Independent Market Operator

MRCPWG

Agenda

Meeting No.	10
Location:	IMO Board Room, Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Monday, 20 June 2011
Time:	Commencing at 3.00 to 5.00pm

Item	Subject	Responsible	Time
1.	**WELCOME AND APOLOGIES / ATTENDANCE**	**Chair**	5 min
2.	**MINUTES OF PREVIOUS MEETING**	**Chair**	5 min
3.	**ACTIONS ARISING**	**Chair**	5 min
4.	**FORCED OUTAGE REFUND ALLOWANCE**	**IMO**	20 min
5.	**ANNUALISATION PERIOD – CASHFLOW ANALYSIS**	**IMO**	20 min
6.	**DRAFT PROCEDURE CHANGE PROPOSAL**	**IMO**	30 min
7.	**GENERAL BUSINESS**	**IMO**	15 min
8.	**NEXT MEETING**	**Chair**	5 min

Independent Market Operator

MRCPWG

Minutes

Meeting No.	9
Location:	IMO Board Room Level 3, Governor Stirling Building, 197 St Georges Terrace, Perth
Date:	Thursday 5 May 2011
Time:	Commencing at 3:05 to 5:05pm

Attendees	
Greg Ruthven	IMO (Chair)
Monica Tedeschi	IMO (Minutes)
Johan van Niekerk	IMO
Corey Dykstra	Market Customer
Steve Gould	Market Customer
Stephen MacLean	Market Customer
Chin Koay	Market Generator (proxy)
Patrick Peake	Market Generator
Pablo Campillos	DSM Aggregator (3.05- 4.25pm)
Jeff Staloch	Observer/DSM Aggregator (proxy after 4.25pm)
Neil Gibbney	Western Power
Neil Hay	System Management
Adam Boyd	New Investor
Ben Tan	Observer
Chris Brown	Economic Regulation Authority (ERA) (Observer)
Apologies	
Allan Dawson	IMO
Brad Huppatz	Market Generator
Shane Cremin	Market Generator

Item	Subject	Action
1.	**WELCOME AND APOLOGIES / ATTENDANCE** The Chair opened the 9th meeting of the Maximum Reserve Capacity Price (MRCP) Working Group (Working Group) at 3:05pm. It was highlighted that there was an extra item added to the agenda, being a discussion of the potential inclusion of a Forced Outage Refund Allowance in the MRCP. Apologies were noted from Allan Dawson (IMO), Brad Huppatz	

	(Market Generator) and Shane Cremin (Market Generator). Mr Chin Koay was welcomed in place of Mr Huppatz. The Chair also welcomed Adam Boyd, who had replaced Nenad Ninkov as the New Investor representative, and Ben Tan who attended as an observer.	
2.	**MINUTES OF PREVIOUS MEETING** The minutes of the 8th MRCP Working Group meeting, held 24 March 2011, were circulated prior to the meeting. The following amendment was agreed: • Mr Corey Dykstra suggested under Agenda Item 5 in the third paragraph that the word "reviewing" be replaced with "called to review". *Action Point: The IMO to make the agreed amendment and publish Meeting 8 minutes on the website as final.*	**IMO**
3	**ACTION POINTS** The actions arising were either complete or on the meeting agenda. Mr van Niekerk noted the following: • AP37: The review of the relationship between humidity rates and generator output is still pending. It was noted that the outcomes of the Working Group were not dependent on the completion of this action item, and that the exercise would be completed in due course. • AP59: The IMO is still awaiting the final report from Sinclair Knight Merz (SKM). • AP61: While the IMO did not receive any comments on the draft Market Procedure following the previous meeting, it was noted that the Working Group would have a further opportunity to comment on it at subsequent meetings.	
4	**DETERMINATION OF MARGIN M AND FORWARD ESCALATION FACTORS** Mr van Niekerk explained that the IMO had commissioned WorleyParsons to provide independent advice on the margin M and forward escalation factors, as previously requested by the Working Group. Mr van Niekerk confirmed that WorleyParsons broadly agreed with SKM's method for calculation of Margin M. In addition they agreed that the total value of 18.6% was a valid approximation. WorleyParsons highlighted that some of the component costs of the margin M were largely independent of project size (e.g. legal and environmental approval costs). WorleyParsons suggested that these components were more appropriately expressed as a fixed sum, rather than as a percentage of the capital cost of the project. Mr van Niekerk confirmed that the IMO had consulted SKM, who had previously developed the margin M for the IMO, and had received confirmation that this had been taken into account in	

	their calculations. In light of this, the Chair proposed that the current methodology for determination of the margin M be retained. Mr Dykstra noted that the Working Group had previously agreed that debt issuance costs would be included in the WACC and removed from the financing cost component of the Margin M. The Chair agreed, noting that the IMO would review the wording in the draft Market Procedure to ensure that his was adequately reflected. Mr Koay pointed out that clause 1.12.1(b) in the draft Market Procedure describes the component included in M as additional cost not covered in the debt issuance cost in WACC. The debt issuance cost in WACC will be paid to the lenders and included in the interest payments whereas the financing cost component in M relates to the cost incurred by the borrower in setting up the loan. The Working Group agreed that the Margin M calculation basis should remain unchanged except for the removal of debt issuance costs. *Action Point: IMO to review the Market Procedure to ensure there is no double counting of debt issuance costs.*	**IMO**
	Mr van Niekerk explained that the WorleyParsons report had also provided a number of options for forward escalation of costs. These included the use of: • a weighted average of various Australian Bureau of Statistics (ABS) indices, reflecting cost movements from the previous 12 months; • linear regression of the historical ABS indices to predict future price movements; or • a combination of Consumer Price Index (CPI) and Wage Price Index (WPI) forecasts published in the State budget papers. Mr van Niekerk noted the relative strengths and weaknesses of each methodology and proposed that the Working Group consider adopting the method based on CPI and WPI forecasts as it considered future expectations of economic conditions, and was simple and transparent. The Chair noted that the change previously agreed by the Working Group to the application of the WACC, assuming that costs were incurred, on average, 6 months before payments are received, required that costs will now need to be escalated forward almost 3 years. Mr Dykstra stated that CPI is not necessarily a good indicator of the typical input costs for a power station, with other indices, such as those available for steel and copper, possibly being better predictors for escalation purposes. Mr van Niekerk reiterated that transparency and simplicity were the key advantages of moving to a forward-looking CPI/WPI basis for determining escalation factors. Mr Tan asked if WorleyParsons had compared longer-run historical changes in power station capital costs against CPI. The Chair noted that WorleyParsons had included this in its report as part of its suggestion of a linear regression method, indicating that this was approximately 3% over the period from 2005 to 2010.	

	Mr Campillos noted that the use of CPI allows the calculation to be replicated. However, if CPI is significantly different from expected escalation in power station costs then perhaps it might be better not to use it as a basis for escalation. Mr Dykstra agreed with Mr Campillos, however noted that the MRCP was a cap and therefore contains some head room. The Chair explained the discussions held previously with the ERA in relation to the use of forward commodity price estimates to develop escalation factors. The Chair noted that SKM had advised that its forward escalation factors for switchyard and transmission costs had previously been endorsed by the Australian Energy Regulator. Switchyard and transmission costs are typically incurred by regulated entities and are significantly more transparent, allowing easier development and refinement of a weighting matrix to determine the relative contribution of various costs (e.g. copper, steel, cement and labour). However, SKM had only determined a weighting matrix for the power station capital cost recently and had not had the opportunity to refine this over several years. Mr Chris Brown noted that there was limited transparency under the forward looking methodology as proposed by SKM. Mr Brown of the ERA noted that the assessment of the suitability of an escalation methodology is based on its reliability in reflecting the true cost of a power station. Notwithstanding these issues, the Working Group generally agreed that the use of escalators based on forward estimates of power station input costs, as recommended by SKM, would be more appropriate than CPI/WPI forecasts. The Chair asked whether participants could be satisfied with the accuracy of a cost that was predicted 3 years ahead. Mr Dykstra indicated that the professional judgment of the consultant should be applied, using the best available information at the time. He proposed that the consultant provide the power station capital cost as at the date 6 months before payments are received, along with an explanation of how the cost was developed, including any escalation. The Working Group agreed with Mr Dykstra's proposal. *Action Point: The IMO to amend the Market Procedure to state that the Consultant provides a price as at April in Year 3 of the Reserve Capacity Cycle and explain its derivation, including any escalation factor applied.* The Chair noted that, as Western Power was responsible for calculating the transmission connection cost, the IMO would still require escalation factors for the transmission and switchyard costs. The Chair proposed that the IMO would confirm the history of regulatory acceptance of SKM's recommended forward cost escalators for these costs. *Action Point: The IMO to investigate the history of regulatory acceptance of SKM's recommended forward cost escalators for switchyard, transmission and O&M costs.*	**IMO** **IMO**
5	**FORCED OUTAGE ALLOWANCE** The Chair introduced Mr Chin Koay from Verve Energy to present the paper on Forced Outage Allowance in Maximum Reserve	

	Capacity Price. Mr Koay stated that Gas Turbines are not designed to have 100% availability. Mr Koay proposed that the corresponding Forced Outage Refund liability be allowed for within the MRCP calculation by including a provision, based on an average forced outage rate of 3%. Mr Hay noted that the Reserve Capacity Mechanism accounts for forced outages through the procurement of extra capacity to satisfy the Planning Criterion. He also noted that the 15% reserve margin in the paper is based on 1 in 2 year peak demand forecasts rather than the 1 in 10 year peak demand. The Chair noted that the IMO had analysed the forced outage rates of peaking gas turbine facilities that were built in the previous 10 years, as these most closely relate to the power station upon which the MRCP is based. The average forced outage rate in the last year for these facilities was under 1%. The Chair also noted that the theoretical peaking plant upon which the MRCP is based has a 2% capacity factor, so any outage allowance above this level would make little sense. Mr Peake noted that outage costs are very significant to gas turbines. He suggested that forced outage rates are typically 1-2%, with outages commonly occurring at times where refund costs are higher as faults can sometimes not be identified until the facility is dispatched. Mr Peake proposed that the IMO should calculate what a likely refund level is and apply that within the MRCP to compensate for an inevitable level of forced outages. Mr Koay noted that a 3% level for forced outages may not be the right number and that he would be satisfied for any agreed level to be based on market statistics. Mr Peake also explained that working capital is typically set aside to account for outages and refunds. He stated that a high level of forced outages, in the region of 3%, falling during peak periods could seriously threaten the profitability of an operator. He proposed that a number be determined, which was likely to be lower than 3%, and then be incorporated into the MRCP to compensate operators. Mr Tan noted his support for this proposal. Mr Boyd noted that generally a 3% outage rate is a conservative estimate that would be unlikely to be exceeded and that an investor should allow for this in their business model. Mr Boyd stated that if it was the intention of the MRCP to compensate investors for costs then a provision for refunds should be included. This was supported by Mr Campillos. Mr Peake noted that long periods of plant idleness can result in uncertainty surrounding reliability when called upon at short notice, which will naturally result in forced outages due to unforeseen circumstances. Mr MacLean stated that it was his experience that gas turbines typically start when needed as long as proper maintenance is undertaken. The Chair questioned the validity of using a percentage-based Forced Outage Refund allowance for a plant that only runs 2% of the time, particularly given that market statistics suggest average forced outage rates for OCGT's in the market of less than 1%.	

	Mr Peake suggested that, as refund rates were more punitive during peak periods, the IMO could consider looking at refund quantities to gauge the financial impact of forced outages for similar facilities. Mr Mclean noted that any changes in the MRCP in relation to forced outage rates could only be implemented pending the outcome of further discussions on the capacity refund mechanism by the Rules Development & Implementation Working Group. *Action Point: The IMO to analyse the value of refunds paid by newer peaking gas turbines in the market to investigate whether these facilities are typically exposed to higher refund multipliers.*	**IMO**
6	**ANALYSIS OF SENSTIVITY TO CHANGES TO MRCP METHODOLOGY** Mr van Niekerk explained that the IMO had performed a sensitivity analysis for a number of changes to the MRCP methodology. These included changes in the transmission cost calculation methodology, changes in the Debt Risk Premium methodology, the change in the effective construction period in applying the WACC, the inclusion of annual insurance costs and changes in the capitalisation period. Mr van Niekerk noted that the paper presented by the IMO suggested that all of the variations taken together, under the current capitalisation period of 15 years, would have resulted in an MRCP that was approximately 18% lower than the 2013/14 MRCP. However, the Chair noted that the IMO had noticed that this analysis had not taken account of the need to escalate the capital costs forward by a further two years to align the costs with the payment timing assumed in the application of the WACC. He indicated that this escalation could, on average, lead to a 5-8% increase in the capital costs. With this taken into account, the overall reduction in the MRCP was in the order of 10-13%. Mr Dykstra noted that the Working Group had previously agreed that the adoption of the Debt Risk Premium methodology proposed by the ERA was subject to it becoming “accepted regulatory practice”. The Chair noted this and indicated that the IMO should remove this from the graph prior to inclusion in the Procedure Change Proposal. *Action Point: The IMO to remove the change to the Debt Risk Premium from the sensitivity analysis and provide the graph in the draft Procedure Change Proposal.* Mr Van Niekerk explained the impact of a change in the capitalisation period. He noted that an increase in the capitalisation period to 20 years was, in isolation, likely to reduce the MRCP by approximately 11%. Mr van Niekerk proposed that the Working Group consider a transition to a capitalisation period of 20 years. He suggested that this would still provide head room while moving closer to the likely operating life of such a Facility. He also noted that a glide path could be considered for this change to avoid significant price	**IMO**

	shocks. Mr Tan questioned if the analysis had considered any adjustment to the O&M costs corresponding to the longer capitalisation period. Mr van Niekerk confirmed that the annual variable O&M cost was estimated for the IMO by SKM, which had considered this cost to be flat in real terms. Mr Koay questioned the apparent inconsistency in a WACC based on 10 year bond rates versus its use over a 15 year capitalisation period within the MRCP. Mr Dykstra noted this was due to the Special Price Arrangement, which is for a period of 10 years. Mr MacLean noted that alignment of the capitalisation period with the WACC was not necessary as gas turbines could be sold and relocated. Mr Peake suggested that there may be limited scope for increasing the capitalisation period to 20 years given the limited availability of debt facilities of 10 years or longer. Mr Tan noted that a change to the capitalisation period may require reconsideration of the WACC. For example, the cost of funding a 5 year period is cheaper than 10 years. Mr Dykstra agreed and noted there is a lower risk premium in a short debt period. Mr Peake noted that the MRCP should allow an investor to be profitable during the term of the Special Price Arrangement. He raised concern that an increase in the capitalisation period could prevent this from occurring. It was agreed that in order to determine the impact of a change in capitalisation period, the IMO should model the cash flows of a model plant for the first 10 years under both a 15 and 20 year capitalisation period. *Action Point: The IMO to perform financial modelling on cash flow impacts of a change to the capitalisation period and report back to the Working Group.*	**IMO**
7	**DRAFT MARKET PROCEDURE** Mr van Niekerk briefly outlined the changes to the Market Procedure that had been made since the last meeting. Mr Dykstra noted the need to confirm that the fuel tank capacity corresponded to the requirement for sufficient fuel for 24 hours of operation. *Action Point: The IMO to confirm that the fuel tank size in Section 1.9 of the Market Procedure is sufficient for 24 hours of operation.* He also noted that the reference to CPI in section 1.9.5 should be specified. *Action Point: The IMO to ensure that section 1.9.5 of the Market Procedure is sufficiently descriptive regarding CPI.* The Chair noted that Mr Chris Brown from the ERA had already suggested that the readability of step 1.13.7(h) could be improved	**IMO** **IMO**

	and had offered to provide suggestions for improvement. Mr Gould noted that the corporate tax rate in section 1.13.8 is currently a Major WACC parameter, suggesting that it would only be reviewed five-yearly. He noted that it is possible that the corporate tax rate will be changed soon and proposed that it be changed to be a Minor parameter. The Chair agreed to amend this. *Action Point: The IMO to change the corporate tax rate to be a Minor WACC parameter in section 1.13.8 of the Market Procedure.* The Chair requested that Working Group members send their comments on the draft Market Procedure to the IMO by email. Mr Dykstra requested that the IMO sends a reminder email to Working Group members. *Action Point: Any comments regarding the proposed MRCP Procedure to be forwarded via email to the IMO by COB 12 May 2011.*	**IMO** **All**
8	**GENERAL BUSINESS** No general business.	
9	**NEXT MEETING** Mr Ruthven noted that the date of the next meeting would be confirmed at a later date. *Action Point: The IMO to advise prospective attendees of the next meeting details.*	**IMO**
10	**CLOSED:** The Chair declared the meeting closed at 5:05 pm.	

Agenda Item 3: MRCPWG - Action Points

Legend:

Unshaded	Unshaded action points are still being progressed.
Shaded	Shaded action points are actions that have been completed

#	Meeting Arising	Responsibility	Action	Status/Progress
37	Meeting 5	IMO	The IMO to initiate a review of the relationship between humidity rates and generator output across a range of locations.	Delivery of MRCPWG outcomes not contingent upon this action. The IMO will undertake this exercise at a later date.
47	Meeting 7	IMO	IMO to engage an engineering consultant to undertake an exercise to independently provide a Margin M calculation for comparison purposes.	Completed. Presented at Meeting 9.
52	Meeting 7	IMO	IMO to engage an engineering consultant to independently provide a view on forward-looking cost escalation factors.	Completed. Presented at Meeting 9.
59	Meeting 8	SKM / Western Power	Western Power and SKM to complete any clean-up of data, and SKM to finalise the Research Report.	Completed and published on the IMO website.
62	Meeting 9	IMO	IMO to make the agreed amendment to the Meeting 8 minutes and publish on the website as final.	Completed and published.

#	Meeting Arising	Responsibility	Action	Status/Progress
63	Meeting 9	IMO	IMO to review the draft Market Procedure to ensure that there is no double counting of debt issuance costs between the WACC and Margin M.	Completed. Initial and ongoing debt related costs are dealt with under clauses 1.12.1(b) and 1.13.7(b) respectively in the Draft Market Procedure.
64	Meeting 9	IMO	IMO to investigate the history of regulatory acceptance of SKM's recommended forward cost escalators for switchyard, transmission and O&M costs.	Completed. SKM have advised that their methodology has been accepted in AER determinations for Ergon, the 5 Victorian DNSPs, Transend, TransGrid and SP Ausnet.
65	Meeting 9	IMO	IMO to update the draft Market Procedure to indicate that the Consultant will provide the Power Station Capital Cost as at April in Year 3 of the Reserve Capacity Cycle, with other capital costs being escalated according to the methods recommended by SKM, subject to the IMO's investigation of regulatory acceptance of this method.	Completed. The Draft Market procedure has been amended accordingly under clause 1.7.3.
66	Meeting 9	IMO	IMO to analyse the value of refunds paid by newer peaking gas turbines in the market to investigate whether these facilities are typically exposed to higher refund multipliers.	Completed. Analysis presented for Agenda Item 4 of Meeting 10.
67	Meeting 9	IMO	IMO to remove the change to the Debt Risk Premium from the sensitivity analysis prior to inclusion in the draft Procedure Change Proposal for Meeting 10.	Completed. It has been agreed that there shall be an option to utilise the alternative methodology rather than a requirement to do so.
68	Meeting 9	IMO	IMO to perform financial modelling on cash flow impacts of a change to the capitalisation period and report back to the Working Group.	Completed. The results of this analysis, undertaken by PwC, is included under Agenda Item 5.
69	Meeting 9	IMO	IMO to confirm that the fuel tank size in Section 1.9 of the Market Procedure is sufficient for 24 hours of operation.	Completed. GHD confirmed in their November 2010 report, based on a fuel high heat value of 45 MJ/kg, a fuel to electrical energy efficiency of 32% and a fuel specific gravity of 0.84.

#	Meeting Arising	Responsibility	Action	Status/Progress
70	Meeting 9	IMO	IMO to change the corporate tax rate to be a Minor WACC parameter.	Completed. The IMO has amended the corporate tax rate to be a Minor WACC parameter, allowing for annual adjustment if necessary.
71	Meeting 9	MRCPWG members	Members to provide comments regarding the draft Market Procedure to the IMO.	Completed. No comments have been received up to distribution of this pack.
72	Meeting 9	IMO	IMO to advise details of next meeting.	Completed. The next meeting date of 20 June 2011 at 3pm was confirmed on 24 May 2011.

Agenda Item 4: Forced Outage Refund Allowance

1. BACKGROUND

The MRCPWG discussed the issue of the inclusion of an allowance for Forced Outage Refunds within the MRCP at the 5 May 2011 meeting, following the receipt of a discussion paper from Verve Energy.

Verve explained that it is reasonable to expect that Open Cycle Gas Turbines (OCGTs) will experience forced outages from time to time. Verve proposed that an allowance be included within the MRCP to cover a 3% forced outage rate, suggesting that this was an expected level for gas turbines.

The MRCPWG considered that a 3% forced outage rate was not necessarily appropriate for a newly built facility with 2% capacity factor, as is assumed in the Market Procedure. The IMO advised the MRCPWG that its preliminary analysis suggested that historical outage rates for relevant facilities (gas turbines, up to 10 years old, peaking operation) were below 1%. The MRCPWG noted, however, that it was possible that forced outages for a peaking facility may be more likely to align with peak periods where the Forced Outage Refund payments were higher. Consequently, the MRCPWG requested some further analysis of the historical refund payments for relevant facilities.

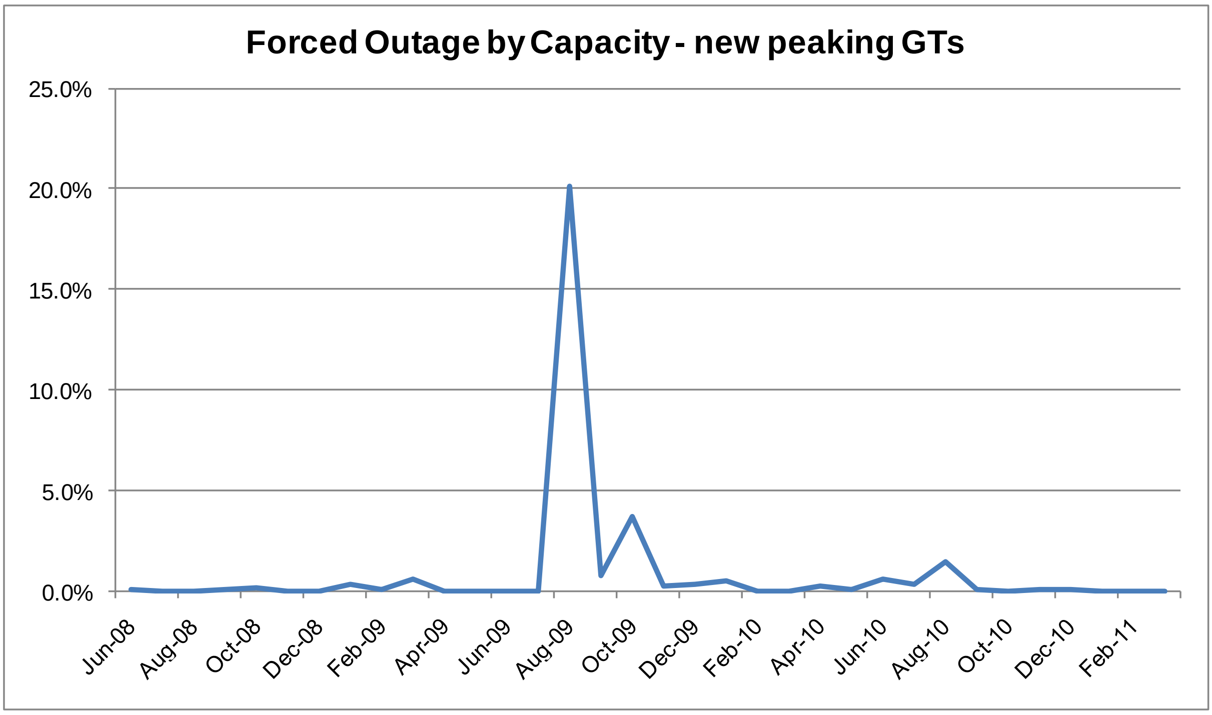
2. ANALYSIS OF HISTORICAL OUTAGE RATES AND PAYMENTS

The IMO has analysed the historical outages of a set of six OCGT facilities that:

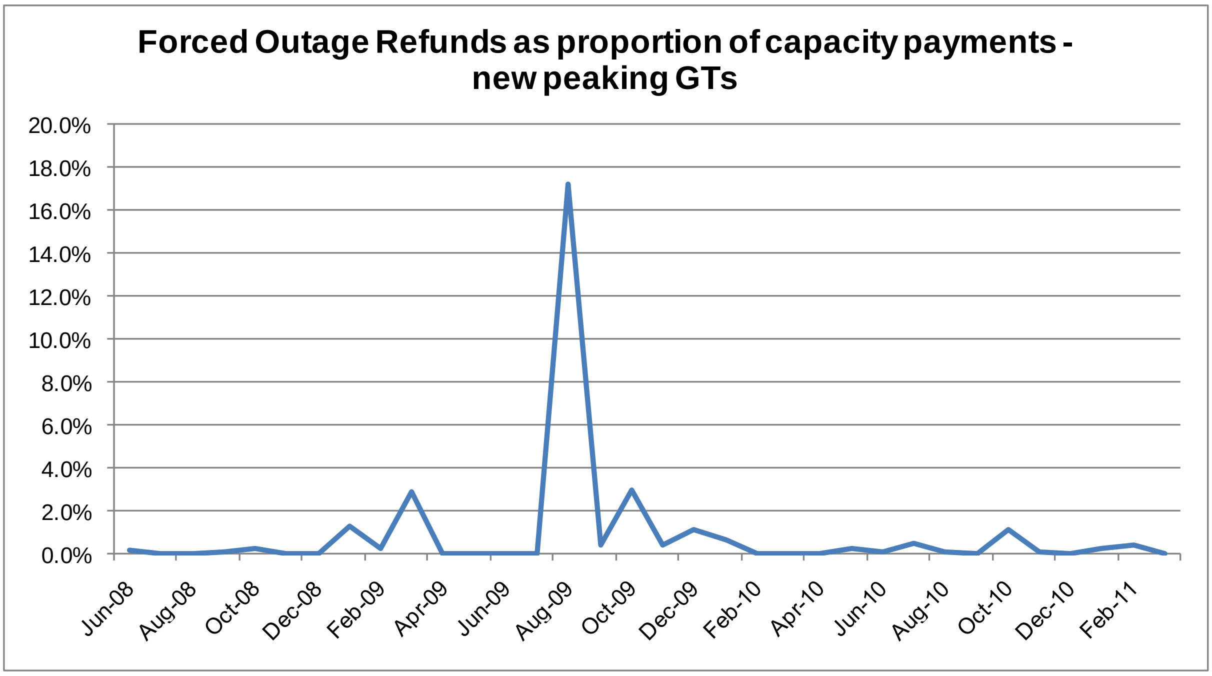
- have commenced operation in the last ten years (aligned with the maximum term of a Long Term Special Price Arrangement); and
- have an average capacity factor in 2009 and 2010 below 10%.

The analysis covered the period from 1 June 2008, following the commencement of Forced Outage Refunds with Rule Change RC_2007_36, through to 31 March 2011.

The IMO initially considered the proportion of capacity that was on forced outage during the analysis period. The analysis considered the outage quantity in each interval in order to ensure that full and partial outages were handled appropriately. The percentage of capacity subject to forced outage is plotted below by month. Note that the average forced outage rate for the analysis period, by capacity, is 0.73%.



The IMO also considered the total refund payments for the selected facilities during the analysis period, which is presented in the graph below. Note that the average forced outage payment for the analysis period, assessed as a proportion of capacity payments, is 0.67%.



This data suggests that there is no bias towards peak trading intervals. Less than one-quarter of the Forced Outage Refunds paid for the selected facilities during the analysis period were during the Hot Season (December – March).

Given that the forced outage liability has historically been a very small proportion of the capacity payments for facilities similar to the hypothetical power station, the IMO considers that the inclusion of an allowance for Forced Outage Refunds within the MRCP is unnecessary.

Therefore, the IMO recommends that no allowance be included in the MRCP for Forced Outage Refunds.

3. RECOMMENDATIONS

The IMO recommends that the MRCPWG:

- **Note** the analysis of historical forced outages and Forced Outage Refunds; and
- **Note** the IMO's recommendation to not include a Forced Outage Refund allowance in the MRCP.

Agenda Item 5: Annualisation Period – Cash-flow Analysis

1. BACKGROUND

At the meeting held on 5 May 2011 the MRCPWG discussed the possibility of increasing the MRCP Annualisation Period from 15 to 20 years. It was agreed that the IMO would undertake financial modelling to ascertain the cash flow impacts of a change to the capitalisation period and report back to the Working Group.

2. ANNUALISATION PERIOD – CASH-FLOW ANALYSIS

The IMO engaged PricewaterhouseCoopers (PwC) to perform the exercise. A letter from PwC detailing their findings is attached.

PwC has applied a number of scenarios including an increase in the Annualisation period from 15 to 20 years, a range for the assumed Debt Risk Premium (DRP) between 2.75 and 5.25%, and a project life of 25 or 30 years.

The IMO notes that the exercise undertaken by PwC has been performed in an environment of unfavourable debt markets. PwC has assumed an initial debt to total assets ratio of 55% compared to 40% listed in the Market Procedure. The terms used by PwC are based on their appraisal of an indicative debt funding structure which could be achievable for the project based on revenue arrangements and given their experience. The model utilised by PwC has applied a reduced debt to total assets ratio over the life of the project as debt is repaid and the level of Reserve Capacity income becomes less predictable.

The advice from PwC suggests that an increase in the capitalisation period within the MRCP to 20 years could reduce the return to the owner to a level below the level required to support an investment. The IMO notes that the analysis suggests that this scenario reflects a more marginal project under generally less favourable financial market conditions.

Notwithstanding this the IMO supports PwC's recommendation to maintain the Annualisation period at 15 years and recommends that the MRCPWG endorses this.

3. RECOMMENDATIONS

The IMO recommends that the MRCPWG:

- **Note** the analysis of performed by PwC; and
- **Note** the IMO's recommendation to maintain the Annualisation period at 15 years.

Allan Dawson
Chief Executive Officer
Independent Market Operator
Level 3 Governor Stirling Tower
197 St Georges Terrace,
PERTH WA 6000

15 June 2011

Dear Allan

Subject: Cash flow modelling to evaluate an increase in the capitalisation period in calculation of the Maximum Reserve Capacity Price

We are pleased to present to this letter setting out the results of the cash flow modelling we have undertaken to assess the impact on the viability of the generic power station project of a change in the capitalisation period within the formula for the Maximum Reserve Capacity Price (MRCP).

Background

The MRCP is intended to represent the price which would be required by the marginal project that is awarded capacity credits in the Reserve Capacity Auction; defined within the Market Procedure as a 160 MW open cycle gas turbine (OCGT) peaking power station located in the South West interconnected system (SWIS).

The MRCP Working Group (MRCPWG) is considering an increase in the time period applied in the calculation of the annualised capital cost component of the MRCP from 15 years to 20 years. The IMO has estimated that this change would reduce the estimated MRCP for the 2014/15 period from $202,411[1] to $181,539 per MW of capacity allocated per annum. We understand that concerns have been raised by industry participants that this would threaten the viability of the generic project, particularly where project finance debt facilities are used.

The scope of our work was to develop an indicative project financing structure and terms that might reasonably apply to the generic project and to evaluate the impact of the reduction in revenue stream on the cash flow and financial returns to the notional owner of the project.

The financial modelling and scenarios set out in this letter are for illustrative purposes to assist the MRCPWG in its consideration of only one potential change to the MRCP formula. This letter is provided for the use and benefit of the IMO for this purpose only and is not to be used for any other purpose. PwC does not assume any responsibility to third parties to which this letter is disclosed or otherwise made available or for the use of this letter for any other purpose.

[1] The estimated MRCP of $202,411 per MW is an approximation of what the 2013/14 MRCP would have been given the recently agreed changes to the MRCP formula for the calculation of total connection costs, the reduced construction period, revised DRP methodology and inclusion of annual insurance costs.

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Approach and Assumptions

The debt financing terms that could be supported by a stand-alone 160 MW OCGT peaking plant in the SWIS are highly dependent on the revenue profile, contractual arrangements in place and financial strength of the investor. For example, fully contracted revenues over the entire life of the generation plant (particularly with a strong counter-party) would support a materially different debt structure than a plant taking merchant risk.

The following key assumptions have been applied for the purposes of the evaluation:

1. ***Life of the project***

   We have applied two scenarios for the asset life (following one year construction and commissioning period):

   - 30 years, based on a standard assumption for the operational life of a gas turbine power station;

   - 25 years, to reflect a potentially shorter economic life for the project. The shorter life scenario can also be used to illustrate, in a simplified way, the uncertainty of the revenue stream in the final years of the asset's life and decommissioning costs that are not explicitly modelled in the cash flows.

2. ***Revenue***

   The revenue for the first ten years is based on the owner being awarded capacity credits under the Reserve Capacity Auction at the MRCP and opting to take a ten year contracted position under the Market Rules and administered by the IMO. The price per MW of capacity credit is escalated annually using the Consumer Price Index (CPI) less 1%, consistent with the Market Rules. Capacity credits would be for 136 MW per annum after allowing for the summer de-rating adjustment.

   The revenue for the remaining life of the project is based on the estimated economic price for a new entrant into the market operating a 160 MW OCGT peaking power station, taking a merchant position in the market (that is, without a long term off take contract). Revenue has been assumed to escalate annually at CPI. The potential for a reduction in revenue in the final years of the asset's life has not been explicitly modelled for the purposes of this analysis. The range of outcomes for a 25 year or 30 year project life provide an indication of the sensitivity of the financial returns to lower revenue in the later years of the project.

   The revenue stream under the two MRCP capitalisation periods (15 years and 20 years) only varies in the first ten years of the project when the pricing is established under the MRCP. At the end of this period, the plant would be identical (irrespective of the earlier MRCP pricing) and therefore expected to achieve the same revenue in the market for the remainder of the asset life.

3. *Project finance and gearing*

Project finance terms are based on our appraisal of an indicative debt funding structure which could be achievable for the project with the revenue arrangements outlined above and based on our experience in debt markets with similar types of assets. The leveraging capacity would be higher during the initial ten year period while the revenue stream is supported by a contract under the Market Rules and administered by the IMO. Beyond the initial ten year term, when the project moves to a merchant position in the market, the debt capacity would be reduced.

The illustrative debt terms we have developed focus on the key attributes set out in the following table. The terms have been simplified for the purposes of this evaluation:

Debt term	18 years in total, based on an initial term of 5 years, two refinancing periods of 5 years and a final refinancing for 3 years
Amount and DSCR	The level of debt based on the repayment capacity over the 18 year term applying a debt service cover ratio (DSCR) of 1.5 times in years 1 to 10 and 2.5 times in years 11 to 18 of the debt. An allowance for a debt service reserve account (DSRA) has been incorporated by adding 0.05 to the required DSCR in each year.
Bank fees	Fees determined as 2% of the loan amount at initial drawdown and at each refinancing in years 5, 10 and 15 of the debt facility life.
Other debt ratios	Two key ratios have been considered; gearing (debt/ enterprise value) at the commencement of the loan not to exceed 55% and debt multiple (debt/ EBITDA) not to exceed 4.5 during the term of the facility.

The DSCR is calculated as cash flow available for debt service (CFADS) (comprising EBITDA less tax on ungeared earnings) divided by the annual debt service requirement (including both principal repayment and interest). The DSCR in combination with the revenue stream drives a lower debt capacity under the 20 year capitalisation period for MRCP than is available under the 15 year capitalisation period for MRCP.

The level of gearing under a project financing structure varies over the life of the project as the debt is repaid. This differs from the definition of gearing under the WACC methodology for the MRCP, where the level of gearing is determined based on benchmarks for an efficient business undertaking in the investment assuming a BBB+ credit rating. The level of gearing (defined as debt divided by debt plus equity or enterprise value) assumed in the IMO's current WACC is 40%, with an inherent premise of this being a stable, long term gearing position.

The variable gearing over the life of a project financed asset impacts on the calculation of the cost of equity, WACC and net present value (NPV), requiring a modified methodology to be applied which recalculates the gearing structure annually over the life of the project, as discussed further below.

4. ***Cost of debt and equity***

For the purposes of this evaluation, we have modelled two scenarios for the cost of debt. Firstly, we have applied the same underlying cost of debt and equity parameters as the IMO's current WACC, including the debt margin of 5.25%, as summarised below:

Nominal risk free rate of return	5.59%
Expected inflation	2.90%
Market risk premium	6%
Asset beta	0.5
Debt margin	5.25%
Corporate tax rate	30%

The cost of debt applying these parameters is a relatively high 10.84%. We note that the debt margin applied in the IMO's WACC of 5.25% is higher than the recommended debt margin of 4.65% (plus 0.125% for debt issuance costs) set out in our February 2011 report for the IMO on the WACC methodology for the MRCP. As discussed in that report, the high debt margins reflected the tighter markets for debt capital and perceptions of greater risk for debt finance subsequent to the onset of the global financial crisis.

We note that the outcomes of the IRR and NPV analysis are very sensitive to the WACC, and reductions in the debt margin would impact on the project returns. To illustrate the impact if more favourable debt pricing were to prevail, we have also set out a sensitivity analysis applying a lower debt margin of 2.75%.

5. ***Capital expenditure –*** revised cost of $192 million, consistent with the capital cost applied in the estimated MRCP and as advised by the IMO. Depreciation allowance for tax purposes on a straight line basis over the asset life[2].

6. ***Other costs and revenue*** – revised fixed O&M costs of $29,648 per MW per annum, consistent with the O&M cost applied in the estimated MRCP and as advised by the IMO. Variable costs are not considered in the analysis as income from energy sales is assumed sufficient to cover these costs.

[2] Off take arrangements involving government entities may trigger Division 250 of the ITAA 1997, which would operate to deem the arrangement to be loan for tax purposes and deny the owner tax depreciation deductions for depreciating assets. Given the assumptions of the revenue structure moving to a merchant position after the initial ten year period, we consider there is a low risk of these tax provisions applying.

The financial returns to the notional owner have been evaluated on a nominal post tax basis and the outcomes for the two MRCP pricing scenarios compared under the following key metrics.

Project internal rate of return (IRR)

IRR measures the enterprise rate of return inherent in the initial capital investment and the ungeared, post tax cash flow over the project life. When compared to the hurdle rate of return, the IRR provides an indicator of whether the project achieves an acceptable return for the risk of investment.

For this evaluation, the IRR has been compared to both:

- The IMO's WACC (nominal, post tax) for MRCP purposes of 9.39%. The IMO's WACC is based on a constant gearing of 40%, benchmarked from a group comparator power generators. This comparison therefore provides a measure of the financial performance for the notional owner under a generic gearing profile; that is, irrespective of the individual financing structure and specific projects.
- The required rate of return for the project on a stand-alone basis; namely the WACC derived by applying the gearing under the illustrative project financed debt structure.

Net present value (NPV)

Discounted cash flow analysis measures the level of value created (where positive) or lost (where negative). We have applied a modified NPV approach which explicitly accounts for the variable gearing over the life of the project. The rolling discounting method recognises the variable gearing position by applying the illustrative project finance debt structure to re-calculate the gearing and WACC in each year of the project's life.

Cash flow profile before and after debt service

The cash flow profiles demonstrate the change in the MRCP price on the financial outcome to the owner on an annual, undiscounted basis.

It was beyond the scope of the assignment to undertake comprehensive sensitivity analysis, range analysis or risk-adjusted modelling of the project outcomes for uncertainty in the underlying assumptions. The analysis does not comprise a full business case assessment of the risks and returns of the notional peaking power station defined under the Market Procedure. The illustrative debt structure we have developed for this evaluation has not been specifically tested in the market.

Results of the Analysis

Project internal rate of return

Applying the assumptions, the change in the MRCP pricing formula to a 20 year capitalisation period results in a reduction in the IRR of the power station investment. For the 25 year project life, high debt margin scenario, the IRR moves from above the hurdle required rates of return to a position below the hurdle IRR, as summarised in the following table:

Table 1 - Comparison of IRR	Project Outcomes		Hurdle Rates of Return (note)	
	15 year capitalisation period in MRCP	20 year capitalisation period in MRCP	Project WACC	IMO WACC
30 year project life				
Higher debt margin (5.25%)	10.42%	9.71%	9.07%	9.39%
Lower debt margin (2.75%)	10.14%	9.42%	8.66%	8.69%
25 year project life				
Higher debt margin (5.25%)	9.91%	**9.11%**	9.20%	9.39%
Lower debt margin (2.75%)	9.63%	8.82%	8.67%	8.69%
Note: Project WACC is the inherent WACC over the project life under debt finance structure. The range in gearing structure is outlined in Table 2 below. The IMO WACC is based the standard gearing of 40%.				

Importantly, the analysis suggests that the change in the MRCP pricing formula would reduce the project's returns for **a scenario of 25 year project life and higher debt margin** to a level below the required rate even applying the standard gearing structure which underpins the IMO WACC. In other words, even leaving aside the issue of project finance structures, the project returns under this scenario and under a 20 year capitalisation period for MRCP are not adequate for the generic power station project to be viable when assessed against the IRR criterion.

The underlying gearing levels in the project WACC benchmarks are as set in the following table. By way of comparison, the IMO WACC applies a standard gearing of 40%

Table 2 - Gearing underlying Project WACC benchmarks	Higher Debt Margin (5.25%		Lower Debt Margin (2.75%)	
	15 year capitalisation period in MRCP	20 year capitalisation period in MRCP	15 year capitalisation period in MRCP	20 year capitalisation period in MRCP
30 year project life				
At outset	41.3%	40.0%	46.8%	45.5%
Simple arithmetic average of annual gearing positions over project life	14.8%	14.4%	16.4%	16.0%
25 year project life				
At outset	44.9%	43.7%	50.5%	49.4%
Simple arithmetic average of annual gearing positions over project life	20.4%	19.9%	22.5%	22.0%

Net present value

Under the assumptions set out above, the change in the MRCP formula to a 20 year capitalisation period results in a $13 million to $14 million reduction in the net present value of equity in the project under a debt finance structure. For the scenario of a 25 year project life and higher debt margin, the net present value of equity in the project falls to a negative value (–$1.3 million) if the MRCP price is reduced for the 20 year capitalisation period in the price formula. :

Table 3 – Net present value to owner (pre capital expenditure) under debt finance structure (note)	15 year capitalisation period in MRCP	20 year capitalisation period in MRCP
30 year project life		
Higher debt margin (5.25%)	$25.9 million	$12.8 million
Lower debt margin (2.75%)	$29.2 million	$15.4 million
25 year project life		
Higher debt margin (5.25%)	$11.8 million	**($1.3 million)**
Lower debt margin (2.75%)	$16.4 million	$2.5 million

Note: The NPV analysis applies the annual nominal, post tax WACC for the gearing position under the debt finance debt structure to project cash flows (ungeared, post tax) for each MRCP price scenario. The inherent project WACC over the life of the project is as set out in Table 1.

This reduction in equity value by between $13 million and $14 million is in line with the change in net present value using the IMO's WACC under the standard gearing structure, as set out in the following table:

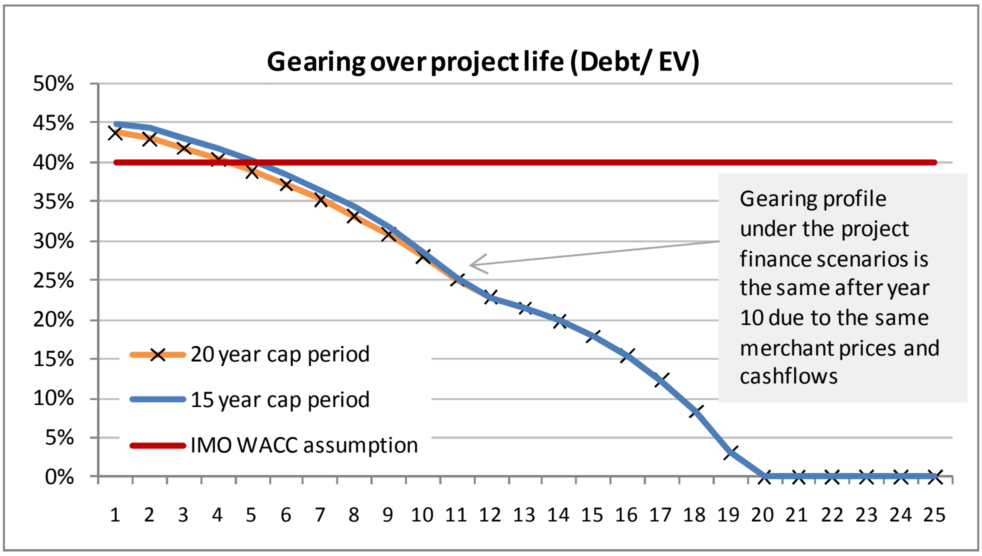
Table 4 – Net present value to owner (pre capital expenditure) under IMO standard gearing structure (note)	**15 year capitalisation period in MRCP**	**20 year capitalisation period in MRCP**
30 year project life		
Higher debt margin (5.25%)	$19.7 million	$6.2 million
Lower debt margin (2.75%)	$28.6 million	$14.7 million
25 year project life		
Higher debt margin (5.25%)	$8.7 million	**($4.7 million)**
Lower debt margin (2.75%)	$16.1 million	$2.2 million
Note: NPV applying the IMO's standard gearing of 40% and nominal, post tax WACC of 9.39% to the project cash flows (ungeared, post tax) for each MRCP price scenario for the higher debt margin scenarios. The lower debt margin scenarios apply a WACC of 8.69% calculated using the lower debt cost and leaving other parameters unchanged.		

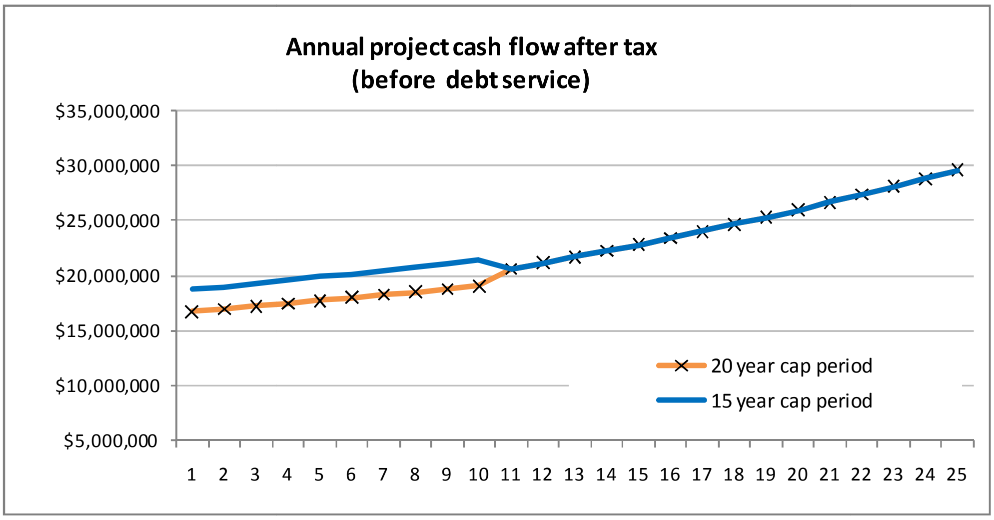
Consistent with the IRR metric, the analysis suggests that in a less favourable scenario of higher debt cost and uncertainty of income stream at the end of the project's life, the change in MRCP would reduce the equity value to a level below that required for an owner to invest in the project where a 25 year life for the generation asset is assumed, irrespective of whether a project finance debt structure is used.

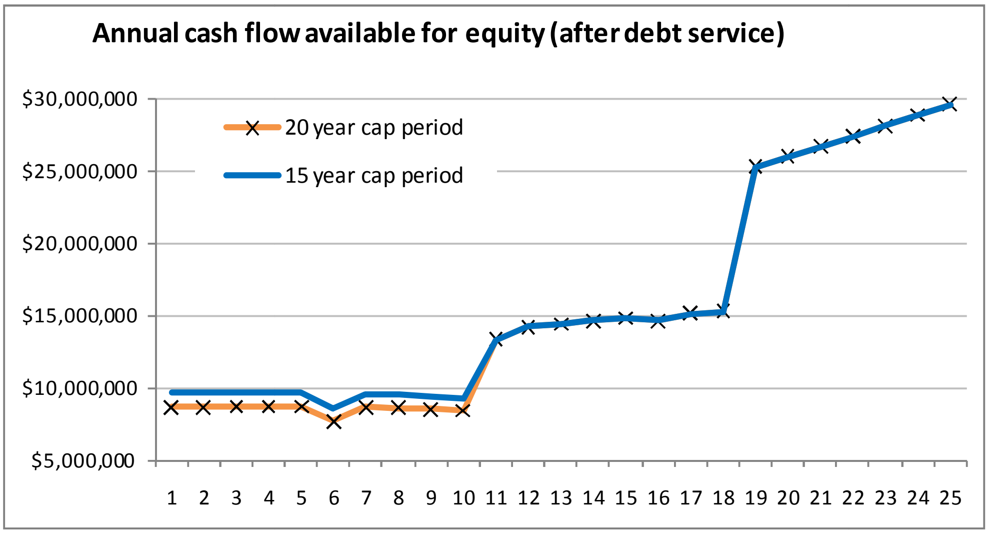
Cash flow profiles

The charts on the next page set out the trend in gearing, CFADS and cash flow to the owner for the 25 year project life, higher debt scenario. The level of debt supported in each of the eight debt finance scenarios examined is set out in the following table:

Table 5 - Level of project debt	**Higher Debt Margin (5.25%)**		**Lower Debt Margin (2.75%)**	
	15 year capitalisation period in MRCP	**20 year capitalisation period in MRCP**	**15 year capitalisation period in MRCP**	**20 year capitalisation period in MRCP**
30 year project life	$90.4 million	$82.3 million	$103.9 million	$94.8 million
25 year project life	$91.8 million	$83.7 million	$105.5 million	$96.4 million


Gearing over project life (Debt/ EV)
50%
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25
20 year cap period
15 year cap period
IMO WACC assumption
Gearing profile under the project finance scenarios is the same after year 10 due to the same merchant prices and cashflows


Annual project cash flow after tax (before debt service)
$35,000,000
$30,000,000
$25,000,000
$20,000,000
$15,000,000
$10,000,000
$5,000,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25
20 year cap period
15 year cap period


Annual cash flow available for equity (after debt service)
$30,000,000
$25,000,000
$20,000,000
$15,000,000
$10,000,000
$5,000,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25
20 year cap period
15 year cap period

9 of 10

Concluding Remarks

The analysis suggests that the 15 year capitalisation period applied in the MRCP formula provides a return to the owner of the notional power station above the benchmark return. Increasing the capitalisation period in the MRCP formula to 20 years could reduce the return to the owner below the levels required to support investment in the notional power station in the case of less favourable conditions, as represented in the higher debt cost, 25 year project life scenario. This outcome is the same applying the standard gearing profile used in the IMO's WACC and the illustrative project finance debt structure we have developed for this analysis.

If a 30 year project life is assumed, then the project remains viable with the increase in capitalisation period within the MRCP formula from 15 to 20 years.

The outcomes of this analysis are sensitive to the assumptions made and should be considered in the context of uncertainty surrounding key assumptions; in particular:

- cost of debt, with debt margins having escalated since the global financial crisis;
- capacity price achieved beyond the initial 10 year contract period with the IMO.

Thank you for retaining us to assist in this important matter for the IMO. If you have any questions or we can assist further, please do not hesitate to contact Julie Cox.

Yours sincerely,

Dr Ray Challen Principal	Julie Cox Director

Agenda Item 6: Draft Procedure

1. BACKGROUND

The MRCPWG has arrived at a number of agreed outcomes during its work to date. These outcomes include the following:

- Power Station type: the appropriate quantity of capacity is 160 MW, provided as a single facility with a nominal nameplate capacity of 160 MW;
- Power Station type: the appropriate power station type is an Open Cycle Gas Turbine with low NOx burners and inlet cooling, operating on distillate with 2% capacity factor;
- Power Station cost: the Consultant who develops the Power Station costs should specify uplift factors for construction costs in the current list of geographical locations;
- Summer De-rating Factor (SDF): the SDF should be specified by the Consultant who develops the Power Station costs, according to available turbine and inlet cooling technology, and taking into account humidity conditions, replacing the value of 1.18 currently indicated in the Market Procedure;
- Transmission Connection Cost: Western Power is the appropriate party to determine shallow connection costs;
- Transmission Connection Cost: the Total Connection Cost methodology proposed by SKM should be implemented;
- Fixed Fuel Cost: the Fixed Fuel Cost should include an allowance to maintain sufficient fuel levels for 14 hours of operation at all times, not 12 hours as currently indicated in the Market Procedure;
- Fixed Operation and Maintenance (O&M): the cost of insurance to replace the facility should be included as a Fixed O&M cost;
- Land Cost: Landgate is the appropriate party to determine land costs;
- Land Cost: the current list of land locations is appropriate, although there should be greater flexibility to add to the list where appropriate;
- Land Cost: a Market Participant may not be required to purchase any required buffer zone if the facility was located in an industrial precinct, so the land size should be standardised at 3 hectares with the stipulation that the buffer zone must exist where required;
- Land Cost: for any location where 3 hectare lots can not be purchased, the lot size should be amended to represent the next largest available lot size in that location;
- Weighted Average Cost of Capital (WACC): the IMO should continue to determine the WACC with the ERA reviewing this in its approval of the MRCP in accordance with clause 2.26.1 of the Market Rules;
- WACC: the majority of recommendations by Pricewaterhouse Coopers will be accepted, excluding the gearing ratio and debt risk premium;

- WACC: the IMO will continue to determine the WACC on a real pre-tax basis
- WACC: debt issuance costs will be included in the WACC calculation and no longer included in the margin M;
- WACC: the gearing ratio will be kept at 40%;
- WACC: the IMO should be allowed the flexibility to select the Debt Risk Premium methodology to align with accepted regulatory practice; and
- Cost optimisation: Land, Transmission and Construction Costs should be optimised to determine the cheapest location.

The IMO presented an updated draft Market Procedure to the 5 May 2011 meeting and requested that the MRCPWG members provide out-of-session feedback on this document.

2. UPDATED DRAFT MARKET PROCEDURE

The IMO has updated the *Market Procedure: Maximum Reserve Capacity Price* to reflect the IMO's new format arising from its Market Procedure project and to incorporate the agreed changes listed above.

The following changes have been made since the last meeting, reflecting agreed outcomes:

- Power Station Costs to be calculated by the Consultant as at April of Year 3 and be accompanied by an explanation of the calculation methodology as well as the use of any escalation factors;
- Transmission Connection, Fixed Fuel and Land Costs to be calculated as at April of Year 3 to align with the application of the WACC at the midpoint of a 12 month construction period;
- Corporate tax rate to be a Minor component to allow for annual update where necessary; and
- General improvements to the document.

The updated draft Market Procedure is provided to the MRCPWG for its evaluation and consideration.

3. REQUIREMENTS OF MRCPWG TERMS OF REFERENCE

The MRCPWG Terms of Reference require the MRCPWG to "Develop an integrated suite of solutions, including drafted Procedure Change Proposals to be presented to the MAC by way of presentation/s and supporting discussion papers." The Terms of Reference also require a full impact assessment be conducted.

The IMO has provided a Draft Procedure Change Proposal. The IMO notes that the impact assessment must be updated to include the impact of inlet cooling.

4. RECOMMENDATIONS

The IMO recommends that the MRCPWG:

- **Review** the amendments made to the *Market Procedure: Maximum Reserve Capacity Price*;
- **Review** the attached draft Procedure Change Proposal;
- **Note** that the IMO will update the Market Procedure and Procedure Change Proposal following the meeting on 20 June 2011 to reflect agreed outcomes from the meeting; and
- **Provide** any additional feedback by no later than 5pm on Monday 27 June 2011.

Wholesale Electricity Market – Procedure Change Proposal

Procedure Change No: PC_2011_XX

Change requested by:

Name:	Greg Ruthven
Phone:	(08) 9254 4301
Fax:	(08) 9254 4399
Email:	Greg.Ruthven@imowa.com.au
Organisation:	IMO
Address:	Level 3, 197 St Georges Terrace, Perth, WA 6000
Date submitted:	XX XXXX 2011
Procedure change title:	Transitional arrangements for the Registration of Demand Side Programmes and the association of Non-Dispatchable Loads
Market Procedure affected:	Market Procedure for Maximum Reserve Capacity Price

Introduction

The Independent Market Operator (IMO) or System Management, as applicable, may initiate the Procedure Change Process by developing a Procedure Change Proposal. Rule Participants may notify the IMO or System Management, as applicable, where they consider an amendment or replacement of a Market Procedure would be appropriate.

If an Amending Rule requires the IMO or System Management to develop new Market Procedures or to amend or replace existing Market Procedures, then the IMO or System Management, as applicable, is responsible for the development, amendment, or replacement of Market Procedures so as to comply with the Amending Rule.

Market Procedures:

(a) must:

- i. be developed, amended or replaced in accordance with the process in the Market Rules;
- ii. be consistent with the Wholesale Market Objectives; and
- iii. be consistent with the Market Rules, the Electricity Industry Act and Regulations; and

(b) may be amended or replaced in accordance with clause 2.10 and must be amended or replaced in accordance with clause 2.10 where a change is required to maintain consistency with Amending Rules.

The Wholesale Market Objectives are:

(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;
(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;
(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;
(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and
(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

Details of Procedure Change Requested

1. Provide a reason for the proposed new, amended or replacement Market Procedure:

Background

The Maximum Reserve Capacity Price (MRCP) sets the maximum bid that can be made in a Reserve Capacity Auction and is used as the basis to determine an administered Reserve Capacity Price if no auction is required. The MRCP aims to reflect the marginal cost of providing additional reserve capacity. Each year the IMO determines the MRCP.

Clause 4.16.9 of the Market Rules requires the IMO to review the MRCP Market Procedure once in every five year period. To assist in undertaking this five year review, the MAC established the MRCP Working Group (WG) in 2010 to consider, assess and develop any recommendations for changes to the Market Procedure. The WG first met on 31 May 2010 and last met on 20 June 2010 with a total of ten meetings held. A record of the proceedings of the WG can be found at www.imowa.com.au/MRCPWG.

The MRCPWG's Review

Early in its review the MRCPWG agreed that the MRCP should continue to be based on the concept of a 160 MW Open Cycle Gas Turbine (OCGT) power plant. However the MRCPWG has agreed a number of changes, as follows, that will require amendments to the Procedure:

- the definition of the model power station is to include a provision for an inlet air cooling system which will affect power station capital costs and impact the summer de-rating factor. The MRCPWG agreed that a developer for a facility similar to the model plant would be likely to install inlet cooling as a cost effective method of boosting Capacity Credit income;
- the power station capital costs are to be determined specifically for each prospective location to take into account variable construction costs. This was agreed by the MRCPWG as the construction costs for the model plant are likely to vary depending on the location of the power station;

- the Fixed Fuel Cost should include an allowance to initially fill the fuel tank with sufficient distillate for 14 hours of operation, not 12 hours as currently indicated in the Market Procedure. This aligns the Market Procedure with the requirements for Certified Reserve Capacity under clause 4.11.1 of the Market Rules;
- the allowance for the inclusion of a greater land size, in excess of the current limit of 3ha, where the minimum available land size in any particular location is greater than 3ha. In addition the IMO shall have the scope to include additional locations, where appropriate, for purposes of the MRCP. The MRCPWG adopted these changes to allow for instances where a minimum land size of 3ha is not available and the inclusion of additional regions to reflect the areas, within the SWIS, where generation projects are most likely to be proposed ;
- a change in the effective compensation period for the total investment costs for the generic power station cost, which was previously 2 years, to 6 months. This is based on the assumption that the total investment cost of the generic power station will be incurred in even incremental amounts over the 12 month period immediately preceding the first Reserve Capacity Year. PricewaterhouseCoopers recommended the change in assumed construction period in their report on the WACC[1] methodology and the MRCPWG has agreed the change. In relation to this it has been agreed that the total investment costs for the generic power station shall be determined as at the same date, being April of Year 3 of the relevant Reserve Capacity Cycle;
- an allowance for the IMO to determine a methodology for determining cost escalation factors in respect of power station, transmission, switchyard and Operating and Maintenance (O&M) costs that is justifiable and has regulatory acceptance. This amendment allows for the utilisation of forward looking escalation factors in the determination of the MRCP;
- an allowance for the use of an alternative methodology for determination of the Debt Risk Premium (DRP) as long as that methodology is justifiable and has regulatory acceptance. This amendment is primarily required to meet inadequacies in the current methodology due to a lack of available up to date data from Bloomberg which is required under the current methodology to determine the DRP. This issue was highlighted by the ERA[2] in their presentation at Meeting 8;
- an allowance for the inclusion of annual costs, within Fixed O&M Costs, associated with asset insurance for the model power plant. The MRCPWG agreed a provision should be made within the Procedure for the inclusion of annual asset insurance costs;
- a change in methodology for the forecast of Transmission Connection Works costs based on historical connection costs and relevant access offers determined by Western Power. The SKM[3] report on determining Deep Connection Costs recommended the use of an alternative methodology of using historic connection costs to indicate future connection costs. The MRCPWG has agreed to adopt the recommended methodology;
- inclusion of debt issuance costs within the WACC and removal of corresponding financing costs from within margin M. The Procedure distinguishes between debt raising costs associated with the development of the power station project which are provided for within margin M and those debt issuance costs associated with the ongoing debt funding of the project accounted for within the WACC; and
- re-classification of CAPM components to reflect the need for annual review. Specifically the Corporate tax rate is to be classified as a Minor component to allow for annual review as the rate of corporate tax can change from year to year. The Debt issuance costs are to be

[1] Maximum Reserve Capacity Price – WACC methodology http://www.imowa.com.au/f2179,1210106/PwC_MRCP_WACC_-_Final_Report_28_February_2011.pdf
[2] Debt Risk Premium – ERA Methodology http://www.imowa.com.au/f2179,1210187/Appendix_A_-_ERA_presentation_-_DRP_to_the_MRCPWG_-_24_March_2011.pdf
[3] Calculation Methodology to be Applied in Determining Deep Connection Costs http://www.imowa.com.au/f2179,1254370/WP04128_-_IMO041_MRCP_Deep_Connection_Cost_Calculation_Method_Interim_Report_Rev3.pdf

classified as a Major component, with a fixed value of 0.125%, subject to 5 yearly review as they are not considered to be significantly volatile on an annual basis.

The MRCPWG considered the limitations of the existing DRP calculation methodology based data supplied by Bloomberg. The ERA presented an alternative approach that it has applied in a recent decision (WAGN[4]), however that decision is being challenged at the Australian Competition Tribunal by WAGN[5]. The MRCPWG noted the merits of the ERA's approach, but also noted that the method could not be considered as accepted regulatory practice whilst the decision was being challenged. Based on this the IMO considers it prudent to allow for the continued use of the current methodology with some minor amendments as recommended by PwC. However noting the in principle agreement by the MRCPWG of the merits of the ERA's approach the IMO intends to further amend the Market Procedure if and when the ERA's proposed methodology is adopted as accepted regulatory practice.

To enact the outcomes of the MRCPWG review, the IMO has made related amendments to the MRCP Market Procedure as detailed in the attached copy of the Market Procedure.

Impact of Procedure change

Analysis has been performed by the IMO to establish the estimated impact of an implementation of the agreed changes with regards to annual insurance costs, the increase in the fuel requirement from 12 to 14 hours, the allowance for a minimum land size above 3 ha, the application of a construction uplift factor, the revised Transmission Connection Cost (TCC) methodology and the reduced effective construction period of 6 months.

The comparison is based on the following assumed variations:

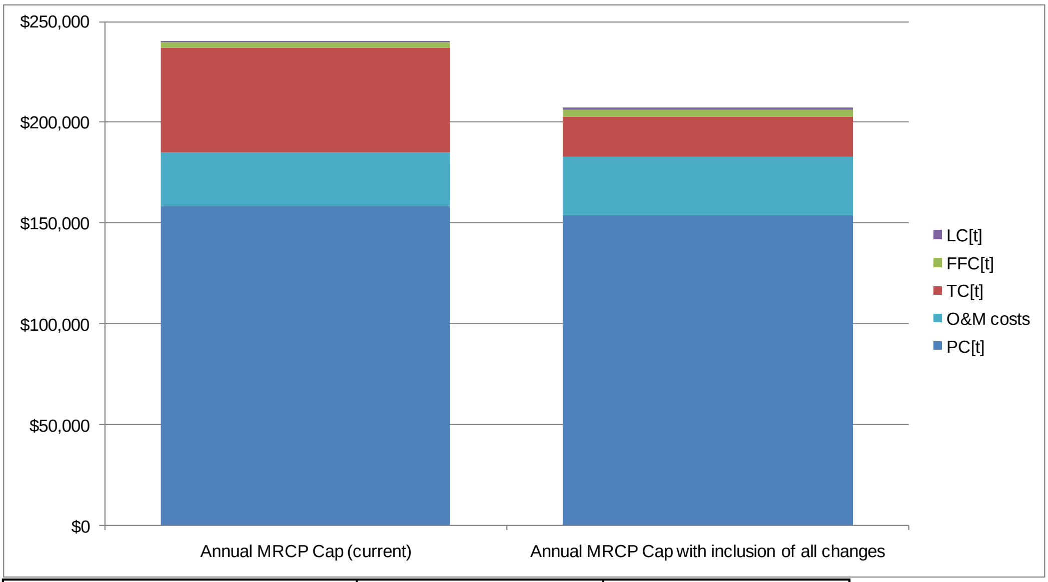
- The WACC has been applied to allow 6 months of return during the construction period (as proposed by PricewaterhouseCoopers and endorsed by the MRCPWG) versus 2 years, as is currently applied. In order to calculate a value at 6 months prior to completion of construction (April of Year 3) an escalation rate of 3% has been estimated and applied for 1.5 years. The rate of 3% has purely been used for comparison purposes;
- The TCC methodology as proposed by SKM and endorsed by the MRCPWG, producing a TCC of $127,000 per MW versus the current value of $305,000 per MW has been used for comparison purposes;
- The fuel requirement has been increased from 12 to 14 hours at full operation;
- The minimum available land size at Kemerton is 5 ha;
- An uplift factor of 5% has been applied to the power station construction costs to produce a value for Kemerton; and
- The inclusion of annual insurance premiums within the fixed O&M cost as agreed by the MRCPWG. An estimated asset insurance cost of $2,500 per MW has been used for this exercise. This estimate is based on indicative quotations obtained from insurance brokers. This cost shall be determined on an annual basis.

[4] ERA Final decision on WA Gas Networks Pty Ltd proposed revised access arrangement http://www.erawa.com.au/cproot/9382/2/20110228%20Final%20decision%20on%20WA%20Gas%20Networks%20Pty%20Ltd%20proposed%20revised%20access%20arrangement%20for%20the%20MW%20and%20SW%20GDS.pdf

[5] WA Gas Networks (WAGN) Media Release http://www.wagn.com.au/LinkClick.aspx?fileticket=RwkyI238dUs%3d&tabid=39

Annual MRCP Cap (current)	240,621	-
MRCP with Rawlinsons uplift factor of 5% for Kemerton	248,556	+ 3%
MRCP with Insurance costs	243,121	+ 1%
MRCP with increase in fuel requirement from 12 to 14 hours	241,241	+ 0.3%
MRCP with increase in Land size, for Kemerton, from 3 to 5 ha	241,228	+ 0.3%
MRCP with WACC applied based on 6 months return	224,149	-7%
MRCP with proposed TCC methodology	210,657	-12%
MRCP with all changes incorporated	207,255	-14%

The graph shown below illustrates the relative contribution of the various component costs to the total MRCP, both under the current methodology and under a methodology where the WACC is applied based on 6 months return, the TCC calculation methodology is amended, the fuel requirement is increased from 12 to 14 hours, the land size used for Kemerton is 5 rather than 3 ha, a construction uplift factor of 5% is applied for Kemerton, and annual asset insurance costs are included within the Fixed O&M component. A comparison for implementation of the revised DRP methodology has not been included as there is to be an option to use an alternative methodology rather than a requirement to do so.



Capacity Year	**13/14 current**	**13/14 revised**
Power Station Cost	$ 158,710	$ 153,817
Transmission Costs	$ 51,621	$ 19,990
Fixed O& M	$ 26,649	$ 29,149
Fuel Costs	$ 2,825	$ 3,042
Land Costs	$ 818	$ 1,258
MRCP (nearest $100)	$ 240,600	$ 207,300

Request for public consultation

The IMO is seeking submissions regarding this proposal. The submission period is 20 Business Days from the publication of this Procedure Change Proposal. Submissions must be delivered to the IMO by **XX, XX XX XX.**

The IMO prefers to receive submissions by email to market.development@imowa.com.au using the submission form available on the IMO website: http://www.imowa.com.au/procedure-changes

Submissions may also be sent to the IMO by fax or post, addressed to:

Independent Market Operator
Attn: General Manager Development
PO Box 7096
Cloisters Square, Perth, WA 6850
Fax: (08) 9254 4399

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2. Provide the wording of the Procedure

The proposed revised Market Procedure for Maximum Reserve Capacity Price is provided as an attachment to this proposal.

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3. Describe how the proposed changes to the Market Procedure would be consistent with the Market Rules, the Electricity Industry Act and Regulations

The proposed new Market Procedure has been reviewed as a whole by the IMO to ensure compliance of the Market Procedure with the relevant provisions in the:

- Market Rules (including the Amending Rules currently proposed under the RC_2010_29);
- Electricity Industry Act; and
- Regulations.

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4. Describe how the proposed changes to the Market Procedure would be consistent with the Wholesale Market Objectives

The IMO considers that the revised Market Procedure improves Market Objective (a), promoting economic efficiency through greater alignment with real-world costs.

The IMO considers that the steps are drafted in a way that does not change the operation or objectives of the Market Rules. As a result the IMO considers that the revised Market Procedure, as a whole, is consistent with the Wholesale Market Objectives.

MARKET PROCEDURE: Maximum Reserve Capacity Price

VERSION 54

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ELECTRICITY INDUSTRY ACT 2004

ELECTRICITY INDUSTRY
(WHOLESALE ELECTRICITY MARKET)
REGULATIONS 2004

WHOLESALE ELECTRICITY MARKET RULES

COMMENCEMENT:

This Market Procedure took effect from 8:00am (WST) on the same date as the Wholesale Electricity Market Rules.

VERSION HISTORY

VERSION	EFFECTIVE DATE	NOTES
1	13 October 2008	Market Procedure for Determination of the Maximum Reserve Capacity Price resulting from PC_2008_06
2	4 December 2008	Amended Market Procedure for Determination of the Maximum Reserve Capacity Price resulting from PC_2008_14
3	1 April 2010	Amendments to the Procedure resulting from Procedure Change Proposal PC_2009_12
4	11 October 2010	Amendments to the Procedure resulting from Procedure Change Proposal PC_2010_04
5	XXXX	Amendments to the Procedure resulting from XXXX

CONTENTS

1 PROCEDURE FOR DETERMINING THE MAXIMUM RESERVE CAPACITY PRICE

This procedure for determining the Maximum Reserve Capacity Price sets out the principles to be applied and steps to be taken by the Independent Market Operator (IMO) in order to develop and propose the Maximum Reserve Capacity Price as required under the Market Rules. Under the Market Rules, the Maximum Reserve Capacity Price is used as the price cap for the Reserve Capacity Auction in the event that one is held. It is also used as the basis of determining the price of uncontracted Capacity Credits in the case where the Reserve Capacity Auction is cancelled.

1.1 Interpretation

1.1.1 In this procedure, unless the contrary intention is expressed:

(a) terms used in this procedure have the same meaning as those given in the Wholesale Electricity *Market Amending Rules* (made pursuant to Electricity Industry (Wholesale Electricity Market) Regulations 2004);

(b) to the extent that this procedure is contrary or inconsistent with the Market Rules, the Market Rules shall prevail to the extent of the inconsistency;

(c) a reference to the Market Rules or Market Procedures includes any associated forms required or contemplated by the Market Rules or Market Procedures; and

(d) words expressed in the singular include the plural or vice versa.

1.2 Purpose

The purpose of this procedure is to describe the steps that the IMO must undertake in determining the Maximum Reserve Capacity Price in each Reserve Capacity Cycle.

This procedure is made in accordance with clause 4.16.3 of the Market Rules.

1.3 Application

1.3.1 This procedure applies to:

(a) The IMO in determining the Maximum Reserve Capacity Price; and

(b) Western Power in developing estimates of the costs associated with connecting a notional Power Station to the 330 kV transmission system.

1.4 Overview of the Maximum Reserve Capacity Price

The Maximum Reserve Capacity Price sets the maximum offer price that can be submitted in a Reserve Capacity Auction and is used as the basis to determine an administered Reserve Capacity Price if no auction is required. Each year the IMO is required to conduct a review of the appropriateness of a number of the components that are used to determine the Maximum Reserve Capacity Price.

1.5 Definition of Power Station

1.5.1 The Power Station upon which the Maximum Reserve Capacity Price shall be based will:

(a) be representative of an industry standard liquid-fuelled Open Cycle Gas Turbine (OCGT) power station;~~.~~

(b) have a nominal nameplate capacity of 160 MW;~~.~~

(c) operate on distillate as its fuel source;~~.~~

(d) have a capacity factor of 2%;~~.~~

(e) include low Nitrous Oxide (NOx) burners or associated technologies as would be required to demonstrate good practice in power station development; and~~.~~

(f) include an inlet air cooling system.

1.6 Scope of the Factors to Maximum Reserve Capacity Price

1.6.1 The Maximum Reserve Capacity Price is to include all reasonable costs expected to be incurred in the development of the Power Station, which will include estimation and determination of:

(a) Power Station balance of plant costs, which are those other ancillary and infrastructure costs that would normally be experienced when developing a project of this nature;

(b) land costs;

(c) costs associated with the development of liquid fuel storage and handling facilities;

(d) costs associated with the connection of the Power Station to the bulk transmission system;

(e) allowances for legal costs, insurance costs, financing costs and environmental approval costs;

(f) reasonable allowance for a contingency margin; and

(g) estimates of fixed operating and maintenance costs for the Power Station, fuel handling facilities and the transmission connection components.

1.7 Development of Costs for the Power Station

1.7.1 The IMO shall engage a consultant to provide advice, including an estimate of the costs associated with designing, purchasing and constructing the Power Station. The Power Station costs shall be determined with specific reference to the use of actual project-related data and shall take into account the specific development conditions under which the Power Station will be developed. This may include direct reference to:

(a) Existing power stations, or power station projects under development, in Australia and more particularly Western Australia.

(b) Worldwide demand for gas turbine engines for power stations.

(c) The engineering, design and construction, environment and cost factors in Western Australia.

(d) The level of economic activity at the state, national and international level.

1.7.2 Development of the Power Station costs shall include components for the gas turbine engines, and all Balance of Plant costs that would normally be applicable to such a Power Station. This must include, but will not be limited to the following items:

(a) Civil Works.

(b) Mechanical Works.

(c) Electrical Works.

(d) Buildings and Structures.

(e) Engineering and Plant Setup.

(f) Miscellaneous and other costs.

Independent Market Operator

(g) Communications and Control equipment.

(h) Commissioning Costs.

1.7.3 The advice provided under step 1.7.1 shall include estimates of Power Station Costs for each location, listed in step 1.11.1, determined through the use of locational multipliers, as at April in Year 3 of the Reserve Capacity Cycle.

A summary of any escalation factors used in determining the Power Station Costs must be included in the advice.

1.7.4 The advice provided under step 1.7.1 shall include a Summer De-rating Factor for the Power Station which shall take into account available turbine and inlet cooling technology, likely humidity conditions and any other relevant factors.

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1.8 Transmission Connection Works

1.8.1 Western Power will forecast the Total Connection Costs based on historic connection costs and relevant access offers for generators that are capable of being liquid fuelled. This forecasting methodology will incorporate the following:

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(a) Each Connection Cost or Access Offer should include all transmission costs from the terminals of the generator step up transformer into the network (including costs of procuring land easements etc.). If Western Power's connection cost data does not include all of the costs within this scope these costs should be estimated using Western Power's estimating methodology. All costs shall be with reference to the year of commissioning of the generator.

(a) For years for which no suitable historic data is available a connection cost will be calculated on the basis defined in clause 1.8.2.

(b) The sum of connection costs for each year should be divided by the sum of the generators' certified capacity in that year to provide an "average per unit capacity" connection cost for each year.

(c) The average per unit capacity costs should be escalated into the dollars of the year of calculation. The basis of escalation will be the average change over 5 years in the estimates calculated consistent with clause 1.8.2.

(d) The escalated per unit capacity costs for the relevant Capacity Year and the 4 years preceding should be multiplied by the weighting factor in the table below:

Year	Weighting
MRCP Calculation Year	7
MRCP Calculation Year - 1	5
MRCP Calculation Year - 2	3
MRCP Calculation Year - 3	1
MRCP Calculation Year – 4	1

The sum of the 5 years of scaled, escalated, average per unit capacity costs for the 5 years under consideration should be divided by 17 to provide a weighted average per unit connection cost.

(e) The weighted average per unit cost shall be scaled up by a 15% forecasting error margin and escalated forward to April of Year 3 of the Reserve Capacity Cycle to provide the forecast connection cost.

(f) Western Power must appoint a suitable auditor to review the application of the process in clause 1.8.1 on an independent and confidential basis. Western Power must provide the advice of the auditor to the IMO, who must publish the advice.

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~~Western Power shall provide Transmission Connection Cost Estimates on the basis defined in Step 0.~~

1.8.2 ~~The Transmission Connection Cost Estimate shall be developed on the following basis~~For the purposes outlined in step 1.8.1, Western Power will also estimate the cost of a direct transmission connection on the following basis:

(a) The capital cost (procurement, installation and commissioning, excluding land cost) of a generic, industry standard 330kV substation that facilitates the connection of the Power Station will be estimated.

(b) The estimate will include all the components and costs associated with a standard substation.

(c) The estimated cost will be based on a generic three breaker mesh substation configured in a breaker and a half arrangement.

(d) The substation will be located adjacent to an existing transmission line and include an allowance for 2km of 330kV overhead single circuit line to the power station that will have one road crossing.

(e) It shall be assumed that the transmission connection to the Power Station will be located on 50% flat - 50% undulating land, 50% rural - 50% urban location and there will be no unforeseen environmental or civil costs associated with the development.

(f) The connection of the substation into the existing transmission line will be turn-in, turn-out and will be based on the most economical (i.e. least cost) solution. It is assumed that the existing transmission line will not require modification to allow the connection with the exception of one new tower located at the substation to allow a point of connection.

(g) Costs associated with any staging works will not be considered.

(h) Shallow connection easement costs will be considered.

1.9 Fixed Operating and Maintenance Costs

1.9.1 The IMO must determine Fixed Operating and Maintenance (O&M) costs for the Power Station and the associated transmission connection works.

1.9.2 The Fixed O&M costs may be separated into those costs associated with the Power Station, those costs associated with the transmission connection infrastructure and any other major components that are considered likely to be of sufficient magnitude so as to require separate determination.

1.9.3 Fixed O&M costs shall also include:

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(a) fixed network access and/or ongoing charges, which are to be provided by Western Power; and

(b) annual asset insurance costs.

~~1.9.3~~1.9.4 To assist in the computation of annualised Fixed O&M costs, the costs associated with each major component shall be presented in 5 year periods covering 1 to 5 years; 6 to 10 years; 11 to 15 years; 16 to 20 years; 21 to 25 years; 26 to 30 years; 31 to 35 years; 36 to 40 years; 41 to 50 years; 51 to 55 years; and 56 to 60 years as required respectively.

~~1.9.4~~1.9.5 The Fixed O&M costs shall be converted into an annualised Fixed O&M cost as required under the determination methodology in section 1.14.

1.9.6 The IMO shall engage a consultant to assist the IMO in reviewing and estimating the Fixed O&M costs.

1.9.7 Fixed O&M costs must be determined as at April in Year 3 of the Reserve Capacity Cycle. Where Fixed O&M costs have been determined at a different date, those costs must be escalated using the following escalation factors which shall be provided as part of the advice provided under step 1.9.6 and applied to relevant components within the Fixed O&M cost:

(a) a Generation O&M Cost escalation factor for Generation O&M costs

(b) a Labour cost escalation factor for transmission and switchyard O&M costs

(c) CPI for fixed network access and/or ongoing charges determined with regard to the forecasts of the Reserve Bank of Australia and, beyond the period of any such forecasts, the mid-point of the Reserve Bank's target range of inflation.

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1.10 ~~Liquid Fuel Storage and Handling Facilities~~Fixed Fuel Cost

1.10.1 The IMO must determine appropriate and reasonable costs for the Liquid Fuel storage and handling facilities. Costs associated with the following items should be developed:

(a) A fuel tank of 1,000 t (nominal) capacity including foundations and spillage bund.

(b) Facilities to receive fuel from road tankers.

(c) All associated pipework, pumping and control equipment.

1.10.2 The estimate should be based on the following assumptions:

(a) Land is available for use and all appropriate permits and approvals for both the power station and the use of liquid fuel have been received.

(b) The capacity of the storage tank should be sufficient to allow for 24 hours of continuous operation at maximum capacity for a 160 MW open cycle gas turbine power station.

(c) Any costing components that may be time-varying in nature must be disclosed as part of the modelling. Such components might be the cost of the liquid fuel, which will vary over time and as a function of exchange rates etc.

1.10.3 The costing should only reflect fixed costs associated with the Fixed Fuel Cost (FFC) component and should include an allowance ~~for keeping~~ to initially supply fuel sufficient to allow for the Power Station to operate for 14 hours at maximum capacity~~the tank half full at all times~~.

1.10.4 The IMO may engage a consultant to assist the IMO in reviewing and estimating the costs associated with liquid fuel storage and handling facilities.

1.10.5 Fixed Fuel Costs (FFC) must be determined as at April in Year 3 of the Reserve Capacity Cycle. Where Fixed Fuel Costs have been determined at a different date, those costs must be escalated using the annual CPI cost escalation factor determined in step 1.9.7(c).

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1.11 Land Costs

1.11.1 The IMO shall retain Landgate under a consultancy agreement each year to provide valuations on parcels of industrial land. The regions in which the analysis would be conducted ~~are~~will include:

(a) Collie Region

(b) Kemerton Industrial Park Region

(c) Pinjar Region

(d) Kwinana Region

(e) North Country Region

(f) Kalgoorlie Region

These areas represent the regions within the South West interconnected system (SWIS) where generation projects are most likely to be proposed and should provide a broad cross-section of options. Where appropriate, the IMO may include additional locations.

1.11.2 Land costs must be determined as at April in Year 3 of the Reserve Capacity Cycle. Where Land costs have been determined at a different date those costs must be escalated using the CPI escalation from step 1.9.7(c).

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1.11.3 The IMO will contract with Landgate to conduct the valuations on the same land parcel size, so as to provide a consistent method of valuing the cost of purchase of the land. The IMO will provide an indication as to the size of land required, which should be limited to the following options:

(a) One 3ha parcel of land in an industrial area of a standard size with consideration given to any requirements for a buffer zone in that specific location. ~~which does not require a significant buffer zone due to its classification. For example. 3 ha.~~ Where the minimum land size available in any specific location is greater than 3ha, for the purpose of calculating the land cost for that specific location, the minimum available land size at that location shall be used.

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(b) The summation of multiple smaller parcels of land as appropriate to meet the requirements above.

c) ~~One larger parcel of land which includes the requirement of a buffer zone. For example. 30 ha.~~

1.12 Legal, Financing, Insurance, Approvals and Other Costs (margin M)

1.12.1 The IMO shall determine ~~an estimate for~~ the value of margin M, which shall constitute the following costs associated with the development of the Power Station project:

(a) legal costs associated with the design and construction of the power station.

(b) financing costs such as debt and equity raising costs not directly covered in the debt issuance costs within the Weighted Average Cost of Capital~~application of the cost of finance the Maximum Reserve Capacity Price~~.

(c) insurance costs required to insure the replacement of capital equipment and infrastructure;~~. This component shall be computed as part of the determination of the Weighted Average Cost of Capital (WACC).~~

(d) approval costs including environmental consultancies and approvals, and local, state and federal licensing, planning and approval costs;

(e) other fixed costs associated with operating and maintaining the Power Station; and

(f) contingency costs, where this shall be equal to a factor of 0.15.

1.12.2 The IMO may engage a consultant or consultants to directly estimate costs associated with the provision of Legal Costs, Financing, Insurance and Environmental approval costs.

1.13 Weighted Average Cost of Capital (WACC)

1.13.1 The IMO must determine the cost of capital to be applied to various costing components of the Maximum Reserve Capacity Price. This cost of capital shall be an appropriate WACC for the generic Power Station project considered, where that project is assumed to receive Capacity Credits through the Reserve Capacity Auction and be eligible to receive a Long-Term Special Price Arrangement through the Reserve Capacity Mechanism.

1.13.2 The WACC will be applied directly:

(a) in the annualisation process used to convert the Power Station project capital cost into an annualised capital cost; and

(b) to account for the cost of capital in the time period between when the Reserve Capacity Auction is held (i.e. when capital is raised), and when the payment stream is expected to be realised. ~~To maintain computational simplicity, the nominal time for this period is two years.~~To maintain computational simplicity it is assumed that the total investment cost of the generic power station will be incurred in even incremental amounts over the 12 month period immediately preceding the first Reserve Capacity Year. As a result the effective compensation period for the total investment cost for the generic power station will be six months as detailed in the CAPCOST formula in step 1.14.1.

1.13.3 The methodology adopted by the IMO to determine the WACC ~~may~~ will involve a number of components that require review. These components ~~will normally be~~are classed as those which require review annually (called Minor components) and those structural components of the WACC which require review less frequently (called Major components) as detailed in step 1.13.8.~~.~~

~~1.13.4 The IMO must determine the WACC for the purposes of calculating the Maximum Reserve Capacity Price.~~

~~1.13.5~~1.13.4 In determining the WACC, the IMO:

(a) must annually review the Minor components; and.

(b) may review the Major components if, in the IMO's opinion, a significant economic event has occurred since undertaking the last 5 yearly review of the Maximum Reserve Capacity Price in accordance with clause 4.16.9 of the Market Rules.

~~1.13.6~~1.13.5 The IMO may engage a consultant to assist the IMO in reviewing the Major and Minor components of the WACC.

~~1.13.7~~1.13.6 The IMO shall compute the WACC on the following basis:

(a) The WACC shall use the Capital Asset Pricing Model (CAPM) as the basis for calculating the return to equity.

(b) The WACC shall be computed on a Pre-Tax basis.

(c) The WACC shall use the standard Officer WACC method as the basis of calculation.

~~1.13.8~~1.13.7 The pre-tax real Officer WACC shall be calculated using the following formulae

$$WACC_{real} = \left(\frac{(1+WACC_{nominal})}{(1+i)}\right) - 1 \text{ and}$$

$$WACC_{nominal} = \frac{1}{(1-t(1-\gamma))} R_e \frac{E}{V} + R_d \frac{D}{V}$$

Where:

(a) R_e is the nominal return on equity (determined using the Capital Asset Pricing Model) and is calculated as:

$$R_e = R_f + \beta_e \times MRP$$

Where:

R_f is the nominal risk free rate for the Capacity Year;

β_e is the equity beta; and

MRP is the market risk premium.

(b) R_d is the nominal return on debt and is calculated as:

$$R_d = R_f + DM$$

Where:

R_f is the nominal risk free rate for the Capacity Year;

~~*DRP*~~ *DM* is the debt ~~risk premium for the Capacity Year~~margin, which is calculated as the sum of the debt risk premium (DRP) and debt issuance cost (d).~~;~~

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(c) *t* is the benchmark rate of corporate income taxation, established at either an estimated effective rate or a value of the statutory taxation rate;

(d) γ is the value of franking credits;

(e) *E/V* is the market value of equity as a proportion of the market value of total assets;

(f) *D/V* is the market value of debt as a proportion of the market value of total assets; and

(g) The nominal risk free rate, R_f, for a Capacity Year is the rate determined for that Capacity Year by the IMO on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of 10 years:

– using the indicative mid rates published by the Reserve Bank of Australia;

and

– averaged over a 20-trading day period.

(h) The debt risk premium, *DRP*, for a Capacity Year is the premium determined for that Capacity Year by the IMO as the margin between the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a BBB~~+~~ (or equivalent) credit rating from Standard and Poors and a maturity of 10 years and the nominal risk free rate:

– using the predicted yields for corporate bonds published by Bloomberg for 10 year BBB rated bonds;

– using the nominal risk free rate calculated as directed above; and

– the nominal risk free rate and Bloomberg yields averaged over the same 20-trading day period.

(i) If there are no Commonwealth Government bonds with a maturity of 10 years on any day in the period referred to in s~~S~~tep~~s~~ 1.1.1(g)~~1.13.7(g) and 1.1.1(h)~~, the IMO must determine the nominal risk free rate ~~and the *DRP*~~ by interpolating on a straight line basis from the two bonds closest to the 10 year term and which also straddle the 10 year expiry date.

(j) If the ~~methodology~~ methods used in s~~S~~teps 1.13.7(h) and 1.13.7~~8~~(i) cannot be applied due to suitable bond terms being unavailable, the IMO may determine the nominal risk free rate and the DRP by means of an appropriate approximation.

~~(j)~~(k) *i* is the forecast average rate of inflation for the 10 year period from the date of determination of the WACC. In establishing a forecast of inflation, the IMO is to have regard to the forecasts of the Reserve Bank of Australia and, beyond the period of any such forecasts, the mid-point of the Reserve Bank's target range of inflation.

~~1.13.9~~1.13.8 The CAPM shall use the following parameters as variables each year.

CAPM Parameter	Notation/Determination	Component	Value
Nominal risk free rate of return (%)	R_f	Minor	TBD
Expected inflation (%)	~~π_e~~ i	Minor	TBD
Real risk free rate of return (%)	R_{fr}	Minor	TBD
Market risk premium (%)	*MRP*	Major	6.00
Asset beta	β_a	Major	0.5
Equity beta	B_e	Major	0.83
Debt risk premium~~margin~~ (%)	~~*DM*~~*DRP*	Minor	TBD
Debt issuance costs (%)	d	~~Minor~~Major	~~TBD~~0.125
Corporate tax rate (%)	*t*	~~Major~~Minor	30

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Franking credit value	γ	Major	0.5
Debt to total assets ratio (%)	*D/V*	Major	40
Equity to total assets ratio (%)	*E/V*	Major	60

1.14 Determination of the Maximum Reserve Capacity Price

1.14.1 The IMO shall use the following formulae to determine the Maximum Reserve Capacity Price:

A value for PRICECAP shall be determined for each of the locations as listed under step 1.11.1. The lowest determined value for PRICECAP shall be used as the Maximum Reserve Capacity Price.

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~~The Maximum Reserve Capacity Price to apply for a Reserve Capacity Auction held in calendar year t is PRICECAP[t] where this is to be calculated as:~~

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PRICECAP~~[t]~~ = (ANNUALISED_FIXED_O&M~~[t]~~ + ANNUALISED_CAPCOST~~[t]~~ / (CAP / SDF))

Where:

PRICECAP~~[t]~~ is the Maximum Reserve Capacity Price to apply in a Reserve Capacity Auction ~~held in calendar year t~~;

ANNUALISED_CAPCOST~~[t]~~ is the CAPCOST~~[t]~~, expressed in Australian dollars ~~in year t~~, annualised over a 15 year period, using a Weighted Average Cost of Capital (WACC) as determined in step 1.13~~as part of the Maximum Reserve Capacity Price Market Procedure and updated as required~~;

CAP is the capacity of an open cycle gas turbine, expressed in MW, and equals 160MW;

SDF is the summer derating factor of a new open cycle gas turbine, and ~~equals 1.18~~shall be determined, in conjunction with Power Station costs in step 1.7.4;~~;~~

CAPCOST~~[t]~~ is the total capital cost, expressed in million Australian dollars ~~in year t~~, estimated for an open cycle gas turbine power station of capacity CAP; and

ANNUALISED_FIXED_O&M~~[t]~~ is the annualised fixed operating and maintenance costs for a typical open cycle gas turbine power station and any associated electricity transmission facilities determined in step 1.9 and~~,~~ expressed in Australian dollars in year t, per MW per year.

The value of CAPCOST~~[t]~~ for each location is to be calculated as:

CAPCOST~~[t]~~ = (PC~~[t]~~ x (1 + M) x CAP + TC~~[t]~~ + FFC~~[t]~~ + LC~~[t]~~) x (1+ WACC)^~~2~~$^{1/2}$

Where:

PC~~[t]~~ is the capital cost of an open cycle gas turbine power station ~~in year t~~, expressed in Australian dollars ~~in year t~~ per MW as determined in step 1.7 for that location;

M is a margin to cover legal, approval, financing and ~~and financing~~ other ~~costs and~~ contingencyies costs as detailed in step 1.12;

TC~~[t]~~ is the Transmission Connection Cost Estimate as determined in step 1.8 for that location, ~~is the cost of electricity transmission assets required to connect an open cycle gas turbine power station to the SWIS, plus an estimate of the costs of augmenting the shared network to facilitate the connection of the open cycle gas turbine power station, expressed in Australian million dollars in year t~~;

FFC~~[t]~~ is the Fixed Fuel Cost as determined in step 1.9; ~~is the fixed fuel costs and must represent the fixed costs associated with an on-site liquid storage tank with sufficient capacity for 24 hours of Liquid Fuel including the cost of keeping this tank half full at all times expressed in Australian million dollars in year t;~~

LC~~[t]~~ is the Land Cost as determined in step 1.11 for that location ~~is the cost of land purchased in year [t]~~; and

WACC is the Weighted Average Cost of Capital as determined in step 1.13.

1.14.2 Once the IMO has determined a revised value for the Maximum Reserve Capacity Price, the IMO must publish a draft report describing how it has arrived at the proposed revised value **[MR4.16.6]**. In preparing the draft report, the IMO must include details of how it has arrived at any proposed revised values for the Major and Minor components used in calculating the WACC.

1.14.3 The IMO must publish the draft report on the Market Web-site and advertise the report in newspapers widely distributed in Western Australia and request submissions from all sectors of the Western Australian energy industry, including end users. The IMO must publish any supporting consultant reports.

1.14.4 After considering any submissions on the draft report the IMO must propose a final value for the Maximum Reserve Capacity Price and submit the report to the Economic Regulation Authority (ERA) of Western Australia for approval.

1.14.5 Once the final value for the Maximum Reserve Capacity Price, with any updates, has been approved by the ERA, the IMO shall post a final report on the IMO website advising of the revised Maximum Reserve Capacity Price.

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1.14.6 The IMO shall publish the Maximum Reserve Capacity Price in the Request for Expressions of Interest document which must be published before 31 January of Year 1 of the relevant Reserve Capacity Cycle.

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1.15 Major Review

1.15.1 In accordance with clause 4.16.9, the IMO must conduct a review of the methodology used to determine the Maximum Reserve Capacity Price at least once every five years ("Major Review"). This process will review the basis for determining the Maximum Reserve Capacity Price, the structural methodology by which the Maximum Reserve Capacity Price is computed each year and the method the IMO uses to estimate each of the constituent components of the Maximum Reserve Capacity Price.

1.15.2 For annual reviews carried out between Major Reviews the IMO must use the same methodology as it used in the most recent Major Review. However, where the IMO considers that any of the comparator companies used in the most recent Major Review are no longer available or that its characteristics have significantly changed, the IMO may select a different set of comparator companies, applying the following criteria:

(a) the company must be a power generator, energy transmitter or distributor;

(b) market capitalisation must be more than $200m AUD; and

(c) the company must be listed on Bloomberg.

Maximum Reserve Capacity Price Basis

1.15.3 The basis of determining the Maximum Reserve Capacity Price shall be reviewed by the IMO with particular reference to the following factors:

(a) The type of power station

(b) The size of the power station

(c) The expected load factor of the power station

(d) Primary and secondary fuel types of the power station.

1.15.4 The above review must give consideration to the Wholesale Electricity Market Objectives.

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Power Station

1.15.5 In accordance with Market Rule 4.16.9, the IMO must conduct a review of the definition of the Power Station and its associated components. The IMO is required to take into consideration the following factors:

(a) The method used to determine the Power Station price

(b) The summer derating factor applied to the Power Station

(c) The capacity factor of the Power Station.

Transmission Connection

1.15.6 In accordance with Market Rule 4.16.9, the IMO must conduct a review of the type of direct connection assumed in step 1.8.2 ~~used to connect the Power Station to the bulk transmission network~~. The IMO is required to take into consideration the following factors:

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(a) Which part of the bulk transmission system the Power Station will be connected to (eg 330kV / 220 kV/ 132 kV).

(b) Land use type assumptions (rural/urban options).

(c) The switchyard configuration.

(d) The number of road crossings.

Fixed Fuel Costs

1.15.7 In accordance with Market Rule 4.16.9 the IMO must conduct a review of the fixed fuel costs with direct reference to the outcome of the review of the Maximum Reserve Capacity Price in s~~S~~tep ~~0~~ 1.15.1 above.