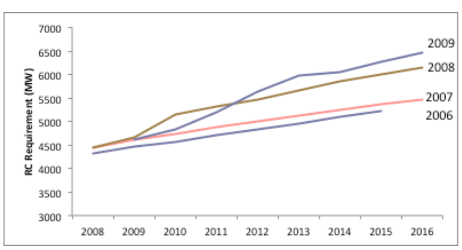




Just SIX “lumpy” loads – represent very significant uncertainty – what commitment should be expected of loads to be commensurate with other resources?

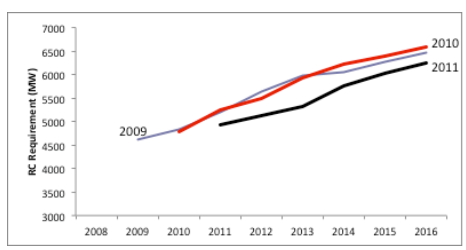


## Demand uncertainty is inherent in the WEM (2 of 2)

UPWARD REVISIONS



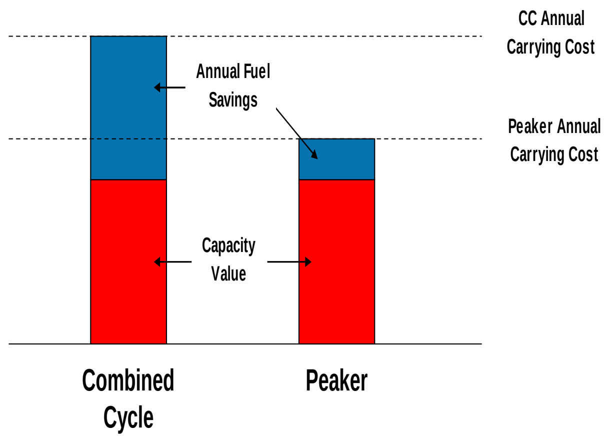

DOWNWARD REVISIONS




Probably any forecast can be made “better”, but you cannot eliminate fundamental uncertainty in a small, lumpy market – the RCM has to be sufficiently responsive so as not to ADD TO the problem

## A capacity credit value is the value of "pure capacity"

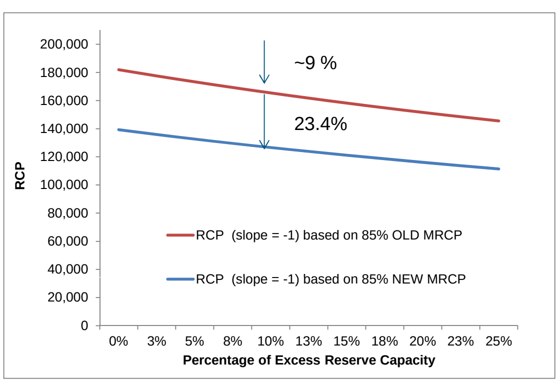
- Consider the choice between investing in an incremental MW of a pure peaking resource or an incremental MW from a unit with a lower marginal dispatch cost.
- Both units would provide exactly the same reliability benefit.
- In addition, the unit with the lower dispatch cost could displace higher-cost resources.
- Accordingly, the unit with the lower dispatch cost has a ***second*** source of value.




It is the role of the RCM to produce the "red" portion, which is the same "value" no matter what technology or side of the equation (demand or supply)

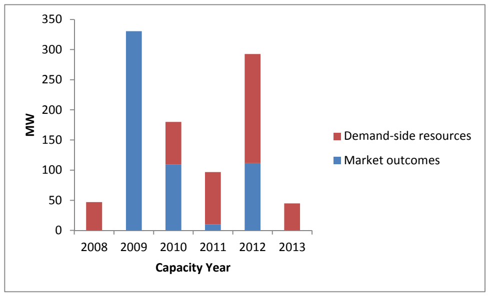


## Before MRCP methodological and definitional adjustments, and after




The MRCP has changed, but the RCP is no more sensitive to market conditions than before, and the lower MRCP has implications for longer-term investment incentives

## Reduced investment in the WEM has already (apparently) begun




This is to be expected, and is good, given the current level of excess reserve capacity…but



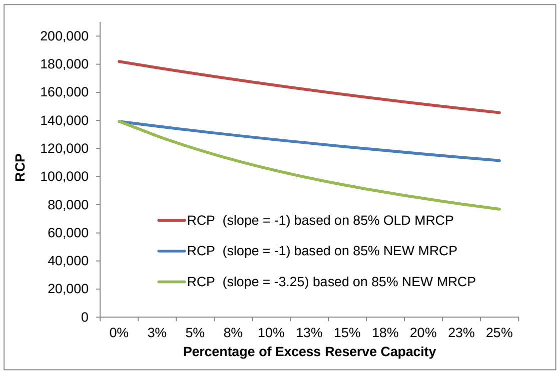
## Market-based pricing of capacity credits is not simple

- What is the value horizon (one year, multiple years)?
- What is the reference point (today, next year, three year's hence, longer term)?
- How big is the market (thickness, level of competitive sourcing/dynamics)?
- What is the starting point and how did it get there (transition, fairness, contracting, etc)
- What is the role of forecasting and forecast uncertainty? (who bears?)
- What is the level of accepted exposure to non-market risks?

- The RCM currently bypasses or simplifies most of these, keeping it but imperfect

Changing the formula of the RCP can make a significant "pro-market" improvement, even if it does not address every imperfection immediately

## Current approach, varying slope



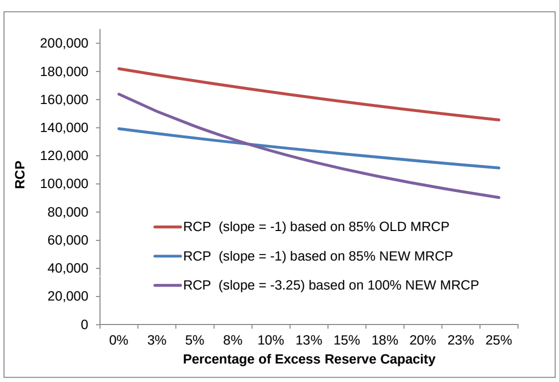

Steeper – more responsive to market conditions

Could be steeper still, as current market value of a single year credit is very very low

The steeper and lower the Credit price can go, the more one has to worry about whether the credit value can go "higher" on the upside to create correct expected values in the longer term



## Capped by MRCP




Steeper – more responsive to market conditions

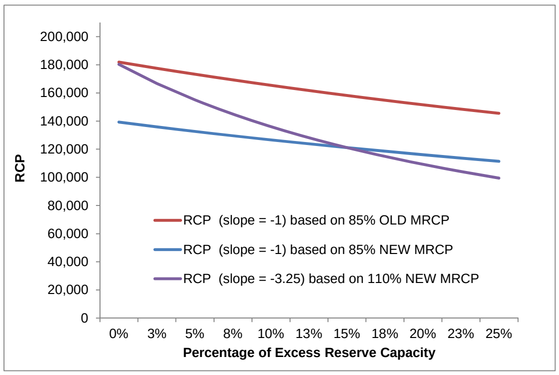
No 85% cap

But still limited to MRCP

What is the MRCP? It is the expected cost of pure peaking capacity provided by a 160MW OCGT

It is not the estimated "maximum" cost of peaking capacity in economics, but a price cap in the WEM

## Capped by 110% of MRCP




Steeper – more responsive to market conditions

110% of MRCP – is that enough?

The higher the cap above MRCP, the more incentive to bilaterally contract around this exposure.

An “uncapped” and “unbottomed” RCP would drive stakeholders into more contracting to manage risk

This principle is key to the bilateral contracting incentive in modern capacity markets



## Comment

- Currently, the RCP is adjusted downward in proportion to the amount of excess reserve capacity that exists.
- A straightforward change would focus on sharpening the administrative price adjustment mechanism to be more responsive to the amount of excess reserve capacity in the WEM.
- An alternative of “spigot control” would go against market-based provision of capacity by new investors, though it would help protect existing generation investors from further potential reductions in CC value
- Consequently, we favour a price-based adjustment either driven by more use of auctions (complex implementation and more volatile value impacts), or a sharpened RCP price adjustment formula
- The risk to be avoided is one in which the adjustments to the RCP are so sufficiently and consistently downward without any chance of an offsetting upward adjustment that the expected value of a Capacity Credit over the life of a capacity investment is not sufficient to support that investment commercially.

RCM Progress Update

**Mike Thomas**

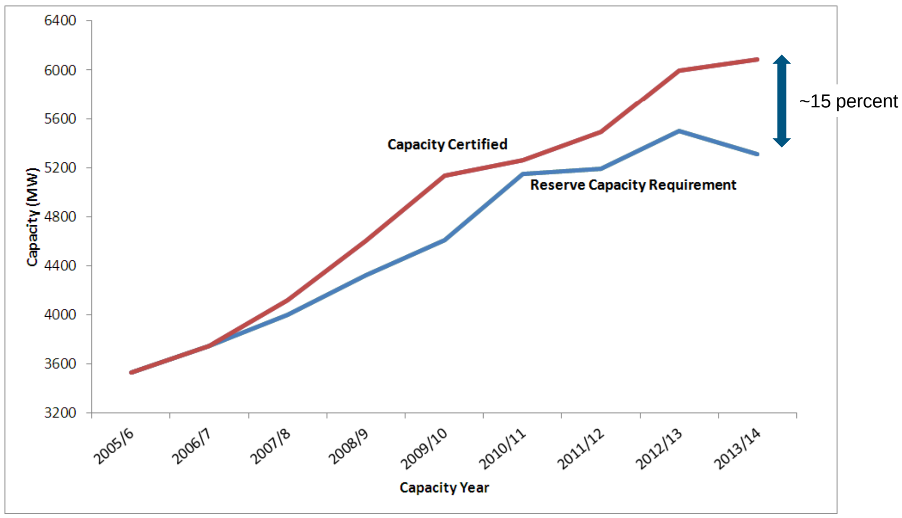
29 May 2012

THE LANTAU GROUP
strategy & economic consulting

## Agenda

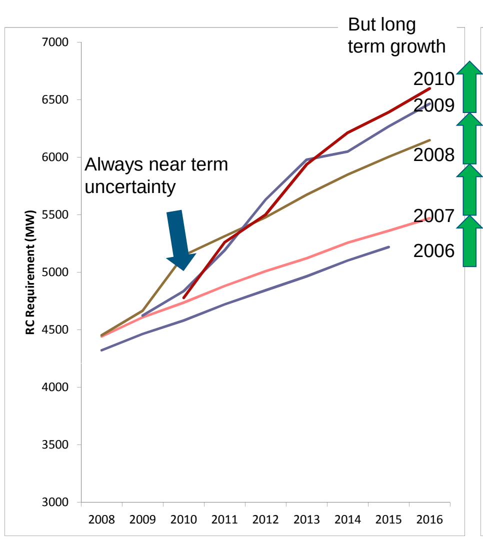
- Situation
  - Excess reserve capacity has increased
  - Demand uncertainty
  - The MRCP has decreased substantially
  - Investment appears to have curtailed
- Problem
  - Economic value of capacity is highly sensitive to market conditions
  - The RCP formulation does not respond to these factors nearly enough (up or down)
- Proposal

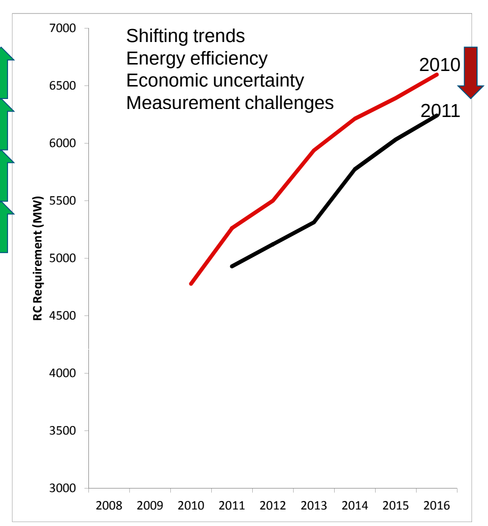
## The growing issue of excess reserve capacity



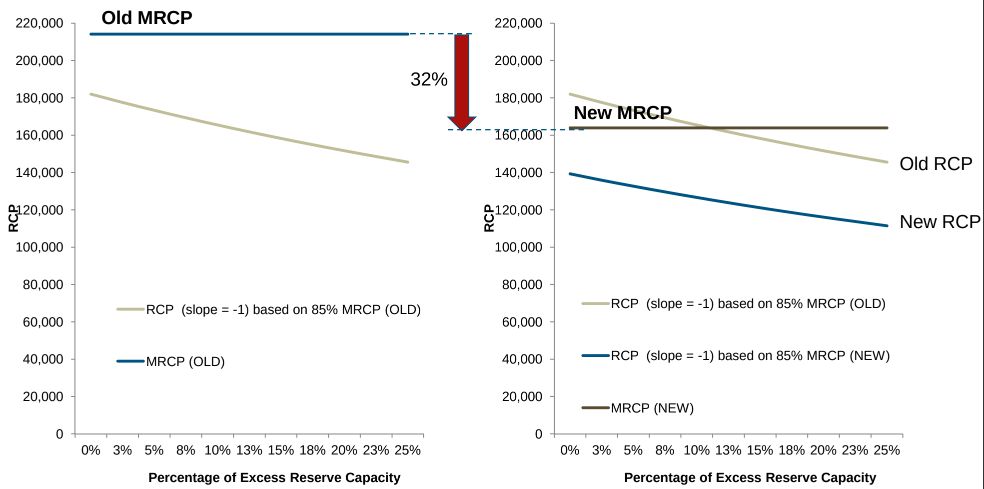



## Demand uncertainty



## Recent MRCP revision significantly reduces the RCP



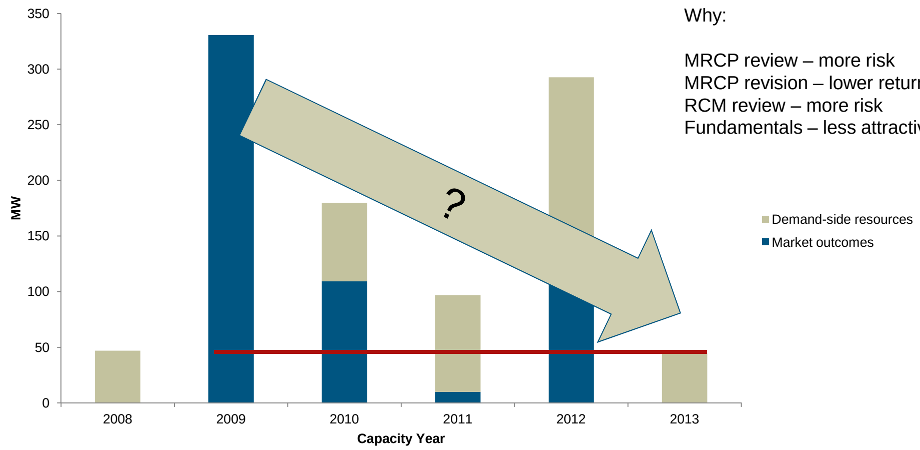



## Why is the MRCP called the MRCP?

- M = Maximum
- But the process for calculating the "MRCP" defines an expected value
  - Rigorously determined estimates
  - Actual costs
- Maximum range values are not used to calculate the MRCP
- No probability of exceedence factor or explicit allowance for contingency is incorporated
- No allowance for any other commercial risk beyond the WACC
- Other markets do not define a "maximum" based on an expected value.

Proposal: Rename the MRCP to reflect that it is a best estimate ("Benchmark RCP")

## Apparent reduction in capacity investment




Why:

MRCP review – more risk
MRCP revision – lower return
RCM review – more risk
Fundamentals – less attractive

Investment has slowed – various reasons. While this is "good" , the RCM remains relatively unresponsive to market conditions



## Concern: Some excess reserve capacity costs flow through to end-users

- If retailers are bilaterally contracted, they bear a portion of the cost of excess reserve capacity
  – The RCP adjustment only flows through capacity credits that are purchased through the IMO
  – Not consistent with a market design intended to feature bilateral contracting
- If there is any incentive to support excess reserve capacity then at least some end-users bear additional costs
  – They do obtain somewhat more "security"
  – But the costs are borne disproportionately by bilaterally contracted load-serving entities
  – And the cost of additional capacity credits is above their market value

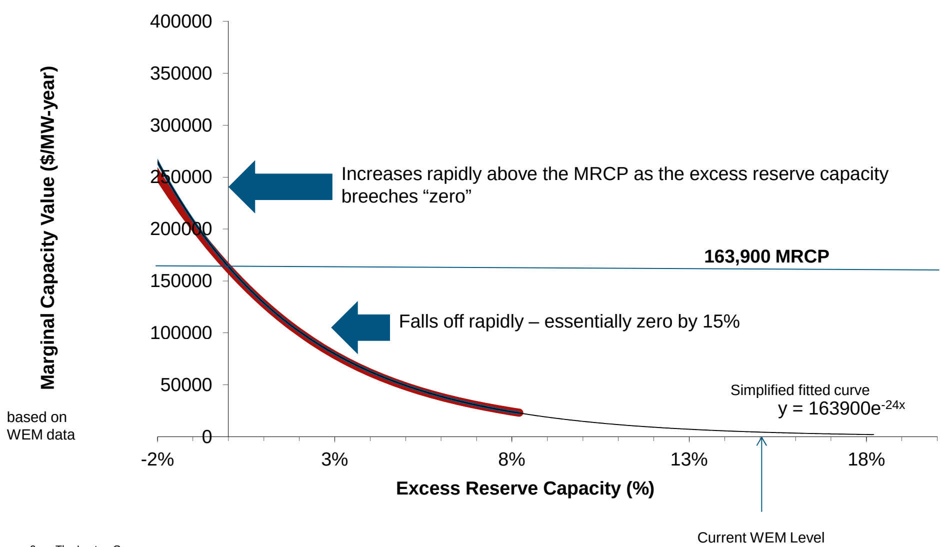
Anything that reduces the incentive and cost of excess reserve capacity reduces this risk

## Summary of situation

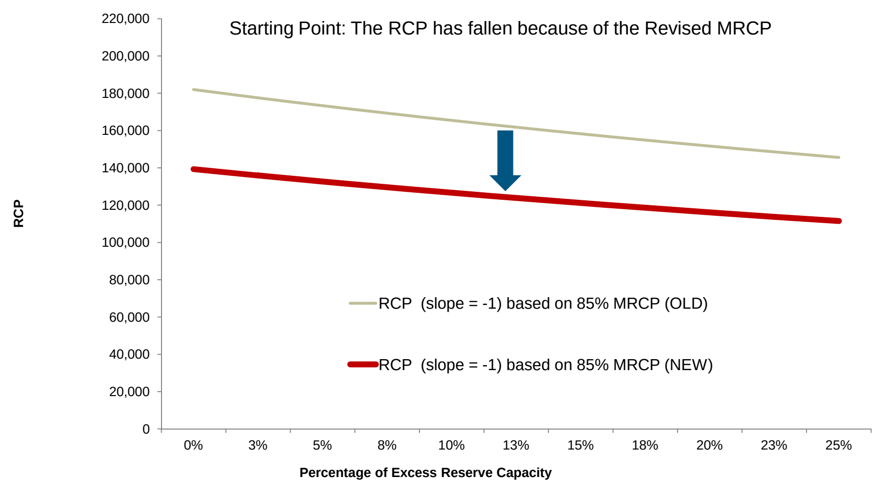
- Excess reserve capacity has persisted, stubbornly, and increased.
- Impact on retailers and end-users is not benign
- MRCP review introduced significant changes
- RCP does not respond sufficiently (up or down) when market conditions change
- Uncontracted capacity receives a valuable “option” benefit to utilise IMO capacity credits when retailers or end-users place no value on them, but the cost of this option is charged to contracted retailers and end-users



## Observation: the economic value of capacity declines at an exponential rate as the amount of excess reserve capacity increases

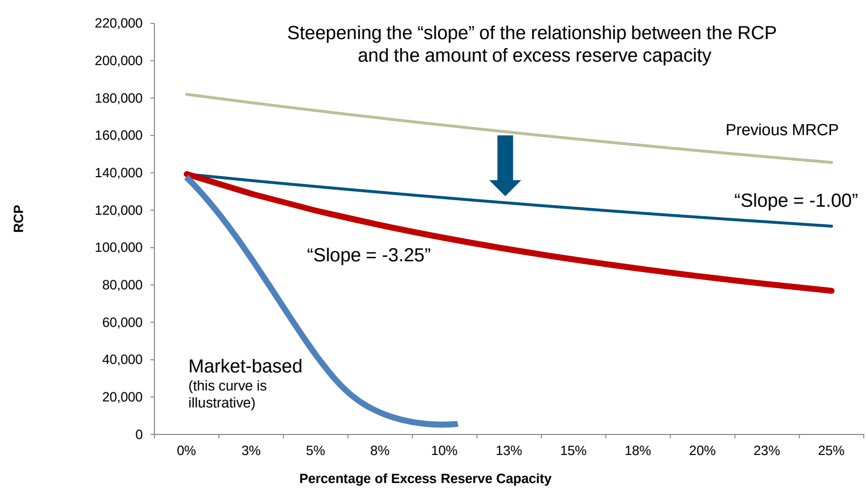


## The RCP falls at a much more shallow rate – the bigger reduction is due to the MRCP revision






## Steeper slope makes the RCP more responsive



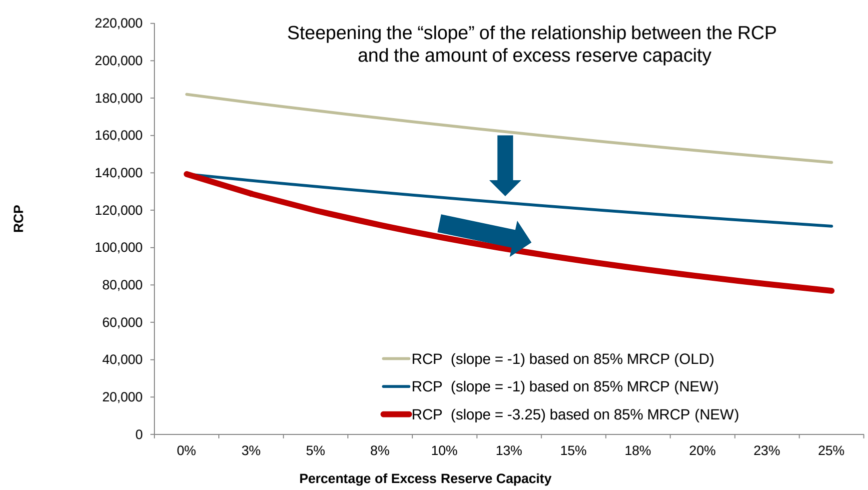
## But how steep? Some design principles

- Steepness should not be greater than what a market would produce
- Mechanism should support needed investment without supporting excess
- Should support commercial risk management (contracting and trading) where possible, without imposing offsetting volatility or risk
- Should not reward inefficient behaviours or rent-seeking gaming
- Should not hamper (should be consistent with) a longer-term evolution towards greater reliance on market mechanisms

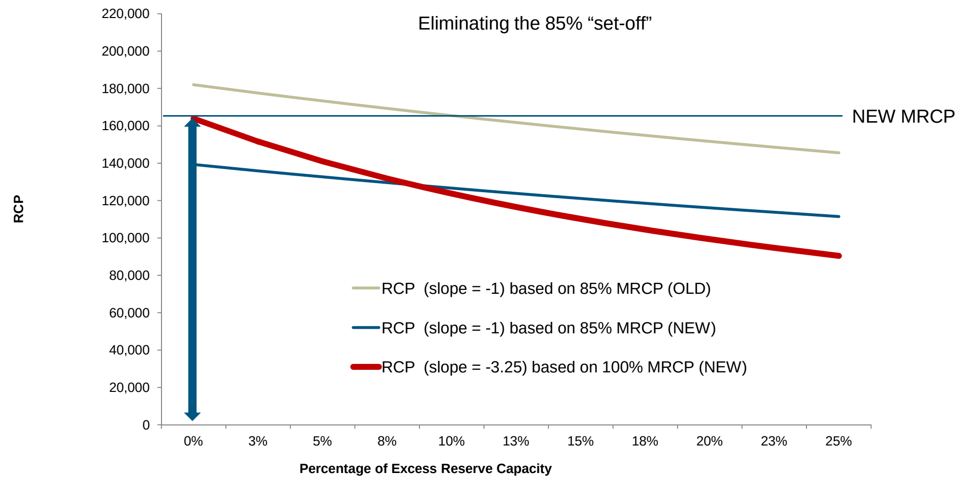
Should promote or be consistent with the Market Objectives



## Walking through changes to the RCM (1 of 3)

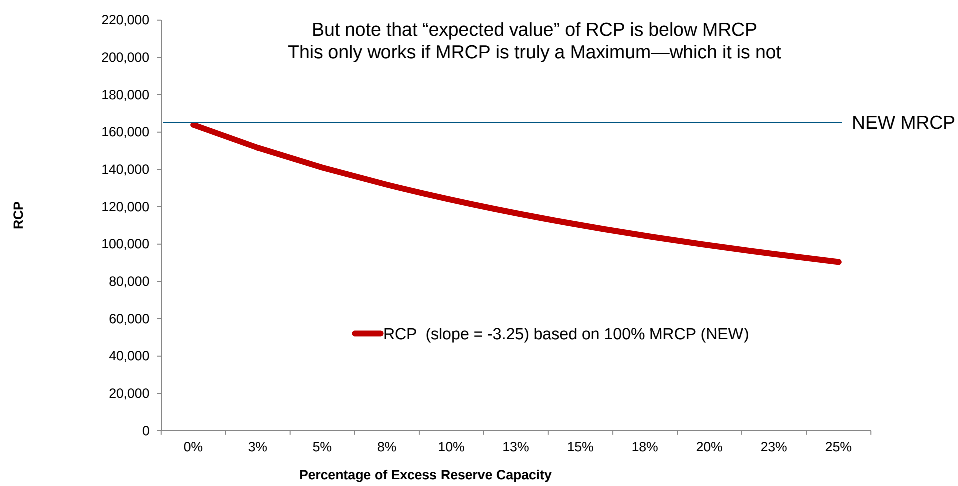


## Walking through the proposed changes to the RCM  (2 of 3)






## Interaction between RCP and "MRCP"



## Selecting the ceiling above "benchmark" RCP

| Amount of Excess Reserve Capacity | RCP (slope = -3.25) based on 110% NEW MRCP |
|---|---|
| 0.0% | 180,290 |
| 2.5% | 166,742 |
| 5.0% | 155,088 |
| 7.5% | 144,957 |
| 10.0% | 136,068 |
| 12.5% | 128,206 |
| 15.0% | 121,203 |

| | Expected Value |
|---|---|
| 0-10.0% (average of 5 values) | 156,629 |
| 0-7.5% (average of 4 values) | 161,769 |
| 0-5.0% (average of 3 values) | 167,373 |

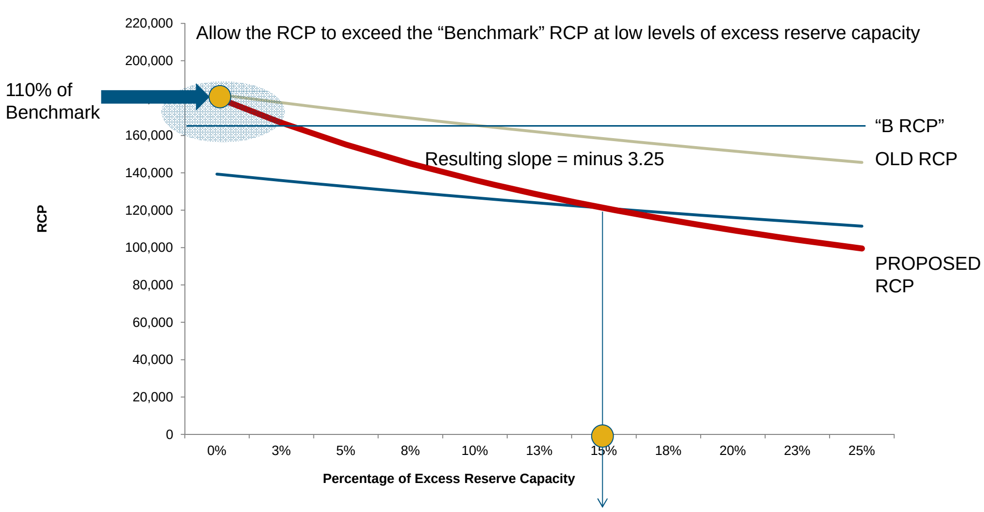
Benchmark

163,900

110% appears reasonable if long-term excess reserve capacity is within 0 to 5 or 7 percent
(Not advised to increase above this, as supplementary auction provides secure backstop)

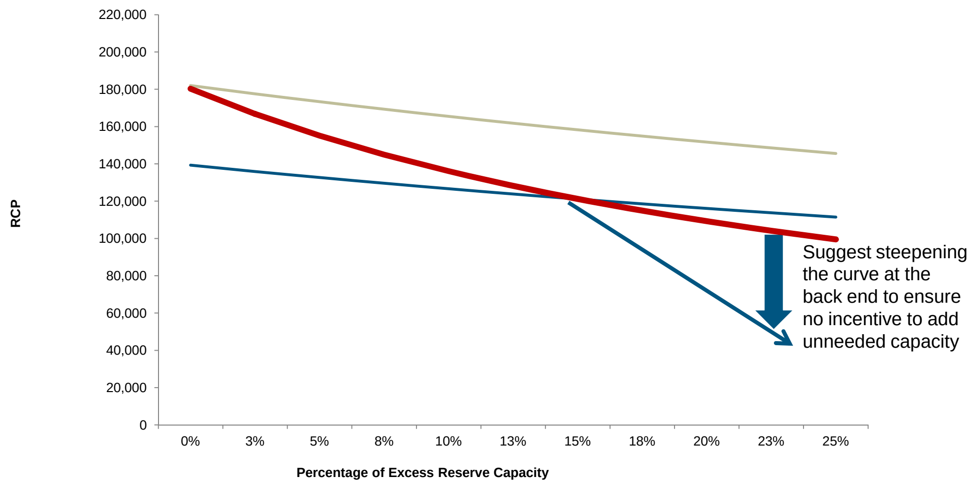


## Setting the slope and reference point to benchmark results in minimal change in RCP compared to current settings – no transition required



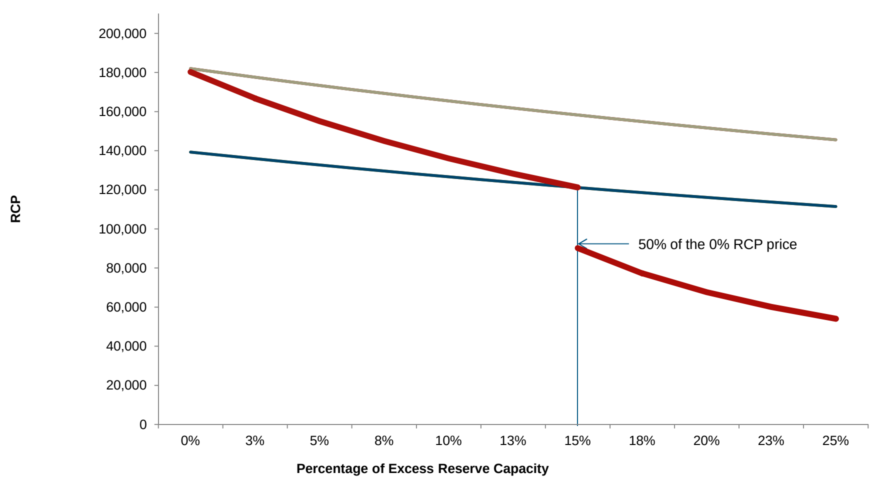

Approximate current level of excess reserve capacity

## While steeper than present arrangements, the proposed "slope" does not necessarily mitigate the cost of severe excess reserve capacity

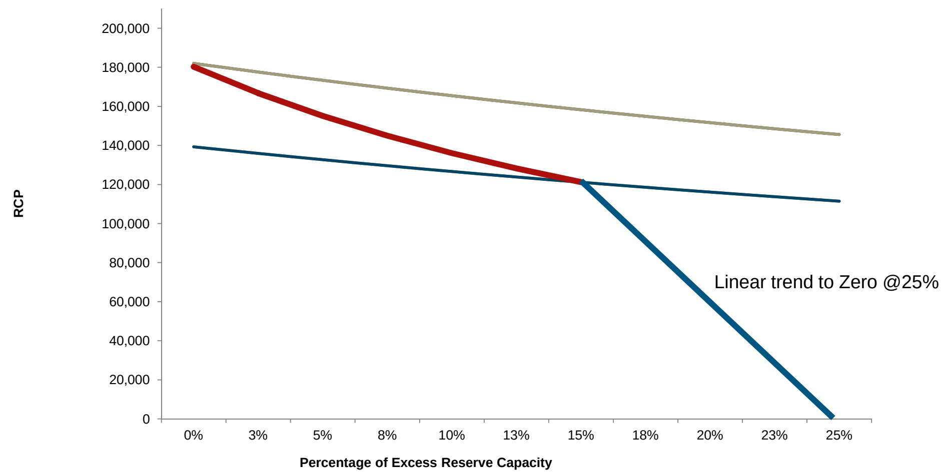





## Option 1: Introduce a step change at 15%

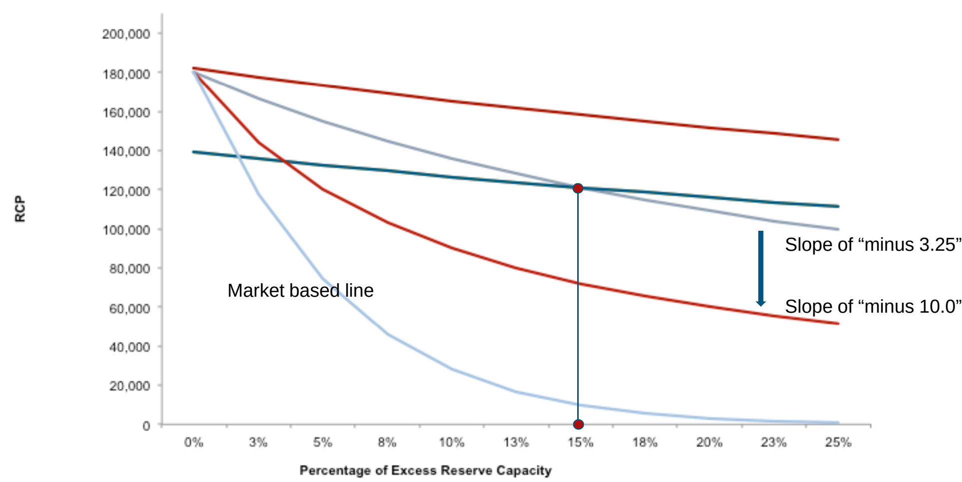


## Option 2: Trend to RCP=Zero at 25%






## Option 3: Use even steeper slope, but transition



## Summary

- The RCP is not dynamic enough to accommodate the significant changes in market conditions that we see in the WEM
- The RCP can easily be made more dynamic
  - Steepen the “slope” factor
  - Up to 3.25 slope without any transition issues
  - Some additional adjustment after 15% excess reserve capacity is reasonable
- At same time
  - Change name of “MRCP” to reflect what it actually is and avoid confusion
  - Eliminate 85% MRCP offset as it has no basis in logic given the way the MRCP is now calculated
- The above would link the RCP more strongly to market conditions, while retaining a managed character
  - More robust during “up” and “down” economic cycles



## The proposed changes are consistent with a longer-term evolution direction

- Key elements of a workable auction model for valuing capacity credits
  - Develop a profiled future obligation for load serving entities (LSEs) – similar to the IRCR
    - 1 year-out: 100% of IRCR
    - 2 years-out: 95 to 100 % of IRCR
    - 3 years-out: 80% to 90% of IRCR
    - 4 years-out: 50% to 80% of IRCR etc.
  - Develop an acceptable verification process and potential backstop to assure capacity forward contracts are credible
    - Can be achieved by a material financial commitment
    - Standard may need to become more physical / supported by testing/verification as date approaches
  - Define auction “product” and differentiate role of auction from role of trading
    - multi-year contracts or single year credits?
    - if single-year credits: for what (future) year
    - determine if credits need to have vintages or other attributes
- Auction processes involve considerable complexity – as indicated by the frequent revisions to capacity auction designs found in other major capacity markets

## Devil is in the details: PJM's Reliability Pricing Model (RPM)

- Implemented in 2007, the RPM, based on making capacity commitments three years ahead, is designed to create long-term price signals to attract needed investments in reliability in the PJM region.
  - The long-term RPM approach…includes incentives that are designed to stimulate investment both in maintaining existing generation and in encouraging the development of new sources of capacity – resources that include not just generating plants, but demand response and transmission facilities.
  - The RPM model works in conjunction with PJM's Regional Transmission Expansion Planning (RTEP) process to ensure the reliability of the PJM region for future years.
  - The RPM includes the continued use of self-supply and bilateral contracts by load-serving entities (LSEs) to meet their capacity obligations.
  - The capacity auctions under the RPM obtain the remaining capacity that is needed after market participants have committed the resources they will supply themselves or provide through contracts.
- The RPM provides:
  - Procurement of capacity three years before it is needed through a competitive auction;
  - Locational pricing for capacity that reflects limitations on the transmission system's ability to deliver electricity into an area and to account for the differing need for capacity in various areas of PJM;
  - A variable resource requirement to help set the price for capacity;
  - A backstop mechanism to ensure that sufficient resources will be available to preserve system reliability.



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## Observation: the longer-term value of capacity credits is more stable than the shorter-term value

- The existing "RCM" is not a spot market for capacity credits – it is merely a support mechanism for a reasonable and secure capacity supply
  - The longer-term value is based on the estimated LRMC, not current supply & demand conditions
- The RCM needs to respond to short-term conditions, but should also be consistent with longer-term investment signals

| Year new capacity is needed | Present Value of a future Capacity Credit |
|---|---|
| Year 0 | 163,900 |
| Year +1 | 153,421 |
| Year +2 | 143,613 |
| Year +3 | 134,431 |
| Year +4 | 125,836 |
| Year +5 | 117,791 |
| Year +6 | 110,260 |
| Year +7 | 103,211 |
| Year +8 | 96,612 |
| Year +9 | 90,436 |
| Year +10 | 84,654 |

Based on WACC = 6.83

**Independent Market Operator**

**Reserve Capacity Mechanism Working Group**

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**Minutes**

| | |
|---|---|
| **Meeting No.** | 4 |
| **Location:** | IMO Boardroom<br>Level 3, 197 St Georges Terrace, Perth |
| **Date:** | Tuesday 29 May 2012 |
| **Time:** | Commencing at 2.00pm – 5.45pm |

| **Attendees** | |
|---|---|
| Allan Dawson | Chair |
| Suzanne Frame | IMO |
| Brendan Clarke | System Management |
| Andrew Sutherland | Market Generator |
| Brad Huppatz | Market Generator (Verve Energy) |
| Ben Tan | Market Generator |
| Shane Cremin | Market Generator |
| Corey Dykstra | Market Customer |
| Patrick Peake | Market Customer |
| Steve Gould | Market Customer |
| Stephen MacLean | Market Customer (Synergy) |
| Andrew Stevens | Market Customer/Generator |
| Jeff Renaud | Demand Side Management |
| Geoff Down | Contestable Customer |
| Justin Payne | Contestable Customer |
| Wana Yang | Observer (Economic Regulation Authority) |
| **Additional Attendees** | |
| Richard Tooth | Presenter (Sapere Research Group) |
| Mike Thomas | Presenter (The Lantau Group) |
| Aditi Varma | Minutes |
| Fiona Edmonds | Observer |
| Greg Ruthven | Observer |
| **Apologies** | |
| Paul Hynch | Observer (Public Utilities Office) |

| | |
|---|---|
| Wayne Trumble | Observer (Griffin Energy) |

| Item | Subject | Action |
|---|---|---|
| 1. | **WELCOME AND APOLOGIES / ATTENDANCE**<br>The Chair opened the fourth meeting of the Reserve Capacity Mechanism (RCM) Working Group (RCMWG) at 2:05pm.<br><br>The Chair welcomed the members in attendance and noted apologies from Mr Paul Hynch and Mr Wayne Trumble received prior to the meeting. | |
| 2. | **MINUTES ARISING FROM MEETING 3**<br>The following change was noted on Page 3:<br><br>*Mr Geoff Down observed that some level of ~~uncertainty~~ flexibility needs to be factored in dispatch decisions.*<br><br>The minutes were accepted as a true and accurate record of the meeting, subject to the aforementioned change. | |
| 3. | **ACTIONS ARISING**<br>Ms Suzanne Frame noted that work would be ongoing to assess the cost-effectiveness of proposed options for harmonisation (Action Item 2). Other action items were noted as completed. | |
| 4. | **PRESENTATION: Harmonisation of Demand Side and Supply Side Resources by Dr Richard Tooth, Sapere Research Group**<br>The Chair invited Dr Richard Tooth to present his paper.<br>The following points of discussion were noted:<br>• On the issue of availability of DSM (Demand Side Management), Mr Corey Dykstra observed that Planned Outages of generators could not be equated to DSM's unavailability if dispatched because generators had already forecast the outage. Dr Tooth disagreed and noted that the effect on the market was the same in both situations i.e., facility not being available when needed.<br>• Mr Dykstra questioned if the Wholesale Electricity Market (WEM) had already matured with regard to DSM penetration. Mr Jeff Renaud noted that DSM penetration in most capacity markets in the US had plateaued at about 7-8% of total capacity. He added that the penetration in the WEM was similar although the uptake profile was steeper.<br>• On Proposal 1 *(DSP facilities may be dispatched outside of nominated availability limitations on a best efforts basis)*, Mr Cremin mentioned that dispatching DSM on a best efforts basis in an emergency operating state did not qualify as harmonisation with generators. Dr Tooth argued that generators would also be expected to perform on a best efforts basis if they were on a Planned Outage and an emergency situation was experienced, i.e. with regards to being called back to service. He noted that a baseload facility could be requested to operate in excess of its maximum sent out capacity on a best efforts basis if required.<br>• On the topic of Hours of Availability, Mr MacLean queried if the 1-in- | |

| Item | Subject | Action |
|---|---|---|
| | 10 peak year event had been used to estimate dispatch events for DSM. He observed that the extent of generation availability on a day other than a 1-in-10 peak year event would be so much that it would minimise the need to dispatch DSM. Dr Tooth mentioned that the analysis included high demand days and Forced Outages and did not include generation availability.<br><br>• Discussion ensued on the sufficiency of 15 dispatch events to provide System Management enough certainty while making dispatch decisions. Mr Cremin questioned if there was merit in considering unlimited dispatch events. Mr Renaud observed that there are two different approaches used to specify DSM dispatch conditions- first, a prescriptive approach based on historical data and second, identifying system operating conditions that would trigger DSM dispatch. He noted that the latter approach is used in other international markets. Mr Cremin added that every year system reliability conditions to dispatch could change and so an unlimited number of dispatch events should be the preferred approach. Dr Tooth added that unlimited number of dispatch events with clear guidelines for dispatch was a more reasonable approach.<br><br>• Discussion ensued on how dispatch decisions are made currently when system reliability is under threat. Mr Clarke observed that System Management would use liquid plants before dispatching DSM. If there is a concern on fuel availability, then the order of dispatch would be different. The Chair noted that in high risk conditions, System Management would consider conservation of liquid inventory and DSP's may be dispatched before liquid plants. Mr Patrick Peake queried if System Management would hold generation or DSM as Spinning Reserve when system reliability was under risk to which Mr Clarke responded that generation would generally be held as Spinning Reserve.<br><br>• On the Hours of Duration for DSM, Mr MacLean requested that information be provided on why other markets have more hours of duration. Mr Renaud observed that there might be learning's from other markets that could be used to WEM's benefit. He noted that hours of duration was a complex issue for a demand side aggregator because of the need to limit the duration of load curtailment for its customers, except in cases where a back-up generator was installed. He added that this issue was closely linked to the refund mechanism. He stated an example of non-performance penalty mechanism used in New York-ISO market. Mr Andrew Sutherland asked if this risk couldn't be spread across the aggregator's portfolio. Mr Renaud noted that analysis would need to be done on how an aggregator could reconstruct its portfolio to mitigate the risk.<br><br>• Discussion ensued on System Management's decisions on dispatching DSM. Mr Ben Tan questioned if the risk of being dispatched at any time shouldn't lie with the DSP. Mr Renaud noted that the risk could be transferred to DSP and more flexibility provided to System Management as long as system conditions were set objectively. Discussion ensued on the system conditions needed to dispatch DSM. The Chair observed that in a high risk operating state, System Management could dispatch any capacity source in order to avoid involuntary load-shedding. Mr Mike Thomas added that in a fuel | |

| Item | Subject | Action |
|---|---|---|
| | constrained situation, the issue is not capacity but energy.<br>• Discussion ensued on how DSM's would cope with unlimited number of hours. Mr Renaud reiterated that unlimited number of dispatch events was not a problem however the system conditions needed for DSM dispatch would need to be stated clearly.<br>• Mr Huppatz questioned if a similar analysis had been done for over the winter months as the Ready Reserve Standard are reduced in winter as Planned Outages occur predominantly during this time. He observed that System Management might not have the confidence to dispatch DSM if a fuel shortage happened in winter. The Chair noted that it would be worthwhile to conduct some analysis around the profiles of DSM during the winter months.<br>• On Notice Period for DSM's, Mr Renaud noted that a day ahead notification with two hours notice period would be welcome as it would help DSP's to prepare to respond to a dispatch event. He added that the current four hours notice period regime was also acceptable and that if it was changed, a two hours notice period with day ahead notification would reduce dispatch risk.<br>• On the Third Day Rule, Mr Renaud noted that System Management has the ability to dispatch different DSM facilities to meet the Third Day Rule. Discussion ensued on dispatching DSM in the non balancing merit order.<br>• On the topic of participation of DSP in the Balancing Market, discussion ensued on the cost of dispatching DSP compared to the cost of dispatching thermal generators. Members discussed the concept of a dynamic baseline methodology. The Chair noted that DSM's participation in the balancing market should be kept as a separate stream of work and included in the Market Rules Evolution Plan.<br>• Mr MacLean noted that differential capacity price for DSM and generators should be considered as an alternative option. Mr Renaud noted that such an approach has not worked in other markets. He gave examples of international markets where DSM participation was non-existent because a level playing ground with generators was not created. Members requested that some further information be provided so that this alternative could be assessed.<br>*Action Points:*<br>• *The IMO to conduct analysis of the profiles of DSPs during winter months.*<br>• *The IMO to present a clear set of recommendations for harmonisation of DSM with Market Generators.*<br>• *The IMO to provide to the Working Group for its consideration an overview of the experiences of international markets with differential capacity pricing* | **IMO**<br>**IMO**<br>**IMO** |
| 5 | **PRESENTATION: RCM Review Report-2 by Mr Mike Thomas, The Lantau Group**<br>The Chair invited Mr Thomas to present his paper. | |

| Item | Subject | Action |
|---|---|---|
| | The following points of discussion were noted:<br><br>• Mr Patrick Peake noted that if all capacity was uncontracted then the cost was pushed back on the providers of capacity rather than retailers.<br>• Mr Dykstra noted his concern that the steeper slope for adjusting the Reserve Capacity Price did not indicate that a retailer would be pushed towards bilateral contracting. He offered a retailer's perspective on contracting for capacity and energy to meet the Individual Reserve Capacity Requirement and noted that the Maximum Reserve Capacity Price (MRCP) was not relevant to a retailer's contracting behaviour. Mr Thomas noted that the fundamental issue was the value of capacity to the market when there is excess capacity available.<br>• Mr Cremin noted that manipulating the slope to create a market-based pricing mechanism would not create an entry barrier for new capacity. He offered that a ceiling and a floor price would be better suited to incite contracting behaviour among retailers, so that retailers contract for the amount of capacity they need and all the excess capacity is priced at the floor price. Mr MacLean noted that Mr Cremin's proposal did offer a non-zero solution. Mr Cremin added that it was important to minimize volatility by setting a floor price. Mr Stevens observed that Mr Cremin's proposal suggests incentivizing retailers to contract bilaterally thereby signalling the amount of capacity that enters the market. Mr Cremin further observed that the current mechanism is such that retailers are choosing not to contract bilaterally as the higher the uncontracted capacity, the greater the excess capacity adjustment is and the cheaper it is for retailers to procure capacity from the IMO cheaply.<br>• Mr Dykstra noted that the market design was envisaged as a bilateral contracting market and modifications had been made since market start in response to various levels of capacity. In his opinion, The Lantau Group's proposal offered another modification to deal with the current situation. It did not offer sufficient proof that a disincentive for new capacity would be created. He added that the group should consider revisiting the original set of issues and outcomes before concurring that the proposed solution was the way forward.<br>• Discussion ensued on the proposed solution being an interim solution to deal with the excess capacity currently present in the market.<br>• Mr Dykstra noted that Synergy being the largest retailer was the only one with the incentive to contract for energy. Other retailers being too small would take a conservative view and rely on the IMO's mechanisms to procure capacity. Mr Huppatz and Mr Cremin agreed with that point. The Chair noted that going forward and at the appropriate time the IMO would like to create appropriate signals for entry of capacity into the market when it was needed. Mr Tan noted that the proposed solution does not provide any correcting investment signal to capacity that enters the market with no intention of contracting. Discussion ensued on the use of price mechanism versus a spigot control mechanism. Mr MacLean observed that the proposed approach would deal transitionally with excess capacity currently present in the market.<br>• The Chair noted that the proposal had been canvassed with the IMO | |

| Item | Subject | Action |
|---|---|---|
| | Board and the sentiment was that a slope of 3.25 might not provide a strong enough price signal. He noted that the IMO Board would favour a sharper signal.<br>• Members discussed the implications of the proposed approach. Mr Peake noted that a sharper signal would not be very welcome to investors in generation. Mr Dykstra reiterated that the proposal did not offer any incentive to contract bilaterally and that it was important to review expectations of outcomes. Mr MacLean noted that the group needed more time to evaluate possible options before coming to a conclusion. Mr Tan also noted his disagreement with the sharper signal approach and requested further work-shopping on this matter.<br>• Members requested that a workshopping session be held where potential proposals would be evaluated.<br><br>*Action Points:*<br>• *The IMO to organise a workshop for RCMWG Members to evaluate alternative proposals to deal with the oversupply of capacity.* | **IMO** |
| **6** | **CLOSED**<br>The Chair postponed the agenda item on Dynamic Refunds to the next meeting due to lack of time and thanked all members for attending the meeting. The Chair declared the meeting closed at 5.45 pm. | |

# Reserve Capacity Mechanism Working Group Discussion

**Everyone**

4 July 2012

THE LANTAU GROUP
strategy & economic consulting

# Agenda

- What is the problem?  / Is there a problem?
- History
- Options
- Way forward

What is the problem? / Is there a problem?

# Setting the scene – some issues currently perceived about the RCM

- Excess reserve capacity currently
  - This might be OK if the costs were not high
- The MRCP review and other reviews have greatly increased uncertainty – changing the RCP value significantly over a short period
- Administered (regulated) mechanism determines price of Capacity Credits that are not traded bilaterally
  - (and may influence bilaterally traded prices or availability of bilateral contracts)
  - What is the basis for value?
- Economic value of excess reserve capacity to consumers (to WA in general) is less than the value rewarded by the RCM
  - What happens when more value is attributed to something than it is worth?
- Retailers cannot hedge exposure to RCM
  - Bear costs associated with excess reserve capacity if they hold bilateral contracts
  - Incentive to minimize bilateral contracts
- Retailers are protected by RCM structure
  - Compared to other forms of capacity market mechanisms elsewhere
- RCM supports investment and works fine
- Resources have too much incentive to invest in the WEM, even when resources are not needed
- Too easy for resources to get credits

# Design challenges

- Must work in a small, lumpy market, with relatively highly concentrated stakeholder positions in the retail and generation sectors
- Should avoid the “zero” / “infinity” problem – in which credits are worth nothing when there is too much, and more precious than gold when there is too little
- Should be mindful of costs and risks borne by end-users
- Should have some degree of “self-correctedness” -- should not work against natural incentives
- Should support some degree of reasonable hedging
- Should not discriminate against different types of resources

# Some basic realities

- Excess reserve capacity has value – just as all capacity has value – because it contributes to a reduction in risk of supply shortage
- The economic value (to end users) declines rapidly with more reserve capacity
- End-users should not want to pay any more for excess reserve capacity than it is worth to them
- Capacity and energy together, not just capacity
- If we make end-users pay more for excess reserve capacity than it is worth to them, then we need to be mindful of the risk that we are incentivising excess investment
- If we push risks into the investment environment, we need to be mindful of the risk of reduced investment or higher financing investment costs

History

# History (Brendan Clarke)

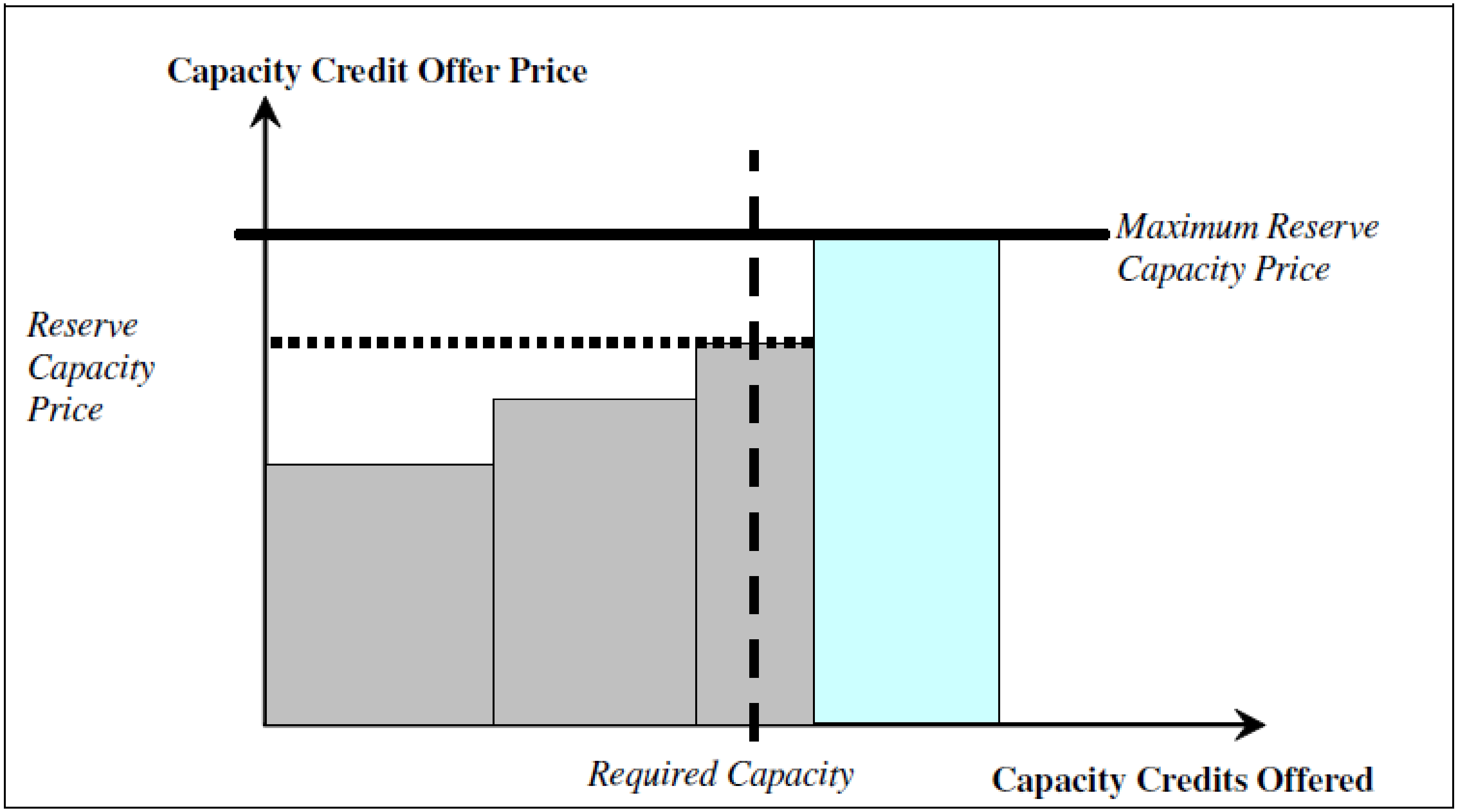
- The incentive for retailers to contract is that they would end up with a high cost solution as they would only be able to buy high energy priced energy from the IMO. The incentive for generators to contract is that they would receive no capacity credits to maintain their investments.

- What was the philosophy if the total capacity procured by the retailers is less than that that would have been procured by the integrated utility forecast?
  - The Reserve Capacity Mechanism was put in place as reliability back stop. (this is my recollection not an opinion from the market designers). This is embodied in the following philosophy
- “The primary role of the Reserve Capacity Mechanism is to ensure that there
  - is adequate generation and Demand Side Management (DSM) capacity available each year to meet system peak demand plus a reserve margin.” *Source Wholesale Electricity Market Design Summary*

- The IMO would intervene (run a capacity auction) if the reliability criteria was not met that is total capacity procured by the retailers was less than that that would have been procured by the integrated utility forecast.

# History 2

## *Exhibit 7-1. The Reserve Capacity Auction*



## History 3

- "In determining which bilateral trades can contribute to satisfying the required Reserve Capacity, the IMO will generally accept bilateral trades in order of decreasing availability until all trades are exhausted or until the Reserve Capacity requirements are satisfied." *Source Wholesale Electricity Market Design Summary*

- I suggest that this philosophy means the intent of the RCM is that Capacity offers above the required capacity are not allocated capacity credits. (this is my recollection not an opinion from the market designers)

# Some questions for discussion

- Can a generator or demand resource actually "enter" without a commitment to a credit? – How to reconcile the use of an auction with the existence or need for capacity to participate in it?
- Where does market power fit into this picture?
- Does the description of how history was supposed to work comport with the reality of commercial market operation?
- If a resource can provide capacity, why not issue it a capacity credit and let the value be determined in the auction process?
- Why was there a maximum reserve capacity price?  What is its purpose?
- What happens if too little capacity is available?  Is the supplementary auction enough?
- Who decides what type of capacity (existing vs new) is best suited to provide capacity?
- If capacity exists or seeks to exist because the RCP is attractive, what is the point of keeping the RCP high and preventing entry?

Clean sheet of paper approach

# Why not start with a clean sheet of paper

- Open reserve capacity auction – no caps, no floors
- Each year or when needed
- Free to bilaterally contract if, as and when desired
- Full market-based pricing of capacity and free choice of risk management strategy
- Retailers (Load Serving Entities) must demonstrate they hold the right number of credits at end of each period
- No administrative back up or pricing formula

# Auction basics

- If there is ample competition and no market power – you don't need caps or floors

- If you are not sure the auction will be competitive or if you are not sure of your own valuation
  - You set a reservation price

- But the auctioneer never caps the auction price!

- A retailer exposed to an uncapped auction price will have to devise a risk management strategy

- Auction price caps are intended to protect retailers (buyers) from seller market power

# Auctions basics (cont)

- If all capacity is forced into an auction without an “offer”, the auction will clear at 0 if there is a surplus available, and it won’t clear if there is a shortage (“infinity”)
- Resources will need to be able to offer a sale price into the auction
- Given that capacity is essentially “sunk” once it is present in the WEM, capacity auction results would reflect, to some extent, market power – or any other constraints imposed
- Different auctions at different times may have very different results due to the particular allocation of credits being auctioned (who owns them, how concentrated is the ownership, etc)

# Open Market Observations

- If the “spot” market or auction process is highly volatile and risky → natural incentive to hedge that risk in bilateral market
- Natural incentive for bilateral market and short-term market to track each other
- Extreme case would be an energy-only market – highly volatile short-term market, with extensive use of contracts as risk management instruments
- WEM is not an energy-only market.  Nor was it designed to be highly volatile
- But without risk in the capacity market, there will be uncertain incentives in the bilateral contract market



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# Two-sided

- Removing risk to retailes from bilateral contracting
  - MRCP caps the RCP
  - The negative slope reduces the RCP with excess capacity
  - No super-strong penalties from being at risk of being under contracted
- Increases risk to generators
  - Difficulty obtaining long-term contracts
  - Increased cost of financing
  - Greater exposure to regulatory risk (reduced long-term certainty)
- And vice versa

Options (open discussion)

## Interpretation and implementation of MRCP

- Based on a standard reference technology
- Set up as an expected value
- Treated as a maximum value in the RCM
- Risk increased in RCM that long-term investment will be impaired
- 85% of MRCP value is used to set RCP for IMO purchased/sold credits
- The MRCP construct is inconsistent with its use → a risk to the future

# Options for role of MRCP

- Treat MRCP as an expected value – allow RCP to exceed MRCP?
  - What about in short-term auctions?
- Change nothing?
- Choice has significant implications for the interpretation and implementation of virtually all other options.

# Options

- Spigot control
- Synergy proposal (truth telling + auction)
- Buy/ask spread – bilateralism
- Managed formula
- Do nothing
- Other?

# Spigot control

- If there is excess capacity in the RCM, should further capacity credits be issued?

- In markets, when capacity can enter a market freely, the price adjusts to signal when to stop and when more is needed
  - Markets create oversupply and undersupply sometimes
  - Look at US shale gas market for an example of a rampant oversupply and a price response

- Markets that throw up barriers to entry whenever there is "enough" tend to be more insulated and are at risk of being less innovative
  - Again, look at US shale gas – there had been ample "capacity" in the US market before

- On the other hand, the RCP is an administered price and not a free-flowing market price
  - Some degree of quantity control is merited just because the administered price could be wrong and might not adjust enough

# What should be the basis for enhanced "spigot" control

- What should be the basis for enhanced "spigot" control?
  - Merely the existence of excess reserve capacity?

- What protections should those who are uncontracted be provided by spigot control?
  - Why should an uncontracted genco investor be protected against new entry risk?

- If the value of reserve capacity credits to customers is less than the reserve capacity price, doesn't spigot control merely lock in higher costs to end-users?

- What are the elements that should be considered in determining eligibility for capacity credit certification?

# Who wins and who loses?

- Spigot control protects uncontracted resources againt the impact of new entrants who, as a result, might reduce the value of capacity credits
  - Is this a good thing?
  - Why?

- Spigot control protects retailers from excess capacity costs given an RCM that does not price-adust effectively

- Spigot control can hurt consumers if it limits innovation and protects higher cost resources in the energy market?

- Would spigot control effectively throw up a barrier to entry that can be used by older capacity resources to prevent newer resources from gaining access to the market (financing costs, etc)

## Structured discussion of Synergy Proposal

- Capacity making a bilateral trade declaration is ineligible from receiving an IMO reserve capacity payment
- Undeclared capacity goes into an auction which would set the clearing price
- If no auction then a high administered price would be set by the IMO to facilitate for capacity trades and allow the refund mechanism to function

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## Synergy Proposal Discussion

- Consequence of a bilateral trade declaration?
  - What if a declaration fails to produce a bilateral trade?
  - What if retailers do not enter into a bilateral contract?
  - Will generation investors still invest if they cannot obtain a bilateral contract?
  - Why should “intentions” matter in any form of commercial market?

- Consequence if undeclared capacity goes into an auction?
  - What type of auction? How often?
  - If someone misses auction 1, when is the next opportunity?
  - An auction clearing price requires that there be a cleared auction quantity?
  - Should the cleared auction quantity be limited to the RCR? Or to all available capacity, needed or not?
  - How does the auction deal with the zero / infinity problem?

# Should there be some incentive to force more bilateral trades?

- Consequence of a punitive (high administered price) being set by the IMO to facilitate capacity trades in the event that an auction otherwise fails to clear?
  - Retailers who need credits would face the alternative of a high credit price – subjecting them to generator market power?
  - Would generators receive the high credit price – creating incentives for them to game the auction?

- If retailers pay a punitive price and generators receive a punitive price – they have an incentive to bilaterally contract?

What makes bilateral contracting preferable?

# Is bilateral contracting of capacity a desired end-point to be actively promoted?

- The WA WEM is often called a bilateral market – or, as we have put it, a market with a strong “bilateral DNA”
- The presumption is that bilateral contracting is to be encouraged as a “good” thing in its own right
- Taken to an extreme, this could imply the use of “penalty” values in spot transactions so as to incentivise greater reliance on bilateral contracting



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# It would be easy (but not costless) to incentivise more bilateral contracting

- Punitively **high** values payable by retailers for capacity credits to cover uncontracted capacity / and punitively **low** payment values to generators for credits purchased to settle uncontracted reserve capacity requirements

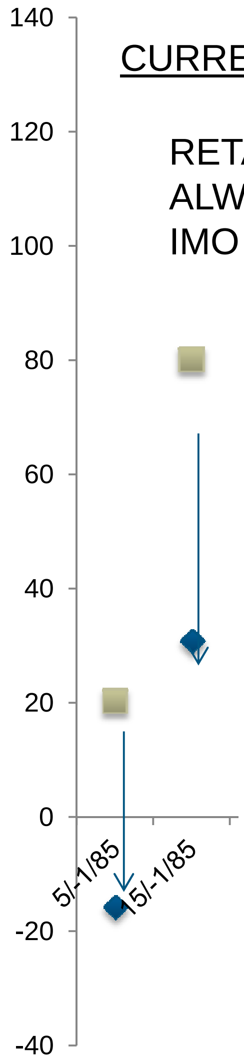
- Market-based auctions that introduce greater credit price volatility (much higher in shortage, much lower in excess) – creating a natural incentive for parties to hedge through contracts to reduce financial risk

- Steeper “slope” mechanisms that raise the level of volatility – particularly insofar as the potential clearing price can be much higher or much lower than the expected value – a “managed” version of an open market pricing pricess

- Ironically, for a market alleged to be based on bilateral contracting, the current “managed” RCM, has limited incentives for stakeholders to bilaterally contract

# Current RCM settings do not favour bilateral contracting against any amount of excess reserve capacity *per se*

RETAILER COST (INCLUDING EXCESS CAPACITY)




<u>CURRENT ARRANGEMENT</u>

RETAILERS SHOULD ALWAYS BUY FROM IMO

5% EXCESS CAPACITY VS 15 % EXCESS CAPACITY
SLOPE = -1
MAX RCP = 85% * MRCP

All else equal…..

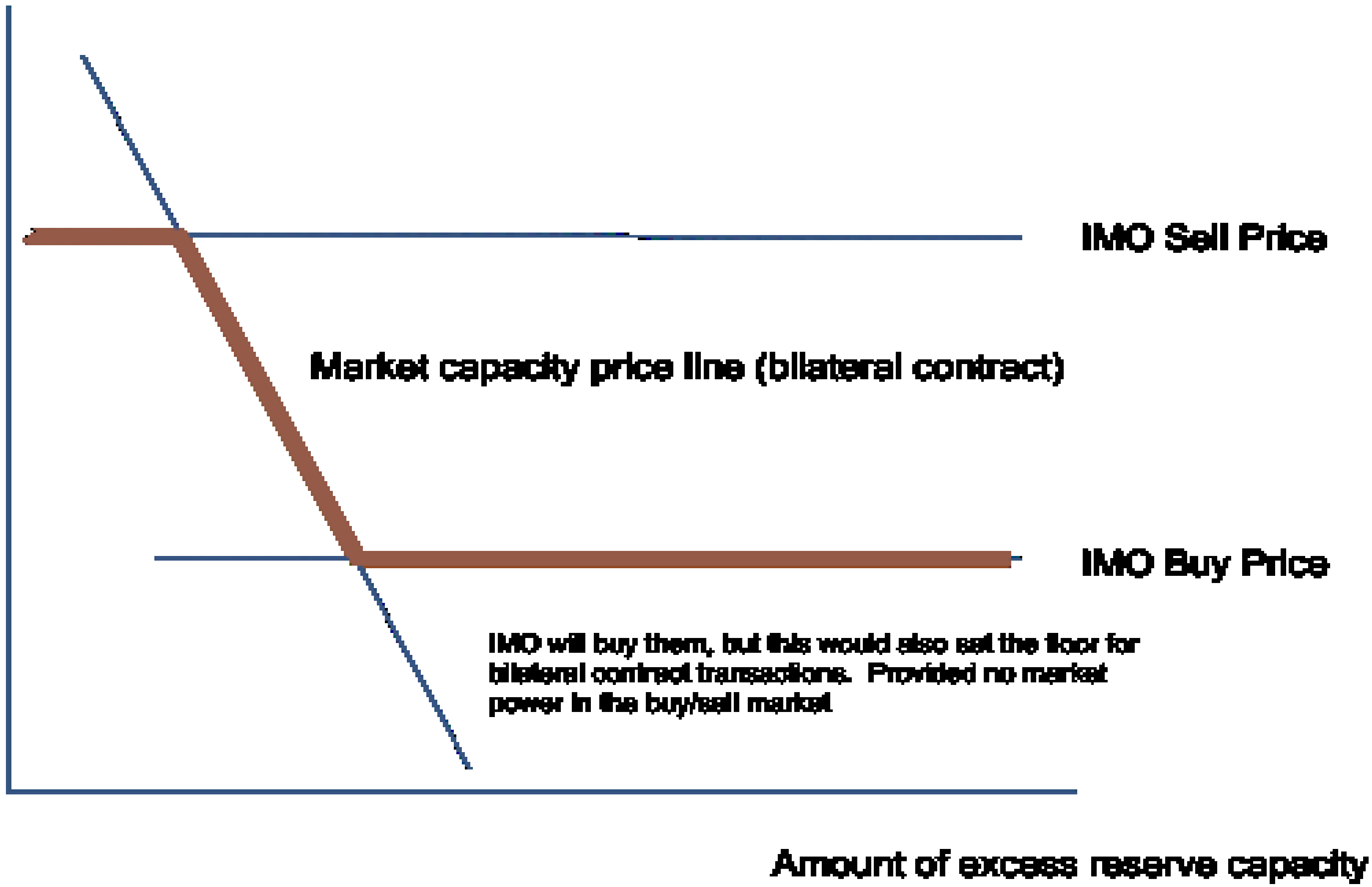
The only incentive to bilaterally contract is the belief that future RCM reviews or settings will be higher than present, such that locking in current costs is preferable

But hedging is not a strategy to manage exposure to excess reserve capacity, per se

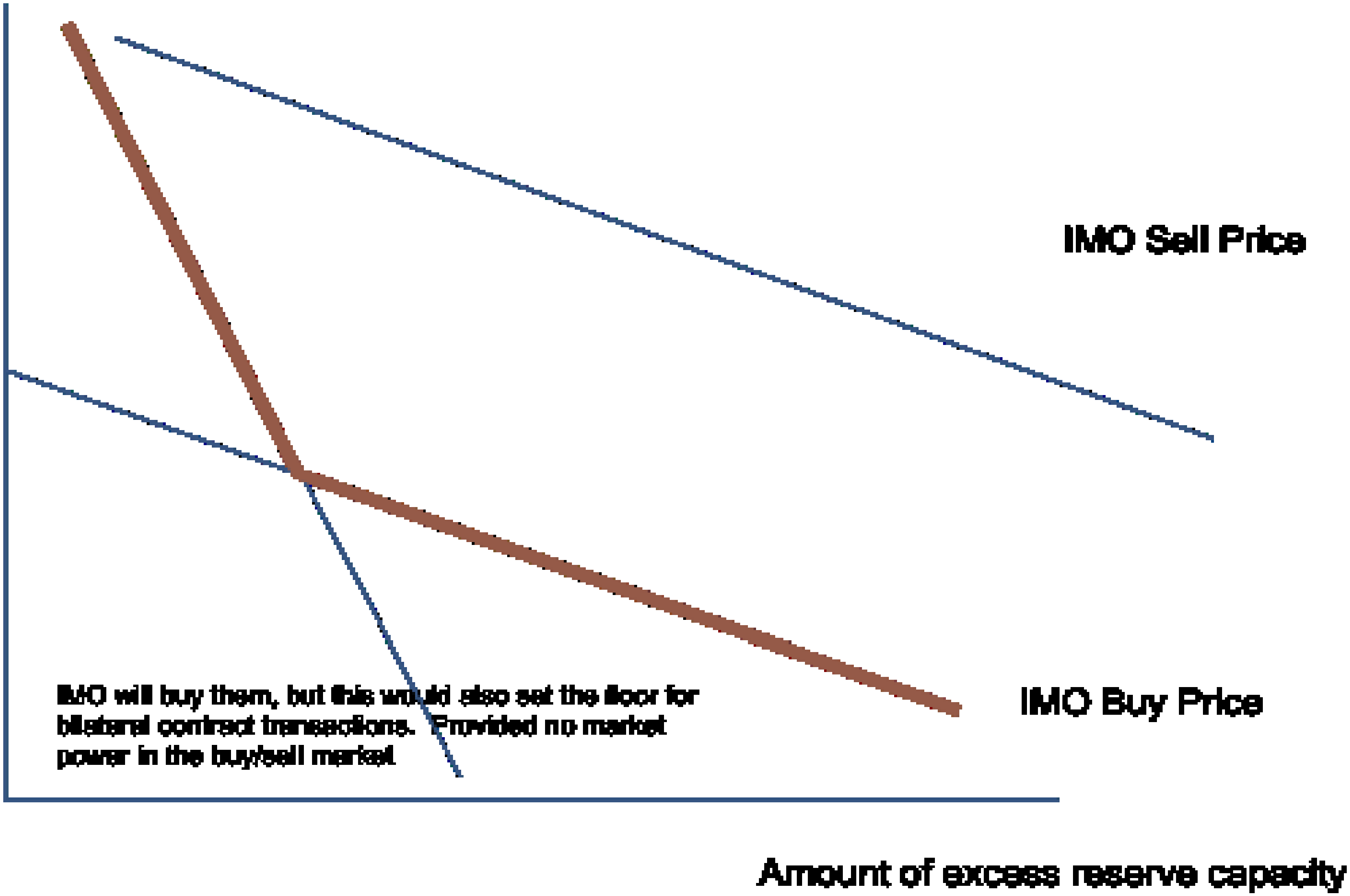
This is because the IMO capacity credit price is always below the MRCP. As long as retail believes future MRCPs will be lower, it has no incentive to contract. If retail believes they will be higher, then you do.

Is this intended?

## Buy-ask spread approach (A) would clearly incentivise bilateral contracting according to the size of the spread



# Buy-ask spread approach (B) can be incorporated in many other mechanisms



# What to do with the middleperson's profits?

- IMO receives the buy-ask spread
- Refund against fees?
- Refund to franchise customers (presumably those bearing the bulk of costs of excess capacity)?
- Something else?



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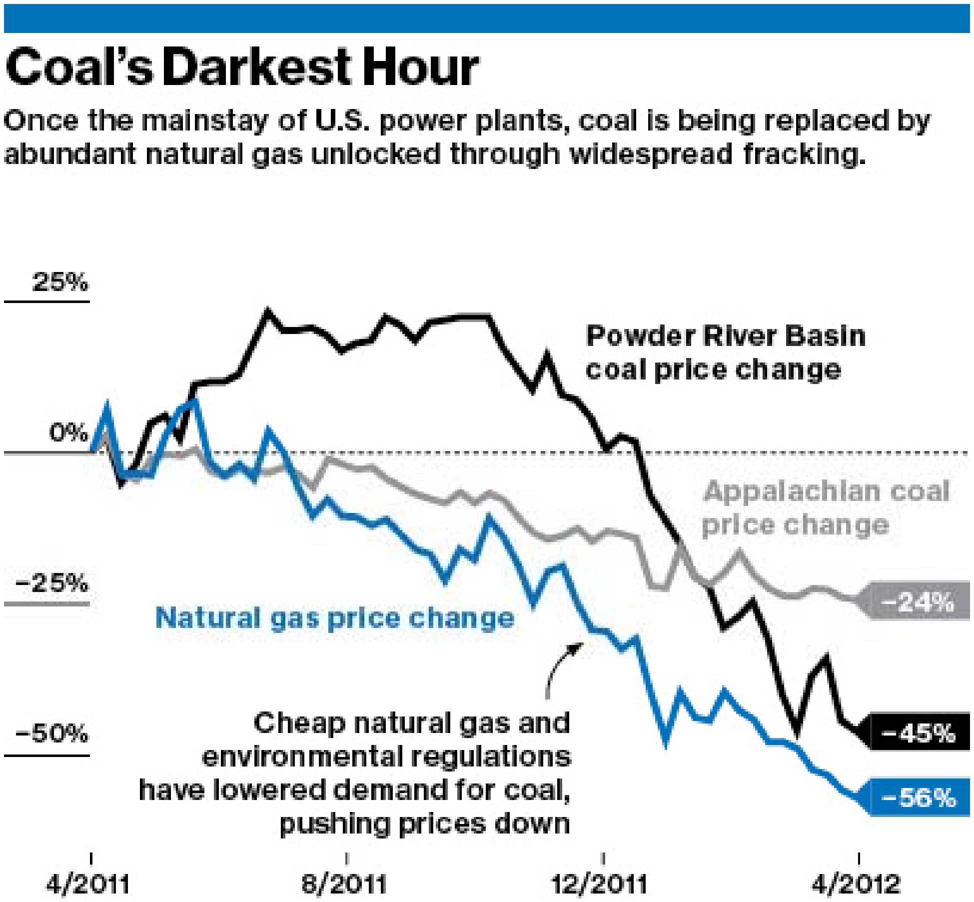
# Forecasting

- Currently we lock in the RCR 2.5 years in advance of a capacity year
  - In the interim, things can change
  - Recent changes have tended to be downward (less growth than expected)
  - The absence of an adjustment mechanism represents a cost
  - But what if it had gone the other way?

## Markets can change dramatically

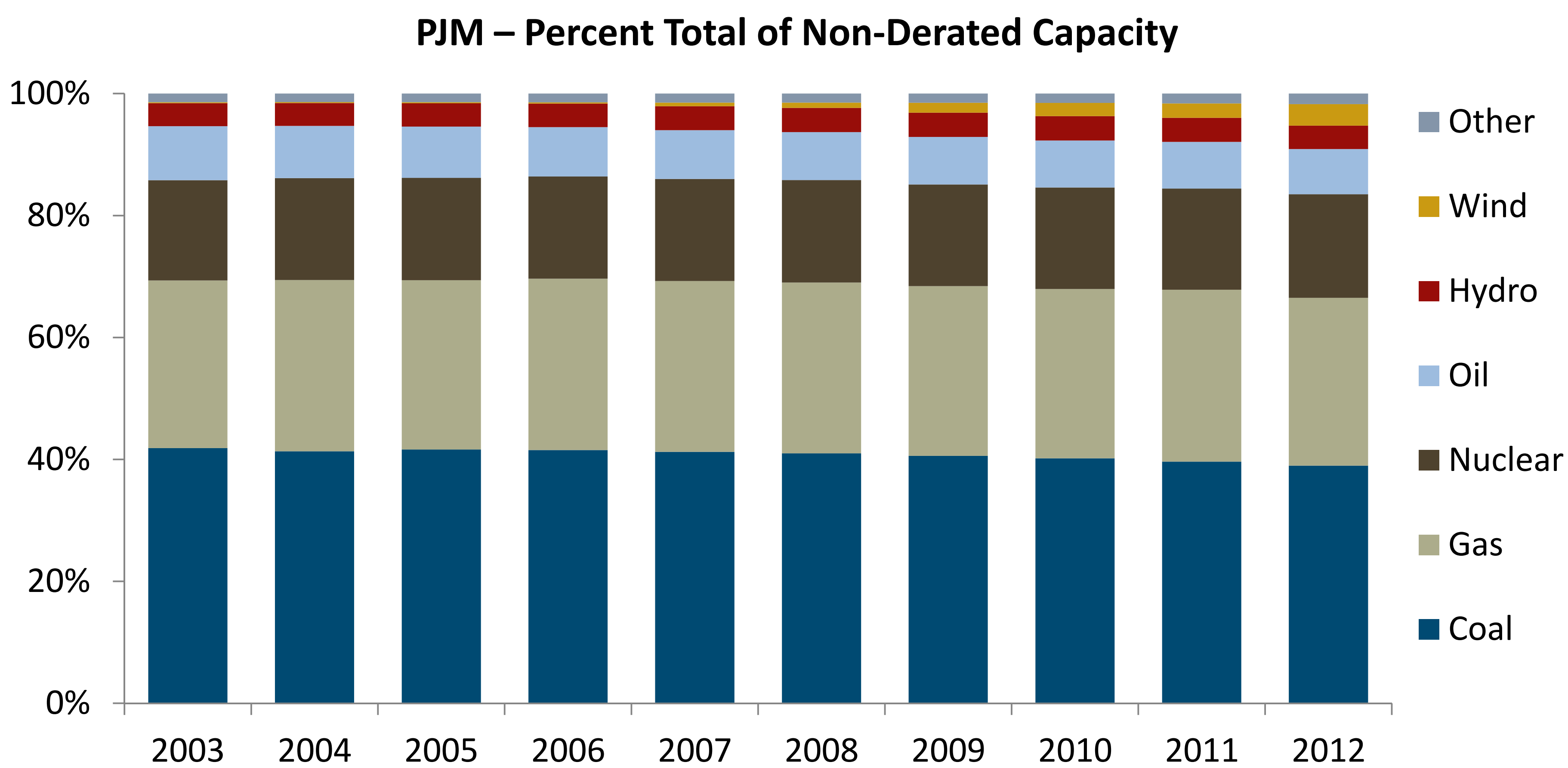
- BusinessWeek's obituary for American coal




With the increase in demand for natural gas stemming from low prices, domestic demand for coal has declined.

Coal prices have also decreased in the US – though not as significantly as natural gas prices

# Market Opportunities Worldwide (PJM)

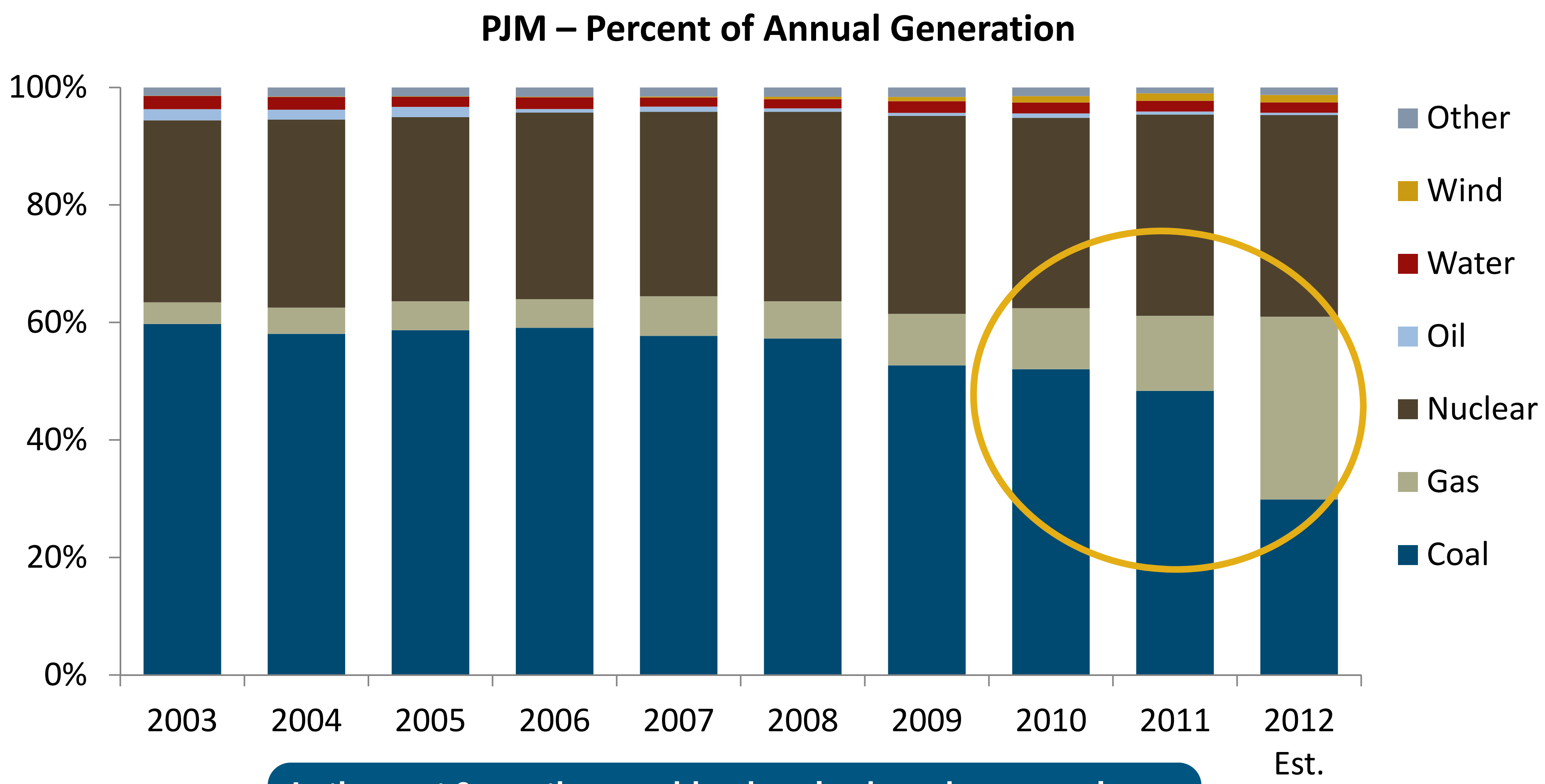



**PJM has traditionally been a coal and nuclear dominated market. There are many forecast coal retirements (about 20 GW) due to forthcoming air pollution regulations that take effect in 2015. But there is something even more interesting driving the market these days…**



Source: SNL Financial, TLG analysis

# Market Opportunities Worldwide (PJM)




**In the past 6 months, combined cycles have become a lower marginal cost unit on the supply stack than coal-fired units. This has radically reshaped PJM's generation profile.**



Source: SNL Financial, TLG analysis

# Forecasting is a dance with uncertainty

- Who bears the risk of forecast errors?

- Generators?
  - If uncontracted?
  - If contracted?

- Retailers / End Users
  - If contracted?
  - If uncontracted?

Some types of changes can dramatically
Increase the amount of reserve capacity
In the WEM – (eg., economic displacement)

Does the WEM facilitate efficient “exit”
Or should the capacity price remain high
even when other factors drive investment?

# Block loads are a particular problem in the WA context

- The projected holding requirements may need to reflect available information about these loads
  - If one gets to 1 year out and projected block loads have not (yet) materialised, should they be included or excluded?
  - What can be done to exact stronger commitments from block loads?
  - Should block loads be compelled to bilaterally contract to a minimum percentage in order to be covered?
  - What would be the implication if a block load could not be served in a given year?
- Should block loads be required to purchase capacity credits as an indication of firmness?
- Why should block loads be required to do so 2.5 years ahead of the entry decision?

# Other market-based mechanisms incorporate forecast error in reserve capacity requirements

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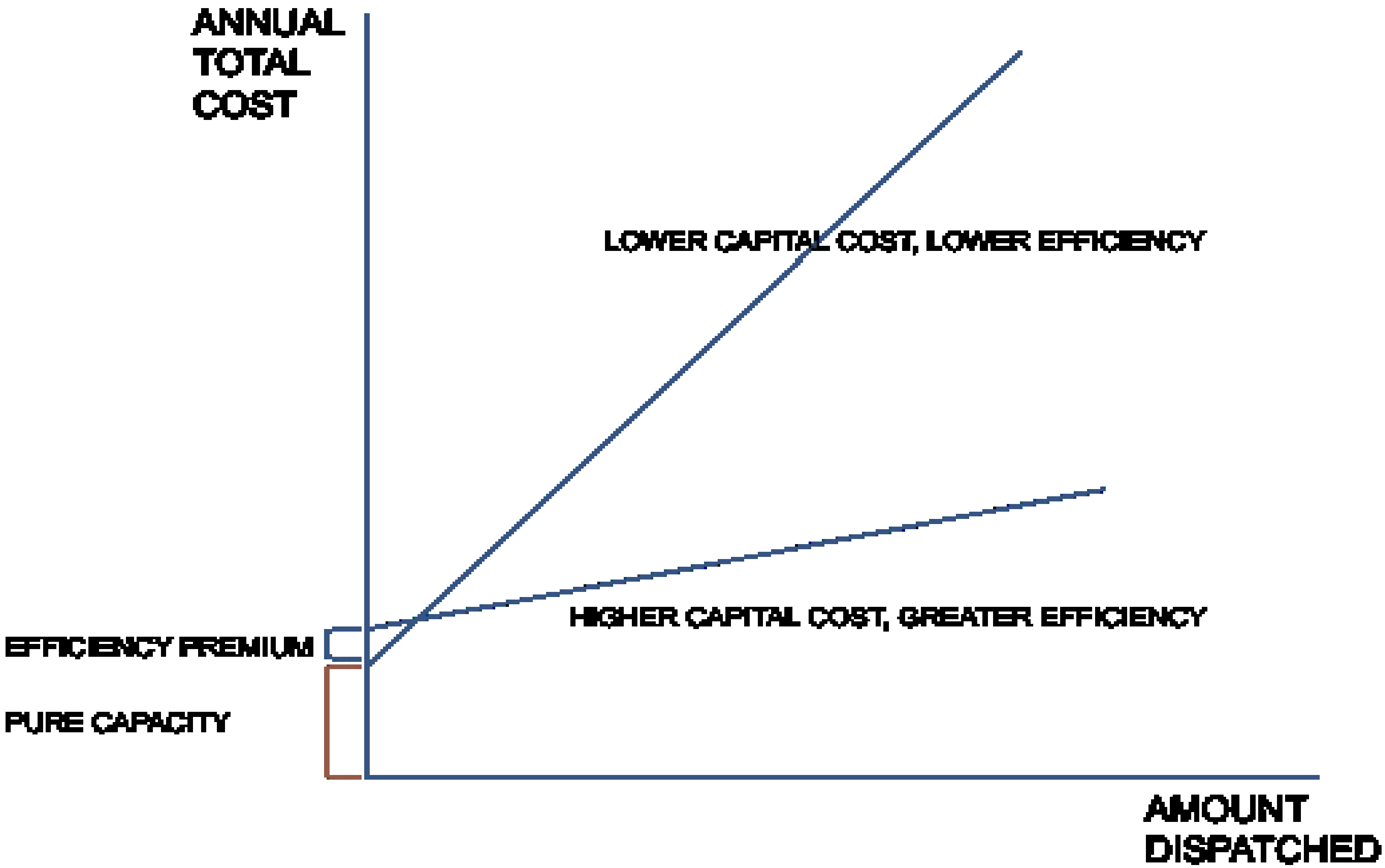
- Say (for example):
  - 0.5 years out must hold 100% of updated RCR, failing which a supplemental auction is held
  - 1 year out, must hold 100% of updated projected RCR
  - 2 years out, must hold at least 90% of updated projected RCR
  - 3 years out, must hold at least 75% of updated projected RCR
  - 4 years out, must hold at least 60% of updated projected RCR
  - 5 years out, must hold at least 40% of projected RCR
- A capacity source that comes into existence “too early” still has value – but the value is related more to future growth in the RCR
- How many auctions and how many auction “products” are suitable for a small market like the WEM?
- Is the complexity a barrier to entry for a new retailer entrant?

# Slope option

- The slope needs to be steep enough to curtail the risk of unnecessary investment aiming to be supported by excess capacity credits.  This determines a minimum slope, which we have estimated to be at least -3.25 as that corresponds to a 15% discount to the reference capacity value.  That may not be enough, of course, to absolutely stop all investment that is not needed.  But it would certainly have a positive impact relative to the current formula.
- The resulting level needs to be high enough that the RCM can support new capacity when needed (and before relying on a supplementary auction, which is currently designed for essentially emergency situations).  This requires that the RCP be able to exceed the MRCP as the amount of excess reserve capacity reduces towards zero.
- The value impact of the resulting slope and level should not be overly disruptive, if possible, so as to avoid or minimize the need for a complex transition mechanism

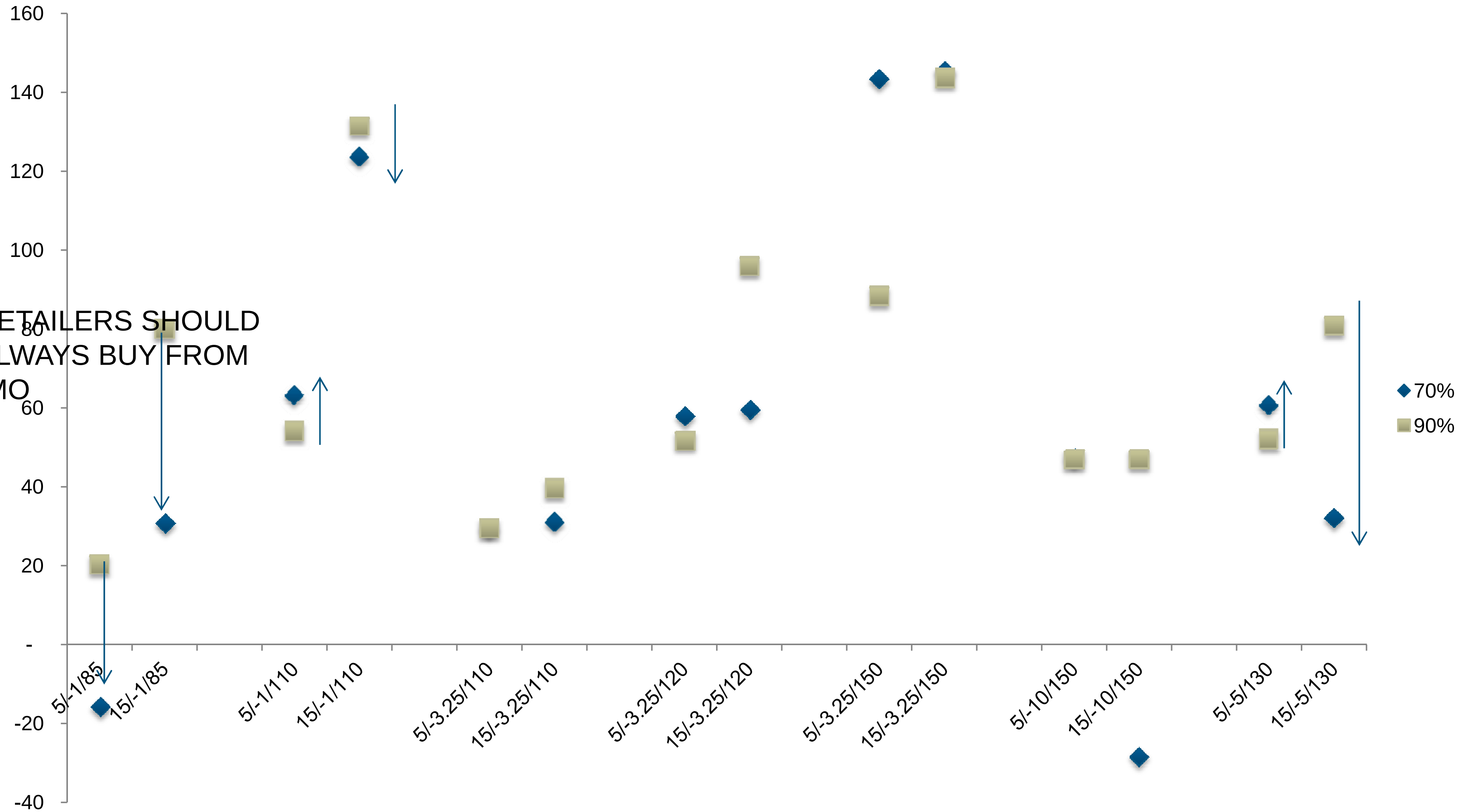
# Slope options versus MRCP of 163,900

| | 70% | 90% | 1 | 5 | 15 |
|---|---|---|---|---|---|
| 5/-1/85 | **-16** | 20 | **137** | **133** | **121** |
| 15/-1/85 | **31** | 80 | | | |
| 5/-1/110 | 63 | **54** | 179 | 172 | 157 |
| 15/-1/110 | **123** | 132 | | | |
| 5/-3.25/110 | 30 | **30** | 175 | 155 | 121 |
| 15/-3.25/110 | **31** | 40 | | | |
| 5/-3.25/120 | 58 | **52** | 190 | 169 | 132 |
| 15/-3.25/120 | **60** | 96 | | | |
| 5/-10/150 | 47 | **47** | 223 | 164 | 98 |
| 15/-10/150 | **-28** | 47 | | | |
| 5/-5/130 | 61 | **52** | 203 | 170 | 122 |
| 15/-5/130 | **32** | 81 | | | |


ANNUAL TOTAL COST
LOWER CAPITAL COST, LOWER EFFICIENCY
HIGHER CAPITAL COST, GREATER EFFICIENCY
EFFICIENCY PREMIUM
PURE CAPACITY
AMOUNT DISPATCHED

# SETTING THE MAX RCP > E-MRCP CHANGES INCENTIVES

RETAILERS SHOULD ALWAYS BUY FROM IMO



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# Memo

| | |
|---|---|
| To: | RCM Working Group |
| From: | Mike Thomas |
| Date: | June 2012 |
| Subject: | Additional information about RCM options |

In anticipation of the special RCM brainstorming session, I have tried to address some of the questions recently raised as well as some addition ones that might be useful to the Working Group members.

## 1.1. What is the purpose or objective of the exercise?

### 1.1.1. First, what is the RCM supposed to do?

The RCM is intended to support needed capacity. It operates in conjunction with all the other aspects of the WEM, but most fundamentally it complements the energy pricing aspects of the WEM. The reason it complements the energy pricing aspects of the WEM is that short-term energy prices (generator offers, effectively, and the resulting STEM and balancing prices) are capped by generator short-run marginal costs. Absent a capacity credit value, the WEM would be unable to support new investment needed to meet demand. In this sense, the WEM is a two-part market similar to other two-part markets in the world, including the Korean cost-based pool and several markets in the United States, most notably the PJM market.

In each of these two part markets, the justification for a capacity mechanism or capacity value is that the energy price is not able to support the investment needed to cover the cost of pure capacity (typically a peaking unit) because if that unit is dispatched it only is paid its short-run marginal cost—a value that makes no contribution to fixed costs. The resulting situation is called "missing money". Missing money implies that the market will be unable to needed investment. Any market that materially caps energy prices (spot market) runs the risk of missing money unless there is a capacity payment of some sort.

At the same time the capacity value and the energy market need to work together to produce the appropriate commercial signal. If the combination of capacity value and energy price projection is persistently high, investment should be expected. If the combination is low, investment should not be expected. The capacity mechanism needs to work dynamically with the energy market to create the right signal regarding the need for (or lack of need for) new investment.

### 1.1.2. Does the RCM do this?

Currently, by any objective standard, there is a lot of excess reserve capacity in the WEM. The amount of excess capacity arose, at least in part, because the RCM has not adjusted dynamically to a degree sufficient to reflect changing market conditions. That is not to say that the capacity credit value has been rigid – in fact, the capacity credit value has changed dramatically recently as a result of the MRCP review. It is also not to suggest that some portion of excess reserve capacity is the result of factors outside of the influence of the RCM.

### 1.1.3. What is wrong?

Rather than dwell on specific causes of excess reserve capacity, it is better to work within the framework of what the RCM is supposed to do, what its parameters are supposed to mean and how the various elements are supposed to work together. When we do this, we find, quite quickly, that the current RCM reflects a number of inconsistencies. Simply sorting out the inconsistencies would create a more robust RCM—one that is more transparent and easier to review and evaluate in the future.

First, now that the MRCP has been recalculated, it is clear that it is not an appropriate “cap” for the RCP. One can quibble with small issues around this estimate or that, but the MRCP has not been put forward as a credible “maximum”. Therefore it is logically inconsistent with the RCM as it is structured. If nothing else were to be done, I would recommend rebasing the MRCP so that it is no longer put forward as a “maximum”. Failure to do that greatly increases the risk that the RCM will not support needed investment in the future.

Second, a series of follow-on changes, at minimum, are then required to maintain consistency with the features of the RCM as a mechanism intended to complement an energy market. First, the implication of recognising the MRCP as an expected value rather than as a properly constituted maximum value is that the RCP values must be allowed to increase above the reference value at some diminishing level of excess reserve capacity – else the “expected” RCP cannot ever equal the reference value.

If the expected RCP is always below the value required to support capacity, retailers would have less incentive to contract with generators. Indeed, their only incentive to contract with generators would be if they are penalised by more than the cost of a capacity credit if they fail to procure sufficient contracts. But if retailers can be penalised by more than the cost of a capacity credit, why not let the capacity credit value itself increase – thereby ensuring that generators have access to a value stream consistent with the cost of capacity investment? In effect, putting an artificial cap at the expected value level limits the effectiveness of trading as a clearing function and raises the costs associated with market-based bilateral contracting.

Some might consider that if the RCP cannot equal the reference value (160 MW OCGT technology), then investment will still occur since there are lots of other "cheaper" sources of capacity available. If so, the choice of reference technology needs to be reviewed. The point of the reference technology is that it should be a proxy for the *least expensive* source of capacity that can be obtained in the market on a reasonably unlimited basis.

Third, the RCP relationship to the MRCP (slope and set-off) bears closer review. First, it makes no sense to use an 85% set-off against an expected value of the cost of the reference capacity. Perhaps the offset was intended to give generators an incentive to enter into bilateral contracts as they would be receiving a discount to the RCP if they did not do so. Buy why stop there? Why not impose a 15% uplift on any credits purchased from the IMO by retailers—effectively a 15% bi-directional penalty for using the IMO as a clearing house. Symmetry and balance are important in markets. Where there is upside, there needs to be downside, and vice versa.

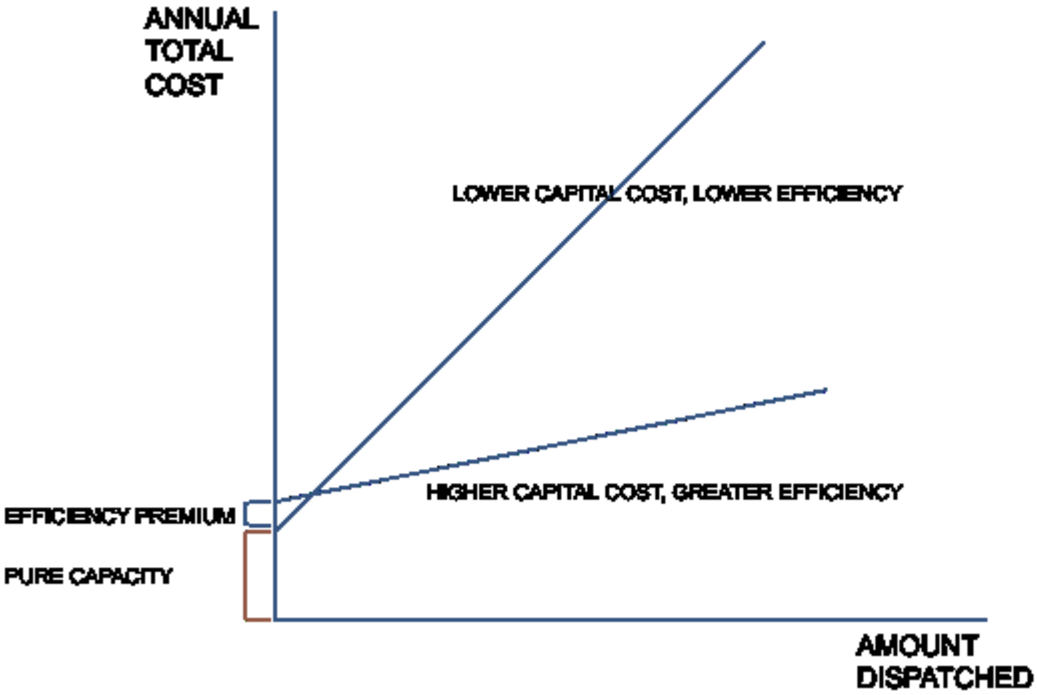
And, finally, the mild "slope" of the relationship between the RCP and the amount of excess reserve capacity means that the RCP plays only a limited role in helping to signal or moderate incentives to invest in new reserve capacity. For a market that was argued to be bilateral-centric, the incentives to bilaterally contract for risk management purposes are weak. Indeed, choosing not to bilaterally contract can perversely appear less risky (reducing and improving certainty of costs) compared to contracting heavily.

Given the excess reserve capacity that exists and the prospect of eventual dysfunction should the various logical inconsistencies not be addressed, we conclude that the RCM needs some repair. None of the above observations necessarily prescribes a particular form of "fix". The proposed "slope" approach would address these, but so too might other approaches. So, at least at this point, it is useful to keep an open mind on how best to bring consistency to the various elements of the RCM so that they work together more effectively and predictably.

The questions are these: (1) what form should those repairs take; (2) what degree of certitude should we expect those repairs to produce an improvement over the current arrangements (while avoiding the risk of any unintended consequences) and (3) how much of a change to the current "bone structure" is needed to achieve the needed improvements?

## 1.2. What is pure capacity?

I'd like to use a definition of "pure capacity" as follows: Pure Capacity is that source of capacity that can deliver what is needed but virtually never has to do so – perhaps running just a few hours each year. One does not want to, nor should one need to, pay anything more for pure capacity than the absolute minimum value that secures that type of virtually pure standby capability. If one pays more than the cost of pure capacity, one needs to ask what one is getting in return? That is, are you getting some sort of flexibility or efficiency premium? The norm is to expect that any fixed payment greater than the cost of pure capacity should buy you access to valuable fuel and operating cost savings from actual dispatch -- sufficient to at least cover the premium you have paid.




When I talk about the value of a capacity credit, I am only talking about the value of pure capacity. That is the definition that “fits” with the concept of a capacity market or capacity mechanism that is matched to an energy market that is capped at short-run marginal cost generation offers.

The RCM, like any capacity mechanism or market, needs to be linked to the cost of pure capacity or it will produce inefficient or ineffective outcomes. The reason I argue that there is a single value of capacity applicable to all sources and types of capacity in the WEM is that the point of the RCM is to cover the missing money that is arises because the WEM is not an energy-only market. If you don’t pay baseload capacity the pure capacity credit value, the energy market will not reward sufficient baseload capacity—even though baseload capacity will earn an efficiency premium in the energy market every time something of higher merit sets the energy price. And if you don’t pay peaking capacity the pure capacity value, you won’t get any peaking capacity, either.

## 1.3. The Capacity Market and the Energy Market

If a market produces too much peaking capacity due to the capacity payment being too high, the energy market price will naturally rise (relative to the “optimum”) due to the higher cost associated with dispatching less efficient capacity, then two things should happen: the market “efficiency premium” conveyed by energy prices should increase, while the market capacity value should decrease below the value of pure capacity. The latter *has to happen* or the market will keep getting more high cost peaking capacity.

Conversely, if the plant mix is skewed towards low dispatch cost capacity, the market efficiency premium should be below the efficiency premium evident across various technologies. It should not be commercially viable to pay a premium for a generation technology that is highly efficient at a time when there is a surplus of capacity with low dispatch costs relative to the overall load duration curve. In the extreme, markets with excess baseload generation can see extensive negative pricing in off-peak periods and, more generally, market prices that clear at the SRMC of baseload capacity – producing little to no operating profit from spot market dispatch. Only as demand grows does the risk of shortage during peak periods start to emerge—causing the market value of capacity to increase rapidly, even as the market efficiency premium does not grow as fast. Peaking capacity can then enter the market economically.

The RCM needs to be consistent with the energy market that is also part of the WEM. On the other hand, the RCM has administrative features (ie. the RCP formula) for a variety of reasons probably relating to risk management or a desire to avoid extreme volatility. These additional features can be fine, so long as the RCM overall produces outcomes that are reasonably consistent with market-based outcomes and does so at reasonable cost. Otherwise either supply or cost will be at risk.

## 1.4. What is the appropriate level of “risk” in the RCM?

The WEM is not a very deep market by any standards, but the basic logic and mechanisms all key off the same concepts found in wholesale electricity markets everywhere.

The RCM and the energy market form an alternative to bilateral contracting. Bilateral contracting will be promoted (incentivised) to the extent that being exposed to the RCM and energy market is seen as risky. The more risky the RCM and energy market are perceived to be, the more valuable a bilateral contract becomes as a hedge. At the same time, it the overall WEM is perceived to be too risky, overall investment may be reduced. In contrast, if the RCM produces high RCP values, then we would expect to see greater investment, as high RCP values reduce financing risk. The principle here is simple: no one will have an incentive to do “A” (ie., contract) if they see a better value proposition in “B” (ie., not contract), and vice versa.

If there is more capacity than is needed, someone has to pay for it. If consumers are going to bear the cost of excess reserve capacity credits, they are entitled to get value in return. The value they get is linked only to the improvement in overall system reliability. If the costs coming out of the RCM exceed the economic value actually created by the capacity that has been brought forward, then the incentives are wrong.

Investors in the WEM can protect themselves to a degree against some of these risks by entering into long-term contracts. On the other hand, it has been alleged that it is difficult to obtain a long-term contract in the WEM currently. Analysis shows that the amount of “uncontracted” capacity credits has increased and been quite volatile in recent years. Some argue that is because of market power in the retail segment. But a closer look indicates that the cost of excess reserve capacity is a function of the amount of capacity under contract. The more capacity is contracted, the higher the exposure to the cost of excess reserve capacity. This is perverse, as it works against any contracting incentive that might have otherwise been thought to exist in the WEM (or to be desirable).

On the other hand, if the cost of excess reserve capacity credits is reduced, all else equal, the disincentive to contract is also necessarily reduced, at least in relative terms. To the extent contracting is a source of value and excess reserve capacity credits is a source of cost, then reducing the cost of excess reserve capacity credits will tend to allow more of the value of contracting to be realised. It is hard to say whether this effect will be significant, but it is easy to say that it will be larger if the reduction in the cost of excess capacity credits is greater.

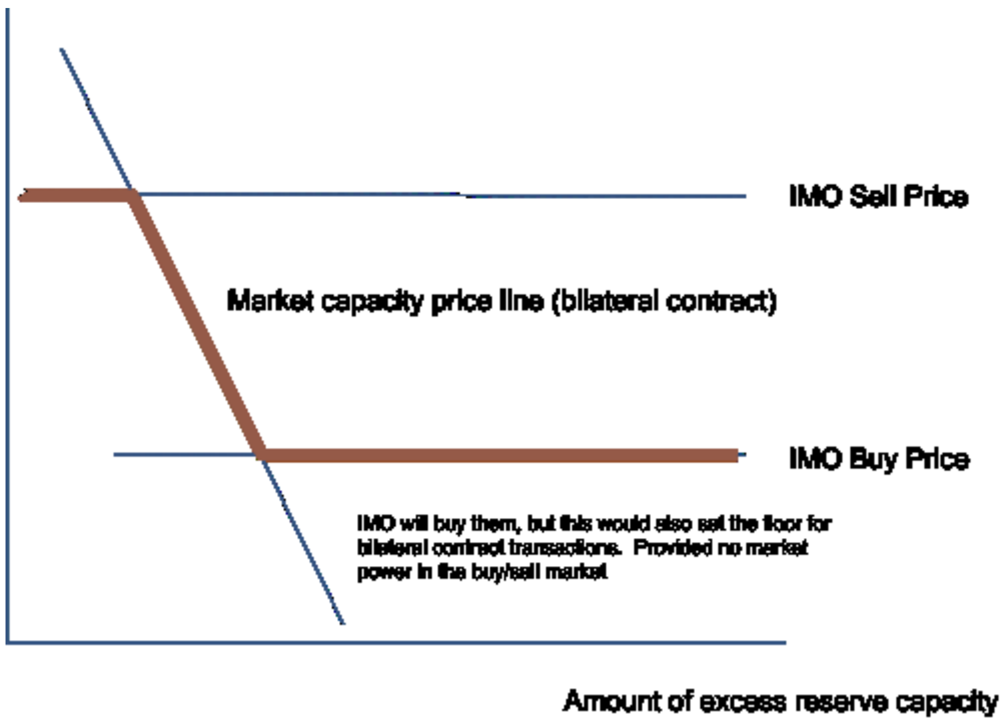
## 1.5. What is the basis for the revised slope proposal?

In order to develop the "slope" proposal, we first had to develop a view about how a market process would value capacity credits. As indicated, a market value of a single-year capacity credit three years out will be very sensitive to the amount of excess reserve capacity. Our estimate of the market value is at or near zero at this time.

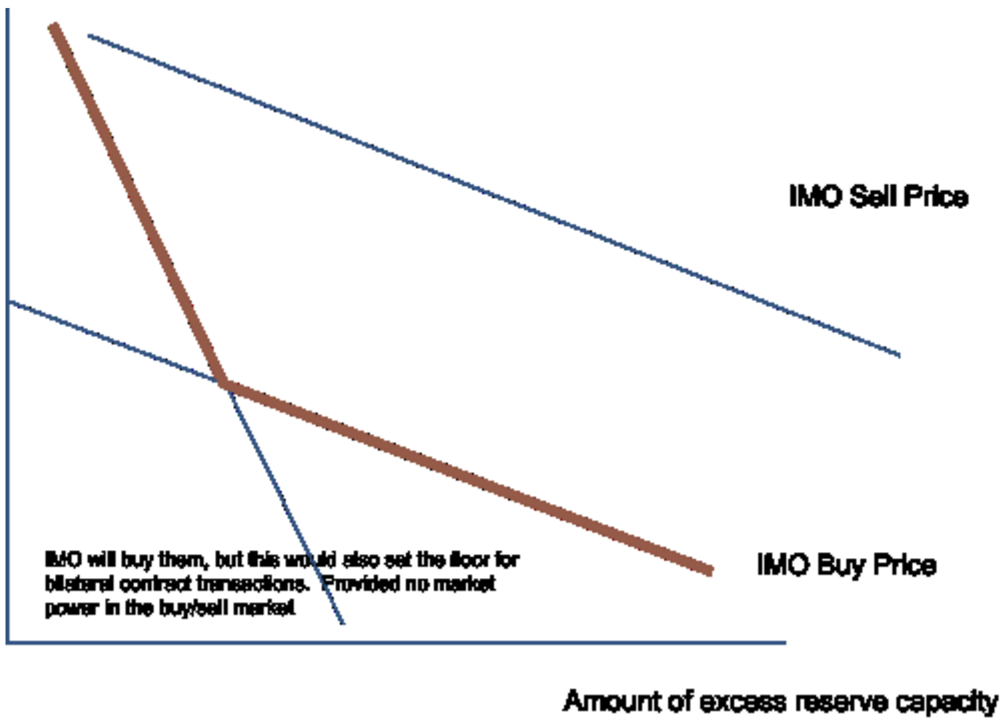
We note that the WEM does not use a market mechanism for valuing uncontracted capacity credits. Such a mechanism could be developed. It could take several forms. Two of the most common alternate forms are:

- Bilateral contracting incentive through buy/sell penalties
    - impose a sharp penalty on uncontracted retailers (ie: make them pay a very high price to procure such credits from the IMO
    - impose a sharp penalty on any uncontracted suppliers (ie. Pay them a very low price for any uncontracted credits).
- Auction based price discovery

If we were to propose a large enough penalty for contractual shortfalls, then contracting will be promoted. In the extreme we could probably drive the whole market to be fully contracted, at which point the remaining uncontracted capacity credits will trade at the punitively low uncontracted supplier price. But consider the incentives for price discovery – which depend in part on the level of competition in each sector. The thick line would mark the expected negotiated values simply because the market price line is so steep. Over most of the relevant range, the bilateral contract price would be just a bit above the IMO buy price, unless either generators had market power in the capacity credit market.




This option was noted in the first presentation to the WG, and a stakeholder has put a version forward for discussion. It's a fine structure, well worth discussing. It has a lot to recommend it, and it can be seen either an alternative to, or an overlay on top of, a proposal that employs an administratively set "slope", as well. The question is just one of the level of volatility and risk that is intended to be pushed into the bilateral contracting market, especially at the point in which there might still be considerable excess reserve capacity in existence when the mechanism goes live.




Effectively the slope becomes a value management mechanism. It is recommended as being relatively more consistent with the RCM as it was originally constituted to be a mechanism rather than a highly volatile market pricing structure.

The other approach, involving an auction-based price discovery, would involve using an auction to value uncontracted credits. Basically the IMO would make uncontracted credits available as needed through an auction, the auction would determine the value of those credits and that value would then be paid to all sources of uncontracted credits. In a sense, this is a musical chairs-based approach to fill up any uncontracted IRCR on a highly competitive basis.

Issues arising with this approach include the one about how to manage the value implications in the event that the market value of excess reserve capacity is zero. Second, how to avoid gaming of the auction. Third, how to make the auction work in the manner intended. Consider that if the RCR is known, the uncontracted positions are known and the amount of uncontracted capacity credits are known and the auction merely clears the uncontracted RCR requirement, which is less than the total amount of reserve capacity available. If there is a lot of excess reserve capacity, the bids will clear at the floor price. In order to clear above the floor price, it has to be profitable for generators to not offer all of their uncontracted credits for auction, or to be able to offer credits at a price in which they take greater risk that they do not sell all of their available credits (quasi market power). If so, then as the amount of excess reserve capacity starts to reduce it will eventually reach a point where the clearing price will fall between the floor and ceiling—precisely when this happens is a function of the competitiveness of the credit clearing market.

But if you have to develop a floor value, then we are back to the question of what value to choose.  The reality is that this value depends on the amount of excess reserve capacity there is.  But if the auction process only has to clear part of the excess reserve capacity, then there is always at least some capacity credit still “standing” when the music stops. The more excess there is, the more likely the value drops to the floor.

One way to fix this is to introduce uncertainty in the amount of credits that will be needed to be held.  This introduces a big change to the approach to forecasting and setting the RCR, and might just as well trigger a whole broader host of auction-based reforms.  As interesting as this approach would be, it would take longer to develop and implement and to stress test and vet the performance of such a market-based approach.  Consequently, it has been floated for evaluation in the evolution programme, but not for immediate consideration.

Thus, the RCP slope concept was thus put forward as a way to reconcile all of these complexities while still providing a strong-bone framework for something more market like (the buy/sell incentive could be added to it, easily, for example).

But what slope?

It has been suggested that the slope is inherently arbitrary.  There are certainly many choices – an infinite number – of possible slopes that could be adopted, but if we focus on accomplishing three simple things, the range of slopes narrows considerably:

- The slope needs to be steep enough to curtail the risk of unnecessary investment aiming to be supported by excess capacity credits.  This determines a minimum slope, which we have estimated to be at least -3.25 as that corresponds to a 15% discount to the reference capacity value.  That may not be enough, of course, to absolutely stop all investment that is not needed.  But it would certainly have a positive impact relative to the current formula.
- The resulting level needs to be high enough that the RCM can support new capacity when needed (and before relying on a supplementary auction, which is currently designed for essentially emergency situations).  This requires that the RCP be able to exceed the MRCP as the amount of excess reserve capacity reduces towards zero.
- The value impact of the resulting slope and level should not be overly disruptive, if possible, so as to avoid or minimize the need for a complex transition mechanism

A maximum RCP equal to 110 percent of the reference price and a slope of minus 3.25 had the happy coincidence of supporting capacity investment when the amount of excess reserve capacity dipped below 10% and also intersecting the current RCP value at the 2013/14 level of excess reserve capacity.  These values will be reviewed for further future capacity years.

The above logic supported the initial proposal.

The problem with the initial proposal is that it might not go far enough. The resulting values would still be well above the “market” value of a capacity credit given the current level of excess reserve capacity. On the other hand, the current level of excess reserve capacity may not be the level of reserve capacity that actually exists by the time the changes are implemented.

There may be scope to introduce a steeper slope – perhaps in combination with a buy/sell spread. We can discuss the merits of steepening the slope or other ways to manage risk and value across a reasonable range of excess reserve capacity outcomes at the workshop.

## 1.6. What about spigot control?

Some have communicated a continuing preference for a spigot control approach – to basically tighten up the assessment of what constitutes committed capacity. To the extent that the commitment determination is looser than was originally intended, it would be useful to explore how it can be tightened up.

But we should keep a few reservations in mind just to be clear about the practical limits of attempts to nip excess reserve capacity in the bud at the designation of commitment stage.

As previously explained, if the RCP is attractive to investors – and there can be no doubt that it has been in the past—then a spigot control approach will require that the IMO make judgments about whether contracts are in place and that those contracts are valid and not sham contracts, temporary contracts or cannot otherwise be easily cancelled, terminated or costlessly breached. Maybe this can be performed robustly and reliably. Maybe all stakeholders will make their contracts available to the IMO for full legal inspection, maybe any clauses in such contracts that might allow termination, cancellation or abrogation could be monitored, but it seems fairly obvious that this is not a practical structure.

Spigot control also becomes very difficult to administer during periods when the capacity mix is shifting, say, from low capital cost high fuel cost technology to more traditional baseload capacity. For example, consumers would not wish to see baseload capacity *prevented* from entering the WEM due to an inability to gain committed status. But if fuel prices are very high due to a large amount of high variable cost plant, it is entirely possible that even low capacity credit values would support some new capacity investment (the Korean market has this situation currently). The only way to enable this to happen is for the IMO to commit based on essentially the same type of evidence that the IMO currently reviews and considers today. More extreme versions of spigot control introduce risk that economically valuable capacity would be disallowed just because the amount of capacity currently in the WEM appears sufficient.

Finally, it is not generally desirable to impose specific limits on the potential contestability of a market. Innovation and new technology should be able to access the WEM without being necessarily prevented from being eligible simply because other capacity already exists. It would not be sensible for spigot control to devolve into a form of unmerited protectionism. On the other hand, a free option to enter a market in which one’s services are not valued is not efficient, either. A price-based control has the advantage of focussing on value-added, whereas a quantity-based control risks being protectionist.

## 1.7. Other possible issues

In addition to the above, it may be worthwhile to consider the role and purpose of the supplementary auction in more detail. Is it appropriate to reserve the supplementary auction until 6 months ahead of need? If the supplementary auction were to be available from one year out, rather than just at six months, it might be possible to introduce modest changes to the way the IRCR is calculated three years before. For example, if there were more time to deploy a supplementary auction, would it be possible to reduce the amount of capacity determined to be required three years ahead? If so, it might be possible to reduce the risk of excess reserve capacity arising due to strong downward revisions to forecasts. At the same time, if forecasts are revised strongly upward, the additional time available to execute the supplementary reserve auction may allow a greater range of short-term options to be available.

The logic here borrows from insights from other markets where a major cost arises from irreducible forecast uncertainty. Forecast uncertainty greatly reduces as the timescale reduces. The problem is that with reduced timescales comes reduced supply-side resource response capability.

## 1.8. Summary

It would be ideal to come out of the brainstorm session with a broad outline “package” of elements that establish a logically structured RCM, together with solid ideas about how to improve the certification process and, potentially, how to address forecast uncertainty in a way that is not just “try to make better forecasts”. At some point, forecasting is hard. The greater spoils come from improving responsiveness to changes in forecasts.

# Independent Market Operator

## Review of Capacity Cost Refunds

Date: 5 April 2011

# 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;

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

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

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

### *2.2 The RCM and Reserve Capacity Refunds*

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

[3] See clause 4.26 of the Market Rules.

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

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

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

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

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

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

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

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

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[4] To extend the contract analogy further, the refunds are a commercial mechanism rather strict terms of delivery that could be breach of contract in other contexts.

[5] The current structure of the Market Rules requires the IMO to pay this refund amount to Market Customers proportional to their IRCR

# 3. ISSUES AND POTENTIAL FOR IMPROVEMENT

## *3.1 Introduction*

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

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

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

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

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

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

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

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

**Figure 1 Cal 2009 Refund Factor v Reserve**

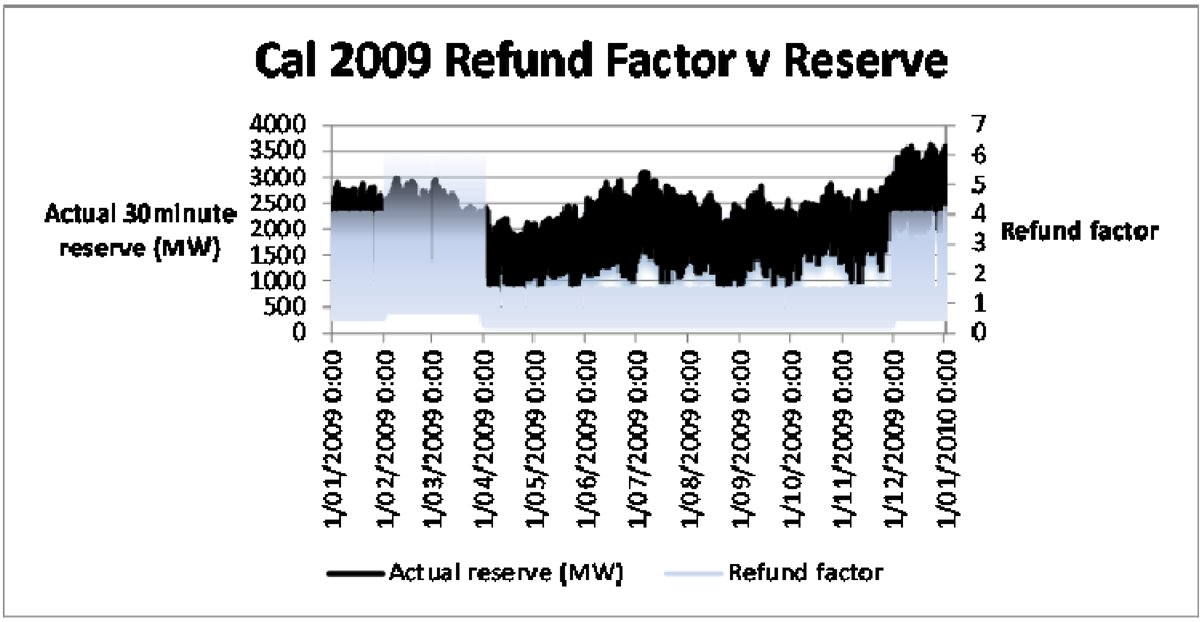
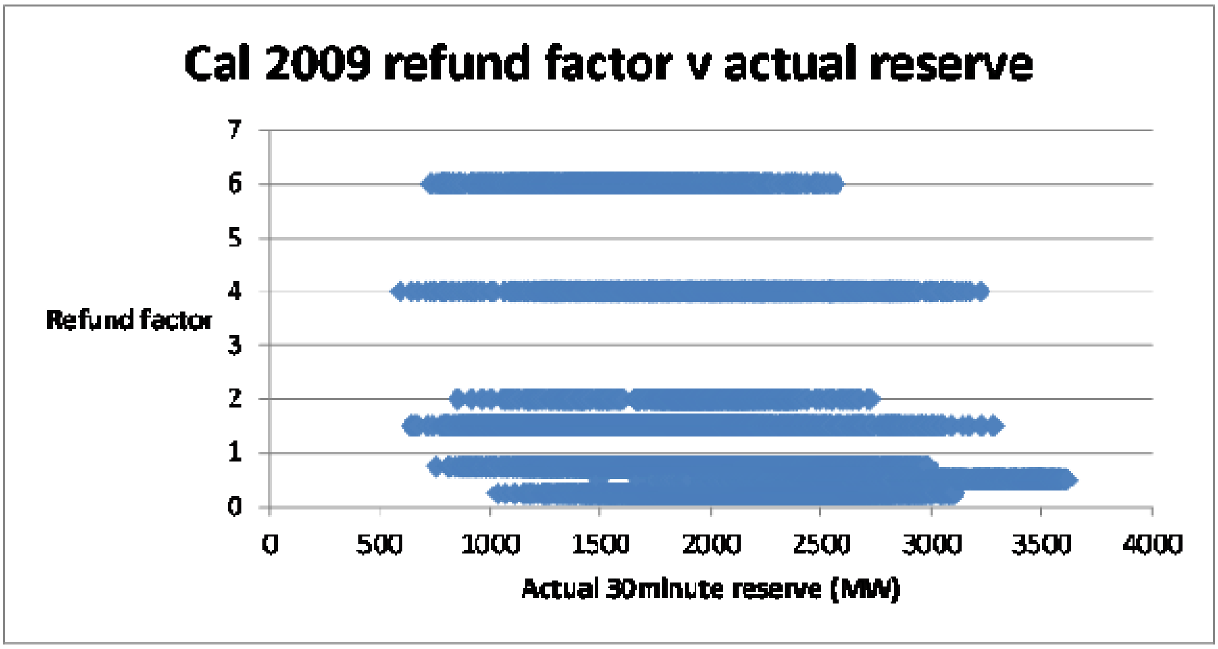



Figure 1 shows actual reserve in solid base plot (as the data covers the entire year only the envelope of maximum and minimum values is readily seen). Figure 2 shows the range of refunds for different reserves across the year. The highest refund rate of 6 applied some of the times of low reserve (as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

**Figure 2 Cal 2009 Refund Factor v Actual Reserve**




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

## 4. POTENTIAL SOLUTIONS

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

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

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

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

### *4.1 Basic reserve related refund*

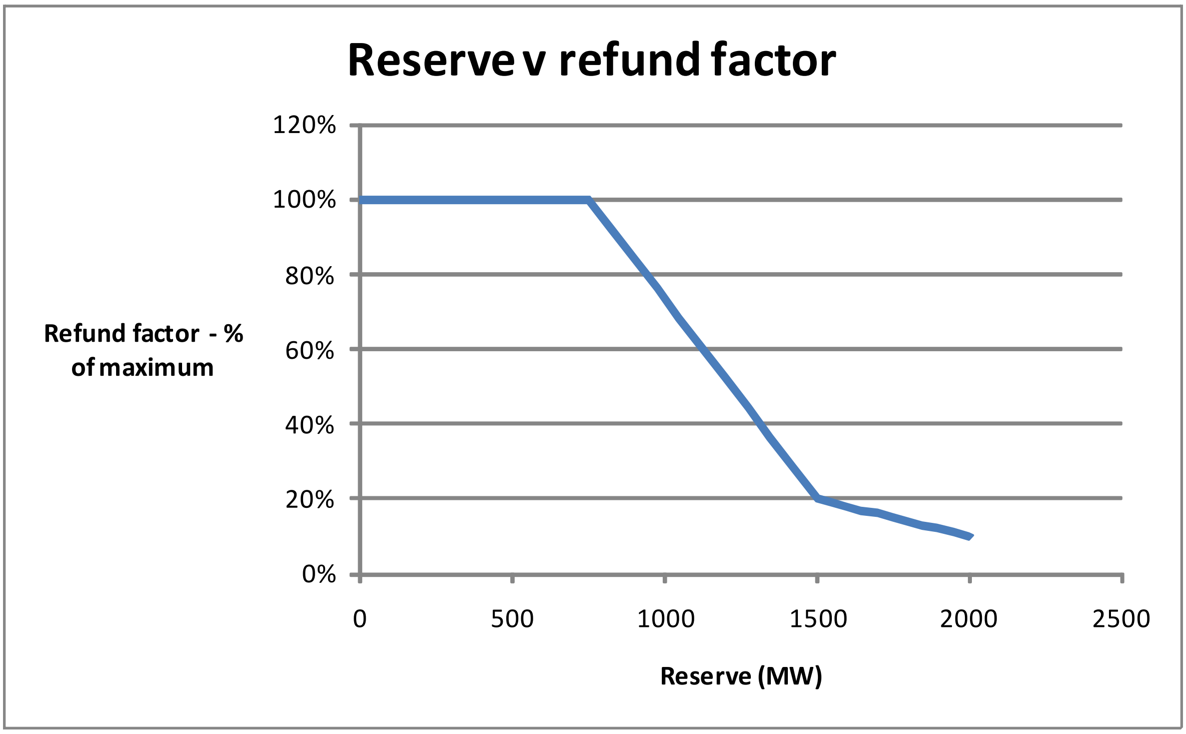
The first alternative is a simple regime that is responsive to prevailing conditions and would:

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

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

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

**Figure 3 Reserve v Refund Factor**




### *4.2 Combination actual and annual forecast reserve*

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

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

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

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

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

### *4.3 Combination forecast and actual reserve related refund*

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

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

## 5. IMO PROPOSED SOLUTION

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

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

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

### *5.1 Defining the magnitude and profile of the dynamic regime*

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

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

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

### *5.2 Cumulative Refund Cap*

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

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

### *5.3 Analysis: Status Quo Compared to Dynamic Mechanism*

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

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

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

**Figure 4 Comparison of cumulative total refund: calendar 2008**

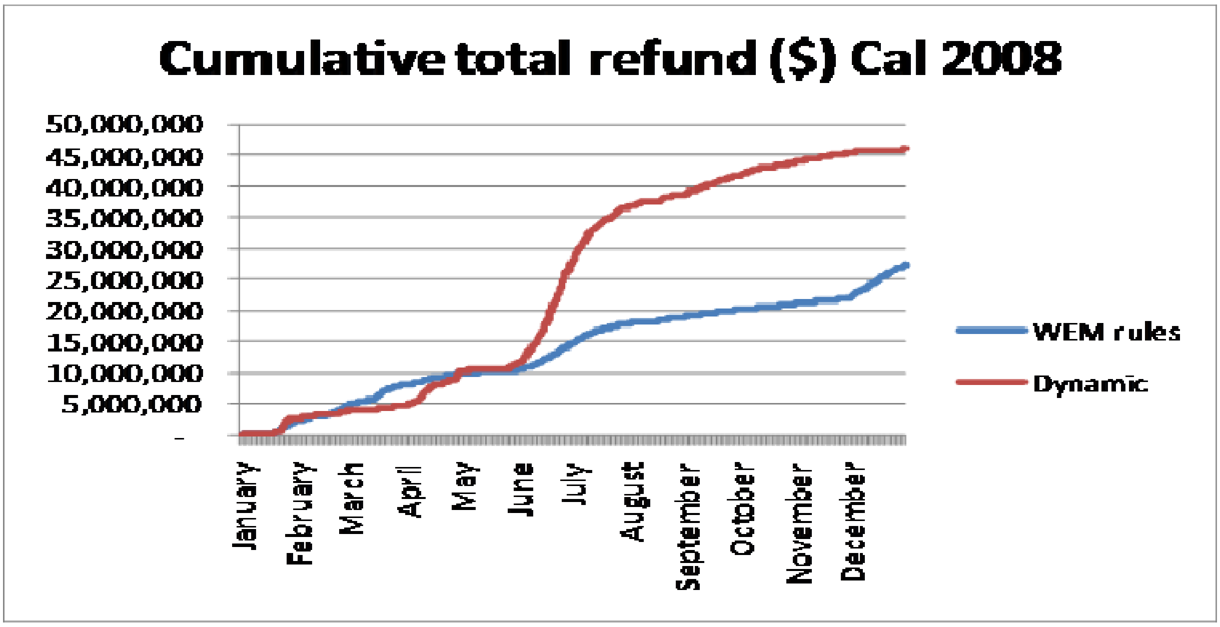



**Figure 5 Refund rate versus reserve in calendar 2008: WEM rules**

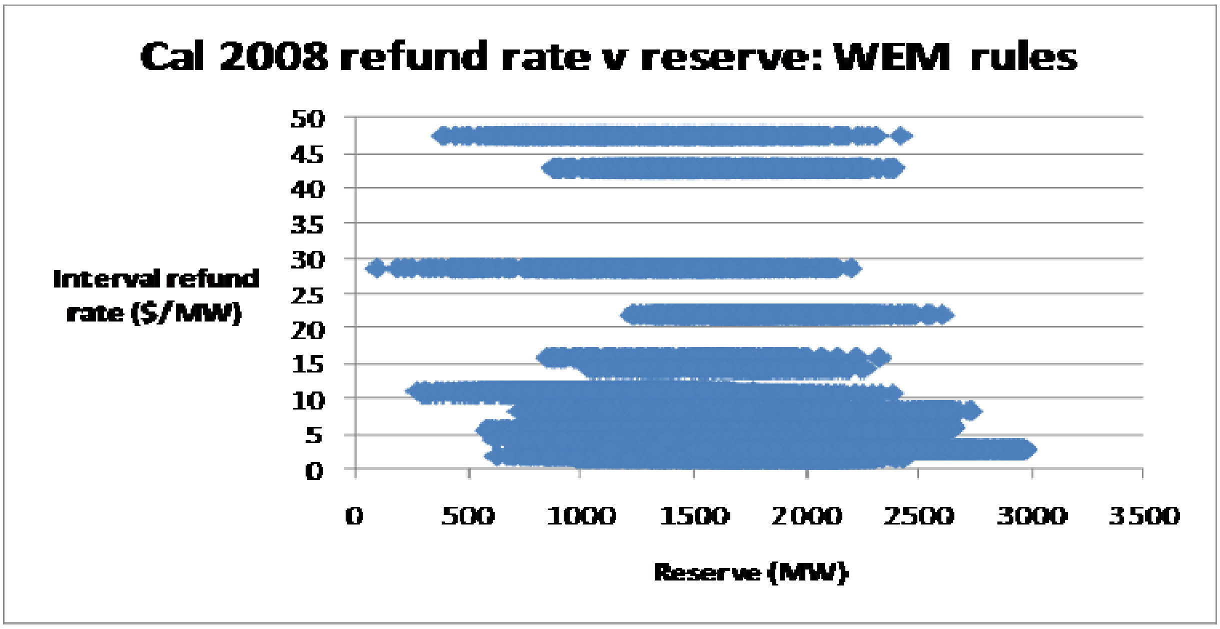


**Figure 6 Refund rate versus reserve in calendar 2008: Dynamic settings**

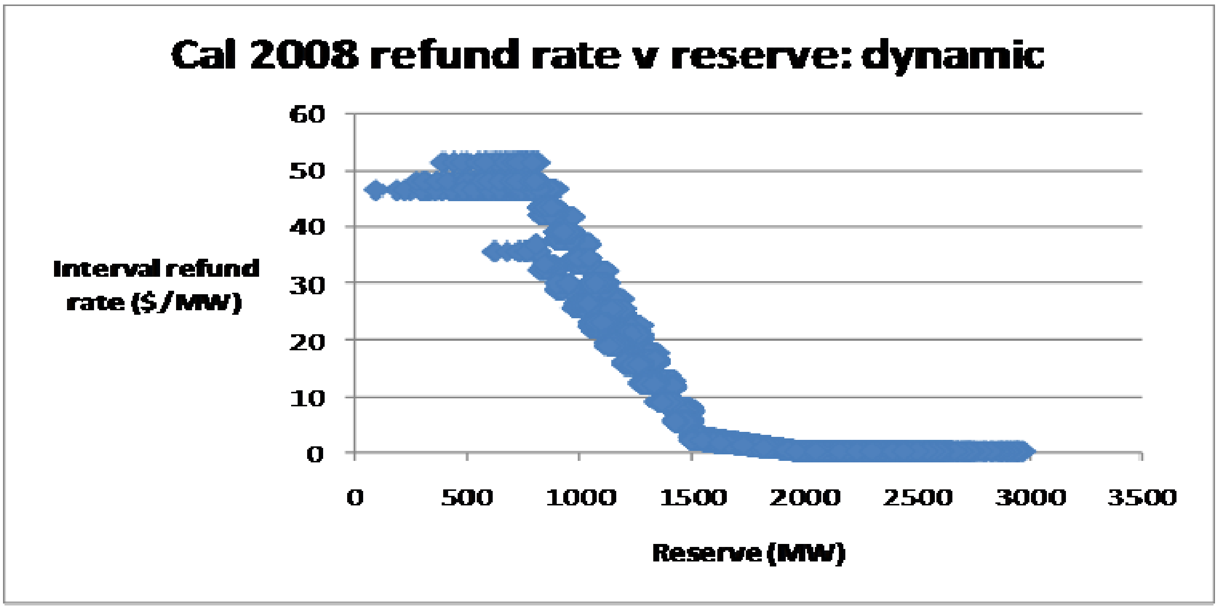



**Figure 7 Comparison of cumulative refunds: calendar 2009**

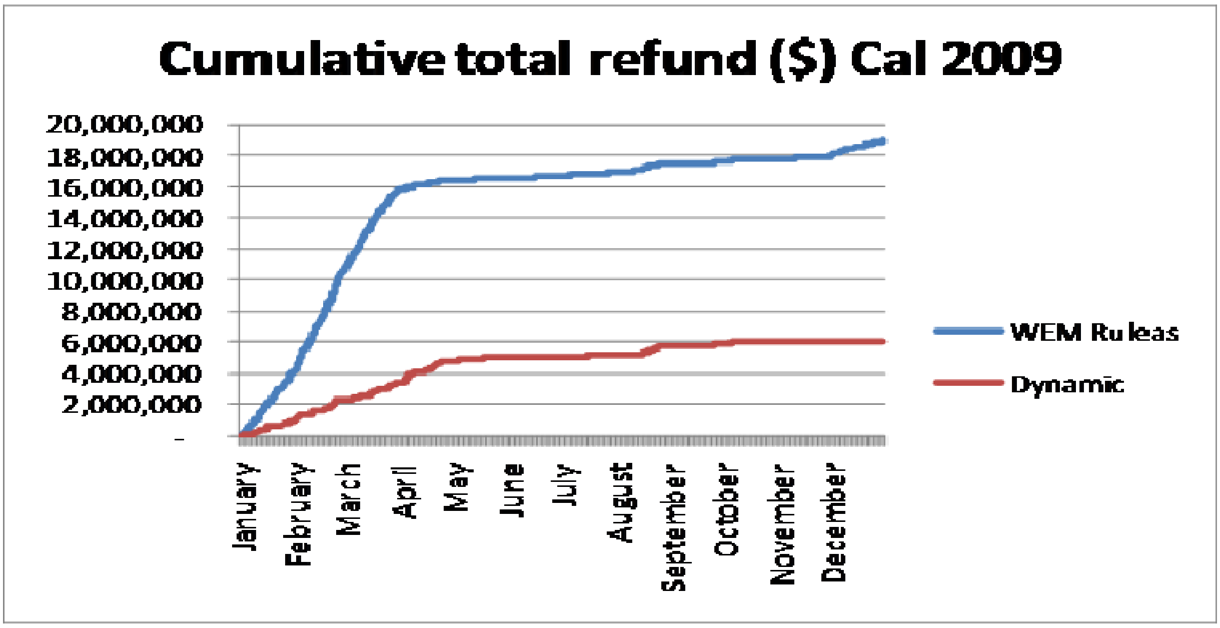


**Figure 8 Refund rate versus reserve in calendar 2009: WEM rules**

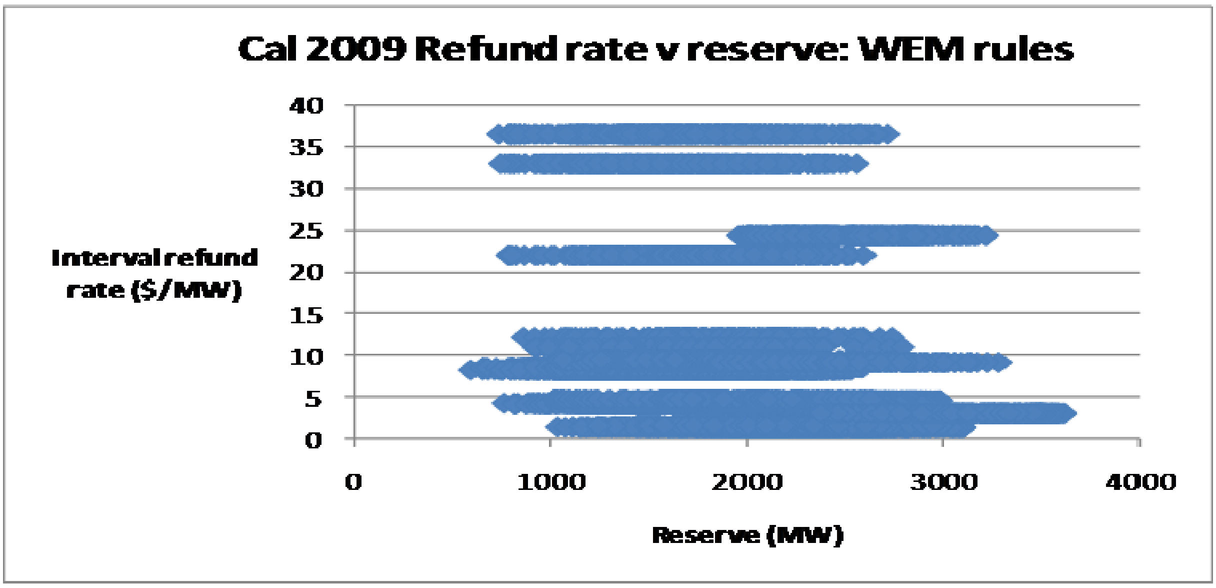



**Figure 9 Refund rate versus reserve in calendar 2009: dynamic settings**

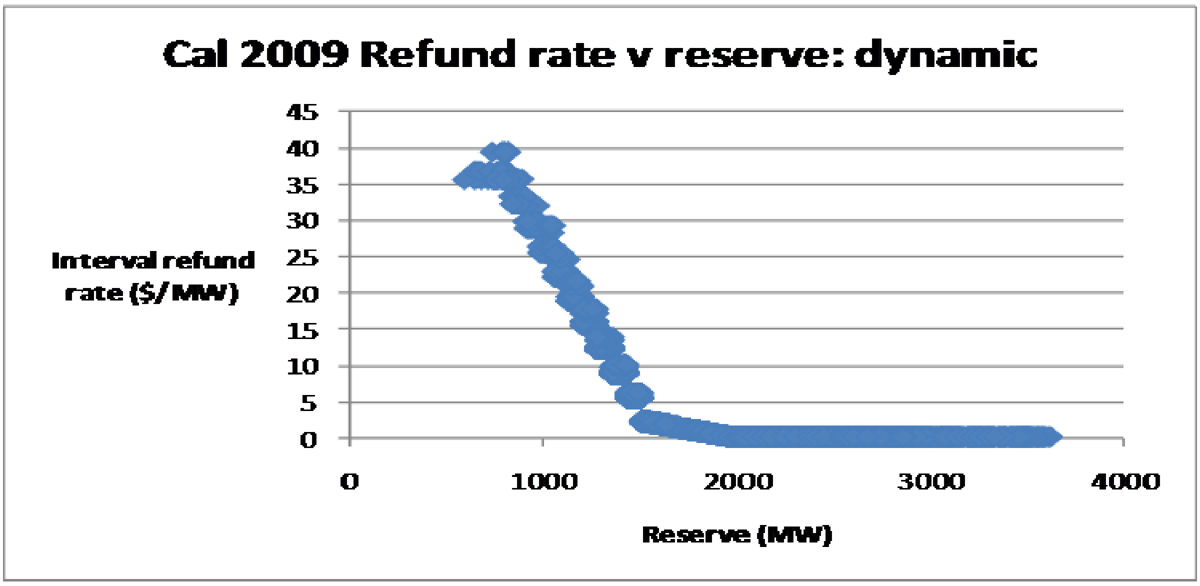



Figure 4 and Figure 7 show that across the year refunds can be higher or lower under the dynamic regime compared to the current WEM rules. Interestingly, over the two years studied the current refund rules were introduced the total refund is approximately the same.

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

### 5.4 *IMO Proposed Solution*

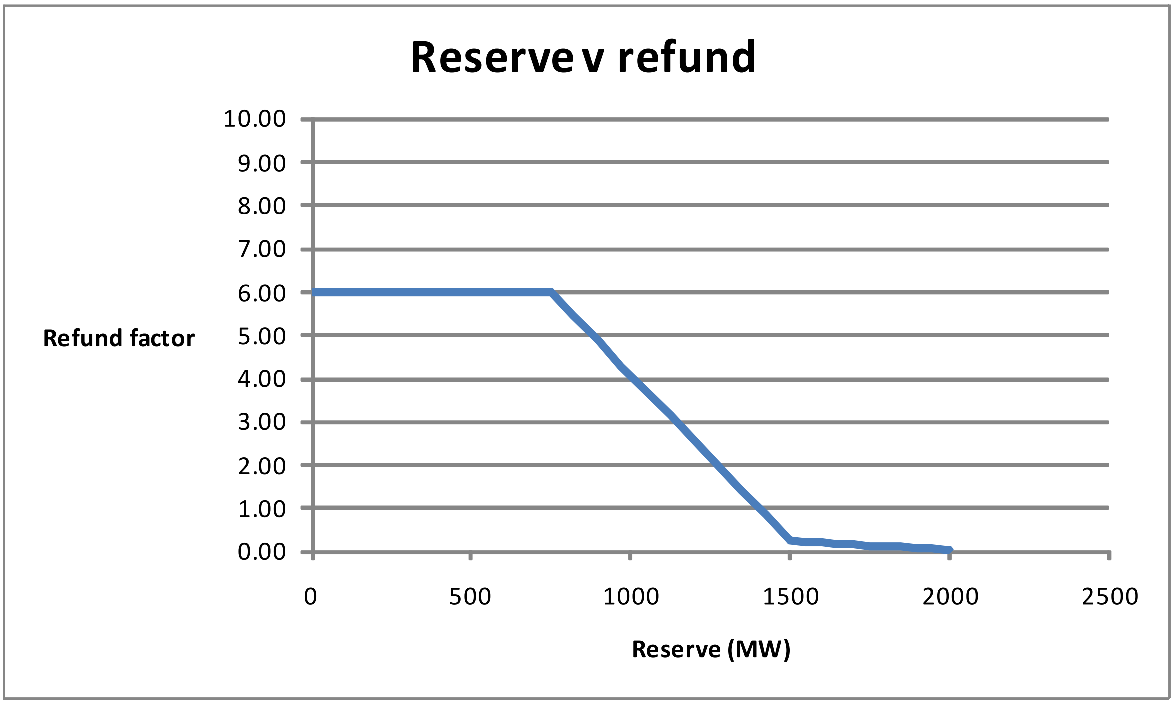
The IMO proposes that the maximum refund factor remain at the maximum value of 6. As noted analysis of the 2008 and 2009 calendar years shows that the cumulative refund amounts under the Market rules and the proposed methodology are similar. The IMO considers that as the design is aiming to produce a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

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

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

Figure 4 illustrates the relationship using the breakpoints noted above.

**Figure 10 Reserve v Refund**



## 6 EXPOSURE TO REFUNDS

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

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

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

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

Figure 11 Forced Outage v Net STEM Shortfall Refund

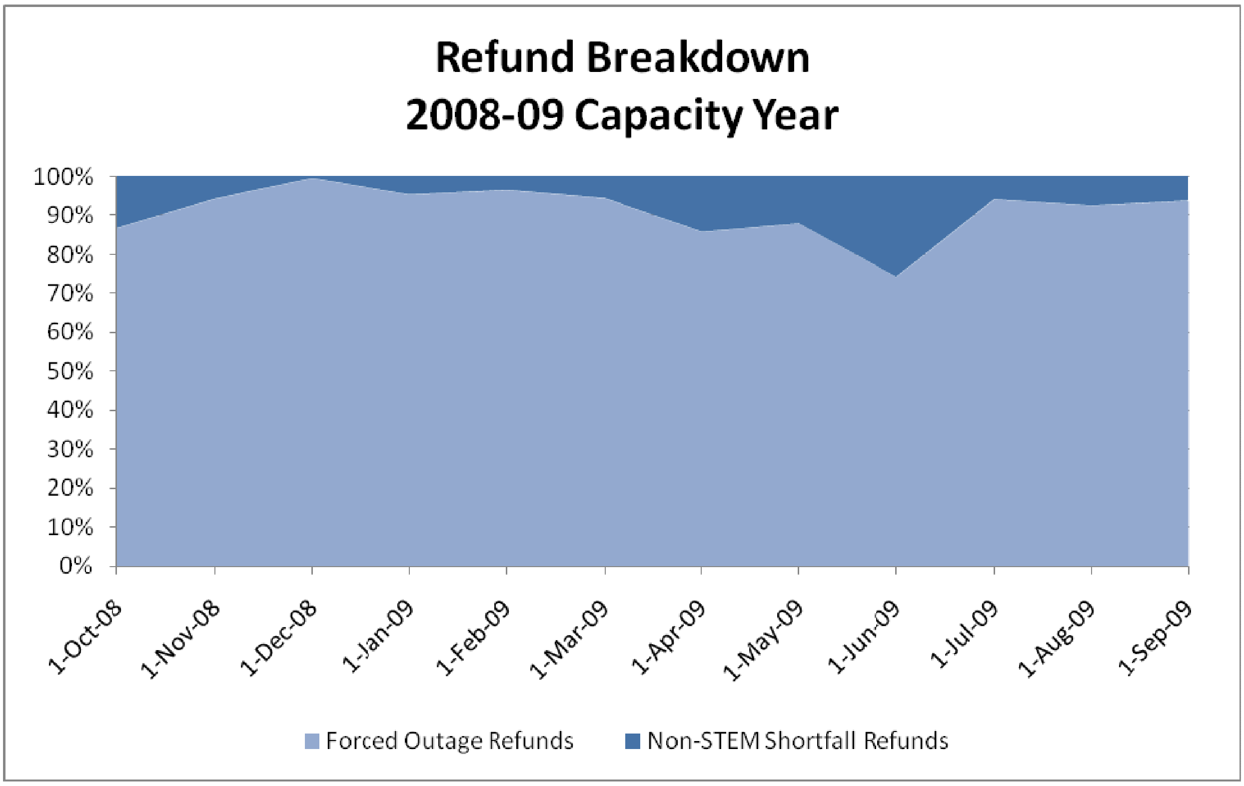



Figure 12 Forced Outage v Net STEM Shortfall Refund

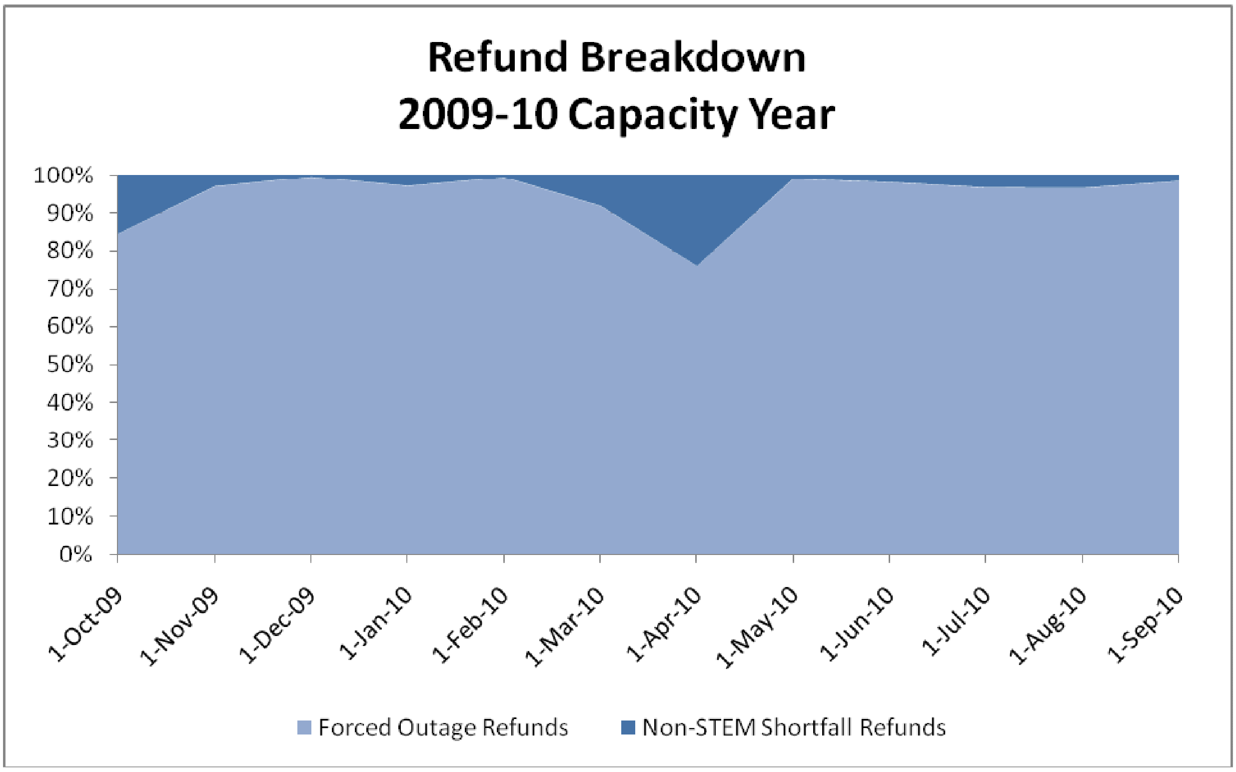


Figure 13 Forced Outage v Net STEM Shortfall Refund (Griffin Adjusted)

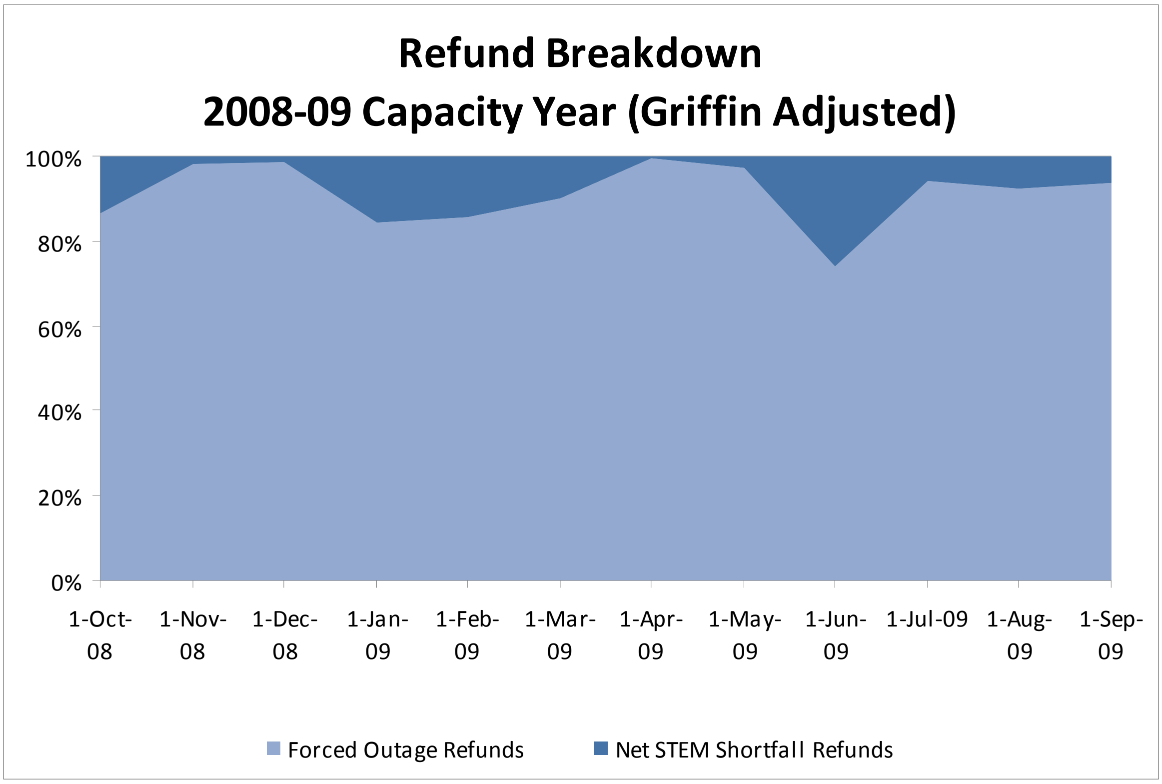



Figure 14 Forced Outage v Net STEM Shortfall Refund (Griffin Adjusted)

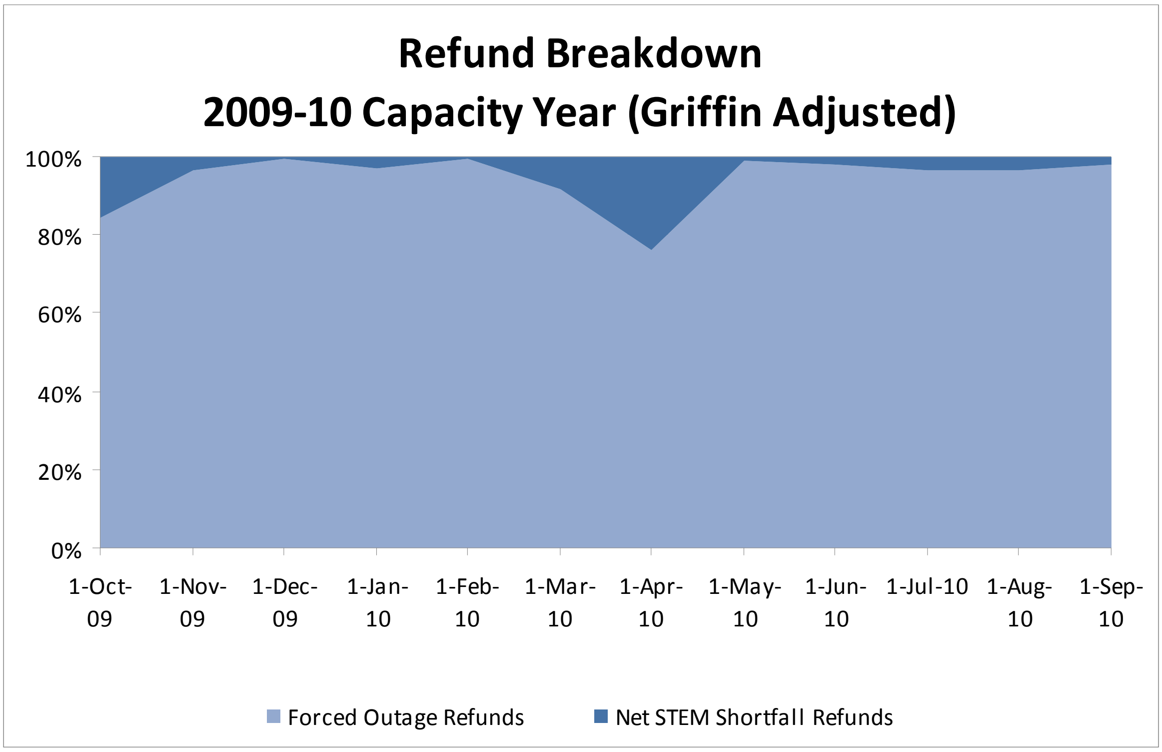
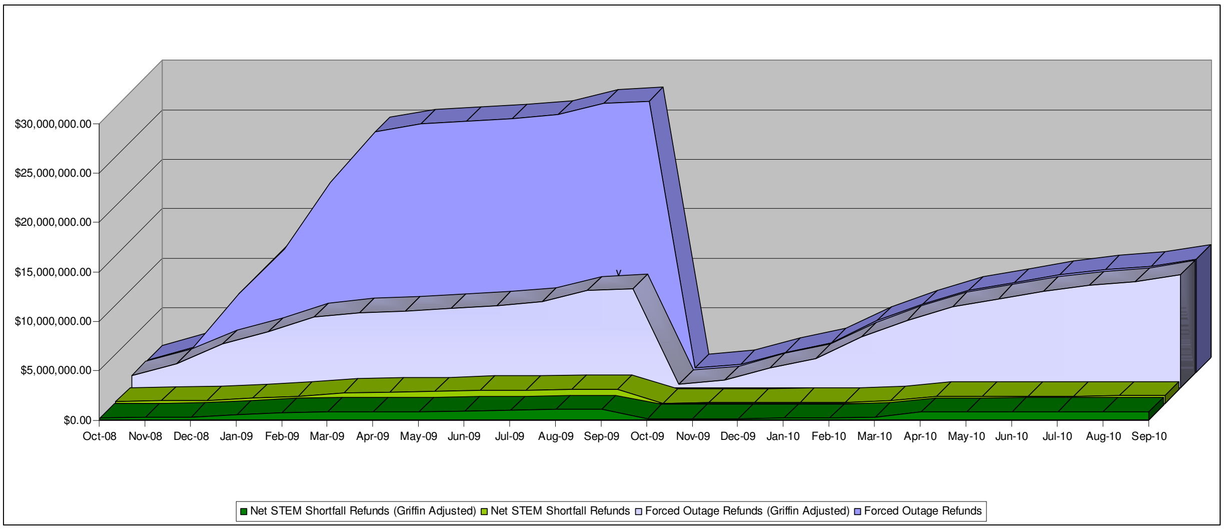


Figure 15 Cumulative Forced Outage and Net-STEM Shortfall Refunds (Per Capacity Year) - Normal and Griffin Bluewaters Adjusted




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

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

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

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

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

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

### *6.1 IMO Proposed solution*

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

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

## 7 DISTRIBUTION OF RESERVE CAPACITY REFUNDS

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

### *7.1 Current Arrangements*

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

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

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

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

The market settlement arrangements also include that:

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

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

The current arrangements results in the following issues:

### *7.2 Refund Distribution Issues*

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

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

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

***Security deposit issues***

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

***SRC Related Issues***

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

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

### *7.3 Opportunity for refinement*

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

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

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

### *7.4 Mechanisms considered*

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

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

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

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

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

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

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

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

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

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

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

- Approach 2 – Cyclic Market SRC Fund

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

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

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

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

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

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

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

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

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

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

### 7.5 Proposed amendments

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

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

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

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

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

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

## 8 RECOMMENDATION

That IMO recommends that the RDIWG:

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

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

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

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

THE LANTAU GROUP
strategy & economic consulting

The RCM Working Group met last week to discuss concerns related to the workings of the Reserve Capacity Mechanisms (RCM). The following summarises the issues noted and presents a recommended way forward.

1. The RCM, a mechanism intended to assure an appropriate amount of reserve capacity at reasonable costs, is not working as it was intended, though views differ with respect to the extent of the problem and the need for specific types of solutions.

2. The "do nothing" option was considered as a possible alternative given the extent of recent MRCP value changes – however, the MRCP change did nothing to make the RCM more responsive to market conditions.

3. The current amount of excess reserve capacity imposes costs on retailers particularly those that have a bi-lateral contract position. Changes to the RCP and MRCP and the RCM also impose risks on all parties – to the extent these make it more difficult to project the future and enter into appropriate risk management contracts. The cost imposition and associated risks are more directly concerning than the actual amount of excess reserve capacity.

4. The nature of current RCM parameter settings and design is such that retailers *always* have an incentive to reduce their level of contracting as a way to reduce their exposure to the cost of excess capacity. This situation is perverse relative to the more typical situation of symmetrical risks – in which both generators and retailers have incentives to contract to manage risk, especially as the amount of excess capacity reduces.

5. While it might appear desirable to simply stop certifying new capacity whenever there is an excess of reserve capacity in the WEM, many complications would then arise that cannot be overcome without introducing other problems – some of which would contravene the Market Objectives:

- New technologies or changes in fuel market conditions may make it possible for new capacity to enter the market at lower cost, but would be prevented from doing so without access to capacity credits – potentially keeping energy market prices higher, artificially;

- A market can be in excess overall but can be out-of-balance in terms of the generation mix. An inability for new capacity to enter its proper place in the load curve can result in higher energy costs – as for example, an inability of a baseload generating unit to obtain a capacity credit so as to be able to displace reliance on higher-cost peaking capacity;

- Old and inefficient generation that under normal circumstances should be decommissioned will be incentivised to remain in service; and

- Placing undue reliance on "spigot control" has the potential to politicize the determination of x "need" for new capacity -- undermining the commercial aspects of the WEM.

- Just to name a view.

- The option of limiting capacity credits to Category "A" resources only would have the potential of reducing the amount of excess reserve capacity by as much as 700 MW virtually overnight. Such an extreme change would merit a transition arrangement so as to avoid signaling an increase in opportunistic regulatory risk in the WEM, which could have unintended consequences with respect to longer-term investment incentives. By the time one works through the design of a transition arrangement, and works through the on-going harmonization of demand resources with supply resources, it seems unlikely this would be a worthwhile approach.

6. A price-base adjustment was therefore seen broadly as a natural response to excess capacity in a market environment, even if some considered a quantity-based approach (spigot control) desirable from a value management perspective.

7. The group discussed a full range of price-base mechanisms:

- Promote bilateral contracting – market price discovery – using a buy/sell spread approach;

- Auction – "spot" market for excess capacity credits; and

- Managed formula – modification of existing RCM methodology.

8. Under the "buy" / "sell" spread approach the IMO would purchase excess credits from generators at a steep discount and would sell available excess credits to retailers at a steep surcharge:

- The intent would be to encourage bilateral contracting to discover market prices;

- If significant excess reserve capacity exists, the result would be that the discounted buy-price would set the floor. If very little excess reserve capacity exists, the surcharged sell-price would likely dominate;

- An open "uncapped" and "unfloored" auction would produce similar outcomes, with excess reserve capacity attracting floor prices and prices tending upwards towards "infinity" as shortage looms;

- By increasing the spread between the buy and sell price, more bilateral contracting, or less, would be encouraged;

- It was not resolved what to do with the IMO's collected funds.

9. Most importantly, the use of a buy/sell spread would complicate the administration of commercial contracts that have terms linked to the RCP. The buy/sell spread approach would require a significant renegotiation of existing contracts, and is therefore not recommended.

10. An open auction approach would clearly produce "market prices" and would immediately solve the excess reserve capacity "value" problem, but it would be highly susceptible to the "zero" or "infinity" problem that arises when capacity credit values are determined against hard targets in the short-term. If there were many excess capacity credits, the market value (the value to end-users of the reliability benefits the excess credits represent) quickly goes to zero. As shortage looms, the value appreciates quickly towards infinity if the auction is not capped.

11. Efforts to impose caps, floors, limits or transition mechanisms to constrain the resulting "market-based" price discovery would move an open auction or broad buy/sell spread approach towards a managed model. The result was generally agreed to resemble a managed slope adjustment approach, at least during a transition period. The question is merely what form and extent of constraint and managed structure is best suited to the WEM.

12. An auction approach is clearly a desirable long-term target because it has the potential to establish credible market prices. However, the complexities of auction design and competitive price discovery in a small, lumpy market are no small challenge – more difficult than in a much larger electricity markets, like the PJM market in the USA, which has a successful, though evolving, auction-based mechanism.

13. The auction approach would likely require a complex set of auction processes:

    - Multiple and progressive capacity auctions for each capacity year,
    - Validation mechanisms or penalty regimes for new capacity that participates in auctions prior to certification;
    - A secondary market mechanism that allows auction participants to adjust their capacity position between auctions; and
    - Various value management features, such as caps or floors or slopes (demand curves) as have been needed in other markets to reduce or mitigate the risk of excess volatility.

14. We therefore propose to adopt a price-slope formula together with a suite of associated changes designed to improve the RCM by making it more responsive to market conditions and less likely to incentivise un-needed capacity while also being more likely to support timely new capacity (of the right type) when needed in the future.

15. Proposal:

- Redefine the MRCP to reflect its role as the Long-Term Indicative Peaking Technology Support Price;
- Allow the RCP to increase above the MRCP by no more than 120% to increase risk in the capacity market for retailers, as this creates a natural incentive to pursue contracting as excess reserve capacity reduces and to reduce reliance on contracting when excess reserve capacity increases.

- Steepen the “slope” from -1 to between -3 and -5 to increase risk in the capacity market for resource investors, as this creates a natural incentive to prefer contracting when there is excess reserve capacity and to prefer not-contracting when there excess reserve capacity reduces—precisely the opposite as the retail position;

- The intent of relaxing the RCP cap and steepening the slope is to present a more balanced (more symmetrical) set of incentives and risks to both generators and retailers, while avoiding the “zero” / “infinity” valuation problem of an open auction.

16. Forecasting error was identified as a separable challenge in the WEM

    - Short term forecasting uncertainty related to block loads that were part of the RCR but that which do not materialise is a risk to the effective working of the RCM, potentially resulting in costs borne by retailers and end-users;

    - The desirability of reducing this risk was discussed but no proposal has yet been developed.

    - If such a proposal can be developed it would complement and supplement the price-based approach proposed in this note.

17. A possible transition implementation:

    - For the first year, set the maximum RCP at 110% and the slope at -3.25 – minimising initial value disruption

    - In each subsequent two years, move the maximum RCP up 5% and the slope by a further -0.75, such that the 2nd year is RCP max at 115% and slop -4.0 and 3rd year, RCP max at 120% and slope at -4.75.

Report

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# Capacity Refund Proposal: Brief Review


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# 1. INTRODUCTION

## 1.1. SCOPE

The Lantau Group (HK) Limited (TLG) has been asked to provide a peer review of changes proposed to the Reserve Capacity Refund (RCR) scheme.

In this review we set out the current proposals and then assess their impact and consistency with the overall Reserve Capacity regime. In conducting this review we have had regard to the Wholesale Market Objectives as set out in Section of 122(2) of the Electricity Industry Act and repeated in clause 1.2.1 of the Market Rules and the report by the IMO entitled "Review of Capacity Cost Refunds" dated 22 February 2011" (referenced in this paper as "RCCR"). TLG has also been reviewing other aspects of the Reserve Capacity Mechanism (RCM). Insights from that on-going review also inform our views of the Reserve Capacity Refund scheme.

A change to the way the RCM responds to market conditions will affect the value at stake when refunds are triggered. Alternatively, a change to the refund regime will affect the value and effectiveness of the overall RCM. We therefore have advised the IMO board that a change to the capacity refund regime should be considered in conjunction with potential changes to the RCM arising from the broader RCM review.

## 1.2. THE CURRENT REGIME

The RCM and the capacity refund regimes currently operate as follows:

- The IMO determines the minimum Reserve Capacity requirement three years in advance;
- Asset owners or developers seek accreditation for their capacity to meet the IMO's requirement. (Other steps occur if there is a need to induce additional capacity into the market);
- Accredited capacity can enter into bilateral arrangements with loads or, failing that, can receive a flat monthly payment from the IMO at a price established by a process set out in the Market Rules;
- If the accredited capacity fails to perform as certified when it is called upon by System Management, then it must refund a portion of the capacity payment it has received or is expected to receive during the relevant Capacity Year.

The IMO describes the capacity refunds regime as a commercial contract in which capacity providers are contracted to meet certain standards of service.

## 1.3. CURRENT SITUATION

Currently there is excess reserve capacity in the WEM. As a result, the economic value of incremental reserve capacity is substantially below the administered capacity credit price paid by the IMO (and which has been the basis for capacity refund obligations). Furthermore, this means that the costs imposed on generators who are obligated to make refund payments can exceed, potentially greatly, the economic value at stake when an event occurs that triggers a refund obligation.

The IMO's analysis (see Figure 1) highlights the substantial disconnect between the current refund amounts and market conditions.

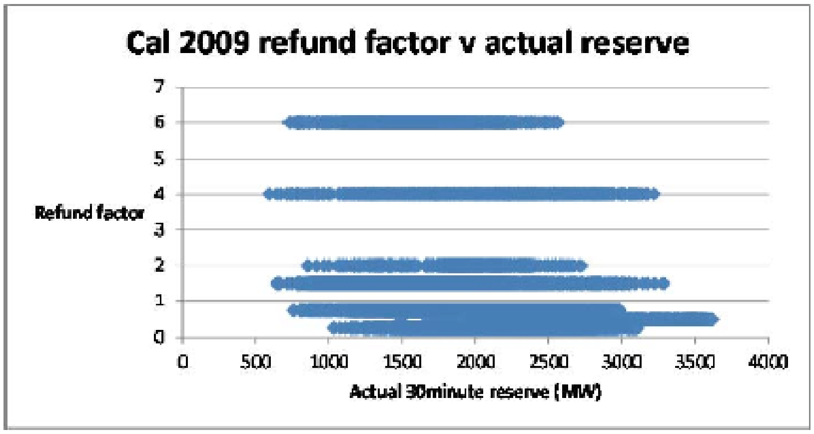


**Figure 1: IMO Analysis of the calendar 2009 refund factor vs. actual reserve**

The existing refund mechanism applies a set of "refund factors" that vary according to specific time periods, rather than to system conditions. The correlation between available reserve at a point in time and the applicable refund factor is, as a practical matter, zero. A generator can be exposed to a refund factor of 0.25 all the way up to 6.0 even if there is always 2500 MW of 30 minute reserve available. Conversely, a generator can be exposed to a refund factor ranging from 0.75 up to 6.0 when available reserve falls below 1000 MW. A generator has an incentive to ignore system conditions when scheduling maintenance, as the larger exposure is potentially to the refund factors themselves.

## 1.4. THE IMO'S PROPOSAL

The IMO's proposal would establish a dynamic regime that links more clearly to market conditions. Under the proposal, exposure to refunds would depend, in part, on the amount of reserve capacity available rather than on predefined time periods.

The idea of flexing the value of capacity refunds with the amount of excess capacity makes good sense. But how tight should the relationship between refunds and economic value be? During periods of excess capacity, the economic value of an incremental MW of reserve capacity can be extremely low. Conversely, during periods of looming shortage, the economic value of access to one more MW of reserve capacity can be extremely high. A regime that fully reflected short-term market conditions has the potential to be extremely volatile.

The IMO's proposal retains the use of refund factors which supress this volatility. The refund factors cap the maximum refund exposure and set a floor for the minimum obligation. Implicitly the factors imply that a trade-off between the accuracy of the economic signal and risk profile that is transmitted by that signal to stakeholders. This same question of how sharply to align the value of capacity credits with the economic value of reserve capacity is also relevant to the broader review of the RCM.

The linkage between the capacity refund regime and the value of capacity credits in the overall RCM is an important one. Given current excess reserve capacity, the proposed dynamic refund regime would reduce the value of refund payments. A reduction in capacity refund exposure without corresponding reduction in the value of capacity credits would increase the expected value to generators from the overall RCM. Perversely, such one-sided change would increase the incentive to bring more capacity into the WEM at a time when the economic value of such incremental capacity is close to zero.

Linking changes to the refund regime to changes in the broader RCM would reduce the risk of unsynchronized and unintended effects.

# 2. ASSESSING THE DYNAMIC PROPOSAL

## 2.1. OVERVIEW

The proposed changes to the RCR regime represent an improvement in the form of the existing design. But we have concerns related to the potential disconnect between changes to the RCR and the workings of the overall RCM. Sensible changes to the RCR regime that are implemented without making corresponding changes to the RCM can introduce distortions. One concern is the focus on efforts to reduce cost of the RCM through the implementation and design of the RCR regime. Another concern is that the design and implementation of the RCR at times attempts to treat blurs the distinction between capacity and energy as wholly separate products. We therefore have included a brief comment on the distinction between these two products in the context of the WEM.

Furthermore, by considering changes to the RCR *in conjunction* with those to the RCM, it might be possible to identify a more fundamentally robust mechanism.

## 2.2. IDENTIFIED ISSUES AND OBJECTIVES

The RCCR identifies a number of issues and objectives underlying the choice of the proposed refunds mechanism.

- **Long-term incentives**. The stated intent of the refunds mechanism is to "incentivise long term maintenance activity which will minimise future risk to system security and system reliability." [RCCR, p. 90] In particular, there is a strong feeling that episodic refunds provide an insufficient motivation to provide a consistent incentive and that the lack of a consistent refund may lead to "free-riders." "The profile can be structured so the probability of the peak refund not applying at any time 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." [RCCR, p. 95]

- **Short-term incentives.** A second stated intent is to "Incentivise short term behaviours to ensure day to day operation and maintenance activities are directed to maximising reliability at time of greatest value, generally when actual reserves are lowest." [RCCR, p. 90] It is interesting to note, however, that the short-term incentive is not really an incentive to make capacity available. "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." [RCCR, p. 95]
- **Fairness.** A key issue that arises is the differing treatment of baseload and peaking generators. "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." [RCCR, p. 90] Similarly, the proposal "provides a refinement that creates incentives for both short and long term scheduling of maintenance effort and more equitable treatment of different forms of capacity." [RCCR, p. 93] "As far as practicable all capacity providers should be treated equally." [RCCR, p. 103]
- **Level of refunds.** We understand the *level* of refunds overall to be an issue in the design of the mechanism. If the overall RCM is considered too generous, then a reduction in the level of refunds without a commensurate change to the RCM would make the RCM more generous. The temptation therefore is to design or adopt a modified refund regime that does not reduce the overall level of refunds. The alternative, which we recommend, is to view changes to the refund regime in the context of the outcome of a broader review of the RCM.
- **Volatility of refund revenues.** Volatility of refund revenues is also understood to be a concern. The issue of volatility arises in relation to the shape of the refund/reserve level relationship. "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." [RCCR, p. 92]

In general, this seems like an appropriate list. Our main concern is with respect to the emphasis on maintaining the level of refunds and keeping down the overall cost of capacity. Forcing the cost of refunds to be above the associated economic cost of outages in order to achieve a "discount" to the cost of capacity has the potential to introduce other distortions that can undermine the effectiveness of the overall RCM. If the overall cost of capacity is too high, then other steps can be taken to bring that cost into better alignment with the economic value of capacity. The objective of keeping down the overall cost of capacity is best viewed as the purview of the RCM rather than the RCR regime, which is just a component of the overall RCM.

## 2.3. THE CAPACITY PRODUCT

The concept of reserve capacity is central to an understanding of the refunds regime and to the RCM itself. Capacity as offered into the RCM is a specific product. The rights and responsibilities associated with this product – and the associated payments and the allocation of costs – flow naturally from its definition. In order to provide clear guidance, however, it is crucial to define clearly what capacity is – and what it is not.

"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… Specifically the capacity refund mechanism requires a Capacity Credit holder to make repayments to the IMO if the capacity is not presented." [RCCR, p. 89]

The WEM, unlike the NEM in eastern Australia, can be characterised as a two-product "market". One product is sold through the bilateral energy market (and centralised balancing mechanism) that provides for the provision and delivery of energy in each hour. This capacity product may be bundled within a bilateral contract, or be provided via the centralised and administered capacity "market" associated with the RCM.[1] Given the existence of these two separate products, the requirement that capacity be made "available to the market" is a somewhat ambiguous statement. The fact that the obligation to make repayments exists in all hours – even when the possibility of shortage is virtually non-existent – suggests that there is some lingering expectation that the capacity procured through the RCM should be available to supply energy at all hours of the year.

In theory, however, this capacity product is entirely separate from the energy product. It does not provide for energy per se – that is the purpose of the energy market. The RCM is intended to compensate generators for providing capacity that is *able* to generate energy under situations of scarcity. Capacity as a separate product has no value at any other time.

These situations of scarcity are intermittent and occasional occurrences. While some capacity mechanisms have tried to compensate generators only during these conditions of scarcity, these markets proved ineffective. Accordingly, it has become common practice to provide capacity payments on an on-going basis throughout the year, as is done in the WEM through the RCM. As noted [RCCR, p. 88], "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."

Nonetheless, we must not confuse the terms of payment with the nature and value of the service being provided. While *payment* is continuous across the year, the *nature* of the service, and its intrinsic *value*, is episodic.

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1 The RCM is technically better characterised as a "mechanism" and not a "market". The price and quantity of capacity procured does not adjust freely as they would in a market. Nonetheless, the RCM has a clear impact on merchant investment behavior in the WEM, so the use of the term "market" in this context is valid.

We must also distinguish the capacity in the RCM from the notion of “capacity” embedded into many bilateral contracts (or PPAs). These contracts give the buyer the right to purchase the energy from a generation facility whenever it is available at a price that approximates its dispatch cost. In return for this right, the buyer commits to a stream of “capacity” payments. Capacity in this sense is a bundled product. It not only compensates the generator for providing capacity that is able to generate under conditions of scarcity, but also provides compensation for the difference between the dispatch cost of the energy and its market value.

The capacity in the RCM is not intended to be a bundled product – it is pure capacity in the reliability sense. Because “capacity” in a bilateral contract is a bundled product, the contract must contain restrictions and incentives to ensure the provision of energy. The capacity product in the RCM needs no such requirements. To the extent that such restrictions or incentives are required, they are (or should be) established via the energy market.

The importance of the WEM as a two product “market” is that the value at stake when an accredited source of capacity fails to present itself depends entirely on market conditions (supply and demand) at the time. The simple failure to provide energy has no consequence for the capacity market except under shortage conditions.

## 2.4. Linkages with the RCM

The quantum of refunds payable is based on the administered capacity price. The administered capacity price is the subject of at least two on-going reviews, including the review of its constituent assumptions and parameters as well as our own review of the RCM in which we consider the basis for adjusting the administered capacity price to reflect the overall supply and demand for capacity credits. In our review of the RCM, we highlight how the current, essentially proportional, adjustment to the administered capacity price materially understates the extent to which the economic value of reserve capacity declines as the amount of excess capacity increases.

An economic-based adjustment in the administered capacity price to reflect excess capacity credits would make the administered capacity price more dynamic (and thus more volatile), but it would also have the impact of greatly reducing the penalty associated with capacity refunds during periods in which there is excess capacity. We think that this linkage should be an important consideration in the design of the RCR scheme. Changes should not assume continuity of the current administered capacity price.

## 2.5. Interactions between the RCR and the RCM

In concept, the “dynamic refund regime” is an improvement on the existing static scheme. However, the RCM and refund regime clearly interact in ways that shape incentives in the WEM. In this section we take a brief look at some aspects of the RCM and capacity refunds regime together:

1. The RCM pays generators for their full capacity, but then requires rebates in the event of forced outages.

- An improvement that would both sharpen the incentive for reliability and potentially address value transfer concerns is to pay generators for their de-rated capacity and allow them to earn credits or expose them to refund obligations depending on whether they exceed or fall short of "standard" performance. A "symmetric" regime in which there are rewards as well as refunds could be set up such that the *expected* level of *net* refunds is essentially zero. Such a "symmetric" approach would be a pure incentive regime;

- Failure to set refunds so as to fully reflect the cost of outages means that the refunds will not actually relate to the economic costs associated with failing to behave as intended. The current "asymmetric" approach means that an "economic" refund signal would introduce significant volatility but without any offsetting beneficial incentive to actually aim for better performance on average over time, as there is no potential reward for improved reliability above the certified capacity level;

- It has been noted that current capacity prices may diverge from the historical prices for capacity embedded into contracts. The current refund regime and the IMO's dynamic proposal involve value exposure for those generators whose contract capacity prices diverge from current market prices. This exposure would not exist (or would be much smaller) for a symmetric system.

- The asymmetric system relies on forced outage-related refunds in order to align the net cost of capacity with its value. Assuming all the parameters are set right, such a system might arguably work well for baseload generators, as these are likely to suffer forced outages on a regular basis. But it does not work well for peaking generators, since they are rarely called (and will be called even less often during periods of excess capacity)[2]. Ensuring equitable treatment requires the creation of some parallel means of valuing reliability (such as the operational testing). Under a symmetric system, peaking generators could be deemed to have a standard forced outage rate and compensated on that basis until they have enough dispatch events to estimate a specific forced outage rate.

2. The refund levels are far too low to act as appropriate short-term signals when capacity actually has value. Given the capacity price and a reasonable VoLL estimate, the annual LoLP should be on the order of 10-15 hours under equilibrium conditions. This suggests that the capacity refund should be 500-1000 times the average hourly capacity price under a loss-of-load situation. But the proposal caps the refund at 6 times the hourly price – two orders of magnitude lower than the potential outage cost. This refund level seems far too low to incentivise short-term behaviour in situations in which capacity has high value – which, of course, is the only time that these price signals are relevant.

2 Perversely rewarding peaking generators the most when they are valued the least.

3. The refunds apply only to capacity underage associated with forced outages. The value of capacity, however, is indifferent to whether an incremental MW arises by avoiding a capacity underage or creating an additional MW of capacity that was not otherwise being compensated under the RCM. If short-term price signals are to be used at all, there would appear to be no reason not to use them as an incentive to create additional capacity under shortage conditions when capacity has high value. While such short-term price signals could, in theory, create possibilities for the potential abuse of market power, the existence of the RCM contracts should act to mitigate such potential.

4. The desire to set charges low so as to minimise the volatility of refunds seems misplaced. In order to induce efficient behaviour, short-term signals should reflect the underlying value of capacity. If the volatility of refunds associated with such prices is truly a concern, then it may in fact be appropriate to institute some form of "insurance" to reduce this volatility. This could be done via a system analogous to "co-payments" for health insurance. In other words, rather than distorting the price signal represented by the refund price, part of this cost could be met via an insurance pool funded by generators making payments proportional to their forced outage rates. In the event of an outage, the majority of the refund would be paid by the insurance pool; the generator itself would make a much smaller payment. Note that the "symmetric" structure described above effectively creates such an insurance pool.

5. If refunds are to recover the expected cost of outages, setting the refund levels far below the outage cost under true shortage conditions means that charges must be set above the true cost of outages in many more hours. While there is some benefit to spreading the charges out across enough hours so that they are not simply a random and episodic price signal, spreading them across too many hours creates a diffuse short-term price signal that fails to reflect the true outage cost.

# 3. RECOMMENDATION

The proposed dynamic regime is an improvement on the existing regime in that it does incorporate market conditions in the setting of the refunds. Implementing the proposed dynamic refund regime without making any other changes to the RCM itself, however, would have the effect of reducing refund exposure to generators. We therefore recommend consideration of the refund regime only in the context of the broader review of the RCM.

A change to just the refund regime in the direction of the proposed dynamic refund scheme would result in a perverse outcome. Generators would implicitly receive a higher "expected value" of capacity at a time when the economic value of reserve capacity is nearly zero. A more integrated solution would be to link changes to the refund regime to changes in the RCM itself. A consistent change, for example, would see the introduction of a more market-based price paid by the IMO for capacity credits. In a period of excess capacity, that price would be lower. That lower price would also flow through to the capacity refunds regime.

Other possible changes to the refunds regime include adding a symmetric aspect to it such that penalties for failure to present capacity can be offset to a degree by the ability to present more capacity than has been accredited. A derating-based refunds regime could then be constructed in which the cumulative value impact of the refunds would be essentially zero over the course of a year, but the desirable incentive aspects would each be enhanced. Such a refund regime would make the most sense in the context of possible changes to the RCM to introduce more economic pricing of those capacity credits that are not traded bilaterally.

We caution against early adoption of the dynamic refund regime even though it is clearly an improvement to the current static regime. Instead, we recommend that the IMO explicitly consider the interactions between the RCR scheme and the RCM and coordinate proposed changes.

# Reserve Capacity Mechanism Working Group Discussion

**Everyone**

4 July 2012

THE LANTAU GROUP
strategy & economic consulting

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## Agenda

- What is the problem? / Is there a problem?
- History
- Options
- Way forward

What is the problem? / Is there a problem?

## Setting the scene – some issues currently perceived about the RCM

- Excess reserve capacity currently
  - This might be OK if the costs were not high
- The MRCP review and other reviews have greatly increased uncertainty – changing the RCP value significantly over a short period
- Administered (regulated) mechanism determines price of Capacity Credits that are not traded bilaterally
  - (and may influence bilaterally traded prices or availability of bilateral contracts)
  - What is the basis for value?
- Economic value of excess reserve capacity to consumers (to WA in general) is less than the value rewarded by the RCM
  - What happens when more value is attributed to something than it is worth?
- Retailers cannot hedge exposure to RCM
  - Bear costs associated with excess reserve capacity if they hold bilateral contracts
  - Incentive to minimize bilateral contracts
- Retailers are protected by RCM structure
  - Compared to other forms of capacity market mechanisms elsewhere
- RCM supports investment and works fine
- Resources have too much incentive to incest in the WEM, even when resources are not needed
- Too easy for resources to get credits

## Design challenges

- Must work in a small, lumpy market, with relatively highly concentrated stakeholder positions in the retail and generation sectors
- Should avoid the “zero” / “infinity” problem – in which credits are worth nothing when there is too much, and more precious than gold when there is too little
- Should be mindful of costs and risks borne by end-users
- Should have some degree of “self-correctedness” -- should not work against natural incentives
- Should support some degree of reasonable hedging
- Should not discriminate against different types of resources



## Some basic realities

- Excess reserve capacity has value – just as all capacity has value – because it contributes to a reduction in risk of supply shortage
- The economic value (to end users) declines rapidly with more reserve capacity
- End-users should not want to pay any more for excess reserve capacity than it is worth to them
- Capacity and energy together, not just capacity
- If we make end-users pay more for excess reserve capacity than it is worth to them, then we need to be mindful of the risk that we are incentivising excess investment
- If we push risks into the investment environment, we need to be mindful of the risk of reduced investment or higher financing investment costs

History

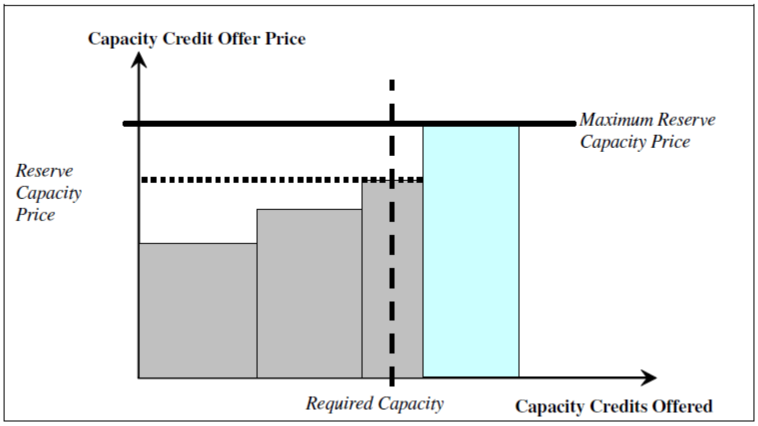


## History (Brendan Clarke)

- The incentive for retailers to contract is that they would end up with a high cost solution as they would only be able to buy high energy priced energy from the IMO. The incentive for generators to contract is that they would receive no capacity credits to maintain their investments.
- What was the philosophy if the total capacity procured by the retailers is less than that that would have been procured by the integrated utility forecast?
  - The Reserve Capacity Mechanism was put in place as reliability back stop. (this is my recollection not an opinion from the market designers). This is embodied in the following philosophy
- “The primary role of the Reserve Capacity Mechanism is to ensure that there
  - is adequate generation and Demand Side Management (DSM) capacity available each year to meet system peak demand plus a reserve margin.” *Source Wholesale Electricity Market Design Summary*
- The IMO would intervene (run a capacity auction) if the reliability criteria was not met that is total capacity procured by the retailers was less than that that would have been procured by the integrated utility forecast.

## History 2

***Exhibit 7-1. The Reserve Capacity Auction***






## History 3

- "In determining which bilateral trades can contribute to satisfying the required Reserve Capacity, the IMO will generally accept bilateral trades in order of decreasing availability until all trades are exhausted or until the Reserve Capacity requirements are satisfied." *Source Wholesale Electricity Market Design Summary*

- I suggest that this philosophy means the intent of the RCM is that Capacity offers above the required capacity are not allocated capacity credits. (this is my recollection not an opinion from the market designers)

## Some questions for discussion

- Can a generator or demand resource actually “enter” without a commitment to a credit? – How to reconcile the use of an auction with the existence or need for capacity to participate in it?
- Where does market power fit into this picture?
- Does the description of how history was supposed to work comport with the reality of commercial market operation?
- If a resource can provide capacity, why not issue it a capacity credit and let the value be determined in the auction process?
- Why was there a maximum reserve capacity price? What is its purpose?
- What happens if too little capacity is available? Is the supplementary auction enough?
- Who decides what type of capacity (existing vs new) is best suited to provide capacity?
- If capacity exists or seeks to exist because the RCP is attractive, what is the point of keeping the RCP high and preventing entry?



Clean sheet of paper approach

## Why not start with a clean sheet of paper

- Open reserve capacity auction – no caps, no floors
- Each year or when needed
- Free to bilaterally contract if, as and when desired
- Full market-based pricing of capacity and free choice of risk management strategy
- Retailers (Load Serving Entities) must demonstrate they hold the right number of credits at end of each period
- No administrative back up or pricing formula



## Auction basics

- If there is ample competition and no market power – you don't need caps or floors
- If you are not sure the auction will be competitive or if you are not sure of your own valuation
  - You set a reservation price
- But the auctioneer never caps the auction price!
- A retailer exposed to an uncapped auction price will have to devise a risk management strategy
- Auction price caps are intended to protect retailers (buyers) from seller market power

## Auctions basics (cont)

- If all capacity is forced into an auction without an "offer", the auction will clear at 0 if there is a surplus available, and it won't clear if there is a shortage ("infinity")
- Resources will need to be able to offer a sale price into the auction
- Given that capacity is essentially "sunk" once it is present in the WEM, capacity auction results would reflect, to some extent, market power – or any other constraints imposed
- Different auctions at different times may have very different results due to the particular allocation of credits being auctioned (who owns them, how concentrated is the ownership, etc)



## Open Market Observations

- If the "spot" market or auction process is highly volatile and risky → natural incentive to hedge that risk in bilateral market
- Natural incentive for bilateral market and short-term market to track each other
- Extreme case would be an energy-only market – highly volatile short-term market, with extensive use of contracts as risk management instruments
- WEM is not an energy-only market. Nor was it designed to be highly volatile
- But without risk in the capacity market, there will be uncertain incentives in the bilateral contract market

## Two-sided

- Removing risk to retailes from bilateral contracting
  - MRCP caps the RCP
  - The negative slope reduces the RCP with excess capacity
  - No super-strong penalties from being at risk of being under contracted
- Increases risk to generators
  - Difficulty obtaining long-term contracts
  - Increased cost of financing
  - Greater exposure to regulatory risk (reduced long-term certainty)
- And vice versa



## Options (open discussion)

## Interpretation and implementation of MRCP

- Based on a standard reference technology
- Set up as an expected value
- Treated as a maximum value in the RCM
- Risk increased in RCM that long-term investment will be impaired
- 85% of MRCP value is used to set RCP for IMO purchased/sold credits
- The MRCP construct is inconsistent with its use → a risk to the future



## Options for role of MRCP

- Treat MRCP as an expected value – allow RCP to exceed MRCP?
  - What about in short-term auctions?
- Change nothing?
- Choice has significant implications for the interpretation and implementation of virtually all other options.

## Options

- Spigot control
- Synergy proposal (truth telling + auction)
- Buy/ask spread – bilateralism
- Managed formula
- Do nothing
- Other?



## Spigot control

- If there is excess capacity in the RCM, should further capacity credits be issued?
- In markets, when capacity can enter a market freely, the price adjusts to signal when to stop and when more is needed
  - Markets create oversupply and undersupply sometimes
  - Look at US shale gas market for an example of a rampant oversupply and a price response
- Markets that throw up barriers to entry whenever there is “enough” tend to be more insulated and are at risk of being less innovative
  - Again, look at US shale gas – there had been ample “capacity” in the US market before
- On the other hand, the RCP is an administered price and not a free-flowing market price
  - Some degree of quantity control is merited just because the administered price could be wrong and might not adjust enough

## What should be the basis for enhanced “spigot” control

- What should be the basis for enhanced “spigot” control?
  - Merely the existence of excess reserve capacity?
- What protections should those who are uncontracted be provided by spigot control?
  - Why should an uncontracted genco investor be protected against new entry risk?
- If the value of reserve capacity credits to customers is less than the reserve capacity price, doesn’t spigot control merely lock in higher costs to end-users?
- What are the elements that should be considered in determining eligibility for capacity credit certification?



## Who wins and who loses?

- Spigot control protects uncontracted resources againt the impact of new entrants who, as a result, might reduce the value of capacity credits
  - Is this a good thing?
  - Why?
- Spigot control protects retailers from excess capacity costs given an RCM that does not price-adust effectively
- Spigot control can hurt consumers if it limits innovation and protects higher cost resources in the energy market?
- Would spigot control effectively throw up a barrier to entry that can be used by older capacity resources to prevent newer resources from gaining access to the market (financing costs, etc)

## Structured discussion of Synergy Proposal

- Capacity making a bilateral trade declaration is ineligible from receiving an IMO reserve capacity payment
- Undeclared capacity goes into an auction which would set the clearing price
- If no auction then a high administered price would be set by the IMO to facilitate for capacity trades and allow the refund mechanism to function



## Synergy Proposal Discussion

- Consequence of a bilateral trade declaration?
  - What if a declaration fails to produce a bilateral trade?
  - What if retailers do not enter into a bilateral contract?
  - Will generation investors still invest if they cannot obtain a bilateral contract?
  - Why should "intentions" matter in any form of commercial market?
- Consequence if undeclared capacity goes into an auction?
  - What type of auction? How often?
  - If someone misses auction 1, when is the next opportunity?
  - An auction clearing price requires that there be a cleared auction quantity?
  - Should the cleared auction quantity be limited to the RCR? Or to all available capacity, needed or not?
  - How does the auction deal with the zero / infinity problem?

## Should there be some incentive to force more bilateral trades?

- Consequence of a punitive (high administered price) being set by the IMO to facilitate capacity trades in the event that an auction otherwise fails to clear?
  - Retailers who need credits would face the alternative of a high credit price – subjecting them to generator market power?
  - Would generators receive the high credit price – creating incentives for them to game the auction?

- If retailers pay a punitive price and generators receive a punitive price – they have an incentive to bilaterally contract?

What makes bilateral contracting preferable?



## Is bilateral contracting of capacity a desired end-point to be actively promoted?

- The WA WEM is often called a bilateral market – or, as we have put it, a market with a strong "bilateral DNA"

- The presumption is that bilateral contracting is to be encouraged as a "good" thing in its own right

- Taken to an extreme, this could imply the use of "penalty" values in spot transactions so as to incentivise greater reliance on bilateral contracting

## It would be easy (but not costless) to incentivise more bilateral contracting

- Punitively **high** values payable by retailers for capacity credits to cover uncontracted capacity / and punitively **low** payment values to generators for credits purchased to settle uncontracted reserve capacity requirements

- Market-based auctions that introduce greater credit price volatility (much higher in shortage, much lower in excess) – creating a natural incentive for parties to hedge through contracts to reduce financial risk

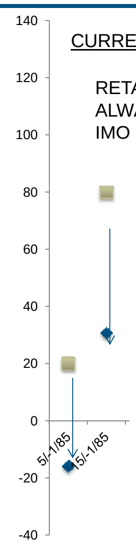
- Steeper “slope” mechanisms that raise the level of volatility – particularly insofar as the potential clearing price can be much higher or much lower than the expected value – a “managed” version of an open market pricing pricess

- Ironically, for a market alleged to be based on bilateral contracting, the current “managed” RCM, has limited incentives for stakeholders to bilaterally contract



## Current RCM settings do not favour bilateral contracting against any amount of excess reserve capacity *per se*

RETAILER COST (INCLUDING EXCESS CAPACITY)




CURRENT ARRANGEMENT

RETAILERS SHOULD ALWAYS BUY FROM IMO

5% EXCESS CAPACITY VS 15 % EXCESS CAPACITY
SLOPE = -1
MAX RCP = 85% * MRCP

All else equal…..

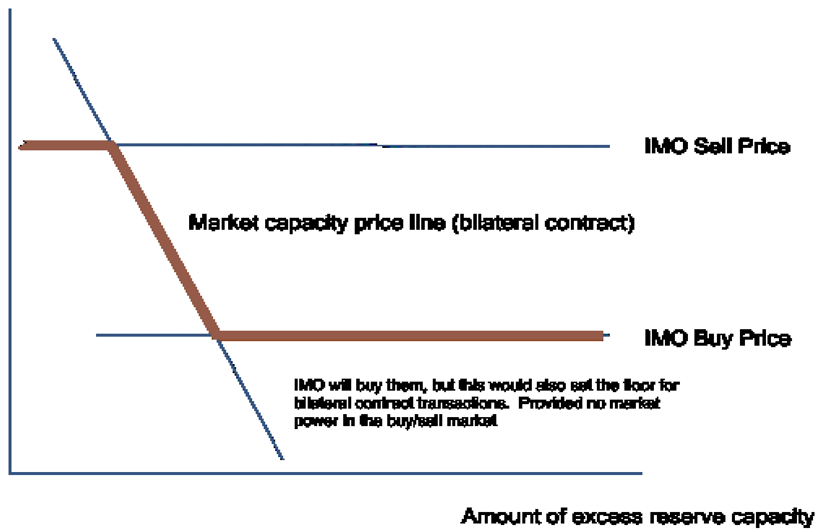
The only incentive to bilaterally contract is the belief that future RCM reviews or settings will be higher than present, such that locking in current costs is preferable

But hedging is not a strategy to manage exposure to excess reserve capacity, per se

This is because the IMO capacity credit price is always below the MRCP. As long as retail believes future MRCPs will be lower, it has no incentive to contract. If retail believes they will be higher, then you do.

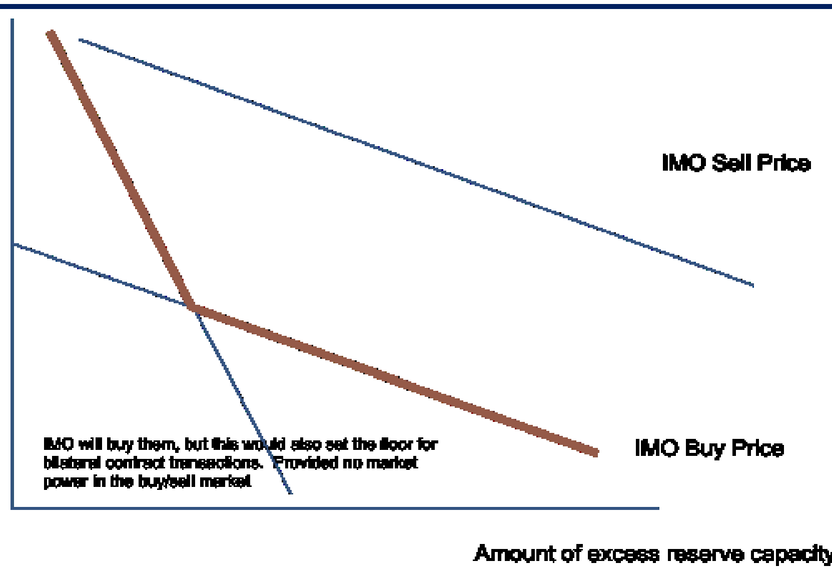
Is this intended?

Buy-ask spread approach (A) would clearly incentivise bilateral contracting according to the size of the spread






Buy-ask spread approach (B) can be incorporated in many other mechanisms



## What to do with the middleperson's profits?

- IMO receives the buy-ask spread
- Refund against fees?
- Refund to franchise customers (presumably those bearing the bulk of costs of excess capacity)?
- Something else?

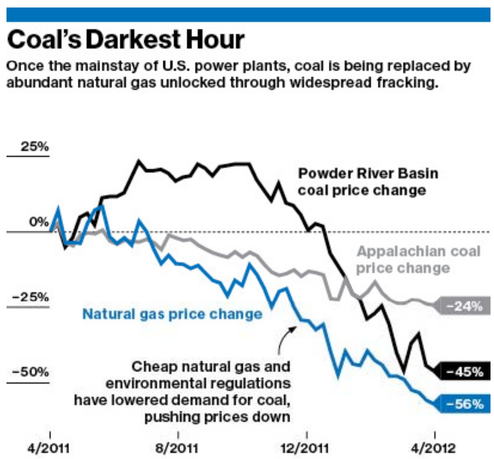


## Forecasting

- Currently we lock in the RCR 2.5 years in advance of a capacity year
  - In the interim, things can change
  - Recent changes have tended to be downward (less growth than expected)
  - The absence of an adjustment mechanism represents a cost
  - But what if it had gone the other way?

## Markets can change dramatically

- BusinessWeek’s obituary for American coal

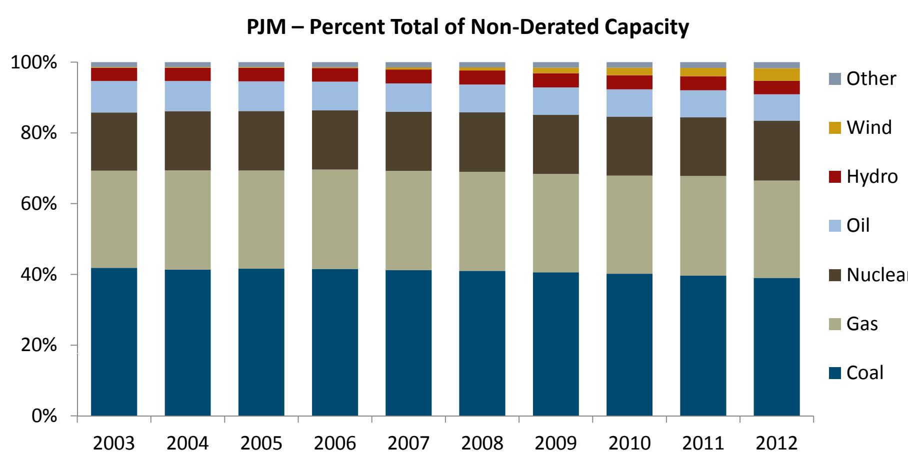



With the increase in demand for natural gas stemming from low prices, domestic demand for coal has declined.

Coal prices have also decreased in the US – though not as significantly as natural gas prices



## Market Opportunities Worldwide (PJM)

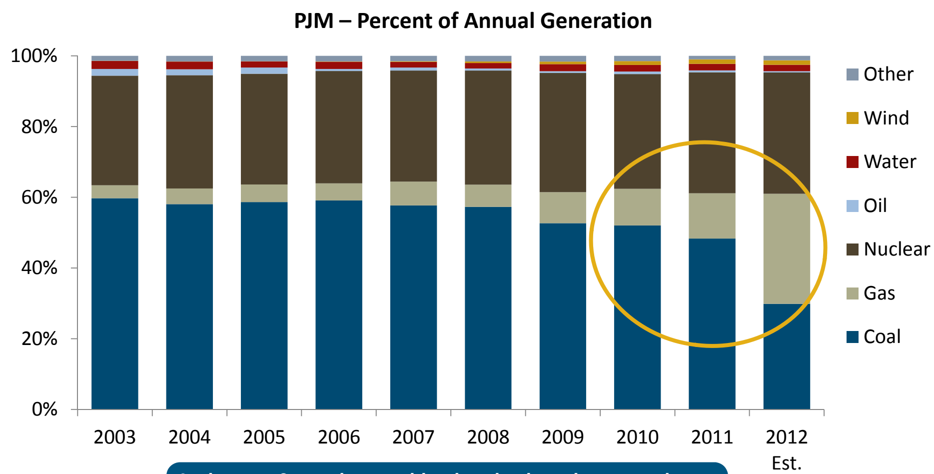



**PJM has traditionally been a coal and nuclear dominated market. There are many forecast coal retirements (about 20 GW) due to forthcoming air pollution regulations that take effect in 2015. But there is something even more interesting driving the market these days…**



Source: SNL Financial, TLG analysis

## Market Opportunities Worldwide (PJM)




**In the past 6 months, combined cycles have become a lower marginal cost unit on the supply stack than coal-fired units. This has radically reshaped PJM's generation profile.**

Source: SNL Financial, TLG analysis



## Forecasting is a dance with uncertainty

- Who bears the risk of forecast errors?
- Generators?
  - If uncontracted?
  - If contracted?
- Retailers / End Users
  - If contracted?
  - If uncontracted?

Some types of changes can dramatically
Increase the amount of reserve capacity
In the WEM – (eg., economic displacement)

Does the WEM facilitate efficient "exit"
Or should the capacity price remain high
even when other factors drive investment?

## Block loads are a particular problem in the WA context

- The projected holding requirements may need to reflect available information about these loads
  - If one gets to 1 year out and projected block loads have not (yet) materialised, should they be included or excluded?
  - What can be done to exact stronger commitments from block loads?
  - Should block loads be compelled to bilaterally contract to a minimum percentage in order to be covered?
  - What would be the implication if a block load could not be served in a given year?
- Should block loads be required to purchase capacity credits as an indication of firmness?
- Why should block loads be required to do so 2.5 years ahead of the entry decision?



## Other market-based mechanisms incorporate forecast error in reserve capacity requirements

- Say (for example):
  - 0.5 years out must hold 100% of updated RCR, failing which a supplemental auction is held
  - 1 year out, must hold 100% of updated projected RCR
  - 2 years out, must hold at least 90% of updated projected RCR
  - 3 years out, must hold at least 75% of updated projected RCR
  - 4 years out, must hold at least 60% of updated projected RCR
  - 5 years out, must hold at least 40% of projected RCR
- A capacity source that comes into existence “too early” still has value – but the value is related more to future growth in the RCR
- How many auctions and how many auction “products” are suitable for a small market like the WEM?
- Is the complexity a barrier to entry for a new retailer entrant?

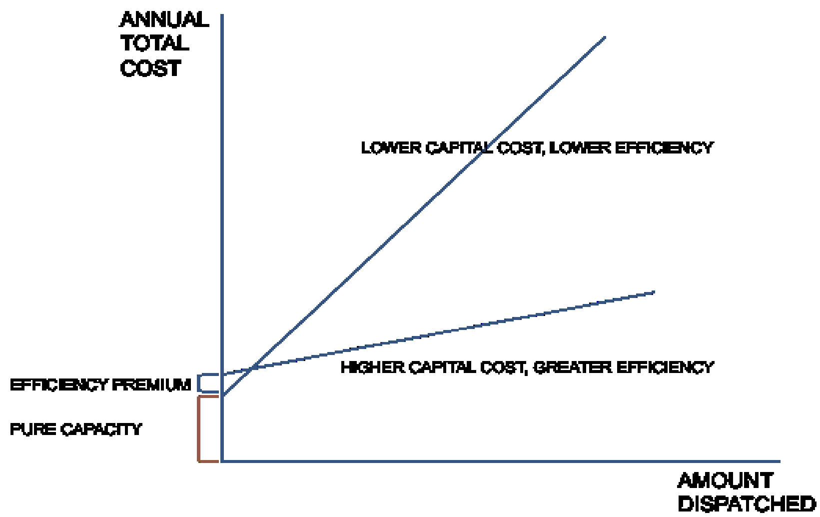
## Slope option

- The slope needs to be steep enough to curtail the risk of unnecessary investment aiming to be supported by excess capacity credits. This determines a minimum slope, which we have estimated to be at least -3.25 as that corresponds to a 15% discount to the reference capacity value. That may not be enough, of course, to absolutely stop all investment that is not needed. But it would certainly have a positive impact relative to the current formula.
- The resulting level needs to be high enough that the RCM can support new capacity when needed (and before relying on a supplementary auction, which is currently designed for essentially emergency situations). This requires that the RCP be able to exceed the MRCP as the amount of excess reserve capacity reduces towards zero.
- The value impact of the resulting slope and level should not be overly disruptive, if possible, so as to avoid or minimize the need for a complex transition mechanism



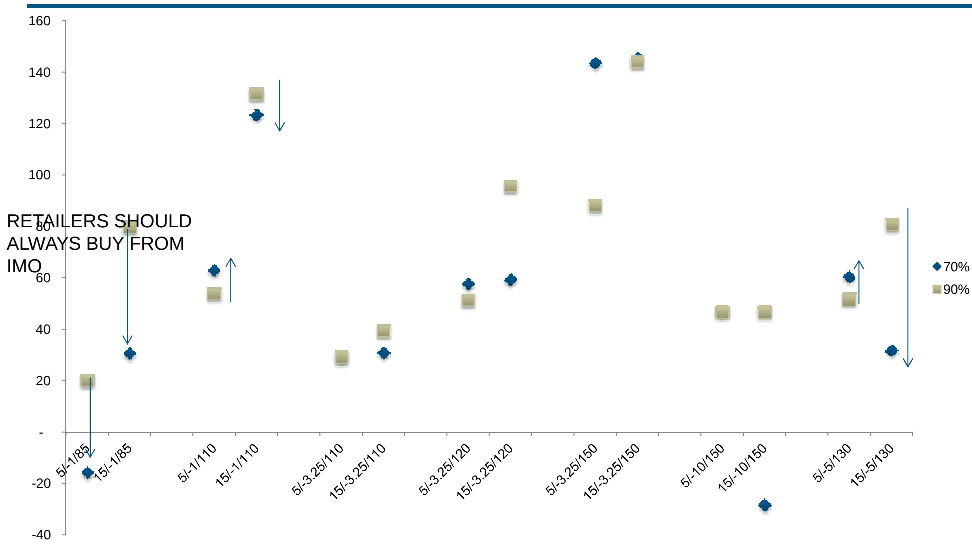
## Slope options versus MRCP of 163,900

| | 70% | 90% | 1 | 5 | 15 |
|---|---|---|---|---|---|
| 5/-1/85 | **-16** | 20 | **137** | **133** | **121** |
| 15/-1/85 | **31** | 80 | | | |
| 5/-1/110 | 63 | **54** | 179 | 172 | 157 |
| 15/-1/110 | **123** | 132 | | | |
| 5/-3.25/110 | 30 | **30** | 175 | 155 | 121 |
| 15/-3.25/110 | **31** | 40 | | | |
| 5/-3.25/120 | 58 | **52** | 190 | 169 | 132 |
| 15/-3.25/120 | **60** | 96 | | | |
| 5/-10/150 | 47 | **47** | 223 | 164 | 98 |
| 15/-10/150 | **-28** | 47 | | | |
| 5/-5/130 | 61 | **52** | 203 | 170 | 122 |
| 15/-5/130 | **32** | 81 | | | |






## SETTING THE MAX RCP > E-MRCP CHANGES INCENTIVES



**Independent Market Operator**

**Reserve Capacity Mechanism Working Group**

## Minutes

| | |
|---|---|
| **Meeting No.** | 5 |
| **Location:** | IMO Boardroom<br>Level 3, 197 St Georges Terrace, Perth |
| **Date:** | Thursday 12 July 2012 |
| **Time:** | Commencing at 2.05pm – 5.05pm |

| | |
|---|---|
| **Attendees** | |
| Allan Dawson | Chair |
| Suzanne Frame | IMO |
| Andrew Sutherland | Market Generator |
| Brad Huppatz | Market Generator (Verve Energy) |
| Ben Tan | Market Generator (arrived at 2.20pm) |
| Shane Cremin | Market Generator |
| Wendy Ng | Market Customer |
| Patrick Peake | Market Customer |
| Steve Gould | Market Customer |
| John Rhodes | Market Customer (Synergy) (proxy) |
| Andrew Stevens | Market Customer/Generator |
| Jeff Renaud | Demand Side Management |
| Peter Huxtable | Contestable Customer (proxy) |
| Justin Payne | Contestable Customer |
| Wana Yang | Observer (Economic Regulation Authority) |
| Paul Hynch | Observer (Public Utilities Office) |
| **Additional Attendees** | |
| Richard Tooth | Presenter (Sapere Research Group) |
| Mike Thomas | Presenter (The Lantau Group) |
| Aditi Varma | Minutes |
| Fiona Edmonds | Observer |
| Jenny Laidlaw | Observer |
| **Apologies** | |
| Brendan Clarke | System Management |
| Stephen MacLean | Market Customer (Synergy) |
| Geoff Down | Contestable Customer |
| Wayne Trumble | Observer (Griffin Energy) |

## KEY DECISIONS REGISTER

### A] HARMONISATION OF DEMAND SIDE AND SUPPLY SIDE RESOURCES (WORK STREAM 2)

- *The IMO to relax its requirement for Facilities to have firm fuel supply contracts in place if the capacity refund mechanism is assessed to provide sufficient commercial incentives for Facilities to be available when required.*
- *The revised DSM availability requirements for the 2013 Reserve Capacity Cycle will be as follows:*

| | |
|---|---|
| *Days of Availability* | *All Business Days* |
| *Dispatch events per year* | *Unlimited* |
| *Hours per day* | *6 hours* |
| *Total hours available* | *Unlimited* |
| *Earliest Start* | *10:00 AM* |
| *Latest Finish* | *8:00 PM* |
| *Minimum notice period of dispatch* | *2 hours + day before notice (best endeavours) of probable dispatch* |

- *All DSPs to provide a telemetry service that enables real time information on availability and performance to be recorded for the 2013 Reserve Capacity Cycle onwards (noting a period of transition to apply for existing DSPs, up to mid-2015)*
- *Remove the 'third-day rule' from the 2013 Reserve Capacity Cycle onwards — whereby a DSP dispatched for a third continuous day is not subject to capacity refunds.*
- *Incorporate into the Market Rules ability for DSP's to be dispatched outside of nominated availability limitations on a best efforts basis (i.e. with no implications for capacity refunds for non-performance).*

### B] RESERVE CAPACITY PRICE (WORK STREAM 1)

- *The IMO to include The Lantau Group's proposal into the final list of recommendations. The proposal includes:*
  - *Determine the slope and escalation factor for the Reserve Capacity Price.*
  - *Rename the Maximum Reserve Capacity Price to an expected or a benchmark Reserve Capacity Price.*

| Item | Subject | Action |
|---|---|---|
| 1. | **WELCOME AND APOLOGIES / ATTENDANCE**<br>The Chair opened the fifth meeting of the Reserve Capacity Mechanism (RCM) Working Group (RCMWG) at 2:05pm.<br><br>The Chair welcomed the members in attendance and noted apologies from Mr Stephen MacLean and Mr Geoff Down. In addition to the apologies he noted that Mr Brendan Clarke was absent and Mr Wayne Trumble was expected to attend the meeting as a requested observer. | |
| 2. | **MINUTES ARISING FROM MEETING 4**<br>The minutes were accepted as a true and accurate record of meeting 4. | |
| 3. | **ACTIONS ARISING**<br>Ms Suzanne Frame noted that work would be ongoing to assess the cost-effectiveness of proposed options for harmonisation of demand side and supply side capacity resources (Action Item 2). With respect to Action Item 7, she noted that the workshop on oversupply of capacity was held on 4 July 2012 and had most members in attendance. The Chair noted his appreciation for the members' participation in the workshop and also thanked Mr Mike Thomas for facilitating it. | |
| 4. | **HARMONISATION OF DEMAND SIDE AND SUPPLY SIDE RESOURCES (WORK STREAM 2)**<br>The Chair invited Dr Richard Tooth to present his paper.<br>The following points of discussion were noted:<br>• On the issue of firm fuel supply contracts, Mr Andrew Sutherland noted his agreement with increased flexibility in providing commercial incentives to improve reliability. He added that there are no force majeure provisions in a gas supply crisis, and that if incidents like Varanus Island or North-West Shelf happened, then generators should not have massive penalties imposed when gas prices are high. Mr Patrick Peake questioned the need for higher commercial incentives when, in his opinion, the capacity refunds are already sufficiently high to ensure adequate supply of fuel. Mr Shane Cremin observed that caution needs to be exercised because with increase in capacity refunds or penalties, incentives also get created to not be available in the first instance. Dr Tooth noted that proposed greater weight being placed on commercial incentives to ensure adequate fuel supplies had an inherent interdependency with the capacity refunds work stream.<br>• On the topic of performance requirements of Demand Side Management (DSM), Mr Jeff Renaud noted his support for the proposals, but he added that the current formula used for capacity refunds for DSM would have to be adjusted when new performance requirements are imposed. He proposed that DSM should be subject to the same capacity refunds table as generators. He noted this streamlining was important as currently DSM can lose a full year's capacity payments via the application of refunds for a total period of 24 hours. He also noted that there could be some benefits in reordering the Dispatch Merit Order. Ms Jenny Laidlaw noted that this had already happened through a Rule Change before | |

| Item | Subject | Action |
|---|---|---|
| | commencement of the Balancing Market.<br>• There was some discussion on how DSM is dispatched to cover the peak. Mr Cremin questioned how individual loads actually respond to a dispatch event- if the dispatch event is for a substantial number of hours, do the loads ramp back up at the end of the event? Mr Renaud responded that within EnerNOCs portfolio, different Demand Side Programmes (DSPs) will tend to be used differently to respond in accordance with the nature of the associated loads comprising that DSP.<br>• Discussion ensued on the flexibility available to System Management to dispatch DSM when they need to if the hours of availability of a DSP are increased to unlimited. Discussion also ensued on telemetry provision from DSM. Members also discussed what impacts they might expect to see if enhanced performance requirements are enforced on DSM.<br>• Mr Ben Tan queried if EnerNOC and WaterCorp would experience a significant reduction in the capacity of their portfolios as a result of the proposed changes. Both Mr Renaud and Mr Huxtable noted that it was difficult to predict at that moment, but that expectations would be that the structure of their DSPs would need to be reviewed and that associated loads that had limited flexibility to respond to the new requirements would exit the market.<br>• The Chair noted that the proposals presented would be recorded as key decisions.<br>• Mr Andy Stevens and Mr Renaud noted that the working group should define the system operating conditions when all DSM should be available for unlimited dispatch.<br>***Decision Points:***<br>• *The IMO to relax its requirement for Facilities to have firm fuel supply contracts in place if the capacity refund mechanism is assessed to provide sufficient commercial incentives for Facilities to be available when required.*<br>• *The revised DSM availability requirements for the 2013 Reserve Capacity Cycle will be as follows:* | |

| | |
|---|---|
| *Days of Availability* | *All Business Days* |
| *Dispatch events per year* | *Unlimited* |
| *Hours per day* | *6 hours* |
| *Total hours available* | *Unlimited* |
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| *Latest Finish* | *8:00 PM* |
| *Minimum notice period of dispatch* | *2 hours + day before notice (best endeavours) of probable dispatch* |

| Item | Subject | Action |
| --- | --- | --- |
| | • *All DSPs to provide a telemetry service that enables real time information on availability and performance to be recorded for the 2013 Reserve Capacity Cycle onwards (noting a period of transition to apply for existing DSPs, up to mid-2015)*<br>• *Remove the 'third-day rule' from the 2013 Reserve Capacity Cycle onwards — whereby a DSP dispatched for a third continuous day is not subject to capacity refunds.*<br>• *Incorporate into the Market Rules an ability for DSP's to be dispatched outside of nominated availability limitations on a best efforts basis (i.e. with no implications for capacity refunds for non-performance).* | |
| 5 | **DYNAMIC RESERVE CAPACITY REFUND REGIME (WORK STREAM 3)**<br>The Chair introduced Mr William Street from the IMO and invited him to present a brief history of the Rule Development Implementation Working Groups (RDIWG) previous deliberations on the development of a dynamic reserve capacity refunds regime.<br><br>The following points of discussion were noted:<br>• Mr Sutherland noted whilst the concept was considered workable in the RDIWG, the level of refunds themselves was too high. Mr Stevens agreed that the refunds were designed to apply at peak periods rather than at low reserve margin periods, making it a blunt proxy.<br>• Mr John Rhodes noted that the uncertainty of a dynamic capacity refunds would be difficult for a new generator entering the market. He added that Synergy would prefer a fixed refund profile for a new generator transitioning to a dynamic system after having been being commissioned for a year.<br>• The Chair observed that a dynamic capacity refund mechanism comes with a level of uncertainty which would put focus on System Management's outage approvals process.<br>• Mr Brad Huppatz noted Verve Energy's support for the dynamic regime but added that increasing risk and uncertainty must be balanced by a lowering of expected refunds.<br>• Mr Peake observed that a peaking plant is penalised steeply and unfairly when it is actually dispatched when the forecast is wrong, retailers need to buy from STEM, a generator has broken down or gas is not available. He noted that as refunds increase, the cost of finance for a peaking unit will increase. Unlike larger Market Generators that can spread their losses across a number of facilities in their portfolio, a peaking unit can actually go out of business if it is exposed to very high penalties in the event of a Forced Outage. Mr Shane Cremin supported Mr Peake's point and added that getting the value of available capacity right was quite difficult. He suggested that a potential measure could be the rolling average of a generator's actual performance taking into account the level of Forced or Planned Outages.<br>• Mr Tan asked if outages data would be forecast and published on the IMO's website. Mr Stevens noted that what a generator needs to know is when there is reserve margin available and some level of this information was already available in the market. The Chair observed | |

| Item | Subject | Action |
|---|---|---|
| | that the objective of the current system was to incentivise facilities to be available. Mr Stevens observed that the refund regime did not in itself incentivise a base-load generator to be more available than needed. It was rather a refund that generators would try to avoid by patching up machines to stay online as much as possible rather than taking an outage and fixing them completely. He added that generators would try to do their maintenance to avoid Forced Outages, and bring plant back online to avoid refund. Mr Rhodes noted that that was an appropriate outcome as it means that the market has full capacity and energy prices will be lower. Discussion ensued on why a generator would not take out a Planned Outage when it identifies an issue with the machines.<br>• Mr Mike Thomas observed that there were two issues at hand- one around how sharp the refunds should be for generators to encourage them to solve their problems faster and second, whether it's the right level of refund for that type of problem. He added that in The Lantau Group's previous work, they were trying to assess a balanced approach to measure against expected levels of performance.<br>• Discussion ensued on the differential effects of a dynamic refunds regime on different kinds of generators. Mr Peake noted his concern that a sharper refund regime can potentially put a peaking plant out of business. Mr Sutherland expressed his concern with the effects of high refunds on new, more reliable plants in comparison to old, less reliable plants.<br>• Dr Tooth noted that the main concern for generators seemed to be that there was no creative way to pool their risk effectively. Members discussed what refund multiplier could be considered suitable. The Chair noted that a dynamic refunds regime comes with an inherent uncertainty which would expose smaller generating units to a greater level of commercial risk. He added that the purpose of markets is to provide an enabling environment for businesses to manage their risk and make sound business decisions.<br>• Members discussed the pros and cons of allowing for a certain percentage of Forced Outage rates followed by stricter refunds for non-performance. However, Mr Rhodes observed that Forced Outage rates are accounted for in bilateral contracts and so a retailer should not be paying twice for the cost of Forced Outages. Mr Stevens pointed out that the amount of reserve margin could be considered as a threshold for enforcing high refunds on generators. The Chair noted that dynamic refunds design was a complex issue and that Mr Thomas would be assigned to this work stream.<br>***Action Point:***<br>• *The Lantau Group to investigate the options for implementing a dynamic capacity refund mechanism and present to the RCMWG for discussion.* | **The Lantau Group** |
| **6.** | **RESERVE CAPACITY PRICE (WORK STREAM 1)**<br>The Chair invited Mr Thomas to present the conclusions from the workshop that took place on 4 July 2012. The following discussion points were noted: | |

| Item | Subject | Action |
|---|---|---|
| | • Mr Sutherland noted that if the steeper slope doesn't incentivise bilateral contracting then there would be a major problem for financing merchant plants. Mr Rhodes agreed that increase in bilateral contracting was an obvious outcome of the steeper slope.<br>• Mr Tan and Mr Stevens reiterated their concerns raised previously with respect to how the steeper slope would stop a retailer coming in and incentivising additional capacity to bring down their portfolio of costs.<br>• Mr Tan questioned if Mr Thomas had considered a floor price on the slope to mirror the cap as financing plants in the future would depend on the financer's expectation of the Maximum Reserve Capacity Price (MRCP). With a huge swing in that price, raising finance would be very difficult. Mr Thomas observed that from a value management perspective, a floor price could be implemented. A suggestion of 50% of MRCP was made.<br>• Mr Tan also questioned if Mr Thomas thought enough had been done already with the change in MRCP.<br>• Mr Rhodes noted that enough evidence had not been shown to say that steepening the slope will produce better outcomes for the market.<br>• Ms Wana Yang noted that she was not convinced that the steeper slope formula would solve the excess capacity problem, as even with the reduction in the price, new capacity had entered the market. She also argued that the current practice of assigning Capacity Credits to any Facility that had received Certified Reserve Capacity creates a shared reserve capacity cost burden on Market Customers. This was an inefficient market outcome which implied that a cap should be implemented on the Shared Reserve Capacity Cost.<br>• General discussion ensued on the pros and cons of assigning Capacity Credits only to the level of the Reserve Capacity Requirement and implementing an auction mechanism. Mr Thomas noted that the steeper slope approach could be considered a transitional short term arrangement that could eventually lead to discussions around an auction mechanism.<br>***Decision Points:***<br>• *The IMO to include The Lantau Group's proposal into the final list of recommendations.*<br>• *The IMO to consider adding a floor price to the Reserve Capacity Price.* | **IMO**<br><br>**IMO** |
| | **CLOSED**<br>The Chair thanked the members and declared the meeting closed at 5.05 pm. | |

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# Memo

| | |
|---|---|
| To: | RCM Working Group |
| From: | Mike Thomas |
| Date: | September 2012 |
| Subject: | Brief Note on Capacity Refunds Mechanism |

## 1. THE CAPACITY REFUNDS MECHANISM

This note is intended to facilitate discussion within the RCM Working Group of possible changes to the Capacity Refunds Mechanism (CRM). It attempts to establish a clear purpose for the CRM and indicate how the CRM affects, and is affected by, the Reserve Capacity Mechanism (RCM). Combing through the various studies, statements and reports concerning the CRM, it is clear that a range of views exist as to the purpose, effectiveness, intent and results of the CRM.

We draw on a number of key prior documents: the report by the IMO entitled *Review of Capacity Cost Refunds* (dated 5 April 2011 and referenced here as "RCCR"); a *Reserve Capacity Refunds – some principles, scope of RDIWG work and next steps* (dated 3 May 2011 and referenced here as "RCP"); and TLG's *Capacity Refund Proposal: Brief Review* (dated 26 May 2011 and referenced here as "CRPBR". We also note that significant analysis of the refunds issue has previously been conducted by the IMO and the RDIWG.

### 1.1. WHY HAVE A CRM?

The CRPBR – based on the Wholesale Market Objectives as set out in Section of 122(2) of the Electricity Industry Act and repeated in clause 1.2.1 of the Market Rules, the RCCR and RCP – identified five separate possible purposes of the CRM:

- **Long-term incentives**. The stated intent of the refunds mechanism is to "incentivise long term maintenance activity which will minimise future risk to system security and system reliability." [RCCR, p. 6] In particular, there appears to have been a strong feeling that episodic refunds would provide an insufficient incentive and that the lack of a consistent refund risk may lead to "free-riders." Subject only to System Management's potential reluctance to approve outages at peak "[t]he profile can be structured so the probability of the peak refund not applying at any time 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." [RCCR, p. 11]

- **Short-term incentives**. A second stated intent is to "Incentivise short term behaviours to ensure day to day operation and maintenance activities are directed to maximising reliability at time of greatest value, generally when actual reserves are lowest." [RCCR, p. 6] It is interesting to note, however, that the short-term incentive is not really an incentive to make capacity available. "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." [RCCR, p. 5]

- **Fairness**. "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." [RCCR, p. 6] Similarly, the proposal "provides a refinement that creates incentives for both short and long term scheduling of maintenance effort and more equitable treatment of different forms of capacity." [RCCR, p. 9] "As far as practicable all capacity providers should be treated equally." [RCCR, p. 20]

- **Level of refunds**. "The level of refunds overall" is noted as an issue in the design of the mechanism. [RCP, p. 4] Much effort is directed at retrospective analysis of refund levels. "If there was a significant reduction in the level of refunds returned by the scheme for no specific efficiency gain, – this would, in effect, increase the net value of the reserve capacity scheme itself – right at a time where there are concerns that the reserve capacity market may currently be too 'generous'." [RCP, p. 5] Thus, maintaining the level of refunds appears to have become a goal. [RCP, p. 6] recommends that "the RDIWG would then progress work on… developing a dynamic refund regime with no significant changes in refund levels."

- **Volatility of refund revenues**. This appears explicitly in the discussion of issues – "The volatility of refund revenues." [RCP, p. 5]. It also crops up in discussion of the shape of the refund/reserve level relationship. "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." [RCCR, p. 8]

It seems fair to say that the CRM is at risk of being pulled in a number of potentially different directions. In our view, it is necessary to consider the CRM and RCM together.

# 2. THE CRM AND RCM IN CONTEXT

The key issues with the CRM are similar to those that exist with the RCM. The current forms of each map poorly to the underlying economics of capacity value determination. A perfect match is not the objective here, especially given that the perfect can be the enemy of the good, or fraught with unintended consequences in any event. That said, we believe significant improvement is possible, and is justified by, among other things, the increasing risks over time created by mechanisms that fail to align well with underlying market forces.

It has been argued and accepted that the CRM and RCM should be considered together. Indeed, in our 2011 review of the capacity refunds regime, we noted:

> *A change to the way the RCM responds to market conditions will affect the value at stake when refunds are triggered. Alternatively, a change to the refund regime will affect the value and effectiveness of the overall RCM. We therefore recommend linking a change to the capacity refund regime to the outcome of the broader RCM review.*

As practical options for RCM reform have since narrowed, it is time to consider the RCM and CRM as a package, as their workings, together, will influence future investment and behavioural incentives.

## 2.1. INTER-RELATED MECHANISMS

The fundamental rationale for proposing changes to both the RCM and CRM is that, for all intents and purposes, neither adjusts to changing market conditions. To our view, the extremely limited level of dynamism present in current arrangements is poorly targeted and cannot plausibly be argued to be effective or consistent with the Market Objectives. Changes are necessary and should be made consistently, considering the RCM and CRM as a package, as both affect the commercial risks associate with investment and use of reserve capacity, not to mention risks related to the longer-term adequacy of appropriate resources to support system security.

Whereas the RCP is established based on annual measures, the CRM applies on a much shorter-term timescale. Market conditions in the short-term range more widely than annual measures can capture. Prior work by the IMO and RDIWG support amplifying or attenuating refund exposure based on short-term market conditions. As a matter of economics, this makes clear sense.

The CRM effectively qualifies the capacity resources for which the capacity price is paid. Higher quality capacity (better availability and performance) will naturally face lower refund risk, and thus will earn more value from the overall RCM+CRM "package". As the IMO noted in its "Review of Capacity Cost Refunds", 5 April 2011:

> *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.[1]*

When investing in new capacity resources to serve the WEM, the materiality of exposure to refund-related risks is a natural component of the investor's commercial evaluation. Poor quality capacity should, in fact, be exposed to greater risk of capacity refunds, as that is an obviously sensible way to reward the underlying performance characteristics of different types of capacity in a non-discriminatory way (just in the same manner that other economic performance characteristics—such as lower dispatch costs—are rewarded).

The risks of rewarding poor quality capacity too much are compounded if the RCM and CRM do not work together consistently. The more excess reserve capacity exists, the lower the risk a unit will be called (and thus exposed to refund risk). Clearly, the only way to offset this risk is through the testing regime and through the RCM itself in which the value of a capacity credit is more tightly linked to market conditions and is much lower when there is more excess reserve capacity. The risk of refunds decreases when excess reserve capacity increases, but so to should the value paid for reserve capacity. In the changes proposed to the RCM, the key element is the "slope" factor, intended to better mimic the implications of market-based pricing by varying the IMO-paid value of reserve capacity more dynamically with market conditions.

1 "Review of Capacity Cost Refunds" , IMO, 5 April 2011, section 2.2.

Conversely, as the amount of excess reserve capacity reduces, exposure to the risk of refunds for should increase. Units with relatively higher dispatch costs will see increased likelihood of being dispatched, and thus risk of refunds should they fail when called. These interactions form a logical set of incentives to reinforce desirable operational and investment behaviours.

## 2.2. ALIGNING ECONOMIC MECHANISMS WITH INCENTIVES AND OUTCOMES

As discussed at length with the RCMWG with respect to the RCM itself, the *economic value* of "pure" capacity is determined under a very, very narrow range of circumstances over the course of a capacity year. This point is also noted in the IMO's report:

> *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.*

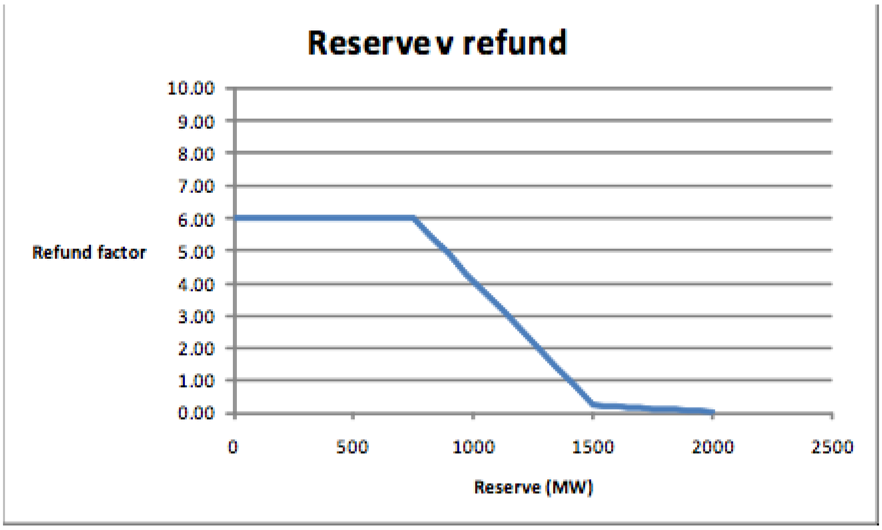
As reflected in discussions within the RCMWG and in the IMO's recommendation with respect to a dynamic capacity refunds regime, there are practical limits to how much economic value of capacity can be attributed to just a few capacity periods without creating an even more problematic financial risk exposure. This problem, which we've termed the "zero/infinity" problem, requires that we draw back from the pure economic case and identify a practical alternative.

## 2.3. THE DYNAMIC REFUND REGIME PROPOSAL

The dynamic refund regime proposal, tabled by the IMO on 5 April 2011, would limit CRM risks through a set of factors proposed to range from zero to six, as noted by the IMO:

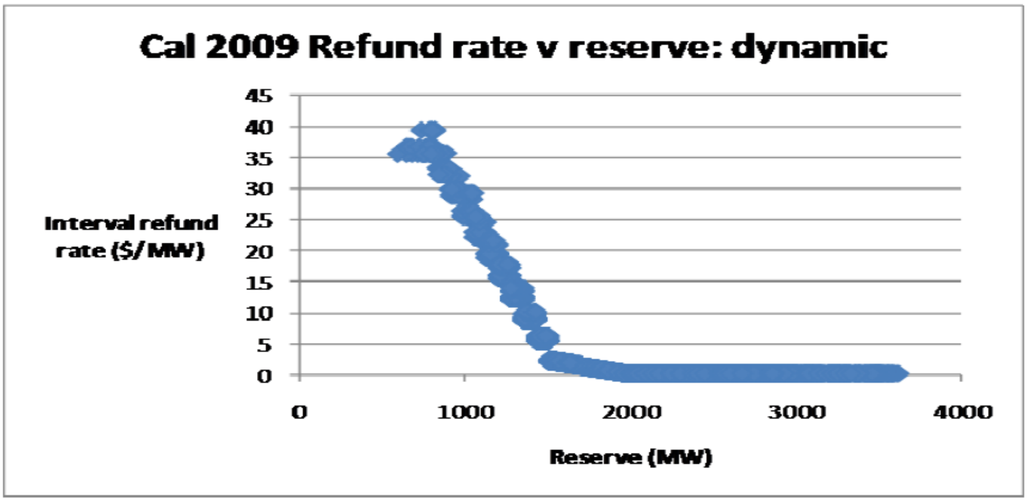
> *The IMO proposes that the maximum refund factor remain at the maximum value of 6. As noted analysis of the 2008 and 2009 calendar years shows that the cumulative refund amounts under the Market rules and the proposed methodology are similar. The IMO considers that as the design is aiming to produce 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 refund factor relationship to reserve is shown in the attached "clipped" figure from the IMO report:



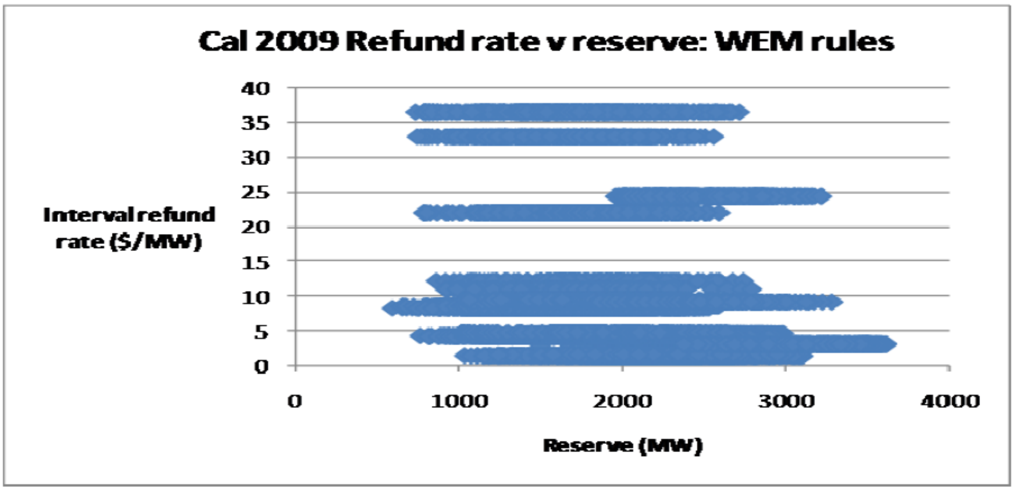

As a result of the proposed dynamic refund relationship, the relationship between reserve and refund exposure "cleans up" considerably as compared to the current arrangements, as shown below, again "clipped" from the IMO report.

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



RDIWG Meeting No. 11: 5 April 2011

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




The proposed "dynamic" regime is very clearly a large step in the right direction. In particular, the dynamic regime would make all capacity resources pay more attention to the level of reserve. The current arrangements present so much noise that it behooves us to think that anyone exposed to refund risk would even bother to be concerned with actual system conditions, as opposed to the simple "clock-based" factors. So the proposed dynamic refund factor regime is an excellent move in the right direction. Furthermore, the dynamic refund regime aligns well with the proposed changes to the RCM, given the steeper slope that defines the maximum annual refund exposure based on system reserve conditions.

## 2.4. Evaluating the Dynamic Refund Proposal

The desired behaviours under the RCM are straightforward:

- Ensure that when capacity additions are not fundamentally economic, they are not added – or are at least not materially paid for by consumers; and
- Ensure that there is enough capacity.

The desired behaviours under the CRM are equally straightforward:

- Ensure that customers do not pay top shelf prices for bottom shelf quality; and
- Ensure that capacity resource providers have incentives to be available and to be able to operate as needed whenever called for dispatch.

Naturally, both should work together to signal appropriate types of capacity so as to promote lower costs of energy and capacity over time, given that it is the interaction of capacity and dispatch that determine costs to customers and revenues to capacity resource investors.

For both the RCM and CRM, therefore, the first central issue is value for money – are consumers getting value aligned with what they are paying for. The second central issue is whether capacity resource providers have sufficient incentives to be available in both the short and longer-terms. In economic terms, both issues are central, and both are equally important.

The RCM and CRM are naturally linked in economic and commercial terms. Operators and investors expect to receive a value for their capacity that is based on their projections of the RCP as modified by their expectation of refund exposure. From a commercial perspective, refund exposure is not merely about operational readiness—though that is principally what it incentivises. It is also a part of the long-term value equation that influences the type and timing of new investment, at least to the extent that that refund exposure is material.

The targeting of refund exposure into "value" periods is therefore an important consideration. If refunds are collected materially from non-peak periods, then the refund exposure could distort the perceived economics of investment in baseload generation, or any other type of generation, such as wind in WA, that operates significantly during non-peak periods. Conversely, if refunds are not sufficiently concentrated in periods of low reserve capacity, the CRM could reduce the perceived benefit of higher quality but more expensive peaking capacity. The degree of distortion depends on the precision of the CRM. Although perfection in targeting is neither possible nor desirable (due to the offsetting problem of exponentially increased financial risk), the search for a practical solution at least needs to reflect on—and ultimately accept a level of exposure to—these risks. An acceptable outcome is one in which the degree of potential distortion is deemed immaterial or acceptable given other risks that have to be taken into account.

The dynamic refund proposal fares well against this framework, at least in theory and concept. The specific "slope" and cut-off points reflect the outcome of significant analysis that has been done to date regarding exposure and targeting. However the analysis and proposal were developed apart from the recommendations regarding the RCM. To that end, some further refinements are worth the consideration of the RCMWG.

## 2.5. ISSUES TO BE CONSIDERED

Using the dynamic refund regime proposal as a baseline, we recommend several changes be considered – some of which will require some additional analysis to fine-tune or vet:

- Steepen the "slope" (e.g., increase certain refund factors) to increase exposure during more critical periods;
- Concentrate more refund risk into peak months (out of off-peak months), subject to consideration of maintenance outage planning requirements;
- Redistribute refunds to those capacity sources that actually provided capacity during refund events;

- Correspondingly adjust next year's RCP downward by the amount of refunds collected to preserve the overall value for money that is currently realized (because current refunds flow through to customers).

Each is discussed below further, with suggestions for analysis and discussion.

- Steepen Slope
  - The incentive aspect can be further strengthened under lower reserve conditions. A much higher factor or a smoother curve could apply such that the maximum factor is higher – more in line with economics of capacity value. Whereas such a steeper CRM slope would certainly introduce more refund risk, the proposed RCM changes clearly reduce the risk that lower levels of reserves would actually occur. Logically, if there will be a stronger signal *as the amount of excess capacity works down*, then there can also be a stronger refund risk – the two signals complement each other.
  - The primary concern is likely to be that a steeper slope introduces additional risk, which of course is the intent, but that the risk may create financial exposure that exceeds the practical value of the corresponding beneficial incentive sought to be created. The arguments to make the slope steeper (and indeed the slope should be made steeper) to the extent that financial exposure to random outcomes ("noise") can e reduced and the exposure to real performance differentials increased. From a value for money perspective, the financial demise of an unreliable capacity source that does, in fact, fail to provide capacity when needed, seems an entirely appropriate situation in which to require a substantial refund.
- Reallocate/concentrate refund risk over time
  - An important CRM issue is to consider what specific level of refund exposure is appropriate in each time period. Currently, some shaping of refund exposure by month (peak vs non-peak) exists, as was introduced in 2007/08. But the result is one in which a significant portion of exposure remains in off-peak or shoulder Trading Intervals. The result would appear to reduce exposure to refund risk for poor performance during peak periods and to increase exposure to refund risk of capacity that is clearly dispatched on a regular basis and that, therefore, has relatively less need to be "qualified" to determine that it can actually *be* dispatched. This issue merits further consideration so as to ensure it is resolved in a manner consistent with the overall CRM/RCM framework.

- "Recycle" refunds to sharpen incentives

  - One of the ways to reduce the impact of "noise" – the random outage that can affect any form of capacity – is to "recycle" the refunds such that noise has an opportunity to cancel across capacity resources over time. Suppose that all resources are likely to fail randomly at any point in time. If the refund incurred during a failure is then redistributed to the capacity resources that do not fail, the average "noise" will cancel out over time, with the capacity that is less reliable, on average, bearing the full brunt of the refund exposure. This creates both a more equitable outcome and an incentive to "improve" average performance over time.

  - Full vetting of this idea will require some additional analysis, and will likely attract a variety of views, but initial indications are encouraging.

  - The value of "recycling" is that it allows sharper incentives that absolutely will disadvantage consistently worse performing capacity resources, but should greatly reduce financial risk to robust capacity resources that experience merely the average level of unplanned failures.

  - A result of recycling would be that Market Customers would not receive "refunds" – unless a separate mechanism is incorporated as per below.

- Adjust RCP to account for loss of transfer of refunds to Market Customers

  - Approach one would simply take the level of refunds that have been recycled and use that calculated value to reduce the RCP in the subsequent year by a corresponding percentage. This approach would be faithful to the current treatment of refunds to Market Customers and would result in zero value loss to Market Customers while simultaneously enable a sharper and more equitable targeting of refund-related incentives for capacity resources.

  - Approach two would skirt the issue of recalculating the level of refunds each year and would simply impose a fixed reduction to the RCP – say 1 or 2 percent – that reflects a broad estimate of foregone refund value. Approach two has the benefit of simplification and may be more appropriate if implementation complications exist.

  - Obviously, the recycling option could be ignored and refunds made to Market Customers directly as per the current arrangements, but one should at least ask what purpose, in economics is served. To the extent that the refunds regime is intended to incentivise availability and qualify performance characteristics such that poor performing capacity loses access to the full value of a capacity credit, then the recycling based approach achieves that significantly more comprehensively than the current regime.

## 2.6. Outage Planning Process

The CRM has a clear logical connection to the outage planning process. If System Management approves a maintenance outage, the resource that is approved is not exposed to refund-related risk. It is possible, therefore to attempt to use the maintenance scheduling process to reduce exposure to refund risk without necessarily undertaking any material improvement in unit performance. In effect, by seeking to schedule as much maintenance as possible through System Management, the number of periods in which a capacity resource is exposed to refund risk is reduced.

The design and features of the CRM as well as the RCM in general affect these incentives. For example, if the amount of excess reserve capacity increases, the proposed RCM settings would result in a reduced RCP – reducing the incentive to retain or develop capacity. A more dynamically oriented CRM would then *reduce,* potentially to zero, exposure to refunds during periods in which there is ample reserve capacity available. The risk of *strategic* reliance on maintenance outages should therefore be reduced – the question being only of whether more refined parameters, mechanisms or settings would reduce this risk even further. The “recycling” approach noted above has the benefit of not only penalising non-performing capacity, but also incentivising performing capacity. The latter constitutes an incentive for units to reduce their time spent in maintenance, as they would be foregoing a “reward” for being available during periods when other capacity has failed.

Two additional considerations seem worthwhile to consider:

- First, if market conditions are such that System Management would have no problem approving scheduled maintenance, these conditions should also correspond to periods in which the risk of material refund exposure are low. In effect, the alignment of refund exposure and system conditions is crucial.
- Second, the testing regime clearly plays a crucial role in supplementing the refunds regime as a way to ensure that capacity resources are of a quality that corresponds with the capacity value they receive over a year. A combination of more frequent testing of little used capacity resources, more extensive reliance on reporting and explanation of extended or unusual reliance on maintenance outages, together with more sharp refund exposure during periods more critical to system security is the prescribed approach.

INDEPENDENT MARKET OPERATOR

# Reserve Capacity Mechanism Working Group

# Minutes

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| **Meeting No.** | 7 |
| **Location:** | IMO Boardroom<br>Level 17, 197 St Georges Terrace, Perth |
| **Date:** | Thursday 13 September 2012 |
| **Time:** | Commencing at 2.10pm – 5.20pm |

| **Attendees** | **Class** | **Comment** |
|---|---|---|
| Allan Dawson | Chair | |
| Suzanne Frame | IMO | |
| Andrew Sutherland | Market Generator | |
| Brad Huppatz | Market Generator (Verve Energy) | |
| Ben Tan | Market Generator | Left at 4.40 pm |
| Shane Cremin | Market Generator | |
| Wendy Ng | Market Customer | |
| Geoff Gaston | Market Customer | Proxy |
| Steve Gould | Market Customer | |
| Stephen MacLean | Market Customer (Synergy) | |
| Andrew Stevens | Market Customer/Generator | |
| Jeff Renaud | Demand Side Management | |
| Geoff Down | Contestable Customer | |
| Justin Payne | Contestable Customer | |
| Brendan Clarke | System Management | |
| Wana Yang | Observer (Economic Regulation Authority) | |
| Paul Hynch | Observer (Public Utilities Office) | Left at 5:00 pm |
| **Apologies** | **Class** | **Comment** |
| Patrick Peake | Market Customer | |
| **Also in attendance** | **From** | **Comment** |
| Richard Tooth | Presenter (Sapere Research Group) | |
| Mike Thomas | Presenter (The Lantau Group) | |
| Aditi Varma | Minutes | |
| Greg Ruthven | Observer | |
| Fiona Edmonds | Observer | |
| Jenny Laidlaw | Observer | |
| Natasha | Observer | |

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| Cunningham | | |
| George Sproule | Observer | |

| Item | Subject | Action |
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| **1.** | **WELCOME AND APOLOGIES / ATTENDANCE**<br><br>The Chair opened the seventh meeting of the Reserve Capacity Mechanism (RCM) Working Group (RCMWG) at 2:10pm.<br><br>The Chair welcomed the members in attendance and noted Mr Patrick Peake's apology. | |
| **2.** | **MINUTES ARISING FROM MEETING 5**<br><br>The following amendments were noted:<br><br>• On page 5, Mr Brad Huppatz requested the following change:<br><br>*Mr Brad Huppatz noted Verve Energy's support for the dynamic regime but added that ~~with~~ increasing risk and uncertainty must be balanced by a lowering of expected refunds ~~a Market Participant's exposure in the market will increase.~~*<br><br>• On page 8, members asked for the following change:<br><br>*~~The Chair noted that the members agreed that the proposed approach seemed the most efficient and feasible solution in the short -term.~~*<br><br>Discussion ensued among members on decisions made on the Reserve Capacity Price (Work Stream 1) in the previous meeting. The following points were noted:<br><br>• Mr Ben Tan and Mr Stephen MacLean noted that the ensuing email conversations after the last meeting indicated that a common understanding on the issue of Reserve Capacity Price had not been reached and that the effects of the recent reduction in the Maximum Reserve Capacity Price (MRCP) needed to be further assessed.<br><br>• Discussion ensued on whether this work-stream should be opened for discussion again. Mr Shane Cremin noted that members had discussed that there could be better solutions to deal with the over-supply of capacity, but *in the short term* a framework was needed to deal with the current problem.<br><br>• Mr Andrew Stevens queried if there was general agreement on the fundamental framework of the model, not on the numbers illustrated in it per se. Mr MacLean noted that following his discussions with Mr Mike Thomas, the model presented might not be practical in achieving the objective of incentivising bilateral contracting. Mr Cremin noted that the implications around bilateral contracting being further incentivised required additional examination. He added that there was a need for further discussion around the structural framework which should be followed. Mr Stevens agreed with Mr Cremin. Mr MacLean added that from the point of view of retailers, retailers would like to hedge their risks by contracting up to the amount of their liability and would not like to see other transactions take place in the market that could impose an extraneous cost to them. | |

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| | • Mr Thomas observed that it was important that the members divide the two questions: does the proposed solution improve the current situation; and whether the proposed solution is the most suitable option that the members would like to progress. Mr Cremin noted that the working group needed a better understanding of how the proposed solution would deliver in the market. Mr MacLean observed that in the past, other more complicated price reduction methodologies had been used to deal with the excess capacity problem. He noted that if a broader reform of the Reserve Capacity Mechanism was the issue to be addressed, it might be useful to give some thought to whether the RCMWG was the appropriate group to deal with it.<br>• The Chair observed that the IMO Board had laid out the terms of reference for the RCMWG as addressing the problem of excess capacity by using price as a signal for entry or exit of capacity. He added that the IMO Board was aware of the impact of the MRCP review on the market and had indicated to Mr Thomas that a material change in MRCP may be sufficient to address the oversupply issue. The Chair also added that the recent Weighted Average Cost of Capital (WACC) determination for Western Power would impact the MRCP for 2016/17. Mr MacLean disagreed and added that Synergy had offered a different proposal with fewer changes suggesting that if a Market Participant made a bilateral declaration in a Capacity Year, then the IMO should not pay that Market Participant for that year. Members discussed the pros and cons of Synergy's proposal.<br>• The Chair observed that after all the discussions; if the group believed that a credible case for change could not be made, then that would be reasonable advice to provide to the IMO Board.<br>• Mr MacLean suggested that the RCMWG consider Mr Cremin's proposal for a broader review to be undertaken to evaluate the RCM holistically. Mr Cremin noted that in his opinion, the RCM was not entirely suitable in the Wholesale Electricity Market. He added that issues around having an unconstrained network, lack of locational signals, continued use of old generation assets etc. were not being considered in the current review. If those issues had to be dealt with, a new working group may have to be created.<br>• Some discussion ensued on the WACC determination used in the MRCP review. The Chair also added that the IMO would recalculate the MRCP with an updated WACC component and present the results at the next RCMWG meeting.<br>*Action Point: The IMO to publish amended minutes of RCMWG meeting no.5 on the Market Web Site.*<br>*Action Point: The IMO to recalculate the MRCP with an updated WACC component and present the results at the next RCMWG meeting.* | |
| **3.** | **ACTIONS ARISING**<br>Ms Suzanne Frame noted that Action Item 1(The Lantau Group to investigate the options for implementing a dynamic capacity refund mechanism and present to the RCMWG for discussion) was on the agenda. | |

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| | She noted that Action Item 2(The IMO to include information on the cost effectiveness of proposed solutions or harmonisation) was in progress. | |
| **4.** | **INDIVIDUAL RESERVE CAPACITY REQUIREMENT (IRCR) (WORK STREAM 4)**<br><br>The Chair invited Dr Richard Tooth to present his paper.<br><br>The following points of discussion were noted:<br><br>• There was discussion among members on non-temperature dependent loads and their behaviour in the market. Mr Geoff Gaston observed that the IRCR could not affect market behaviour because the Trading Intervals used for IRCR calculations are not known by Market Customers even 6-8 months after a peak temperature event. If industrial loads wanted to take advantage, they would have to start reducing their consumption each time the temperature went above 35 degrees, because they would never know for sure what peak intervals are being used for the IRCR calculation. This is generally not possible for industrial loads. Mr MacLean added that whereas in the past, the peak event used to occur in late February, now temperatures are high almost throughout the summer period, implying that customers would have to try and reduce their demand over the entire summer period because they do not have any indication of a peak event beforehand. Discussion ensued on the potential of the peak moving more towards occurring during the evening as more solar PV cells connect to the grid, which might induce some industrial/commercial loads to shut down early and take advantage of a lower electricity bill.<br><br>• On the topic of selection of peak Trading Intervals for IRCR allocation, the members agreed to proposal 1 i.e., the peak Trading Intervals selected for IRCR calculations would be changed to be selected from Trading Days with the highest peak demand rather than the highest daily consumption.<br><br>• Ms Wendy Ng requested clarification on whether the scope of this work included exploring alternative methodologies for calculating IRCR. Dr Tooth answered that the scope was limited to evaluating the current calculation of IRCR. Ms Ng noted that there may be some potential to make the calculation more real-time by aligning it with metering data. She added that the IRCR could be calculated using a load profile weighting mechanism similar to the methodology for capacity refunds. Dr Tooth observed that IRCR was a division of a pie among Market Customers and that any sort of change to the methodology would result in winners and losers.<br><br>• Following the presentation of proposal 2 (the number of Trading Intervals for IRCR calculation is not modified) and 3 (there is no change to the use of the median value in the IRCR calculation); the Chair asked members if there was agreement with regards to presenting the three proposals as advice from the working group to the IMO Board. Ms Ng noted her support in the absence of any other analysis for alternative methodologies for calculating the IRCR. Mr MacLean noted that he was not convinced that other viable options, such as annualising the capacity cost, did not exist.<br><br>• On the relationship between Relevant Demand (RD) and | |

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| | IRCR, Mr Renaud asked for clarification on the definition of gaming. He added that in his view gaming, to the extent that RD and IRCR intervals overlap, would mean a customer requesting a higher RD in an interval because of a maintenance issue while simultaneously not accepting the lower IRCR adjustment. He added that his position on the issue was that the RD and IRCR intervals had no interaction with each other because they were intended for different purposes. He further added that he was supportive of a change that removed the potential for double benefits whenever there was overlap between RD and IRCR intervals. Mr Renaud added that there should be a provision in the Market Rules for adjustment to the IRCR when the Trading Intervals coincide with the RD Trading Intervals.<br><br>• In response to proposal 4 (i.e., consideration be given to limiting the modifications to load values used in the RD calculation whereby the modified RD values cannot exceed the Associated Load's IRCR Calculation of contribution to the system peak load) Mr Renaud noted that the basis for comparison with RD should be the uplifted IRCR, not the unadjusted IRCR. He added that the unadjusted IRCR is roughly 3800 MW whereas there were 5300 MW of Capacity Credits.<br><br>• Mr Brendan Clarke queried if there was any option to remove the IRCR Trading Intervals from those selected in the RD calculation. He added that there were 32 Trading Intervals which could be eliminated from the RD calculation so that there would be no chance of a double benefit being received. Dr Tooth responded that this restriction would not prevent gaming. Mr Renaud reiterated that in his opinion, the concern with gaming the IRCR outside of RD Trading Intervals was a broader question that was independent of the calculation of RD. He stated that the concern with gaming IRCR was if there was an incentive in the system to manipulate IRCR to one's personal benefit without providing a manifest benefit in decreasing the load forecast and so reducing the amount of capacity required. At this point, the Chair asked the members for their opinion on a potential situation where a Market Customer or a DSP would have more Capacity Credits to sell based on its adjusted or uplifted IRCR. Mr Tan noted that this perspective may change if the market had a capacity shortfall rather than excess.<br><br>• Mr Renaud further added that the debate was really about the two extremes: one focussing on the contribution to the system peak in the purest sense- the IRCR; and the other focussing on a truly dynamic baseline approach which was related to the amount of energy and capacity that a DSP could deliver when System Management needed it. This was irrespective of what the load did for the rest of the year. He observed that based on the IMO adopting the philosophical position that you could not sell what you did not buy, he could understand the position that the RD should not be above the uplifted IRCR.<br><br>• Mr MacLean proposed that the RD for a DSP should not exceed the expected peak demand (as measured by the IRCR for each load comprising the DSP). Mr Renaud contested this on the grounds that DSPs were paid for capacity on the basis of what they could deliver to the market when needed whereas linking RD to IRCR would be an | | |

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| | artificial linkage that does not relate to what the market is paying for. Mr MacLean used the example of generators being rated for their effectiveness at an ambient temperature of 41 degrees whereas RD was calculated across four summer months, not the absolute peak days. He added that the equivalent would be to relate the RD to the 12 Trading Intervals used for IRCR as that would link it with the peak days. Mr Renaud noted that this was an issue related to the RD methodology not its linkage with IRCR.<br>• The Chair observed that it would be useful to conduct some analysis on the number of RD Trading Intervals that coincide with IRCR Trading Intervals in the past 12 months to assess the significance of the issue.<br>• Dr Steve Gould questioned when the application for an adjustment for maintenance is made by a DSP; whether prior to the notification of the relevant Trading Intervals or after. Mr Ruthven responded that some were made before the notification and some after. Dr Gould noted that in his opinion, the analogy for this adjustment was the application for a Planned Outage which is made in advance. He questioned why the notification of the adjustment could not be made in advance without knowledge of what the weather was on that particular day. Mr Renaud noted that that would involve a fairly large administrative exercise in terms of proactively filling applications for as many as 500 loads to assess their list of maintenance outages and submitting it to the IMO. The Chair also added that generator Planned Outages are currently managed by System Management and the number of generators was much lower than the number of loads.<br>*Action Point: The IMO and Sapere Research Group to conduct analysis on the number of RD Trading Intervals that coincide with IRCR Trading Intervals in the past 12 months to assess the significance of the issue of gaming.* | |
| **5** | **RESERVE CAPACITY FORECASTING METHODOLOGY**<br>The Chair invited Mr Ruthven to make his presentation.<br>The following points of discussion were noted:<br>• Mr Cremin observed that the forecasts from the IMO in relation to block loads connecting to the grid were different from that of Western Power. He queried whether there was consultation between the two entities on these forecasts. Mr Tan also queried why the forecasts were so different. The Chair responded that the IMO evaluated each project individually with regard to its likelihood of connecting to the grid and shared these details with Western Power.<br>• The Chair noted that the forecasting methodology was currently under a five-year review and ACIL Tasman had been engaged to prepare a draft report that was going to be published the following Monday (17 September 2012). | |
| **6.** | **MOVING TO A DYNAMIC CAPACITY REFUND REGIME**<br>The Chair invited Mr Mike Thomas to make his presentation. The following discussion points were noted:<br>• Mr MacLean queried Mr Thomas if a different overnight capacity refund charge should be considered when the | |

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| | variation in load is considerably less and the need for substantial reserve margin does not exist. Mr Thomas responded that this should be one of the questions to consider.<br>• There was some discussion among members on the effect of dynamic refunds on the energy prices and that ultimately the impact of dynamic refunds may get built into bilateral contracts.<br>• Discussion ensued on the slope of the refund exposure. Mr Thomas noted that the proposed option for consideration of recycling of refunds would reduce the burden of penalties by giving both a reward and a penalty simultaneously. Mr Cremin noted that the recycling approach also reinforced the value proposition of different facilities. He observed that ideally an inferior generator should be liable to pay more refunds. This would further incentivise a mix of reliable, more efficient plants. Mr Stevens added that the incentive or the reward should be there to incentivise generators to run. His opinion was that at the moment, generators react to the high risk in the market associated with refund exposure. Mr MacLean noted that the real test of the implementation of a dynamic refunds regime would be how bilateral contracts get re-written.<br>• The Chair noted that the discussions indicated that these ideas required further consideration. He added that more analysis should be done on increasing certain refund factors to increase exposure during more critical periods. Mr MacLean added that more detail was needed on steepening the slope and concentrating more refund risk into peak months. Mr Sutherland added that the curve showing capacity factor, utilisation factor and refunds paid should reflect the actual scenario.<br>• Ms Wana Yang provided a comment on availability of generating plants in the market. She observed that plants which have high rates of Planned Outages should be included in the review of the refund mechanism. The Chair clarified that the IMO Board had evaluated particular clauses in the Market Rules which allowed the IMO to not allocate Capacity Credits to facilities which had a combined Forced and Planned Outage rate of greater than 30% over the past 36 months. He added that the IMO Board had considered allocating Capacity Credits to those facilities because of various security and reliability reasons. He further added that the IMO Board had requested an evaluation of these clauses to ensure that they provide incentives to improve performance and to expose poorly performing plants to refunds if they were above a certain threshold of outage rates. He noted that the IMO would embark upon this piece of work over the next few months.<br>*Action Point: The Lantau Group to conduct further analysis on various issues and present a preferred proposed dynamic refund regime.* | |
| | **CLOSED**<br>The Chair thanked the members and declared the meeting closed at 5.20 pm. | |


# Reserve Capacity Mechanism: Recommendation

**Mike Thomas**

**October 2012**

THE LANTAU GROUP
strategy & economic consulting

# My views

- The RCM can be improved significantly
  - Valuable incentives are distorted
  - Responsiveness to market conditions is poor

- Primary concern is not quantity of excess reserve capacity per se, but
  - who pays for it;
  - how much do they pay for it and
  - what is it worth
  - For example the RCM results in a residual "shared capacity cost" allocation to retailers across a range of scenarios that cannot be hedged or managed in commercially sensible ways

- In addition to the RCM, concern that the RCM and the refunds regime need to be considered together, for consistency

# How to improve the RCM

- Basic problems stem from two features of the current RCM
  - Not sufficiently dynamic to respond appropriately to market conditions
  - No symmetrical incentives for capacity providers and capacity users to manage risk through contracts

- A range of options have been considered over the past 18 months, falling into two broad categories:
  - Limit access to credits if there is already enough (QUANTITY)
  - Reduce incentive for capacity providers to develop more capacity if there is already enough (PRICE)

- We consider insights from other markets with working capacity mechanisms
  - What sort of quantity adjustment
  - What kind of price adjustment
  - What sort of risk exposure

- We then apply these concepts and insights to develop a recommendation for the WEM

# Option: Limiting Quantity Certified

- If the underlying technical performance and energy market cost characteristics were exactly the same across all types of capacity (existing and new), then it would be trivial to limit new certification whenever there is excess
  - If “new” is exactly the same as “existing”, then they are completely fungible, and there is no point in certifying “new” when there is plenty of “existing”
- But this is not the situation
  - Innovation and technical performance differences exist
  - Different energy cost performance characteristics are possible
- Conferring “protection” on existing capacity is not consistent with a dynamic market with pressure for improved performance over time

Not Recommended

Stifles innovation
Protects inefficient capacity
Creates awkward gate-keeper role
Does not reward “value”
Does not reflect market risk
Inconsistent with energy market

IMO?

# Option: "Truth in Declaration plus Auction"

- Synergy proposed that the IMO would make no payment to capacity electing a bilateral declaration ensuring a truth to the declaration
  - This could be implemented starting in the 2015/16 capacity year allowing uncontracted capacity three years to negotiate bilateral arrangements.
- Capacity remaining uncontracted for the 2015/16 capacity year may offer itself to the auction, if bilateral declarations are less than required; remain credited and receive no payment from the IMO; or if those alternatives are uneconomic, remove itself from the mechanism.
  - Throughout this process of bilateral contracting and excess capacity either remaining credited or exiting the market, the IMO must ensure that capacity requirements of all Availability Classes are met and initiate an auction where there is shortfall of bilateral trade offers.

Not Recommended

Appears to solve problem of retailers bearing the cost of excess capacity, but….

By removing / reducing IMO backstop, it increases impact of credit or counterparty risk to the detriment of competition

Auction does not resolve the zero / infinity problem

Main benefit appears to be reduction of shared capacity costs – which can be achieved in other ways

# Option 3A: “Buy / Sell Spread” Version 1

- Synergy Proposal
  - Uncontracted capacity receive payment from the IMO, albeit at a reduced rate. This payment should be set at no more than XX% of the MRCP.
  - A retailer not covering its capacity requirement would pay a value that is greater than what the capacity resource receives.

Not Recommended

Does not dynamically adjust with market condition

Market power issues on credit procurement based on counterparty risk given absence of backstop and exposure to “reduced” price

Could expose retailers to market power given contrived exposure to full MRCP rate – as “full MRCP rate” is not dynamically revised with market conditions

Does not explicitly address issue of excess capacity without additional mechanisms or assumptions

Must resolve disposition of “spread” revenue to avoid unintended incentives

May be inconsistent / incompatible with existing contractual definitions of the RCP

# Option 3B: “Buy / Sell Spread” Version 2

- As discussed in July WG Session
  - Credits purchased by the IMO would be purchased at a discount to the RCP; credits sold by the IMO would be sold at a premium
  - Suggest adding a “slope” to the buy/sell prices so that they adjust based on the amount of excess reserve capacity

Not Recommended

Contracting incentive relates more to size of spread than to exposure to excess reserve capacity

Could be structured to address symmetry and expected value problems of Synergy version

Must resolve disposition of “spread” revenue to avoid unintended incentives

May be inconsistent / incompatible with existing contractual definitions of the RCP

# Option: Auction
# A workable auction must address the zero / infinity problem, which is not trivial

1. Introduce additional risk to the retailer so that there is "value" in being over-contracted

   Eliminate clear certainty of number of credits required for any given year – make the amount conditional on outcomes plus a margin. Set up the date for the auction sufficiently ahead of time so that the retailer may need to impute value to the risk of being over-contracted – effectively transmitting value to potential "excess" capacity credits

2. Introduce multiple tranches of auctions based on different forward dates

   An auction 1 year from the date may imply significant zero/infinity risk, but this can be reduced if other auctions are held two years out, three years out, etc, such that the total exposure to "zero / infinity" risk is reducing (hopefully) as the actual target date approaches.

3. Impose constraints on auction price outcomes so as to avoid the zero / infinity problem

   1. Buy / Sell spread
   2. Caps or Floors

4. Auction multi-year credits (blend time periods) so that zero value for a single year is blended with rising values in later years

   1. Supplementary Reserve Auction reflects this principle to a degree
   2. But alternative is to use three or five year "products"

5. Complement the formal auction with short-term trading to allow rebalancing of requirements

Not Recommended

Complexity in a small lumpy market

Volatility / Risk

May reduce competition depending on perceptions of contracting alternatives

Addition of "mitigation" of zero/infinity problem makes auctions look more like a managed solution

# We derive insights from auctions and other market mechanisms

- Insight 1
  - When excess reduces price go up, and retailers face higher exposure if they are not contracted
  - When excess increases, prices go do, and generators face higher exposure if they are not contracted
- Insight 2
  - The rate of fall off or increase is very steep in economic terms – implying considerable risk to be managed
  - But complex auction processes / designs endeavor to avoid the zero/infinity problem of capacity value
- Insight 3
  - Backstop processes are usually present to either support or promote competition and facilitate timely capacity
- Insight 4
  - The value of avoiding shortage is universally viewed as greater than the cost imposed by some excess

# Recommended Approach

- Proposal requirements
  - Be consistent with market-based approaches
  - Mitigate zero / infinity risk
  - Be compatible with prudent risk management practices
  - Be aligned with sensible long-term market evolution direction
  - Be implementable at reasonable costs

- Recommendation Outline
  - Increase “85%” parameter to above 100%
  - Set the “slope” to be steeper than “-1” to create greater market sensitivity for all stakeholders, more in line with what an auction would yield
  - Adjust RCR to mitigate shared capacity cost exposure
- Evaluation criteria
  - Sensible symmetry of risks for stakeholders depending on amount of excess reserve capacity
  - Limited exposure to cost of shared capacity
  - Works sensibly in periods of excess as well as in periods of approaching potential shortage
  - Avoids need for transition mechanism/sequence

# Framework

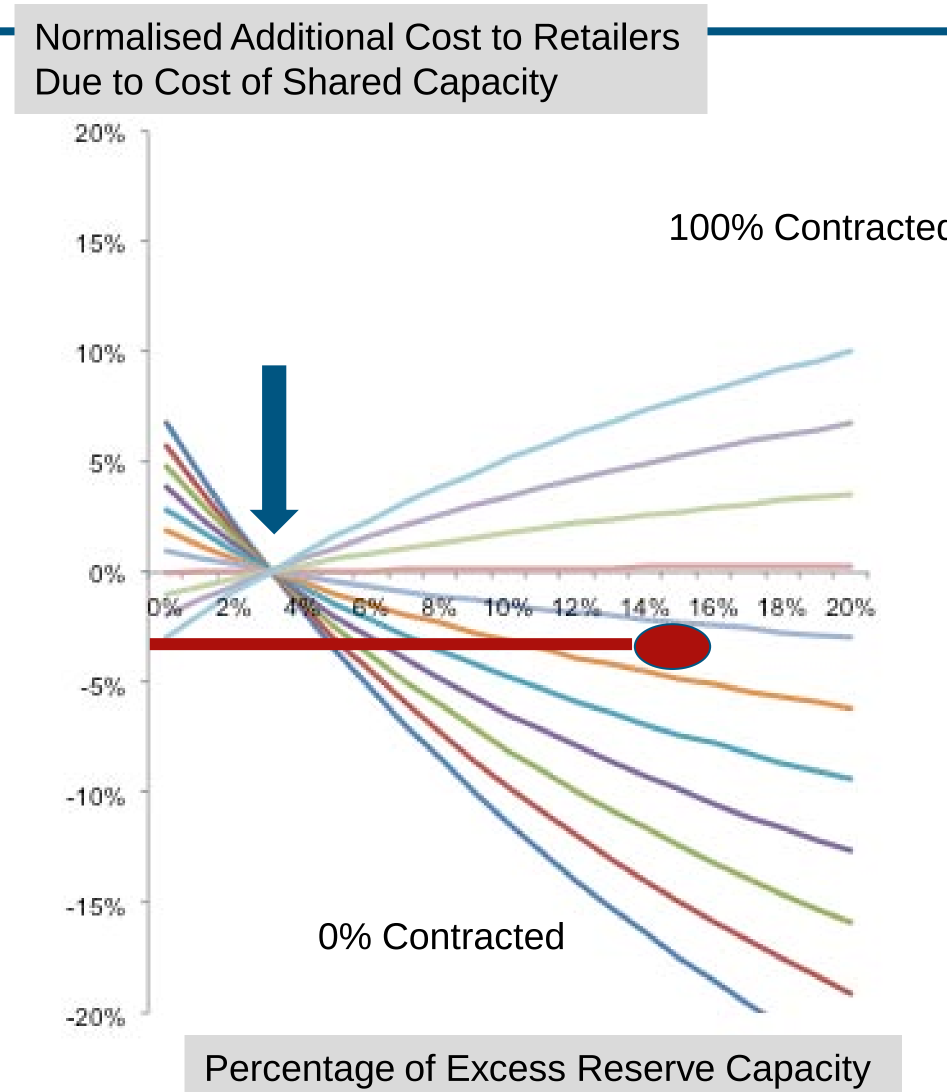
- Analysis compares the difference between two cases
  - Case 1: No exposure to excess reserve capacity costs (“perfect”)
  - Case 2: Proposed RCM settings for evaluation
  - Difference:  How the RCM impacts what is paid for capacity from the IMO and how that translates into shared capacity related costs

# Example

| | | | Parameters | Excess Capacity | No Excess Case |
|---|---|---|---|---|---|
| **Excess Capacity [EC%]** | % | | 15 | 15% | 0% |
| **Market Share (SET TO 100)** | % | | 100 | 100% | 100% |
| **Bilateral_Contract Cover** | % | | 50 | 50% | 50% |
| **SLOPE FACTOR (000s)** | | | 325 | -3.250 | -3.250 |
| **IMO MRCP SCALING FACTOR (%)** | % | | 110 | 10% | 10% |
| | | | | | |
| **Reserve Capacity Requirement [RCR]** | MW | [Input] | | 5773 | 5773 |
| **Credited Capacity [CC]** | MW | [RCR]*(1+[EC%]) | | 6,639 | 5,773 |
| **Excess Capacity [EC]** | MW | [CC]-[RCR] | | 866 | 0 |
| **Retailer_IRCR** | MW | [RCR]*Market Share | | 5,773 | 5,773 |
| **Bilateral_Contract_Cover** | MW | [RCR]*Bilateral Contract % | | 2,887 | 2,887 |
| **Shortage_of_IRCR Cover MW** | MW | Retailer_IRCR - Bilateral Contract Cover | | 2,887 | 2,887 |
| **Retailer's Shared_Capacity MW** | MW | [EC]*Market Share | | 866 | 0 |
| | | | | | |
| **Maximum Reserve Capacity Price (MRCP)** | $/MW | [Input] | | $ 163,900 | $ 163,900 |
| **Reserve Capacity Price (RCP)** | $/MW | Choose(1=Non-Linear; 2=Linear) | 1 | 121,203 | 163,900 |
| | | | 1 Non-Linear | 121,203 | 163,900 |
| | | | 2 Linear | 100,389 | 163,900 |
| **Assumed cost of bilateral capacity** | $/MW | | | $ 473,097,350 | $ 473,097,350 |
| **Cost of Targeted Capacity from IMO** | $/MW | | | 349,853,503 | 473,097,350 |
| **Cost of Shared Capacity from IMO** | $/MW | | | 104,956,051 | 0 |
| | | | | | |
| **Total Cost** | $ | | | $ 927,906,903 | $ 946,194,700 |
| **Difference** | | | | Additional Cost | -$ **18,287,797** |
| | | | | | -1.93% |

# Recommendation

- 110% Maximum RCP to align incentives more symmetrically for balanced risk management
- -3.25 slope to sharpen focus on market conditions and create more dynamism
- Apply a factor of 97% to the RCR, eliminating the persistent cost of shared capacity
- The intersection point on the x-axis becomes the set-off factor for the RCR, creating expected value consistency with the MRCP, while leaving significant exposure for risk management and competition
- No transition is needed



# The next slides build up the recommendation to highlight how each element works together

- The elements proposed would have common analogues in full market-based mechanisms

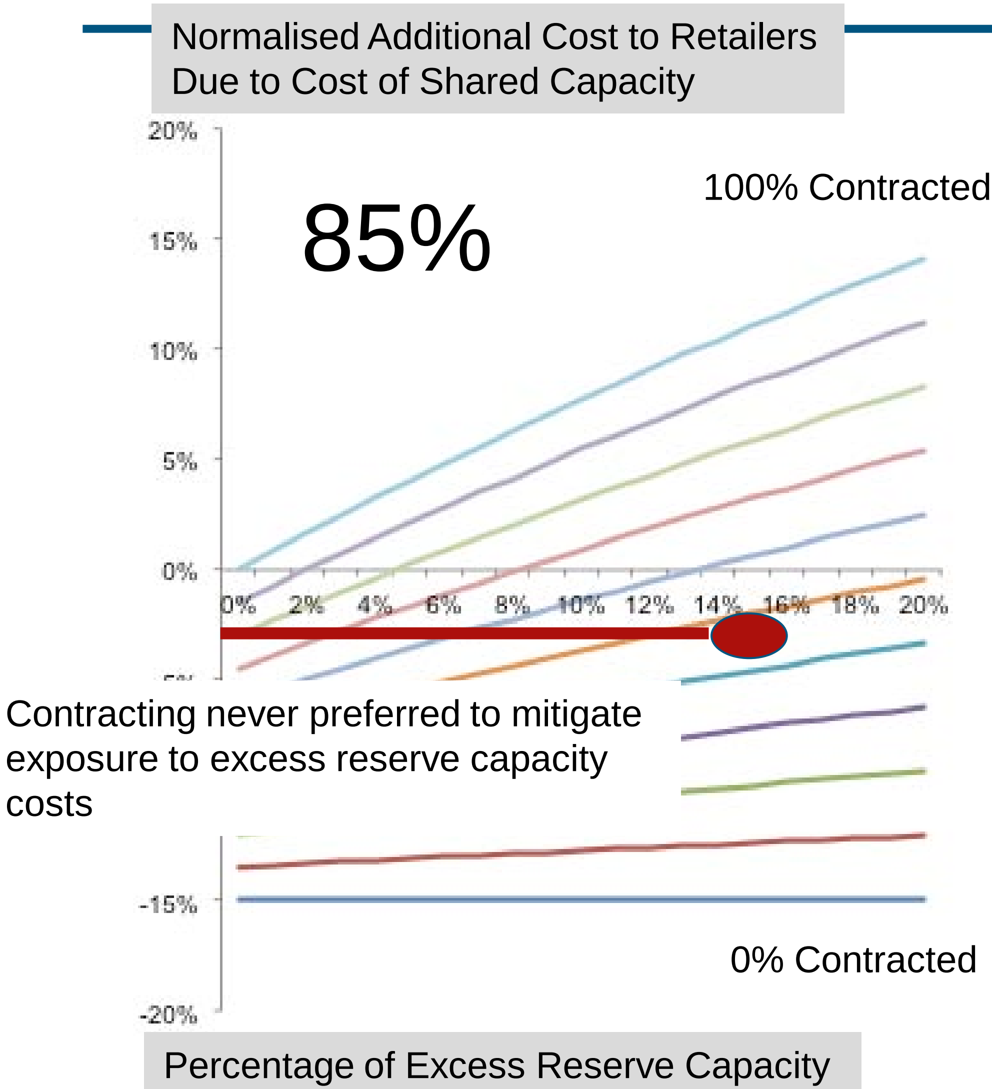
- Step 1: Show how the fixed 85% MRCP adjustment factor (and any factor below 100%) contributes to asymmetrical incentives and undermines risk management options

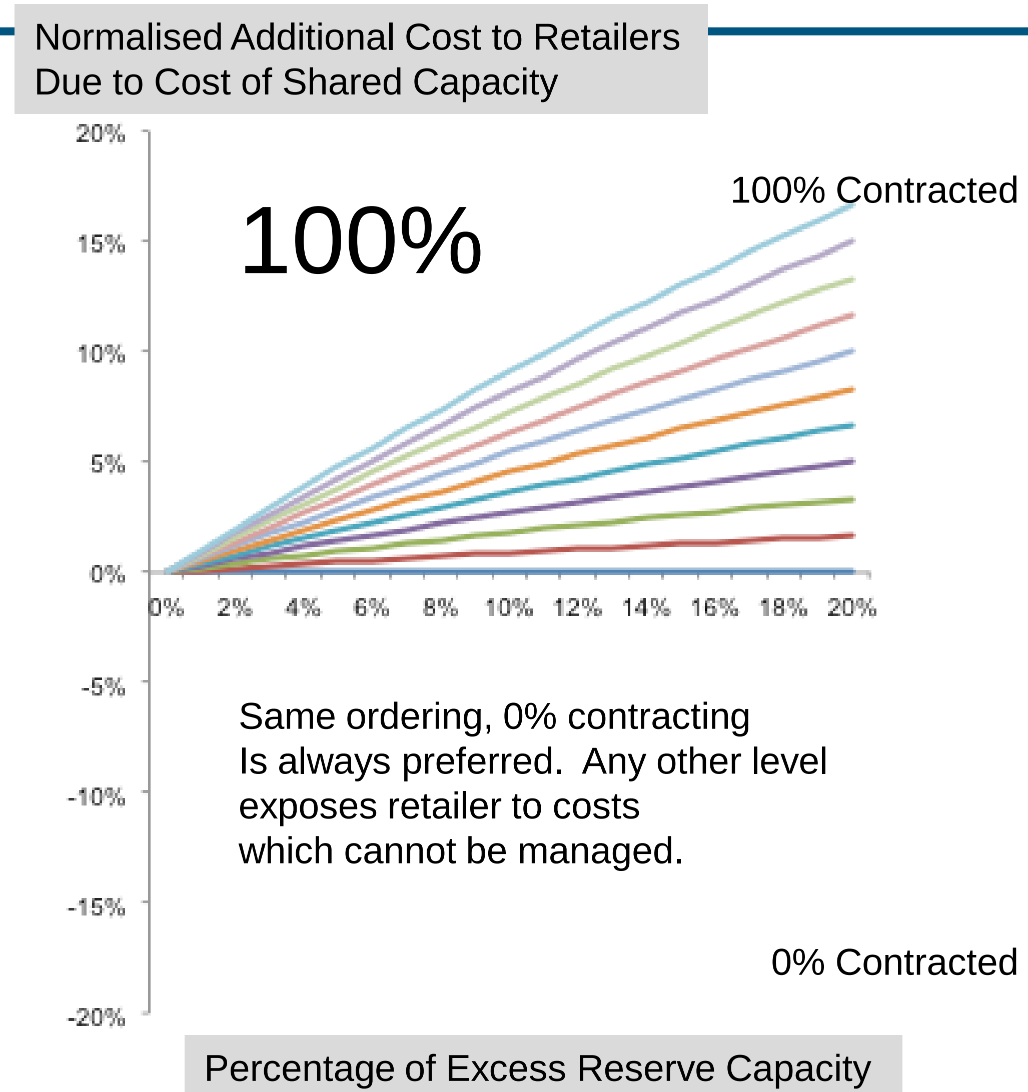
- Step 2:  Show how the choice of steeper slope sharpens incentives and greatly reduces exposure to shared capacity costs to the point of those costs being essentially immaterial

- Step 3: Show how the selection of MRCP uplift improves symmetry and supports risk management options

- Step 4:  Adjust RCR to eliminate impact of residual shared capacity cost exposure

# If MRCP adjustment is less than or equal to 100% then retailers bear shared capacity cost risk when they enter into contracts with capacity resources



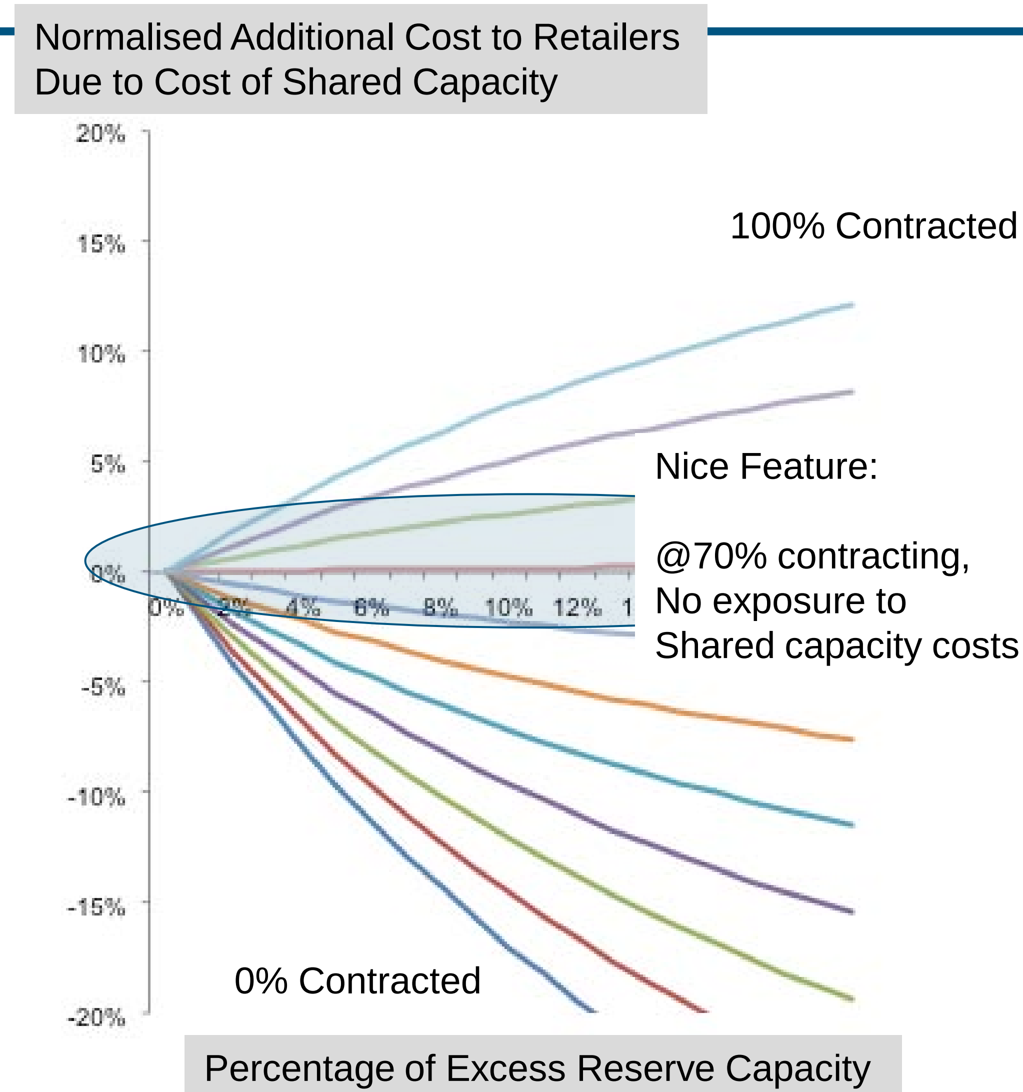
# Increasing the "slope" from "-1" creates greater sensitivity to market conditions

- Capacity providers see more risk due to greater sensitivity to market conditions
  - Value of a CC falls off more quickly as the amount of excess reserve capacity increases
  - Even so, the fall off is much less "steep" than an auction might support

- Possible to reduce exposure to shared capacity costs down to "zero" through fixed policy of 70% contracting, but…..

- Retailers can always do better by contracting less (or not at all)

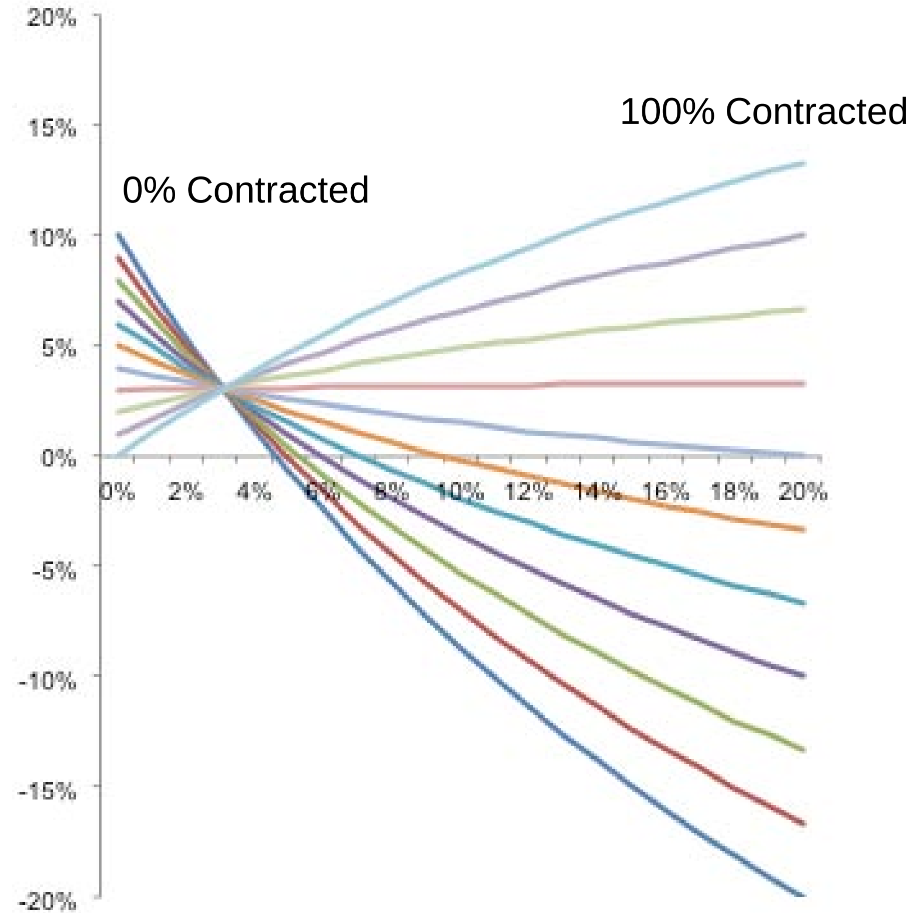
- Not stable



# Symmetrical risks does not appear unless the maximum retailer exposure exceeds “expected” MRCP value

- By exposing retailers to the risk that, as capacity reserves decline, credits may cost more if purchased from the IMO
  - “Shortage” risk is introduced
  - Contracting to manage exposure is possible
  - Retailers have a more balanced incentive to participate in contracts
- The point is not to “incentivise contracts” but to remove distortions that make contracting a cost-increasing activity
  - Contracting should be a way of mitigating risk, not a way to increase exposure to a risk that cannot be hedged
- Higher values could be used to create appearance of even “more” symmetry, but proposal appears ample given that the RCM should not persistently support as much excess reserve capacity going forward

Normalised Additional Cost to Retailers Due to Cost of Shared Capacity




Percentage of Excess Reserve Capacity

# At 110% of MRCP and slope -3.25, most exposure can be managed by contracting

- Best *average* contracting strategy: 70%
- Maximum exposure to shared excess reserve capacity:

  10.0% at 0% contracting

  5.0% at 50% contracting

  4.0% at 60% contracting

  3.3% at 70% contracting

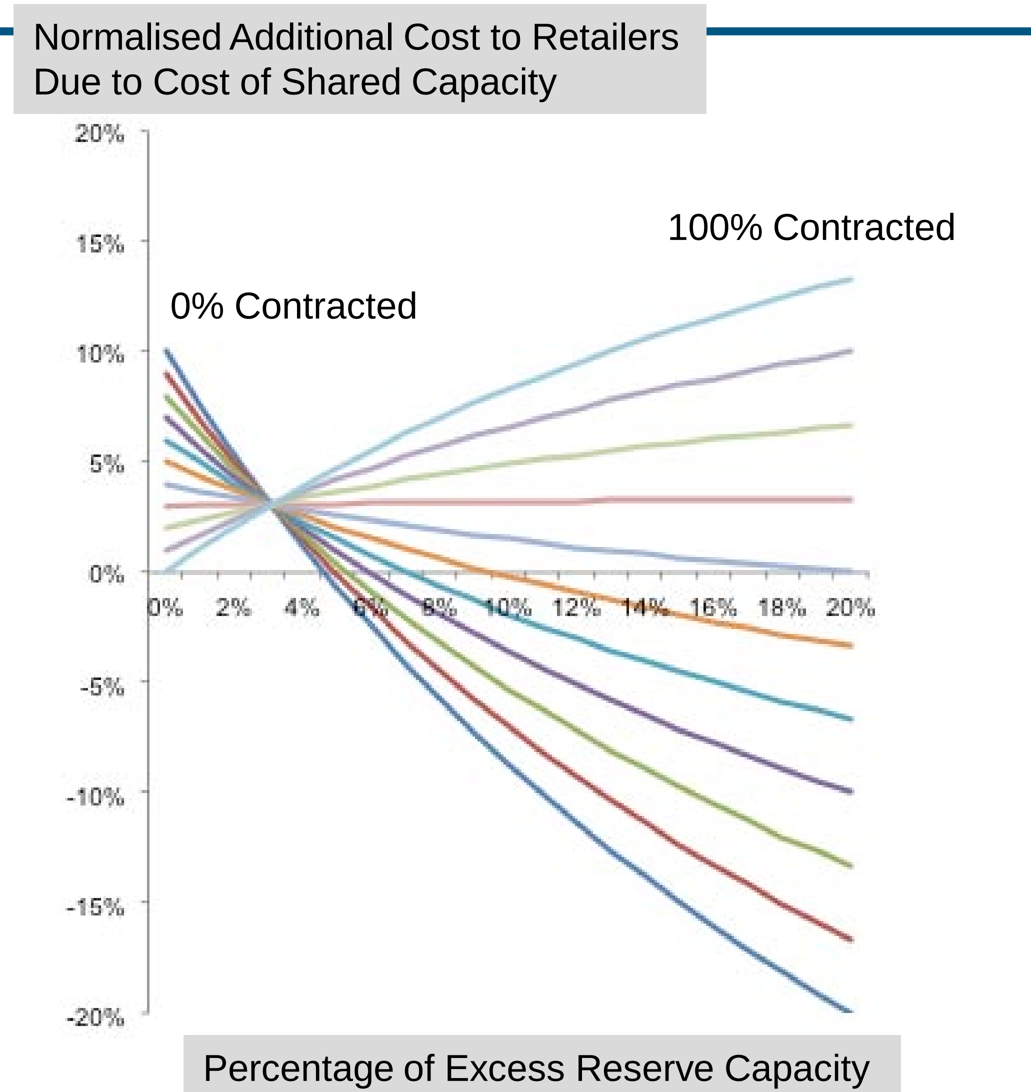
  13.3% at 100% contracting
- Minimum exposure to shared excess reserve capacity:

  -20.0% at 0% contracting

  -3.3% at 50% contracting

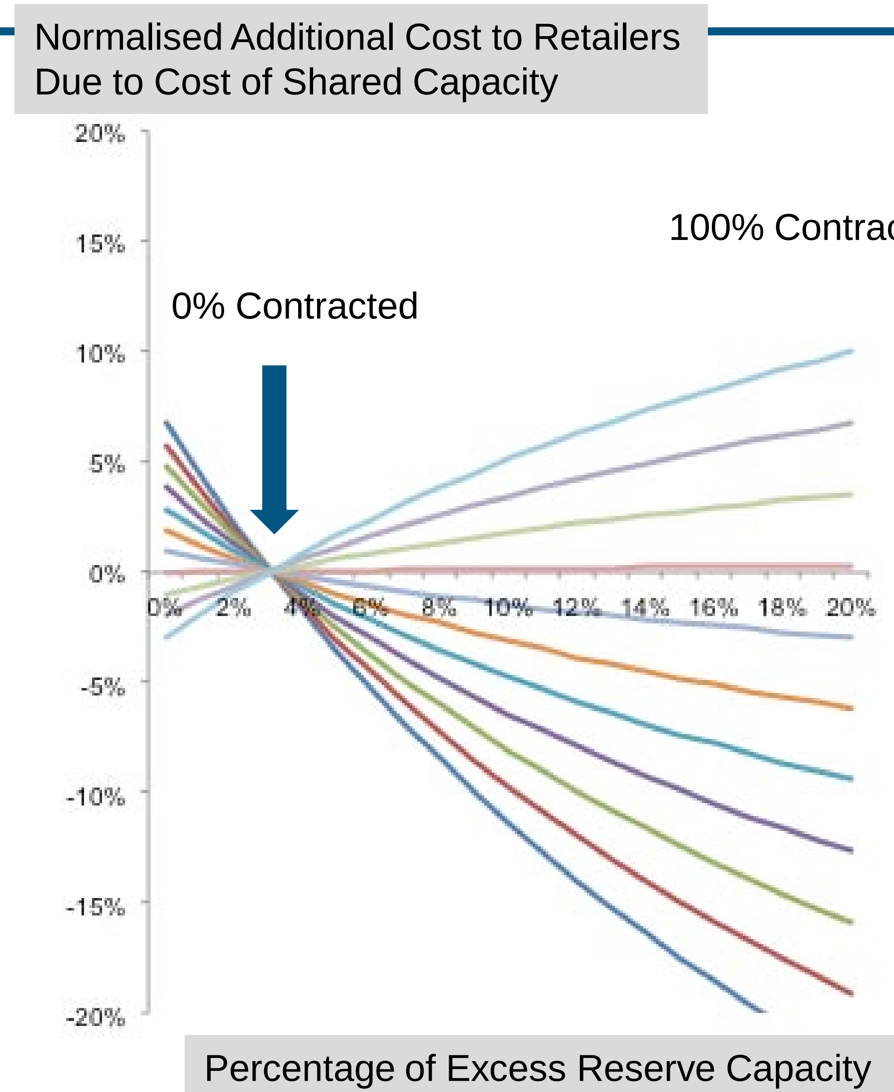
  0% at 60% contracting

  3.0% at 70% contracting
- The small persistent excess reserve capacity cost exposure can be further mitigated through a simple adjustment…



# Recommendation

- 110% Maximum RCP to align incentives more symmetrically for balanced risk management
- -3.25 slope to sharpen focus on market conditions and create more dynamism
- Apply a factor of 97% to the RCR, eliminating the persistent cost of shared capacity
- The intersection point on the x-axis becomes the set-off factor for the RCR, creating expected value consistency with the MRCP, while leaving significant exposure for risk management and competition
- No transition is needed



# Summary

- Dynamic adjustment is crucial
- Symmetrical exposure is essential
  - Generators exposed to excess capacity
  - Retailers exposed to shortage capacity
- Risk management mechanisms must exist, with incentives linked to “market” dynamics, not overly contrived arrangements
  - MRCP becomes “SCP” → Sustainable Capacity Price
  - RCP can reach a maximum of 110% of the SCP, depending on market conditions
  - A slope of -3.25 to sharpen sensitivity to market conditions
- Customer exposure to the small remaining cost of shared capacity can be eliminated through a corresponding adjustment to RCR

# RCM Refunds Regime

# The refunds regime works in conjunction with the RCM

- Refunds are paid by capacity sources when they do not perform

- The basis for payment can be interpreted many ways
  - As a failure to meet a contractual performance obligation (time value invariant)
  - As a failure to deliver value paid for (time-value sensitive)
  - As a way to incentivise specific desirable behaviours (maintenance, availability)

- The key question, though, is how can the refunds regime deliver the most value
  - Incentivising availability and readiness
  - Enhancing the credibility of the RCM by promoting performance worthy of a capacity credit
  - Aligning refund risk with value created

- In this presentation, we present a proposal to better align the Refunds Regime (RR) with the RCM

# The exposure to refund risk should operate in two dimensions

- With respect to the amount of excess reserve capacity that is available at any point in time
- With respect to the performance of capacity that is expected to be available at any point in time
- Incorporating both market conditions and unit performance into the refund regime maximises the value received for the price paid for a capacity credit

Value based on market conditions

| | |
|---|---|
| **Capacity: Reliable**<br>**Market: Shortage** | **Capacity: Unreliable**<br>**Market: Shortage** |
| **Capacity: Reliable**<br>**Market: Surplus** | **Capacity: Unreliable**<br>**Market: Surplus** |

Value based on capacity performance

# The market value of refund exposure is linked to the amount of excess reserve capacity available at any point in time

- The IMO’s dynamic refund factor proposal attempts to capture these impacts.

- The factors are muted somewhat relative to a pure economic value consideration, but the general concept and application is reasonable

Refund exposure = f ( amount of excess reserve capacity )

- Unless otherwise indicated, recommend continuing with the dynamic refund factors as previously analysed and proposed by the IMO
  - Note that the dynamic refund factors will have a different impact each year depending on the overall amount of supply and demand and the specific amount that is available in a given interval

# The other leg of the refund regime is to ensure that capacity performance is adequately incentivised

- Refund exposure should
  - Align with performance versus expectation
  - Underlying dispatch costs should not affect refund exposure – two units with similar reliability levels should face similar refund “risk” if they are equally unreliable during relevant periods

- Refund exposure should not
  - Distort investment incentives
  - Create arbitrary risks that do not align broadly with value

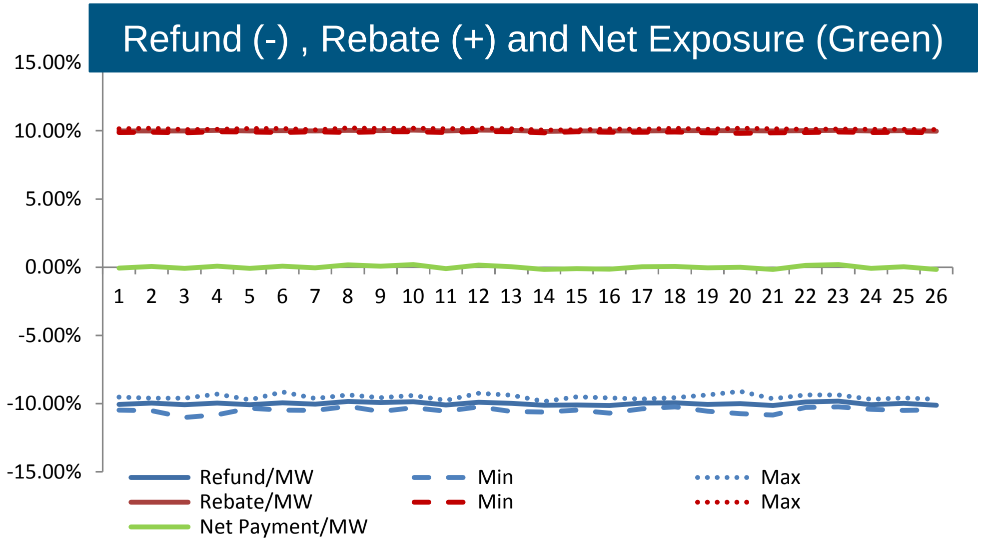
# As proposed last month, the simplest way to align both legs of the refunds regime is to combine a refund regime with a rebate regime

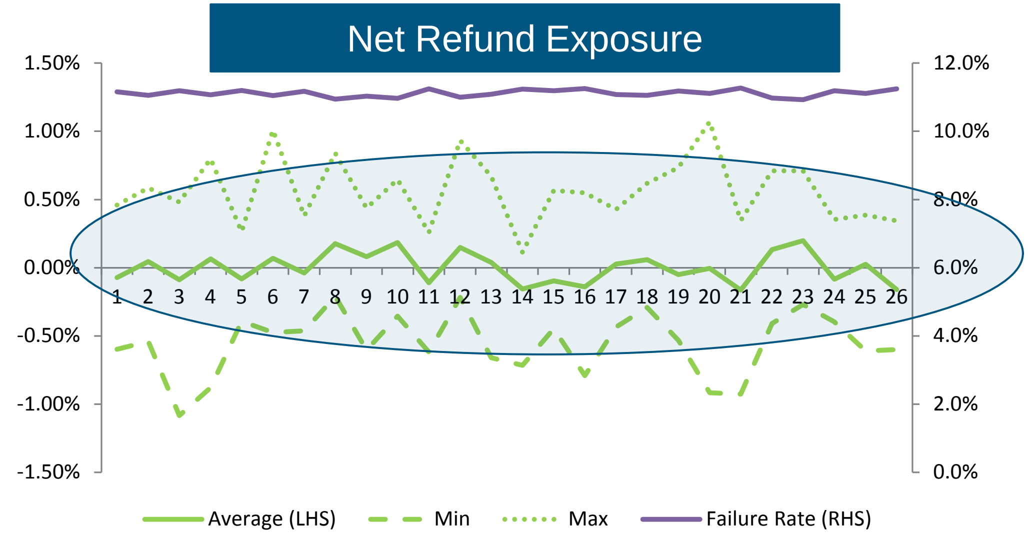
- Refund exposure increases to the extent that availability increases. Two facilities with equal reliability performance expectations (FOR), should face equivalent refund exposure
  - The problem is that dispatch can influence refunds through the sometimes messy relationship between dispatch and FOR
  - Two equally available units, one with low dispatch costs and one with high dispatch costs can have very different refund exposure if their FOR correlate with dispatch
  - This risk can be mitigated through a rebate mechanism<br>Similarly, a rebate mechanism can
  - Incentivise reduction in planned outages (as planned outages can reduce opportunity for rebate)
  - Sharpen incentives for managing capacity during peak periods – the decision to move from FOR to discretionary maintenance can take into account both refund and rebate exposure
- Capacity that performs less reliably pays more refund and loses more rebates – strengthening the incentive
- Aligns with longer term improvement of reliability and efficiency by reducing risk of refunds correlated with dispatch and rewarding better-than-average reliability at the expense of worse-than-average reliability

# Observations

- If capacity is less reliable, it pays relatively more
- If a year has more excess, capacity credits have lower value, so refunds are less (but so are rebates)
- If a year has less excess, capacity credits are more valuable, refunds are more penalising and rebates are more valuable
- DSM earns rebates for availability, pays refunds for non-performance
- Non performing (delayed) facilities lose refunds up to 100% of the value of capacity credits over the year if they do not operate at all
- Planned maintenance windows are accommodated by making a substantial portion of the load duration curve “refund free” (refund factor = zero)
- Maximum refund factor aligns with most valuable periods
- Rebate regime eliminates noise and impacts solely related to utilisation differences
- Rebate regime incentivises return from planned and unplanned outages

# Identical units with uniform refund factor : no net payment exposure



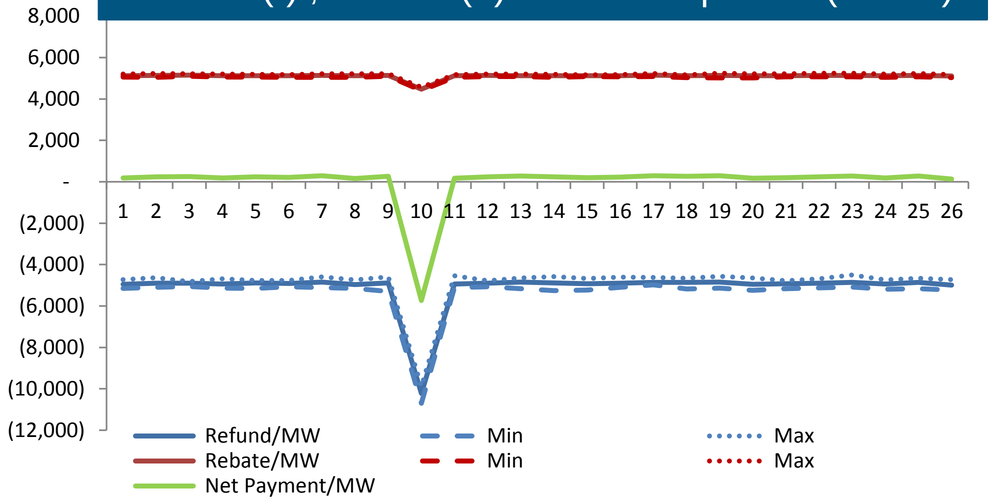




| % of hours | Refund Factor |
|---|---|
| 100% | 1 |
| 72% | 1 |
| 65% | 1 |
| 47% | 1 |
| 17% | 1 |
| 14% | 1 |
| 7% | 1 |
| 1% | 1 |
| 0% | 1 |

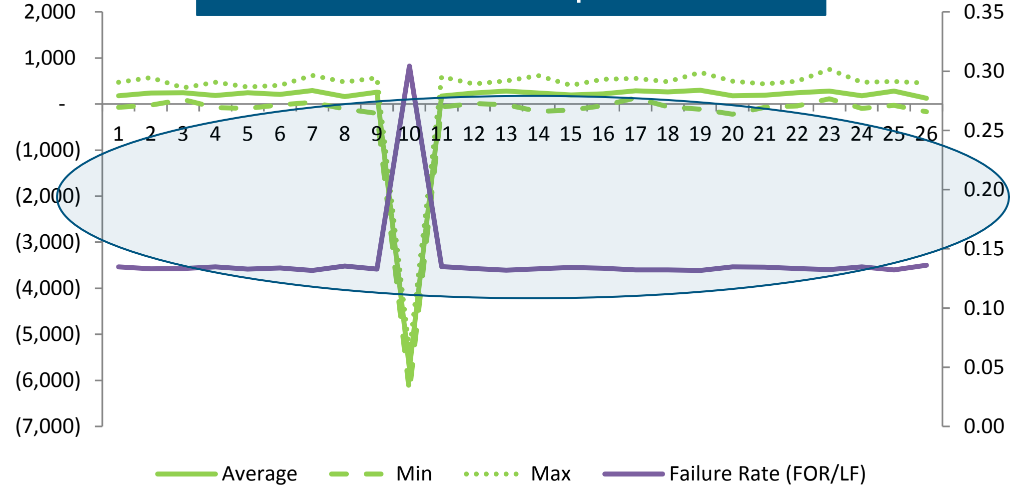
| Plant No. | Net Capacity (MW) | FOR (%) | Availability | Load Factor (%) | Plant No. | Net Capacity (MW) | FOR (%) | Availability | Load Factor (%) | Plant No. | Net Capacity (MW) | FOR (%) | Availability | Load Factor (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 200 | 10.0% | 96.0% | 80.0% | 10 | 200 | 10.0% | 96.0% | 80.0% | 19 | 200 | 10.0% | 96.0% | 80.0% |
| 2 | 200 | 10.0% | 96.0% | 80.0% | 11 | 200 | 10.0% | 96.0% | 80.0% | 20 | 200 | 10.0% | 96.0% | 80.0% |
| 3 | 200 | 10.0% | 96.0% | 80.0% | 12 | 200 | 10.0% | 96.0% | 80.0% | 21 | 200 | 10.0% | 96.0% | 80.0% |
| 4 | 200 | 10.0% | 96.0% | 80.0% | 13 | 200 | 10.0% | 96.0% | 80.0% | 22 | 200 | 10.0% | 96.0% | 80.0% |
| 5 | 200 | 10.0% | 96.0% | 80.0% | 14 | 200 | 10.0% | 96.0% | 80.0% | 23 | 200 | 10.0% | 96.0% | 80.0% |
| 6 | 200 | 10.0% | 96.0% | 80.0% | 15 | 200 | 10.0% | 96.0% | 80.0% | 24 | 200 | 10.0% | 96.0% | 80.0% |
| 7 | 200 | 10.0% | 96.0% | 80.0% | 16 | 200 | 10.0% | 96.0% | 80.0% | 25 | 200 | 10.0% | 96.0% | 80.0% |
| 8 | 200 | 10.0% | 96.0% | 80.0% | 17 | 200 | 10.0% | 96.0% | 80.0% | 26 | 200 | 10.0% | 96.0% | 80.0% |
| 9 | 200 | 10.0% | 96.0% | 80.0% | 18 | 200 | 10.0% | 96.0% | 80.0% | 27 | | | | |

# Higher FOR → Higher exposure

## Refund (-) , Rebate (+) and Net Exposure (Green)



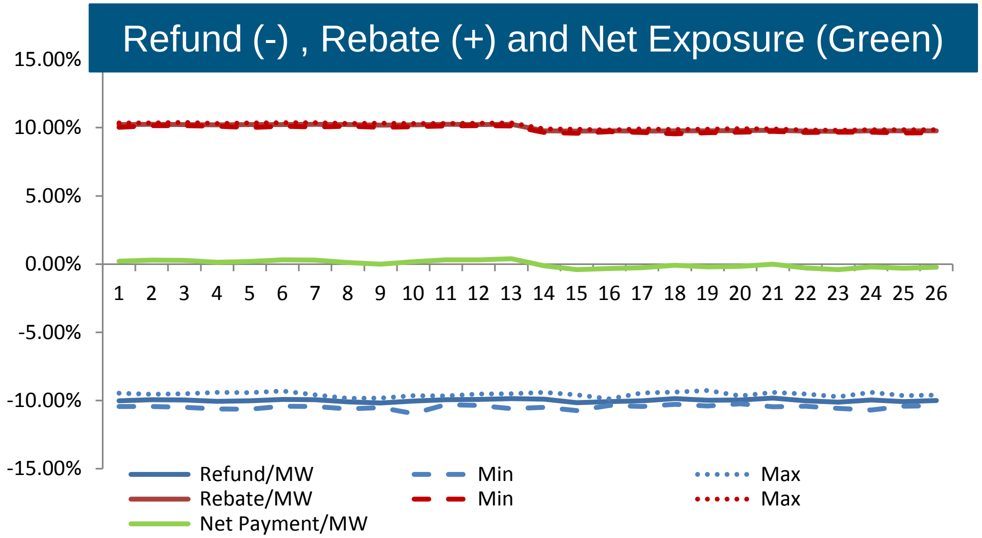

## Net Refund Exposure

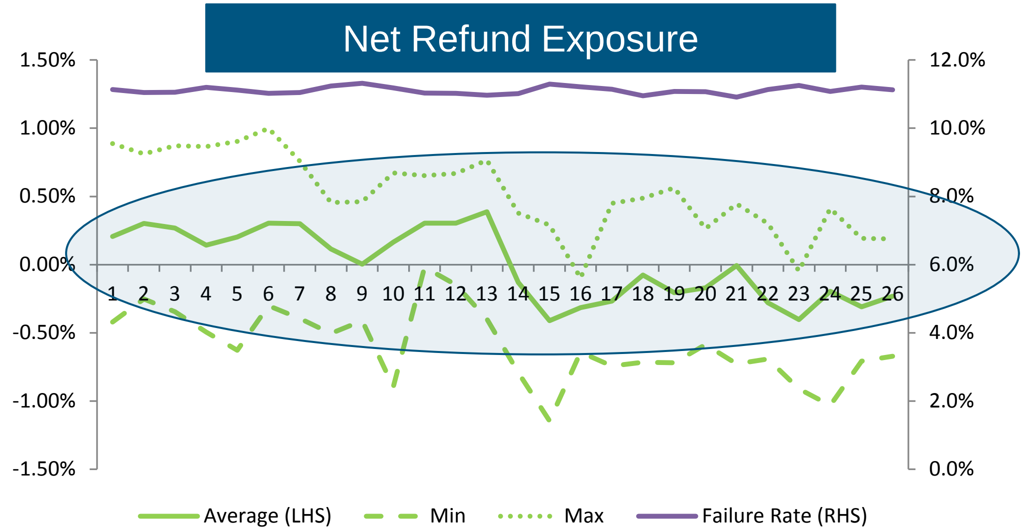



| Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) | Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) | Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 200 | 10.0% | 85.0% | 10 | 200 | 20.0% | 85.0% | 19 | 200 | 10.0% | 85.0% |
| 2 | 200 | 10.0% | 85.0% | 11 | 200 | 10.0% | 85.0% | 20 | 200 | 10.0% | 85.0% |
| 3 | 200 | 10.0% | 85.0% | 12 | 200 | 10.0% | 85.0% | 21 | 200 | 10.0% | 85.0% |
| 4 | 200 | 10.0% | 85.0% | 13 | 200 | 10.0% | 85.0% | 22 | 200 | 10.0% | 85.0% |
| 5 | 200 | 10.0% | 85.0% | 14 | 200 | 10.0% | 85.0% | 23 | 200 | 10.0% | 85.0% |
| 6 | 200 | 10.0% | 85.0% | 15 | 200 | 10.0% | 85.0% | 24 | 200 | 10.0% | 85.0% |
| 7 | 200 | 10.0% | 85.0% | 16 | 200 | 10.0% | 85.0% | 25 | 200 | 10.0% | 85.0% |
| 8 | 200 | 10.0% | 85.0% | 17 | 200 | 10.0% | 85.0% | 26 | 200 | 10.0% | 85.0% |
| 9 | 200 | 10.0% | 85.0% | 18 | 200 | 10.0% | 85.0% | 27 | | | |

| APPLY HRS | % of hours | Refund Factor |
|---|---|---|
| 8760 | 100% | 1 |
| 6320 | 72% | 1 |
| 5700 | 65% | 1 |
| 4134 | 47% | 1 |
| 1446 | 17% | 1 |
| 1210 | 14% | 1 |
| 590 | 7% | 1 |
| 87.6 | 1% | 1 |
| 0 | 0% | 1 |

# Lower availability, lower rebates → Exposure

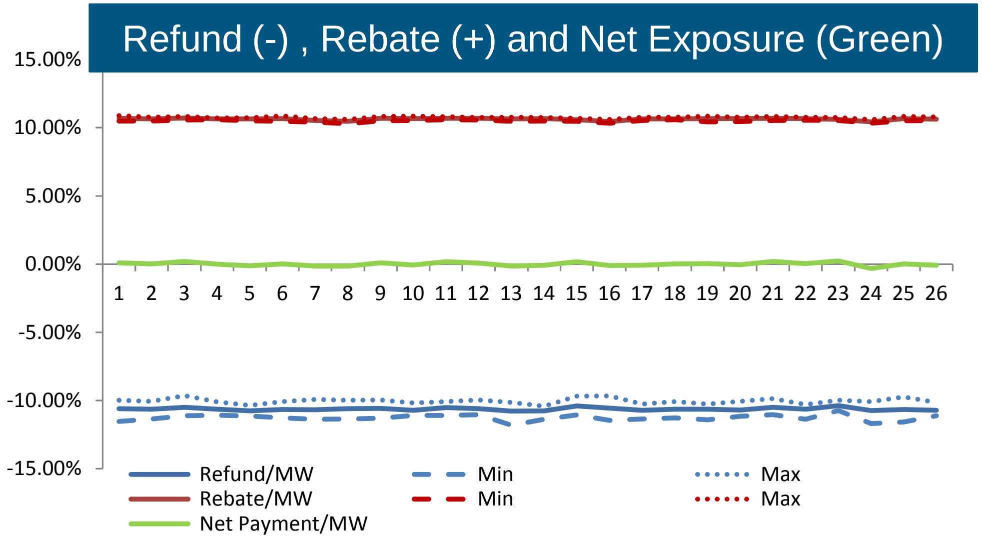


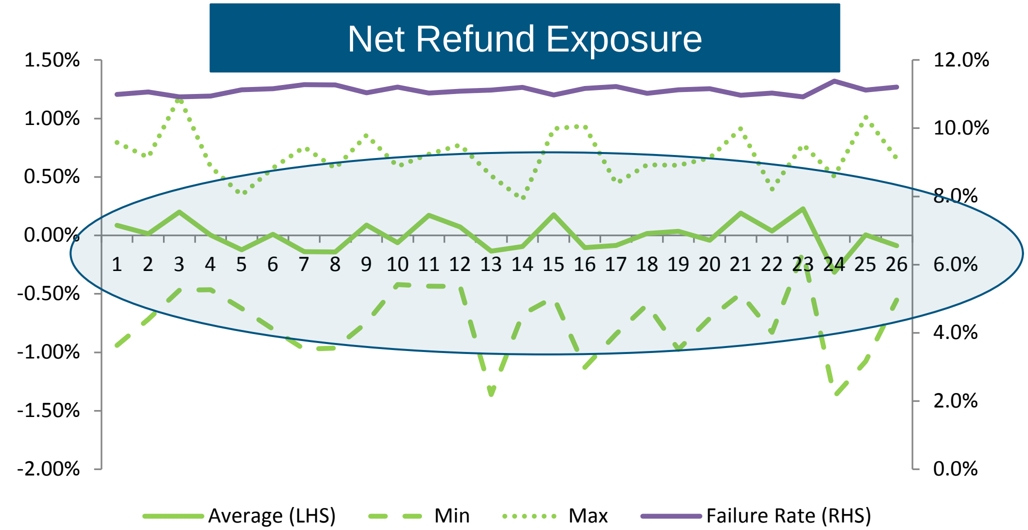




| % of hours | Refund Factor |
|---|---|
| 100% | 1 |
| 72% | 1 |
| 65% | 1 |
| 47% | 1 |
| 17% | 1 |
| 14% | 1 |
| 7% | 1 |
| 1% | 1 |
| 0% | 1 |

| Plant No. | Net Capacity (MW) | FOR (%) | Availability | Load Factor (%) | Plant No. | Net Capacity (MW) | FOR (%) | Availability | Load Factor (%) | Plant No. | Net Capacity (MW) | FOR (%) | Availability | Load Factor (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 200 | 10.0% | 96.0% | 80.0% | 10 | 200 | 10.0% | 96.0% | 80.0% | 19 | 200 | 10.0% | 92.0% | 80.0% |
| 2 | 200 | 10.0% | 96.0% | 80.0% | 11 | 200 | 10.0% | 96.0% | 80.0% | 20 | 200 | 10.0% | 92.0% | 80.0% |
| 3 | 200 | 10.0% | 96.0% | 80.0% | 12 | 200 | 10.0% | 96.0% | 80.0% | 21 | 200 | 10.0% | 92.0% | 80.0% |
| 4 | 200 | 10.0% | 96.0% | 80.0% | 13 | 200 | 10.0% | 96.0% | 80.0% | 22 | 200 | 10.0% | 92.0% | 80.0% |
| 5 | 200 | 10.0% | 96.0% | 80.0% | 14 | 200 | 10.0% | 92.0% | 80.0% | 23 | 200 | 10.0% | 92.0% | 80.0% |
| 6 | 200 | 10.0% | 96.0% | 80.0% | 15 | 200 | 10.0% | 92.0% | 80.0% | 24 | 200 | 10.0% | 92.0% | 80.0% |
| 7 | 200 | 10.0% | 96.0% | 80.0% | 16 | 200 | 10.0% | 92.0% | 80.0% | 25 | 200 | 10.0% | 92.0% | 80.0% |
| 8 | 200 | 10.0% | 96.0% | 80.0% | 17 | 200 | 10.0% | 92.0% | 80.0% | 26 | 200 | 10.0% | 92.0% | 80.0% |
| 9 | 200 | 10.0% | 96.0% | 80.0% | 18 | 200 | 10.0% | 92.0% | 80.0% | 27 | | | | |

# Dynamic refund factor has no “average overall” impact if units are all identical: The real value is incentivising focus on high value periods




| % of hours | Refund Factor |
|---|---|
| 100% | 1 |
| 72% | 2 |
| 65% | 3 |
| 47% | 4 |
| 17% | 5 |
| 14% | 6 |
| 7% | 7 |
| 1% | 8 |
| 0% | 9 |

| Plant No. | Net Capacity (MW) | FOR (%) | Availability | Load Factor (%) | Plant No. | Net Capacity (MW) | FOR (%) | Availability | Load Factor (%) | Plant No. | Net Capacity (MW) | FOR (%) | Availability | Load Factor (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 200 | 10.0% | 96.0% | 80.0% | 10 | 200 | 10.0% | 96.0% | 80.0% | 19 | 200 | 10.0% | 96.0% | 80.0% |
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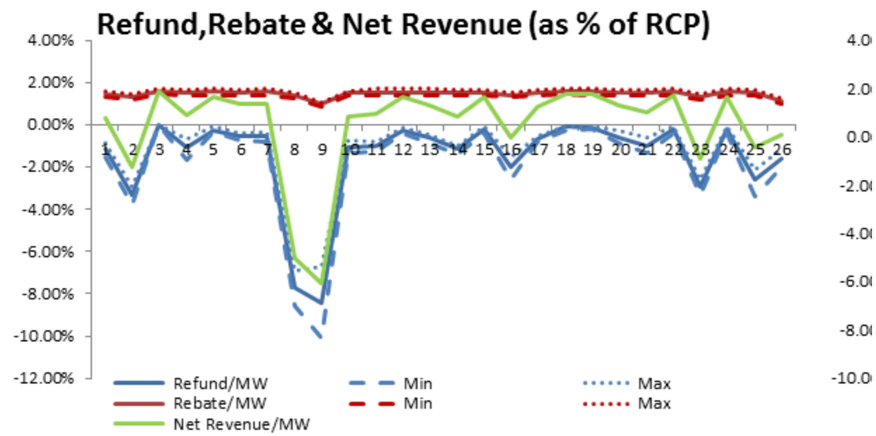
| 7 | 200 | 10.0% | 96.0% | 80.0% | 16 | 200 | 10.0% | 96.0% | 80.0% | 25 | 200 | 10.0% | 96.0% | 80.0% |
| 8 | 200 | 10.0% | 96.0% | 80.0% | 17 | 200 | 10.0% | 96.0% | 80.0% | 26 | 200 | 10.0% | 96.0% | 80.0% |
| 9 | 200 | 10.0% | 96.0% | 80.0% | 18 | 200 | 10.0% | 96.0% | 80.0% | 27 | | | | |

# Simulated refunds and rebates

| % of hours | Refund Factor | APPLY HRS | HRs in interval |
|---|---|---|---|
| 100% | | 8760 | 2440 |
| 72% | | 6320 | 620 |
| 65% | | 5700 | 1566 |
| 47% | 1 | 4134 | 2688 |
| 17% | 2 | 1446 | 236 |
| 14% | 3 | 1210 | 620 |
| 7% | 5 | 590 | 502.4 |
| 1% | 6 | 87.6 | 87.6 |
| 0% | NA | 0 | 0 |




Input
Output

| | Switch | |
|---|---|---|
| Eligible Capacity for Rebate | 0 | 0=ava; 1=dispatch |
| Distribute Unallocated refund | 1 | 0 = not dis; 1 = dis |
| FOR correlated to LF | 0 | 0 = not corr; 1 = corr |

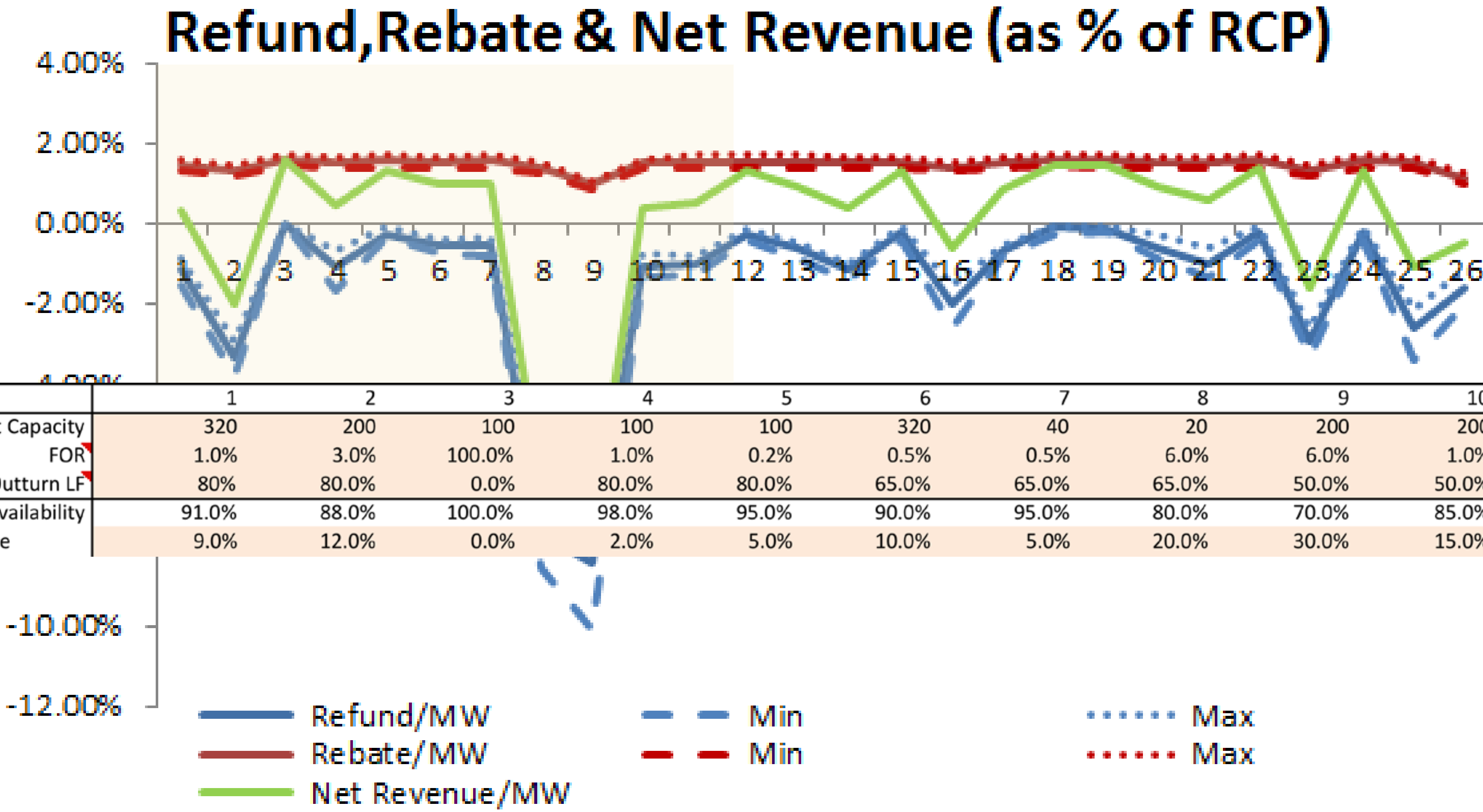
Run

| | |
|---|---|
| RCP (AUS/MW/yr) | 50000 |
| Peak (% of time) | 58% |
| Peak (No. of hours) | 5110 |
| Unit Refund (AUS$/M | 6.21 |

nark :
R + LF + Planned Outage <= 100%
tage start time >58.3% - only in off-peak
outturn LF to 0 if don't consider LF

| | Baseload | | | | Input capacity with reducing load factor | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Plant No. | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 |
| Net Capacity | 320 | 200 | 100 | 100 | 100 | 320 | 40 | 20 | 200 | 200 | 20 |
| FOR | 1.0% | 3.0% | 0.0% | 1.0% | 0.2% | 0.5% | 0.5% | 6.0% | 6.0% | 1.0% | 1.0% |
| Outturn LF | 80% | 80.0% | 0.0% | 80.0% | 80.0% | 65.0% | 65.0% | 65.0% | 50.0% | 50.0% | 50.0% |
| Availability | 91.0% | 88.0% | 100.0% | 98.0% | 95.0% | 90.0% | 95.0% | 80.0% | 70.0% | 85.0% | 95.0% |
| Planned Outage | 9.0% | 12.0% | 0.0% | 2.0% | 5.0% | 10.0% | 5.0% | 20.0% | 30.0% | 15.0% | 5.0% |
| Planned Outage Start | 91.0% | 79.0% | 79.0% | 77.0% | 72.0% | 62.0% | 95.0% | 75.0% | 70.0% | 85.0% | 80.0% |
| Planned Outage End | 100.0% | 91.0% | 79.0% | 79.0% | 77.0% | 72.0% | 100.0% | 95.0% | 100.0% | 100.0% | 85.0% |

# Scenarios: a range of different configurations of utilisation, FOR and planned outages



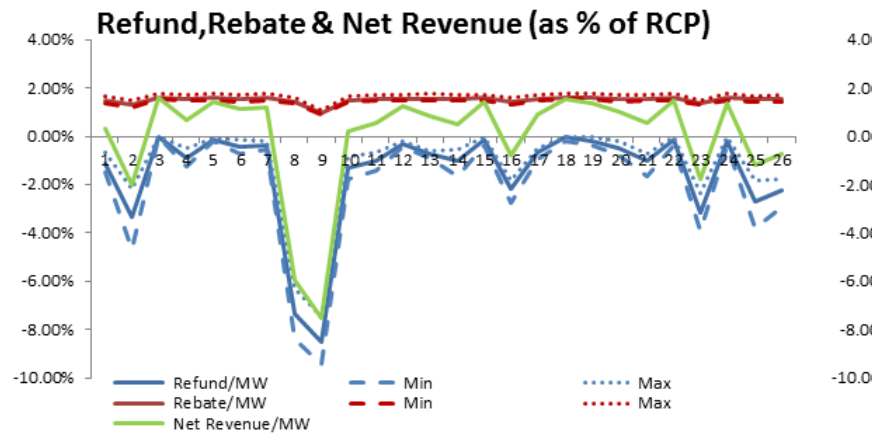

| Plant No. | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Net Capacity | 320 | 200 | 100 | 100 | 100 | 320 | 40 | 20 | 200 | 200 | 20 |
| FOR | 1.0% | 3.0% | 100.0% | 1.0% | 0.2% | 0.5% | 0.5% | 6.0% | 6.0% | 1.0% | 1.0% |
| Outturn LF | 80% | 80.0% | 0.0% | 80.0% | 80.0% | 65.0% | 65.0% | 65.0% | 50.0% | 50.0% | 50.0% |
| Availability | 91.0% | 88.0% | 100.0% | 98.0% | 95.0% | 90.0% | 95.0% | 80.0% | 70.0% | 85.0% | 95.0% |
| Planned Outage | 9.0% | 12.0% | 0.0% | 2.0% | 5.0% | 10.0% | 5.0% | 20.0% | 30.0% | 15.0% | 5.0% |

# Proposal

- Preserve the dynamic refund factor scheme concept, but note that
  - Currently refund relates to “factor * trading interval refund allocation”, but summation over the year may not recover full refund in the event of non performance
  - It would be better if a capacity that did not perform at all over a year received no residual capacity credit value.
- Pay rebates based on availability
  - If a resource is neither on planned or forced outage, it will receive a rebate.  Naturally the rebate will be larger if market conditions justify the “6” refund factor
- Recycle 100% of refunds – no net value change
  - Pure efficiency incentive
- As no net value change, and assuming no security risks, may not need any further adjustment, though it would be possible to incorporate a waning adjustment to the “RCP formula perhaps for a transition if necessary for fairness

# End

| % of hours | Refund Factor | APPLY HRS | HRs in interval |
|---|---|---|---|
| 100% | | 8760 | 2440 |
| 72% | | 6320 | 620 |
| 65% | | 5700 | 1566 |
| 47% | 0 | 4134 | 2688 |
| 17% | 1 | 1446 | 236 |
| 14% | 2 | 1210 | 620 |
| 7% | 3 | 590 | 502.4 |
| 1% | 4 | 87.6 | 87.6 |
| 0% | NA | 0 | 0 |




| Input | |
|---|---|
| Output | |

| | Switch | |
|---|---|---|
| Eligible Capacity for Rebate | 0 | 0=ava; 1=dispatch |
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| FOR correlated to LF | 0 | 0 = not corr; 1 = corr |

Run

| | |
|---|---|
| RCP (AUS/MW/yr) | 50000 |
| Peak (% of time) | 58% |
| Peak (No. of hours) | 5110 |
| Unit Refund (AUS$/M | 15.00 |

Baseload    Input capacity with reducing load factor

| Plant No. | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Net Capacity | 320 | 200 | 100 | 100 | 100 | 320 | 40 | 20 | 200 | 200 | 20 |
| FOR | 1.0% | 3.0% | 0.0% | 1.0% | 0.2% | 0.5% | 0.5% | 6.0% | 6.0% | 1.0% | 1.0% |
| Outturn LF | 80% | 80.0% | 0.0% | 80.0% | 80.0% | 65.0% | 65.0% | 65.0% | 50.0% | 50.0% | 50.0% |
| Availability | 91.0% | 88.0% | 100.0% | 98.0% | 95.0% | 90.0% | 95.0% | 80.0% | 70.0% | 85.0% | 95.0% |
| Planned Outage | 9.0% | 12.0% | 0.0% | 2.0% | 5.0% | 10.0% | 5.0% | 20.0% | 30.0% | 15.0% | 5.0% |
| Planned Outage Start | 91.0% | 79.0% | 79.0% | 77.0% | 72.0% | 62.0% | 95.0% | 75.0% | 70.0% | 85.0% | 80.0% |
| Planned Outage End | 100.0% | 91.0% | 79.0% | 79.0% | 77.0% | 72.0% | 100.0% | 95.0% | 100.0% | 100.0% | 85.0% |
| | TRUE | TRUE | TRUE | TRUE | TRUE | TRUE | TRUE | TRUE | TRUE | TRUE | TRUE |

nark :
R + LF + Planned Outage <= 100%
tage start time >58.3% - only in off-peak
outturn LF to 0 if don't consider LF

# A view of all the pieces

## RISK OF SHORTAGE

The MRCP sets the basis for the *unconstrained capacity resource benchmark cost*

*In theory an upper bound, but actual upper bound costs depends on factors that are uncertain and so is estimated as an expected value*

*Markets generally have to allow for some head-room above the expected value to ensure alignment between spot and contracting incentives*

## RETAILERS

Retailers generally are exposed to some risk of higher costs due to the fact that short-term options tend to be more costly than long-term options.  Failure to take prudent steps to assure sufficient long-term options can expose retailers to risk

As there are options that are more expensive in the short-term than the “target” benchmark, most markets expose retailers to risk of higher cost

## CONTRACTING

Contracting is neither good nor bad; it is about managing risk

Identify the risk and determine if contracting is a solution to it

Contracting helps parties manage uncertainty

*But to work as a risk management instrument, both sides must face some uncertainty for which the contract is a suitable instrument to manage.*

# A view of all the pieces (capacity)

## RISK OF SURPLUS

Supply and demand conditions determine the value of “spot” capacity

If there is excess capacity, the value of uncontracted capacity credits should reflect market conditions

Or, at minimum, signal clearly that new investment should not be required unless it can compete with the SRMC of existing capacity

## GENERATORS

When there is excess then, the value of capacity is supposed to fall.

*Uncontracted generators become exposed to falling “spot” capacity prices*

*New investors re-think their investment decisions – delay or cancel*

*In principle maximum exposure is nearly “zero” when the excess is so large – at least when calculated in economic terms*

## ENERGY MARKET

The RCM needs to ensure that the mix of capacity that is incentivised by the market contribute to lowering the cost of electricity over time through both the capacity and energy components.

## TESTING

Capacity needs to be tested if it is not sufficiently tested in the energy market

## HARMONISATION

A correctly defined capacity resource has the same value whether provided by suppliers or demand reduction

Material differences in resource capability to contribute to meeting peak demand should not exist

But “capability to meet peak demand” is a very generic issue – we are not concerned with fuel types or techonologies – only effectiveness

## NET REFUNDS

A nonperforming capacity resource poses a concern

Value for money?
Correct incentives?

Therefore the refunds regime works with harmonisation to sharpen availability incentives and protect the value-for-money proposition for those who pay for capacity

## BACKSTOP

Backstops are pro-competitive

Backstops can also be cost-increasing or risk-increasing

All depends on how the backstop is designed

But the existence of a backstop between generators and retailers reduces reliance on counterparty creditworthiness and buyer or seller market power – by defining an alternative pathway.

# Reserve Capacity Mechanism Working Group

## Minutes

| | |
|---|---|
| **Meeting No.** | 8 |
| **Location:** | IMO Boardroom<br>Level 17, 197 St Georges Terrace, Perth |
| **Date:** | Thursday 11 October 2012 |
| **Time:** | Commencing at 2.10pm – 5.45pm |

| Attendees | Class | Comment |
|---|---|---|
| Allan Dawson | Chair | |
| Suzanne Frame | IMO | |
| Brad Huppatz | Market Generator (Verve Energy) | |
| Ben Tan | Market Generator | Left at 5:10 pm |
| Wendy Ng | Market Customer | |
| Steve Gould | Market Customer | |
| Stephen MacLean | Market Customer (Synergy) | |
| Andrew Stevens | Market Customer/Generator | |
| Michael Zammit | Demand Side Management | Proxy |
| Geoff Down | Contestable Customer | |
| Justin Payne | Contestable Customer | |
| Brendan Clarke | System Management | |
| Wana Yang | Observer (Economic Regulation Authority) | |
| Paul Hynch | Observer (Public Utilities Office) | Left at 5:10 pm |
| **Apologies** | **Class** | **Comment** |
| Patrick Peake | Market Customer | |
| Andrew Sutherland | Market Generator | |
| Shane Cremin | Market Generator | |
| Jeff Renaud | Demand Side Management | |
| **Also in attendance** | **From** | **Comment** |
| Mike Thomas | Presenter (The Lantau Group) | |
| Greg Ruthven | Presenter (IMO) | |
| Aditi Varma | Minutes | |
| Fiona Edmonds | Observer | |
| Jenny Laidlaw | Observer | |
| Natasha Cunningham | Observer | |

| Item | Subject | Action |
|---|---|---|
| 1. | **WELCOME AND APOLOGIES / ATTENDANCE**<br>The Chair opened the eighth meeting of the Reserve Capacity Mechanism (RCM) Working Group (RCMWG) at 2:10pm.<br>The Chair welcomed the members in attendance and noted apologies from Mr Patrick Peake, Mr Andrew Sutherland, Mr Shane Cremin and Mr Jeff Renaud. | |
| 2. | **MINUTES ARISING FROM MEETING 5**<br>The following amendments were noted:<br>• Mr Greg Ruthven to be included in the list of attendees.<br>• On page 8, Ms Wana Yang requested the following change:<br>*Ms Wana Yang provided a comment on availability of generating plants in the market. She observed that plants which have high rates of Planned Outages should be included in the review of ~~penalised by~~ the refund mechanism.*<br>*Action Point: The IMO to publish amended minutes of RCMWG meeting no.7 on the Market Web Site.* | |
| 3. | **ACTIONS ARISING**<br>Ms Suzanne Frame noted that Action Item 2(The IMO to include information on the cost effectiveness of proposed solutions or harmonisation) was in progress.<br>She added that Mr Greg Ruthven would present his analysis for Action Item 4 and Mr Mike Thomas for Action Item 5. | |
| 3a. | **ACTION ITEM 4: Assess the Significance of the Issue of Gaming by analysing coincidental Relevant Demand (RD) and Individual Reserve Capacity Requirements (IRCR)Trading Intervals**<br>The Chair invited Mr Ruthven to make his presentation.<br>The following discussion points were noted:<br>• Members requested that the presentation be uploaded on the RCMWG webpage.<br>• Mr Stephen MacLean noted that even one load on the system with a Relevant Demand figure that is greater than the adjusted IRCR should be of concern. Mr Andrew Stevens noted that the number of such loads are low and may seem immaterial, but he agreed with Mr MacLean on principle. Mr Stevens proposed that in case of an adjustment to Relevant Demand, the Wholesale Electricity Market (WEM) Rules (Market Rules) should allow for an automatic adjustment to the IRCR. The Chair noted that it would be useful to rectify the anomaly that exists in the Market Rules where the IRCR did not have to be adjusted in response to an adjustment to the RD. He further added that the IMO would assess the potential of this issue for a Rule Change and report back to the group.<br>• Mr Ben Tan also requested that the analysis be provided not just as a percentage of loads but also as a percentage | |

| | | |
|---|---|---|
| | of total capacity so that members can assess the significance of the issue.<br>*Action Points:*<br>• *The IMO to upload presentation for Action Item 4 on the Market Web Site*<br>• *The IMO to assess the need for a Rule Change to allow for an adjustment to the IRCR if the RD is adjusted in a Trading Interval*<br>• *The IMO to include further analysis on RD and IRCR as a percentage of total capacity in addition to as a percentage of loads.* | |
| **3b.** | **ACTION ITEM 5: Present a Preferred Proposal for Dynamic Refunds Regime**<br>The Chair invited Mr Mike Thomas to present on the dynamic refunds regime<br>The following points of discussion were noted:<br>• On the recycling mechanism for refunds, Mr MacLean noted that the proposal only created incentives for generators to come back online quicker from a Forced Outage because of the high prices in the energy market that would result from some generation capacity not being available. Mr Stevens noted that lower capacity refunds would also act as an incentive. Mr Brad Huppatz asked for more clarity on how the rebate would work, whether it would be given to available units or operating units. Mr Thomas responded that there were two options to pay the rebates; the first one being to pay the rebates to those units that were dispatched, however, in doing so there would be a chance that a unit with a higher Forced Outage rate at other times might get unfairly paid, and the second option was to pay the rebates to those units that are available and are not on Planned or Forced Outages. Mr Michael Zammit observed that in this proposal, the impact of the refunds could be diminished for generators who may be on long Outages but are available for the remaining year as they could make up for their losses during the times they are available. In response, members discussed that the situation would be different for generators who are on an average Outage rate. If a generator had an Outage rate higher than the average, then it would be out-of-pocket as a result of the refunds.<br>• Discussion ensued on how the proposal would work. Mr Ben Tan queried if the proposed rebate would just be pro-rated across all available units on a Trading Interval basis. Mr MacLean queried if the principle was to encourage generators to minimise their Planned Outages. The Chair added that the rebates proposal may incentivize generators to take enough time off to fix their equipment and build the potential of earning rebates into their commercial decision-making. Ms Wana Yang requested if analysis should be done using the 2011-12 Capacity Year to assess what rebates might be collected by a generator who was on Outage for more than 30% of the year. Mr Huppatz clarified that the proposal was to apply refunds if the unit was on a Planned Outage as well. | |

| | | |
|---|---|---|
| | The Chair observed that there would be winners and losers. It seemed that good performance would be rewarded, potentially getting more money than they paid, whereas bad performance would still be exposed to refunds.<br>• Mr Geoff Down observed that the proposal seemed to indicate that the value of capacity was different according to the time at which it was running. He noted that this seemed to contradict the original principle of all capacity having the same value, which the working group had agreed to. Mr Thomas responded that capacity does have the same value however, the only way to test if a piece of equipment would deliver that value was to test it and apply refunds.<br>• Mr Huppatz and Mr Stevens noted that the proposal would not address the issue of unfair reward to generators that had a low capacity factor as well as low utilisation. They noted that it would be unfair to reward generators, such as peaking units, that have very low utilisation, at times when another generator goes on a Forced Outage. At such times, the risk is increased for generators that are running; and so it would be unfair to reward generators that are available but not running. Mr MacLean also echoed this concern.<br>• Mr MacLean queried whether the proposed refund mechanism would apply to Demand Side Programmes as well. Mr Thomas responded that his analysis was based on the scenario where harmonization had already been applied and DSP's would have unlimited availability.<br>• Mr Justin Payne observed that the proposal did not address the concerns raised about plants that have high Planned Outage rates such as 30% or above, indicating that they are unavailable for a long time but would still get paid rebates. Mr Huppatz noted that there were current provisions in the Market Rules that allowed System Management to reject Planned Outages and generators would be exposed to refunds thereafter. Discussion ensued whether the proposal created incentives for generators to be available. Mr Huppatz argued that currently there is a strong incentive to conduct planned maintenance to avoid Forced Outages. Mr MacLean added that in his opinion the incentive was not strong enough. He further added that this proposal would warrant renegotiation of contracts because currently the retailer pays for the cost of refunds that generators and DSPs incur. In the case of this proposal, the money and the risk would get reallocated implying that a renegotiation of those contracts would have to take place. The Chair also added that the situation would be worsened for Market Customers if a capacity shortfall occurred and the IMO was forced to recruit Supplementary Reserve Capacity.<br>• Mr Brendan Clarke queried how Intermittent Generators would be treated under this proposal. Mr Ruthven noted that a Facility would be eligible for a rebate in a Trading Interval in which it was potentially liable for a refund. Given that the Reserve Capacity Obligation Quantity of Intermittent Generators is zero, they would not be eligible for rebates. Members also discussed the impact of the proposal on DSPs. Mr Zammit noted that there was an outstanding action item on harmonization related to defining the conditions in which DSP could be dispatched. | |

| | | |
|---|---|---|
| | • Mr Thomas concluded by noting the three main points of concern that were raised by members in response to the dynamic refunds proposal:<br>a) The need to renegotiate bilateral contracts<br>b) The reallocation of money from Market Customers to Market Generators<br>c) The continued application of costs of Supplementary Reserve Capacity to Market Customers<br>• Mr Huppatz added that further analysis should be done on the impact on different generating plants utilising different technologies because in his opinion, the technology of a plant can affect its Outage rates. The Chair suggested that it would be useful to use last year's data to conduct analysis of the impacts on each individual generator. The Chair queried if members were comfortable with pursuing this proposal albeit with further analysis conducted on the concerns raised by members. Mr MacLean mentioned that he was not convinced that this proposal would produce any significant incentives. His suggestion was that this proposal should not be pursued further. The Chair responded that it might be premature to dismiss this proposal without doing further investigation into its merits and demerits.<br>*Action Point:*<br>• *The Lantau Group to address the following specific concerns raised by members on the proposed refunds mechanism:*<br>*a) The need to renegotiate bilateral contracts*<br>*b) The reallocation of money from Market Customers to Market Generators*<br>*c) The continued application of costs of Supplementary Reserve Capacity to Market Customers*<br>• *The Lantau Group to conduct further analysis on the impacts of the proposed refunds regime on individual Facilities.* | |
| **4.** | **RESERVE CAPACITY PRICE (WORK STREAM 1)**<br>The Chair invited Mr Thomas to make his presentation. The following discussion points were noted:<br>• Ms Yang mentioned that the quantity of excess capacity was a concern. The concern stemmed more from an economic efficiency perspective because excess capacity indicated inefficient over-investment. She also noted that the Shared Capacity Cost was always borne by the Market Customers, irrespective of whether there was excess capacity or a shortfall.<br>• Mr Tan noted that Mr Thomas's proposal was based on an implicit assumption about the price of reserve capacity in bilateral contracts. He added that a retailer would be in a better position if most of its capacity was bilaterally contracted, if the contract price was lower than the Reserve Capacity Price.<br>• There was some discussion around the nature of bilateral contracting, spigot control mechanism and the potential for introducing auction. Members also discussed the existence of | |

| | | |
|---|---|---|
| | market power and its interaction with the excess capacity problem.<br>• Discussion ensued on the proposed 110% of MRCP and -3.25 slope. Members also discussed the potential impact of the reduction in MRCP that might come about due to revisions in the Weighted Average Cost of Capital (WACC).<br>• At this point, the Chair invited Mr Ruthven to present the analysis on MRCP with the revised assumptions. He highlighted that this MRCP was only calculated for purely theoretical purposes and should not be taken as the real, binding MRCP for next year. Mr Tan clarified with Ms Yang what the impact of a revised debt risk premium might be on the MRCP.<br>• The Chair concluded that more analysis was needed in terms of the impact of the RCP parameters on the market as it currently stands. He further added that the working group members needed to decide whether a strong case for change to the recommended proposal could not be made. If that was the case, then the working group might consider seeking further advice from the Market Advisory Committee and the IMO Board on whether a more radical approach to the RCM should be examined. The Chair also added that the next RCMWG meeting should focus on working out these issues and recommending a way forward.<br>*Action Item:*<br>• *The Lantau Group to examine the effects of the Reserve Capacity Price proposal with the help of some worked examples.* | |
| | **CLOSED**<br>The Chair thanked the members and declared the meeting closed at 5.45 pm. | |

# Recommendation: Dynamic Capacity Refund Regime

22 November 2012

THE LANTAU GROUP
strategy & economic consulting

# Purpose and Summary

- This presentation summarises analysis related to the dynamic refund proposal.
- It recommends a dynamic refund regime with recycling based on availability
- It starts with the IMO dynamic refund proposal and then proposes two changes to improve it
  - Impose a minimum refund level for all trading intervals
  - Set the maximum refund factor annually based on the ratio of the MRCP to the RCP, thus normalising refund value for similar system conditions one year to the next (without being distorted by differences in the RCP due to changes in average annual excess reserve capacity)
- We present simulation results based on detailed modeling
- We review and compare refund results under the current regime to the proposed regime

# Refund Recycling

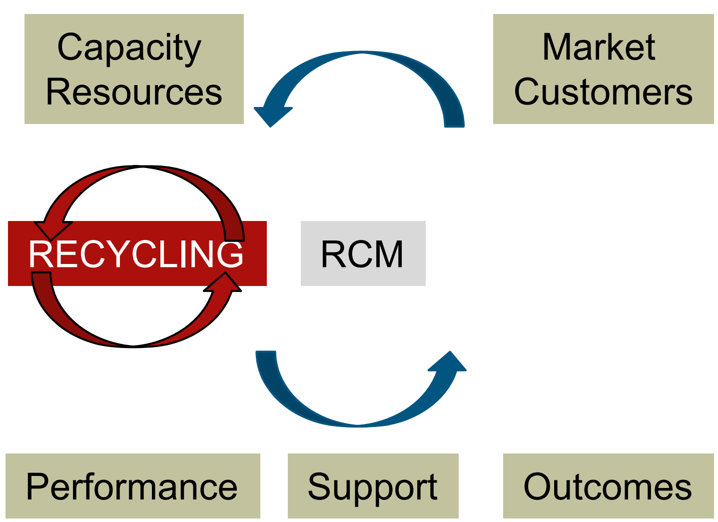
- Summary of recommendation
  - Recycling to improve efficiency and mitigate risk of unintended consequences / distortions
  - Rebates of refund revenue based on availability (to be explained)
  - Dynamic refund factors reflective of system conditions
  - Minimum refund factor to tie refund exposure to capacity credit value
  - Maximum refund factor determined annually based on ratio of MRCP / RCP
- Revenue loss to market customers offset by adjustments to RCM proposal
  - Offset RCR using 97 percent factor
  - Slope steepened to -3.75 from -3.25
- Contractual disposition of refunds not affected
  - Rebates to go to party exposed to refund
- Eligibility for rebate corresponds to exposure to refund risk

# Refunds constitute a small, but meaningful value component to Market Customers

In the capacity year 2010/11:

| | | Rebate (k$) | Proportion |
|---|---|---|---|
| STMRFINT | Participant 30 Min Interval Net STEM Refund | 716 | 3.7% |
| ILCREF | Intermittent Load Capacity Refund Amount | 322 | 1.7% |
| FRCDRF_FO | Facility Reserve Capacity Deficit Refund for Forced Outage | 0 | 0.0% |
| FRCDRF_NGC | New Generation System Test Refund for 30 Minute Interval | 0 | 0.0% |
| FFORFINT | Facility Forced Outage Refund for 30 Minute Interval | 18153 | 94.6% |
| Total | | 19191 | 100.0% |

| | |
|---|---|
| FFORFINT Refund as Capacity Payment (at MRCP) | 2.42% |
| FFORFINT Refund as Capacity Payment (at RCP) | 2.91% |




- Current: refunds are collected when capacity resources are on FO and are paid out to Market Customers
  - Incentive to be available linked to penalty
  - Analogous to a performance contract between capacity providers and capacity users
  - But "value" to Market Customers is delivered by the *overall* RCM, not by the performance of individual capacity resources
- Proposed: refund revenue to be recycled amongst eligible capacity resources
  - Creates a stronger performance incentive, rather than a value transfer risk or revenue loss
  - Impact stays within RCM, making it easier and clearer to align long-term investment incentives, RCP adjustments and other RCM features with RCM purpose

# Key decisions

1. Availability based rebates – to align refund regime and RCM

2. Dynamic refund factors – to reflect system conditions and sharpen incentives

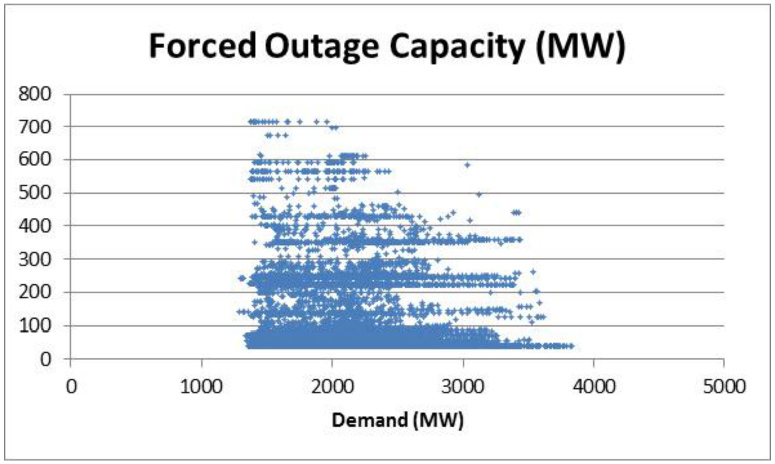
# 1) Setting the basis for rebates: availability vs dispatch?

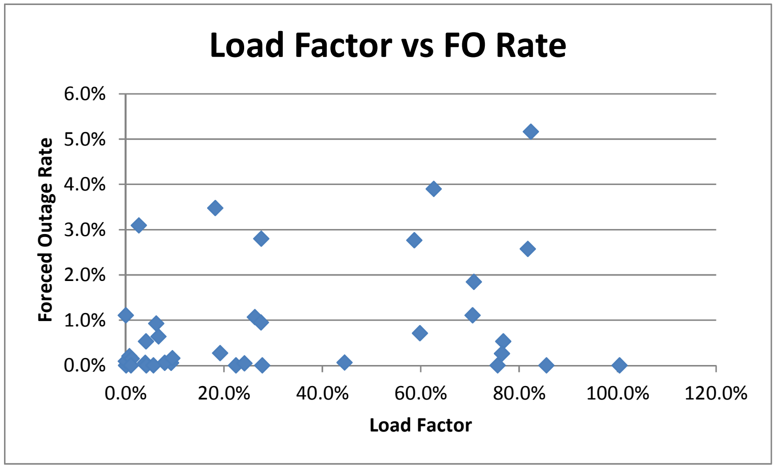
- Rebates can be
  - paid to units dispatched in times refunds are incurred, or
  - paid to units that are available

- The RCM is about incentivising availability.
  - Actual dispatch is the acid test of availability.
  - But availability still has value, even when not dispatched

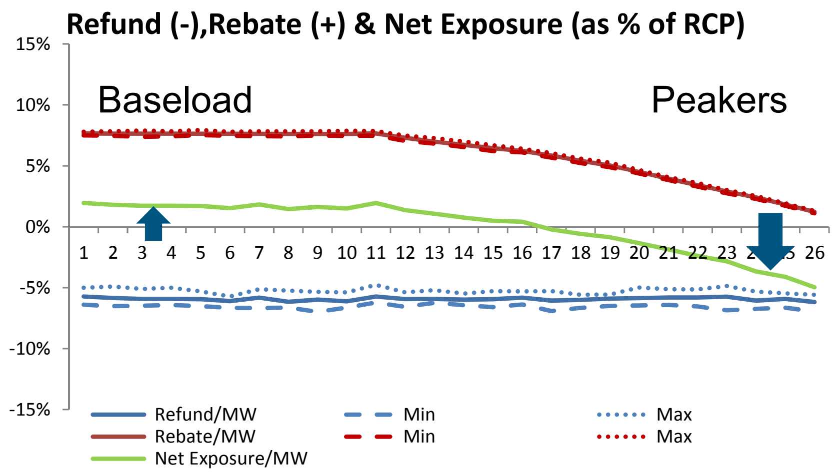
- Forced outages are not highly correlated with dispatch
  - If a unit on FO wasn't going to be dispatched, anyway, why should its refund go to units that *were* dispatched?

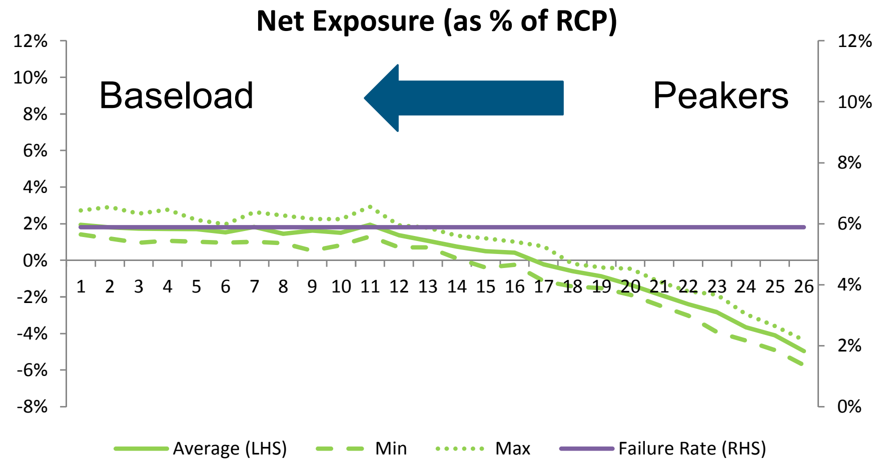
- Based on FO data and experience, we recommend rebate based on availability
  - Avoids significant risk of distorting value transfer and prospective reward to rent seeking behaviour



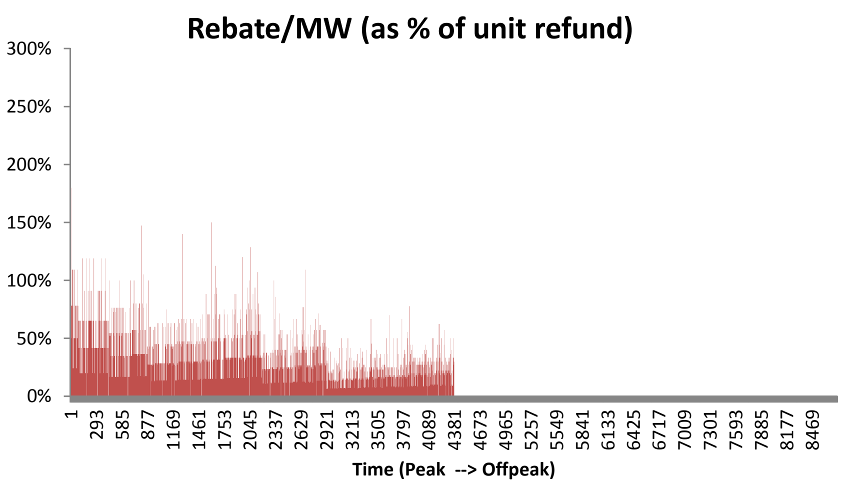



# *Dispatch-based rebates transfer value based on utilisation (when FO events are independent)*



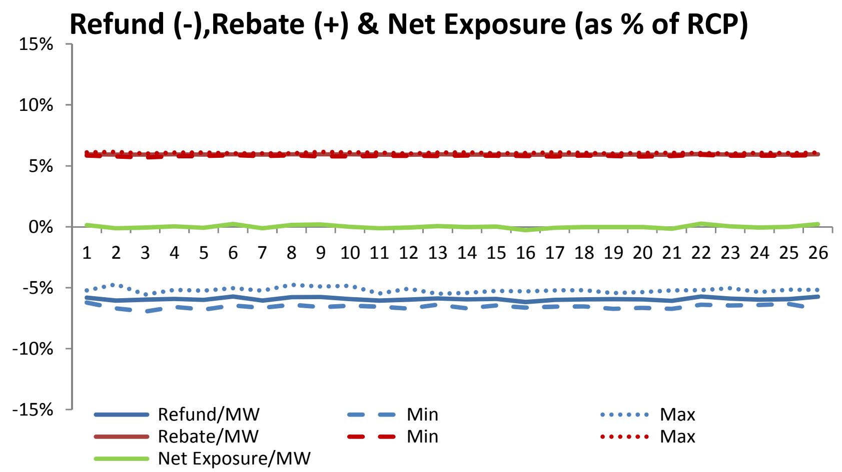

| % of hours | Refund Factor |
|---|---|
| 100% | 0 |
| 75% | 0 |
| 67% | 0 |
| 50% | 1 |
| 33% | 2 |
| 25% | 3 |
| 10% | 4 |
| 5% | 5 |
| 1% | 6 |

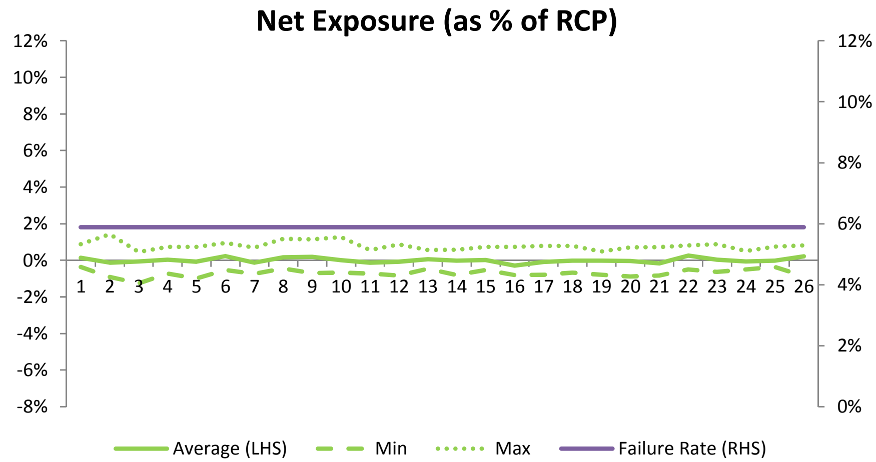



**Hypothetical system of identical units with same FO and availability but different load factors**

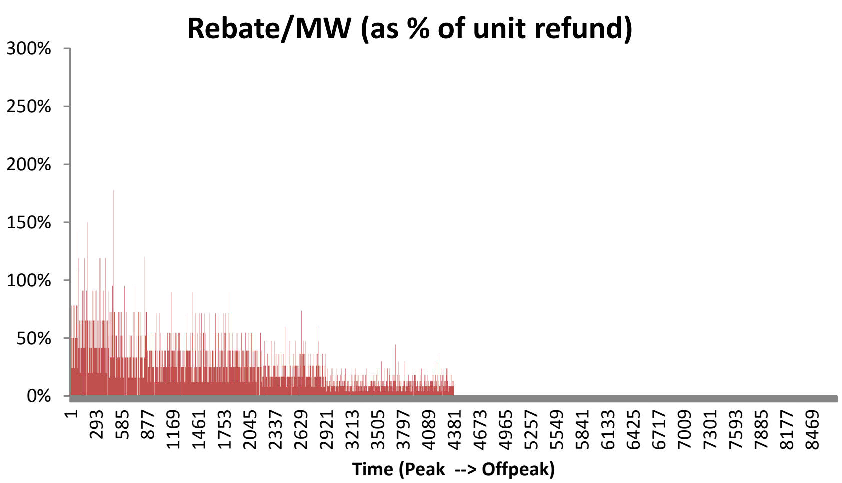
| Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) | Availability (%) | Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) | Availability (%) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 200 | 5.0% | 80.0% | 85.0% | 14 | 200 | 5.0% | 41.0% | 85.0% |
| 2 | 200 | 5.0% | 77.0% | 85.0% | 15 | 200 | 5.0% | 38.0% | 85.0% |
| 3 | 200 | 5.0% | 74.0% | 85.0% | 16 | 200 | 5.0% | 35.0% | 85.0% |
| 4 | 200 | 5.0% | 71.0% | 85.0% | 17 | 200 | 5.0% | 32.0% | 85.0% |
| 5 | 200 | 5.0% | 68.0% | 85.0% | 18 | 200 | 5.0% | 29.0% | 85.0% |
| 6 | 200 | 5.0% | 65.0% | 85.0% | 19 | 200 | 5.0% | 26.0% | 85.0% |
| 7 | 200 | 5.0% | 62.0% | 85.0% | 20 | 200 | 5.0% | 23.0% | 85.0% |
| 8 | 200 | 5.0% | 59.0% | 85.0% | 21 | 200 | 5.0% | 20.0% | 85.0% |
| 9 | 200 | 5.0% | 56.0% | 85.0% | 22 | 200 | 5.0% | 17.0% | 85.0% |
| 10 | 200 | 5.0% | 53.0% | 85.0% | 23 | 200 | 5.0% | 14.0% | 85.0% |
| 11 | 200 | 5.0% | 50.0% | 85.0% | 24 | 200 | 5.0% | 11.0% | 85.0% |
| 12 | 200 | 5.0% | 47.0% | 85.0% | 25 | 200 | 5.0% | 8.0% | 85.0% |
| 13 | 200 | 5.0% | 44.0% | 85.0% | 26 | 200 | 5.0% | 5.0% | 85.0% |

# *Availability-based rebates are indifferent to load-factor*




| % of hours | Refund Factor |
|---|---|
| 100% | 0 |
| 75% | 0 |
| 67% | 0 |
| 50% | 1 |
| 33% | 2 |
| 25% | 3 |
| 10% | 4 |
| 5% | 5 |
| 1% | 6 |



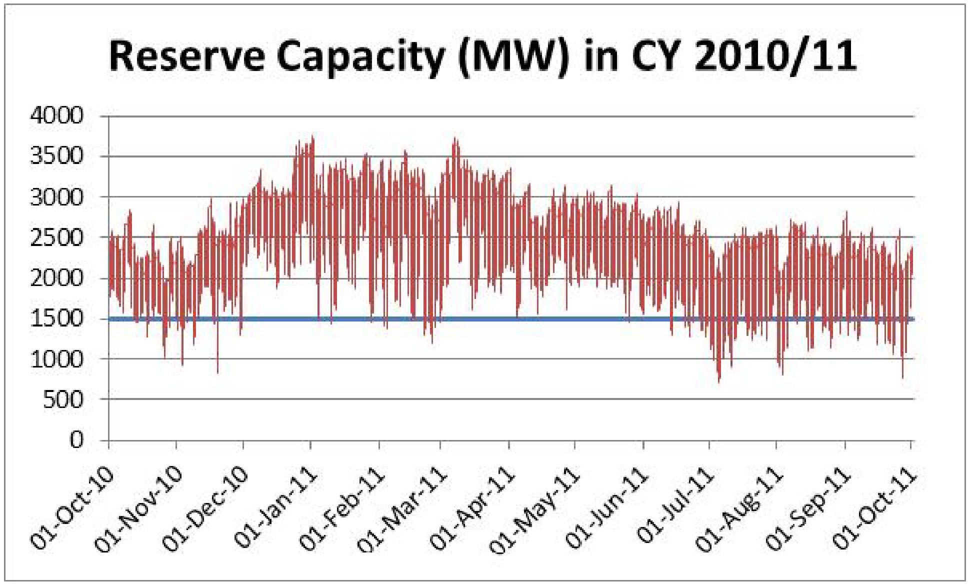

Hypothetical system of identical units with same FO and availability but different load factors

| Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) | Availability (%) | Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) | Availability (%) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 200 | 5.0% | 80.0% | 85.0% | 14 | 200 | 5.0% | 41.0% | 85.0% |
| 2 | 200 | 5.0% | 77.0% | 85.0% | 15 | 200 | 5.0% | 38.0% | 85.0% |
| 3 | 200 | 5.0% | 74.0% | 85.0% | 16 | 200 | 5.0% | 35.0% | 85.0% |
| 4 | 200 | 5.0% | 71.0% | 85.0% | 17 | 200 | 5.0% | 32.0% | 85.0% |
| 5 | 200 | 5.0% | 68.0% | 85.0% | 18 | 200 | 5.0% | 29.0% | 85.0% |
| 6 | 200 | 5.0% | 65.0% | 85.0% | 19 | 200 | 5.0% | 26.0% | 85.0% |
| 7 | 200 | 5.0% | 62.0% | 85.0% | 20 | 200 | 5.0% | 23.0% | 85.0% |
| 8 | 200 | 5.0% | 59.0% | 85.0% | 21 | 200 | 5.0% | 20.0% | 85.0% |
| 9 | 200 | 5.0% | 56.0% | 85.0% | 22 | 200 | 5.0% | 17.0% | 85.0% |
| 10 | 200 | 5.0% | 53.0% | 85.0% | 23 | 200 | 5.0% | 14.0% | 85.0% |
| 11 | 200 | 5.0% | 50.0% | 85.0% | 24 | 200 | 5.0% | 11.0% | 85.0% |
| 12 | 200 | 5.0% | 47.0% | 85.0% | 25 | 200 | 5.0% | 8.0% | 85.0% |
| 13 | 200 | 5.0% | 44.0% | 85.0% | 26 | 200 | 5.0% | 5.0% | 85.0% |

## 2) Setting the refund factors

- Current refund factors are time-based
- Dynamic refund factors reflect system conditions

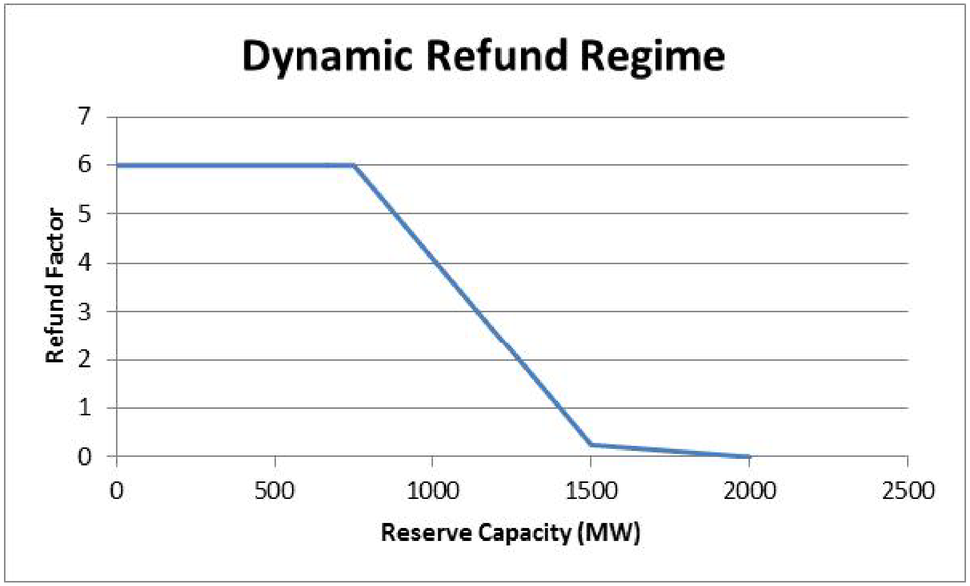
In capacity year 2010/11, reserve capacity exceeded 1500 MW 93.4% of time




The applicable refund factor should be be higher when reserve capacity is lower; time-based factors do not capture system conditions robustly

# Option (1) : IMO proposal per RDIWG Meeting No. 11

- In RDIWG Meeting No.11 note, the IMO proposed
  - a capped refund factor that would apply whenever the reserve capacity is below the required minimum reserve used by System Management in outage planning, say 2*min reserve ~ 750MW;
  - a 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 ~ 1500MW; and
  - a final break point set such that the refund factor is zero when reserve is greater than 6 * min reserve ~ 2000MW.
  - the cap on cumulative refunds and translation factor, Y, is retained




Reserve Capacity = Capacity Credits – Demand – Planned Outage – Forced Outage

Y = Annual Reserve Capacity Price / 12 months / Number of Trading Intervals per month

Interval Refund rate ($/MW) = Refund factor * Y

# Option (1) : IMO proposal: Pros and Cons

- Pros
  - Implements dynamic refund factors that reflect system conditions
  - Significant improvement on existing time-based arrangements (as noted in previous meetings)

- Cons
  - The spread of refund factors could be increased to better reflect the spread of economic value implications of differing reserve capacity levels in real time
  - Possible under extreme conditions of excess reserve capacity for a unit on prolonged FO to retain some of its capacity payment revenue
  - Value of TI refunds varies from year to year for the same system condition due to changes in the RCP
    - If TI reserve capacity is 500 in two different years, the value of a TI refund will be Refund Factor * Y, where Y reflects a different RCP in each year
    - But if TI reserve capacity is same in both years, should not the refund exposure be the same – only the probability of hitting that exposure should be different

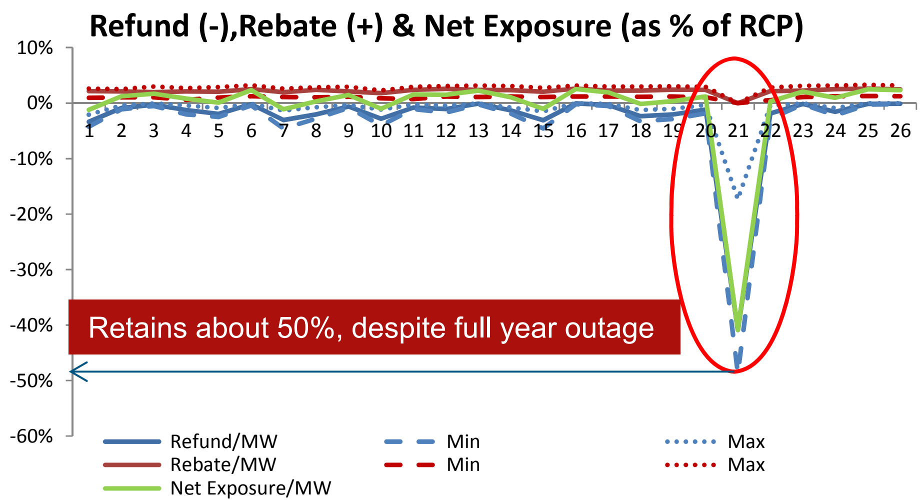
**Pros outweigh the cons, but material improvement is also possible**

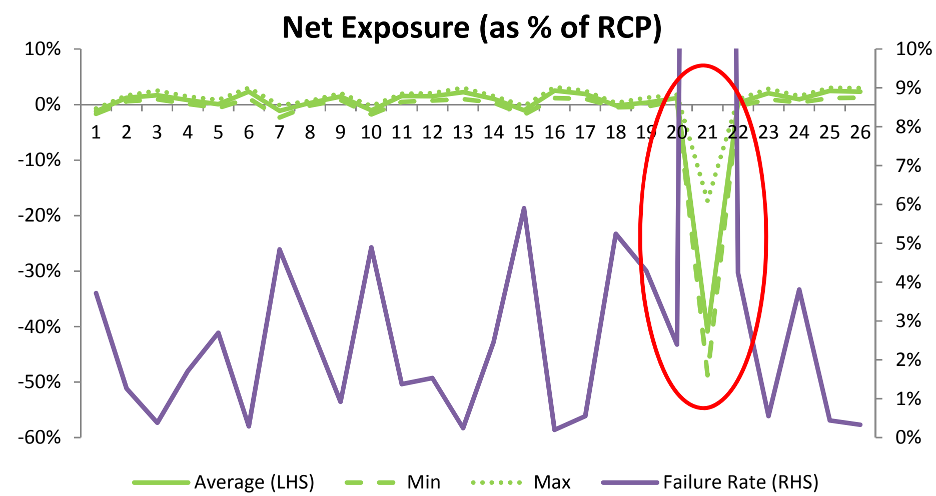
## Improving Option (1) : Addressing the risk of unmerited CP value capture

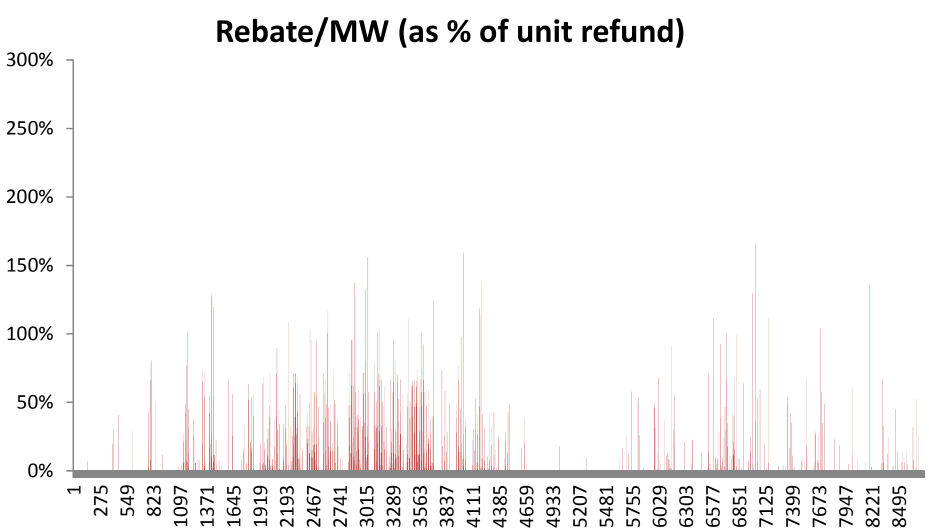
- Small possibility of retaining some capacity credit value even if year-long FO
  - Refund factors can be zero or less than 1 for substantial portions of the year
  - Higher factors may not occur enough to cause sum-of-factors to claw back full CP value
- Only happens if
  - Sufficient excess reserve capacity
  - Few other planned and forced outages (so refund factors are minimised)
- RCP pricing (slope) assists
  - Lower RCP when more excess reserve capacity reduces benefit of strategy
- Options for dealing with this
  - Ignore – small probability / cannot be assured (strategy of exploitation is not without significant risk)
  - Set minimum conditions for retention of capacity credit value
  - Set minimum refund factors to prevent situation from being possible

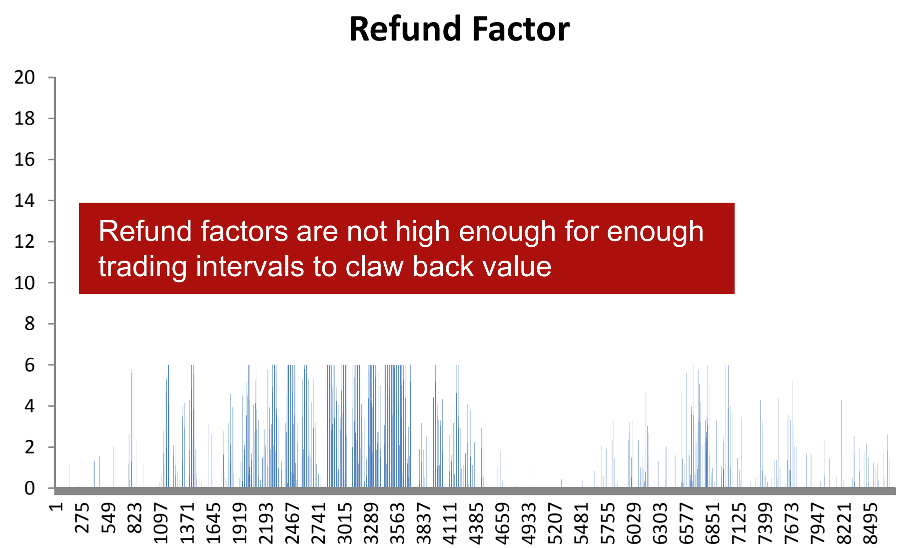
5% ERC

# A facility on FO for a year year could (theoretically) retain some capacity credit value – at least in this hypothetical simulation

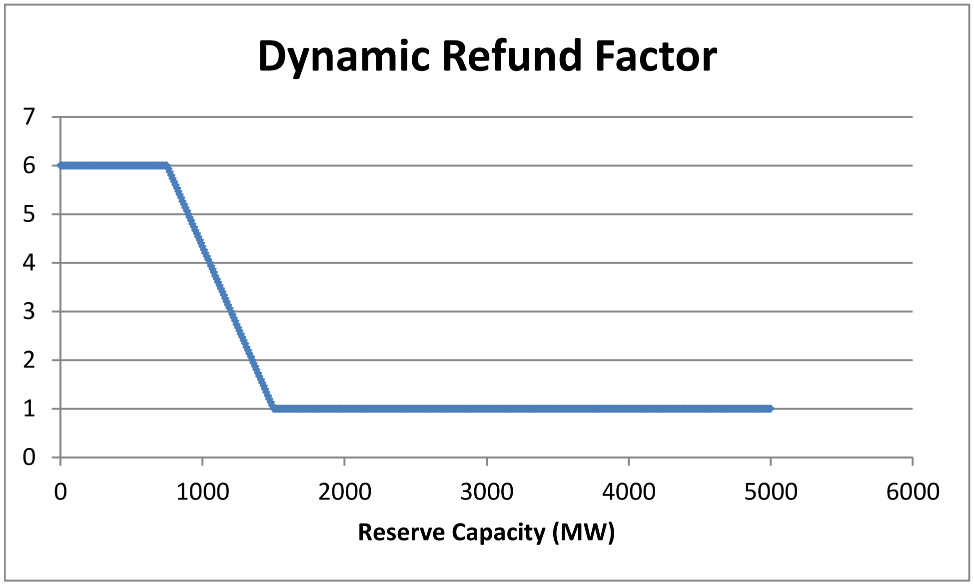


# Option (2) : IMO's proposal with **minimum refund factor level**

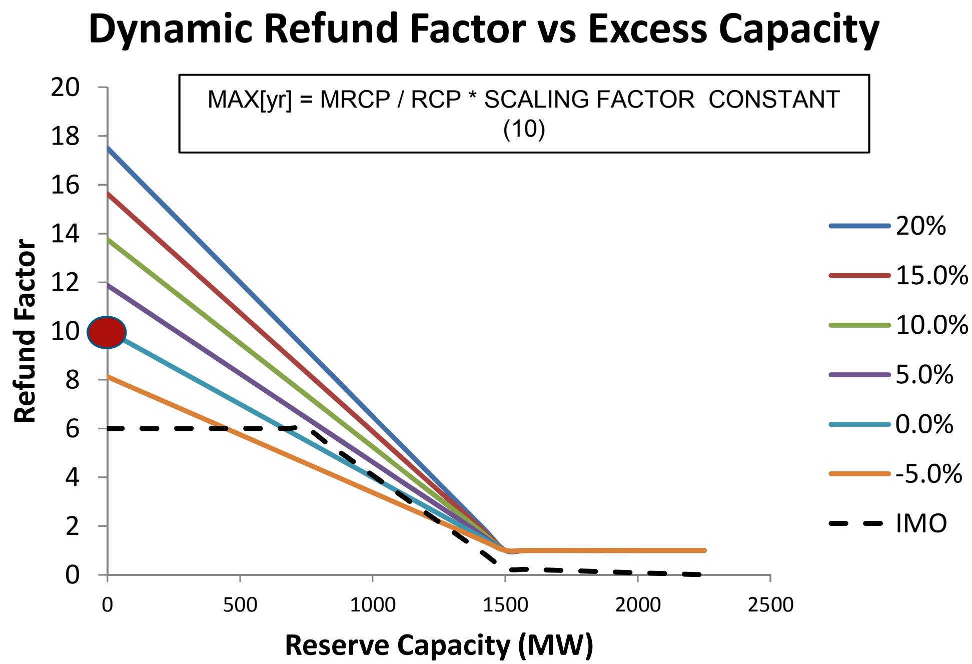



- Pros
  - Impossible to avoid refund exposure or full clawback for complete non-performance
  - Signals that any period is potentially a value period, so reduces incentive to game FO into ultra low periods – improving truthful declaration

- Cons
  - Exposure to refunds, even in low value periods
  - Reduces "spread" between highest refund factor period and lowest – dulling the overall incentive mildly
    - (0 to 6 is a larger spread than 1 to 6)

# Option 3 : RCP-linked dynamic refund factors

- Same principles as IMO Dynamic Proposal
- Except that
  - Linear (no cap) – so potentially higher refund risk
  - Linked to ratio of MRCP/RCP – equalises refund value for same levels of excess capacity in a TI, regardless of RCP
- Despite sharper incentives, this approach increases financial stability / robustness / predictability




Principle: At the point of 0 reserve capacity in a TI, no matter what the RCP is for the year, the refund exposure should be (MRCP / TI) * Scaling factor constant

# Option 1: IMO DR PROPOSAL (5 and 15% Excess Reserve Capacity)

| | |
|---|---|
| Refund Regime | IMO |
| Availiability or Dispatched Based Rebate | Availability |
| Excess Capacity | 5% |
| Maximum Reserve Capacity Price ($/MW) | 163900 |
| Reserve Capacity Price ($/MW) | 138685 |
| Unit Refund ($/MWh) | 15.76 |

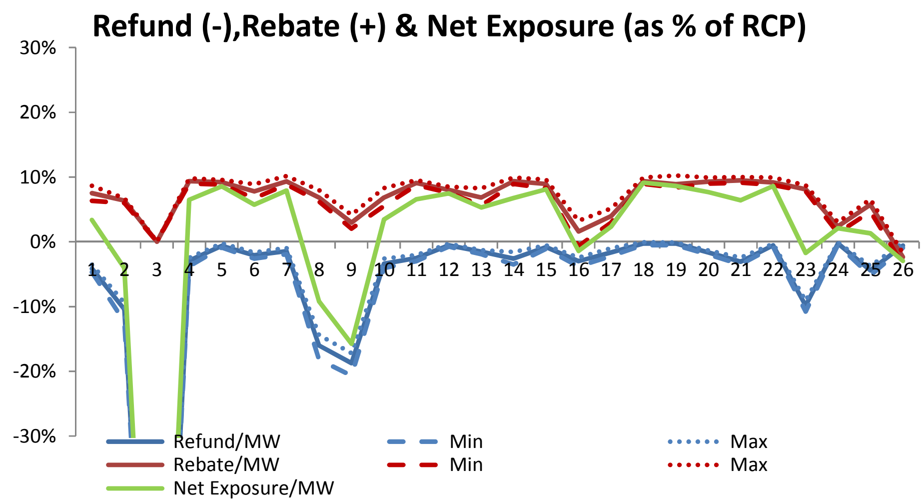
| | |
|---|---|
| Refund Regime | IMO |
| Availiability or Dispatched Based Rebate | Availability |
| Excess Capacity | 15% |
| Maximum Reserve Capacity Price ($/MW) | 163900 |
| Reserve Capacity Price ($/MW) | 107636 |
| Unit Refund ($/MWh) | 11.97 |

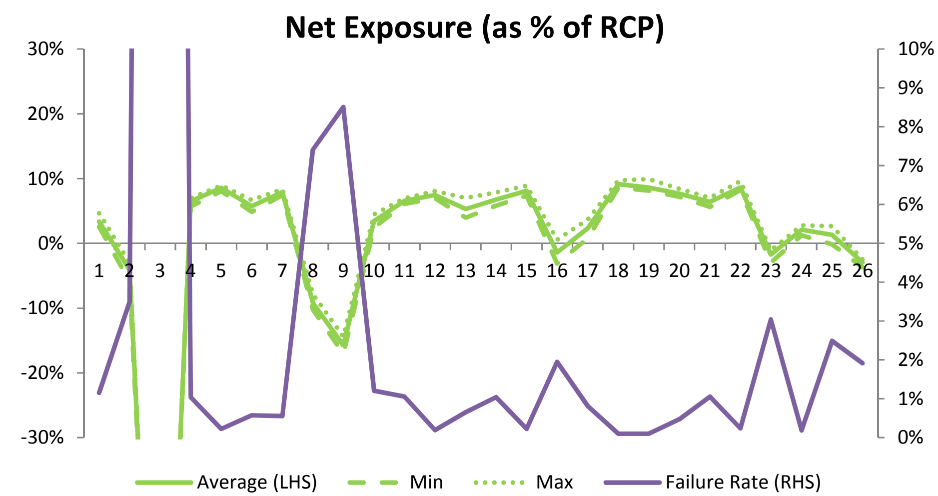
| Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) | Availability (%) | Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) | Availability (%) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 320 | 1.0% | 91.1% | 91.0% | 14 | 40 | 1.0% | 51.7% | 96.0% |
| 2 | 200 | 3.0% | 84.9% | 88.0% | 15 | 320 | 0.2% | 48.1% | 95.0% |
| 3 | 100 | 100.0% | 0.0% | 100.0% | 16 | 200 | 1.0% | 7.9% | 50.0% |
| 4 | 100 | 1.0% | 97.0% | 98.0% | 17 | 200 | 0.5% | 14.0% | 65.0% |
| 5 | 100 | 0.2% | 94.8% | 95.0% | 18 | 100 | 0.1% | 11.4% | 95.0% |
| 6 | 320 | 0.5% | 89.5% | 90.0% | 19 | 40 | 0.1% | 8.1% | 90.0% |
| 7 | 40 | 0.5% | 94.5% | 95.0% | 20 | 200 | 0.5% | 7.1% | 98.0% |
| 8 | 20 | 6.0% | 74.0% | 80.0% | 21 | 100 | 1.0% | 3.7% | 99.0% |
| 9 | 200 | 6.0% | 64.0% | 70.0% | 22 | 40 | 0.2% | 2.5% | 95.0% |
| 10 | 200 | 1.0% | 78.0% | 85.0% | 23 | 200 | 3.0% | 1.7% | 98.0% |
| 11 | 20 | 1.0% | 74.4% | 95.0% | 24 | 100 | 0.1% | 1.1% | 50.0% |
| 12 | 200 | 0.2% | 69.7% | 90.0% | 25 | 20 | 2.0% | 0.1% | 80.0% |
| 13 | 100 | 0.5% | 50.9% | 80.0% | 26 | 50 | 0.5% | 0.0% | 25.0% |

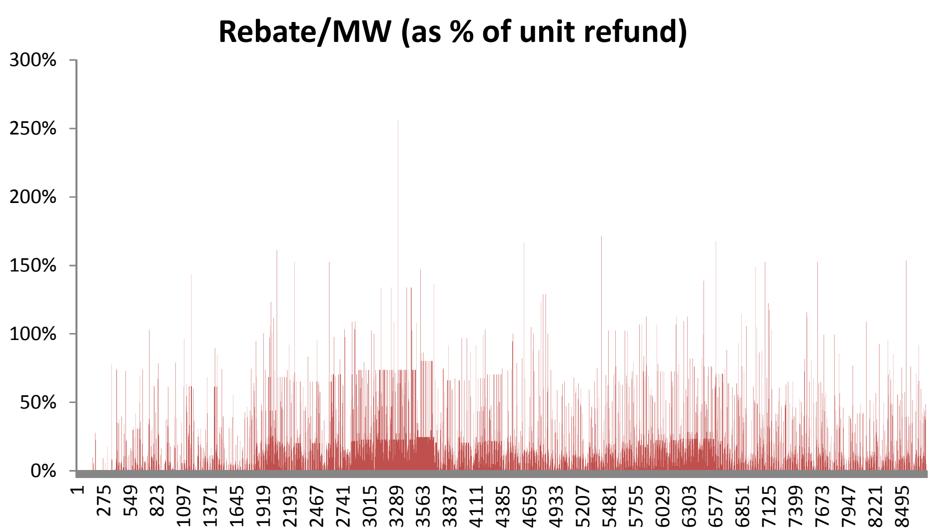
| Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) | Availability (%) | Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) | Availability (%) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 320 | 1.0% | 90.0% | 91.0% | 14 | 40 | 1.0% | 38.3% | 96.0% |
| 2 | 200 | 3.0% | 84.9% | 88.0% | 15 | 320 | 0.2% | 34.6% | 95.0% |
| 3 | 100 | 100.0% | 0.0% | 100.0% | 16 | 200 | 1.0% | 3.9% | 50.0% |
| 4 | 100 | 1.0% | 97.0% | 98.0% | 17 | 200 | 0.5% | 8.0% | 65.0% |
| 5 | 100 | 0.2% | 94.8% | 95.0% | 18 | 100 | 0.1% | 5.3% | 95.0% |
| 6 | 320 | 0.5% | 89.5% | 90.0% | 19 | 40 | 0.1% | 3.4% | 90.0% |
| 7 | 40 | 0.5% | 93.6% | 95.0% | 20 | 200 | 0.5% | 2.8% | 98.0% |
| 8 | 20 | 6.0% | 72.8% | 80.0% | 21 | 100 | 1.0% | 1.0% | 99.0% |
| 9 | 200 | 6.0% | 61.6% | 70.0% | 22 | 40 | 0.2% | 0.5% | 95.0% |
| 10 | 200 | 1.0% | 71.9% | 85.0% | 23 | 200 | 3.0% | 0.2% | 98.0% |
| 11 | 20 | 1.0% | 65.6% | 95.0% | 24 | 100 | 0.1% | 0.2% | 50.0% |
| 12 | 200 | 0.2% | 61.5% | 90.0% | 25 | 20 | 2.0% | 0.0% | 80.0% |
| 13 | 100 | 0.5% | 38.7% | 80.0% | 26 | 50 | 0.5% | 0.0% | 25.0% |

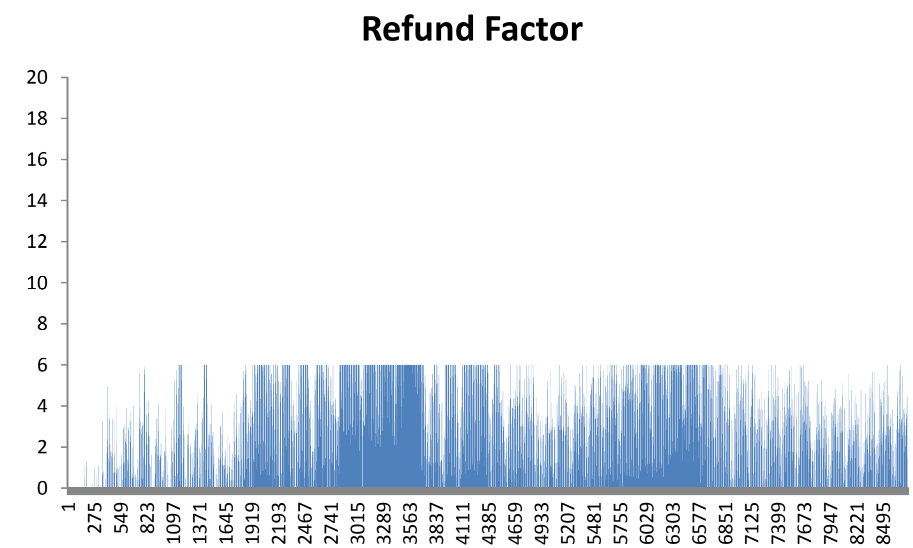
Simulation Model

# Option 1: IMO DR Proposal (5% ERC)



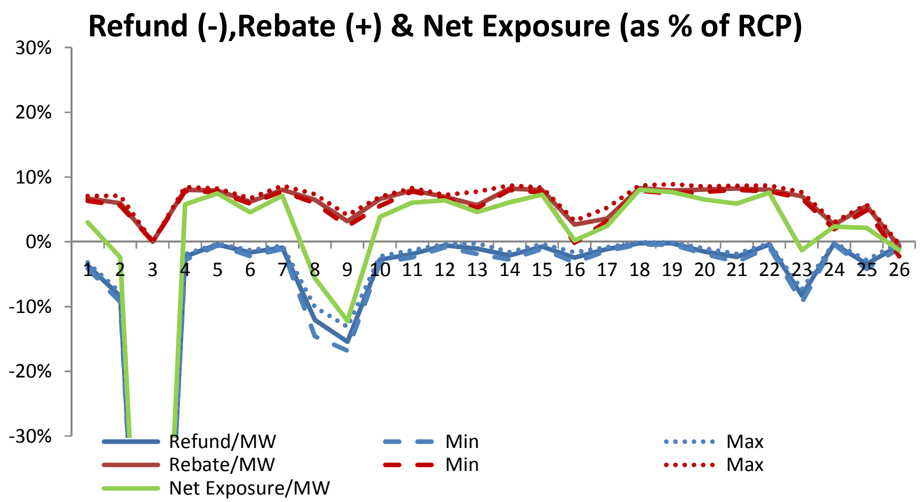



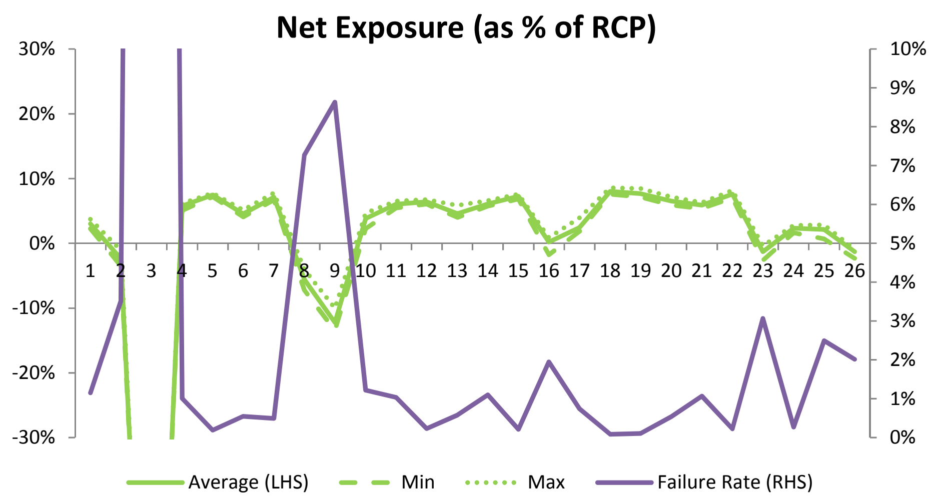



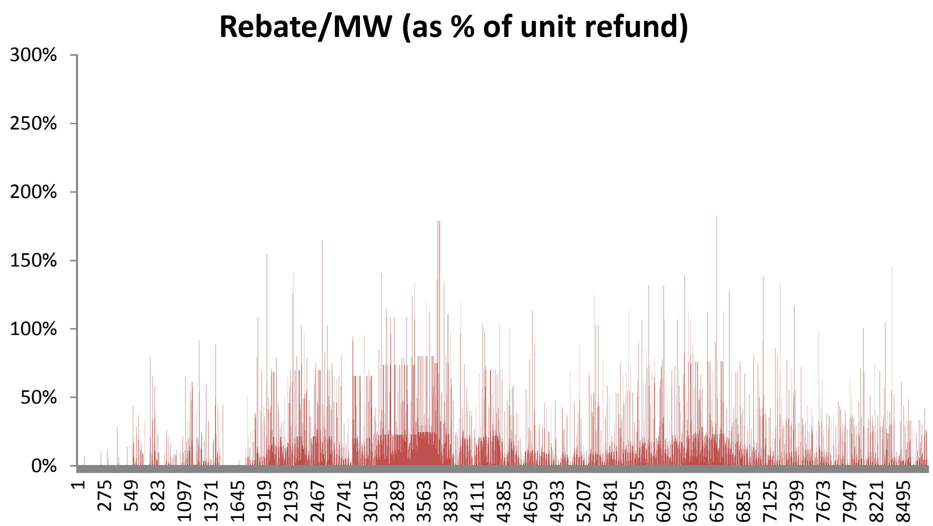



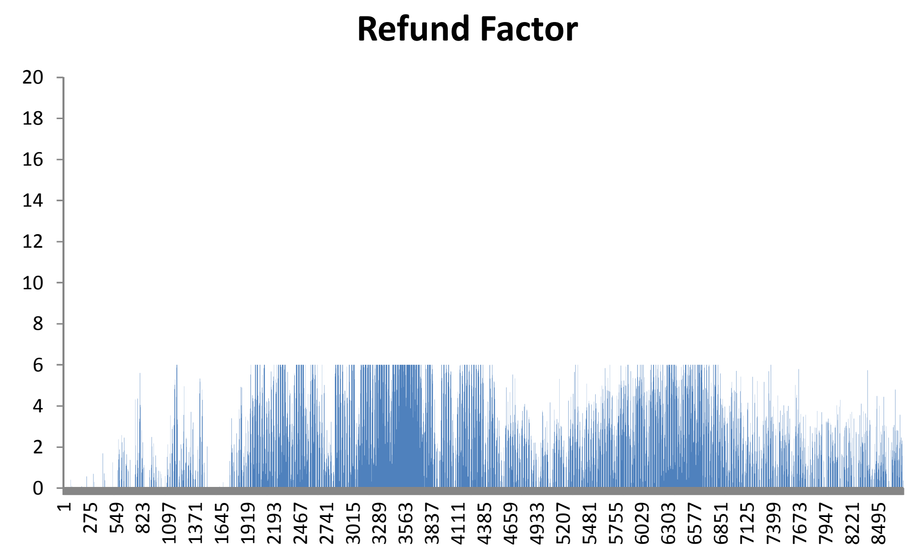
Simulation Model

# Option 1: IMO DR Proposal (15% ERC)



# Option 2: IMO DR Proposal W/ MIN RF = 1 (5 and 15% ERC)

| | |
|---|---|
| Refund Regime | IMO with Floor 1 |
| Availiability or Dispatched Based Rebate | Availability |
| Excess Capacity | 5% |
| Maximum Reserve Capacity Price ($/MW) | 163900 |
| Reserve Capacity Price ($/MW) | 138685 |
| Unit Refund ($/MWh) | 15.76 |

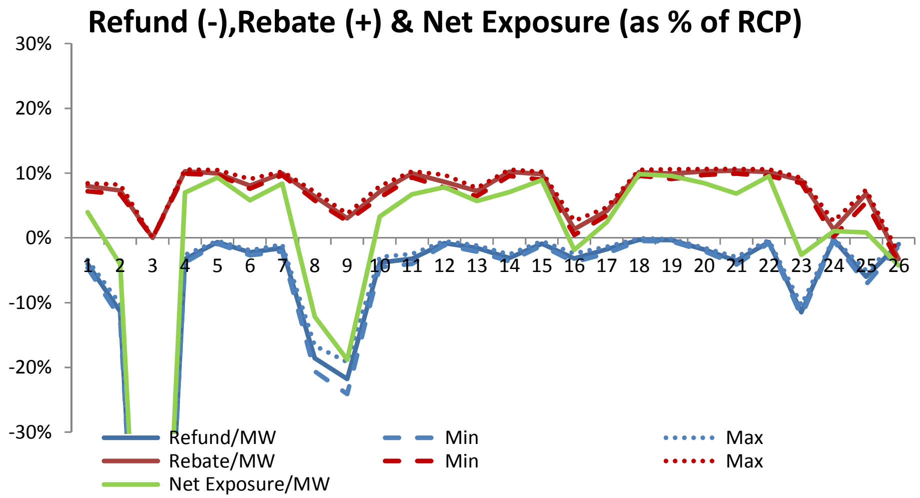
| | |
|---|---|
| Refund Regime | IMO with Floor 1 |
| Availiability or Dispatched Based Rebate | Availability |
| Excess Capacity | 15% |
| Maximum Reserve Capacity Price ($/MW) | 163900 |
| Reserve Capacity Price ($/MW) | 107636 |
| Unit Refund ($/MWh) | 11.97 |

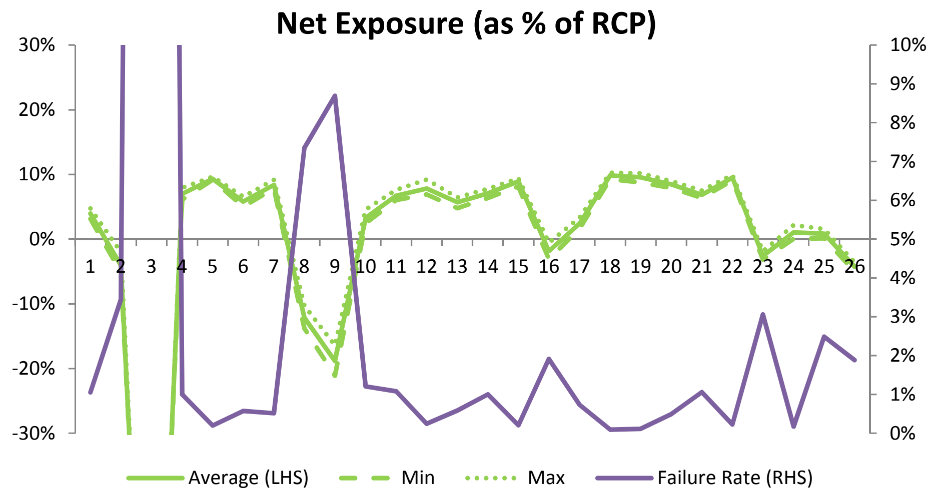
| Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) | Availability (%) | Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) | Availability (%) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 320 | 1.0% | 90.0% | 91.0% | 14 | 40 | 1.0% | 52.3% | 96.0% |
| 2 | 200 | 3.0% | 85.0% | 88.0% | 15 | 320 | 0.2% | 48.8% | 95.0% |
| 3 | 100 | 100.0% | 0.0% | 100.0% | 16 | 200 | 1.0% | 9.7% | 50.0% |
| 4 | 100 | 1.0% | 97.0% | 98.0% | 17 | 200 | 0.5% | 13.4% | 65.0% |
| 5 | 100 | 0.2% | 94.8% | 95.0% | 18 | 100 | 0.1% | 11.1% | 95.0% |
| 6 | 320 | 0.5% | 89.5% | 90.0% | 19 | 40 | 0.1% | 7.8% | 90.0% |
| 7 | 40 | 0.5% | 94.5% | 95.0% | 20 | 200 | 0.5% | 6.7% | 98.0% |
| 8 | 20 | 6.0% | 74.1% | 80.0% | 21 | 100 | 1.0% | 3.2% | 99.0% |
| 9 | 200 | 6.0% | 63.9% | 70.0% | 22 | 40 | 0.2% | 2.0% | 95.0% |
| 10 | 200 | 1.0% | 77.7% | 85.0% | 23 | 200 | 3.0% | 1.5% | 98.0% |
| 11 | 20 | 1.0% | 75.2% | 95.0% | 24 | 100 | 0.1% | 0.6% | 50.0% |
| 12 | 200 | 0.2% | 70.4% | 90.0% | 25 | 20 | 2.0% | 0.2% | 80.0% |
| 13 | 100 | 0.5% | 50.7% | 80.0% | 26 | 50 | 0.5% | 0.0% | 25.0% |

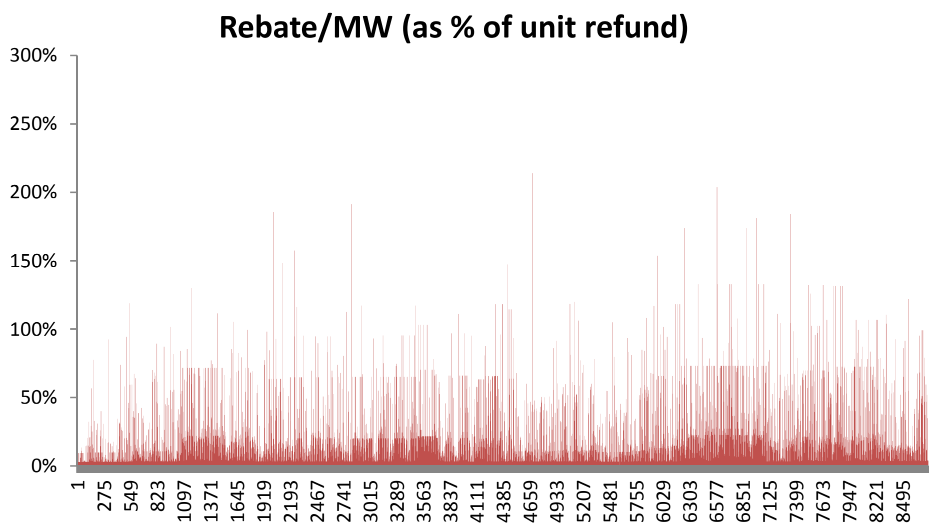
| Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) | Availability (%) | Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) | Availability (%) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 320 | 1.0% | 90.0% | 91.0% | 14 | 40 | 1.0% | 36.9% | 96.0% |
| 2 | 200 | 3.0% | 85.0% | 88.0% | 15 | 320 | 0.2% | 33.4% | 95.0% |
| 3 | 100 | 100.0% | 0.0% | 100.0% | 16 | 200 | 1.0% | 6.7% | 50.0% |
| 4 | 100 | 1.0% | 97.0% | 98.0% | 17 | 200 | 0.5% | 6.7% | 65.0% |
| 5 | 100 | 0.2% | 94.8% | 95.0% | 18 | 100 | 0.1% | 6.5% | 95.0% |
| 6 | 320 | 0.5% | 89.5% | 90.0% | 19 | 40 | 0.1% | 4.6% | 90.0% |
| 7 | 40 | 0.5% | 93.4% | 95.0% | 20 | 200 | 0.5% | 3.9% | 98.0% |
| 8 | 20 | 6.0% | 71.4% | 80.0% | 21 | 100 | 1.0% | 1.6% | 99.0% |
| 9 | 200 | 6.0% | 61.6% | 70.0% | 22 | 40 | 0.2% | 0.9% | 95.0% |
| 10 | 200 | 1.0% | 71.1% | 85.0% | 23 | 200 | 3.0% | 0.6% | 98.0% |
| 11 | 20 | 1.0% | 65.0% | 95.0% | 24 | 100 | 0.1% | 0.2% | 50.0% |
| 12 | 200 | 0.2% | 59.5% | 90.0% | 25 | 20 | 2.0% | 0.1% | 80.0% |
| 13 | 100 | 0.5% | 39.3% | 80.0% | 26 | 50 | 0.5% | 0.0% | 25.0% |

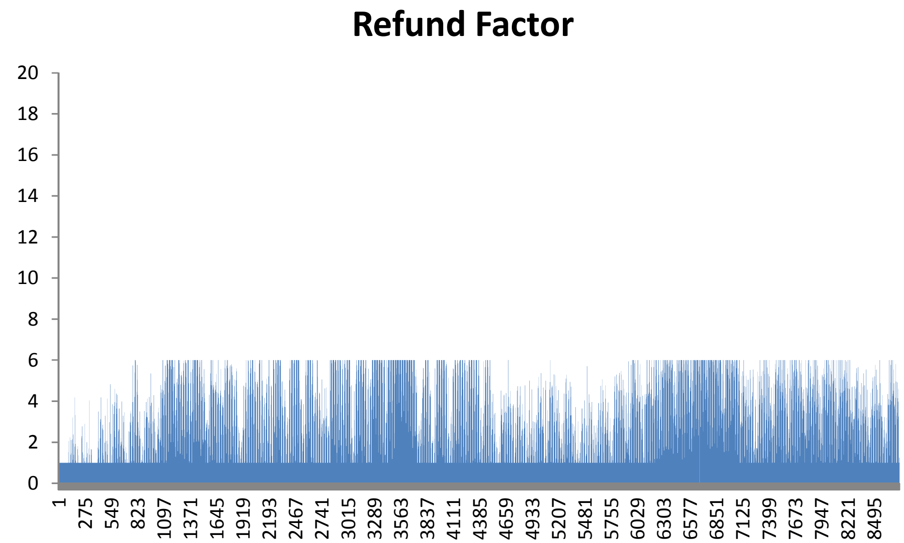
Simulation Model: Unit 3 Full Year FO

# Option 2: IMO DR Proposal W/ MIN RF=1 (5% ERC)



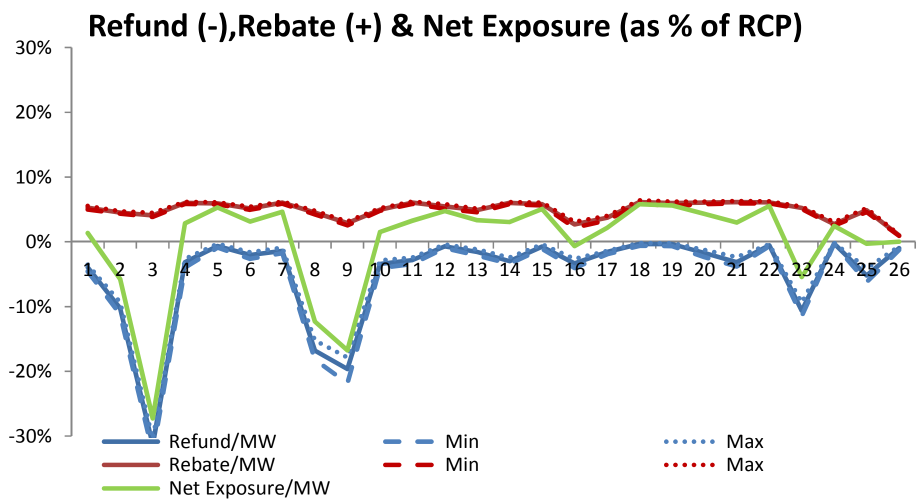



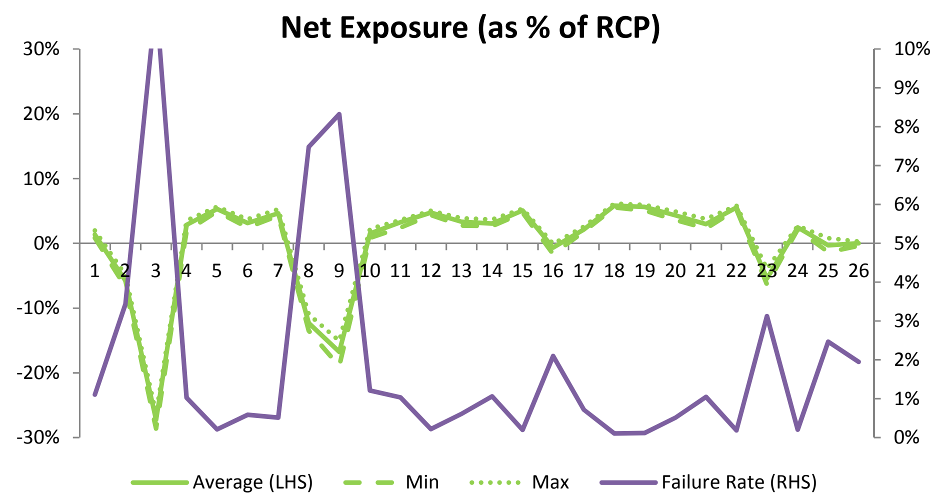



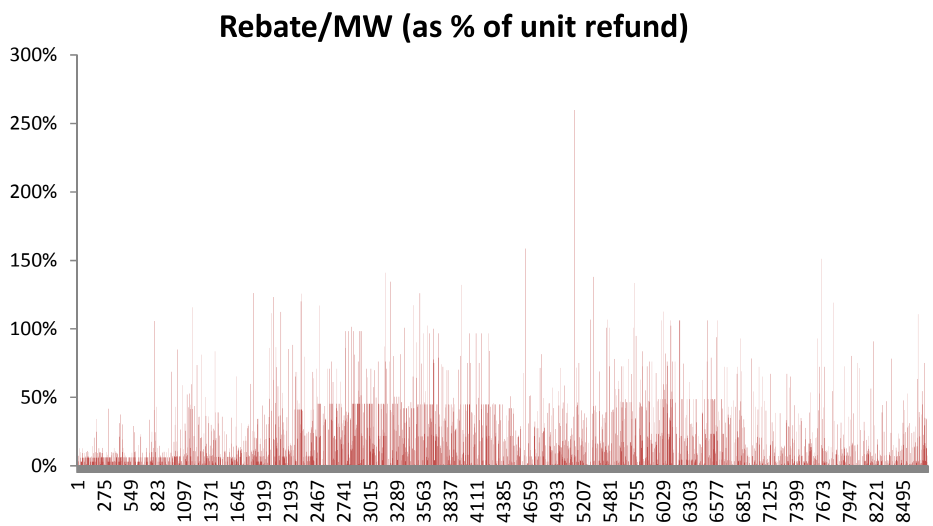



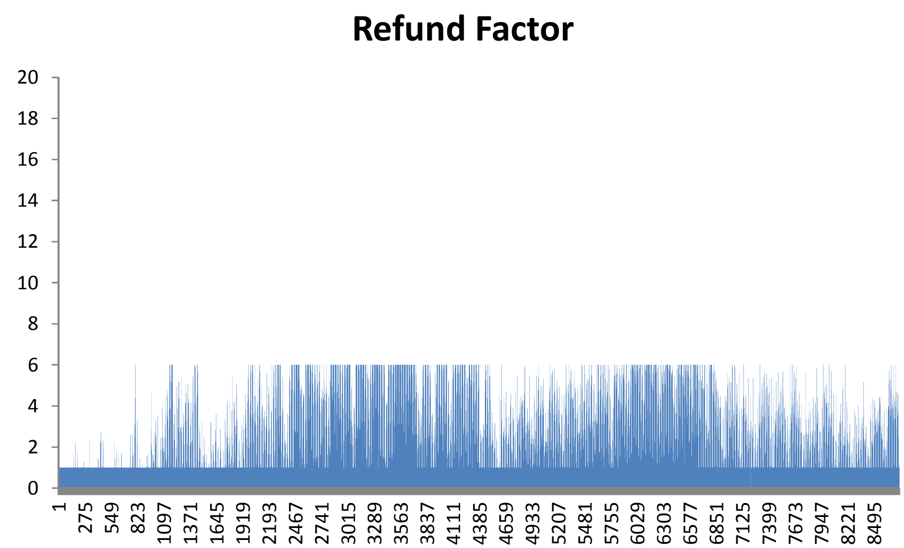
Simulation Model: Unit 3 Normal

# Option 2: IMO DR PROPOSAL W/ MIN RF=1 (5% ERC)



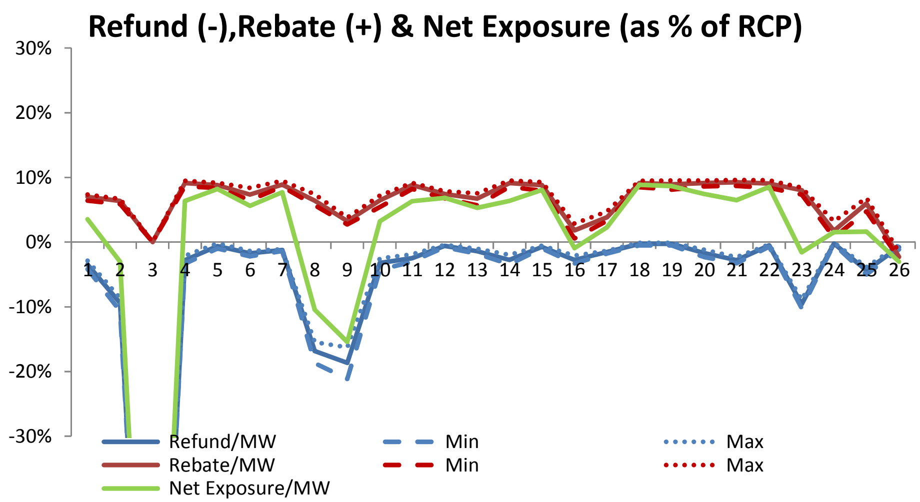



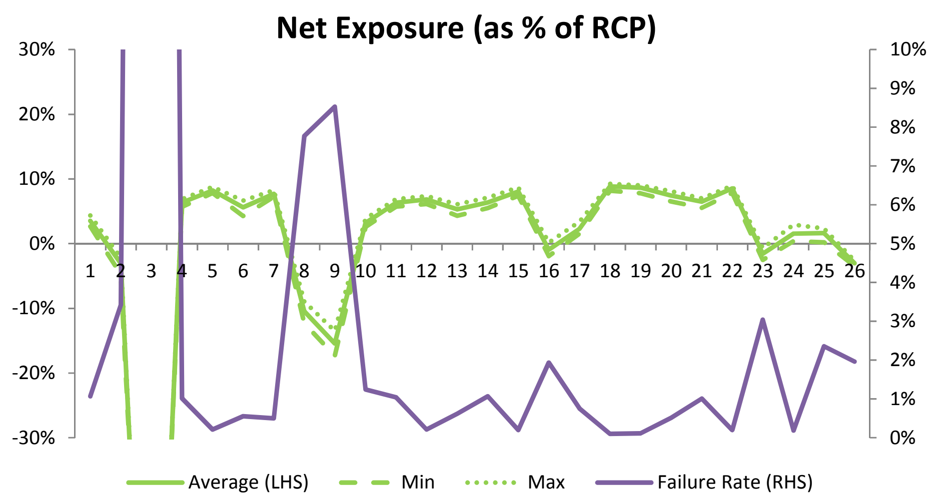



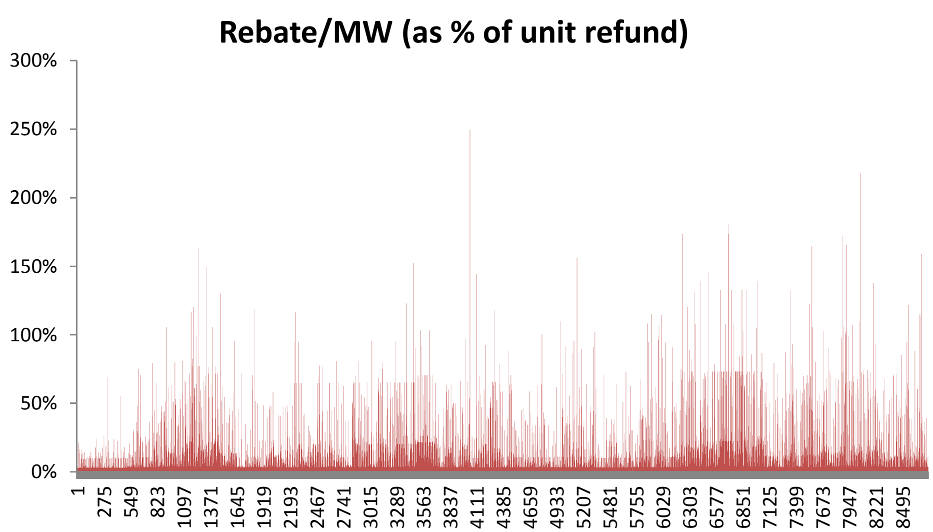



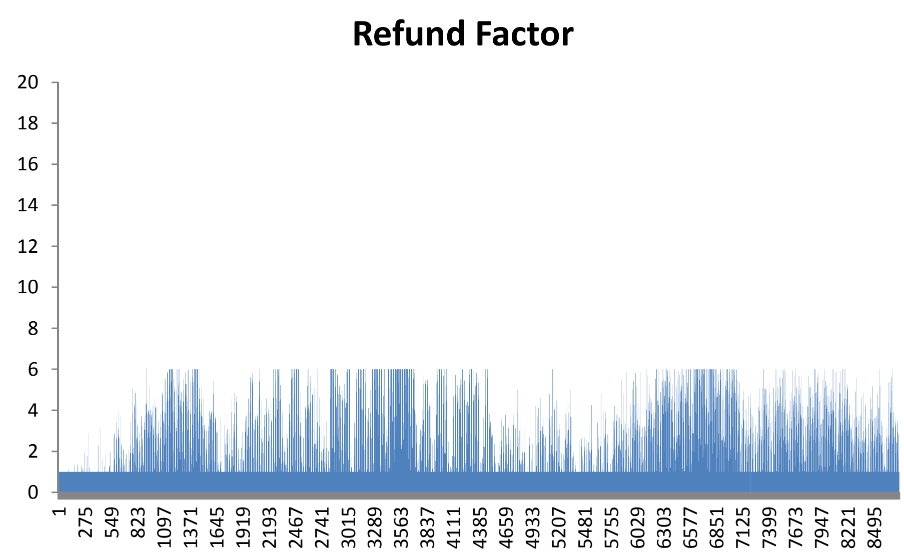
Simulation Model: Unit 3 Full Year FO

# Option 2: IMO DR Proposal W/ MIN RF=1 (15% ERC)

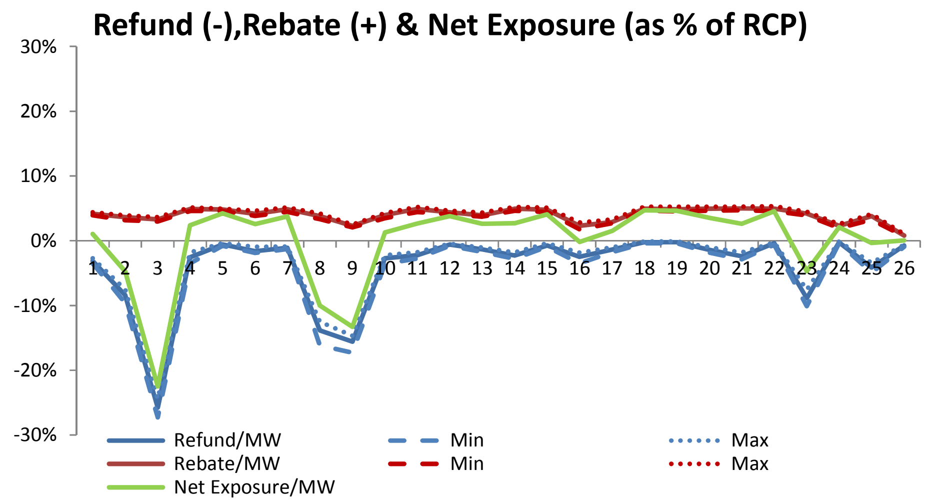


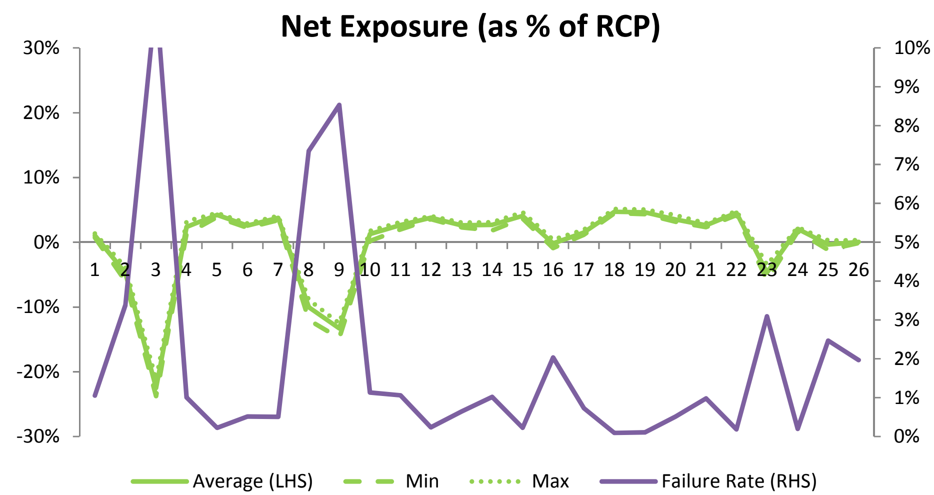



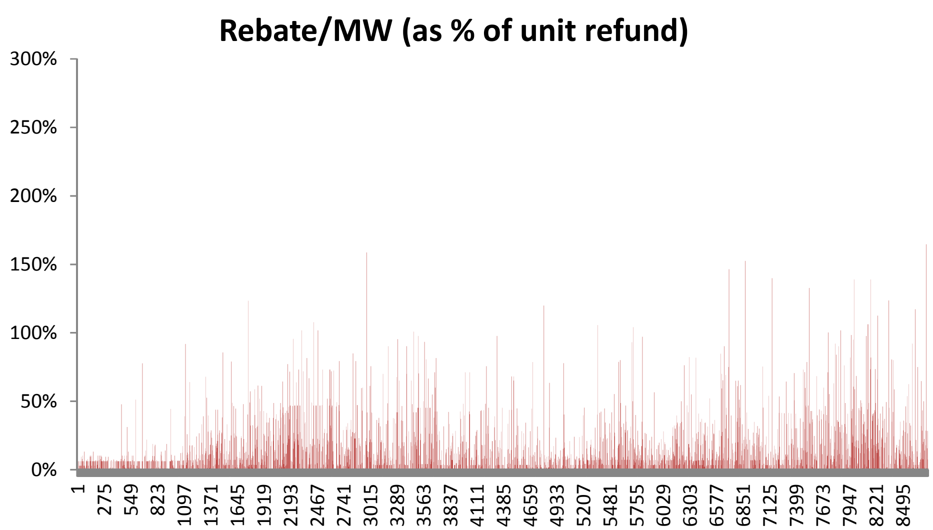



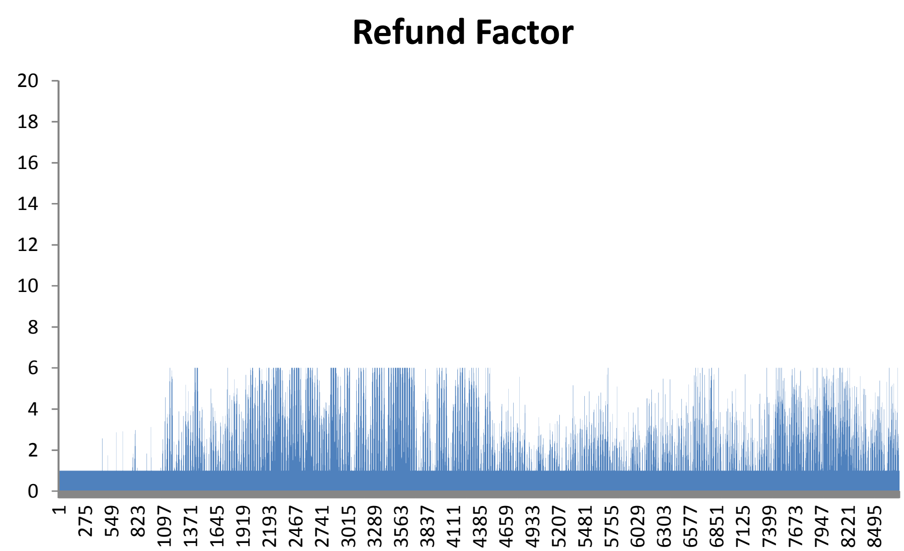



# Option 2: IMO DR PROPOSAL W/ MIN RF=1 (15% ERC)



# Option 3: RCP-LINKED IMO DR Proposal W/ MIN RF=1 (5 and 15% ERC)

| | |
|---|---|
| Refund Regime | RCP-LINKED |
| Availiability or Dispatched Based Rebate | Availability |
| Excess Capacity | 5% |
| Maximum Reserve Capacity Price ($/MW) | 163900 |
| Reserve Capacity Price ($/MW) | 138685 |
| Unit Refund ($/MWh) | 15.76 |

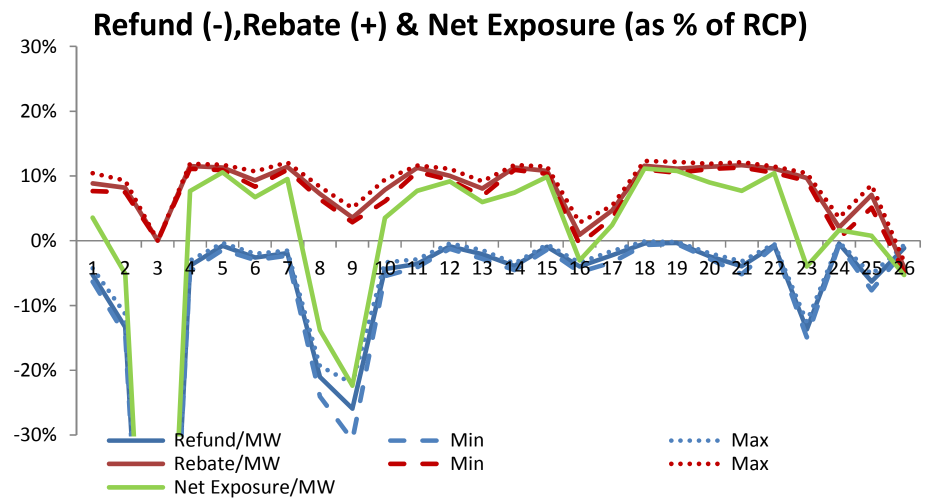
| | |
|---|---|
| Refund Regime | RCP-LINKED |
| Availiability or Dispatched Based Rebate | Availability |
| Excess Capacity | 15% |
| Maximum Reserve Capacity Price ($/MW) | 163900 |
| Reserve Capacity Price ($/MW) | 107636 |
| Unit Refund ($/MWh) | 11.97 |

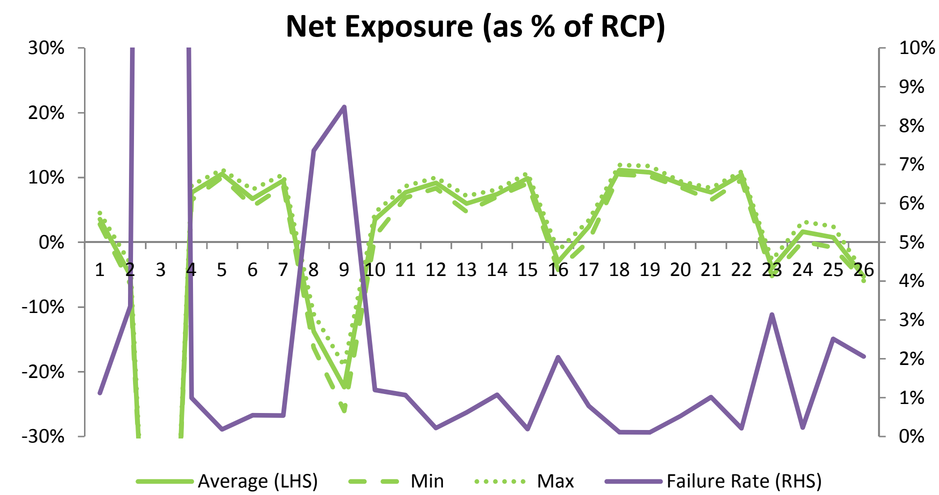
| Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) | Availability (%) | Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) | Availability (%) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 320 | 1.0% | 90.6% | 91.0% | 14 | 40 | 1.0% | 52.0% | 96.0% |
| 2 | 200 | 3.0% | 85.0% | 88.0% | 15 | 320 | 0.2% | 48.6% | 95.0% |
| 3 | 100 | 100.0% | 0.0% | 100.0% | 16 | 200 | 1.0% | 8.5% | 50.0% |
| 4 | 100 | 1.0% | 97.0% | 98.0% | 17 | 200 | 0.5% | 13.7% | 65.0% |
| 5 | 100 | 0.2% | 94.8% | 95.0% | 18 | 100 | 0.1% | 10.8% | 95.0% |
| 6 | 320 | 0.5% | 89.5% | 90.0% | 19 | 40 | 0.1% | 7.4% | 90.0% |
| 7 | 40 | 0.5% | 94.5% | 95.0% | 20 | 200 | 0.5% | 6.3% | 98.0% |
| 8 | 20 | 6.0% | 74.1% | 80.0% | 21 | 100 | 1.0% | 3.0% | 99.0% |
| 9 | 200 | 6.0% | 64.0% | 70.0% | 22 | 40 | 0.2% | 1.9% | 95.0% |
| 10 | 200 | 1.0% | 78.7% | 85.0% | 23 | 200 | 3.0% | 1.3% | 98.0% |
| 11 | 20 | 1.0% | 75.0% | 95.0% | 24 | 100 | 0.1% | 0.8% | 50.0% |
| 12 | 200 | 0.2% | 70.6% | 90.0% | 25 | 20 | 2.0% | 0.1% | 80.0% |
| 13 | 100 | 0.5% | 50.9% | 80.0% | 26 | 50 | 0.5% | 0.0% | 25.0% |

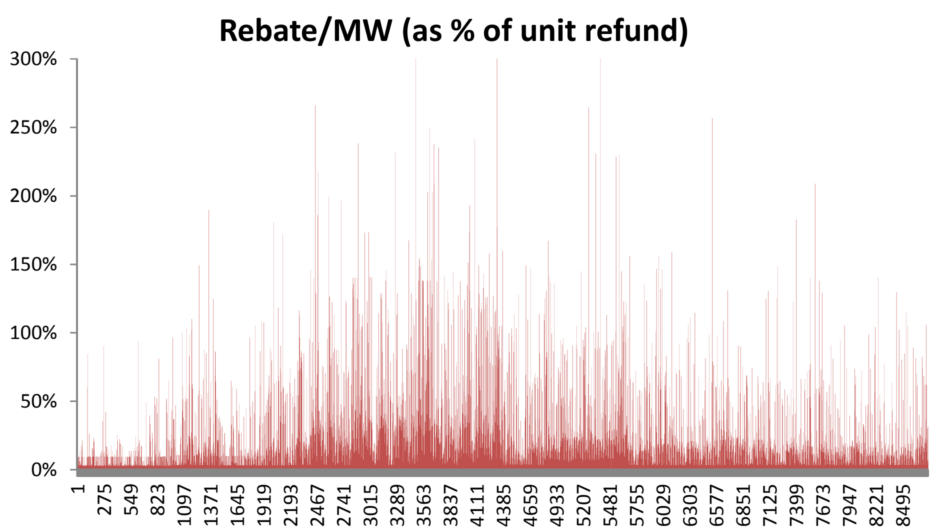
| Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) | Availability (%) | Plant No. | Net Capacity (MW) | FOR (%) | Load Factor (%) | Availability (%) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 320 | 1.0% | 90.0% | 91.0% | 14 | 40 | 1.0% | 35.8% | 96.0% |
| 2 | 200 | 3.0% | 85.0% | 88.0% | 15 | 320 | 0.2% | 32.5% | 95.0% |
| 3 | 100 | 100.0% | 0.0% | 100.0% | 16 | 200 | 1.0% | 2.9% | 50.0% |
| 4 | 100 | 1.0% | 97.0% | 98.0% | 17 | 200 | 0.5% | 11.1% | 65.0% |
| 5 | 100 | 0.2% | 94.8% | 95.0% | 18 | 100 | 0.1% | 7.2% | 95.0% |
| 6 | 320 | 0.5% | 89.5% | 90.0% | 19 | 40 | 0.1% | 4.9% | 90.0% |
| 7 | 40 | 0.5% | 93.5% | 95.0% | 20 | 200 | 0.5% | 4.1% | 98.0% |
| 8 | 20 | 6.0% | 71.7% | 80.0% | 21 | 100 | 1.0% | 1.9% | 99.0% |
| 9 | 200 | 6.0% | 61.3% | 70.0% | 22 | 40 | 0.2% | 1.1% | 95.0% |
| 10 | 200 | 1.0% | 70.5% | 85.0% | 23 | 200 | 3.0% | 0.5% | 98.0% |
| 11 | 20 | 1.0% | 64.1% | 95.0% | 24 | 100 | 0.1% | 0.4% | 50.0% |
| 12 | 200 | 0.2% | 59.5% | 90.0% | 25 | 20 | 2.0% | 0.0% | 80.0% |
| 13 | 100 | 0.5% | 41.2% | 80.0% | 26 | 50 | 0.5% | 0.0% | 25.0% |

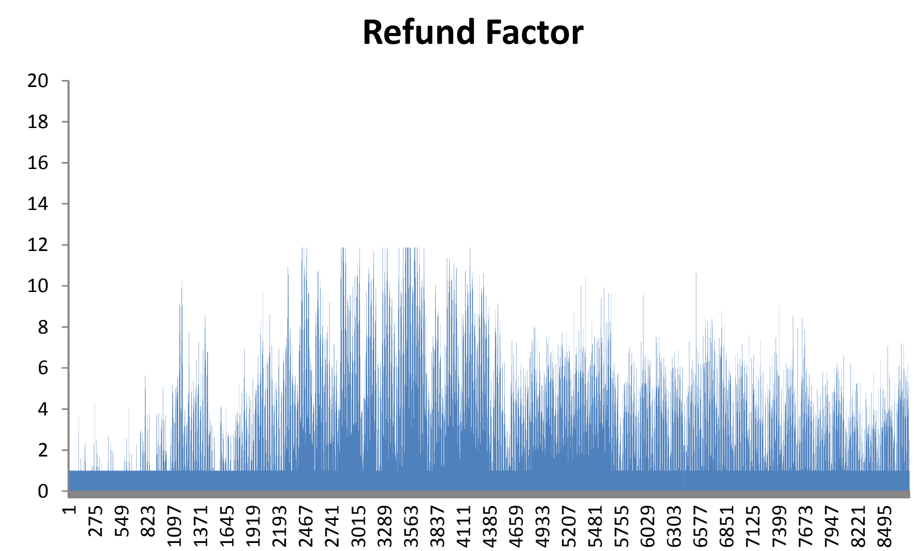
Simulation Model: Unit 3 Full Year FO

# Option 3: RCP-Linked IMO DR Proposal W/ MIN RF=1 (5% ERC)

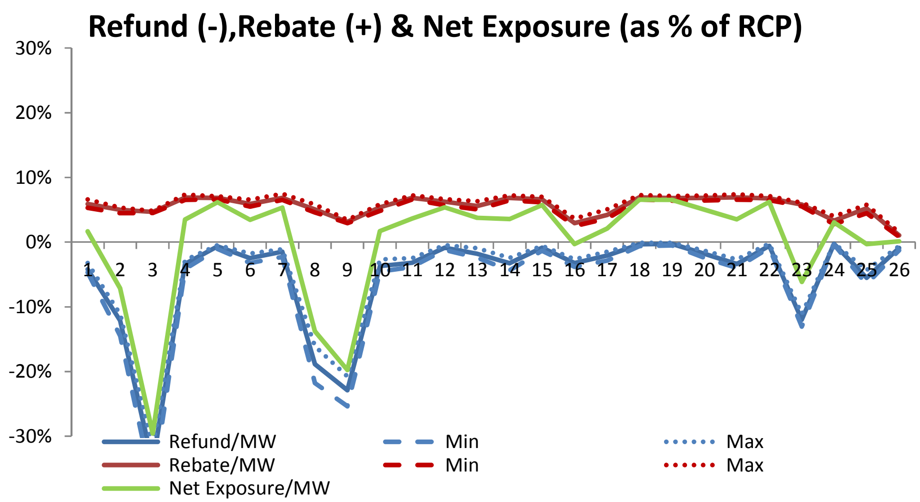


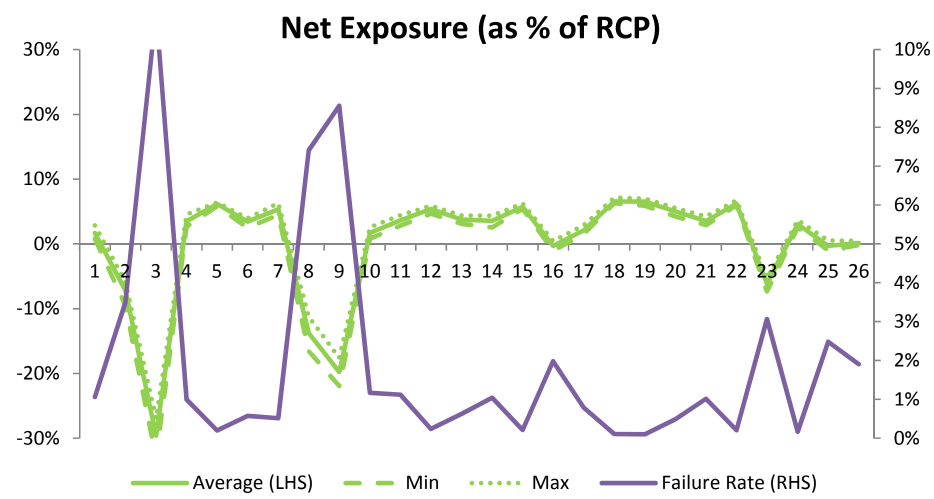



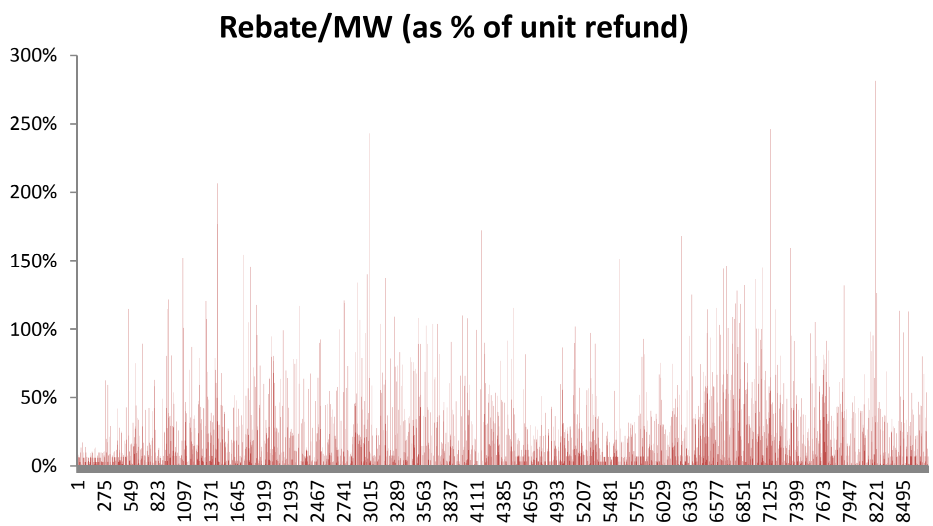



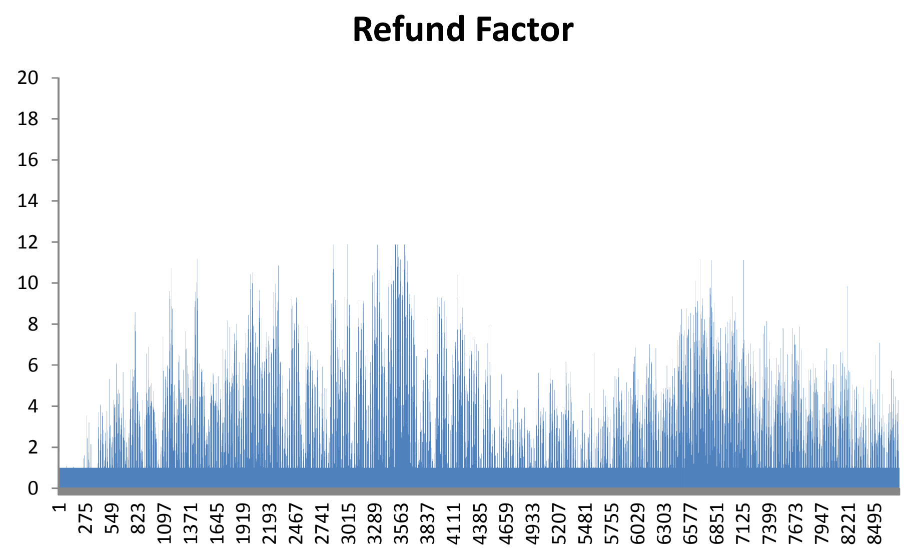



# Option 3: RCP IMO DR PROPOSAL W/ MIN RF=1 (5% ERC)



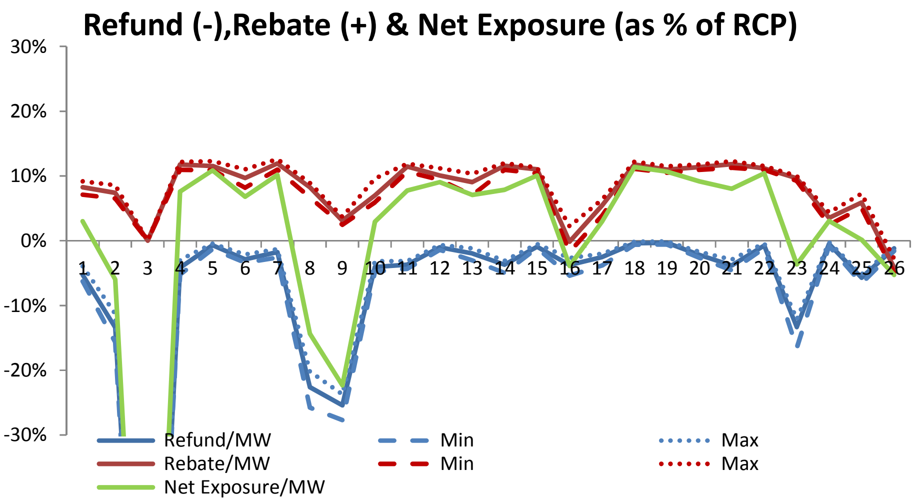



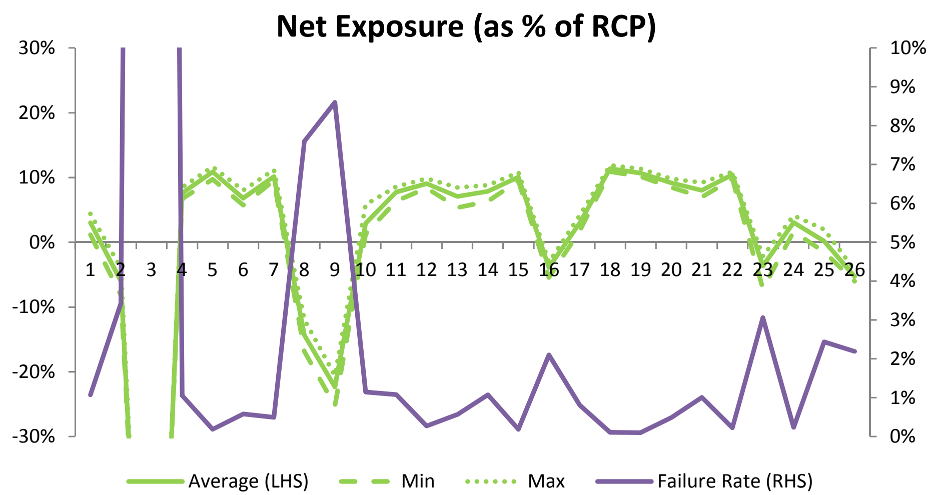



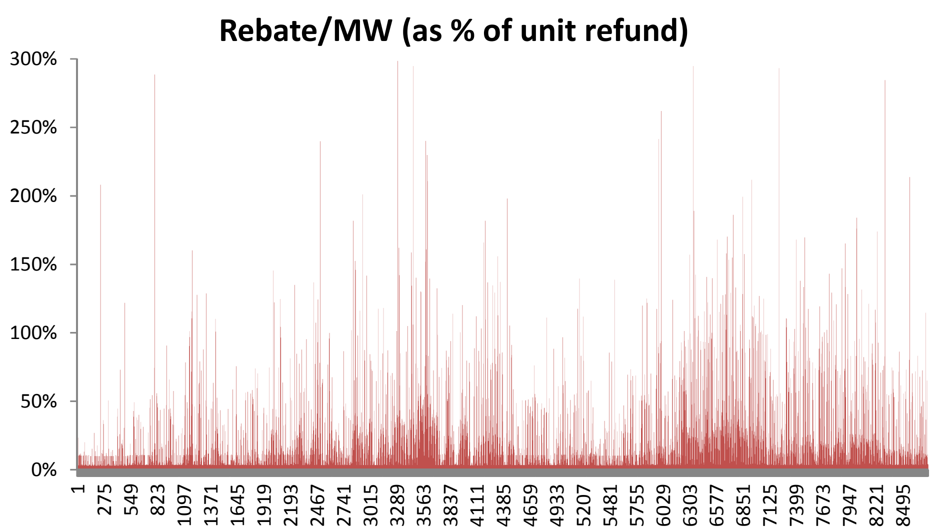



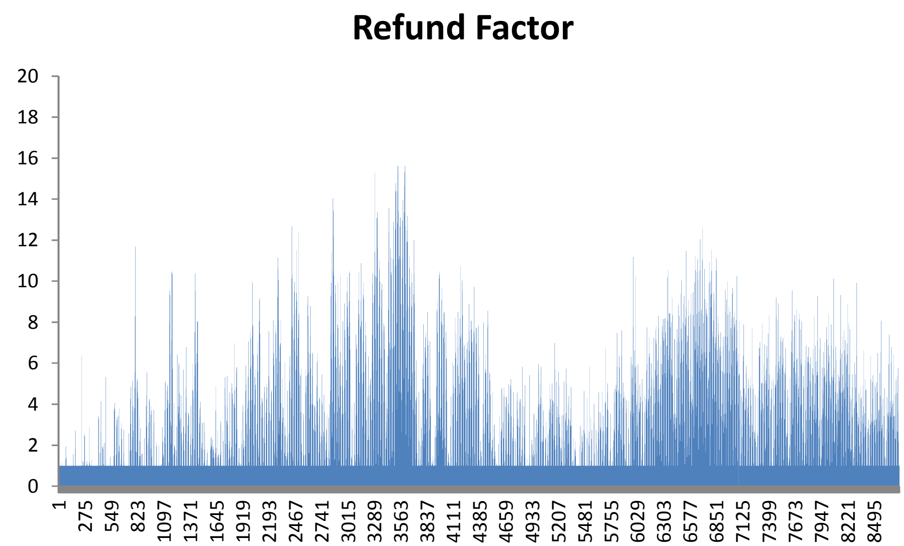
Simulation Model: Unit 3 Full Year FO

# Option 3: RCP-Linked IMO DR PROPOSAL W/ MIN RF=1 (15% ERC)



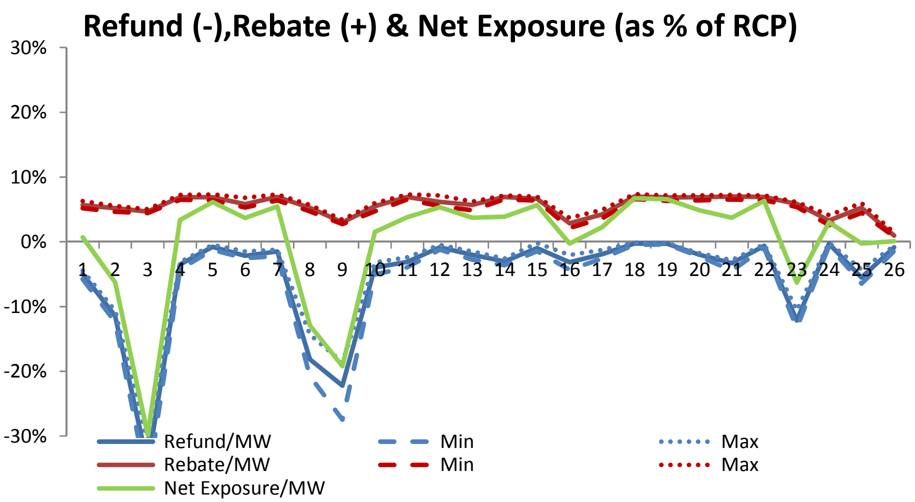



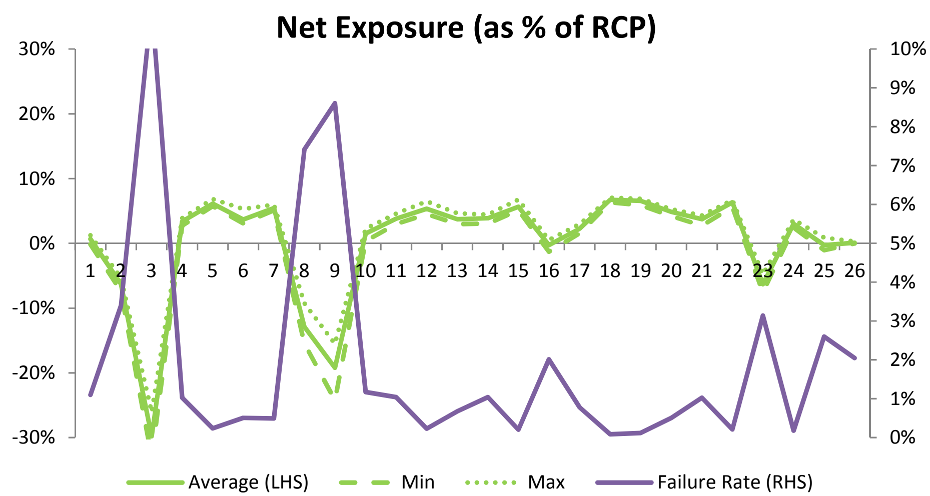



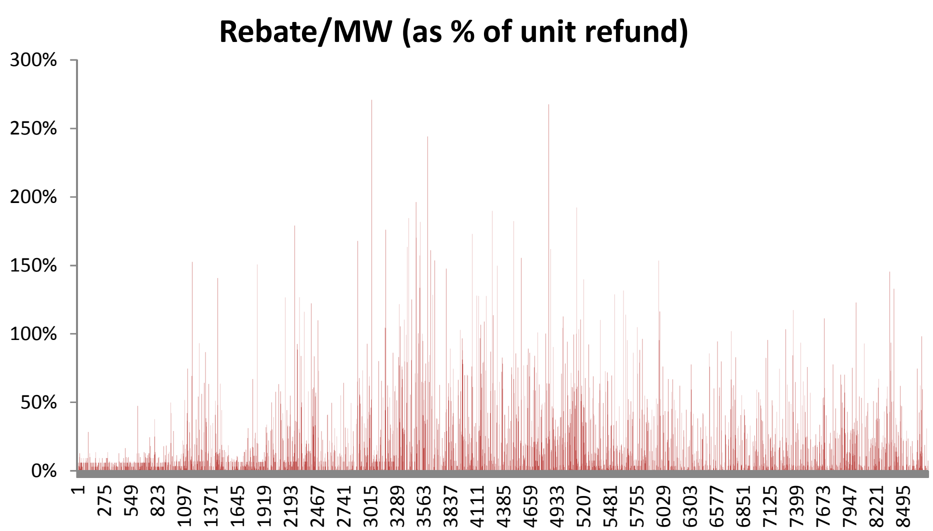



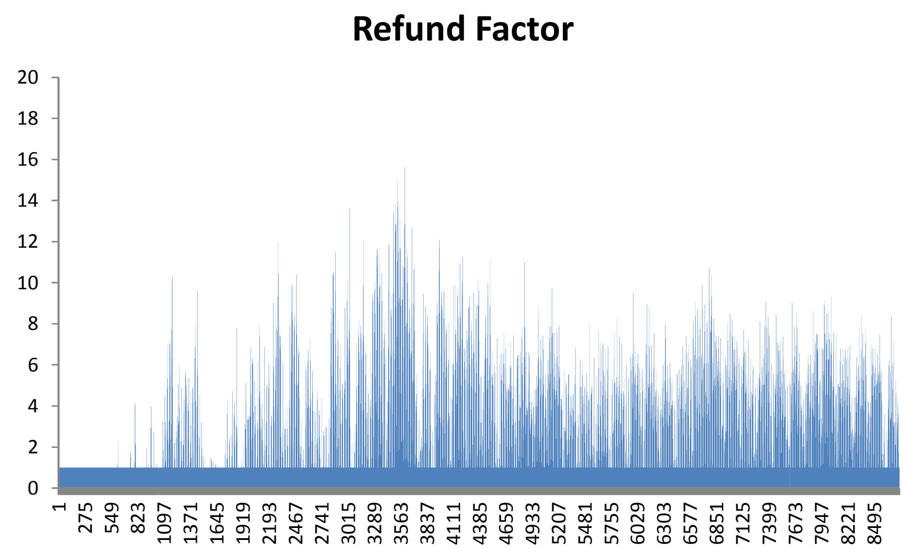
Simulation Model: Unit 3 Normal

# RCP IMO DR PROPOSAL W/ MIN RF=1 (15% ERC)



# Option 3 vs Option 2

- Option 3 has very little year-over-year volatility for the same performance levels
  - If RCP increases from one year to the next due to falling reserve capacity, volatility increases significantly
- Option 3 has slightly more within year uncertainty based on actual out-turn due to higher refund factors
  - If a major change in system performance, then refund factors can be much higher, on average, or much lower, on average
  - But for a reasonable sized system, volatility will largely be limited within reasonable bounds and appears to be less than change in volatility that can occur due to reducing reserve margin

- Option 2 has significant year-over-year volatility, with volatility increasing as reserve margin decreases
- Option 2 has somewhat less within year volatility due to capped refund factors

# Recommendation

- A dynamic refund regime makes strong economic sense in line with the Market Objectives

- A minimum refund factor of 1 is non-issue given the existence of a rebate regime, and solves a tricky incentive problem in a simple way
  - Removes / reduces rent-seeking incentive with respect to FO timing
  - At the end of the day, the rebate regime compensates better performers, so that only worse performers are actually exposed – which is the intention of an incentive regime

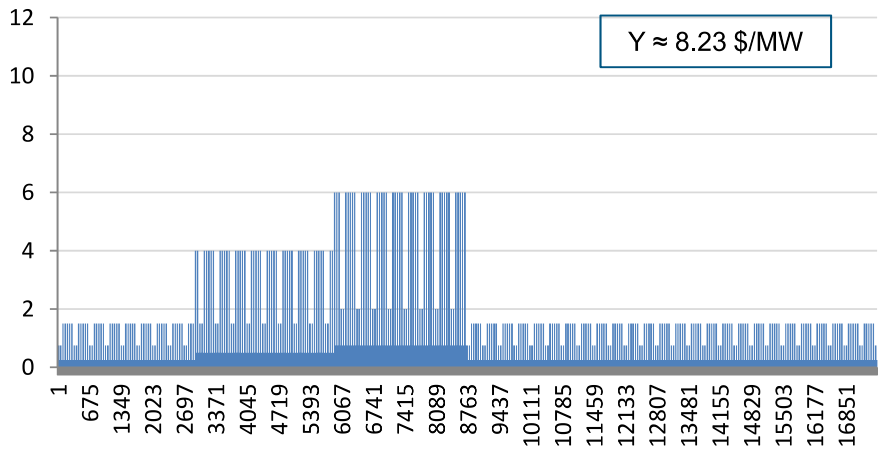
- Linking the maximum refund factor to the MRCP/RCP ratio produces more stable results over time and sharper incentives, without any evident counter-effects
  - Financially more predictable outcomes from year to year
  - Just because the RCP is low for a given year does not mean that the risk of shortage is worth less on the day

**Recommend Option 3: RCP-Linked Dynamic Refund Regime**

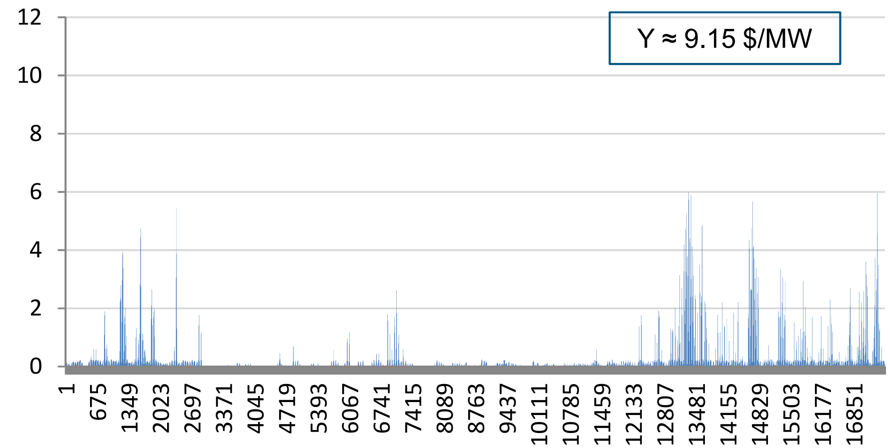
# BACKUP SLIDES

# Refund Factor and Unit Refund (Y) over Capacity Year 2010/11

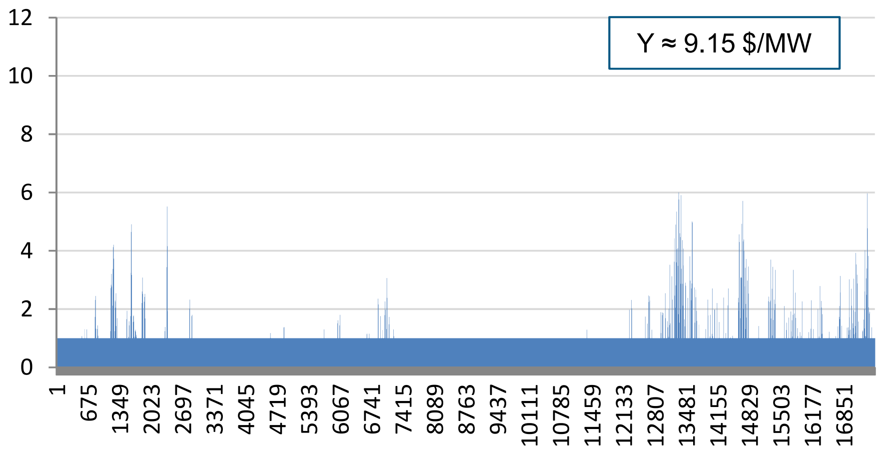
**Current Mechanism**



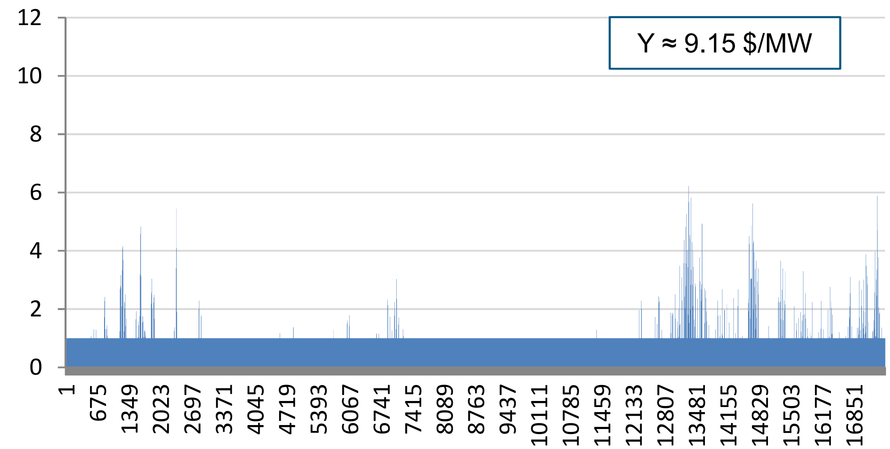

**IMO**




**IMO with Floor**

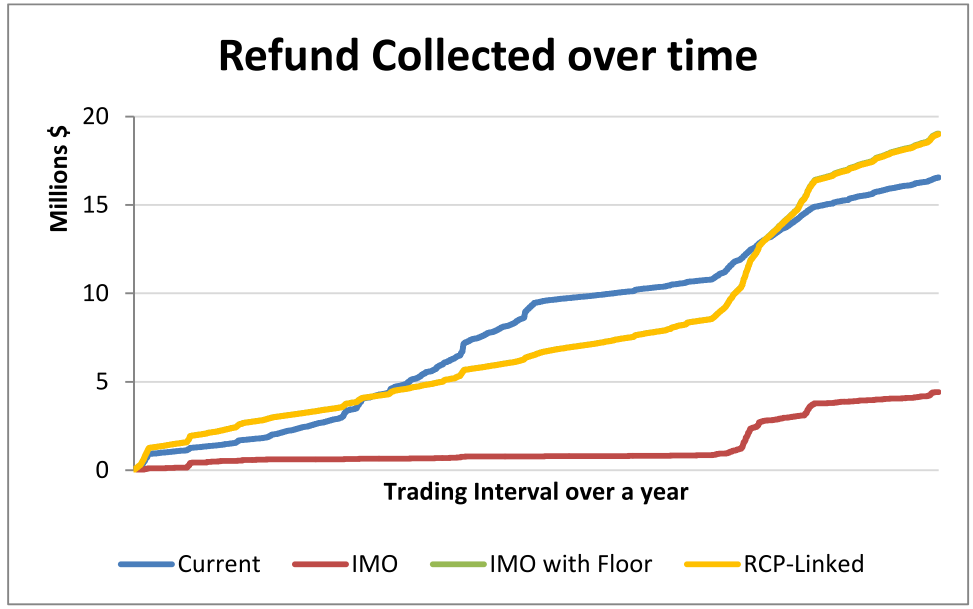



**RCP-linked**

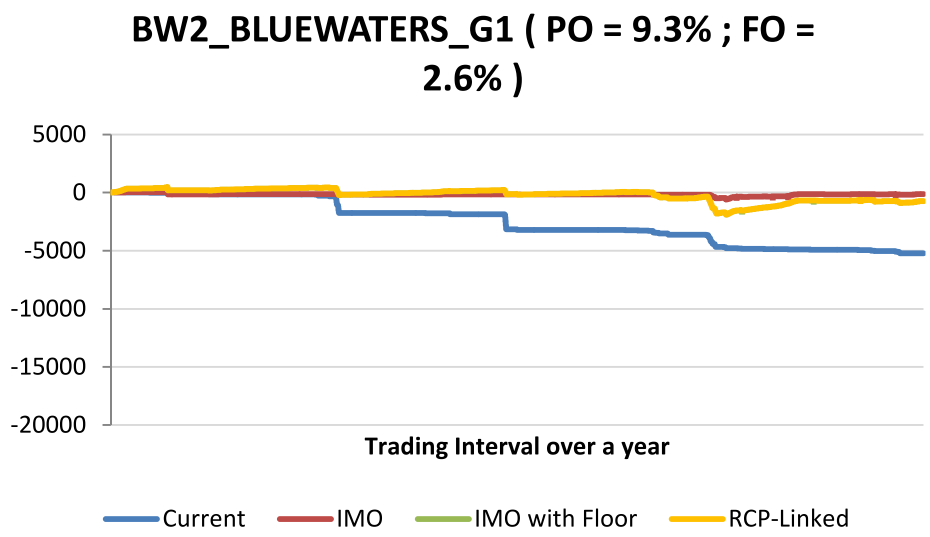


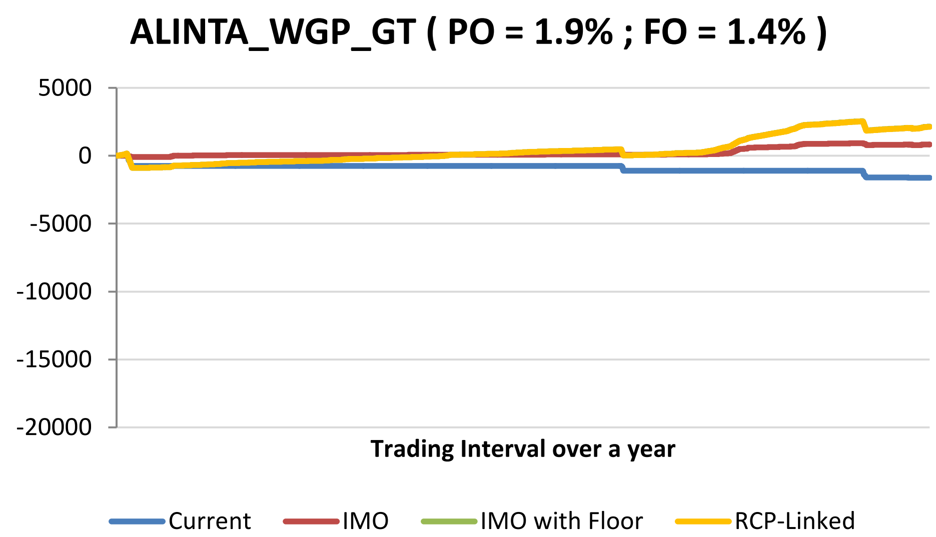
# Cumulative Refund

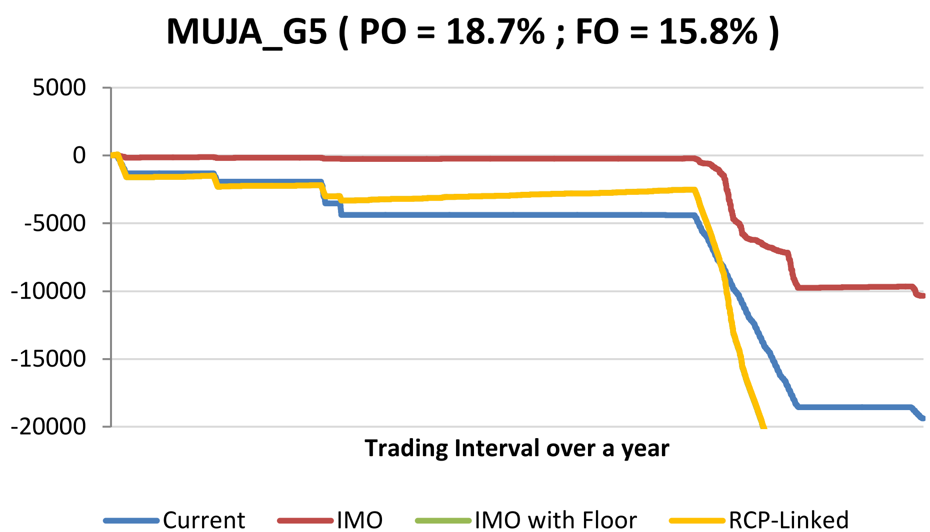
- For the current mechanism, refund collected will be distributed to market customers according to their IRCR.
- Under the new proposals (IMO, IMO with Floor and RCP-Linked), all the refund collected will be recycled and distributed to facilities that are available.

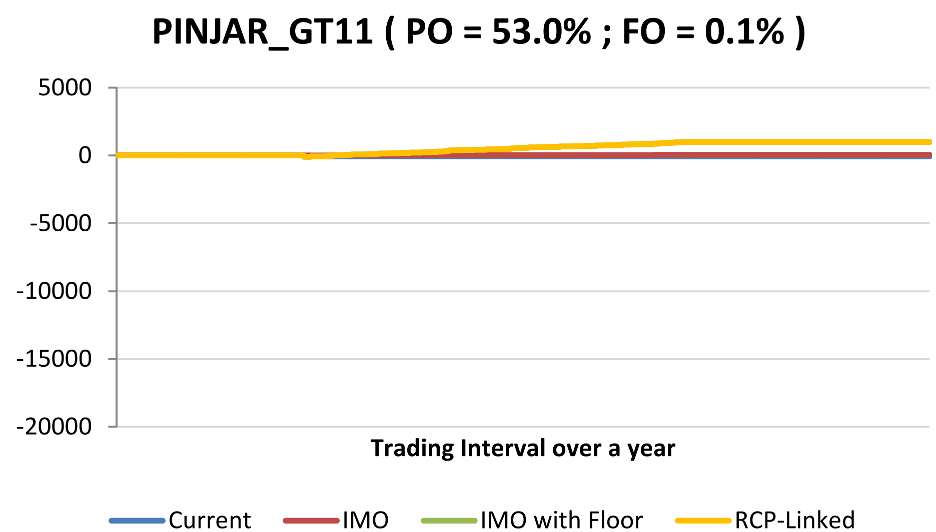


# Net Exposure of Facilities (per MW) under different proposals




Note: System average PO and FO rates are 15.4% and 2.0% respectively

# Reserve Capacity Mechanism Working Group

## Minutes

| | |
|---|---|
| **Meeting No.** | 9 |
| **Location:** | IMO Boardroom<br>Level 17, 197 St Georges Terrace, Perth |
| **Date:** | Thursday 22 November 2012 |
| **Time:** | Commencing at 12.30pm – 5.45pm |

| Attendees | Class | Comment |
|---|---|---|
| Allan Dawson | Chair | |
| Suzanne Frame | IMO | |
| Brad Huppatz | Market Generator (Verve Energy) | |
| Ben Tan | Market Generator | |
| Andrew Sutherland | Market Generator | |
| Shane Cremin | Market Generator | |
| Wendy Ng | Market Customer | |
| Steve Gould | Market Customer | |
| Stephen MacLean | Market Customer (Synergy) | |
| Andrew Stevens | Market Customer/Generator | |
| Geoff Gaston | Market Customer | Proxy |
| Jeff Renaud | Demand Side Management | |
| Geoff Down | Contestable Customer | |
| Brendan Clarke | System Management | |
| Wana Yang | Observer (Economic Regulation Authority) | |
| Lisa Taylor | Observer (Public Utilities Office) | |
| **Apologies** | **Class** | **Comment** |
| Patrick Peake | Market Customer | |
| Justin Payne | Contestable Customer | |
| Paul Hynch | Observer (Public Utilities Office) | |
| **Also in attendance** | **From** | **Comment** |
| Wayne Trumble | Observer (Griffin Energy) | |
| John Rhodes | Observer (Synergy) | |
| Fiona Edmonds | Observer (Alinta) | |
| Mike Thomas | Presenter (The Lantau Group) | |
| Dr Richard Tooth | Presenter (Sapere Research Group) | |
| Aditi Varma | Minutes | |

| | | |
|---|---|---|
| Greg Ruthven | Observer (IMO) | |
| Natasha Cunningham | Observer (IMO) | |

| Item | Subject | Action |
|---|---|---|
| **1.** | **WELCOME AND APOLOGIES / ATTENDANCE**<br>The Chair opened the ninth and final meeting of the Reserve Capacity Mechanism (RCM) Working Group (RCMWG) at 12:30pm.<br>The Chair welcomed the members in attendance and noted apologies from Mr Patrick Peake, Mr Justin Payne and Mr Paul Hynch. He acknowledged observers present from Griffin Energy, Synergy and Alinta. | |
| **2.** | **MINUTES ARISING FROM MEETING 8**<br>The following amendments were noted:<br>On page 6, Ms Wana Yang requested the following change:<br>• *Ms Yang mentioned that ~~it was not~~ the quantity of excess capacity ~~that~~ was a concern. The concern stemmed more from an economic efficiency perspective because excess capacity indicated inefficient over-investment. She also noted that the Shared Capacity Cost was always borne by the Market Customers, irrespective of whether there was excess capacity or a shortfall.*<br>On page 7, Mr Brendan Clarke requested that the minutes reflect that no agreement was reached among working group members on the Reserve Capacity Price proposal. The Chair noted that such a change was not required as the minutes appropriately reflected that members had discussed the proposal. The minutes were silent on whether any agreement was reached. Mr Clarke then requested that his support for Option 3a be minuted.<br>*Action Point: The IMO to publish amended minutes of RCMWG meeting no.8 on the Market Web Site.* | **IMO** |
| **3.** | **ACTIONS ARISING**<br>Ms Suzanne Frame noted that Action Item 2 (The IMO to include information on the cost effectiveness of proposed solutions or harmonisation) remained a work in progress until a full suite of recommendations had been proposed.<br>Ms Frame added that Action Items 3, 4 and 5 were completed subsequent to the last meeting.<br>Ms Frame advised that Action Item 6, 7 and 8 would be addressed over the course of the meeting.<br>Mr Greg Ruthven noted that further information on Action Item 4 – (Relevant Demand (RD) and scaled Individual Reserve Capacity Requirements (IRCR)) had been provided as part of the meeting papers. Mr Ben Tan questioned whether this action item would be discussed any further. Mr Tan noted that he was aware that further work had been undertaken to assess the extent of the issue, which would help working group members in deciding if this issue required | |

| | | |
|---|---|---|
| | further attention. Mr Andrew Stevens noted that the numbers had changed since the last meeting. Mr Geoff Gaston observed that it was incorrect to compare Relevant Demand with scaled IRCR instead of unscaled IRCR, because Demand Side Programmes (DSPs) did not have control over the scale; instead they had control over the actual MegaWatt demand.<br><br>Mr Tan queried if the main point of the discussion was the philosophy behind it; that a Load should not be able to sell more than it had bought. Mr Jeff Renaud noted that a similar philosophy had been applied in the PJM Capacity Market. He added that in his view the comparison should be made with the scaled IRCR as that was what the market paid for. Mr MacLean also supported the philosophy of not being able to sell more than you had bought. The Chair considered that this philosophy seemed fundamental to the discussion. Dr Steve Gould observed that the principal issue was whether, given that a DSM contributor is able to manage its Load, that a Market Customer could actually manage its IRCR by design, for example, by deliberately curtailing load so as to minimise the IRCR, whilst simultaneously maintaining high Relevant Demand. Mr Renaud responded that he was not aware of the extent to which this happened, but noted that it was a concern that could be addressed by capping RD at IRCR, and added that in his view, capping at the scaled IRCR would resolve the issue. He also observed that DSPs that had several Associated Loads did not have individual RD's for each load, so it was not possible to tease out the attributable value.<br><br>The Chair asked if members would agree to adopt the principle that 'what was not bought could not be sold'. Members agreed to proceed as suggested.<br><br>*Action Item: The IMO to develop a Pre Rule Change Proposal to implement the principle: what was not bought cannot be sold, in the context of Relevant Demand and IRCR.* | **IMO** |
| **4.** | **AGENDA ITEM 5: Conditions for Demand Side Programme Dispatch**<br><br>The Chair invited Dr Richard Tooth to make his presentation. The following discussion points were noted:<br><br>• Mr Gaston noted that harmonisation of dispatch could not be interpreted in the true sense of the word because DSP dispatch conditions were proposed to be different from generators. He argued that a notice period of two hours for DSPs makes it easier for them to perform, whereas obligations were much more stringent on generators because they get dispatched even within their two hour gate closure. Mr Renaud noted that the obligation on System Management to give notice did not negate the requirement for DSPs to perform and that it was in System Management's interest to provide notice to DSPs to be prepared.<br><br>• Mr Andrew Sutherland queried if Capacity Cost Refunds for non-performance by DSPs would still be much higher than those for generators. Mr MacLean answered that the 'understanding he received from the last meeting was that DSPs would fall in the same refund category as generators because now they would be subjected to unlimited hours of availability. Mr Renaud noted that DSPs would always be subject to a higher denominator for refunds. Discussion ensued on the capability of DSPs to respond | |

| | | |
|---|---|---|
| | within minutes. In response to a query from Mr Tan, Mr Renaud noted that the capability of DSPs to respond within minutes varies across Loads, and reducing the two hour notice of dispatch would create a significant impact. Mr Gaston questioned why if it was indeed possible for DSPs to respond within minutes, they received the two hour notice of dispatch period from System Management rather than receiving a Dispatch Instruction, akin to what generators receive. He further added that managing the dispatch of different DSPs by giving them adequate notice should be the decision of the business owner, and considered that this should occur in the Balancing Merit Order. Mr Renaud argued that managing the dispatch of different DSPs in the current market would be practically impossible because currently all DSPs bid in at the same price and a random number generator is used for dispatch. Ms Frame noted that during Market Rules Evolution Plan meetings, votes were canvassed on the proposal for including DSPs in the Balancing Market; however there was no desire to progress that proposal at that time. Ms Frame queried members whether the priority of the proposal for DSM to participate in the Balancing Market had now changed. Mr Gaston considered that the question was whether DSM was being harmonised to perform like a generator in terms of dispatch. Ms Frame noted that the philosophical discussion around what was intended by "harmonisation" of demand and supply side sources of capacity occurred early in the working group meetings, and explained that the intent was not to make them identical, rather to more closely align their performance requirements to level the playing field.<br>• During discussion on Proposal 1[1]; Mr Stevens noted that the decision for using any amount of DSM should be solely System Management's responsibility and that it should be able to justify that decision accordingly. Mr Shane Cremin and Mr Brad Huppatz also agreed with this point. Mr MacLean observed that System Management might not be comfortable with making a decision which can be open to criticism. Dr Gould observed that the Power System Operation Procedure (PSOP) on Dispatch already included powers for System Management to issue Dispatch Advisories when it considered that the Operating State had changed from Normal to High-Risk. Having issued that Dispatch Advisory, System Management had unrestricted powers to use whatever it considered suitable. He further added that it seemed that the proposal would make an incremental adjustment on protections which already existed. Dr Tooth mentioned that this recommendation was not expected to change current behaviour.<br>• On Proposal 2[2]; members sought some clarification on whether DSPs could be dispatched as a priority by using the consumption decrease price. Mr Gaston noted that the proposal seemed to add another layer of complexity when in fact tie-breaking rules already existed. The Chair clarified that this was beyond the Balancing Merit Order and that a random number generator could | |

[1] Proposal 1: A rule is established to ensure that the DSM quantity dispatched is not more than can be reasonably justified to manage the uncertainty of the short-term requirements consistent with the Dispatch Criteria

[2] Proposal 2: the rank-based-on load size rule in the Non-Balancing Dispatch Merit Order be removed and replaced with a ranking based on time since last dispatch

| | | |
|---|---|---|
| | not be integrated into this part of the system. Mr Tan queried if self-dispatches by DSPs could be considered when counting the most recent dispatch. In response to this query, Dr Tooth clarified that only dispatches conducted by System Management would be counted. Mr Renaud and Mr Clarke discussed whether System Management could conduct partial dispatches of DSPs for example, System Management only dispatching a DSP for a fraction of the total amount it had initially bid in. The Chair noted that clarity on this action item would be sought by the IMO. | |
| | • Dr Tooth noted that the discussion indicated that members agreed that rank based on load size needed to be removed and the point of contention was whether dispatch should instead be conducted on rank-based-on-time. Ms Wana Yang queried whether this logic should also exist for generators to facilitate consistency. In response, the Chair and other members noted that this would not be possible because generators are allowed to bid in different offer tranches at different values. | |
| | • Discussion ensued on the possible scenarios in which DSPs would likely be dispatched. Dr Tooth noted that there would need to be an unlikely disaster scenario for all of the DSPs to simultaneously get dispatched. Mr John Rhodes argued that the proposal placed an unlimited liability on Market Customers who are contracting for an unknown level of risk. He queried as to why the burden of a disaster scenario, which is the principle behind the design of the Reserve Capacity Mechanism, should be placed on DSPs. Discussion ensued on the risk of unlimited dispatch for DSPs. Mr Cremin observed that the risk profile for DSPs was similar to that for generators. If generators went on outage for prolonged periods of time then they would be liable for refunds. Similarly, for DSPs the risk that they would be dispatched existed and must be built into their business risk plans. Members agreed that the market should not underwrite this risk for DSPs. Mr MacLean argued that unlimited hours of availability for DSPs constituted discrimination because by definition this technology could not be available for an unlimited time period. Mr Geoff Down noted that the risk depends on whether the DSP is a portfolio of programmes or a single large programme. He added that the market might lose some of the DSPs because of this unlimited availability criterion, as programmes will have to assess how much they have available to curtail. Discussion continued on what risk management techniques might be applied by DSPs as the new rule comes into play. | |
| | • The Chair summarised the discussion and questioned members for their consent to move forward with the recommended proposals. He acknowledged that more work needed to be done on rule development and implementation. Members agreed to move forward as proposed. Mr MacLean did not agree with the proposal of unlimited hours of availability for DSPs. | |
| | *Action Points:* | |
| | • *On Proposal 2, the IMO to check whether System Management can dispatch DSM for a part of its full quantity.* | **IMO** |
| | • *The IMO to work through rule change development process on the recommended proposals.* | **IMO** |

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| **5.** | **AGENDA ITEM 6: Dynamic Refunds Mechanism**<br><br>The Chair invited Mr Mike Thomas to make his presentation. The following discussion points were noted:<br><br>• On the topic of recycling, Mr MacLean opined that the benefit being accorded to better performing resources had not been quantified and thus it was difficult to ascertain how the recommendations would improve the current situation.<br><br>• On the topic of recycling refunds by either availability versus dispatch, Mr Cremin disagreed with Mr Thomas that rebates should be based on availability. He noted that in this market Capacity Credits are paid three years in advance for capacity to be available even though it may never get used. He observed that Mr Thomas's proposed recycling approach attached more value to capacity which is available but rarely gets dispatched such as peaking units and DSPs. He added that such an approach should be balanced by a reduction in the compensation they get for Capacity Credits.<br><br>• Mr MacLean observed that the proposal did not present enough incentive for improvement. He added that if this change was implemented, it would imply that bilateral contracts might need to be rewritten as generators would now be able to recoup some of their costs through the recycling mechanism. Mr Stevens argued that this might be the case for only a few contracts, but most other contracts would not be affected.<br><br>• Discussion ensued on the topic of refund factors. Mr Sutherland noted that the principle behind Mr Thomas's refund factor proposal was that the value of capacity would be higher as the system reserve margin went lower. He added that payments on the revenue side, however, did not respond the same way i.e., higher payments for capacity as the system reserve margin went lower<br><br>• Discussion ensued on how Planned and Forced Outages would get treated under the dynamic refunds regime. While evaluating various options, Mr Gaston observed that a refund factor of 18 would translate into very high financing risks and that this was compounded by the fact that the Maximum Reserve Capacity Price was not a forecast-able figure. Mr Tan agreed with this observation. Mr Sutherland noted that as the refund factor gets high, generators would start building the risk margin into the energy price. Mr Gaston agreed that a high refund factor would price capacity out of the energy market.<br><br>• Mr Gaston noted that the underlying behaviour that the dynamic refunds regime was striving to correct was generators not coming back online from an outage as soon as possible. He observed that for peaking plants, even a refund factor of one was stringent enough to make them undertake repairs as soon as possible. He noted that baseload generators would be hit even harder when on outage as they would have to cover their energy prices by having to buy at high prices in the Balancing Market. He further added that the proposal did not seem to be having an effect on the incentives for generators to come back online from an outage. The Chair noted that the proposal was not trying to change current incentives; instead it was making the refunds regime more | |

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| | reflective of system conditions. He added that it also had the extra benefit of incentivising better performing generation assets.<br>• Mr MacLean observed that the question for generators to consider was that if the recycling of refunds was implemented, how the generators would share the money between them.<br>• The Chair asked members if the proposal should be progressed. Mr MacLean noted his objection to the proposal on the grounds that some bilateral contracts that were already in place would need to be re-written. Mr Gaston noted his support for Option C[3] as long as the maximum refund factor remained at 6 and did not increase any further. However, he did not agree with the recycling mechanism as he was not convinced as to how this would translate into reduced cost for retailers. Mr Clarke noted his support for the recycling mechanism but added that the sharing of the pool of money between generators and retailers needed to be further clarified. He also noted his support for the option of recycling refunds to generators based on dispatch rather than availability because for System Management, a generator that may be able to start within minutes would be preferable to the one which may take hours. The Chair noted that the recommendations will be put forward to the IMO Board with an acknowledgement of the objections raised by some MAC members. He also added that the recommendations would be developed into rule changes and the rule change process would also offer members time to register their objections.<br>*Action Item: The IMO to make recommendations to the IMO Board on the dynamic refunds regime whilst acknowledging the objections raised by some MAC members.* | **IMO** |
| **6.** | **AGENDA ITEM 7: Reserve Capacity Price**<br>The Chair invited Mr Mike Thomas to make his presentation on the Reserve Capacity Price. The following discussion points were noted:<br>• The Chair observed there were a number of factors contributing to excess reserve capacity. The current process was to move incrementally in the direction of incentivising the right outcome in the Reserve Capacity Mechanism. This did not necessarily mean that the excess capacity problem would get fixed or that the Reserve Capacity Mechanism would be shielded from the detrimental effects of other external factors such as commercial and government policy decisions.<br>• Mr Clarke agreed that there was an excess capacity problem and added that the cost-benefit analysis conducted on the Planning Criterion suggesting that the reserve margin could be reduced to 7.6%, further reiterated this problem. Mr Clarke added that the Rule Change Proposal recently submitted to implement the 7.6% reserve margin (RC_2012_21) was a step in the right direction.<br>• Ms Yang noted that the Market Rules allowed for the IMO to hold an auction if the Reserve Capacity Requirement was not met. | |

[3] The following options were presented in Mr Thomas's presentation: Option A- IMO's proposal as presented in RDIWG meeting no.11; Option B- IMO's proposal with a minimum refund factor level; Option C- IMO's proposal linked to the Reserve Capacity Price.

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| | The Chair observed that the auction had never taken place since market start. Mr Thomas noted that even if the auction had to happen, the market would have to go through several learning processes to adjust to the mechanism. Ms Yang also queried which one of the three capacity markets (PJM, NYISO and New England) had the most economically efficient auction. Mr Thomas observed that in any auction process, an administrative demand curve had to be instituted to avoid the high volatility in price.<br>• Mr MacLean opined that the contextual discussion was too little too late. He added that members had missed the opportunity of thinking through the context of the problem and could only just react to the proposals on the table. However, Mr Renaud argued that members had discussed the problem and the proposed solution many times over the past few months.<br>• Mr Tan noted that the underlying assumption was that generators which were already embedded in the market would hurt themselves and other generators by bringing in new capacity, but new Participants who have had no exposure to the market would not care as to what the price per Capacity Credit was, because they would get that anyway. Mr Cremin counter-argued that the new participant would only enter the market if it was profitable to do so. If the MRCP was also adjusted then the market would not remain that profitable anymore.<br>• Mr MacLean questioned whether the effect would be exactly the same if instead of the price curve starting at 110% of the MRCP and 97% of the Reserve Capacity Requirement (RCR), it was to simply commence at the intersection of the MRCP and the RCR. Mr Thomas replied that the result would not be the same because 110% was a higher number over the MRCP and strengthened the incentive for retailers to contract for new capacity as supply and demand approached balance. Discussion ensued over how reserve capacity is paid for when there is a shortfall in the market. Ms Yang confirmed that currently there is no price limit on Supplementary Reserve Capacity under the Market Rules.<br>• Mr Clarke argued that it was not clear why a generator would want to offer a contract to a retailer in the current situation. Mr Renaud suggested that a greater concern for the market should be the cost of excess capacity rather than the quantity. Mr Clarke observed that the cost benefit analysis recently conducted on the Planning Criterion recommending that the reserve margin should be reduced to 7.6% suggested that excess capacity should be zero. Mr Ruthven clarified that the reserve margin was be used in determining the RCR, whereas the current discussion was considering the price outcomes when the quantity of capacity in the market exceeded the RCR. Mr Stevens added that it was important to note that from a retailer's perspective, the lowest cost for energy was the most beneficial outcome, but from a market's perspective, the matter at hand was how to shape the market so that excess capacity did not cost more. Mr Cremin echoed that point of view and added that the two numbers that were used to shape the capacity mechanism- the RCR and the MRCP were both prone to errors and Mr Thomas's proposal was just one way of sending the market a signal when to bring in or not bring in additional capacity. The Chair added that the market | |

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| | | should not bear the cost of that additional capacity.<br>• Mr Gaston observed that the Reserve Capacity Mechanism was a prescribed process and was never intended to provide a market based outcome. He added that the MRCP was known two years in advance and that acted as a signal for the market to bring in additional capacity. Discussion ensued among members on what had incentivised excess capacity to enter the market. Mr Cremin was of the view that so much excess would not exist in the current market if the MRCP had not been so volatile. The Chair disagreed with this point of view and observed that decisions around bringing in new capacity were not based on price alone. He added that the market must also be able to guard against a situation of shortfall.<br>• Mr MacLean observed that the price would be predictable if the IMO was able to reduce volatility in the MRCP and the entry of capacity would become regulated. Further, if the price signal was unable to bring in sufficient capacity, then the Market Rules allowed for an auction process to be carried out. He added that the auction process would be able to bring in excess capacity because it allowed the price to rise up to the MRCP. However, Mr Tan argued that an auction would be unlikely to bring in excess capacity because of the long lead time for a project to be built and ready.<br>• Discussion ensued on a retailer's desire to contract for capacity under the current mechanism. Mr Thomas argued that under the current mechanism there was very little incentive for a retailer to contract bilaterally for capacity. Mr MacLean observed that contracts were based on the future expectation of price and were forged for many years. As a result, what happened in the short-term would not be a big concern to the retailer. He stressed that the higher price reduction as suggested in Mr Thomas's proposal made the situation uncertain and difficult to contract in. Mr Down observed that the customers who had entered into contracts expecting a fixed price on energy would also be affected by any changes on the price. The Chair observed that parameters such as devaluation of the Australian dollar and the Weighted Average Cost of Capital which are not controllable by the IMO affect the MRCP.<br>• Mr Tan asked for some clarification on the numbers proposed in Mr Thomas's proposal. He noted his support for the structure and the theories that went behind it, but he was not convinced that the proposed numbers were correct. The Chair observed that if a change in slope were to be considered, it would need to be transitioned through using the IMO's transitional arrangements guidelines.<br>• The Chair canvassed members' opinions on proceeding further with the recommendations. Mr MacLean noted any change at present time would be too early because the effect of the changes in MRCP and load forecasting capacity still needed to play out. Mr Clarke noted that a case for change sooner rather than later existed because of the presence of excess capacity in the market. Mr Renaud noted that he was generally supportive of the changes as it seemed to be balanced around a reasonable pivot point of 7% excess capacity in the market. Mr Cremin noted | |

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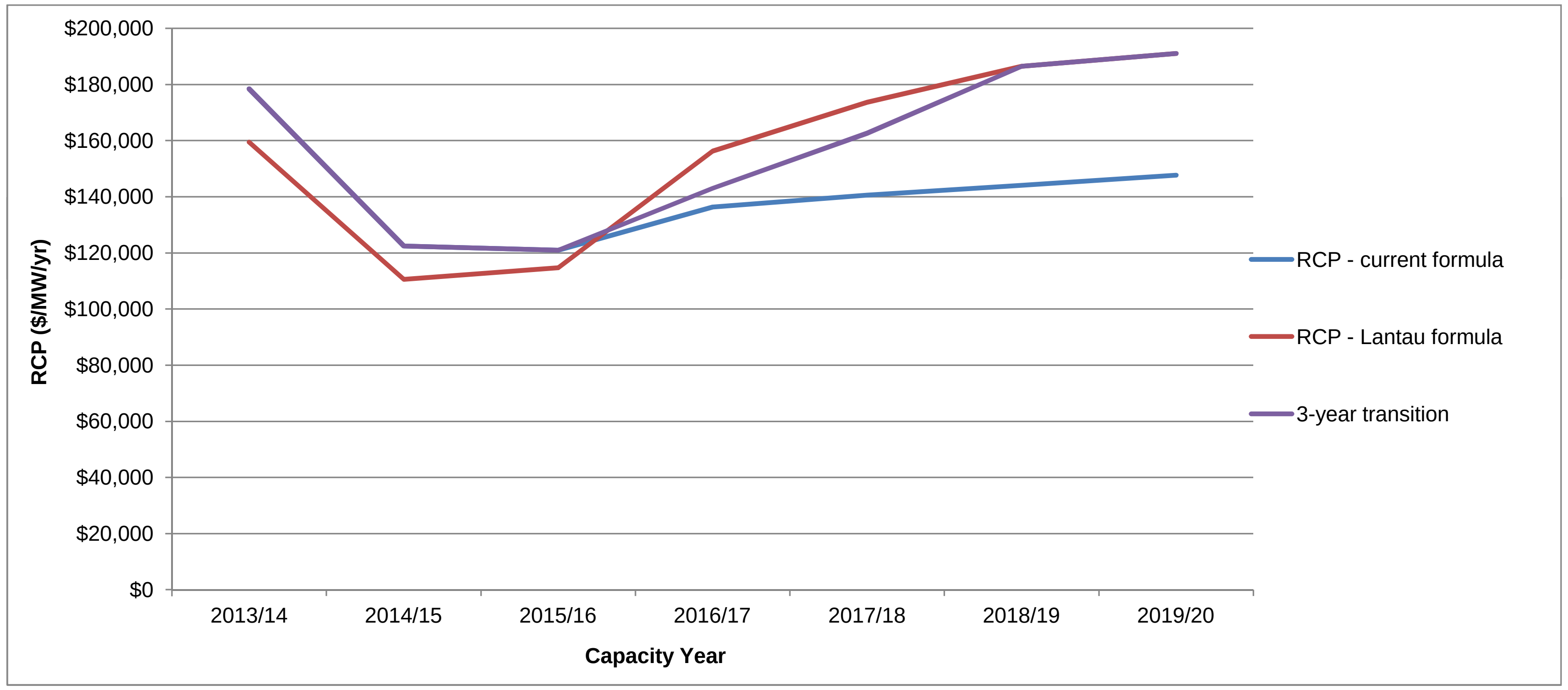
| | his view that the MRCP and the sliding scale should be delinked from each other. He supported the idea of implementing the change because it was a suitable way forward without completely changing the market. Ms Lisa Taylor asked if more analysis could be made available before this was progressed to the rule development stage. Mr Gaston did not support the proposal. Dr Gould observed that under the proposed mechanism, prices would rise sending a strong signal to retailers to contract bilaterally.<br>• The Chair offered that the IMO would conduct more analysis, including a proposed transition path, and send it via email to gauge MAC members' support.<br>*Action Item:*<br>*The IMO to conduct more analysis on Reserve Capacity Price, including a proposed transition path and send it via email to canvas MAC members' support.* | **IMO** |
| | **CLOSED**<br>The Chair thanked the members and declared the meeting closed at 5.45 pm. | |

**Reserve Capacity Price: projections and potential transitions**

***Kwinana C retires for 2016/17***

| Capacity Year | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | Notes |
|---|---|---|---|---|---|---|---|---|
| Actual/projected RCR | 5312 | 5308 | 5378 | 5569 | 5728 | 5859 | 6007 | From RCMWG papers, Nov 2012, page 95/99 |
| Actual/projected capacity | 6086.829 | 6040.161 | 5949 | 5604 | 5629 | 5654 | 5679 | From RCMWG papers, Nov 2012, page 95/100 |
| Surplus (MW) | 774.829 | 732.161 | 571 | 35 | -99 | -205 | -328 | |
| Surplus (%) | 14.6% | 13.8% | 10.6% | 0.6% | -1.7% | -3.5% | -5.5% | |
| Actual/projected MRCP | $240,600 | $163,900 | $157,500 | $161,400 | $165,400 | $169,500 | $173,700 | Actuals for 13/14 & 14/15; 15/16 from Draft Report with $\gamma$=0.25; indexed at 2.5% thereafter |
| ***Note that RCP calculations below assume that administered price applies, even in shortfall*** | | | | | | | | |
| RCP - current formula | $178,477 | $122,428 | $121,025 | $136,333 | $140,590 | $144,075 | $147,645 | RCP (current) = MRCP * 85% * RCR / capacity; *capped at 85% of MRCP* |
| RCP - Lantau formula | $159,483 | $110,624 | $114,686 | $156,276 | $173,659 | $186,450 | $191,070 | RCP (Lantau) = MRCP * 110% / (1 - ((Surplus% + (1-97%)) * (-3.75))); *capped at 110% of MRCP* |
| ***Transition path is projected to commence from 2016/17*** | | | | | | | | |
| 3-year transition | $178,477 | $122,428 | $121,025 | $142,981 | $162,636 | $186,450 | $191,070 | |

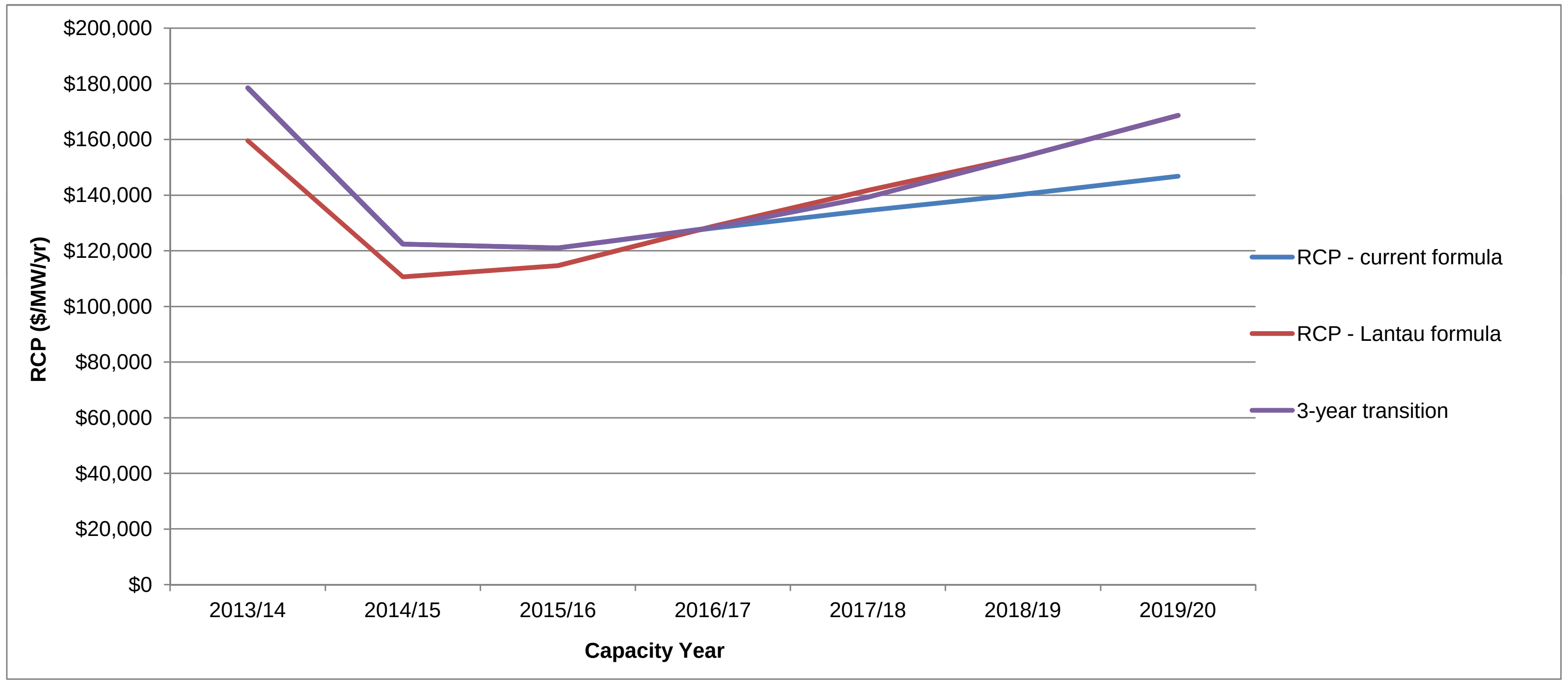



| ***Total capacity costs:*** | | | | | | | |
|---|---|---|---|---|---|---|---|
| ***Percentage bilaterally contracted*** | | 70% | | | | | |
| ***Bilateral contracts priced at*** | | 80% | of MRCP | | | | |
| RCP - current formula | $1,146,022,128 | $776,235,343 | $740,695,725 | $735,715,269 | $758,794,829 | $781,057,695 | $803,950,475 |
| RCP - Lantau formula | $1,111,338,299 | $754,845,820 | $729,381,442 | $769,242,914 | $814,638,059 | $852,934,170 | $877,933,647 |
| 3-year transition | $1,146,022,128 | $776,235,343 | $740,695,725 | $746,891,151 | $796,023,649 | $852,934,170 | $877,933,647 |

## Reserve Capacity Price: projections and potential transitions

***Kwinana C remains in service***

| Capacity Year | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | Notes |
|---|---|---|---|---|---|---|---|---|
| Actual/projected RCR | 5312 | 5308 | 5378 | 5569 | 5728 | 5859 | 6007 | From RCMWG papers, Nov 2012, page 95/99 |
| Actual/projected capacity | 6086.829 | 6040.161 | 5949 | 5965 | 5990 | 6015 | 6040 | From RCMWG papers, Nov 2012, page 95/100 |
| Surplus (MW) | 774.829 | 732.161 | 571 | 396 | 262 | 156 | 33 | |
| Surplus (%) | 14.6% | 13.8% | 10.6% | 7.1% | 4.6% | 2.7% | 0.5% | |
| Actual/projected MRCP | $240,600 | $163,900 | $157,500 | $161,400 | $165,400 | $169,500 | $173,700 | Actuals for 13/14 & 14/15; 15/16 from Draft Report with $\gamma$=0.25; indexed at 2.5% thereafter |
| ***Note that RCP calculations below assume that administered price applies, even in shortfall*** | | | | | | | | |
| RCP - current formula | $178,477 | $122,428 | $121,025 | $128,082 | $134,441 | $140,338 | $146,838 | RCP (current) = MRCP * 85% * RCR / capacity; *capped at 85% of MRCP* |
| RCP - Lantau formula | $159,483 | $110,624 | $114,686 | $128,731 | $141,695 | $153,793 | $168,626 | RCP (Lantau) = MRCP * 110% / (1 - ((Surplus% + (1-97%)) * (-3.75))); *capped at 110% of MRCP* |
| ***Transition path is projected to commence from 2016/17*** | | | | | | | | |
| 3-year transition | $178,477 | $122,428 | $121,025 | $128,299 | $139,277 | $153,793 | $168,626 | |



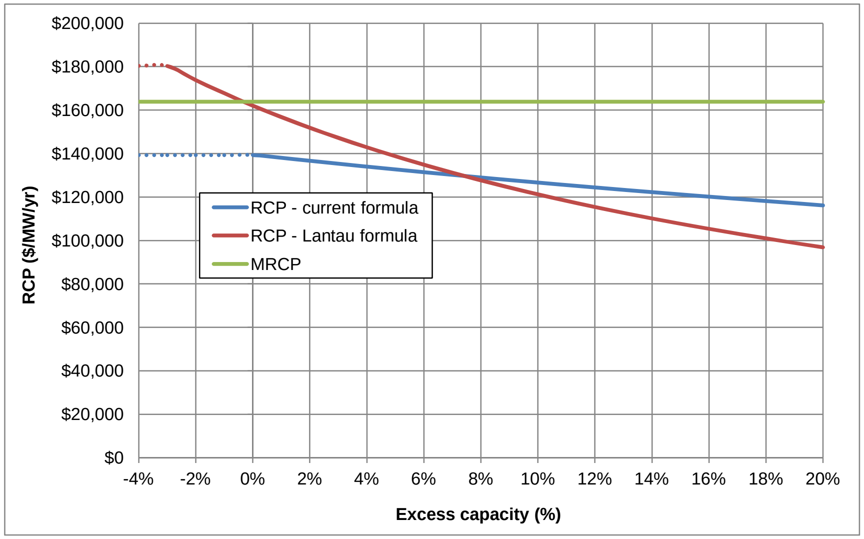

| ***Total capacity costs:*** | | | | | | | |
|---|---|---|---|---|---|---|---|
| ***Percentage bilaterally contracted*** | | 70% | | | | | |
| ***Bilateral contracts priced at*** | | 80% | of MRCP | | | | |
| RCP - current formula | $1,146,022,128 | $776,235,343 | $740,695,725 | $768,343,893 | $796,407,616 | $824,184,428 | $853,593,935 |
| RCP - Lantau formula | $1,111,338,299 | $754,845,820 | $729,381,442 | $769,504,732 | $809,443,617 | $848,462,690 | $893,072,739 |
| 3-year transition | $1,146,022,128 | $776,235,343 | $740,695,725 | $768,730,839 | $805,098,284 | $848,462,690 | $893,072,739 |

**Reserve Capacity Price: comparison of current and Lantau formulae versus excess capacity**

MRCP ($/MW/yr) $163,900
RCR (MW) 5308

RCP (current) = MRCP * 85% * RCR / capacity; *capped at 85% of MRCP*
RCP (Lantau) = MRCP * 110% / (1 - ((Surplus% + (1-97%)) * (-3.75))); *capped at 110% of MRCP*

| Percentage excess | MRCP | RCP - current formula | CP - Lantau formula | |
|---|---|---|---|---|
| -4% | $163,900 | $139,315 | $180,290 | |
| -3% | $163,900 | $139,315 | $180,290 | |
| -2% | $163,900 | $139,315 | $173,773 | |
| -1% | $163,900 | $139,315 | $167,712 | |
| 0% | $163,900 | $139,315 | $162,058 | |
| 1% | $163,900 | $137,936 | $156,774 | |
| 2% | $163,900 | $136,583 | $151,823 | |
| 3% | $163,900 | $135,257 | $147,176 | |
| 4% | $163,900 | $133,957 | $142,804 | |
| 5% | $163,900 | $132,681 | $138,685 | |
| 6% | $163,900 | $131,429 | $134,796 | |
| 7% | $163,900 | $130,201 | $131,120 | |
| 8% | $163,900 | $128,995 | $127,639 | |
| 9% | $163,900 | $127,812 | $124,338 | |
| 10% | $163,900 | $126,650 | $121,203 | |
| 11% | $163,900 | $125,509 | $118,223 | |
| 12% | $163,900 | $124,388 | $115,386 | |
| 13% | $163,900 | $123,288 | $112,681 | |
| 14% | $163,900 | $122,206 | $110,101 | ***2014/15 EXCESS*** |
| 15% | $163,900 | $121,143 | $107,636 | |
| 16% | $163,900 | $120,099 | $105,279 | |
| 17% | $163,900 | $119,073 | $103,023 | |
| 18% | $163,900 | $118,064 | $100,862 | |
| 19% | $163,900 | $117,071 | $98,789 | |
| 20% | $163,900 | $116,096 | $96,800 | |



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# Memo

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| To: | RCM Working Group |
| From: | Mike Thomas |
| Date: | 22 February 2013 |
| Subject: | RCM and Refunds Package |

## 1. OVERVIEW

At the RCM WG meeting in November 2012, we set out our recommended changes to the RCM and the associated Refunds Regime, as discussed and evolved over the course of WG meetings that commenced in February 2012.[1] These changes reflect a number of findings and observations, repeated below in high-level, summary form:

- The RCM has flaws;
  - Does not reflect market conditions;
  - Distorts incentives to invest and contract;
  - Therefore reduces efficiency;

[1] The IMO had completed analysis of a dynamic refund regime proposal in 2011, just ahead of commencing an analysis of the RCM regime. The RCM regime review recommended deferring consideration of the refund regime proposal until it could be harmonised with recommendations related to the RCM regime. As identified at the time, the potential changes to the refund regime would have reduced refund exposure, which would have *increased* the value expected to be recovered by an investor in reserve capacity – the very opposite of what was determined to be the appropriate economic signal at that time. Consequently, the IMO's refund regime recommendations were held in abeyance so as to be considered jointly with recommendations arising from the RCM review.

- The refunds regime also has flaws:
    - Does not reflect market conditions;
    - Is not integrated consistently with the RCM;
    - Therefore reduces efficiency;
- And, finally, that the RCM and refund regime should be viewed as a coherent package.

The RCM regime clearly impacts the value of refund exposure, and vice versa. In particular, new investment will only be economic if the combination of energy revenues plus capacity credit revenues *less* any lost revenue from the refund regime is at least equal to the long-run marginal cost of new capacity.

## 2. FORMING A COHERENT PACKAGE

The RCM and Refunds Regime establish crucial parameters and mechanisms that, depending on how well they work, can either enhance or impair the competitive processes and pressures of the WEM. The components of a coherent package, covering both the RCM and the associated Refunds Regime, are summarised below:

- Enhanced linkage between the RCP and market conditions;
    - In the form of a more sensitive linkage between changes in the amount of excess reserve capacity and changes in the level of the RCP;
    - This is mainly achieved through the setting of the slope parameter;
- Enhanced linkage between refund exposure and market conditions;
    - In the form of refunds that vary depending on the amount of available reserve capacity;
    - This is mainly achieved through setting of the dynamic refund factors that are based on actual market outcomes;
- Consistent and robust incentives for desirable outcomes;
    - In the form of a more robust and logical nexus between the RCP formulation and the MRCP concept and definition[2]; and

2 This was substantially achieved through the MRCP review that was undertaken and that has occurred separately and independently of this consultation on the RCM itself.

- Align investment incentives with desired capacity resource performance characteristics;
  - This is achieved through the introduction of refund revenue recycling across reserve capacity resource providers, which rewards better performing resources, treats average resources in an average way, and penalises, relatively speaking, less available resources.
  - In addition, recycling prevents value spill over (leakage) arising when refunds are paid to retailers and, thus must, be "offset" by other revenue sources when new capacity resources are required.

Making changes to the Refunds Regime without considering the potential impact on the RCM itself has the potential to be little more than a transfer of value, which, once achieved, locks in positions that must then be reconsidered when evaluating changes to the RCM. Reviewing the RCM and refunds regime as a package avoids this problem.

## 3. THE ADJUSTMENTS TO THE RCM

Competitive market forces, backstopped by the RCM, ultimately determine the reserve capacity quantity in the WEM. The RCP is determined by an adjustment formula linked, on the one hand, to a robust estimate of the cost of new capacity via the MRCP and, on the other hand, to the level of excess reserve capacity. The MRCP revisions reduced future MRCP values materially relative to those determined for the 2012/13 and 2013/14 capacity years.

The adjustment formula used in the WEM incorporates a slope function, which has been recommended to be changed to "-3.75", a value significantly steeper than the "-1" value embedded in the current formulation. The recommended "-3.75" value evolved from the previously recommended slope value of "-3.25", which had been developed to yield a point of equivalence at a given level of excess reserve capacity between the current RCM formula and the modified RCM formula – a value selected to minimise the need for a transition given the already material changes implemented with respect to the MRCP methodology.[3] The increase in proposed slope to -3.75 from -3.25 also was advised in the context of introducing recycling within the refunds regime.

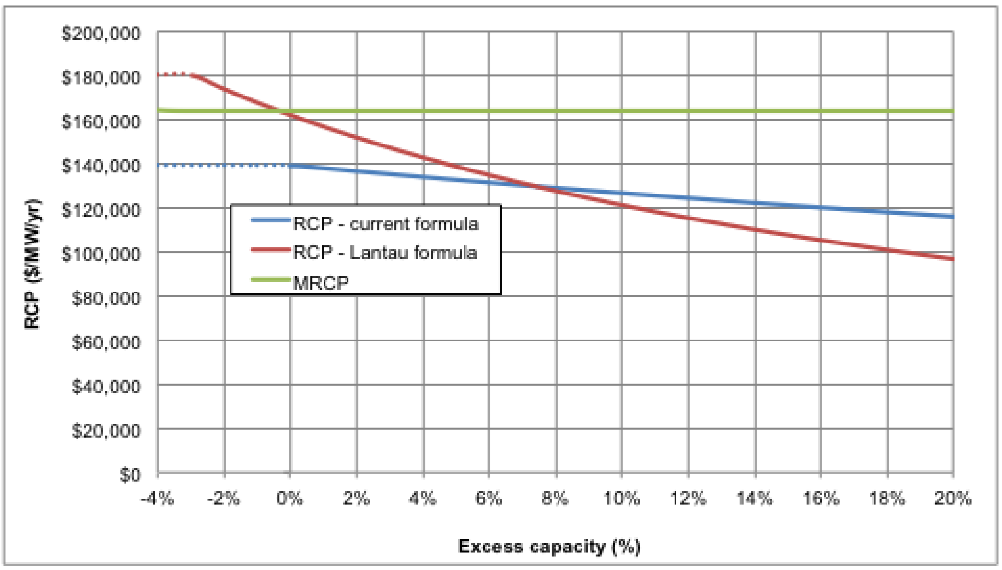
3 It was also noted that given the existence of significant excess reserve capacity the *economic* value of *incremental* reserve capacity can be virtually zero (based on the impact on the LOLP) – a fact that could, in theory, support a far steeper slope function linked to the LOLP. Such extreme steepness, however, would introduce significant and disruptive risk into the WEM, which is already a small market exposed to disruptions caused by lumpy investment and volatile demand growth. It is observed that those capacity markets in other countries that rely more directly on auctions to discover clearing prices have struggled with the "zero/infinity" challenge. In general, these markets have had to resort to various complex and evolving mechanisms to modulate this extreme sensitivity, analogous to the role the slope function plays in the RCM.

# 4. OTHER ASPECTS OF THE RCP FORMULA

Two other aspects of the RCP formula should be noted. The proposed changes include a provision to allow the RCP to reach a level that is 10 percent *above* than the Benchmark RCP should reserve capacity be only 97 percent or less of the RCR. The selection of 97 percent is reflective of the observation that there exists an approximately three percent forecast error band with respect to demand forecasts made two years forward.

Combining this 97 percent factor, the proposed slope of -3.75 and a maximum RCP of 110% of the BRCP, the RCP would be just below the BRCP at the point of zero excess reserve capacity, as shown in Figure 1.

**Figure 1: Proposed Pricing Regime**




Source: IMO calculations as distributed to the RCM WG in December 2012

In the event that the amount of excess reserve capacity falls below the RCR, a supplemental auction would be called. Under such situation, any uncontracted capacity credits procured through the IMO would be sold at up to 110% of the RCP, per the formula. By allowing the RCP to increase above the BRCP, it is more certain that capacity resources can be economically developed should such a shortage situation arise. These modifications to the RCM are intended to enhance the RCM as a backstop and as a mechanism capable of reinforcing rather than undermining natural incentives for retailers and capacity resource providers to hedge price-related risks through commercial contracts.

# 5. WHY RECYCLE REFUNDS TO CAPACITY PROVIDERS?

The payment of refunds to retailers is a feature of the existing refunds regime. While on one hand it might be argued that retailers who pay for capacity credits ought to get their money back if capacity does not perform, this misses the crucial point that it is the overall RCM and not individual reserve capacity resources that is responsible for ensuring adequate capacity. And, to the extent that incentives for availability can be enhanced further, retailers would benefit through the practical existence of a more robust offer curve – a positive force for enhanced competition and market efficiency.

The refunds payable to retailers, however seemingly valuable in the short-term, are of little benefit to retailers in the longer term, as this value leakage must ultimately be offset by either higher energy costs or higher capacity credit values. The commercial rationale to structure the refunds regime as a compensation mechanism for retailers diminishes rapidly once new capacity resources are required.

We therefore advise that the payment of refunds to retailers constitutes a complication and potential distortion to the RCM by virtue of the fact that it results in uncertain revenue "leakage" which detracts from efficient investment signals and represents a highly uncertain revenue stream to retailers with no long-term benefits as a quid pro quo. Instead, we recommend recycling refund revenues within the realm of capacity resource providers so as to sharpen all the relevant incentives associated with maximising the value of existing capacity resources as well as properly incentivising the addition of more available capacity resources to displace less available ones, all in line with the Market Objectives.

With recycling, the value of the RCM is determined clearly and solely by supply and demand conditions each year and by the setting of the MRCP. There is neither value leakage through the refund regime, nor any potentially perverse incentives whereby retailers derive benefit from outcomes that are disadvantageous to the market overall.

An example of a potentially perverse outcome is that of the WA Biomass facility (40MW), which was issued capacity credits, which it ultimately refunded due to being delayed. The impact on retailers was two-fold:

- The additional credits contributed to excess reserve capacity, lowering the RCP at the expense of other capacity resource providers; and

- The refunds that resulted when the facility was delayed then flowed to retailers.

In effect, retailers perversely received a dual benefit from a facility that did not yet operate. Under the recycling-based regime, the initial issuance of capacity credits would have had a similar impact on the RCP, but the deferral of the facility and subsequent refund recycling would have been at least of directionally appropriate recompense to capacity resource providers. While the refunds associated with capacity credits for a 40 MW facility would not have been enough to offset the reduction in the RCP (which would have impacted *all* uncontracted capacity credits), the principle of recycling is inherently more equitable as well as providing a directionally appropriate set of incentives.

With recycling in place, gencos and retailers are free to protect themselves against other commercial risks, such as unexpected non-performance through their commercial contracting and other risk management activities.

## 6. DYNAMIC REFUND FACTORS

The dynamic refund factor proposal clearly aligns refunds with market conditions much more effectively than do the current fixed, clock-based factors. In the dynamic refund regime presented and discussed at the November 2012 WG meeting, we proposed a maximum refund factor of 6 and a minimum refund factor of 1.

Higher values were discussed but rejected following strenuous stakeholder concerns regarding the impact on financing associated with greatly enhanced refund-related risks. With a maximum refund factor of 6 the economic value of refund exposure is much less than the potential economic detriment associated with unavailability, but an exact matching is not needed to secure a sharper incentive to improve availability during crucial trading intervals.

Over the last three Capacity Years, total refund value has ranged from about 9 to 16 million dollars. These estimates were derived from data provided by the IMO and have considered only refunds related to Forced Outages.  As shown in Table 1, the proposed refund regime with dynamic refund factors and a minimum refund factor exposure yields refund exposure similar in magnitude (8 to 18 million) to the current regime, at least over the years shown.

**Table 1: Refund Regime Exposure (excluding WA Biomass[4]**

| Capacity Year | 2009/10 | 2010/11 | 2011/12 |
|---|---|---|---|
| Capacity Credit (MW) ** | 5079 | 5223 | 5442 |
| MRCP (AUD/MW) | 142,200 | 173,400 | 164,100 |
| **Current Regime** | | | |
| RCP | 108,459 | 144,235 | 131,805 |
| Refund (AUD) | 9 million | 16 million | 16 million |
| Refund as % of total Capacity Credit at RCP | 1.70% | 2.09% | 2.28% |
| **Option B Dynamic Refund Regime (with max refund factor 6 and floor 1)** | | | |
| RCP | 101,464 | 159,678 | 135,618 |
| Refund (AUD) | 8 million | 18 million | 12 million |
| Refund as % of total Capacity Credit at RCP | 1.59% | 2.22% | 1.61% |

## 7. IMPACTS OF THE OVERALL PACKAGE

The changes to the RCM settings produce a benefit to retailers in the near term due to the reduction in the RCP. We estimate an overall reduction in cost to retailers of between 10.4 and 40.5 million depending on whether the amount of excess reserve capacity falls between 9 percent and 15 percent. These values assume a level of 50% bilateral contracting on the basis that additional excess reserve capacity reduces the incentive for retailers to contract with reserve capacity resources directly. At lower levels of bilateral contracting, given such a material amount of excess reserve capacity, the potential savings could be significantly greater.[5]

4 While WA Biomass had Forced Outages logged against it even though it was never built, the same was not done for KWINANA_GT2 and KWINANA_GT3 when each was delayed in commissioning at the start of the 2011/12 Capacity Year. For consistency of treatment, WA Biomass has been excluded from the above table.

5 We assume bilateral contracts are struck at a price that is equal to 90 percent of the MRCP. We note that under the existing RCM settings there is limited incentive for a retailer to enter into a bilateral contract unless the price offered were somewhat below 85 percent of the MRCP. The values shown, therefore, are potentially conservative.

**Table 2: Estimated RCM Value Impact**

| | | |
|---|---|---|
| Capacity (MW) | 6000 | |
| MRCP ($/CC) | 163,900 | CY2014/15 |
| % Bilaterally contracted | 50% | |
| Bilateral contracts priced at | 90% | of MRCP |

| Excess Capacity | 9.00% | 12.00% | 15.00% |
|---|---|---|---|
| RCP – current ($/CC) | 127,812 | 124,388 | 121,143 |
| RCP – proposed ($/CC) | 124,338 | 115,386 | 107,636 |
| Costs to Retailers - current ($) | 825,965,780 | 815,695,179 | 805,960,435 |
| Costs to Retailers - proposed ($) | 815,543,793 | 788,686,800 | 765,437,463 |
| Reduction Value ($) : (current less proposed) | 10,421,987 | 27,008,379 | 40,522,972 |

At lower levels of excess reserve capacity, the incentive to manage risk exposure through bilateral contracting increases. It therefore ceases to make sense to compare scenarios holding the level of bilateral contracting constant. Furthermore, as the amount of reserve capacity reduces below about six percent, the more relevant concerns begin to touch on the question of whether the RCM will properly incentivize new capacity in a timely fashion (given the volatile demand growth that WA is capable of). We would therefore suggest that a focus on refund disposition becomes increasingly irrelevant as the amount of excess reserve capacity reduces.

For example, once new investment is required, retailers no longer gain or lose a net benefit associated with receiving refund revenue. Any increase in refund revenue is potentially at the expense of investment incentives and may be offset by higher energy costs or (in the extreme) reduced reliability. Recycling avoids this problem by ensuring that less reliable capacity pays refunds that ultimately assist the investment case (even if only modestly) of new capacity capable of performing more robustly.

## 8. SCOPE FOR A TRANSITIONAL IMPLEMENTATION

The proposed changes are sufficient to warrant consideration of a transition programme, though there is no inherent requirement that a transition programme be adopted. In December, the IMO prepared and circulated an analysis of a three-year transition.[6]

From an economic efficiency perspective, the main economic benefits of the proposed changes will start being realised virtually immediately, regardless of whether a transition arrangement is implemented, as stakeholders incorporate the present value impact of the substantially increased sensitivity of RCP values to market conditions into their planning.

6 Email 7 December 2012 from Courtney Roberts to the RCM WG conveying a letter from Suzanne Frame and an attached Microsoft Excel workbook.

Note further, that the coherent package to be evaluated comprises changes to the RCM as well as changes to the Refunds Regime. The application of recycling, as discussed further below, naturally offsets some of the revenue loss to capacity resource providers under the more dynamic RCP pricing formula proposed – just as the changes to the RCP formula naturally offsets the revenue loss to retailers associated with the recycling of refund revenues within capacity resource providers.

# 9. SUMMARY

The overall package of changes is set out below:

- Incorporate dynamic refund factors together with a minimum refund factor;
- Recycle refund revenue to all eligible available capacity;
- Remove the 85 percent discount factor applied to the MRCP;
- Rename the MRCP to the "Benchmark RCP" or "BRCP", as this properly reflects how the MRCP is calculated currently based on expected costs for a standard capacity resource;
- Set the MRCP (Maximum BRCP) above the BRCP. We have advised a factor of 110% of the BRCP as representing a sufficient uplift as to allow reasonable expectations of being able to earn the BRCP through a combination of contracts and exposure to the RCP formula (which could be below the BRCP any time there is excess reserve capacity).
- Set the MRCP to apply at a point below the RCR such that at 100% of the RCR the RCP equals the BRCP. This change is required by a logical consideration of what the RCP and BRCP are supposed to represent. The expected RCP cannot equal the BRCP if the RCP is only adjustable downward, below the BRCP due to excess reserve capacity. Allowing the RCP to potentially be higher than the BRCP is consistent with the concept of expected value and is logically consistent with the definition and application of the MRCP. Furthermore, this change assists the working of a reserve capacity auction, should it be required, by providing additional headroom.
- Steepen the "slope" term to -3.75, making the RCP formula more responsive to market supply and demand conditions.

# APPENDIX A: RCP PROJECTIONS AND TRANSITIONS

[see excel spread sheet as prepared by the IMO and circulated in December 2012]

INDEPENDENT MARKET OPERATOR

# Reserve Capacity Mechanism Working Group

# Minutes

| | |
|---|---|
| **Meeting No.** | 10 |
| **Location:** | IMO Boardroom<br>Level 17, 197 St Georges Terrace, Perth |
| **Date:** | Thursday 28 February 2013 |
| **Time:** | Commencing at 2.05pm – 3.50pm |

| Attendees | Class | Comment |
|---|---|---|
| Allan Dawson | Chair | |
| Kate Ryan | IMO (replacing Suzanne Frame) | |
| Brad Huppatz | Market Generator (Verve Energy) | |
| Ben Tan | Market Generator | |
| Andrew Sutherland | Market Generator | |
| Shane Cremin | Market Generator | |
| Wendy Ng | Market Customer | |
| Steve Gould | Market Customer | |
| Stephen MacLean | Market Customer (Synergy) | |
| Andrew Stevens | Market Customer/Generator | |
| Geoff Gaston | Market Customer | Proxy |
| Jeff Renaud | Demand Side Management | |
| Geoff Down | Contestable Customer | |
| Brendan Clarke | System Management | |
| Wana Yang | Observer (Economic Regulation Authority) | |
| Paul Hynch | Observer (Public Utilities Office) | |
| **Apologies** | **Class** | **Comment** |
| Justin Payne | Contestable Customer | |
| **Also in attendance** | **From** | **Comment** |
| Fiona Edmonds | Observer (Alinta) | |
| Mike Thomas | Presenter (The Lantau Group) | |
| Aditi Varma | Minutes | |
| Greg Ruthven | Observer (IMO) | |
| Natasha Cunningham | Observer (IMO) | |
| Johan van Niekerk | Observer (IMO) | |
| Neetika Kapani | Observer (IMO) | |
| Oscar Cleaver-Wilkinson | Observer (IMO) | |

| Item | Subject | Action |
|---|---|---|
| 1. | **WELCOME AND APOLOGIES / ATTENDANCE**<br><br>The Chair opened the tenth and final meeting of the Reserve Capacity Mechanism (RCM) Working Group (RCMWG) at 2.05pm.<br><br>The Chair welcomed the members in attendance and noted an apology from Mr Justin Payne. The Chair introduced the newly appointed Group Manager of Development and Capacity, Ms Kate Ryan to the meeting and acknowledged observers present from the IMO's System Capacity team and Alinta. | |
| 2. | **MINUTES ARISING FROM MEETING 9**<br><br>The minutes were accepted as a true record of the meeting.<br><br>Mr Brad Huppatz observed it was difficult to remember the discussions at the meeting as the minutes were circulated three months after the previous meeting. The Chair apologised on behalf of the IMO and responded that the organisational restructure at the IMO in December 2012 had an impact on some work processes. He further noted that the minutes from this meeting would be circulated much sooner.<br><br>*Action Point: The IMO to publish minutes of RCMWG meeting no.9 on the Market Web Site.* | **IMO** |
| 3. | **ACTIONS AND DECISION REGISTER**<br><br>Ms Wendy Ng noted that Alinta had requested for an extension on the timeframe for members to respond to the email circulated by the IMO on 7 December 2012. Ms Ng noted that while she had received a response from the IMO she understood from the response that Alinta were not to be provided with an extension. Ms Ng would like her name to be removed from the summary of responses on page 16 and added to the list of non-responders on page 17. The Chair responded that this meeting was a result of requests received from Alinta and other members. The Chair added that the IMO Board was notified in December 2012 on progress made, however, it was highlighted that a further RCMWG meeting had been scheduled to resolve the outstanding issues. This meeting had been organised in response to requests to deal with outstanding issues<br><br>The Chair noted that the IMO would progress key proposals to the Rule Change process. He added that objections raised by members had been minuted; however, there would be further opportunities to raise issues during consultation periods in the Rule Change Process. | |
| 4. | **AGENDA ITEM 5 : Reserve Capacity Price and Dynamic Refund Mechanism**<br><br>The Chair invited Mr Mike Thomas to introduce his memorandum, which had been distributed with the meeting papers. The following discussion points were noted:<br><br>• Mr Andrew Sutherland queried why there were negative percentage values on the x axis of representing excess capacity when the IMO must procure capacity up to the Reserve Capacity Requirement under the Market Rules. Mr Greg Ruthven responded that the IMO would only run a Reserve Capacity Auction if capacity had been offered into the auction in the Bilateral Trade Declaration process. Mr Ruthven noted, however, | |

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| | that the Reserve Capacity Price would be 85% of the Maximum Reserve Capacity Price (MRCP) under the current mechanism if there was a shortfall of capacity and no auction was held. In response, Mr Sutherland noted that it seemed unlikely that anyone would offer capacity into the auction. It was further discussed that the Supplementary Reserve Capacity process would be held to procure enough capacity to meet the Reserve Capacity Requirement.<br><br>• Mr Sutherland also queried if the uplift for the proposed Reserve Capacity Price (RCP) regime of 110% would be a strong enough incentive for encouraging bilateral contracts in the market. Mr Geoff Gaston noted that the curve did not provide an adequate incentive for bilateral contracting from both a retailer's and a generator's perspective. Discussion ensued on the nature of bilateral contracting that could be expected in excess and shortfall capacity situations and whether the curve should start at a higher point than 110%. Mr Thomas noted that the issue seemed to be centralised on the premise that by not contracting, there would be less investment and thus there would be a reduction in the reserve margin. Mr Gaston responded that the graph did not appear to be solving the excess capacity issue. He did not believe that a reduction in the price would simultaneously reduce excess capacity. He further added that the MRCP had reduced over the past couple of years and this model added to that volatility in the market. The Chair noted that the MRCP reduction was due to the erroneously calculated transmission cost component that had caused temporary inflations in the price. He further noted that the MRCP calculation methodology was not reviewed to manage excess capacity.<br><br>• Mr Ben Tan echoed Mr Sutherland's point and added that he did not believe that the axis was robust enough on the upside to encourage retailers to contract bilaterally. Mr Shane Cremin noted that the increase from an 85% adjustment factor to a 110% adjustment factor was a substantive change in the right direction. But he also agreed with Mr Sutherland on the point that the incentive to contract bilaterally might be too weak thereby increasing merchant risk and no new generating plants being built. Mr Stephen MacLean considered that the discussion point was moot because what generators should aim for is a firm capacity price over a long period. Mr Andrew Stevens noted that there would never be a time when there would be equal incentive for a retailer and a generator to contract bilaterally.<br><br>• Mr Gaston and Mr Tan registered their concern regarding increasing merchant risk. Mr Cremin noted that the increase in risk would then lead to shortage in capacity which would then encourage the retailer to start contracting because the retailer would tend to avoid a Supplementary Reserve Capacity auction scenario. He added that government policy decisions also play a role in the market. Mr Tan and Mr MacLean agreed with Mr Cremin's point. Ms Wendy Ng observed that many customers are opting for a direct pass-through of capacity charges, which also influences the retailer's willingness to contract bilaterally.<br><br>• Mr Sutherland noted that the proposal was better than the current regime; however the electricity industry required long term financing arrangement and thus required bilateral contracts to ensure certainty for revenue.<br><br>• On the dynamic refunds regime, Mr Stevens stated that he did not | |

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| | support the minimum refund factor of 1 but would support a value that could be affected by either an availability factor or capacity factor determined in relation to a recent time period, the intrinsic value of the assets and their availability or performance. A generating plant that was late to arrive into the market would have an availability or capacity factor of zero and would effectively get charged one times the multiple of its factor. Mr Sutherland added that a minimum refund factor of 1 would only be fair if the maximum was modified every year. Mr Brad Huppatz also did not agree with 1 being the minimum refund factor because any number above zero itself is an incentive to make generation available. Discussion ensued on the validity and application of the minimum refund factor value being 1. Mr Cremin observed that the philosophy behind The Lantau Group's proposal is based on the fact that different value needs to be assigned to different generating plants based on their reliability in providing capacity when needed.<br>• Mr Gaston agreed with the idea of dynamic refunds but questioned the recycling component of the model. He observed that there would be much greater risk of a plant tripping while running.<br>• Mr Thomas noted that reducing the minimum refund factor to zero will make the nature of forced outages even more random without giving an incentive to make plant available. Mr Huppatz and Mr Gaston noted that the overall magnitude of the refunds matter, not the scale. Mr Stevens agreed and noted that the minimum refund factor would only come into play when the reserve margin is so large that the economic value of the capacity is low. Mr Cremin noted that the level of capacity refunds is itself the incentive to correct a random event, not the randomness itself. Mr Sutherland argued that extending the logic of forced outages being random; the refund factor should just be 1 and not different at different times. He queried the logic behind keeping the maximum at 6, to which Mr Thomas responded that the maximum factor of 6 was already built in the rules. The Chair noted that members should keep in mind that the refund revenue was also getting recycled. The Chair offered that the IMO will revisit the proposed minimum refund factor prior to submitting any rule changes.<br>• Mr Gaston questioned how the recycling of refunds would tie in with the Shared Reserve Capacity Cost. Mr Thomas responded that the proposed package should improve the generation offer stack and improve efficiency. He further added that if the package works well, then retailers would benefit, however if the package does not work well then everybody would be worse off. Over time, if excess capacity was being supplied into the market, the Reserve Capacity Price would come down.<br>• The Chair asked members to put forward any further comments on the overall package. Mr Gaston noted his objection to harmonisation and sought clarification pertaining to the scenarios in which Demand Side Management (DSM) would be called on. The Chair responded that System Management would have discretion over which Facilities it would dispatch and what fuel sources it would preserve in a High Risk or Emergency Operating State.<br>• Mr Tan noted that he was happy with the proposed package, however was concerned with the uplift of 110% and believed that | |

| | | |
|---|---|---|
| | a higher number needed to be incorporated into the model. Ms Wendy Ng questioned if a floor was considered to be included in the model. The Chair responded that it had been discussed in previous meetings but the final proposal did not include a floor price.<br>• Dr Steve Gould sought clarification on what constituted as eligible available capacity. The Chair clarified that this was all capacity that was made available in the Balancing Merit Order, and would exclude DSM and Intermittent Generation (i.e., capacity that has a Reserve Capacity Obligation Quantity- RCOQ of zero).<br>• Members sought clarification on how the transitional arrangements would work. The Chair clarified that this proposal would appear to qualify for the transitional arrangement policy. He added that the dynamic refunds regime would commence but the recycling of refunds would be transitioned over a three year period.<br>• Mr Stevens questioned if there had been any confirmation on the conditions when DSM would be dispatched. He asked for more clarity on what would be the level of reserve margin in a Trading Interval for System Management to consider dispatching DSM. The Chair responded that the IMO would revert to the RCMWG with more detail during the Pre Rule Change Process.<br>• The Chair added that the next step forward would be to present the package to both the IMO Board and the Market Advisory Committee (MAC). He added that the next step will incorporate the development of Pre Rule Change Proposals to take forward to the formal submission process.<br>*Action points:*<br>• *The IMO to present the summary of recommendations to the IMO Board and the MAC.*<br>• *The IMO to revisit the proposed minimum refund factor prior to submitting any rule changes.*<br>• *The IMO to revert to the RCMWG with more detail during the Pre Rule Change Process.* | <br><br><br><br><br><br><br><br><br>**IMO**<br>**IMO**<br>**IMO** |
| | **CLOSED**<br>The Chair thanked the members and declared the meeting closed at 3.50 pm. | |

**Financial impact of excess capacity**

Formula for Reserve Capacity Price proposed under Rule Change Proposal RC_2013_20

## UPDATED TO ACCOUNT FOR KWINANA C EARLY RETIREMENT, UDPATED BILATERAL VOLUMES

| Capacity Year | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
|---|---|---|---|---|---|---|
| ***Common input parameters*** | | | | | | |
| Reserve Capacity Requirement (RCR) (MW) | 5146 | 5191 | 5501 | 5312 | 5308 | 5119 |
| Maximum Reserve Capacity Price (MRCP) ($/MW/yr) | $173,400 | $164,100 | $238,500 | $240,600 | $163,900 | $157,000 |
| Percentage of RCR that is bilaterally contracted | 57% | 65% | 68% | *76%* | *75%* | *74%* |
| ***'Actual excess' scenario*** | | | | | | |
| Total Capacity Credits (MW) | 5258.6 | 5493.5 | 5995.6 | 6086.8 | 5862.7 | 5683.3 |
| Excess capacity (MW) | 112.5 | 302.5 | 494.6 | 774.8 | 554.7 | 564.3 |
| Excess percentage | 2.2% | 5.8% | 9.0% | 14.6% | 10.4% | 11.0% |
| Reserve Capacity Price (RCP) ($/MW/yr) | 159,679.52 | 135,618.09 | 180,971.62 | 159,482.77 | 110,623.81 | 113,179.30 |
| Uncontracted Capacity Credits (MW) | 2316.0 | 2103.9 | 2258.4 | *2049.7* | *1893.7* | *1910.0* |
| Cost of uncontracted capacity | $369,823,833 | $285,323,674 | $408,704,553 | *$326,893,271* | *$209,485,097* | *$216,168,503* |
| ***'Zero excess' scenario*** | | | | | | |
| Total Capacity Credits (MW) | 5146 | 5191 | 5501 | 5312 | 5308 | 5119 |
| RCP ($/MW/yr) | 171,451.69 | 162,256.18 | 235,820.22 | 237,896.63 | 162,058.43 | 155,235.96 |
| Uncontracted Capacity Credits (MW) | 2203.5 | 1801.4 | 1763.8 | *1274.9* | *1339.0* | *1345.7* |
| Cost of uncontracted capacity | $377,791,717 | $292,286,700 | $415,934,367 | *$303,289,655* | *$216,997,854* | *$208,893,263* |
| **Cost of excess capacity** | **-$7,967,884** | **-$6,963,026** | **-$7,229,814** | ***$23,603,617*** | ***-$7,512,758*** | ***$7,275,240*** |