Independent Market Operator

Reserve Capacity Mechanism Working Group (RCMWG)

Agenda

Meeting No.	9
Location:	IMO Boardroom, Level 17, Governor Stirling Tower, 197 St. Georges Tce, Perth
Date:	Thursday 22 November 2012
Time:	12:00 pm to 5:00 pm

Item	Subject	Responsible	Time
1.	**WELCOME**	**Chair**	2 min
2.	**APOLOGIES / ATTENDANCE**	**IMO**	2 min
3.	**MINUTES FROM MEETING 8**	**IMO**	10 min
4.	**ACTIONS ARISING**	**IMO**	10 min
5.	**CONDITIONS FOR DSM DISPATCH** *Presentation by Dr Richard Tooth*	**Sapere Research Group**	60 min
6.	**DYNAMIC REFUND MECHANISM** *Presentation by Mr Mike Thomas*	**The Lantau Group**	60 min
7.	**RESERVE CAPACITY PRICE** *Presentation by Mr Mike Thomas*	**The Lantau Group**	60 min
8.	**GENERAL BUSINESS**	**Chair**	5 min

Reserve Capacity Mechanism Working Group

Minutes

Meeting No.	8
Location:	IMO Boardroom 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	

<table>
<tr><th>Item</th><th>Subject</th><th>Action</th></tr>
<tr><td>1.</td><td>WELCOME AND APOLOGIES / ATTENDANCE

The Chair opened the eighth meeting of the Reserve Capacity Mechanism (RCM) Working Group (RCMWG) at 2:10pm.

The Chair welcomed the members in attendance and noted apologies from Mr Patrick Peake, Mr Andrew Sutherland, Mr Shane Cremin and Mr Jeff Renaud.</td><td></td></tr>
<tr><td>2.</td><td>MINUTES ARISING FROM MEETING 5

The following amendments were noted:

• Mr Greg Ruthven to be included in the list of attendees.
• On page 8, Ms Wana Yang requested the following change:

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 <u>included in the review of</u> <s>penalised by</s> the refund mechanism.

Action Point: The IMO to publish amended minutes of RCMWG meeting no.7 on the Market Web Site.</td><td></td></tr>
<tr><td>3.</td><td>ACTIONS ARISING

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.

She added that Mr Greg Ruthven would present his analysis for Action Item 4 and Mr Mike Thomas for Action Item 5.</td><td></td></tr>
<tr><td>3a.</td><td>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

The Chair invited Mr Ruthven to make his presentation.

The following discussion points were noted:

• Members requested that the presentation be uploaded on the RCMWG webpage.
• 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.
• Mr Ben Tan also requested that the analysis be provided not just as a percentage of loads but also as a percentage</td><td></td></tr>
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	of total capacity so that members can assess the significance of the issue. *Action Points:* • *The IMO to upload presentation for Action Item 4 on the Market Web Site* • *The IMO to investigate practicalities of linking Relevant demand adjustments to IRCR calculation* • *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** The Chair invited Mr Mike Thomas to present on the dynamic refunds regime The following points of discussion were noted: • 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. • 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.

- 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.
- 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.
- 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.
- 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.
- 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: a) The need to renegotiate bilateral contracts b) The reallocation of money from Market Customers to Market Generators c) The continued application of costs of Supplementary Reserve Capacity to Market Customers • 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. *Action Point:* • *The Lantau Group to address the following specific concerns raised by members on the proposed refunds mechanism:* *a) The need to renegotiate bilateral contracts* *b) The reallocation of money from Market Customers to Market Generators* *c) The continued application of costs of Supplementary Reserve Capacity to Market Customers* • *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)** The Chair invited Mr Thomas to make his presentation. The following discussion points were noted: • 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. • 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. • 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. • 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). • At this point, the Chair invited Mr Ruthven to present the analysis on MRCP with the revised assumptions. • 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. The Chair also added that the next RCMWG meeting should focus on working out these issues and recommending a way forward. *Action Item:* • *The Lantau Group to examine the effects of the Reserve Capacity Price proposal with the help of some worked examples.*	
	CLOSED The Chair thanked the members and declared the meeting closed at 5.45 pm.	

Independent Market Operator

Reserve Capacity Mechanism Working Group (RCMWG)

Agenda item 4: RCMWG Action Points

Legend:

Shaded	Shaded action points are actions that have been completed since the last RCMWG meeting.
Unshaded	Unshaded action points are still being progressed.

#	Action	Responsibility	Meeting arising	Status/Progress
2	The IMO to include information on the cost effectiveness of proposed solutions or harmonisation	IMO	April	In progress
3	The IMO to upload presentation for Action Item 4 on the Market Web Site	IMO	October	Completed
4	The IMO to investigate practicalities of linking Relevant Demand adjustments to IRCR calculation	IMO	October	Completed
5	The IMO to include further analysis on RD and IRCR as a percentage of total capacity in addition to as a percentage of loads.	IMO	October	Completed
6	The Lantau Group to address the following specific concerns raised by members on the proposed refunds mechanism: • The need to renegotiate bilateral contracts • The reallocation of money from Market Customers to	The Lantau Group	October	Update to be presented at November meeting

#	Action	Responsibility	Meeting arising	Status/Progress
	Market Generators • The continued application of costs of Supplementary Reserve Capacity to Market Customers			
7	The Lantau Group to conduct further analysis on the impacts of the proposed refunds regime on individual Facilities.	The Lantau Group	October	Update to be presented at November meeting
8	The Lantau Group to examine the effects of the Reserve Capacity Price proposal with the help of some worked examples.	The Lantau Group	October	Update to be presented at November meeting

Comparison of RD and IRCR

September 2012 data

Numbers of loads and MW difference

IRCR and Relevant Demand – September 2012 statistics

- 426 Associated Loads
- 3 coincident Trading Intervals for IRCR and RD calculations
  - These occurred on 25th February, on which DSM was dispatched
- Loads with RD > unscaled IRCR
  - 172 loads (40%)
  - Total RD exceeds unscaled IRCR by 39.0 MW
- Loads with RD > scaled IRCR
  - 42 loads (10%)
  - Total RD exceeds scaled IRCR by 15.6 MW

IRCR and Relevant Demand – September 2012 statistics

- Requests for substitution (maintenance/dispatch)
  - 115 loads (27%) have substituted data
  - 69 loads (16%) have substituted data on 25th February
- Loads with RD substitution on 25th Feb and RD > unscaled IRCR
  - 48 loads (11%)
  - Total RD exceeds unscaled IRCR by 23.4 MW
- Loads with RD substitution on 25th Feb and RD > scaled IRCR
  - 23 loads (5%)
  - Total RD exceeds scaled IRCR by 8.5 MW

Practicalities of linking RD and IRCR

Practicalities of linking RD and IRCR

- IRCR:
  - Calculated within Settlements system
  - Computed monthly in advance, initial calculation in early Sept, then late in preceding month
  - Calculated from snapshot of metering database
  - Market Customer aggregate IRCR passed to WEMS
- RD:
  - Calculated in stand-alone system → soon to be integrated into WEMS
  - First calculated just prior to Capacity Year (but after initial IRCR), first applies 1 Oct
  - Data not passed to Settlements
  - Recalculated if meter data changes, new load association/dissociation, substitution request

Applying RD substitutions into IRCR

- Would need to pass RD data to Settlements
- May wish to perform initial RD calculation earlier, prior to initial IRCR calculation
- However, irreducible lag effect, with load association/ dissociation and substitution requests occurring at any time → feeding into next IRCR calculation
- If DSM provider is not the retailer, substitutions by one Market Participant could affect a different Market Customer's IRCR
- Would require method for new loads, currently:
  - defined method for IRCR, 3-month lag
  - IMO discretion for RD
- RD may still exceed IRCR (influenced by non-IRCR intervals)

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Preventing RD substitutions for IRCR intervals

- Can be implemented directly in WEMS
- No impact likely for new meters
- RD may still exceed IRCR (influenced by non-IRCR intervals)

Capping RD to IRCR

- Could upgrade data feed back to WEMS to be at NMI level, as well as aggregated Market Customer level
- Cap would then be implemented in WEMS
- Initial RD calculation would occur after initial IRCR calculation
- Monthly IRCR could be new trigger for RD recalculation
- Would require method for new loads, currently:
  - defined method for IRCR, 3-month lag
  - IMO discretion for RD

Report for the Independent Market Operator

Conditions for DSM Dispatch: November – RCMWG Meeting Draft

Dr Richard Tooth

November 2012

About the Author

Dr Richard Tooth is a Director with the Sydney office of Sapere Research Group. He works on public policy, competition and regulatory issues across a number of industries including water, energy, transport and financial services. Dr Tooth has a PhD in Economics, a Master in Business Administration and a Bachelor of Science.

About Sapere Research Group Limited

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Contents

Glossary

DSM	Demand Side Management
DSP	Demand Side Programme
MWh	Megawatt hour
NBDMO	Non-Balancing Dispatch Merit Order
RCM	Reserve Capacity Mechanism
RCMWG	Reserve Capacity Mechanism Working Group
SWIS	South West Interconnected System

Summary

Background

Proposals are in place to increase the required availability of Demand Side Management (DSM) including unlimited availability in terms of the total number of hours an individual Demand Side Programme (DSP) is dispatched in a Capacity Year. In moving to unlimited availability it is appropriate to review and clarify the conditions under which DSM as a class and individual DSPs are dispatched.

Conditions for dispatching DSM as a class

The current rules (recently modified for the introduction of the Balancing Market) specify that DSPs as non-Balancing Facilities are placed at the bottom of the dispatch order; that is after all available generation capacity has been dispatched. This generation capacity includes the maximum available capacity that other Facilities can provide, and may exceed the Capacity Credit level for many Facilities..

The current Market Rules allow System Management to change the order of dispatch on 'reasonable grounds' to avoid a High Risk (or Emergency) Operating State; or return the SWIS to a Normal Operating State. Identified situations that might constitute reasonable grounds are:

- DSPs are dispatched ahead of Facilities providing services required to maintain the Spinning Reserve Standard (and possibly the Ready Reserve Standard)
- When due to a fuel supply disruption, DSPs are dispatched ahead of Scheduled Generators to preserve fuel stocks in anticipation of a later period when all available resources are required
- In anticipation that they may be required, DSPs with longer notice periods are dispatched prior to Scheduled Generators with shorter lead times.

These situations are not associated with a significant change in dispatch order; that is they coincide with, or precede times, when all other resources may be exhausted.

Due to lead times required for dispatch, there may be some uncertainty as to whether DSM (and other resources before it) will be required. If DSM is dispatched and there is subsequently an oversupply, then (due to the nature of the resources) Scheduled Generators would be used to correct the balance. In such a way DSM can be dispatched when generation resources are idle. Currently there are no rules that limit or guide the choice around DSM dispatch for dealing with this short-term uncertainty.

While the risk of unreasonable dispatch of DSM appears very low, it would be appropriate to make some provision to ensure that the dispatch decisions are reasonable while meeting the needs of the Dispatch Criteria.

The order of individual DSP dispatch

The harmonisation proposals coupled with a reduction in surplus capacity will mean the order of individual DSP dispatch becomes increasingly important. Implementation of the proposals could increase the chance an individual DSP is dispatched more frequently than other DSP Facilities, by:

- removing the three day rule (currently on a third day of continuous dispatch a DSP need only provide best efforts)
- removing limits on total hours of dispatch
- through the proposed telemetry requirements and a reduction in the notice period, increasing System Management's ability to dispatch a limited amount of DSM rather than take an all-at-once approach.

The order of individual DSP dispatch is determined by the Non-Balancing Dispatch Merit Order (NBDMO). The NBDMO is based on the Consumption Decrease Price (nominated by the DSP) and then, in the event of a tie, the size of the registered load. There is no apparent justification for ordering on the base of load size. Such an ordering could result in larger DSPs being called more frequently and might encourage Market Participants to split DSPs to reduce the likelihood of dispatch.

A preferable approach is for the NBDMO to be based on (in the event of identical Consumption Decrease Price) the length of time since the last dispatch in the Capacity Year. This would ensure that in the event DSM is called on a number of occasions in a Capacity Year that some DSPs are not more frequently dispatched (unless they have signalled a desire to do so through a lower Consumption Decrease Price).

Implications of unlimited availability

As DSM is last in the dispatch order, a move to unlimited availability should not have any material change in the likelihood that DSPs would be required to maintain system security and reliability.

By design, it is unlikely that in any year all available capacity resources will be required. However, it is conceivable that a disaster scenario could cause a large amount of extended forced outage and a need to call DSM multiple times to protect system security.

If the availability of DSPs for dispatch was limited and in the unlikely event this prevented DSPs from being dispatched then security would be compromised and involuntary load shedding would be necessary.

In a disaster scenario where load curtailments are necessary, DSPs would be curtailed more frequently than non-DSM loads. However, DSPs would benefit from:

- having advance notification of dispatch, and
- being compensated for dispatch.

Summary of proposals

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.

Proposal 2

> The NBDMO ranking based-on-load size rule be replaced with by a rank based on the length of time since last dispatch (within the Capacity Year).

1. Introduction

The Harmonisation project examining the performance criteria for supply and demand side resources has led to proposals[1] that would increase the required availability of Demand Side Management (DSM) for dispatch. Notably these include unlimited availability in terms of the total number of hours of dispatch each participating Demand Side Programme (DSP) may be dispatched during a Capacity Year.

In moving to unlimited availability it is appropriate to review and clarify the conditions under which DSPs are dispatched. Uncertainty over when DSM is used and the order of DSP dispatch could lead to loads opting out in concern that they will be dispatched too frequently. Conversely if dispatch arrangements are orderly then the perceived probability of DSP dispatch should not be affected.

This document examines the conditions for dispatch for DSM and individual DSPs and implications of the change to unlimited availability. The rest of the document is structured as follows

- Section 2 examines the conditions for which DSM as a class is dispatched
- Section 3 examines the order of dispatch of individual DSPs
- Section 4 examines the implications of unlimited availability.

1 Tooth, R, 'Performance requirements for demand-side and supply-side capacity resources', presented at July 2012, RCMWG.

2. The dispatch of DSM as a class

2.1 The Order of dispatch

The order in which DSM as a class is dispatched relative to other Facilities is set out in section 7.6 of the Market Rules. These rules were significantly modified as a result of rule change RC_2011_10 relating to the Competitive Balancing and Load Following Market. The current dispatch arrangements are broadly as follows.

DSPs, along with Dispatchable Loads, are classed as Non-Balancing Facilities, which are placed at the bottom of the dispatch order (clause 7.6.1C). Prior to Non-Balancing Facilities being dispatched System Management is obliged to dispatch available capacity from Non-Scheduled and Scheduled Generators (Balancing Facilities).[2]

Outages aside, the available capacity from a Scheduled Generator will typically exceed the Reserve Capacity assigned to that generator. The rules require (clause 3.21.5)[3] that Facilities make available for dispatch the *maximum capacity* not subject to outages. Furthermore, Market Participants must (clause 7A.2.8)[4] include in their Balancing Submission their reasonable expectation of the capability of their Balancing Facilities.

Thus in effect in ordinary circumstances DSPs will not be dispatched until after all other available capacity, including the maximum available capacity of Scheduled Generators, is dispatched.

Reasonable grounds for changing the dispatch order

This order may be changed by System Management (clause 7.6.1D) if System Management considers, on 'reasonable grounds', that it needs to do so in order to avoid a High Risk Operating State or an Emergency Operating State; or return the SWIS to a Normal Operating State.

It appears that there is currently no limit as to 'reasonable grounds' however a Market Participant may (clause 2.18) dispute 'the application or interpretation' of the Market Rules. Thus should System Management seek to dispatch a DSP beyond what is 'reasonable', the DSP may dispute System Management's action. While such a dispute appears very unlikely, its possibility helps to ensure confidence in the application of what is reasonable.

Some situations have been identified that would provide System Management 'reasonable grounds' to alter the dispatch order.

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2 A Balancing Facility is, in effect for purposes of clause 7.6.1C, every Scheduled and non-Scheduled Generator held by a Market Generator. Note that clause 7.6.2 specifies that for the purposes of clauses 7.6.1 and 7.6.1C, the Verve Energy Balancing Portfolio is also treated as a Balancing Facility.

3 Clause 3.21.5 specifies that for [all Facilities] '[...] the maximum capacity minus the notified outage, must be available to System Management for dispatch.'

4 Clause 7A.2.8 states that a Balancing Submission must accurately reflect 'b) the Market Participant's reasonable expectation of the capability of its Balancing Facilities to be dispatched in the Balancing Market'

First, other Market Rules necessitate that System Management maintain reserves that may be dispatched at short notice.

In particular, (clause 3.10.2.) requires that Spinning Reserve Service (which may be Scheduled Generator, Dispatchable Load or Interruptible Load) is sufficient (in effect) to cover 70% of the total output of "generation unit synchronised to the SWIS with the highest total output".[5] If the Spinning Reserves drop below this standard then (under clause 3.4.1(a)) a High Risk Operating state is declared. Thus consistent with Clause 7.6.1D, System Management would dispatch DSM to prevent entering a High Risk Operating State.

In addition there is a Ready Reserve Standard (clause 3.18.11A.), which requires that the available generation and demand-side capacity at *any time* satisfies that the additional energy available [in effect]:

- within fifteen minutes must be sufficient to cover 30% of the total output, including Parasitic Load, of the generation unit synchronized to the SWIS with the highest total output at that time plus the Load Following Service; and
- within four hours must be sufficient to cover 70% of the total output, including Parasitic Load, of the generation unit synchronized to the SWIS with the second highest total output at that time less the Load Following Service.

Of note, despite 'additional energy' is referred to Clause 3.18.11A clearly refers to the Ready Reserve Standard, which I understand is in total around 340 MW, including demand side capacity. As the notice period for all DSPs is to be 'within four hours' it appears that only the 'within fifteen minutes' element of the Ready Reserve Standard will be relevant for DSM dispatch considerations. It appears likely that the Spinning Reserve Standard will be a more binding constraint and thus the Ready Reserve Standard will not be a constraint for DSM dispatch.

A second situation is when, as a result of a fuel disruption, reliability may be improved by dispatching DSPs ahead of Scheduled Generators so as to preserve fuel stocks for a later period when resources are likely to be further stretched.

Thus for example, System Management may expect that:

- due to a disruption in a supply chain a number of Scheduled Generators have temporarily restricted or diminished ability to replenish fuel stocks. For example, this might occur due to a disruption that would prevent liquid-only generators from receiving fuel deliveries, or from gas supply disruptions that reduce gas pipeline pressure.
- there is a significant risk that all available generation resources and DSPs will be required in an upcoming period.
- by dispatching DSPs ahead of some Scheduled Generators, the fuel stocks of the Scheduled Generators may be preserved for a later period.

[5] The standard for the Spinning Reserve Service must satisfy a set of principle outlined in Clause 3.10.2. I understand that in effect these will necessitate maintaining around 240 MW ≈ 70% x 340MW to meet the condition of Clause 3.10.2 (a) i.. This 240 MW will include reserves for Load Following and other spinning reserves.

Such a situation occurred during the mini-Varanus island incident that occurred in February 2011.[6] I understand that at this time, preservation of fuel stocks was a concern that justified System Management dispatching DSM prior to some available Scheduled Generation capacity.

A third situation, relates to the lead times in dispatching resources. System Management may need to call a DSP for dispatch prior to a particular Scheduled Generator simply because the notice period for dispatch of the DSP is longer than that of the lead time to dispatch a Scheduled Generator. If the Scheduled Generator is subsequently not required then it will appear as if the dispatch order has been changed.[7] For example, a DSP with a required notice period of 2 hours will be dispatched before a Scheduled Generator with a lead time of 15 minutes if it is expected that in 2 hours time there is risk that both resources will be required. This situation can apply to all resources of differing lead times, however due to the nature of the resources it is more likely that a Scheduled Generator's supply will be reduced to correct the balance if there is an oversupply.

The likelihood of this situation occurring depends on the lead times for dispatch. Under recent agreed proposals the maximum notice period for DSP dispatch will reduce from 4 hours to 2 hours (with a requirement for System Management to provide advance notification of likely use). DSPs also may nominate a shorter notice period.All of the situations identified above as being 'reasonable grounds' for System Management changing the dispatch order do not represent a significant change in order as they coincide with, or precede a situation, when it is likely that all other available resources may be required.

2.2 Managing short-term forecast uncertainty

Due to notice periods, at the time DSM is called for dispatch there can be some uncertainty as to how much, if any DSM will be required. As DSM is the last available resource to be dispatched (with the exception of Spinning Reserve and other Ready Reserve resources), to maintain system security, System Management may need to dispatch DSM to meet a potentially high forecast and subsequently discover that much less, or no DSM, is required. In such situations the additional DSM that is dispatched would be offset by a reduction in supply from another resource that can respond quickly to a request to reduce supply.[8]

System Management needs to be able to dispatch DSM to manage security if there is a reasonable risk that that DSM will be required. However currently (it appears) there is no limitation or guidance provided in the rules as to how much uncertainty is appropriate before DSM is dispatched.

While, there is no reason to suggest that System Management would dispatch DSM unnecessarily, there is a benefit in providing some guidance or limitation, in particular to allay

6 Not that, this was before the implementation of the rule 7.6.1C and 7.6.1D that specify the dispatch order and the 'reasonable grounds' requirement.

7 I understand that this also may have contributed to DSPs being dispatched ahead of Scheduled Generator capacity during the mini-Varanus island incident.

8 This assumes that the DSM that has been dispatched with 2 hours notice cannot quickly reverse the dispatch request should the DSM be no longer required.

any concerns that increased, or unlimited availability would, in itself, result in an increase in the use of DSM.[9]

Potentially a limitation to the amount of DSM dispatched could be based on the high short-term forecast at the time notification of dispatch. For example, this might be similar to the approach used in outage planning whereby a criterion, (under clause 3.18.11.(a)) is 'the capacity of the total generation and Demand Side Management Facilities remaining in service must be greater than the second deviation load forecast'. However there are dangers of being too specific and restricting the use of DSM when it is required as the consequence of not dispatching DSM when it is necessary will be involuntary load shedding.

A possible alternative[10] is to simply require that the DSM quantity dispatched is not more than can be reasonably justified to meet the Dispatch Criteria.[11] This would still allow, for example, System Management to dispatch DSM to meet a high forecast in 2 hours time, but would prevent System Management dispatching a quantity of DSM when the possibility of needing the quantity is remote.

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.

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9 It may be argued that current limitations on availability provide some control over the use of DSM. Of note the current rules (Clause 7.7.4A.) permits System Management to not curtail a DSP when, due to limitations on its availability, such curtailment would prevent that DSP from being available to System Management at a later time when it would have greater benefit with respect to maintaining Power System Security and Power System Reliability.

10 Yet another alternative is to add an additional (i.e. last in terms of priority) criterion to the Dispatch Criteria relating to the efficient dispatch of resources.

11 The Dispatch Criteria are described in Clause 7.6.1.

3. The order of individual DSP dispatch

The harmonisation proposals coupled with a reduction in surplus capacity will mean the order of individual DSP dispatch becomes increasingly important. The proposals if implemented could increase the chance an individual DSP is dispatched more frequently than other DSP facilities, by:

- removing the three day rule (currently on a third day of continuous dispatch a DSP need only provide best efforts)
- removing limits on total hours of dispatch, and
- through the proposed telemetry requirements and a reduction in the notification period, increasing System Management's ability to dispatch a limited amount of DSM rather than take an all-at-once approach.

Given these changes it is appropriate to consider the dispatch order for individual DSP Facilities.

The order of dispatch for Non-Balancing Facilities is determined (clause 6.12.1) by the Non-Balancing Dispatch Merit Order (NBDMO), which is specified by the IMO. The rules require that order is based on the Consumption Decrease Price — a price nominated by DSPs. In the event this price is equal then: (clause 6.12.1(f))

- the IMO must rank a Registered Facility with a greater load registered in Standing Data higher.
- In the event of a tie, the IMO will randomly assign priority to break the tie.

A further condition is that when selecting Non-Balancing Facilities from the NBMDO, System Management must (clause 7.7.4A.) select them in accordance with the Power System Operation Procedure (PSOP). The selection process specified in the PSOP must:

> *(a) only discriminate between Non-Balancing Facilities based on size of the capacity, response time and availability; and*
>
> *(b) permit System Management to not curtail a DSP when, due to limitations on the availability of the DSP, such curtailment would prevent that DSP from being available to System Management at a later time when it would have greater benefit with respect to maintaining Power System Security and Power System Reliability.*

The current PSOP does not explicitly refer to the DSP dispatch.

The second of these requirements will become less important under unlimited availability as unlimited availability means that System Management will not need to consider the likelihood of dispatch later in the year. However, it may be still relevant in organising DSM dispatch over the course of a day.

Issues

The requirement to rank Facilities in the NBDMO on registered load size appears problematic as it could lead to larger DSPs being dispatched more frequently than DSPs with smaller loads. Thus a DSP could nominate a small load or split DSPs so as to reduce the likelihood of dispatch.

There appears no reasonable justification for ranking based on size. A possible original rationale for dispatching larger loads first, may have been that it was simpler and easier to monitor when the demand-side Facility was the Curtailable Load and there were many small loads. This is less important since rule change RC_2010_29 that made the DSP the Facility. Furthermore the proposed telemetry requirements should make dispatching of different sized loads more practical.

It is preferable — in particular given the proposed harmonisation changes — that the rank-based-on-load size requirement is removed from the formation of the NBMDO (clause 6.12.1).[12] A possible replacement is the length of time in the Capacity Year[13] since the DSP was last dispatched. This will reduce the risk that individual DSPs are dispatched too frequently. If a DSP wishes to advance up the order then it can easily do so by nominating a lower Consumption Decrease Price.

Proposal 2

The rank-based-on-load size rule (in clause 6.12.1) in the Non-Balancing Dispatch Merit Order be removed and replaced with a ranking based on time since last dispatch (within the capacity year).

12 If Clause 6.12.1A is modified as suggested an additional modification to Clause 7.7.4A (a) would also be required.

13 It would be preferable to contain the requirement to being within the Capacity Year so as to remove any complications related to DSPs starting in different Capacity Years.

4. Implications of moving to unlimited availability

This section considers the implications for DSP providers of a shift to an unlimited availability (in terms of hours) policy.

As DSPs are last in the dispatch order, a move to unlimited availability should not have any material change in the likelihood that DSPs would be required to maintain security and reliability. Rather if availability was limited and in the unlikely event this prevented DSPs from being dispatched then security would be compromised and involuntary load-shedding would occur. [14]

As noted earlier an increase in the availability could conceivably increase the likelihood of System Management dispatching DSM to manage short-term uncertainty in requirements. However, any perceived risk of inappropriate dispatch of DSM may be addressed with a guiding rule as is proposed in Section 2. Regardless, the concerns are similar whether availability is increased to unlimited hours or another cap (the alternative of a minimum of 100 hours availability was considered).

With this later concern addressed, the implication for DSPs of a shift to unlimited availability primarily rests on the likelihood of DSPs being required for dispatch.An extended outage scenario

By design, the Reserve Capacity Target is such that it is unlikely that in any single year all available capacity resources will be required to meet security. Given that DSPs appear last in dispatch order, the likelihood of a DSP being required for a large number of hours will depend on coincident forced outages.

In February 2011, DSM was dispatched during a time of coincident forced outage as a result of a fuel disruption. However, the fuel disruption was sufficiently short so as to not cause a problem with the availability requirements.

Although extremely unlikely it is conceivable that a disaster scenario could result in a large amount of scheduled generation capacity being unavailable for an extended period of time. If the outage was significant enough it could result in repeated calls of DSPs to maintain system security.

For DSPs to be called a large number of times (e.g. >100 hours) the disaster scenario would most likely be as large as to result in forced curtailments of load during peak times. This is because if DSPs are required on a large number of days, due to the nature of peak demand, the peak would need to be so large as to exceed all available resources.

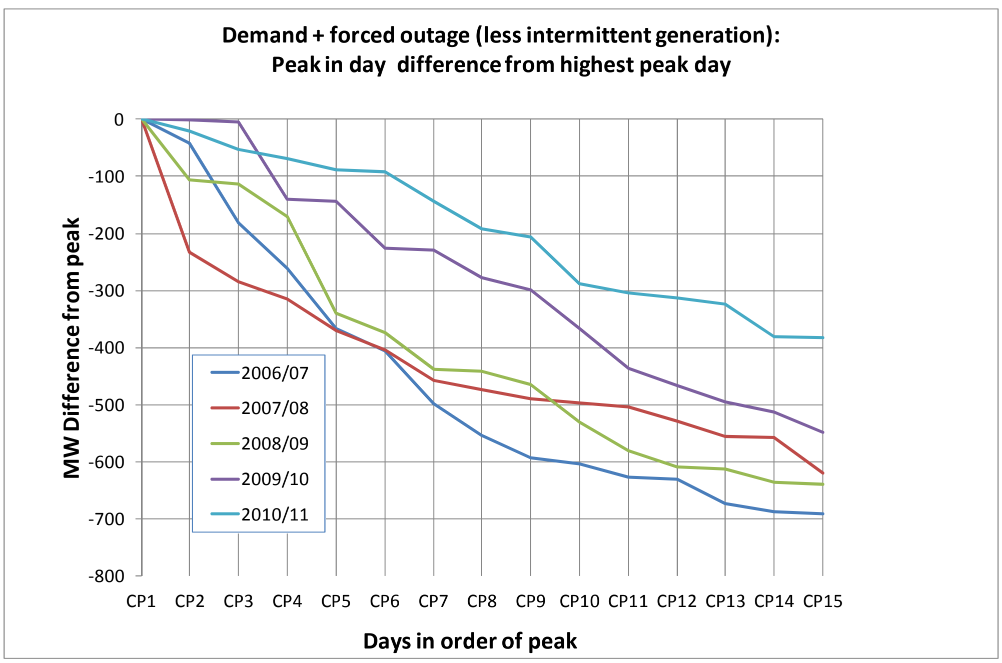
14 There is a very minor qualification. A shift to unlimited availability of DSPs could conceivably be an influence in the level of reserve capacity acquired; that is due to unlimited availability less capacity is acquired. However this is appears extremely unlikely particularly given the Reserve Capacity Target is currently determined by a peak demand scenario.

The figure below shows how the peak load to be met by available Dispatchable resources changes by day for the years 2006/2007 through to 2010/11. For example, it shows that in the year 2008/09 around 525 MW less Dispatchable resource was required on the tenth highest peak (labelled CP10) day than on the peak day (labelled CP1). Thus in this year if 525 MW of DSM was required on the peak day then some DSM would have been required on at most 10 occasions. Using these load curves as a guide, if DSM was to be required more frequently, the peak would need to have been higher and forced curtailments would needed to have occurred.

Furthermore, generally not all DSM is required and so individual DSPs will be dispatched on fewer occasions than DSM as whole. If DSM can be dispatched efficiently in such fashion then using the load profiles below, if all 525 MW of DSM was required on the peak day then across the load profile years an individual DSP would be dispatched on around 6 occasions; which assuming a 6 hour dispatch amounts to less than 40 hours of dispatch.

Using these load profiles as a guide, for DSM to be dispatched in order of 100 hours, the outages would have had to cause the available capacity to be substantially less (around 250 MW less) than required at the peak. In such case there would also need to be substantial involuntary load shedding.

Figure 1 : Peak capacity requirements by day relative to the peak day



Source: Outages and market data.

The above analysis suggests that in a scenario that involves DSPs being dispatched on a large number of occasions there would also likely be a need for involuntary load shedding of non-DSM loads.

In such a scenario there are advantages and disadvantages to being an Associated Load of a DSP. Associated Loads would be curtailed more frequently than non-DSM loads. However Associated Loads of DSPs would benefit from:

- having advance notification of being curtailed
- being compensated on dispatch by the nominated Consumption Decrease Price.[15]

Given these advantages and the low likelihood of a disaster scenario, the impact of unlimited availability should be a negligible consideration for a load considering participation in a DSP programme.

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15 Furthermore, depending on whether, and how, the capacity refund recycling proposal goes ahead, DSPs that are dispatched while other resources are on forced outage may benefit from receiving the refunds paid by non-performing Facilities.

Recommendation: Dynamic Capacity Refund Regime

22 November 2012

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

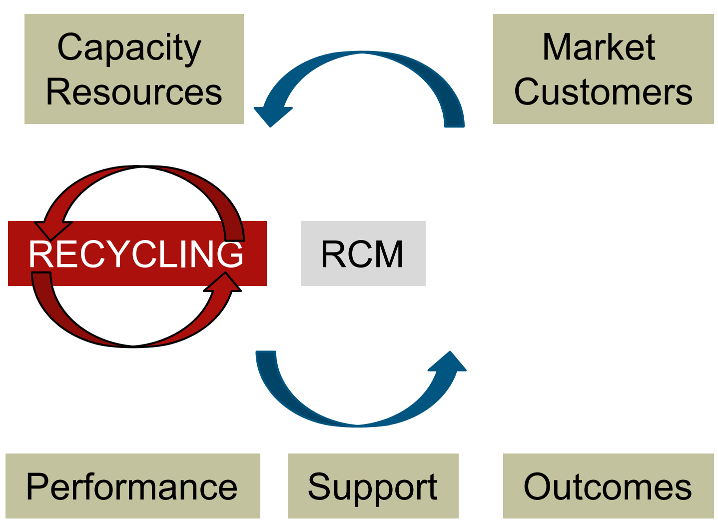
- Summary of recommendation
  - Recycling to improve efficiency and mitigate risk of unintended consequences / distortions
  - Rebates of refund revenue based on availability (to be explained)
  - Dynamic refund factors reflective of system conditions
  - Minimum refund factor to tie refund exposure 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

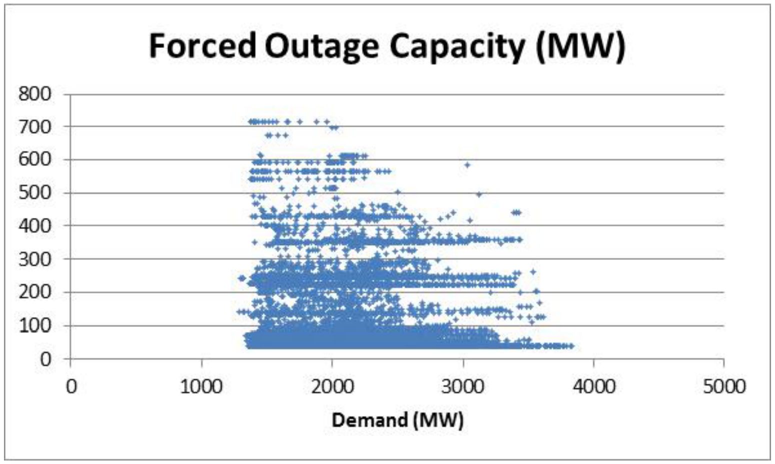
Key decisions

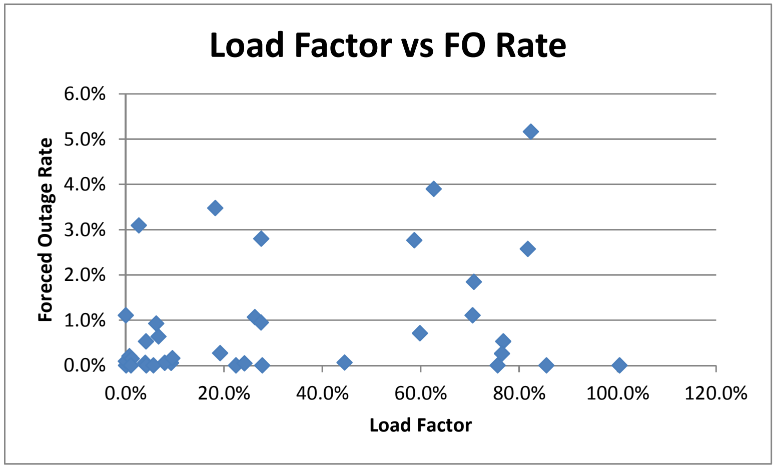
1. Availability based rebates – to align refund regime and RCM

2. Dynamic refund factors – to reflect system conditions and sharpen incentives

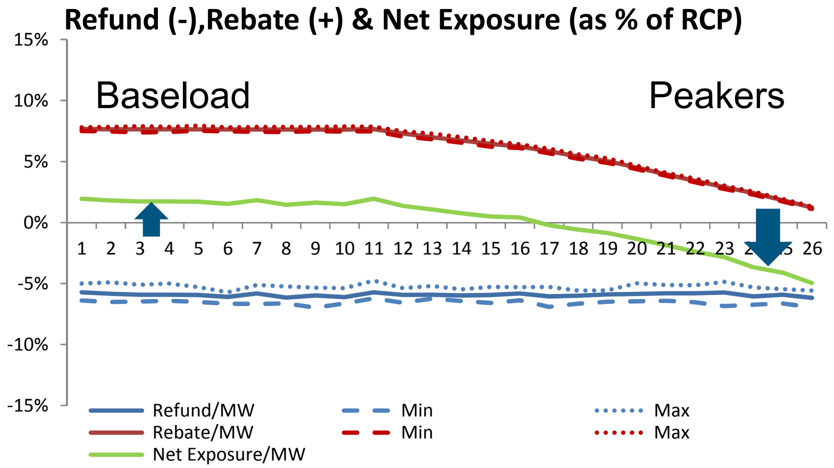
1) Setting the basis for rebates: availability vs dispatch?

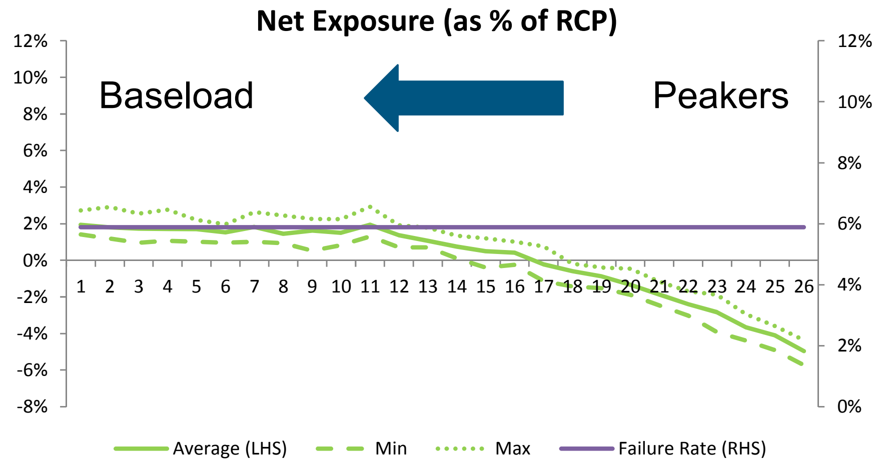
- Rebates can be
  - paid to units dispatched in times refunds are incurred, or
  - paid to units that are available
- The RCM is about incentivising availability.
  - Actual dispatch is the acid test of availability.
  - But availability still has value, even when not dispatched
- Forced outages are 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



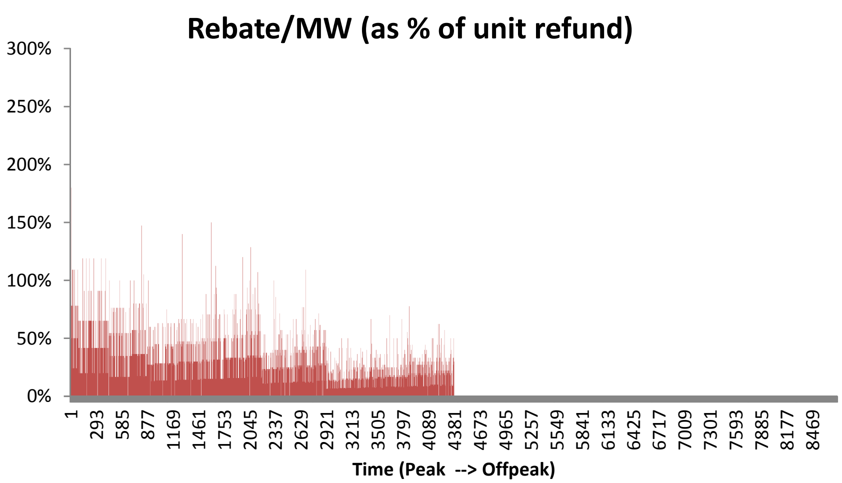


Dispatch-based rebates transfer value based on utilisation (when FO events are independent)





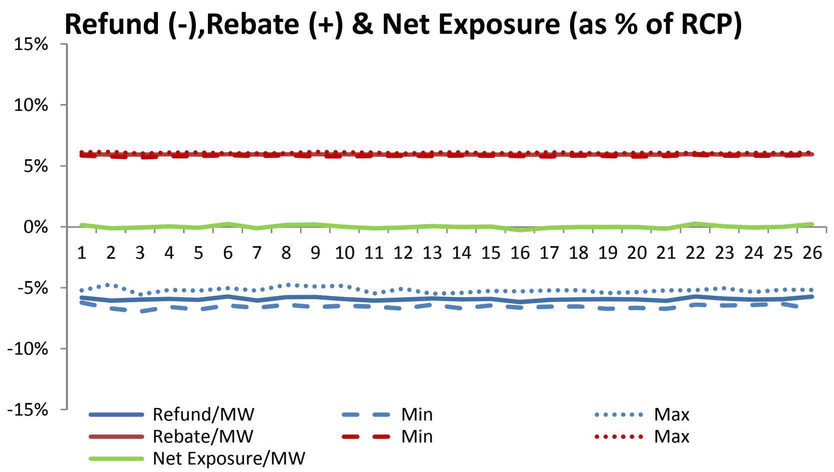
% of hours	Refund Factor
100%	0
75%	0
67%	0
50%	1
33%	2
25%	3
10%	4
5%	5
1%	6

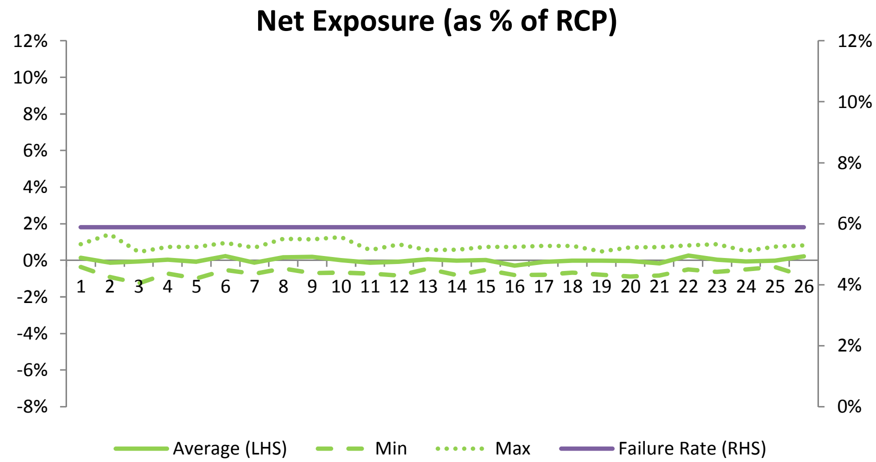


Hypothetical system of identical units with same FO and availability but different load factors

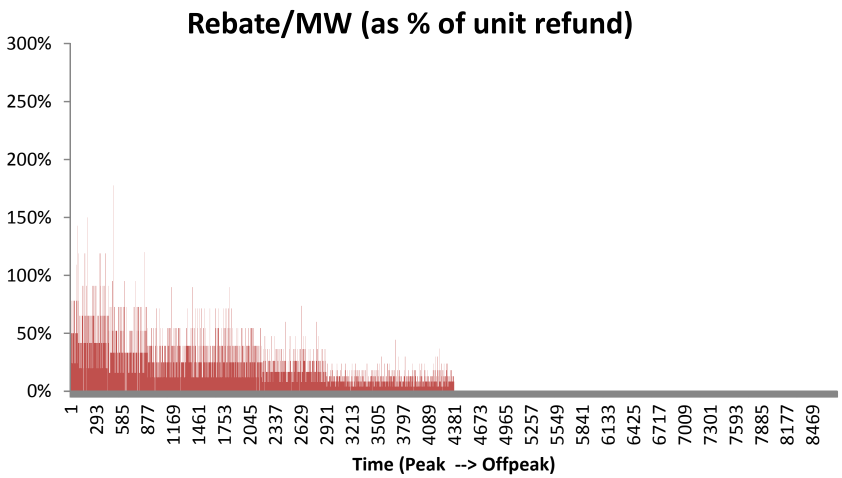
Plant No.	Net Capacity (MW)	FOR (%)	Load Factor (%)	Availability (%)	Plant No.	Net Capacity (MW)	FOR (%)	Load Factor (%)	Availability (%)
1	200	5.0%	80.0%	85.0%	14	200	5.0%	41.0%	85.0%
2	200	5.0%	77.0%	85.0%	15	200	5.0%	38.0%	85.0%
3	200	5.0%	74.0%	85.0%	16	200	5.0%	35.0%	85.0%
4	200	5.0%	71.0%	85.0%	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

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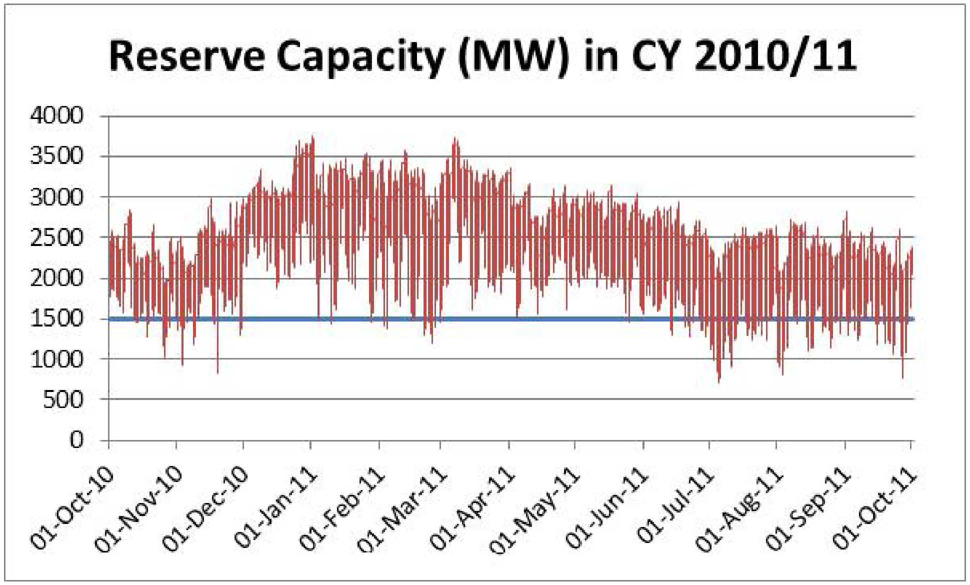
3	200	5.0%	74.0%	85.0%	16	200	5.0%	35.0%	85.0%
4	200	5.0%	71.0%	85.0%	17	200	5.0%	32.0%	85.0%
5	200	5.0%	68.0%	85.0%	18	200	5.0%	29.0%	85.0%
6	200	5.0%	65.0%	85.0%	19	200	5.0%	26.0%	85.0%
7	200	5.0%	62.0%	85.0%	20	200	5.0%	23.0%	85.0%
8	200	5.0%	59.0%	85.0%	21	200	5.0%	20.0%	85.0%
9	200	5.0%	56.0%	85.0%	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

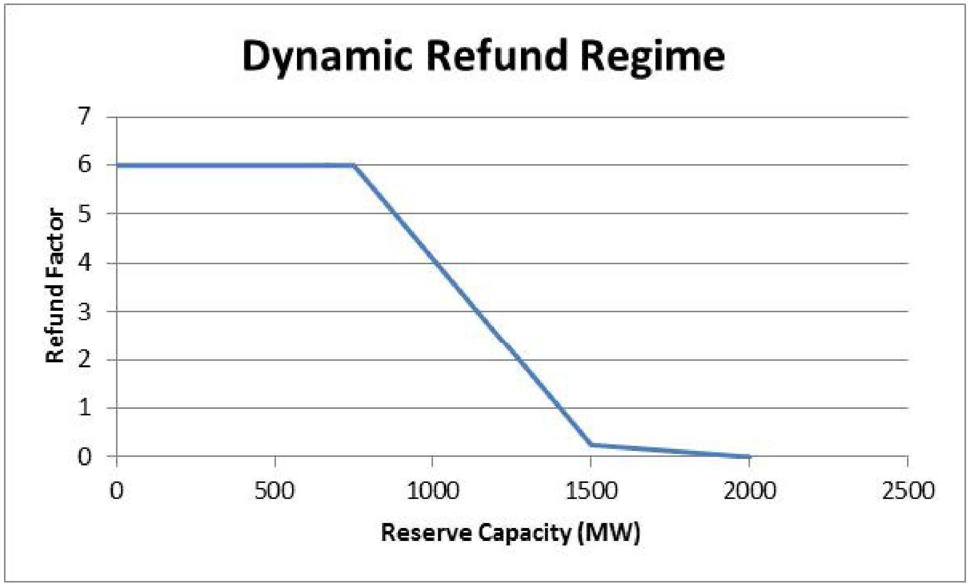
In capacity year 2010/11, reserve capacity exceeded 1500 MW 93.4% of time



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)

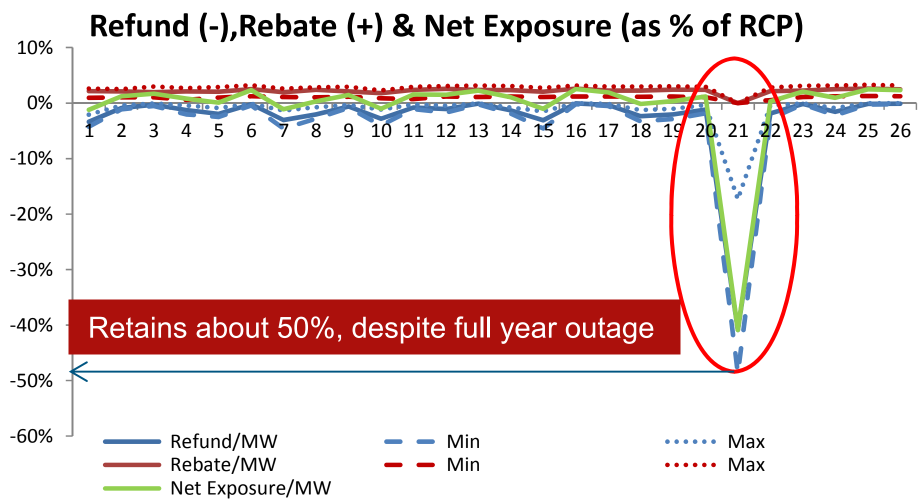
- Cons
  - The spread of refund factors could be increased to better reflect the spread of economic value implications of differing reserve capacity levels in real time
  - Possible under extreme conditions of excess reserve capacity for a unit on prolonged FO to retain some of its capacity payment revenue
  - 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

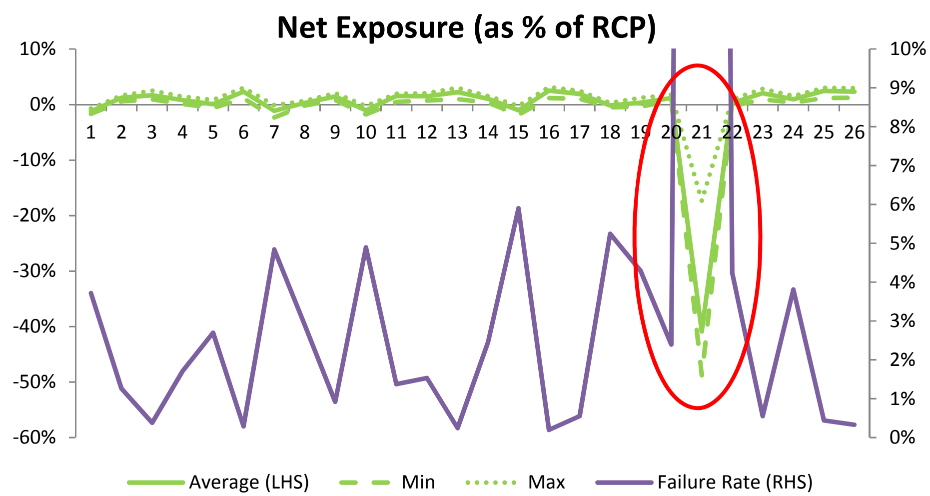
Pros outweigh the cons, but material improvement is also possible

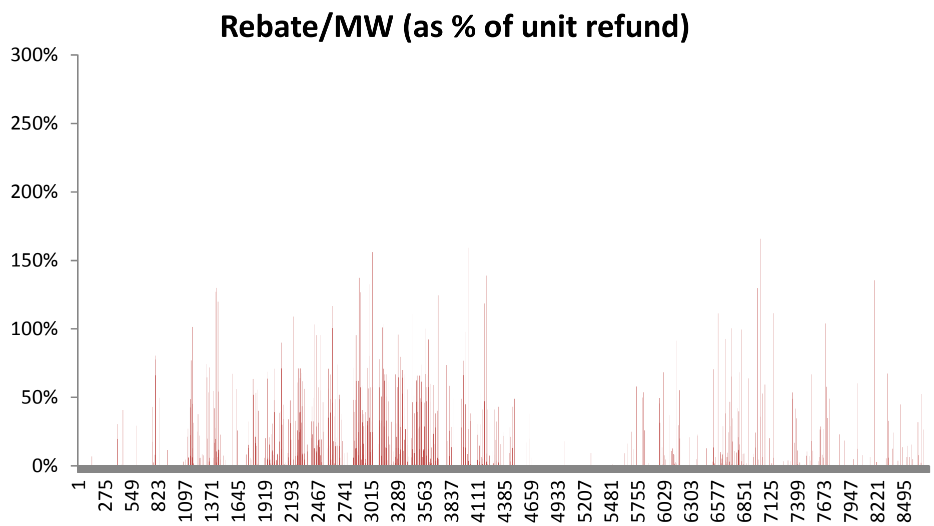
Improving Option (1) : Addressing the risk of unmerited CP value capture

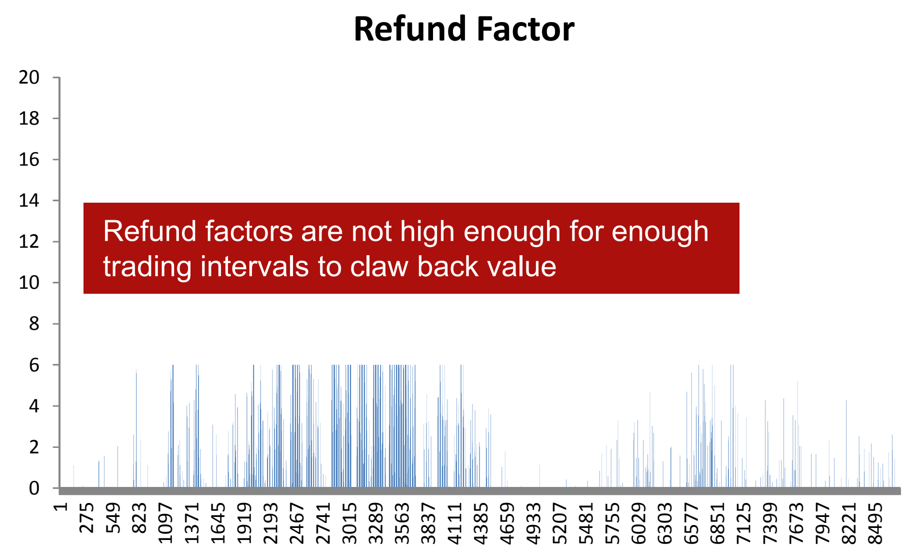
- Small possibility of retaining some capacity credit value even if year-long FO
  - Refund factors can be zero or less than 1 for substantial portions of the year
  - Higher factors may not occur enough to cause sum-of-factors to claw back full CP value
- Only happens if
  - Sufficient excess reserve 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

A facility on FO for a year year could (theoretically) retain some capacity credit value – at least in this hypothetical simulation

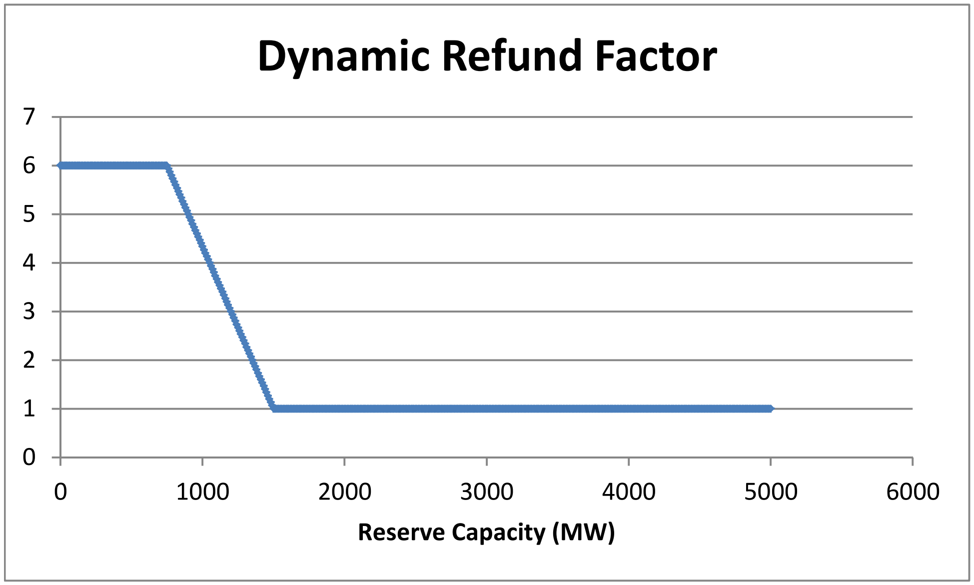








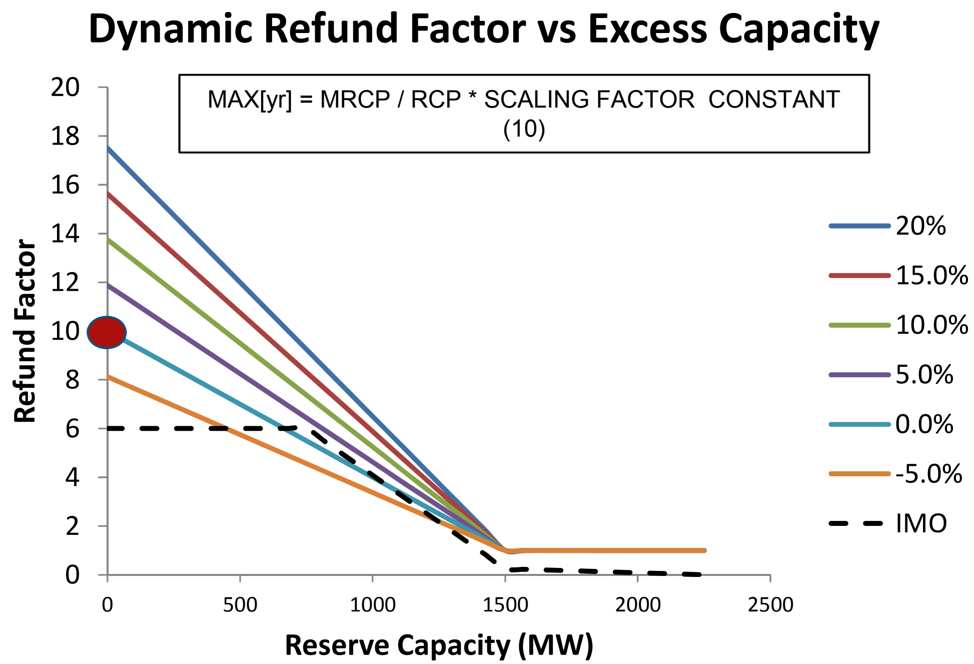
Option (2) : IMO's proposal with **minimum refund factor level**



- 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)

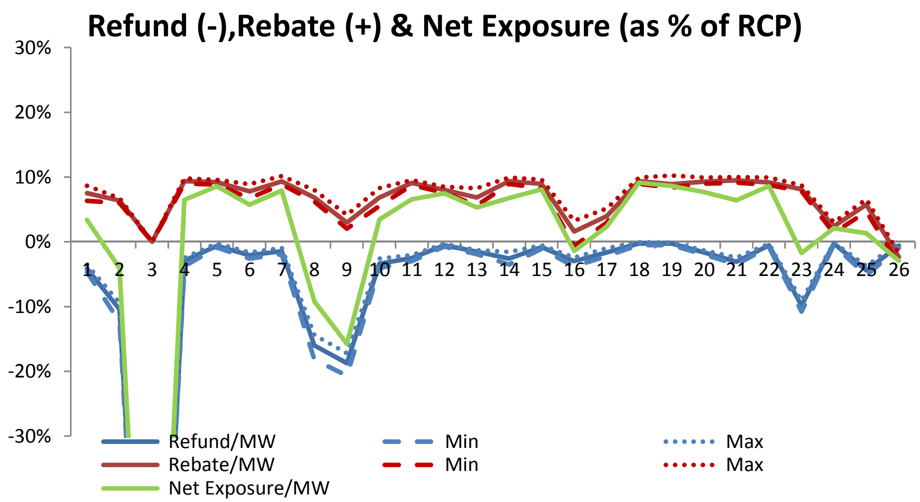
Refund Regime	IMO
Availiability or Dispatched Based Rebate	Availability
Excess Capacity	5%
Maximum Reserve Capacity Price ($/MW)	163900
Reserve Capacity Price ($/MW)	138685
Unit Refund ($/MWh)	15.76

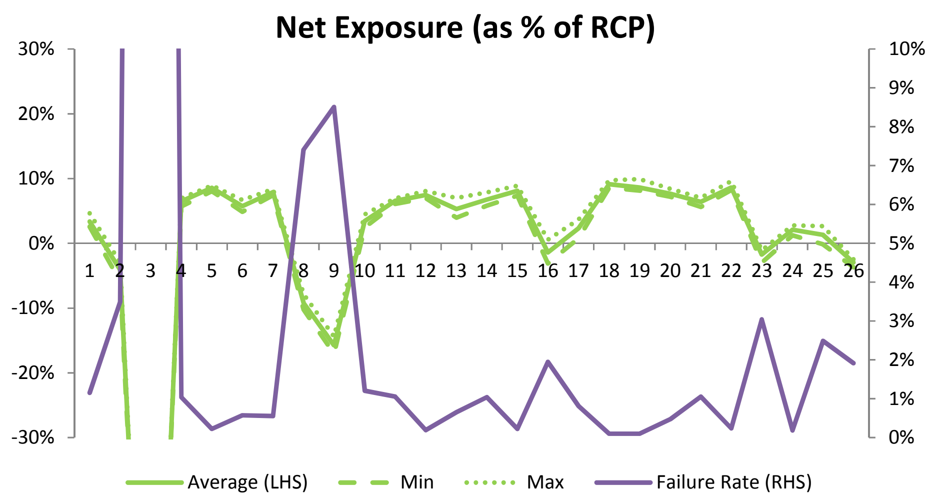
Refund Regime	IMO
Availiability or Dispatched Based Rebate	Availability
Excess Capacity	15%
Maximum Reserve Capacity Price ($/MW)	163900
Reserve Capacity Price ($/MW)	107636
Unit Refund ($/MWh)	11.97

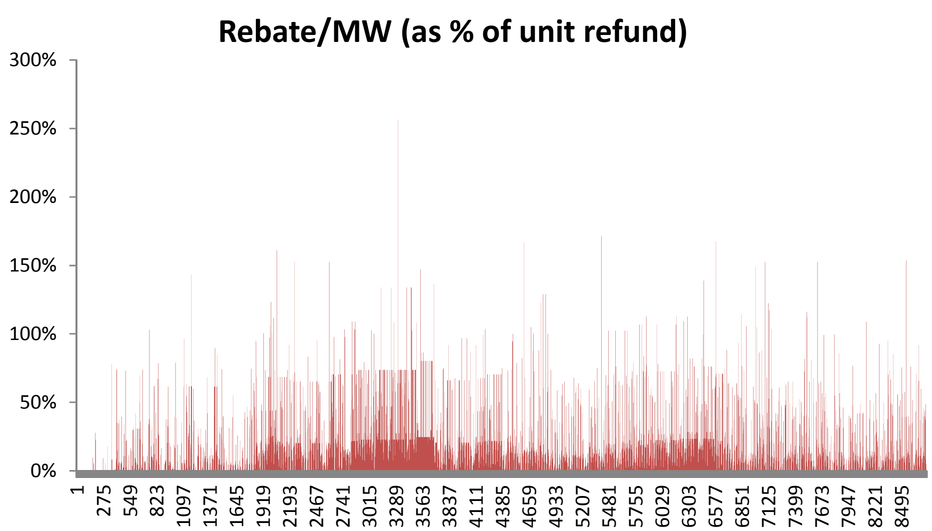
Plant No.	Net Capacity (MW)	FOR (%)	Load Factor (%)	Availability (%)	Plant No.	Net Capacity (MW)	FOR (%)	Load Factor (%)	Availability (%)
1	320	1.0%	91.1%	91.0%	14	40	1.0%	51.7%	96.0%
2	200	3.0%	84.9%	88.0%	15	320	0.2%	48.1%	95.0%
3	100	100.0%	0.0%	100.0%	16	200	1.0%	7.9%	50.0%
4	100	1.0%	97.0%	98.0%	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%

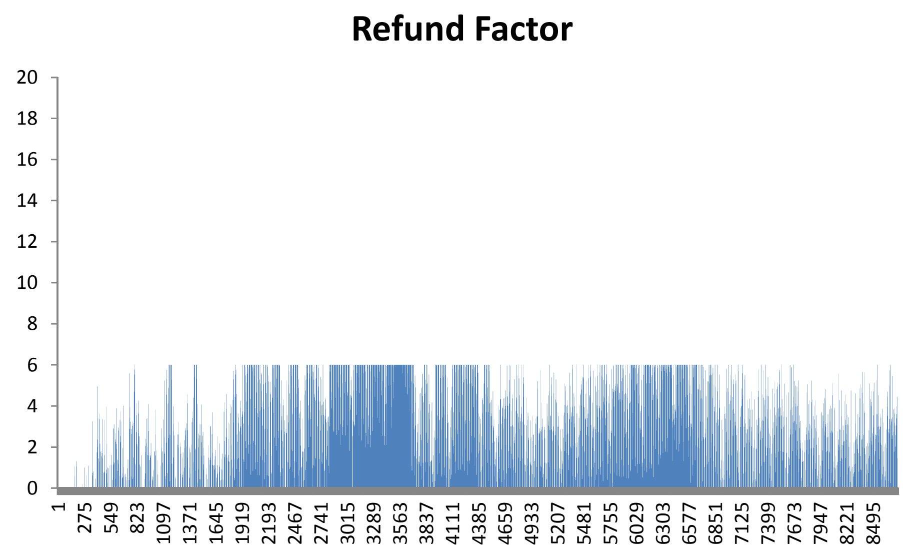
Plant No.	Net Capacity (MW)	FOR (%)	Load Factor (%)	Availability (%)	Plant No.	Net Capacity (MW)	FOR (%)	Load Factor (%)	Availability (%)
1	320	1.0%	90.0%	91.0%	14	40	1.0%	38.3%	96.0%
2	200	3.0%	84.9%	88.0%	15	320	0.2%	34.6%	95.0%
3	100	100.0%	0.0%	100.0%	16	200	1.0%	3.9%	50.0%
4	100	1.0%	97.0%	98.0%	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%

Option 1: IMO DR Proposal (5% ERC)

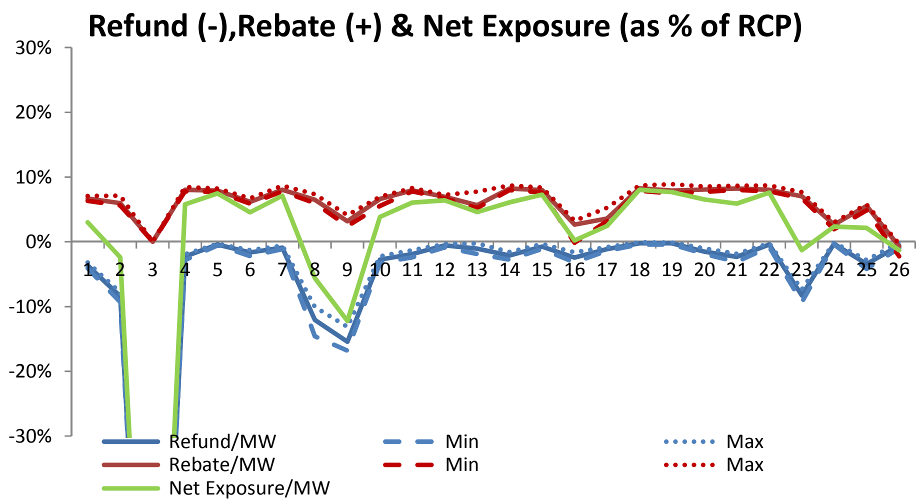


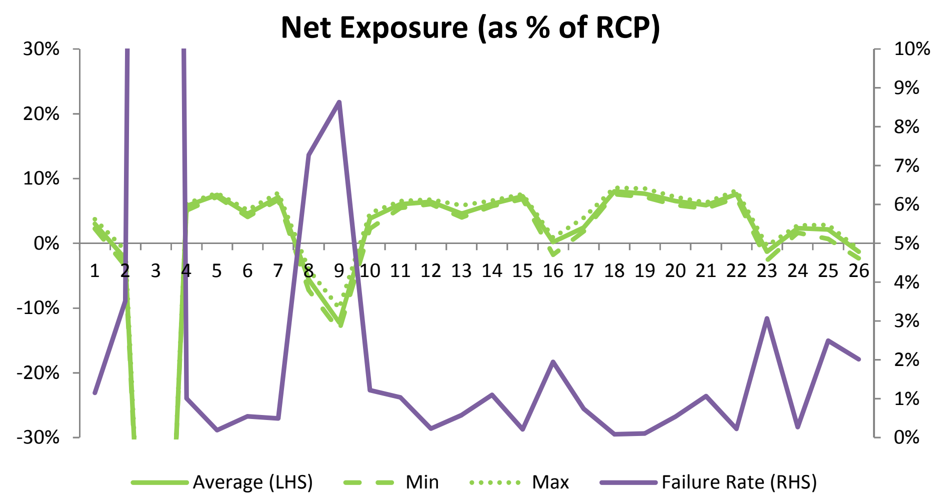


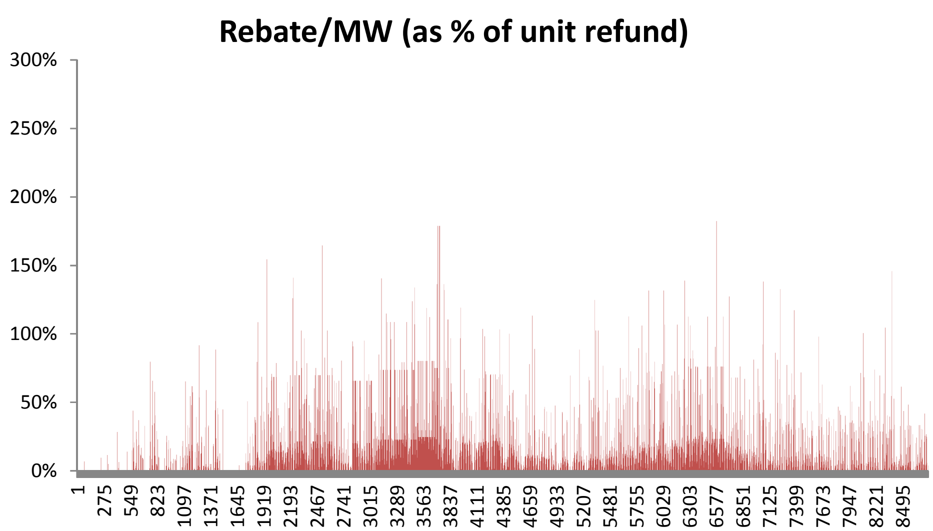


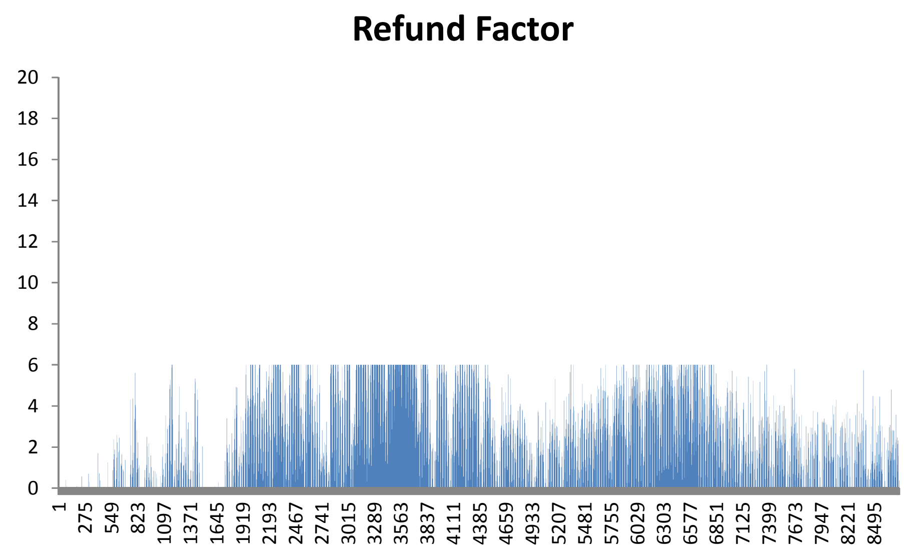


Option 1: IMO DR Proposal (15% ERC)









Option 2: IMO DR Proposal W/ MIN RF = 1 (5 and 15% ERC)

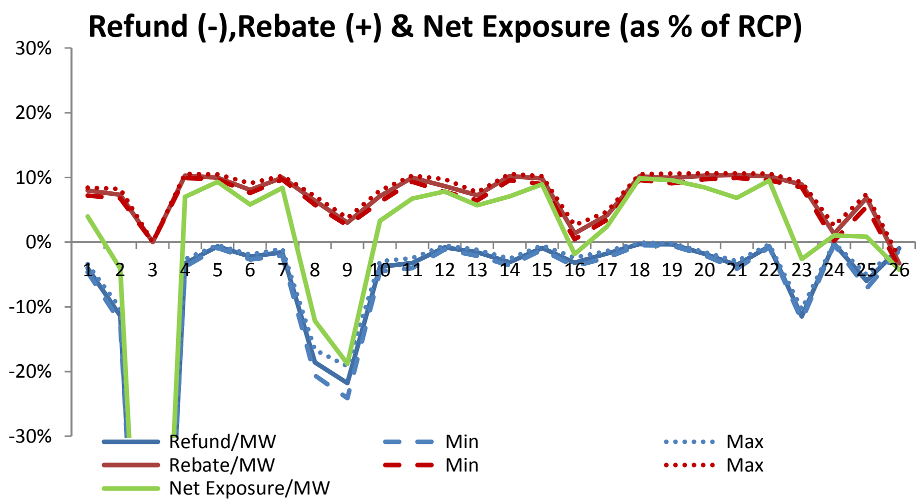
Refund Regime	IMO with Floor 1
Availiability or Dispatched Based Rebate	Availability
Excess Capacity	5%
Maximum Reserve Capacity Price ($/MW)	163900
Reserve Capacity Price ($/MW)	138685
Unit Refund ($/MWh)	15.76

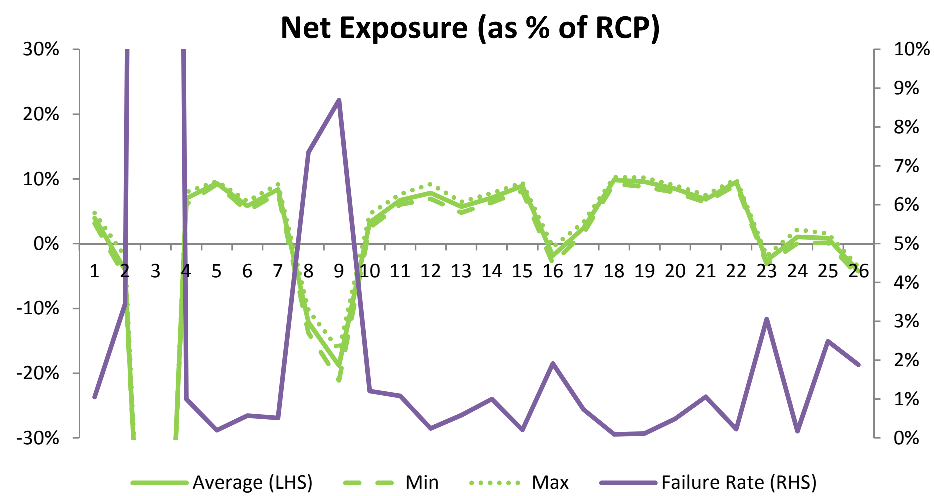
Refund Regime	IMO with Floor 1
Availiability or Dispatched Based Rebate	Availability
Excess Capacity	15%
Maximum Reserve Capacity Price ($/MW)	163900
Reserve Capacity Price ($/MW)	107636
Unit Refund ($/MWh)	11.97

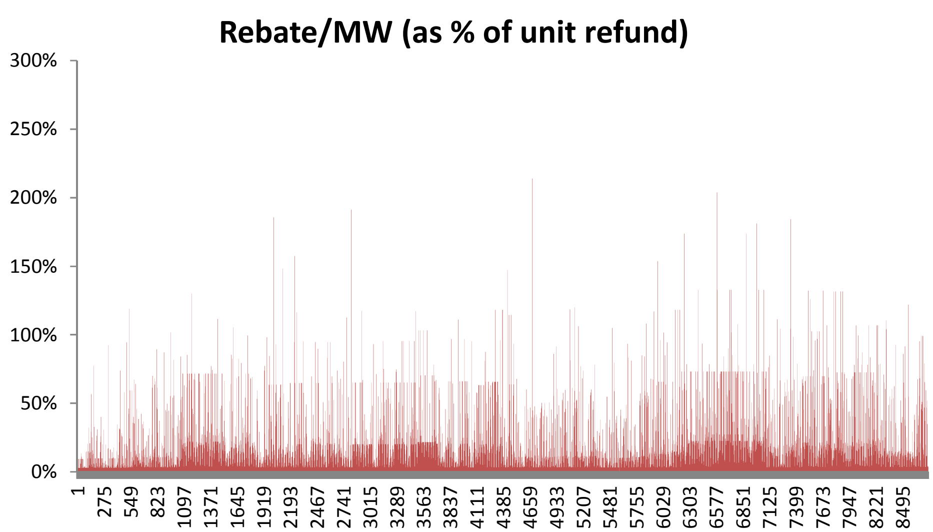
Plant No.	Net Capacity (MW)	FOR (%)	Load Factor (%)	Availability (%)	Plant No.	Net Capacity (MW)	FOR (%)	Load Factor (%)	Availability (%)
1	320	1.0%	90.0%	91.0%	14	40	1.0%	52.3%	96.0%
2	200	3.0%	85.0%	88.0%	15	320	0.2%	48.8%	95.0%
3	100	100.0%	0.0%	100.0%	16	200	1.0%	9.7%	50.0%
4	100	1.0%	97.0%	98.0%	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%

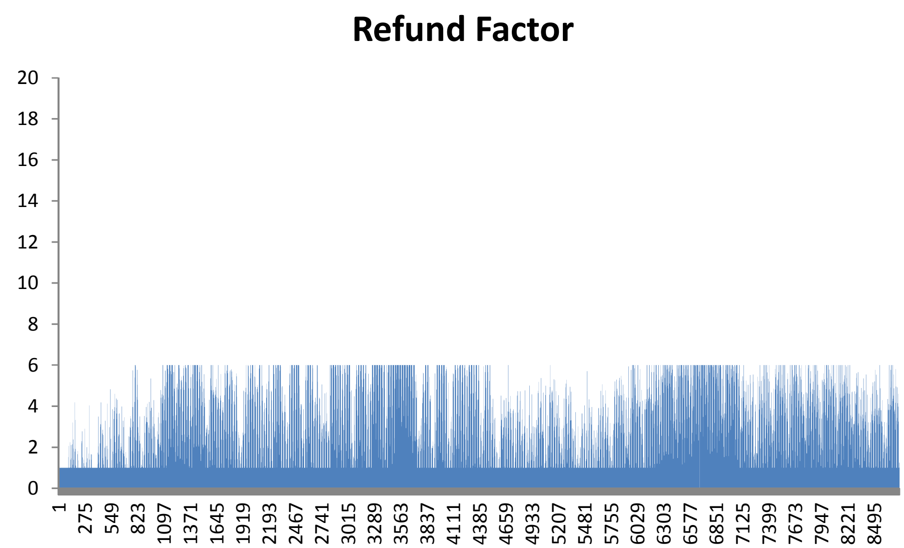
Plant No.	Net Capacity (MW)	FOR (%)	Load Factor (%)	Availability (%)	Plant No.	Net Capacity (MW)	FOR (%)	Load Factor (%)	Availability (%)
1	320	1.0%	90.0%	91.0%	14	40	1.0%	36.9%	96.0%
2	200	3.0%	85.0%	88.0%	15	320	0.2%	33.4%	95.0%
3	100	100.0%	0.0%	100.0%	16	200	1.0%	6.7%	50.0%
4	100	1.0%	97.0%	98.0%	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%

Option 2: IMO DR Proposal W/ MIN RF=1 (5% ERC)

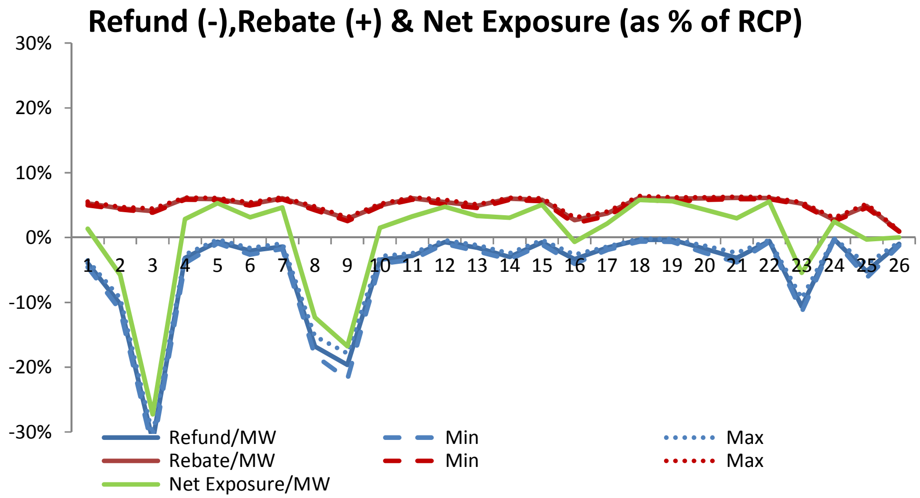


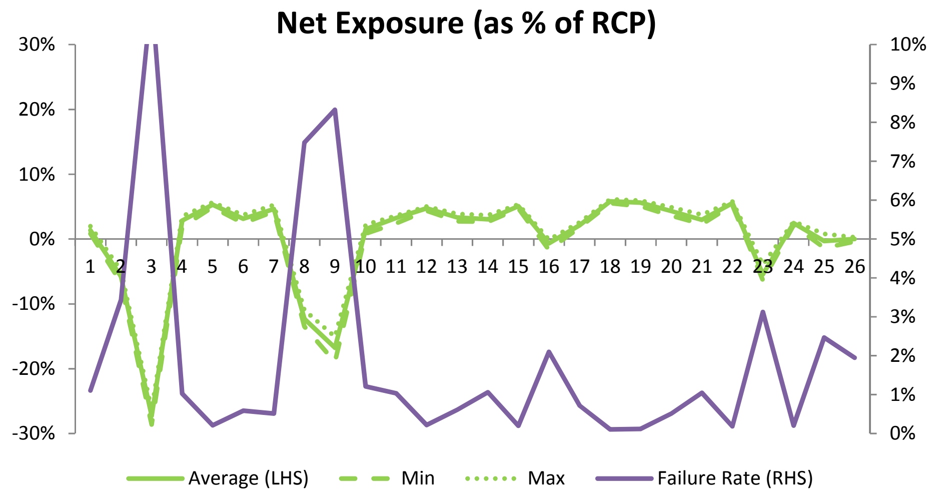


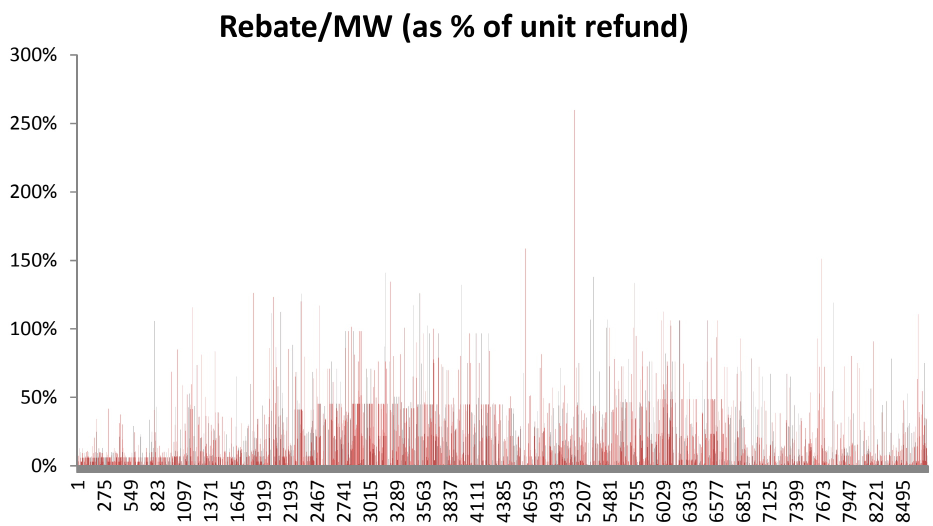


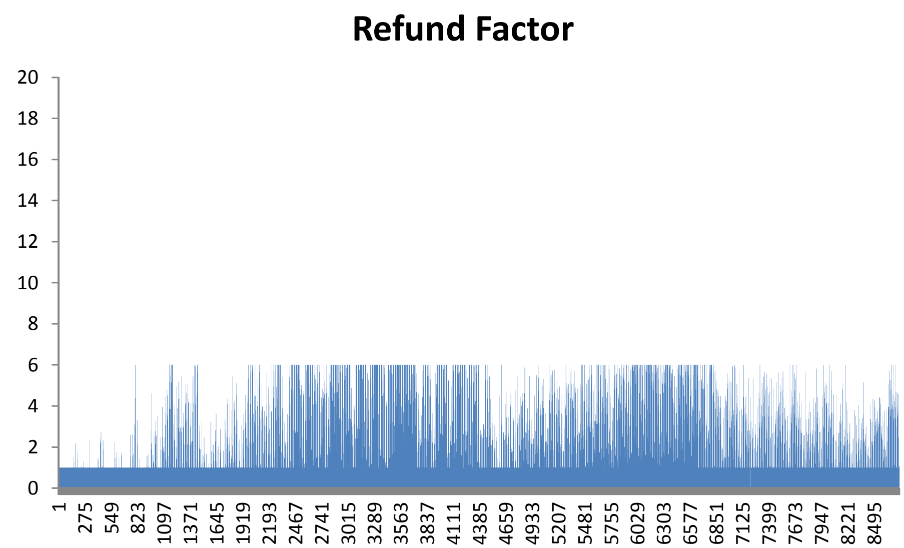


Option 2: IMO DR PROPOSAL W/ MIN RF=1 (5% ERC)

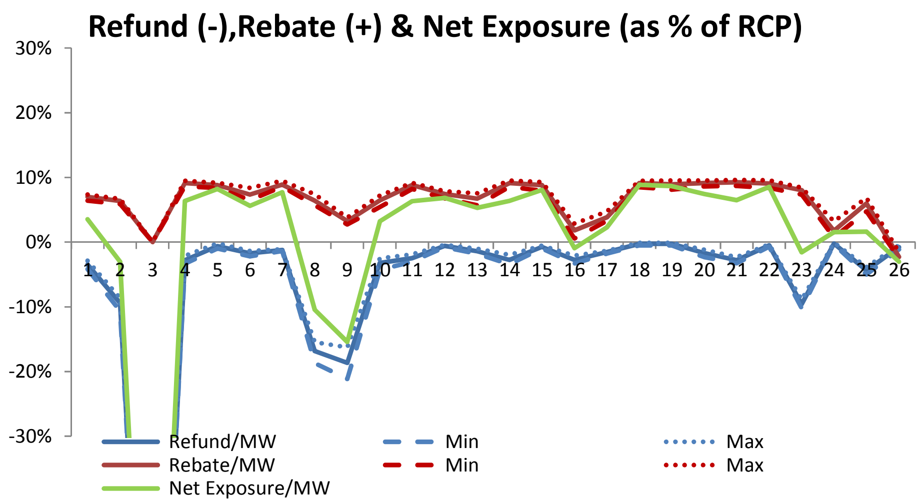


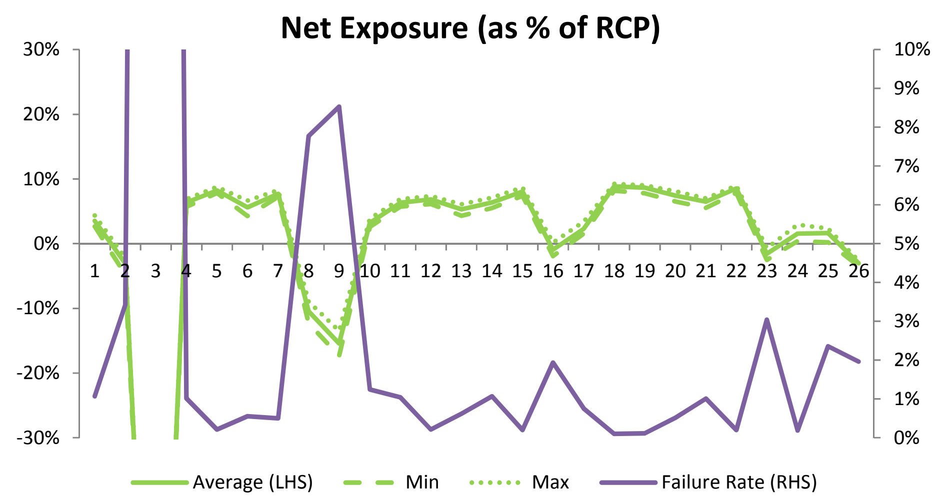


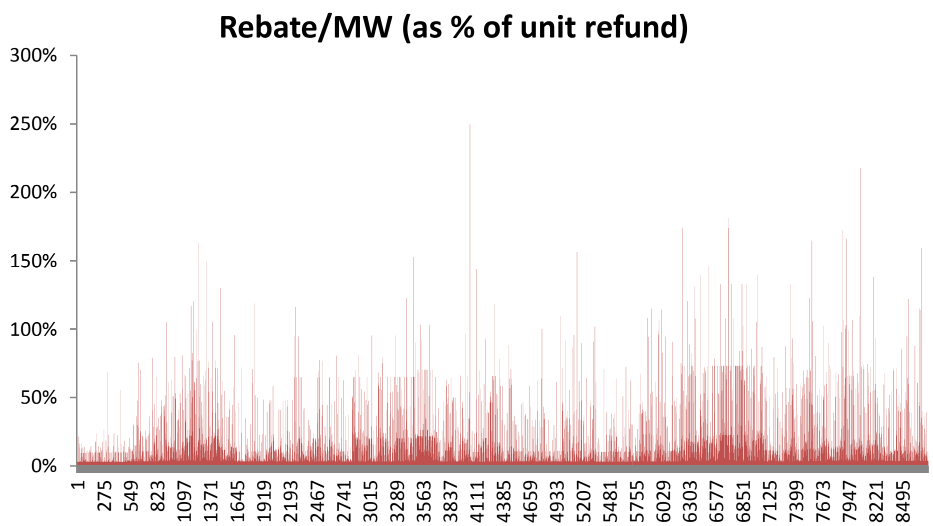


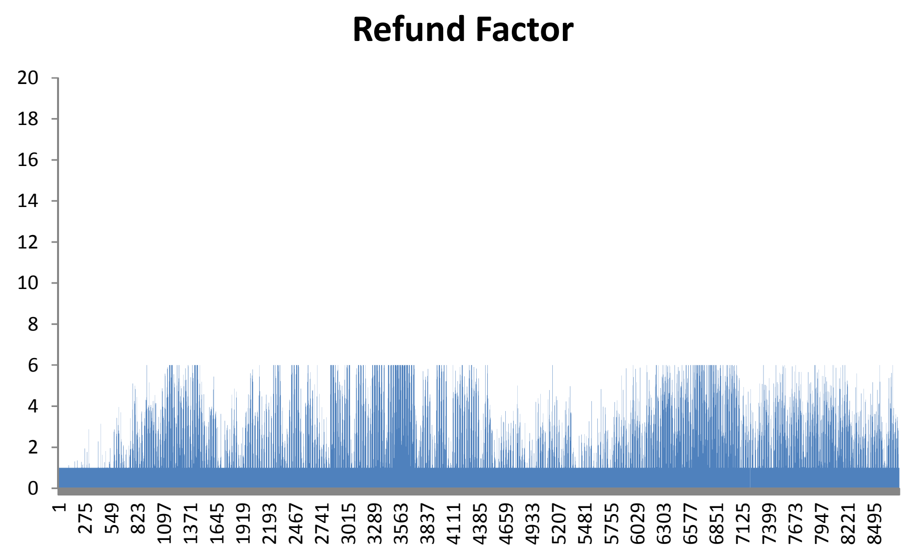


Option 2: IMO DR Proposal W/ MIN RF=1 (15% ERC)

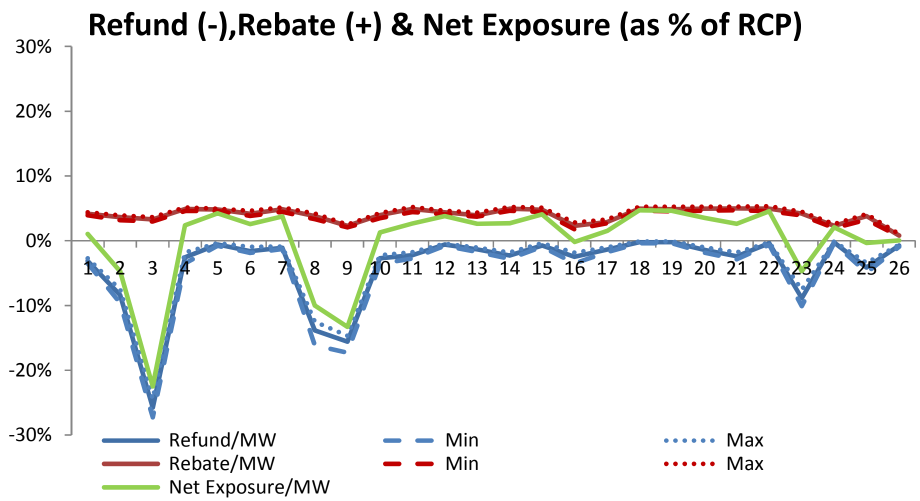


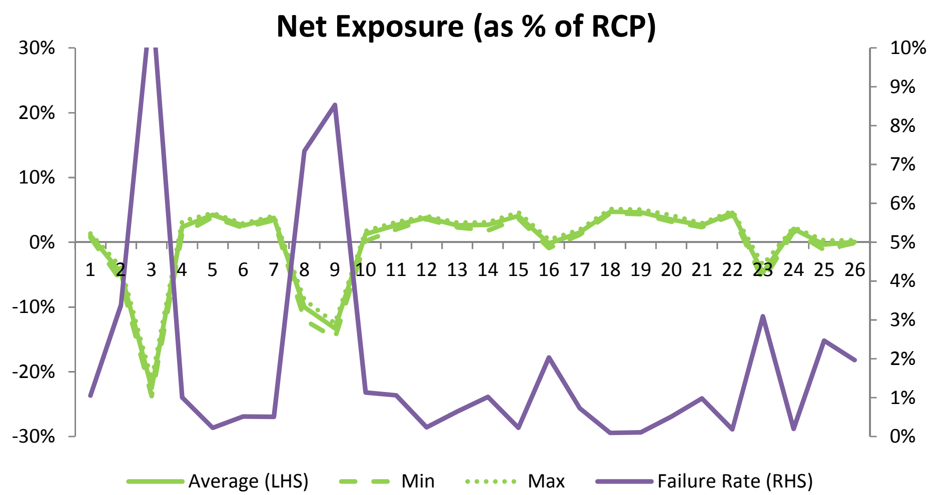


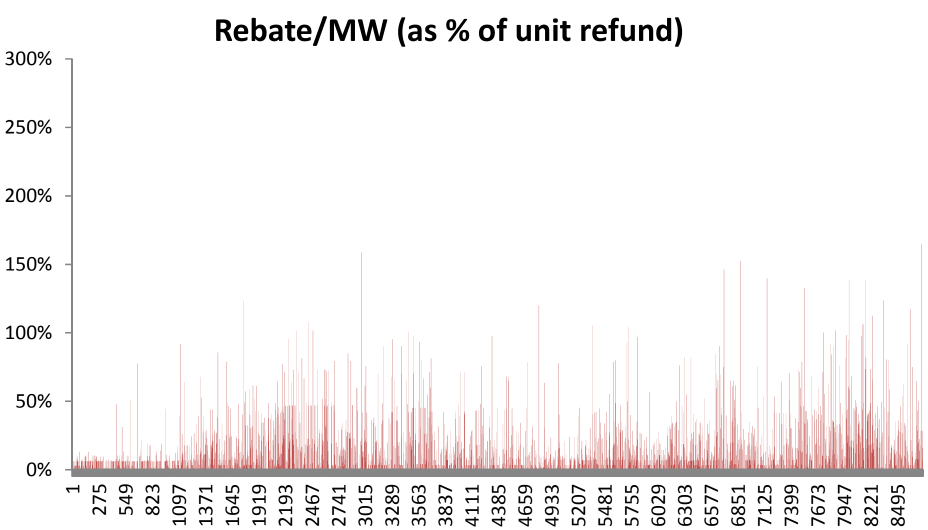


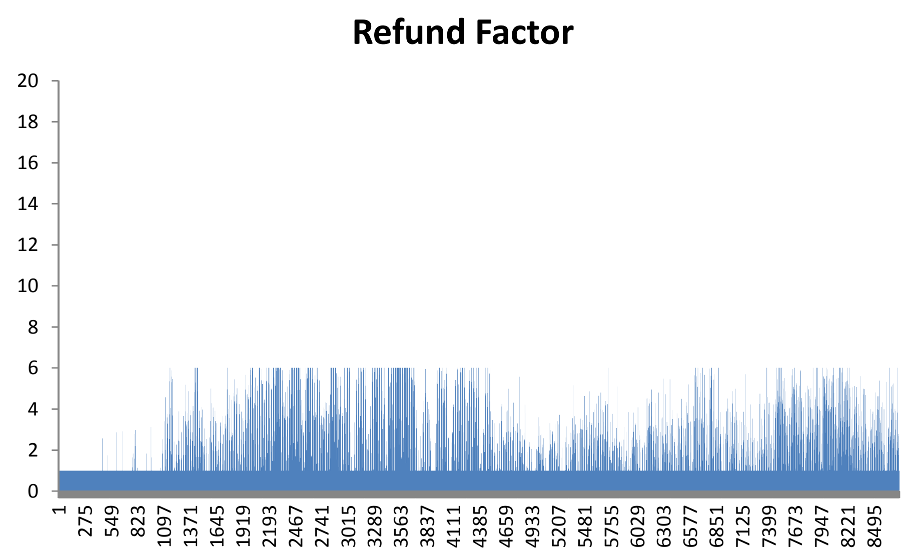


Option 2: IMO DR PROPOSAL W/ MIN RF=1 (15% ERC)









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

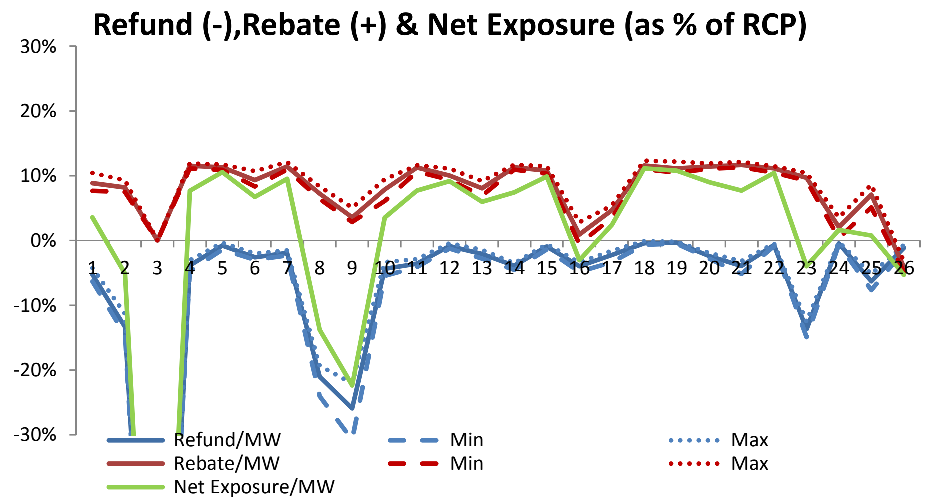
Refund Regime	RCP-LINKED
Availiability or Dispatched Based Rebate	Availability
Excess Capacity	15%
Maximum Reserve Capacity Price ($/MW)	163900
Reserve Capacity Price ($/MW)	107636
Unit Refund ($/MWh)	11.97

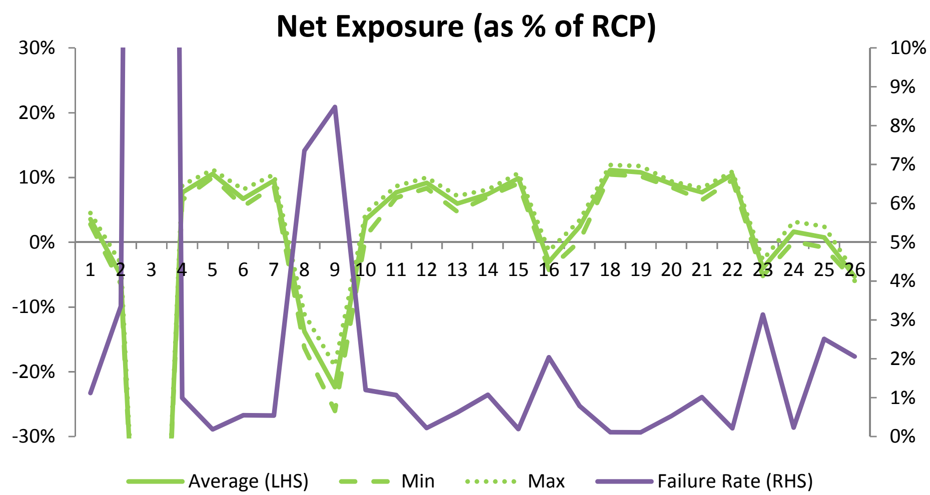
Plant No.	Net Capacity (MW)	FOR (%)	Load Factor (%)	Availability (%)	Plant No.	Net Capacity (MW)	FOR (%)	Load Factor (%)	Availability (%)
1	320	1.0%	90.6%	91.0%	14	40	1.0%	52.0%	96.0%
2	200	3.0%	85.0%	88.0%	15	320	0.2%	48.6%	95.0%
3	100	100.0%	0.0%	100.0%	16	200	1.0%	8.5%	50.0%
4	100	1.0%	97.0%	98.0%	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%

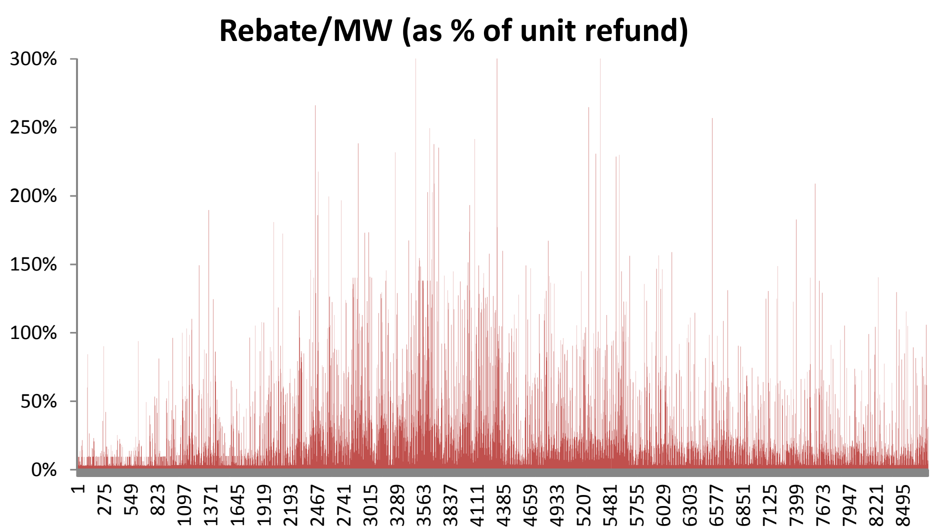
Plant No.	Net Capacity (MW)	FOR (%)	Load Factor (%)	Availability (%)	Plant No.	Net Capacity (MW)	FOR (%)	Load Factor (%)	Availability (%)
1	320	1.0%	90.0%	91.0%	14	40	1.0%	35.8%	96.0%
2	200	3.0%	85.0%	88.0%	15	320	0.2%	32.5%	95.0%
3	100	100.0%	0.0%	100.0%	16	200	1.0%	2.9%	50.0%
4	100	1.0%	97.0%	98.0%	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%

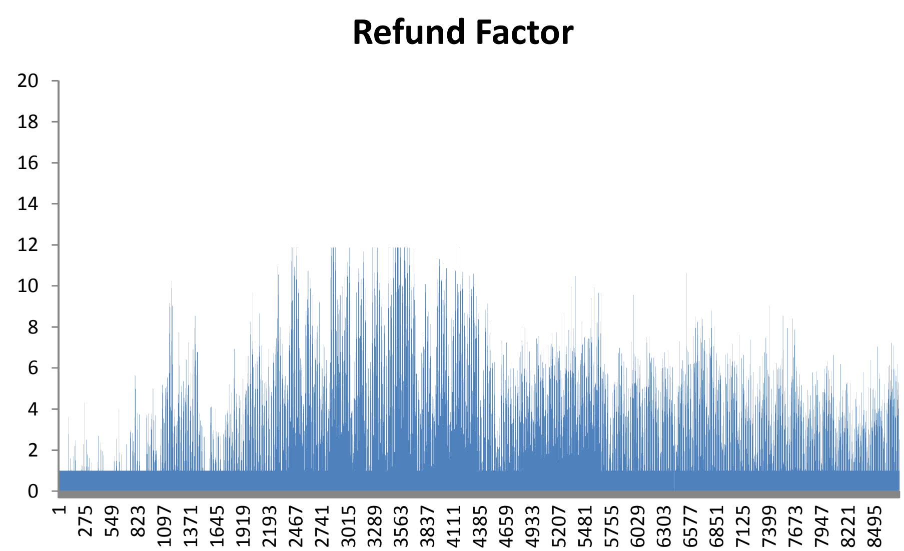
Simulation Model: Unit 3 Full Year FO

Option 3: RCP-Linked IMO DR Proposal W/ MIN RF=1 (5% ERC)

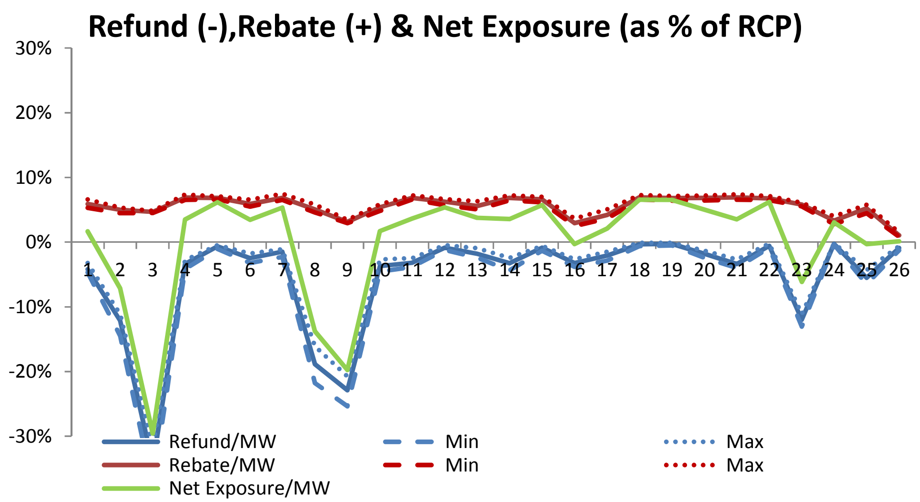


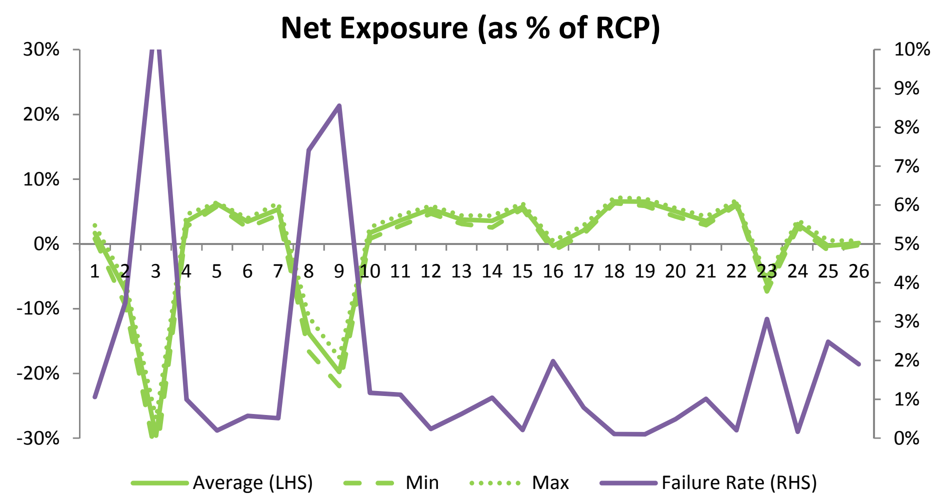


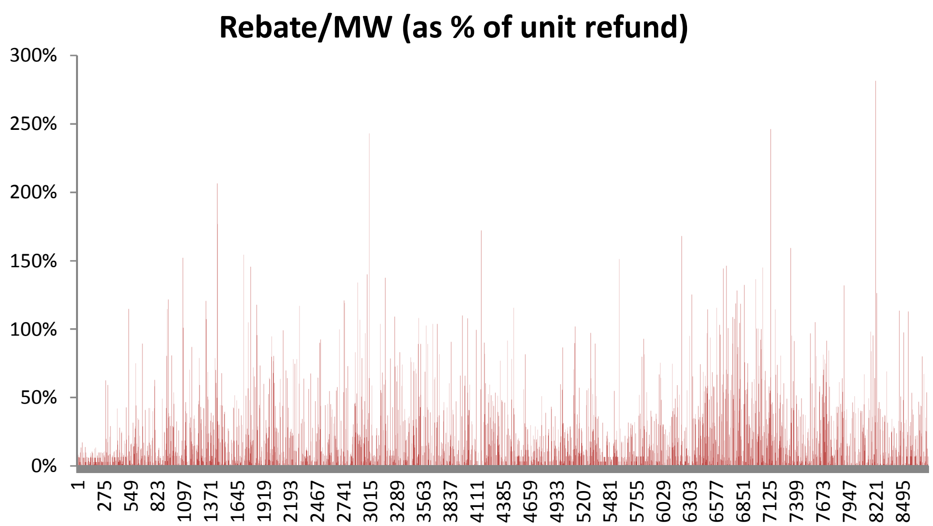


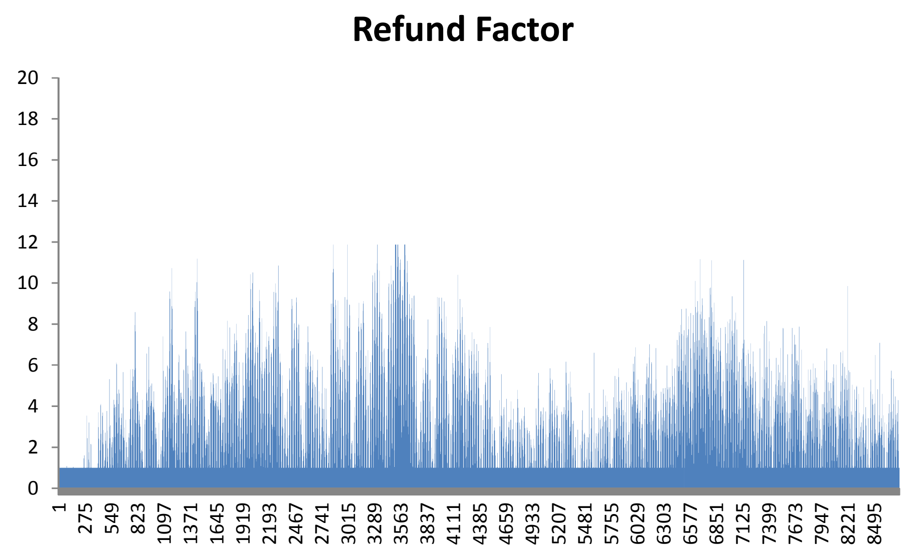


Option 3: RCP IMO DR PROPOSAL W/ MIN RF=1 (5% ERC)



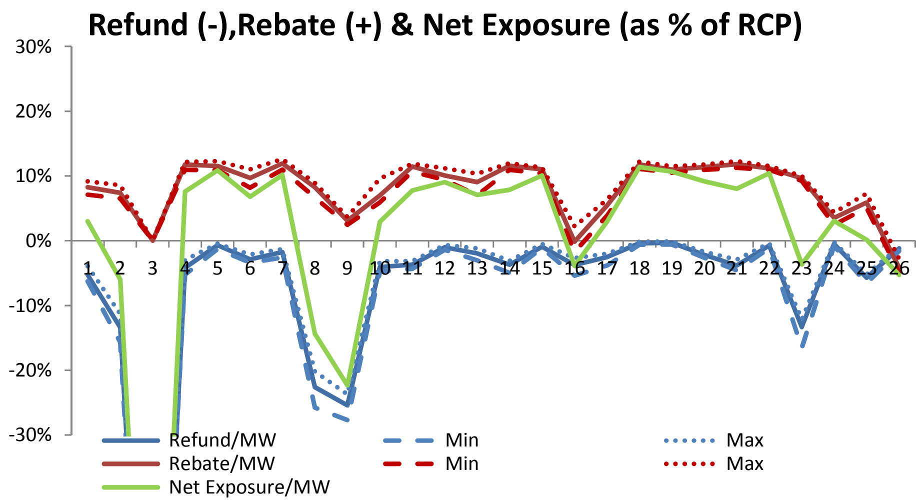


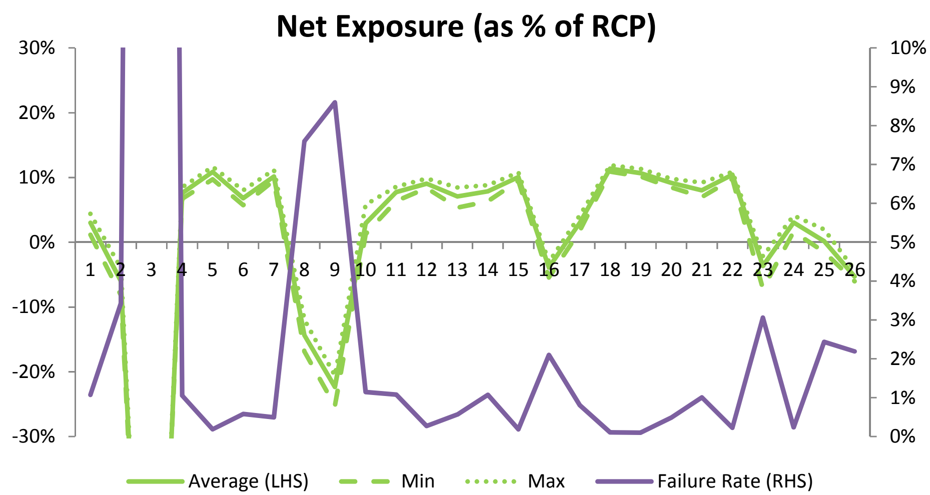


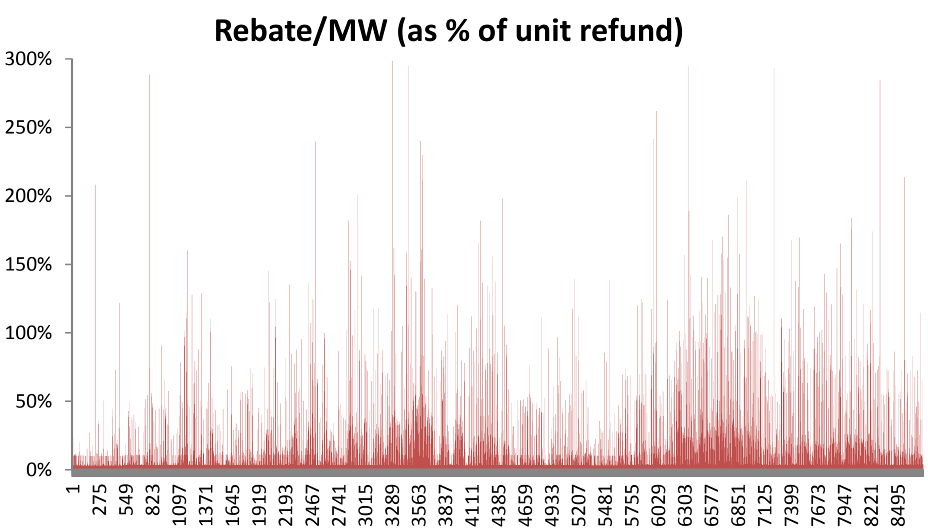


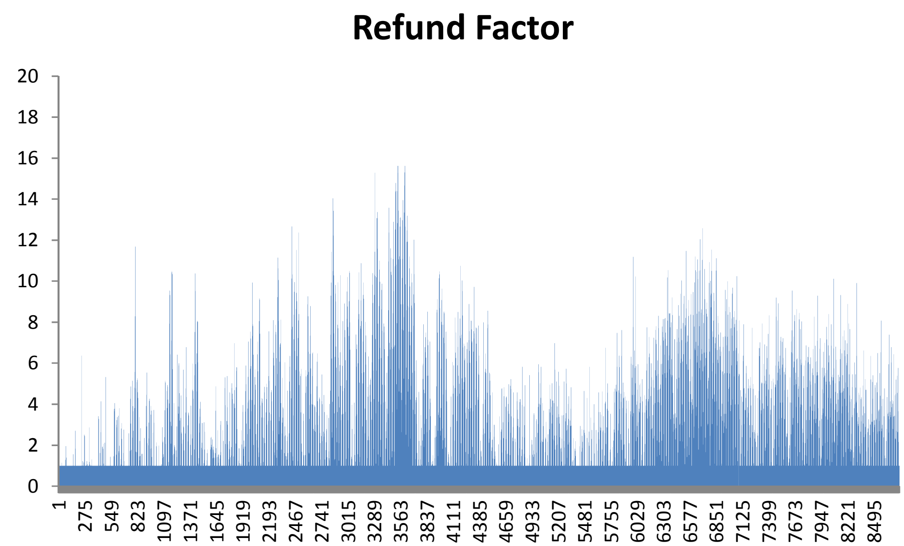
Simulation Model: Unit 3 Full Year FO

Option 3: RCP-Linked IMO DR PROPOSAL W/ MIN RF=1 (15% ERC)

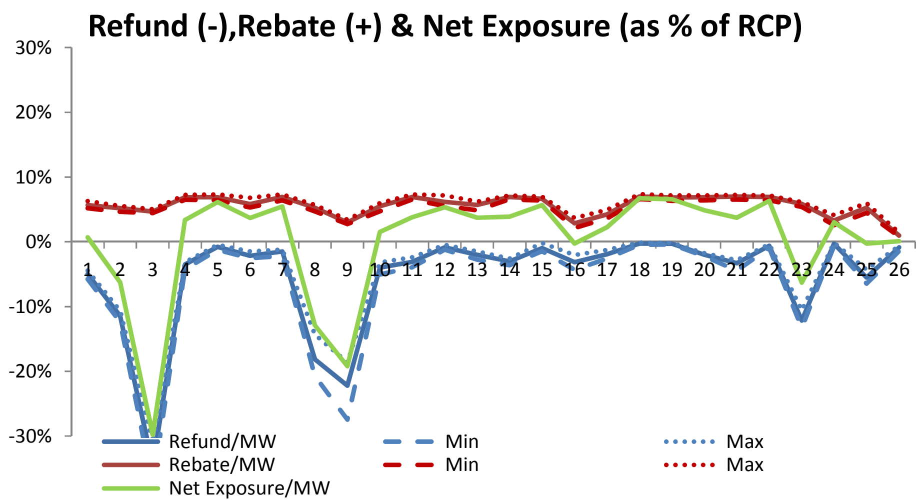


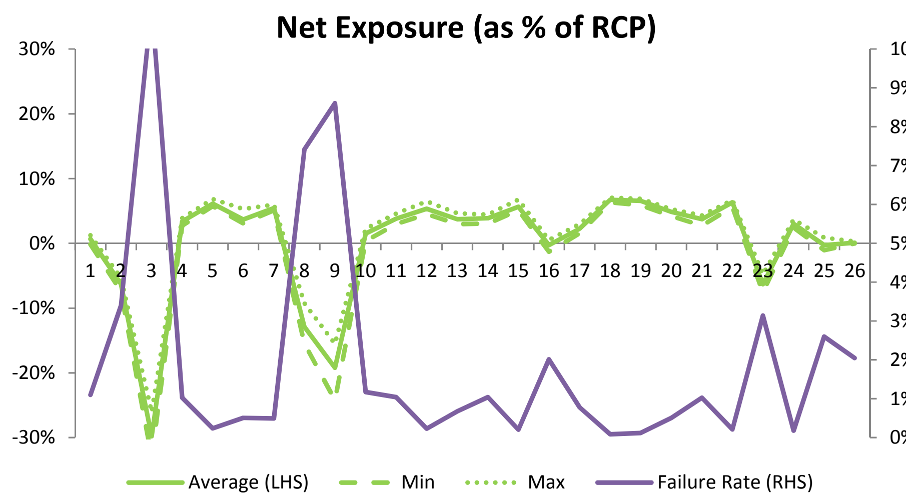


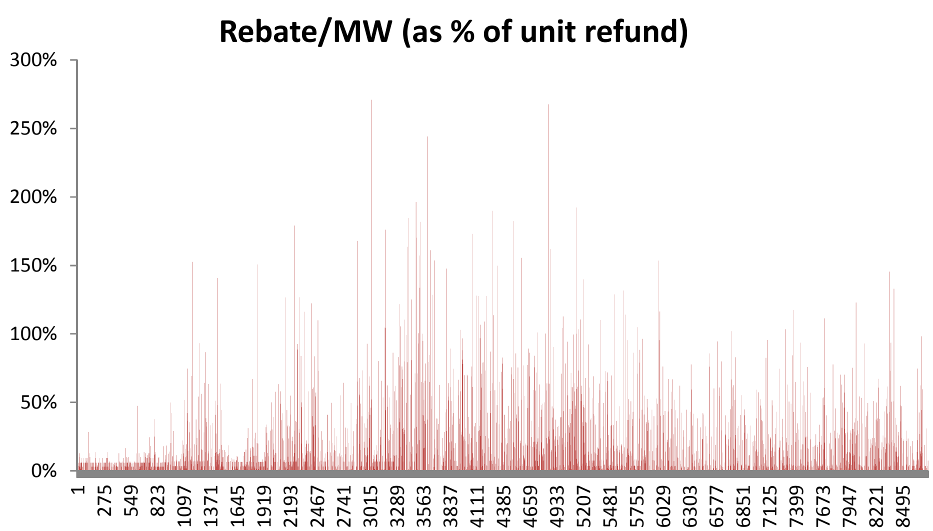


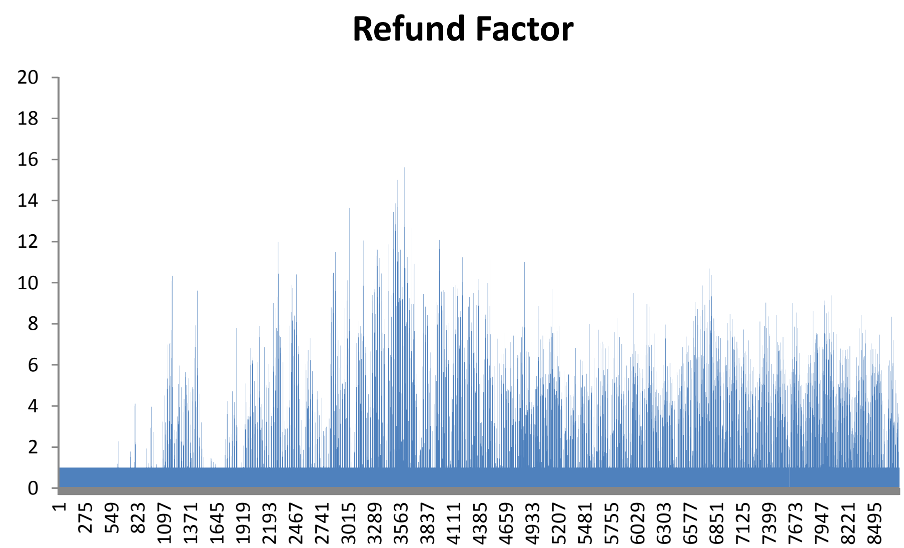


RCP IMO DR PROPOSAL W/ MIN RF=1 (15% ERC)









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

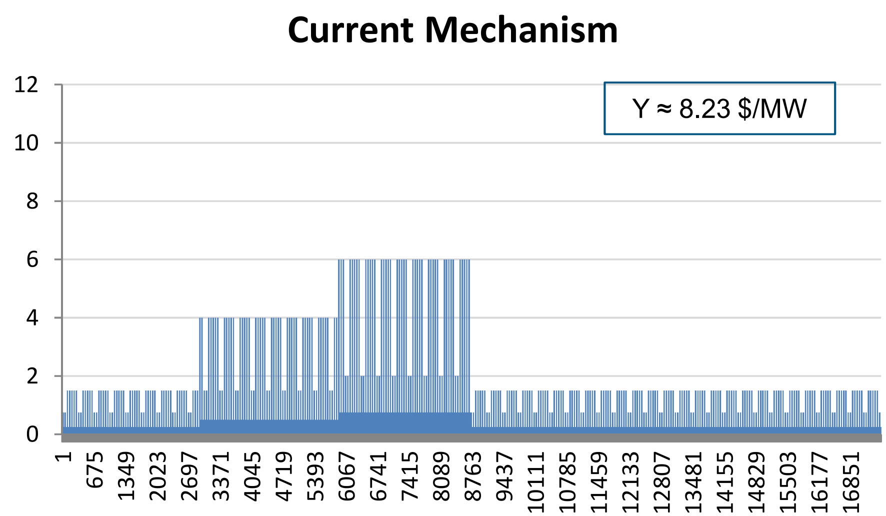
- A minimum refund factor of 1 is non-issue given the existence of a rebate regime, and solves a tricky incentive problem in a simple way
  - Removes / reduces rent-seeking incentive with respect to FO timing
  - At the end of the day, the rebate regime compensates better performers, so that only worse performers are actually exposed – which is the intention of an incentive regime

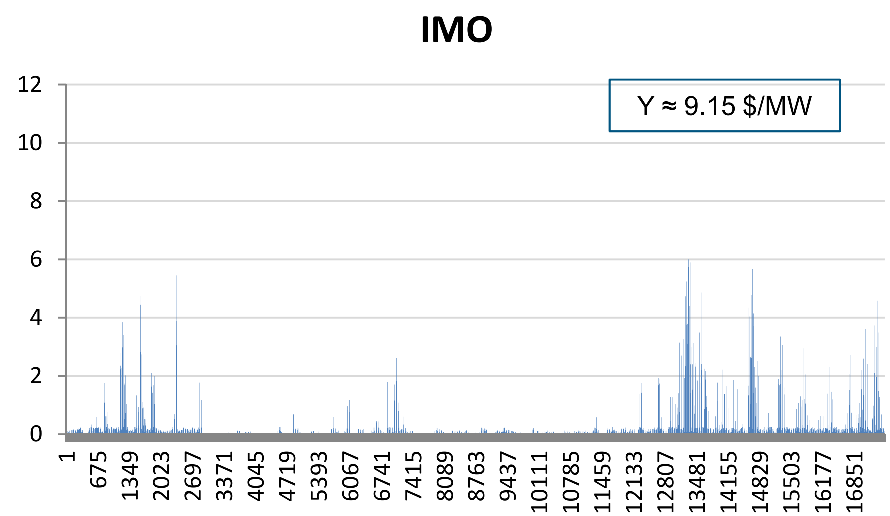
- Linking the maximum refund factor to the MRCP/RCP ratio produces more stable results over time and sharper incentives, without any evident counter-effects
  - Financially more predictable outcomes from year to year
  - Just because the RCP is low for a given year does not mean that the risk of shortage is worth less on the day

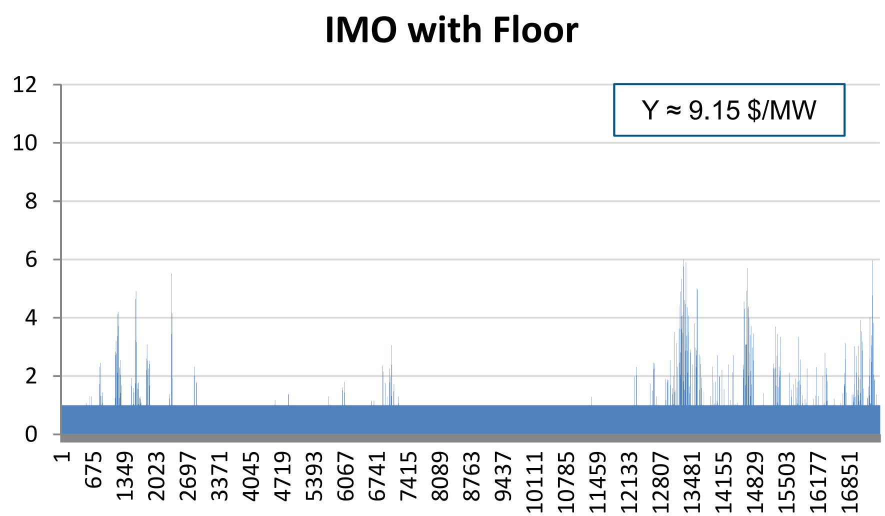
Recommend Option 3: RCP-Linked Dynamic Refund Regime

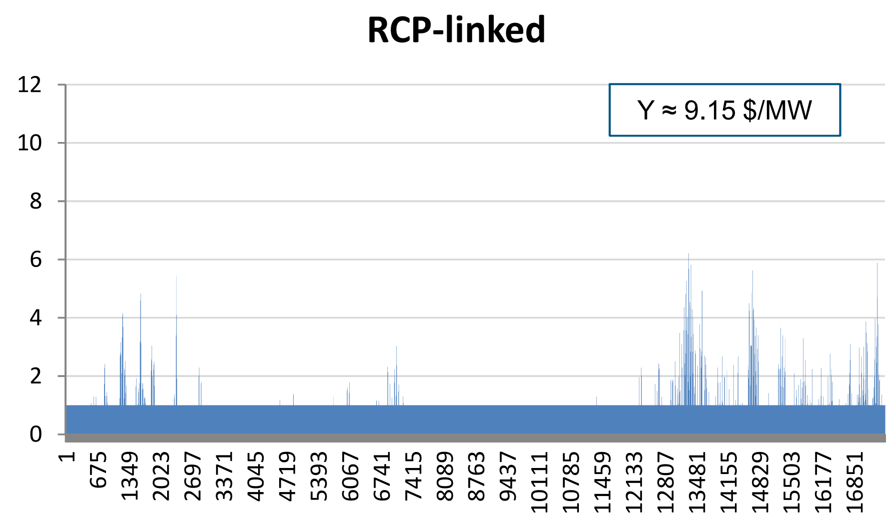
BACKUP SLIDES

Refund Factor and Unit Refund (Y) over Capacity Year 2010/11



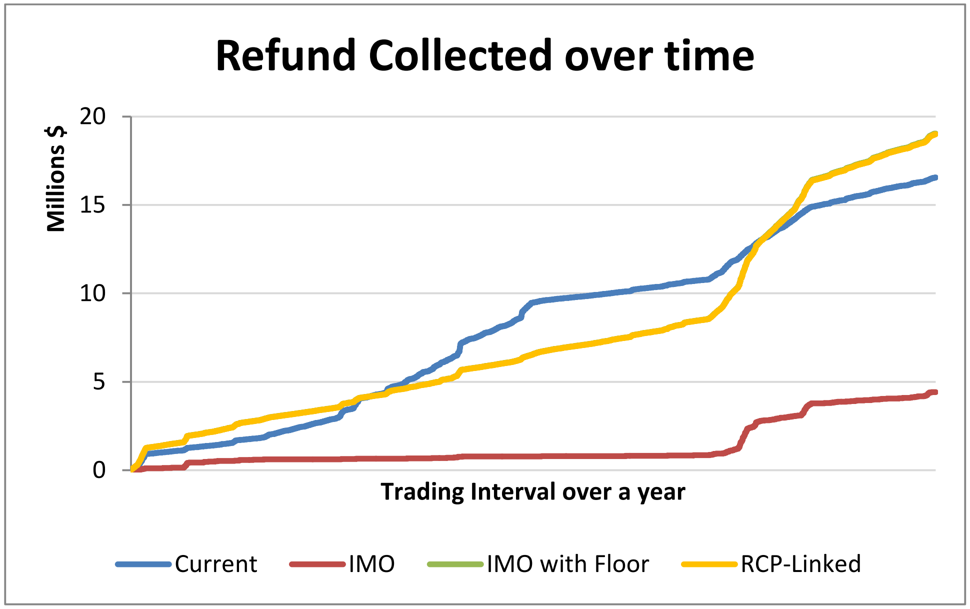




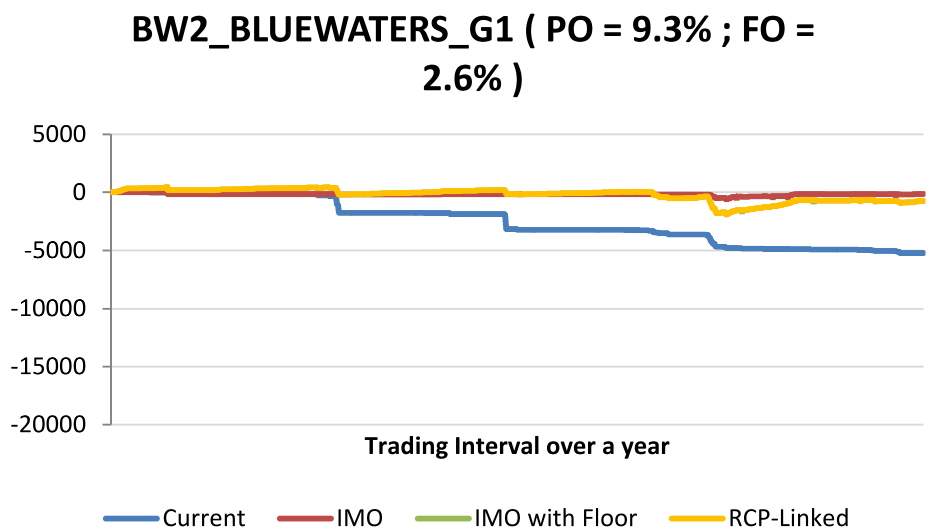


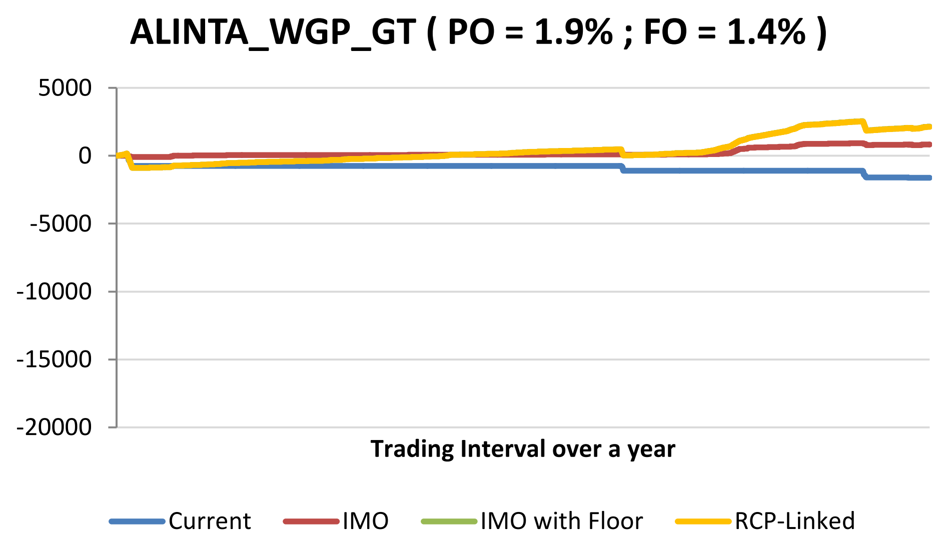
Cumulative Refund

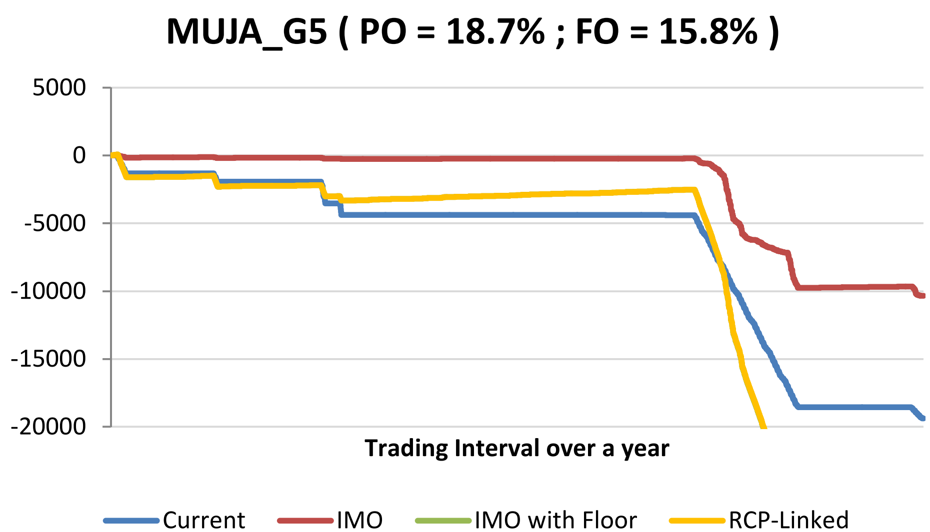
- For the current mechanism, refund collected will be distributed to market customers according to their IRCR.
- Under the new proposals (IMO, IMO with Floor and RCP-Linked), all the refund collected will be recycled and distributed to facilities that are available.

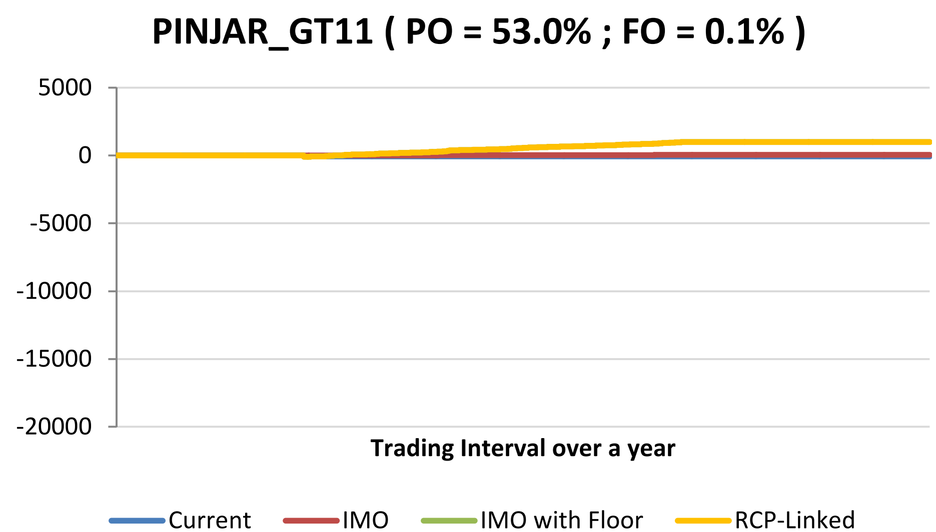


Net Exposure of Facilities (per MW) under different proposals









Note: System average PO and FO rates are 15.4% and 2.0% respectively

INDEPENDENT MARKET OPERATOR

Agenda Item 7: Reserve Capacity Price

Following extensive discussion on the Reserve Capacity Price (RCP) at Meeting No. 8, the Lantau Group was requested to examine the effects of its RCP proposal with the help of some worked examples.

Two papers follow this note.

The Lantau Group has prepared a memorandum that reconsiders the key issues of:

- responsiveness to market conditions; and
- the distorted incentives regarding bilateral contracting under the current RCP formula.

The memorandum outlines Lantau's recommended RCP formula and compares this with the current RCP formula. The incentives to bilaterally contract for capacity are also explored for a range of excess capacity scenarios.

The second paper, prepared by the IMO, projects capacity and the Reserve Capacity Requirement for the next five Reserve Capacity Cycles.

The growth in capacity has slowed in the last two Reserve Capacity Cycles, as reflected in both Expressions of Interest and Capacity Credit allocations. It is also anticipated that future allocations to existing capacity may reduce:

- Capacity allocations to Intermittent Generators are expected to reduce further over the next two Reserve Capacity Cycles as a result of the transition path implemented with Rule Change RC_2010_25.
- RCMWG members have suggested that the level of DSM would reduce as a result of the harmonisation proposal that has been broadly agreed to date.
- The IMO has anticipated the retirement of the Kwinana Stage C facilities in the 2012 Statement of Opportunities (SOO).

However, demand forecasts are also likely to change in the future.

- The forecasts in the 2012 SOO included an allowance for residential solar PV generation but did not consider solar PV generation in the commercial or industrial sectors. The inclusion of an allowance in 2013 will move the forecasts downward.
- Energy consumption in the four months from July to October 2012 is 2.6% higher than the same period in 2011, and 3.1% above the forecast in the 2012 SOO.
- The five-yearly review of the Planning Criterion recommended that the reserve margin be reduced from 8.2% to 7.6%.

The second paper considers the impacts of these potential changes on the supply-demand position and projects RCP outcomes for the current and proposed RCP formulae.

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Memo

To:	RCM Working Group
From:	Mike Thomas
Date:	14 November 2012
Subject:	RCM Recommendations and examples

1. SUMMARY

The amount of excess reserve capacity at any point in time is the result of complex interactions amongst various values, mechanisms and processes. The RCM is the lens through which these interactions affect the perceived economics of new capacity additions. The MRCP is one factor that determines the RCP, the price paid by the IMO for reserve capacity that is not contracted bilaterally between capacity suppliers and demanders. The recent MRCP review reduced the MRCP materially through a combination of methodological and parameter changes.[1]

1 These methodological changes are the more relevant to an assessment of the RCM performance, as these affect the interpretation of investment incentives prior to the MRCP revision as compared to what might reasonably be expected after the MRCP revision. Other parameter changes are conceptually akin to the way a floating dock adjusts to changing tides.

Demand response resources form a material proportion of the capacity resources in the RCM. The recent work streams to “harmonise” the treatment of supply and demand resources would, if implemented fully, increase the performance standards for demand resources and could therefore reduce the quantity of demand response able or willing to participate in the RCM.[2] Finally, the capacity credit eligibility of intermittent generation resources has been under review. These actual and potential changes take place against a backdrop of continuing global economic turmoil, particularly in Europe and in China, with impacts evident on the investment plans of WA’s commodities industries and growth—contributing to demand growth uncertainty.

Not surprisingly, we understand from the IMO that the WEM in 2012 has seen the lowest ever level of investor interest in new capacity resource additions. Indeed, it is possible that the pendulum is now swinging in the other direction—the direction of a reducing excess reserve margin. If so, then let us consider where credit most likely belongs: the pendulum is probably not swinging in the right direction because the RCM worked effectively in response to changing market conditions; but because the pendulum was overwhelmed.

In this note we discuss the rationale for the following recommendation:

1) Retain the RCM and recognise that it can be an effective market-based mechanism, but that it requires several significant adjustments.

2) Steepen the slope factor in the RCP formula to -3.75

3) Increase the maximum RCP to 110% of the MRCP (or build in a 10% margin within the MRCP)

4) Use 97% of the RCR as the basis for the RCP formula (so that the RCP is 110% of the MRCP at 97% of the RCR, and is equal to the MRCP at the RCR).[3]

5) Implement the refunds + rebate (recycling) regime as discussed separately.

These changes would, collectively, yield a small value benefit to retailers for levels of capacity excess above approximately ten percent, while substantially enhancing the investment incentives necessary to assure investment adequacy as the excess reserve capacity level declines below five percent. The increased dynamism of the steeper slope and adjusted maximum RCP would create market-oriented incentives within the RCM that address the RCM’s primary deficiencies in terms of economic signalling and commercial and behavioural in incentives.

2 And cannot logically increase it.

3 Note that a supplemental auction would still be called if the CCs fall below the RCR. Under such situation, any uncontracted CCs procured through the IMO would be sold at up to 110% of the RCP, per the formula.

In discussing the rationale for this recommendation, we refer to several other approaches and provide reasons for not proceeding further with those approaches at this time.

2. EVALUATION FRAMEWORK

The next sections describe different market-based approaches and explain the recommendation to focus on improving the existing RCM.

2.1. Market-Based Approaches: Quantity or Price

Market based approaches can start either with a quantity or a price. If starting with a quantity, the market must discover the price. If starting with a price, the market must discover the quantity. Both cannot be *specified* simultaneously in a market-based framework without risk of conflict. Approaches that attempt to solve for both price and quantity simultaneously are theoretically possible, and potentially superior, but the political sensitivity of capacity adequacy tends to put the kibosh on such schemes in electricity markets. The most important design consideration is that the approach taken be implemented consistently and coherently. Among other things, this requires picking an approach and implementing it faithfully.

2.1.1. Quantity-based approaches

Auction-based approaches as seen in capacity markets are typically quantity-based. The auction process discovers the price that corresponds to the demanded (required) quantity. Much of capacity auction design concerns establishing the capacity required at various points in time – typically beginning several years before the relevant target date and then with updates and reconciliations running right up to the target date. Auction-based approaches carry the promise of being able to match supply and demand of capacity at an appropriate value.

Initial auction designs have evolved significantly so as to address various unexpected problems.[4] For example, earlier auctions focussed on short-term (one-year) requirements and commitments only and wound up introducing unacceptably high price variability. But longer-term focussed auctions run the risk of locking in more or less capacity than is needed by the time the target period actually arrives, especially during periods of considerable demand uncertainty or lumpy resource development (as commonly experienced in WA). As just one example, the PJM capacity market in the United States encountered significant problems with price outcomes that ranged from near zero to exceptionally high – increasing investment risk. To help make its own auction model work acceptably, the PJM capacity market incorporated an administratively determined *demand curve* (the "variable resource requirement") that specifies the quantity required to be purchased as a function of the price.[5]

This "demand curve" concept was a significant evolutionary step, not present in the initial auction design, and was developed to mitigate market power and extreme price volatility. At higher capacity prices, the demand curve specifies a lower capacity resource purchase requirement. If the capacity price turns out to be lower, the demand curve specifies a high capacity resource purchase requirement.

In the figures below, we illustrate how the demand curve concept works in a world in which it is not clear what prices the auction process will "discover". For example, there could be market power or there may genuinely be a surplus or shortage of commercially viable opportunities, resulting in a more or less elastic (steep) supply curve.

4 See for example: "Capacity Markets in Action: Challenges from the Purchasers Point of View", Presentation to the Harvard Electricity Policy Group, Erik Paulson, Director of Regulatory Affairs, PJM.

5 Incidentally, PJM is not the only market that uses demand curves. The New York ISO also employs a demand curve, and the concept is widely discussed in capacity market literature.

Figure 1: Auction used to clear a fixed demand – yielding an uncertain price (to be discovered by auction) could be low or high

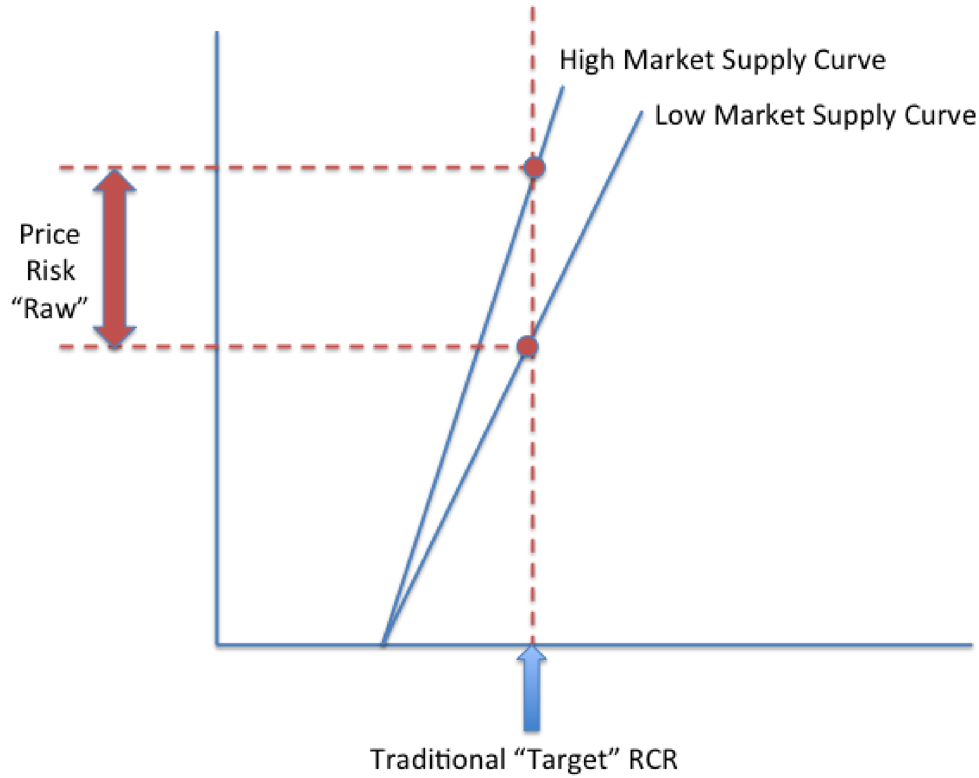
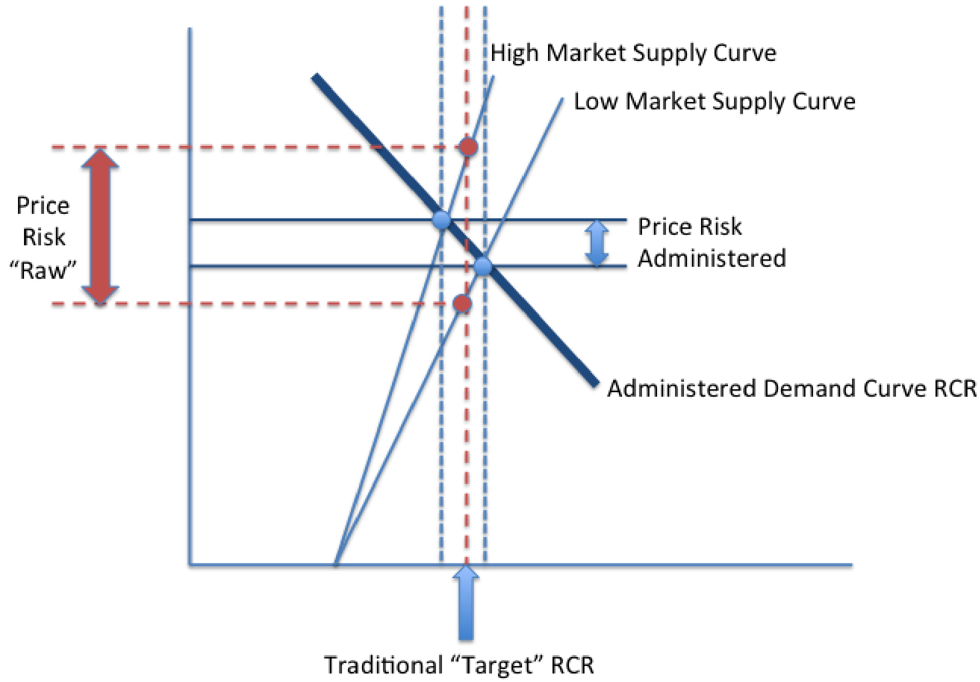


Figure 2: Auction plus an administered demand "curve" – yielding a much narrower uncertain price range



The variable resource requirement trades-off rigidity of the target RCR for reduced price risk. It effectively allows slightly less reliability in exchange for lower price volatility. One of the reasons the auction approach is complex is that the tolerance for different impacts (on target capacity resource requirements and on acceptable levels of pricing risk) must be determined and then translated into the necessary parameters and "curves".

To implement a variable resource requirement would require the IMO to be able to trade off a measure of reliability in exchange for price elasticity in an auction context. This is not something that appears possible in WA under the current reliability standard based on a one in ten year peak load. Gaining such flexibility would require policy asset, which would invariably require a significant level of engagement and study across stakeholders and government and policy makers. To go without a variable resource requirement invites the more difficult zero / infinity problem.

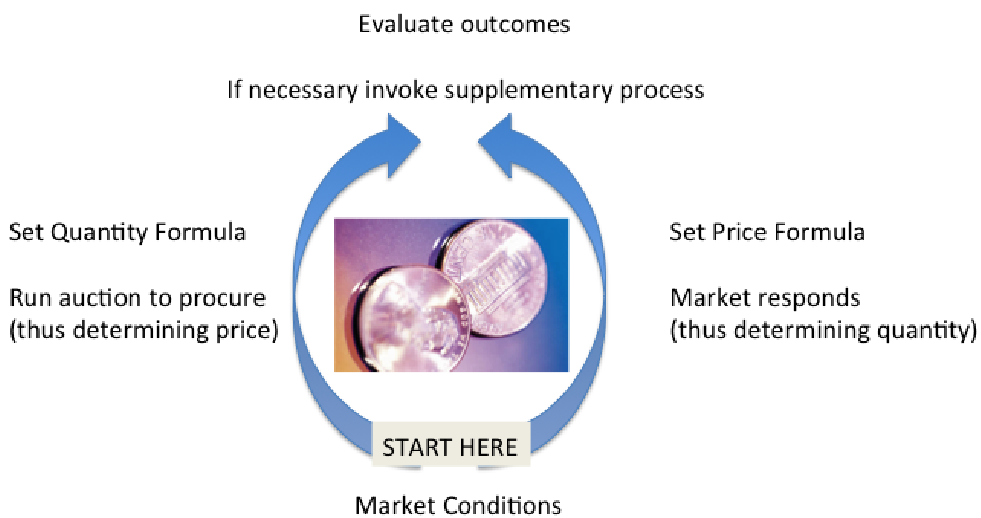
2.1.2. Price-based approaches

The other approach is predominately price-based. A price is offered and as much quantity responds as wishes to do so. Price-based approaches have to manage risks related to the amount of capacity that ultimately is presented to the market. The chief risk of a price-based approach is whether the price is high enough to attract at least the targeted level of capacity. A related risk is whether the price-based approach supports persistent excess capacity. A benefit of a price-based approach is its simplicity and ability to yield robust outcomes regardless of industry structure.

As currently implemented, the WEM's RCM is price-based. The RCM incorporates an administratively determined price adjustment formula that specifies prices as a function of the amount of excess reserve capacity presented to the market. The RCR represents the capacity target and is used in the formation of the administered price relationship. If the amount provided by capacity suppliers exceeds the RCR, the IMO backstop price adjusts downward through a formulaic adjustment to the RCP. If the reserve capacity available from capacity suppliers falls short of the RCR, then, further backstop mechanisms kick-in, such as the Supplementary Reserve Capacity Auction.

2.2. CHOOSING SIDES

Ultimately, price- and quantity-based approaches are both capable of being market-based. Both can be designed to produce credible and reasonably efficient outcomes, and both require a healthy dose of mechanisms, boundaries or constraints to mitigate risk. For example, the quantity-adjusting demand curve of the PJM capacity market is analogous to the price-adjusting RCP formula in the WEM. The two approaches are essentially different sides of the same coin.



The question therefore is whether to fix what is wrong with one side of the coin, or to move to the other side of the coin and attempt to accomplish the same overall outcomes in a completely different way.

Switching comprehensively from the RCM to an quantity / auction-based design would likely necessitate extensive changes to the process timetable; the way forecasts are interpreted and used; and the way the RCR is defined and interpreted; it would almost certainly require the development of an acceptable "variable resource requirement" (demand curve) to manage risk and volatility exposure; as well as the need for a comprehensive evaluation of the degree of competition that would likely be realised. It would require at least a simple trading platform for buying or selling credits amongst stakeholders so they can match supply to demand. And it would require consideration of industry structure in terms of exposure to rent seeking behaviour, market power in either the auction or trading markets under circumstances of both clear excess as well as looming shortage. Finally, if, at the time of introducing an auction, capacity resources are either particularly long or short relative to requirements, a transition could be needed to manage the potentially severe value shifts that can arise when changing from one approach to another.

The level of design changes required to implement a quantity / auction-based design in a manner that delivers predictably robust results, is significant. To get all elements in place and working correctly so as to achieve what is already nearly achieved (and certainly achievable) within the RCM, is a risk that would have to be taken. Auctions have many supporters, for many reasons, but the process of making the auction process work, even in extremely well-resourced (both diverse in supply, robust in demand and well-funded in administration) markets is notably on-going. The risk of taking one step forward and two steps, inadvertently backwards, should at least be noted.

For reasons mainly related to practicality and cost-effectiveness—and because the essential fixes required of the existing RCM within the price-based framework are not especially complex—we recommend staying within the RCM's price-based framework, *but fixing it*, rather than flipping the coin and starting over. That said, there is no reason why one could not first fix the RCM's price-based approach so that it works in a more robust, efficient and consistent manner and then, later, if desired, consider whether the coin should be flipped, and a quantity-based, auction approach developed, having regard for the effort required to do that well.

3. THE PROBLEMS THAT NEED TO BE ADDRESSED

In the course of our review of the RCM, we identified a number of issues and concerns that can be distilled into two simple, but fundamental, problems:

- Insufficient response to market conditions; and
- Distorted incentives.

In addition to these problems, some stakeholders have focussed on implications for costs. Cost implications, while clearly important, are not the fundamental problem that needs to be addressed, but rather are symptoms of the problem. To carry the medical analogy a bit further, we need first to diagnose and recommend the nature of the treatment required. The precise dosage and recovery plan can, if value is the main concern, be varied and/or managed through transition arrangements.

3.1. INSUFFICIENT RESPONSE TO MARKET CONDITIONS

A change in the amount of reserve capacity affects the economic value of capacity, *at the margin*. Therefore, it is the impact on the marginal value of capacity that we must focus to understand the level of response to market conditions currently reflected in the RC. The value of the last increment of capacity (the last MW) can be represented by the value "loss of load probability multiplied by the value of lost load" (LOLP * VOLL).

Given that VOLL is typically treated as a constant, the value of the marginal MW of capacity tends towards zero as a function of how quickly the LOLP goes to zero when more capacity is added. Mathematically, this LOLP-based value relationship is steep, much steeper than the relationship determined by the current RCM. It also only applies to the valuation of the marginal MW. If, for example, a block of capacity were to suddenly enter or exit the WEM, the LOLP-based valuation of the marginal MW could change dramatically. The steeper the curve, the more risk is introduced into the RCM.

3.1.1. Relationship among the elements in the RCP adjustment formula

Under the current RCM, the adjustment to the value of capacity through the RCP formula is about 1% for each 1% increase in the amount of excess reserve capacity. This price adjustment aspect of the RCP formula, however, is very much secondary in impact to the single upfront downward adjustment factor (85 percent) that is applied to the MRCP as a way to get the starting price (at zero percent excess reserve capacity) of a CC transacted through IMO.

The relationship between these elements can be seen in the RCP adjustment formula, which is expressed as follows:

RCP = (85% * MRCP) / (1 + %EXCESS)

For our purposes, we note that this formula can be interpreted mathematically as having an implied "SLOPE" coefficient and expressed either of two ways:

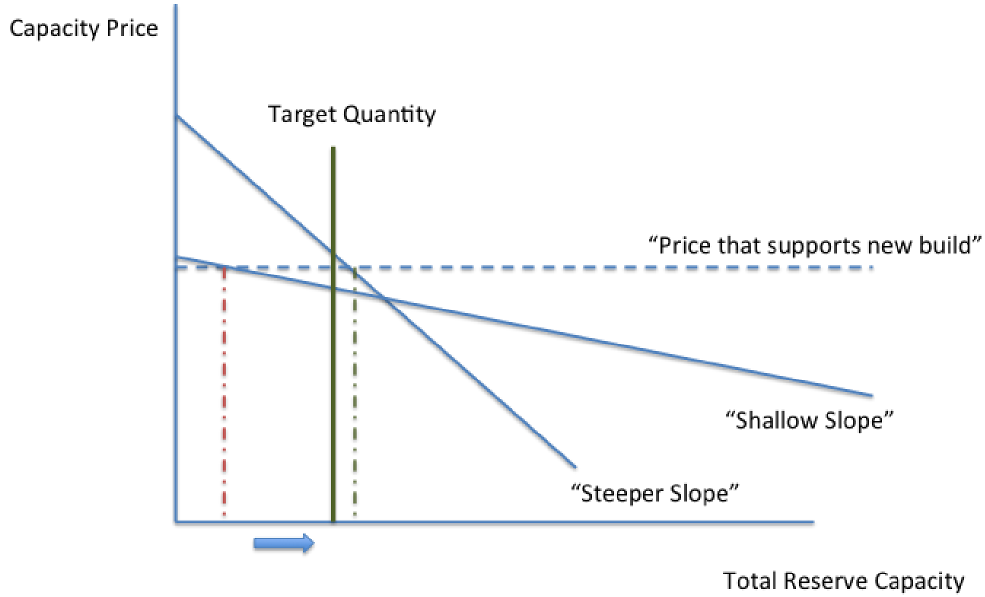
FORMULA 1 = (85% * MRCP) / (1 - (%EXCESS * SLOPE))

FORMULA 2 = (85% * MRCP) * (1 + %EXCESS) ^SLOPE

In both of these generalised formulae, the corresponding *current* value of the "SLOPE" term is minus one (-1). In either formula, if the slope is "-1", the result is the same. As the "slope" term is not explicitly stated in the current formula, one must decide which formula is to be used as a foundation for evaluating alternative parameter values.

A consequence of the choice of “-1 slope” is that uncontracted capacity, once it has entered the WEM, bears relatively modest incremental exposure to the amount of excess reserve capacity in the WEM—modest in comparison to what it would experience in an LOLP-based capacity valuation model.

With such a comparatively mild slope, the main impact on the economics of capacity provision is due to the 85 percent factor applied to the MRCP, a blunt and inflexible adjustment. Compared to a steeper slope, a shallow slope means that more excess reserve capacity must enter the WEM before the RCP falls low enough to cease to be a “build signal” when no capacity is needed. And, conversely, the amount of reserve capacity must fall further before the RCP rises to a level where it might support new investment (if it is able to rise high enough at all).



Now, the problem is not the 85 percent adjustment factor, per se, but that it applies *no matter what the extent of excess reserve capacity is.* If the reduction in the RCP caused by the 85 percent factor happens to be excessive then the IMO backstop may not support the presentation of sufficient capacity in the market when it is actually needed. If the reduction caused by the 85 percent factor happens to be too little, then too much capacity is likely to be presented.[6] In either case, the modest (-1) slope would be hard-pressed to make up for getting the 85 percent factor wrong.

Concern: Following the changes to the MRCP, it has not been established through observed outcomes or analysis that the current RCM with its -1 slope and revised (lower) MRCP in conjunction with the 85 percent adjustment factor can support investment if and when investment is needed.

6 Consider the case of the pre-revised MRCP. The 85 percent offset essentially equalizes the pre-adjusted MRCP with the revised MRCP, making it quite plausible that the pre-adjusted MRCP was high enough to support investment even after the application of the 85 percent factor.

A workable price-based framework must produce a price high enough to support investment in capacity resources when they are needed but that falls to a level at which additional investment is not viable when additional capacity resources are not needed. Within this simple framework, one needs to establish a maximum price that can robustly support investment if it is needed, and a slope that quickly shuts down an investment incentive when there is more reserve capacity than is required. The better approach therefore is to abolish the 85 percent adjustment factor and steepen the slope to provide a more dynamic price response. A steeper slope delivers a combination of price response and risk of price response. So a steeper slope will generally support less investment at *any* given price, as the price at any future point in time is more likely to be very different. Reducing such risks is an important role of bilateral contracts, which gain value as a sensible instrument between retailers and capacity providers as the slope is steepened.

Currently the MRCP is calculated as an expected cost of a reference technology. In order for it to be interpreted as a maximum price, one must make the assumption that other sources of capacity are available at prices below the MRCP. While this may be true in at least some instances, it is not tested or confirmed by a market requirement or process. In the absence of any basis to conclude otherwise, prudence dictates treating the MRCP as the best estimate of the (reasonably unconstrained) long-run cost of capacity.

As such, the use of the MRCP in the RCP formula faces two challenges. First, as already noted, that the MRCP is immediately adjusted downward through the arbitrary 85 percent factor. Second that the RCP is adjusted further downward on account of any excess reserve capacity that exists. Given the definition and calculation of the MRCP, it should be a concern that the current RCP formulation provides no investment support signal unless capacity resources can be developed commercially at a cost no higher than 85 percent of the MRCP minus any adjustment required for the risk and cost of shared capacity.

Concern: When comparing the slope without the 85 percent set off, it will naturally appear that the proposed RCP be "higher" than it would be under the current regime. However, with the changes to the MRCP methodology, it is prudent to consider that the investment that occurred before was driven by expectations of an RCP derived from the old MRCP definition rather than from an RCP derived from the revised MRCP definition. We note an absence of evidence that investment will take place at the lower RCP levels associated with the current RCM given the significant reduction in the MRCP that has taken place.

Looking forward, prudence suggests concern that incentives and responses will now be different.

3.1.2. Summary of issues related to market responsiveness

A workable "price-based" capacity market – one in which a price formula is the predominant means with which to incentivise the presentation of sufficient capacity—could incorporate a slope as steep as the LOLP function. Such a very steep function would transmit considerable financial risk—almost certainly more than any other single aspect of the WEM design. And yet, the full measure of such risk is not necessary to achieve the more practical and sustainable objective: ultimately, the price of capacity does not need to go to zero to stop investors from investing; and it does not have to go to infinity to start them up.

As the slope "steepens" the sensitivity of the RCP to market conditions, including those caused by exogenous factors or government policies, increases; consequently, so too does the value risk to capacity resource suppliers and demanders. The steepness of the administrative relationship (whether it be the demand curve in an auction format or the price-curve in the RCM) is ultimately a parameter that must be chosen through judgement. It can then later be reviewed in due course as experience and market sophistication and conditions require.

Concern: The choice of "slope" needs to be effective at aligning investment behaviour with market conditions. The slope also has value management implications – a steeper slope will impose greater near-term value reduction on capacity resource providers who are uncontracted and a corresponding benefit to retailers. A shallower slope is unlikely to provide sufficient market responsiveness consistent with the Market Objectives. These concerns need to be acknowledged and addressed in a balanced way, potentially with a transition mechanism.

3.2. DISTORTED INCENTIVES

The current RCM exposes retailers to the cost of shared capacity. Shared capacity is capacity that exceeds the RCR. If the RCM works efficiently, an increase in shared capacity costs is mitigated substantially by reductions in the RCP such that as the amount of shared capacity exposure increases, the RCP falls enough to drop below the point where building new reserve capacity is economic.

Observation: The RCP provides a pseudo-maximum cost to a retailer of reserve capacity. If capacity resources are competitively supplied, bilateral contracts may be available at costs below the RCP. Retailers should have an incentive to contract for capacity below the RCP – an incentive that should increase as the amount of excess reserve capacity reduces.

The costs associated with shared capacity can affect risk management and investment decisions, however. So, it is important to ensure that the incentives to reduce shared capacity costs are tuned to market conditions. This dynamic interaction forms the basis of a self-correcting system. The more dynamically and effectively the system self-corrects, the lower the long-term cost of shared capacity will be, the less persistent excess reserve capacity will exist, and the better the Market Objectives related to longer term sustainability and efficient costs can be achieved.

It should be noted, however, that *any* robust price-based system designed to assure the delivery of sufficient capacity to meet a fixed RCR either will:

- require exposure to a special "mega risk" to incentivise retailers and capacity resource suppliers to bilaterally contract and avoid reliance on the RCP backstop;
- naturally attract and support some irreducible level of excess capacity;
- naturally require the use of further backstop arrangements because the basic RCP backstop will fail to support sufficient capacity, leaving a gap to be filled; or
- require a reconsideration of the minimum RCR below a target RCR such that any "persistent excess" merely moves the expected capacity level in line with the target RCR.

Below we consider what happens under the two main extremes of increasing shared capacity costs and decreasing shared capacity costs. The RCM must function effectively under both scenarios.

3.2.1. What happens when shared capacity costs are *increasing?*

In the case of increasing shared capacity costs (implying increasing excess reserve capacity), the best general response for the retailer is, quite reasonably, to cease entering into bilateral contracts for capacity resources. The current RCM achieves this result by setting the RCP as a function of the amount of excess reserve capacity. Thus, by not contracting when there is excess reserve capacity, the cost of uncontracted capacity credits is scaled down under the RCP formula based on the amount of excess reserve capacity that exists.

In the case of increasing shared capacity cost, this response is structurally and directionally normal. If the RCP is being adjusted downward, and retailers have no other incentive to enter into bilateral contracts, then resource providers are going to be less inclined to offer new capacity resources to the WEM. Clearly, shared capacity costs are linked to the responsiveness of the RCP to market conditions.

3.2.2. What happens when shared capacity costs are *decreasing?*

As excess reserve capacity reduces, the prospective need for new investment increases. We therefore consider what happens to investment incentives.

To analyse this issue, we define a metric called the cost-per-targeted-capacity-credit (CPTCC)—this metric represents the total cost borne by retailers for a given level of excess reserve capacity (including shared capacity cost) divided by the RCR. We then calculate the impact on retailer cost of various combinations of excess reserve capacity (as measured in percentage terms relative to the RCR) and bilateral contract coverage (as measured in percentage terms relative to the RCR).

The CPTCC is shown in three scenarios. The first assumes that bilateral contracts are available at 100 percent of the MRCP. The second assumes that bilateral contracts are available at 85 percent of the MRCP. The third adopts a quasi-middle position in which bilateral contracts are available, on average, at a cost of 90 percent of the MRCP.[7] The colour coding highlights relatively lower values in a tint of green and relatively higher values in a tint of red. Note that in each scenario, the lower values are *always* towards the left. Under the current RCM, the cost to a retailer per *targeted* capacity credit reduces the lower the level of bilateral contracting exists in the market—all the way to the point where there is no bilateral contracting, at which point the cost per targeted capacity credit is maintained at a constant through the workings of the RCP price adjustment formula.

Table 1: Cost per Targeted Capacity Credit (100% MRCP) – CURRENT RCM

Cost per targeted capacity credit (CURRENT)

% EXCESS RESERVE CAPACITY	BILATERAL CONTRACT COVER (%)										
	0	10	20	30	40	50	60	70	80	90	100
0	139,315	141,774	144,232	146,691	149,149	151,608	154,066	156,525	158,983	161,442	163,900
1	139,315	141,911	144,508	147,104	149,701	152,297	154,894	157,490	160,086	162,683	165,279
2	139,315	142,047	144,778	147,510	150,242	152,973	155,705	158,437	161,168	163,900	166,632
3	139,315	142,179	145,044	147,908	150,772	153,636	156,501	159,365	162,229	165,093	167,958
4	139,315	142,309	145,304	148,298	151,292	154,287	157,281	160,275	163,270	166,264	169,258
5	139,315	142,437	145,559	148,681	151,803	154,925	158,046	161,168	164,290	167,412	170,534
6	139,315	142,562	145,809	149,056	152,303	155,550	158,797	162,045	165,292	168,539	171,786
7	139,315	142,685	146,055	149,425	152,795	156,165	159,534	162,904	166,274	169,644	173,014
8	139,315	142,805	146,296	149,786	153,277	156,767	160,258	163,748	167,239	170,729	174,220
9	139,315	142,924	146,533	150,141	153,750	157,359	160,968	164,577	168,185	171,794	175,403
10	139,315	143,040	146,765	150,490	154,215	157,940	161,665	165,390	169,115	172,840	176,565
11	139,315	143,154	146,993	150,832	154,671	158,510	162,350	166,189	170,028	173,867	177,706
12	139,315	143,266	147,217	151,168	155,120	159,071	163,022	166,973	170,924	174,875	178,827
13	139,315	143,376	147,437	151,499	155,560	159,621	163,682	167,744	171,805	175,866	179,927
14	139,315	143,484	147,654	151,823	155,993	160,162	164,331	168,501	172,670	176,839	181,009
15	139,315	143,591	147,866	152,142	156,418	160,693	164,969	169,245	173,520	177,796	182,072
16	139,315	143,695	148,075	152,455	156,835	161,215	165,596	169,976	174,356	178,736	183,116
17	139,315	143,798	148,280	152,763	157,246	161,729	166,211	170,694	175,177	179,660	184,142
18	139,315	143,899	148,482	153,066	157,650	162,233	166,817	171,401	175,984	180,568	185,151
19	139,315	143,998	148,681	153,364	158,046	162,729	167,412	172,095	176,778	181,461	186,144
20	139,315	144,095	148,876	153,656	158,437	163,217	167,998	172,778	177,558	182,339	187,119
MAX	139,315	144,095	148,876	153,656	158,437	163,217	167,998	172,778	177,558	182,339	187,119
MIN	139,315	141,774	144,232	146,691	149,149	151,608	154,066	156,525	158,983	161,442	163,900

Table 2: Cost per Targeted Capacity Credit (85% MRCP) – CURRENT RCM

Cost per targeted capacity credit (CURRENT)

% EXCESS RESERVE CAPACITY	BILATERAL CONTRACT COVER (%)										
	0	10	20	30	40	50	60	70	80	90	100
0	139,315	139,315	139,315	139,315	139,315	139,315	139,315	139,315	139,315	139,315	139,315
1	139,315	139,453	139,591	139,729	139,867	140,005	140,143	140,281	140,418	140,556	140,694
2	139,315	139,588	139,861	140,135	140,408	140,681	140,954	141,227	141,500	141,774	142,047
3	139,315	139,721	140,127	140,532	140,938	141,344	141,750	142,155	142,561	142,967	143,373
4	139,315	139,851	140,387	140,922	141,458	141,994	142,530	143,066	143,602	144,137	144,673
5	139,315	139,978	140,642	141,305	141,969	142,632	143,295	143,959	144,622	145,286	145,949
6	139,315	140,104	140,892	141,681	142,469	143,258	144,046	144,835	145,624	146,412	147,201
7	139,315	140,226	141,138	142,049	142,961	143,872	144,783	145,695	146,606	147,518	148,429
8	139,315	140,347	141,379	142,411	143,443	144,475	145,507	146,539	147,571	148,603	149,635
9	139,315	140,465	141,616	142,766	143,916	145,067	146,217	147,367	148,517	149,668	150,818
10	139,315	140,582	141,848	143,115	144,381	145,648	146,914	148,181	149,447	150,714	151,980
11	139,315	140,696	142,076	143,457	144,837	146,218	147,599	148,979	150,360	151,740	153,121
12	139,315	140,808	142,300	143,793	145,286	146,778	148,271	149,764	151,256	152,749	154,242
13	139,315	140,918	142,520	144,123	145,726	147,329	148,931	150,534	152,137	153,740	155,342
14	139,315	141,026	142,737	144,448	146,159	147,869	149,580	151,291	153,002	154,713	156,424
15	139,315	141,132	142,949	144,766	146,584	148,401	150,218	152,035	153,852	155,669	157,487
16	139,315	141,237	143,158	145,080	147,001	148,923	150,845	152,766	154,688	156,609	158,531
17	139,315	141,339	143,363	145,388	147,412	149,436	151,460	153,485	155,509	157,533	159,557
18	139,315	141,440	143,565	145,690	147,816	149,941	152,066	154,191	156,316	158,441	160,566
19	139,315	141,539	143,764	145,988	148,212	150,437	152,661	154,886	157,110	159,334	161,559
20	139,315	141,637	143,959	146,281	148,603	150,925	153,247	155,568	157,890	160,212	162,534
MAX	139,315	141,637	143,959	146,281	148,603	150,925	153,247	155,568	157,890	160,212	162,534
MIN	139,315	139,315	139,315	139,315	139,315	139,315	139,315	139,315	139,315	139,315	139,315

7 Experience in some markets, like PJM, as well as in the WEM, suggests that contracts can be available at less than the price cap level if supply is competitive and a diversity of possible capacity resources are able to be developed.

Table 3: Cost per Targeted Capacity Credit (90% MRCP) – CURRENT RCM

Cost per targeted capacity credit (CURRENT)

% EXCESS RESERVE CAPACITY	BILATERAL CONTRACT COVER (%) 0	10	20	30	40	50	60	70	80	90	100
0	139,315	140,135	140,954	141,774	142,593	143,413	144,232	145,052	145,871	146,691	147,510
1	139,315	140,272	141,230	142,187	143,145	144,102	145,060	146,017	146,974	147,932	148,889
2	139,315	140,408	141,500	142,593	143,686	144,778	145,871	146,964	148,056	149,149	150,242
3	139,315	140,540	141,766	142,991	144,216	145,441	146,667	147,892	149,117	150,342	151,568
4	139,315	140,670	142,026	143,381	144,736	146,092	147,447	148,802	150,158	151,513	152,868
5	139,315	140,798	142,281	143,764	145,247	146,730	148,212	149,695	151,178	152,661	154,144
6	139,315	140,923	142,531	144,139	145,747	147,355	148,963	150,572	152,180	153,788	155,396
7	139,315	141,046	142,777	144,508	146,239	147,970	149,700	151,431	153,162	154,893	156,624
8	139,315	141,166	143,018	144,869	146,721	148,572	150,424	152,275	154,127	155,978	157,830
9	139,315	141,285	143,255	145,224	147,194	149,164	151,134	153,104	155,073	157,043	159,013
10	139,315	141,401	143,487	145,573	147,659	149,745	151,831	153,917	156,003	158,089	160,175
11	139,315	141,515	143,715	145,915	148,115	150,315	152,516	154,716	156,916	159,116	161,316
12	139,315	141,627	143,939	146,251	148,564	150,876	153,188	155,500	157,812	160,124	162,437
13	139,315	141,737	144,159	146,582	149,004	151,426	153,848	156,271	158,693	161,115	163,537
14	139,315	141,845	144,376	146,906	149,437	151,967	154,497	157,028	159,558	162,088	164,619
15	139,315	141,952	144,588	147,225	149,862	152,498	155,135	157,772	160,408	163,045	165,682
16	139,315	142,056	144,797	147,538	150,279	153,020	155,762	158,503	161,244	163,985	166,726
17	139,315	142,159	145,002	147,846	150,690	153,534	156,377	159,221	162,065	164,909	167,752
18	139,315	142,260	145,204	148,149	151,094	154,038	156,983	159,928	162,872	165,817	168,761
19	139,315	142,359	145,403	148,447	151,490	154,534	157,578	160,622	163,666	166,710	169,754
20	139,315	142,456	145,598	148,739	151,881	155,022	158,164	161,305	164,446	167,588	170,729
MAX	139,315	142,456	145,598	148,739	151,881	155,022	158,164	161,305	164,446	167,588	170,729
MIN	139,315	140,135	140,954	141,774	142,593	143,413	144,232	145,052	145,871	146,691	147,510

The leftmost column of each table depicts a WEM in which there are no bilateral contracts. In the leftmost column, all credits are transacted through the IMO. The price of each credit is determined by the RCP, which "corrects" for the amount of excess reserve capacity through the application of the -1 "slope". The cost per targeted capacity credit is always 85% of the MRCP if the level of bilateral contracting is zero. That is, retailers have no exposure to shared capacity costs if no bilateral contracts exist in the WEM.

The rightmost column depicts a WEM in which all required credits are procured through bilateral contracts. In these columns, the cost per targeted capacity credit increases as the amount of excess reserve capacity increases due to the burden associated with the cost of shared capacity. In the rightmost column, the burden of shared capacity costs is maximised.

In the extreme, if all credits were bought and sold through the IMO, the amount of excess reserve capacity would not affect the average cost to the retailer of the targeted amount of capacity resources required. In effect, no matter how much reserve capacity exists, retailers would pay $139,315, which is 85 percent of the MRCP. Any higher level of contracting leads to an assignment of any shared capacity costs. If this situation is possible, then retailers are better off, all else equal, mitigating their exposure to reserve capacity-related financial risks by not contracting—no matter what level of excess reserve capacity exists, whether it be 20 percent or 1 percent.

The risk exposure is completely different for capacity resource providers, however. In the first instance, capacity resource providers would earn, at best, 85 percent of the MRCP. But they would also bear 100 percent of any exposure to excess reserve capacity costs in the event of a demand forecast revision or government policy change that affects the amount of supply or demand in the WEM.

Concern: Two obvious questions arising in these circumstances: (1) why a retailer would seek to contract under plausible market conditions, even in the event of looming shortage; and (2) why potential investors would invest, particularly in capacity resources that depend crucially on capacity credit values.

It may be possible to develop idiosyncratic scenarios in which an investment and contracting incentive might exist—future capacity costs could be expected to increase dramatically, offering an opportunity to contract ahead and lock in something cheaper. Goodwill and political pressure may cause some degree of contracting, given government ownership and control of significant retail and capacity resources in the WEM. But these are hardly sufficient to constitute a passing grade for an RCM that needs to work with reasonable effectiveness across a wide range of market conditions.

This unbalanced risk exposure creates several distortions in the RCM. First, it will inevitably impact the market's ability to support capacity resources that require larger proportions of capital investment, as these are most commercially sensitive to the availability of longer-term contracts. Second, it can promote opportunistic capacity resource supply by resources that do not require long-term contracts, but in turn, may not offer the same degree of long-term certainty of commitment. And finally, it places significant pressure on the performance of other, heretofore untested and late stage, backstop features of the WEM.

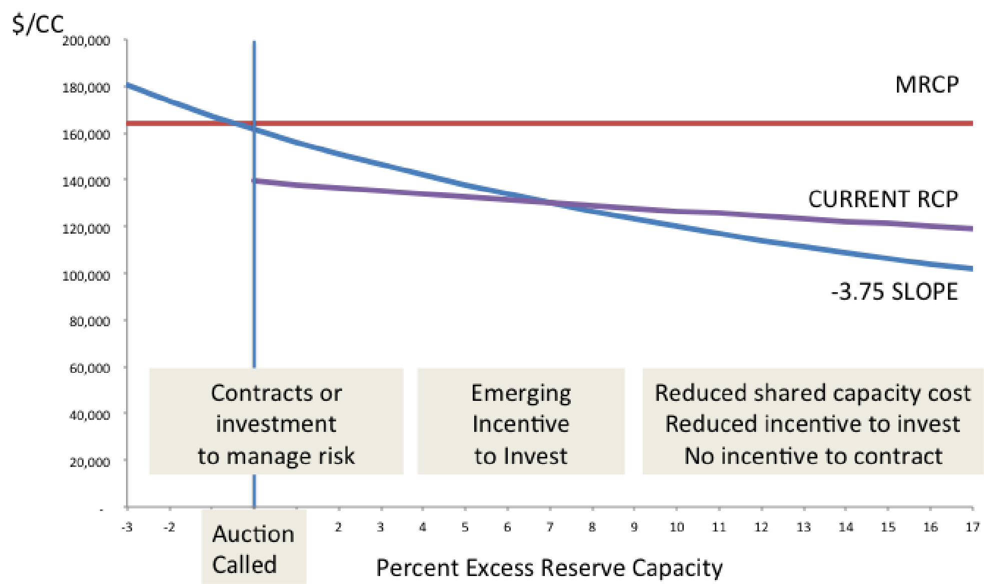
3.3. RECOMMENDATION

A price-base mechanism needs to cover a wide enough range of prices to ensure that capacity will be provided that is needed and not if not needed. We are concerned that planned reliance on a simple quantity-based or auction framework will yield unintended consequence or require extensive changes to make the framework achieve what is intended. By focussing on making the RCM a price-based mechanism, similar market incentives are possible. To the extent that stakeholders wish to see different value outcomes related to the cost of shared capacity, specific slope settings can achieve this, but transition arrangements may be necessary for equity.

With that in mind, the following recommended changes to the RCM are discussed below:

- First, the 85 percent discount factor applied to the MRCP should be removed;
- Second, in order to ensure the existence of a timely investment incentive as the amount of excess reserve capacity reduces, the maximum RCP should be allowed to exceed the MRCP (or the MRCP should be redefined to include a margin over the reasonably estimated cost of new capacity). A maximum RCP that is 10 percent higher than the currently estimated MRCP is advised.
- Third, the price slope should be steep enough to substantially mitigate the cost of shared capacity and the risk of investment in capacity resources that are not needed. Having regard to the proposed recycling treatment of refund regime revenues and noting that the RCP will be higher under lower reserve capacity levels than it would otherwise have been, the recommended slope is -3.75.

- Fourth, modify the price formula to use an offset RCR, which reflects 97 percent of the actual RCR. This adjustment, in combination with the adjustment made to the maximum RCP, ensures a stronger incentive to avoid shortage, and would result in an additional cost to retailers for any uncontracted capacity in the event that an auction must be called to support capacity investment. Uncontracted capacity resources that exist at the time an auction is called would be compensated at a rate of MRCP up to 110% of the MRCP, which could also become the auction price cap in a reserve capacity auction, if required.



The recommendations above would qualify for the application of an implementation transition path. For the next two years, the RCP has already been set and cannot be changed. Therefore a transition could be considered over a two to three year time frame. A transition period to implement these changes may be justified to accommodate the initial value shock associated with introducing the steeper proposed slope.

These settings are evaluated in the table below. The arrows show the underlying tendency or incentive regarding the level of bilateral contracting.

Table 4: Cost per targeted capacity credit (proposed)

Cost per targeted capacity credit (ALTERNATIVE)

% EXCESS RESERVE	BILATERAL CONTRACT COVER (%) 0	10	20	30	40	50	60	70	80	90	100
-3	180,044	176,864	173,685	170,505	167,326	164,146	160,966	157,787	154,607	151,427	148,248
-2	173,675	171,127	168,580	166,032	163,485	160,937	158,389	155,842	153,294	150,747	148,199
-1	167,693	165,733	163,773	161,814	159,854	157,895	[illegible]	153,976	152,016	150,057	148,097
0	162,058	160,647	159,236	157,825	[illegible]	[illegible]	[illegible]	152,180	150,769	149,358	147,946
1	158,342	157,443	156,544	155,646	[illegible]	[illegible]	[illegible]	152,051	151,153	150,254	149,356
2	154,860	154,441	154,023	153,604	[illegible]	[illegible]	[illegible]	151,931	151,513	151,094	150,676
3	151,591	151,623	151,656	151,688	151,721	151,753	[illegible]	151,818	151,850	151,883	151,915
4	148,516	148,973	149,429	149,886	150,342	150,799	151,255	151,712	152,168	152,624	153,081
5	145,619	146,475	147,331	148,187	149,043	149,899	150,755	151,611	152,467	153,323	154,179
6	142,884	144,117	145,351	146,584	147,817	149,050	150,283	151,517	152,750	153,983	155,216
7	140,298	141,888	143,478	145,068	146,658	148,248	149,837	151,427	153,017	154,607	156,197
8	137,850	139,778	141,705	143,633	145,560	147,488	149,415	151,343	153,270	155,197	157,125
9	135,528	137,776	140,024	142,271	144,519	146,767	149,014	151,262	153,510	155,758	158,005
10	133,324	135,875	138,427	[illegible]	143,531	146,082	148,634	151,186	153,738	156,289	158,841
11	131,227	134,068	136,909	[illegible]	[illegible]	[illegible]	148,273	151,113	153,954	156,795	159,636
12	129,232	132,348	135,464	[illegible]	[illegible]	[illegible]	147,928	151,044	154,160	157,276	160,393
13	127,330	130,708	134,087	[illegible]	[illegible]	[illegible]	147,600	150,979	154,357	157,735	161,114
14	125,515	129,144	132,772	[illegible]	140,030	143,658	147,287	150,916	154,544	158,173	161,802
15	123,781	127,649	131,517	135,385	139,252	143,120	146,988	150,856	154,724	158,591	162,459
16	122,123	126,220	130,316	134,413	138,509	142,606	146,702	150,798	154,895	158,991	163,088
17	120,537	124,852	129,167	133,483	137,798	142,113	146,428	150,744	155,059	159,374	163,689
MAX	180,044	176,864	173,685	170,505	167,326	164,146	160,966	157,787	155,059	159,374	163,689
MIN	120,537	124,852	129,167	133,483	137,798	142,113	146,428	150,744	150,769	149,358	147,946

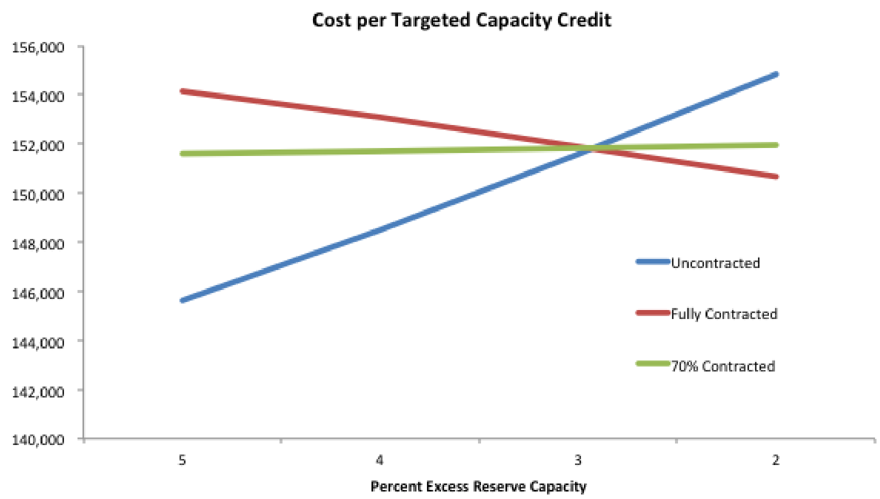
In the table above, quite logically, when there is significant excess reserve capacity, the incentive to contract is very low / non-existent. In general, new capacity resources must offer ever more significant cost savings or other benefits if they are to be commercially viable when there is *already* excess reserve capacity in the RCM.

As the level of excess reserve capacity falls the relative value of contracts increases– ultimately depending on the value offered by capacity resources. With the steeper slope mitigating shared capacity costs, and the higher risk associated with shortage, contracting strategies emerge. It is also important to compare the horizontal value spread associated with contracting to the vertical value spread arising from uncertainty in future load forecast levels. For example, we estimate the annual standard deviation of forecast revision three years ahead of out-turn is on the order of four percentage points, a non-trivial risk to be managed.[8]

For comparison, therefore, a three percent reduction in excess reserve capacity without bilateral contracting would lead to an increase in cost per targeted capacity credit from $145,619 at five percent excess reserve capacity up to $154,860 at two percent excess. In contrast, at full bilateral contracting, the spread from five percent excess reserve capacity down to two percent excess reserve capacity runs from $154,179 down to $150,676, whereas at 70 percent contracting there is nary much change over the whole range from the retailer's perspective. The manageability of cost exposure through contracts does not exist given similar assumptions under the current RCM. And, unlike the current RCM, such strategies benefit both retailers and capacity resource providers, and, thus, the market overall.

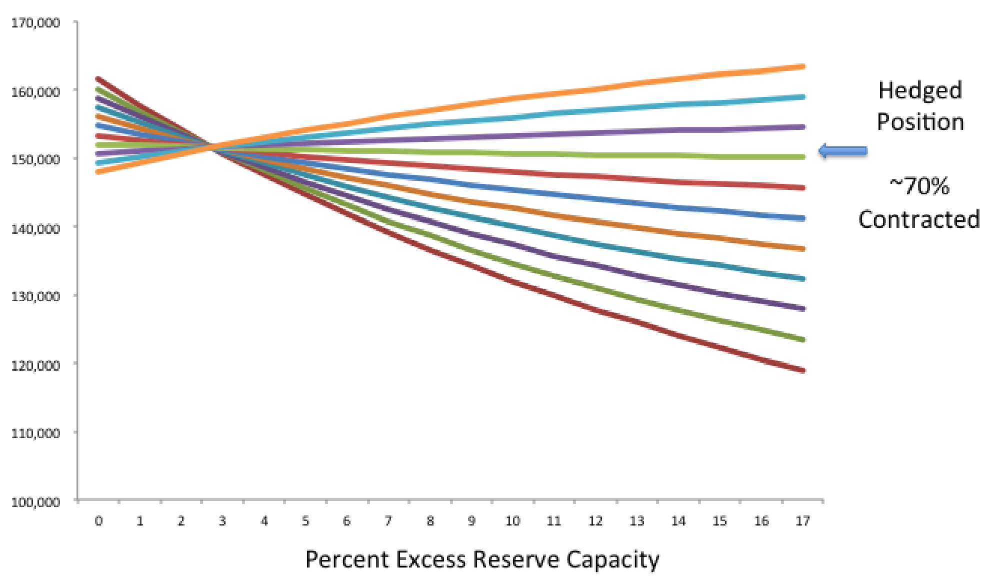
Figure 3: Contracting Strategies

8 See brief appendix.



Indeed, at a level of 70 percent bilateral contracting, the retailer's cost per targeted capacity credit is essentially hedged across a full range of excess reserve capacity levels, as shown below.

Figure 4: Cost per Targeted Capacity Credit at different contract and excess levels



3.4. Simulation

We developed an RCM simulator, attached as an Excel model to this memorandum. With the simulator it is possible to vary a range of inputs and compare the outcomes from an alternative scenario to both the current RCM and to what would be the case in the event of a "perfect" matching of reserve capacity to the RCR (i.e., no excess).

The initial settings are as follows:

- Excess reserve capacity: set at 15%. Sensitivity analysis can be conducted across a wide range, of course.

- Slope: set at -3.75

- RCR "offset" – set at 97% of the RCR. The offset is used to determine the amount of excess reserve capacity in the revised RCP formula.

- RCR – The RCR is used to determine if the RCM requires activation of backstop arrangements (such the current reserve capacity auction).

- INTERCEPT is 110% of the MRCP. The INTERCEPT is used in the revised RCP formula. It yields an RCP that can be as much as 10% above the MRCP in the event that the number of capacity credits equals the RCR_offset value (i.e. in the event that the number of credits is 97% of the RCR). For example, if the RCR is 5,308, then the offset_RCR is 97% of the RCR or 5,149. The RCP at a credit level of 5,149 would be 110% of the MRCP. The RCP would then fall of (at the slope rate) to the extent that the higher RCP level exceeds the cost of providing capacity resources.

- Bilateral contract cover is set at 50%. A lower value would increase the sensitivity of outcomes to the RCP adjustment formula. A higher value would increase exposure to shared capacity costs. The 50% value corresponds, roughly, to current levels, for the sake of evaluating potential transition impacts.

- The expected bilateral contract price is set at 90% of the MRCP. This value is arbitrary and depends on perceptions of the amount of capacity resource that can be competitively procured at prices less than the MRCP.

- Formula: Formula 1 is used in the examples. Formula 2 is an alternative form that produces lower values under more extreme levels of excess reserve capacity.

The settings are shown in the snapshot of the summary control panel below.

RCM SIMULATOR		INPUTS	SCENARIOS: ALTERNATIVE	SCENARIOS: REFERENCE	SCENARIOS: CURRENT
Excess Capacity [EC%]	%	15.0	18.0%	0.0%	15.0%
Market Share	%	100	100.0%	100.0%	100.0%
Bilateral_Contract Cover	%	50	50.0%	50.0%	50.0%
SLOPE FACTOR (000s)		-3.75	-3.75		-1.00
IMO MRCP SCALING FACTOR (%)	%	110	110.0%		85.0%
Reserve Capacity Requirement [RCR]	MW	5308	5308	5308	5308
RCR % Offset (for alternative scenarios only)	%	97.0%			
OFFSET RCR			5149		
Credited Capacity [CC]	MW		6,104	5,308	6,104
Excess Capacity [EC]	MW		955	0	796
Retailer_IRCR	MW		5,149	5,308	5,308
Bilateral_Contract_Cover	MW		2,574	2,654	2,654
Shortage_of_IRCR Cover MW	MW		2,574	2,654	2,654
Retailer's Shared_Capacity MW	MW		955	0	796
Average Expected Bilateral Contract Price as a % of MRCP		90%	147,510	147,510	147,510
Maximum Reserve Capacity Price (MRCP)	$/MW	163900	163,900	163,900	163,900
Reserve Capacity Price (RCP)	$/MW	1	107,636	163,900	121,143
		Formula 1	107,636		121,143
		Formula 2	96,920		121,143
Assumed cost of bilateral capacity	$/MW		379,746,794	391,491,540	391,491,540
Cost of Targeted Capacity from IMO	$/MW		277,095,505	434,990,600	321,514,791
Cost of Shared Capacity from IMO	$/MW		102,839,569	0	96,454,437
Total Cost ($)			$ 759,681,867	$ 826,482,140	$ 809,460,769
Average Cost per Targetted CC ($)			$ 143,120	$ 155,705	$ 152,498
Average Cost per Targetted CC as % of MRCP (%)			87%	95%	93%
age Cost per Targetted CC as % of Assumed Average Bilateral Contract Price (%)			97%	106%	103%
Credits above target (#)			796	0	796
Implied cost of each credit in excess of target (relative to no excess case) ($)			$ (83,899)		$ (21,378)
Percent of MRCP (%)			-51%		-13%
Relative cost to REFERENCE no excess case ($)			$ (66,800,273)		$ (17,021,371)
Relative cost to REFERENCE no excess case (%)			-8.082%		
Relative cost to CURRENT RCM ($)			$ (49,778,902)	$ 17,021,371	$ -
Relative cost to CURRENT RCM (%)			-6.1%	2.1%	0.0%

The resulting calculations show that under the Current RCM these various settings yield a total cost of $809,460,769, or an average cost per targeted capacity credit of $152,498.

Under the alternative RCM settings noted above, the total cost would be $759,681,867. The average cost per targeted capacity credit is correspondingly lower, at $143,120. This result obtains because of the steeper slope of -3.75, even though the 85% factor has been removed from the RCP adjustment formula.

Note that this value is also below the assumed cost of the "no excess" scenario, as well. Unless capacity credits are bilaterally contracted, they are exposed to the change in the RCP as the amount of excess reserve capacity increases. While it might be the case that, in economics, the *incremental* value of a capacity credit (in economic terms) can be nearly zero due to an extreme material excess supply, it would be utterly nonsensical to declare that consumers derive zero value from the collective body of capacity that stands behind the credits. The "no-excess" scenario is therefore included as a reference and reality check on value management concerns.

3.5. ADDITIONAL COMMENTS

If the slope were to be steepened further, value impacts increase significantly. Note that the values below are before any consideration of recycling of capacity refund revenue, which currently constitutes approximately 2.5 percent of total capacity value.

Table 5: Percent savings relative to current RCM[9]
(50 percent bilateral contracting)

	Excess Reserve Capacity Percent		
Slope	5.0	10.0	15.0
-3.25	3.9%	-0.2%	-3.5%
-3.50	3.0%	-1.3%	-4.9%
-3.75	2.2%	-2.4%	-6.1%
-4.00	1.4%	-3.5%	-7.4%
-4.25	0.6%	-4.5%	-8.5%

Table 6: Percent savings relative to current RCM[10]
(40 percent bilateral contracting)

	Excess Reserve Capacity Percent		
Slope	5.0	10.0	15.0
-3.25	4.6%	-0.1%	-4.0%
-3.50	3.6%	-1.5%	-5.6%
-3.75	2.6%	-2.8%	-7.1%
-4.00	1.7%	-4.0%	-8.5%
-4.25	0.7%	-5.2%	-9.9%

Table 7: Percent savings relative to current RCM[11]
(60 percent bilateral contracting)

	Excess Reserve Capacity Percent		
Slope	5.0	10.0	15.0
-3.25	3.1%	-0.2%	-3.0%
-3.50	2.4%	-1.2%	-4.2%
-3.75	1.7%	-2.1%	-5.3%
-4.00	1.1%	-3.0%	-6.3%
-4.25	0.4%	-3.8%	-7.3%

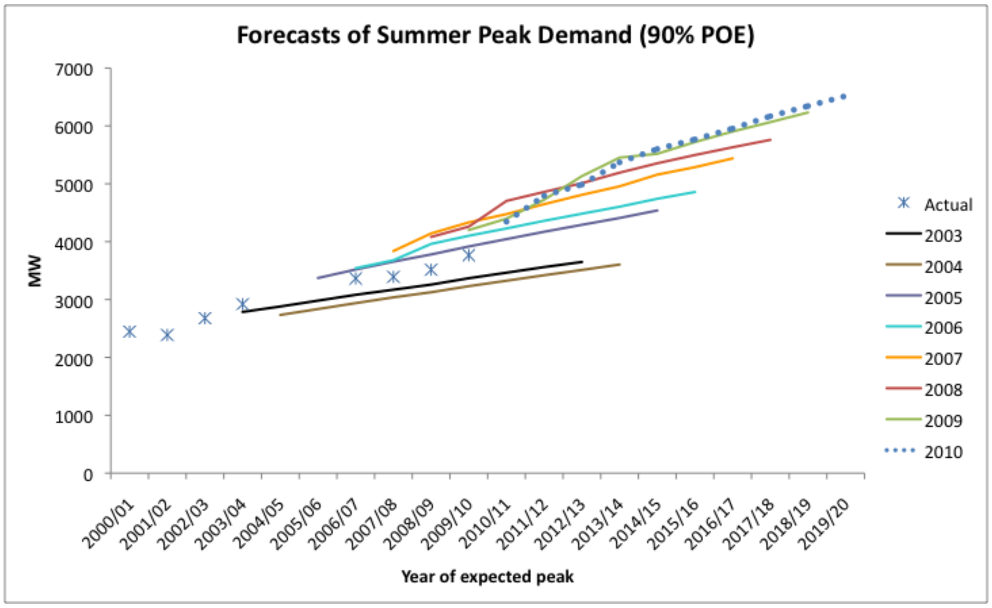
9 Key assumptions: 50% contracting level maintained throughout; bilateral contracts are valued at 90% of the MRCP value. Proposed regime includes: 97% RCR offset and 110% maximum RCP.

10 Key assumptions: 40% contracting level maintained throughout; bilateral contracts are valued at 90% of the MRCP value. Proposed regime includes: 97% RCR offset and 110% maximum RCP.

11 Key assumptions: 60% contracting level maintained throughout; bilateral contracts are valued at 90% of the MRCP value. Proposed regime includes: 97% RCR offset and 110% maximum RCP.

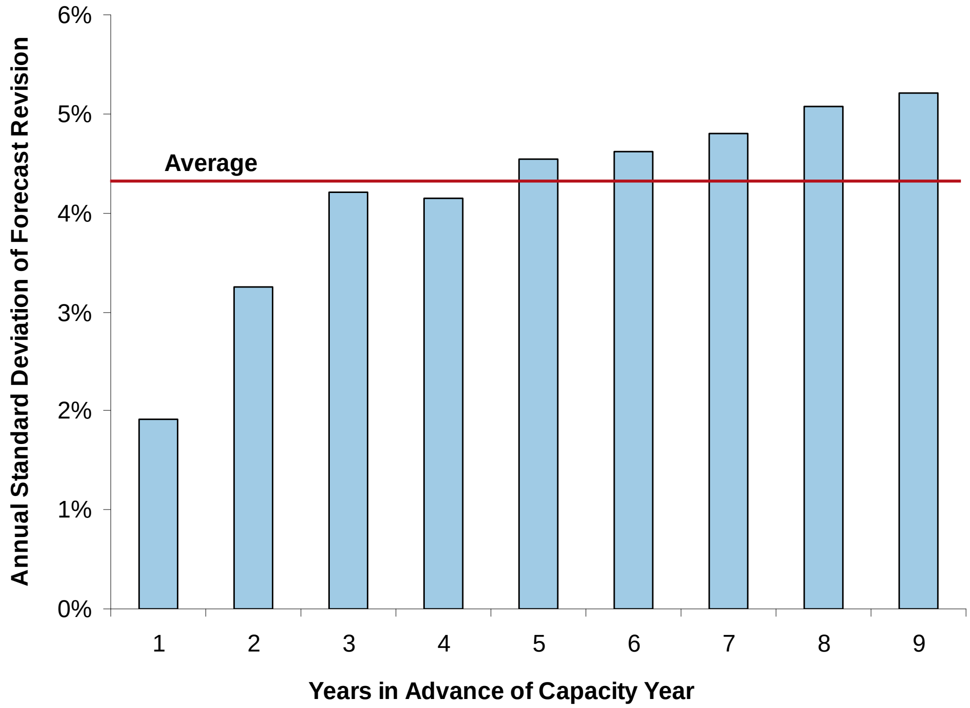
4. APPENDIX: FORECAST UNCERTAINTY

The steepness of the RCP formula is a source of commercial risk to both capacity resource suppliers and resource demanders. Forecast uncertainty accounts for several percentage points of uncertainty in the level of excess reserve capacity over time.



After considering the forecast error in successive annual demand forecasts, we calculated the standard deviation of the magnitude of the forecast revision as the year of the forecast approaches the actual Capacity Year. Figure 5 shows the standard deviations of these forecast revisions over the forecast horizon for the 10 percent POE forecast assuming mean economic growth. Note that the successive revisions get smaller as the forecast year nears the Capacity Year. Based on historical experience, we can expect a forecast made two years ahead to move up or down by about three percent in the next year and another two percent in the following year.

Figure 5: Standard deviation of forecast revision (10 percent POE)



As a result, it is easily seen how additional “steepness” increases commercial risk.

Appendix 2 - Projection of future supply and demand

Demand

The projection of future demand is based on the following assumptions.

- The initial peak demand forecasts have been taken from the 2012 SOO.
- These peak demand forecasts have been reduced to allow for contribution of industrial/commercial PV. This contribution has been estimated to be equal to the residential PV forecast with a 3-year delay.

Capacity Year	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Peak demand reduction (MW)	30	48	60	72	84	96	107

- The Reserve Capacity Requirement (RCR) has then been calculated from the reduced peak demand forecasts on the basis of a 7.6% reserve margin, consistent with the recommendations from the review of the Planning Criterion.

Capacity Year	2015/16	2016/17	2017/18	2018/19	2019/20
Reserve Capacity Requirement (MW)	5378	5569	5728	5859	6007

Supply

The projection of future supply is based on the following assumptions.

- The capacity allocated to existing Intermittent Generators reduces by 11 MW and 9 MW in 2015/16 and 2016/17 respectively, as a result of the transition path implemented in Rule Change RC_2010_25.
- A one-off reduction in DSM capacity of 20% (105 MW) occurs in 2015/16 as a result of the harmonisation proposal that has been agreed by the RCM Working Group.
- Verve Energy retires the Kwinana Stage C facilities (361.5 MW) for 2016/17. This is as projected in the 2012 SOO.
- 25 MW of new capacity is added per year. This matches the quantity of new capacity added for the 2014/15 Capacity Year.

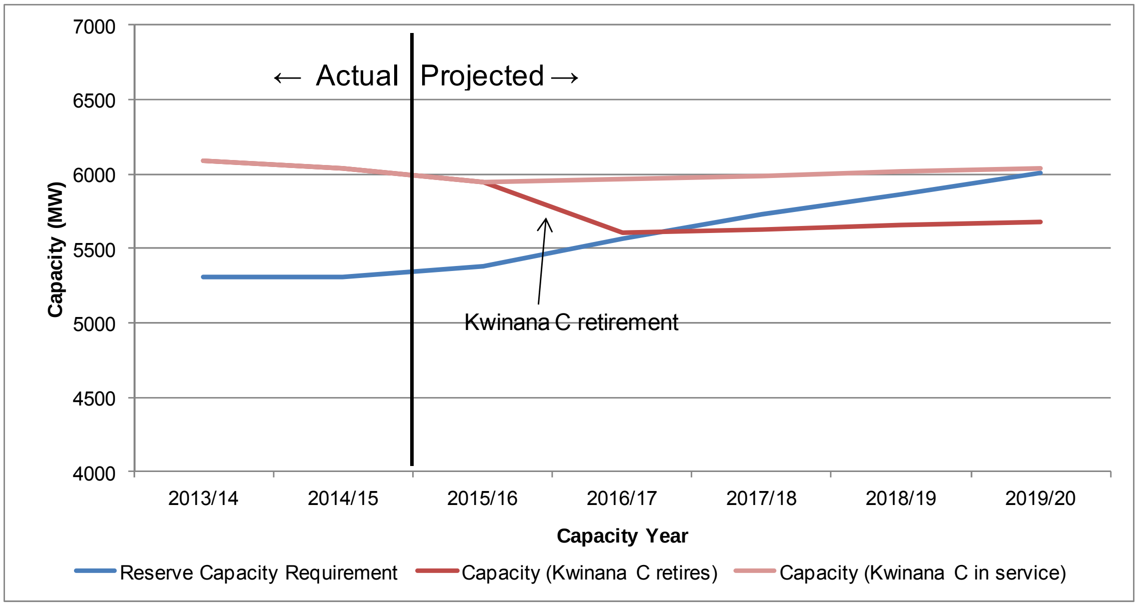
Capacity Year	2015/16	2016/17	2017/18	2018/19	2019/20
Capacity (MW)	5949	5604	5629	5654	5679

Combined supply and demand projection

The combination of the supply and demand projections above is shown in the graph below. The projection indicates a capacity shortfall arising in 2017/18. This would necessitate further addition of capacity at this time.

The Reserve Capacity Price has been estimated for the next two Capacity Years in which a capacity surplus is projected. For this price calculation, the 2015/16 MRCP is set at $157,200 per MW per year, and escalated at 2.5% per annum thereafter.

The RCP is calculated both for the current price calculation formula and the formula proposed by the Lantau Group (110% scaling factor, slope of -3.75, RCR offset of 97%). The RCP has also been calculated for the last two Reserve Capacity Cycles under the Lantau formula.



A summary of the projection is shown below, with the Kwinana C retirement for 2016/17.

Capacity Year	Actual or projected RCR (MW)	Actual or projected capacity (MW)	Excess capacity (MW)	RCP – current formula ($/MW/yr)	RCP – Lantau formula ($/MW/yr)
2013/14	5312	6086.829	775	$178,477	$159,483
2014/15	5308	6040.161	732	$122,427	$110,624
2015/16	5378	5949	571	$120,795	$115,050
2016/17	5569	5604	35	$136,105	$156,808
2017/18	5728	5629	-99	n/a	n/a
2018/19	5859	5654	-205	n/a	n/a
2019/20	6007	5679	-328	n/a	n/a

The table below shows a revised projection if Kwinana C is kept in service.

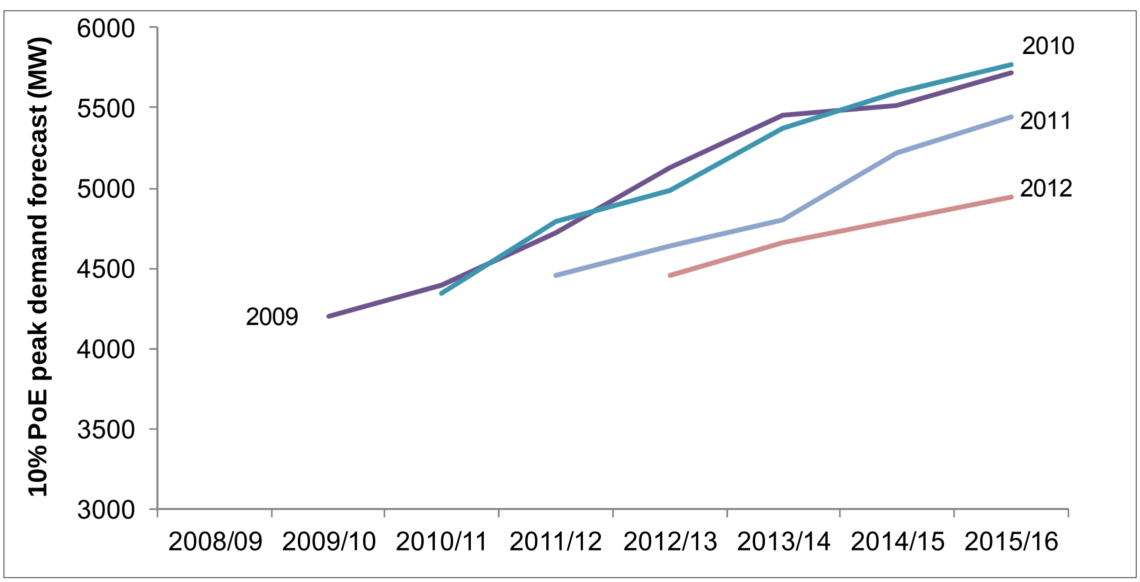
Capacity Year	Actual or projected RCR (MW)	Actual or projected capacity (MW)	Excess capacity (MW)	RCP – current formula ($/MW/yr)	RCP – Lantau formula ($/MW/yr)
2013/14	5312	6086.829	775	$178,477	$159,483
2014/15	5308	6040.161	732	$122,427	$110,624
2015/16	5378	5949	571	$120,795	$115,050
2016/17	5569	5965	396	$127,868	$129,170
2017/18	5728	5990	262	$134,244	$142,208
2018/19	5859	6015	156	$140,162	$154,381
2019/20	6007	6040	33	$146,686	$169,308

Demand Forecast Projections

The IMO's peak demand forecasts have been declining since 2009 due to a range of factors, including:

- reduced allowances for new major block loads;
- increasing penetration of distributed solar PV generation;
- recalibration of NIEIR's air conditioning forecast model;
- the impacts of the GFC; and
- the impacts of retail tariff increases.

The IMO's 10% PoE peak demand forecasts for the period from 2009 to 2012 are shown in the graph below. Note that the 2012 forecasts predicted that peak demand would continue to grow at 3.0% per annum over the ten year forecast horizon.



In terms of potential future changes to forecasts:

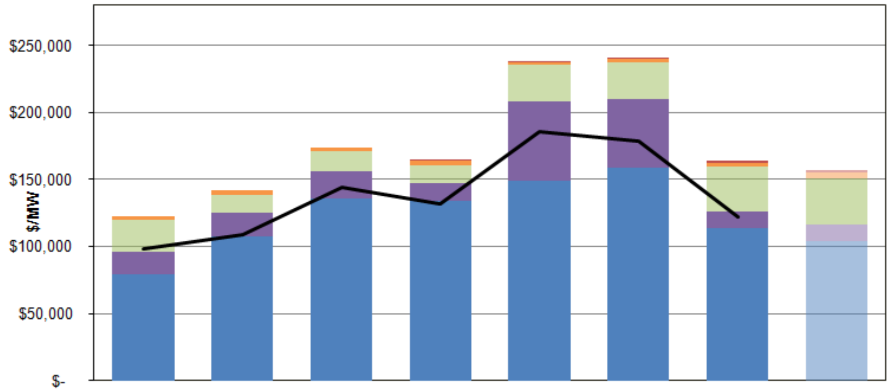
- Preliminary estimates suggest that energy consumption in the period from July-October 2012 is 2.6% higher than the same period last year. This represents an increase in the average demand of 50 MW, with consumption being higher in each of the four months from July to October. The 2012 Expected energy forecast for the 2012/13 financial year was for a reduction in demand of 0.5%. The following factors have contributed:
    - Average winter morning temperatures in July were more than 2°C below the 20-year average and more than 3°C below the July 2011 average. August morning temperatures were also below the corresponding period last year.
    - The Binningup desalination plant, which completed commissioning in late 2011, contributed 28% of the increase.
    - Karara Mining has yet to contribute to this increase. Consumption at Karara has yet to reach 2 MW.
- The 2012 forecasts did not consider the potential impact of larger solar PV systems on commercial or industrial buildings. The IMO plans to develop, in conjunction with stakeholders, a forecast for this sector for the 2013 forecasts. The impact of this inclusion will be a reduction in peak demand forecasts.
    - The IMO included a forecast of residential solar PV generation for the first time in 2012. The Expected case predicted that penetration would increase by approximately 50 MW per year to reach 750 MW by 2022 (nameplate capacity). This corresponds to a reduction of peak demand of 180 MW by 2022.
    - For the purpose of this modelling, we have assumed that the rate of penetration of commercial/industrial solar PV systems is the same as for the residential sector in MW terms but with a three-year delay.

Capacity Pricing

The Reserve Capacity Price (RCP) will peak in the 2012/13 and 2013/14 Capacity Years, driven by the sharp increase in Western Power's estimates of transmission connection costs. However, the 5-yearly review by the MRCP Working Group and the drop in Commonwealth Government bond yields led to a 31% reduction in the RCP for 2014/15.

The 5-yearly review was first signalled to the market in late 2009, commenced in 2010 and concluded in 2011. It is likely that the expectation of a reduction in capacity pricing has contributed to the dampening of investor interest in the WEM.

Capacity pricing is expected to reduce further for 2015/16. The Maximum Reserve Capacity Price (MRCP) for 2015/16 is expected to be approximately 4% lower than the 2014/15 MRCP.



Capacity Year	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16
Power Station Cost	$ 79,110	$ 107,404	$ 135,701	$ 134,091	$ 149,306	$ 158,710	$ 113,956	$ 103,974
Transmission Costs	$ 16,558	$ 18,017	$ 20,672	$ 13,151	$ 58,493	$ 51,621	$ 12,328	$ 12,249
Fixed O& M	$ 23,900	$ 13,363	$ 14,392	$ 13,431	$ 27,335	$ 26,649	$ 33,384	$ 34,558
Fuel Costs	$ 2,907	$ 3,456	$ 2,631	$ 3,151	$ 2,615	$ 2,825	$ 2,239	$ 4,632
Land Costs	$ -	$ -	$ -	$ 293	$ 769	$ 818	$ 1,972	$ 1,765
MRCP (nearest $100)	$ 122,500	$ 142,200	$ 173,400	$ 164,100	$ 238,500	$ 240,600	$ 163,900	$ 157,200
Excess Capacity	6.43%	11.44%	2.19%	5.83%	8.99%	14.59%	13.79%	
Reserve Capacity Price (per yr)	$ 97,837	$ 108,459	$ 144,235	$ 131,805	$ 186,001	$ 178,477	$ 122,427	

Potential New Capacity Additions

Expressions of Interest (EOI)

The quantity of capacity being offered in Expressions of Interest has reduced significantly over the last two years.

Capacity Year	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
EOI capacity (MW)	1192	1036	1279	644	337	214

This reduction may reflect a reduced appetite for capacity investment in the WEM.

Additions of new capacity

Similar to the Expressions of Interest, the quantity of new capacity that has received Capacity Credits has reduced significantly during the last two capacity cycles. Of the 92 MW of new capacity added in the last two capacity cycles, 65 MW has been DSM capacity.

Capacity Year	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
EOI capacity (MW)	547	162	335	531	67	25

Potential Reductions to Existing Capacity Allocations

Intermittent Generators

Following the implementation of Rule Change RC_2010_25, the Capacity Credits assigned to Intermittent Generators reduced by 76 MW (37%) for the 2014/15 Capacity Year. This was dominated by a reduction of 70 MW for Collgar.

The 2014/15 Capacity Year represents the first year of a three-year transition path for the new methodology. However, the reductions in the second and third years will be significantly less than for the first year.

- The projected reduction for the 2015/16 Capacity Year is 11 MW.
- The projected reduction for the 2016/17 Capacity Year is a further 9 MW.

Demand Side Management (DSM)

The entry of sophisticated DSM aggregators into the WEM led to sharp growth in DSM capacity from 2009/10 to 2012/13. However, this growth has slowed over the last two capacity cycles.

Capacity Year	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
DSM capacity (MW)	99	154	260	454	500	524

Anecdotal evidence from EnerNOC suggests that the market is reaching a level of saturation, at which the cost of sourcing additional capacity exceeds the benefits that can be achieved.

The Reserve Capacity Mechanism Working Group has broadly agreed to the proposal for harmonisation of demand side and supply side capacity resources. This proposal would increase the availability requirements for DSM – for example, DSM would no longer be able to specify a limit on the number of hours per year that it may be dispatched.

In discussions with the IMO, DSM providers have suggested that the harmonisation proposal would lead to some reduction in future capacity. For the purpose of this paper, we have assumed a reduction in DSM capacity of 20% for the 2015/16 Capacity Year.

Verve plant retirement

In previous SOO's, the IMO has anticipated the decommissioning of Verve Energy's Kwinana Stage C facilities (KWINANA_G5 and KWINANA_G6) for the 2016/17 Capacity Year. These facilities were allocated a total of 361.5 MW of Capacity Credits for the 2014/15 Capacity Year.

The projections in this paper consider the outcomes that would result if Kwinana C is either retired or kept in service.