Independent Market Operator

MRCPWG

Agenda

Meeting No.	6
Location:	IMO Board Room, Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Thursday, 20 January 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.	**WEIGHTED AVERAGE COST OF CAPITAL METHODOLOGY – DRAFT REPORT**	**IMO/PwC**	45 min
5.	**DEEP CONNECTION COSTS – PRESENTATION ON METHODOLOGY**	**IMO/SKM**	45 min
6.	**GENERAL BUSINESS**	**IMO**	5 min
7.	**NEXT MEETING** Thursday 17 February 2011 (3:00-5:00pm)	**Chair**	5 min

Independent Market Operator

MRCPWG

Minutes

Meeting No.	5
Location:	IMO Board Room Level 3, Governor Stirling Building, 197 St Georges Terrace, Perth
Date:	Wednesday 15 September 2010
Time:	Commencing at 3:00 to 5:00pm

Attendees	
Troy Forward	IMO (Chair)
Fiona Edmonds	IMO (Minutes)
Greg Ruthven	IMO
Ben Williams	IMO
Monica Tedeschi	IMO
Corey Dykstra	Market Customer
Stephen MacLean	Market Customer
Neil Hay	System Management (3.10-4.20pm)
Shane Cremin	Market Generator
Brad Huppatz	Market Generator
Pablo Campillos	DSM Aggregator
Nenad Ninkov	New Investor
Neil Gibbney	Western Power
Chris Brown	Economic Regulation Authority (ERA) (Observer)
Apologies	
Patrick Peake	Market Generator

Item	Subject	Action
1.	**WELCOME AND APOLOGIES / ATTENDANCE** The Chair opened the 5th meeting of the Maximum Reserve Capacity Price (MRCP) Working Group (Working Group) at 3:00pm. Apologies were received from: • Patrick Peake – Market Customer.	
2.	**MINUTES OF PREVIOUS MEETING** The minutes of the 4th MRCP Working Group meeting, held 23 August 2010, were circulated prior to the meeting. The following	

Item	Subject	Action
	amendments were agreed: • Mr Stephen MacLean questioned whether it was necessary to note that the solution around the proposed methodology for determining the deep connection costs should be not inconsistent with the market objectives as this is self evident. Mr Neil Gibbney noted that the Working Group should ensure that this is clear to the Consultant. Dr Steve Gould questioned the use of double negatives in minutes, e.g. “not inconsistent with…”. The Chair agreed to remove the following sentence: “The Chair states it was reasonable to suggest that the solution should not be inconsistent with the market objectives.” • Mr Campillos noted that he did not recall the discussion around the assumption that an auction is held when determining the MRCP and questioned how the action point for the IMO to issue the review of deep connection costs scope of work related. Ms Monica Tedeschi clarified that the IMO had removed from the minutes some of the discussion around the wider Reserve Capacity Mechanism as it was out of scope. The Chair agreed that the IMO would review the discussion presented in the minutes further. • Mr Corey Dykstra suggested that the reference should be to “Declare intent to bilaterally trade capacity and removing uncertainty…” rather than “…free uncertainty”. • The Chair noted that the IMO would update the reference in the discussion around the Gas Turbine Price information provided to Working Group members to MW not kW. • Mr Brad Huppatz clarified his comments around the standard size of plant, saying that 160MW plant was more consistent with other parts of the market and that 100 MW plant was the standard size for Verve Energy plant. Mr Shane Cremin clarified that the Verve Kwinana high efficiency gas turbines are probably installed to provide Load Following and Balancing services rather than operate as peaking plant. The Chair agreed that the IMO would update the minutes to reflect the intent of Mr Huppatz’s comments. • Mr Dykstra suggested amending the discussion around Liquid Fuel Storage and Handling Facilities as follows: “The Market Procedure currently requires on-site storage for 24 hours of operation with an allowance for ~~helping~~ keeping the tank… “ Mr Dykstra also noted that it had been agreed to update the Market Procedure to refer to the 14 hour fuel requirement in the Market Rules. The Chair agreed to make these amendments. *Action Point: The IMO to make the agreed amendments and publish Meeting 4 minutes on the website as final.*	**IMO**
3	**ACTION POINTS** The actions arising were either complete or on the meeting agenda. Mr Greg Ruthven noting the following exceptions:	

Item	Subject	Action
	• AP5: The IMO is currently preparing the Procedure Change Report on the revised Market Procedure (PC_2010_04). One submission supporting the amendment had been received during the public consultation process. • AP12: The IMO will undertake further analysis of the impacts on the MRCP of removing the assumption that an auction is held and present the results to the Market Advisory Committee (MAC). • AP32: The IMO noted that the two requests for tender for the review of deep connection costs and the review of the WACC have been updated to incorporate the Working Group's comments and would be issued in the next few days. • AP34: Mr Neil Gibbney noted that there is currently no capacity on the SWIN in total for adding either a 160MW unit or a combination of smaller units. Dr Gould questioned whether there was less than 40MWs capacity. Mr Gibbney noted that he was unsure. With regard to whether it is likely to be lower cost to add a 160 MW plant as a single unit, Mr Gibbney noted that the simplistic view is that economies of scale would make it cheapest to develop at a single site. In particular, deep augmentation costs have been largely dominated by transmission costs in previous years. If a developer can build a plant closer to its load then it could be cheaper, however there are limitations on the available locations to build. Mr Gibbney noted that there is no obvious benefit in moving towards smaller units. The Chair agreed and suggested that the Consultant might be able to identify further issues. ~~Mr Gibbney noted that as new transmission lines tend to be around 750MW in size. This is considerably more capacity than what would be required by a new 160MW unit. This then creates an issue of how you allocate the costs to each customer. This is further compounded by the issue that augmentations to transmission networks tend to be lumpy in nature. Mr Gibbney noted that once one facility contributes to the capital base for developing the additionally capacity then another new generator can essentially get a free connection.~~ Mr Gibbney noted that even the smallest transmission lines displaying reasonable economies of scope and scale have a capacity of 250MW, which is considerably more capacity than required by a new 160MW generator. Further, augmentations to the transmission network actually tend to be even more 'lumpy' in nature in that new transmission lines can quite easily have capacities around 750MW. Consequently, the most significant issue is not what a new line costs, but how you allocate the costs to each customer. Mr Gibbney noted that under the Access Code once a new transmission facility is added to Western Power's capital base then Western Power can no longer charge capital contributions for use of that facility and new generators can essentially get a free connection. Mr Dykstra noted that load growth has been recently driving	

Item	Subject	Action
	the need for increased connections. Application of the current regulatory provisions creates volatility around these costs which can have a significant effect on the viability of a project. Additionally Mr Cremin noted that there may be a situation where the market already has considerable generation available and an investor wants to add extra capacity which is not required. This would present the ERA with an interesting situation to consider. The Chair noted that it needs to be considered whther the growth is organic load growth or driven by industrial development. The Chair noted that a simple solution to this issue should not be expected and that this will be a challenging task for the Consultant to consider. The Chair noted that the fundamental issue is with the regulatory environment and that the Working Group does not have the mandate to change this. However the Working Group may develop a view that could support a change in the future. Mr Nenad Ninkov questioned the impacts of adopting this philosophy if a high capacity line is built up north prior to the next 5 year review of the MRCP. The Chair suggested that the Working Group should take a step back and consider how these uncertainties impact on the MRCP determination. The Chair suggested that the long term view would be to reduce volatility but that this would be at the expense of accuracy. Mr Gibbney noted that the price needs to reflect the actual costs an investor is imposing on the market. The Chair noted that these costs are dependent on the investor's position in the Access Queue (as this would determine whether they are attributed all or no costs). Mr Gibbney suggested that the ERA needs to consider this issue further. The Chair questioned whether the Working Group is assuming that this process should operate within the current regulatory regime or propose amendments to the regime. The Chair noted that this decision needs to be guided by the outcomes of the Consultant's work. The Chair noted that the recommendation of the Working Group could be presented to the MAC for further consideration at a later stage. Mr MacLean proposed that if in any year there is spare capacity for building a 40MW unit this could be the basis for setting the MRCP rather than the 160MW which requires an upgrade. Mr Gibbney noted that Western Power would not know if they could connect 40MW units more easily as the costings are based on actual estimates providing to investors, who tend to come with larger units for estimates. Mr Dykstra noted that volatility in price creates issue for existing Market Participants who want consistency. Mr Dykstra suggested that a variable capacity price option may result in a better outcome. That is the price a Market Participant would be paid for capacity would be based on the market price when they first entered the market. Mr Gibbney noted that this type of pricing mechanism could have investors waiting for an opportunistic price. Mr Dykstra noted	

Item	Subject	Action
	that if a plant enters the market early then the market is paying for its capacity when it might not be actually required. The Chair noted that the Working Group is considering whether the current assumptions are relevant and that there will be a strategic wash-up at the end of the process. The Chair stated that these issues come back to the question of whether the current complexities and regulatory framework provide reasons to undertake further analysis of smaller units. The Chair considered that there is no reason to analyse the impact of smaller units at this time and therefore the Working Group should continue under the same assumptions, subject to the advice of the Consultant. *Agreed Outcome: The power station capacity to remain at single 160MW plant, pending outcomes of Consultants work.*	
4	**REVIEW OF MRCP COMPONENTS** The Working Group continued to discuss the components of the MRCP. A summary of this discussion is presented below: *<u>Power station – type</u>* Mr Ruthven noted that the inclusion of inlet coolers would impact on the summer de-rating factor. In particular, the Chair outlined the Working Group's options were to either: • lock in the specific type of inlet cooler and associated de-rating factor; or • to require a Consultant to review the applicable type of inlet cooler and appropriate de-rating factor each year as part of the annual review. Dr Gould questioned whether there are significant variations between the available technologies for inlet cooling. Mr MacLean noted that it depends mainly on the intensity of the cooling being undertaken. Mr Dykstra suggested not specifying the type of technology as it would allow for technological changes over time. Mr Huppatz noted that there would need to be an assumption made for the humidity level for the determination of the de-rating factor. The Chair clarified that SKM had previously used its worldwide database of project costs by normalising this information and made adjustments for additional costs incurred for difficult projects. The Chair suggested that a similar basis could be used to determine the inlet cooling costs. The Chair suggested that a Consultant could be requested to determine a year on year optimal outcome including cooling or alternatively they could be requested to conduct a review and then present back to the Working Group on the technology types and related de-rating factors, which could be used to set a specific value either across all technology types (if similar) or for individual types. The Chair noted that there may be merit in getting the Consultant to complete a year-by-year assessment as this would allow for	

Item	Subject	Action
	technological changes to be accounted for. Mr Campillos noted that it was not advisable to prescribe technologies but rather the Working Group should leave it open so other technologies can be taken into account in future reviews. The Chair suggested amending the Market Procedure to allow for the inclusion of inlet cooling in the power station costs, with the ability for the Consultant to specify the most cost effective technology type. *Agreed Outcome: The Market Procedure be updated to allow for the inclusion of inlet cooling in the power station costs, with the ability for the Consultant to specify the most cost-effective technology type.* Mr Cremin noted that every assumption that the Working Group changes impacts on the final cost balance. The Chair noted that the Working Group needs to consider a range of options. In particular, the Chair suggested requiring the Consultant to review sample humidity rates on 41 degree days across a range of locations to get an estimate of humidity impacts. The Chair noted that this may only need to be considered once in order to obtain an assessment of the variability introduced by differing humidity levels. Mr Huppatz agreed that this would be of value to the market. Mr Williams noted that there was a further issue for Market Generators as they could currently be required to complete Reserve Capacity Tests over winter and if the humidity is high this could be difficult. The Chair suggested a small review project be initiated to understand the relationships with humidity. The Chair noted that the outcomes of the Working Group would not be contingent on this being completed. The Working Group agreed that a review should be conducted and that it would not impact on its current wider review. *Action Point: The IMO to initiate a review of the relationship between humidity rates and generator output across a range of locations.*	 **IMO**
	<u>Power station – capacity</u> The Chair noted that this had already been discussed under agenda item 3. *<u>Location- cost optimisation</u>* Mr Ruthven noted that the MRCP considers the next unit to be installed on the grid and that the most cost-effective locations for this marginal unit should be determined. Mr Ruthven noted that this has been the approach in the past but is not prescribed in the Market Procedure. Mr Ruthven noted that transmission and land costs would be combined for each location as part of the selection of the location. The Chair questioned whether the Working Group had previously	

Item	Subject	Action
	agreed on not optimising the outcomes and so taking the cheapest land and location. Mr MacLean confirmed that this was previously agreed. The Chair also questioned whether uplift factors should be used to account for variation in construction costs at different locations. Mr Cremin suggested requesting the Consultant to consider this as well for different sites. Mr Ruthven stated that the Rawlinsons Australian Construction Handbook provided uplift factors that, while not specific to power station development costs, could be used for this purpose. Mr Gibbney noted that the Rawlinson's uplift factors had been considered by Wester Power to be quite general. Mr Ruthven noted that Rawlinson's had been used by Wester Power to estimate rural construction costs for the 2009 MRCP process. Mr Gibbney noted that previously SKM have come up with their own factors. The Chair agreed that the factors that are used by the Consultant would be published as part of the report. *Agreed Outcome: The IMO to require the Consultant to provide uplift factors for construction costs in the specified location.* *<u>Margin M (legal, insurance, financing, environmental approval costs)</u>* Mr Ruthven noted that the Working Group needs to consider whether the current methodology is correct. In particular, there is currently a disconnect between section 1.12 and the final equation in the Market Procedure. Mr Ruthven noted that an amendment to the Market Procedure is required to clarify the link between these two sections. The Chair also noted that there is a double counting of debt issuance costs and that the Consultant selected to review the WACC methodology will be requested to consider this. Mr Dykstra noted that there is currently no methodology prescribed in the Market Procedure. In particular, Margin M has generally been 20 percent and 12.5 basis points for finance. Mr Dykstra noted that this has not changed significantly since the global financial crisis and that there is general recognition is that this is a generous allowance. The Chair noted that Margin M is applied to the cost of a project and that the Working Group needs to consider how to define these terms from a procedural aspect. The Chair questioned whether anything else that should be included or whether simply specifying a value to apply is appropriate given the variability in types of project. In particular the Chair questioned how investors account for this in terms of project development costs. Mr Dykstra noted that the financing variable should be removed as it is dealt with more appropriately elsewhere. Mr Dykstra questioned whether the estimate of power station costs typically include contingencies. The Chair did not recollect this being the case. Mr Ruthven clarified that these are based on actual project costs so if projects struck contingencies then these were	

Item	Subject	Action
	accounted for by adjusting for difficult projects. The Chair agreed to confirm with SKM what was included in its assessment. Mr MacLean questioned whether SKM use actual project costs or an estimate. The Chair indicated he understood that they use actual project costs and there would be an expectation that average exposure is factored into these costs. *Action Point: The IMO to seek clarification from SKM on the components included and excluded in its assessment and seek advice on whether they consider there is a better way to determine Margin M.* *<u>Contingency margin</u>* The Working Group agreed that the contingency margin would be included in the request to SKM to provide details on the components included/excluded in its assessment and provide advice on the determination of Margin M costs *<u>WACC-basis</u>* Mr Ruthven noted that the determination of the WACC based on the assumption that an auction was held had been discussed at the 8 September MAC Meeting. The MAC had requested the IMO to undertake an assessment of the impact on the MRCP of removing the assumption that an auction is held. Mr Ruthven noted that the IMO is currently undertaking this assessment and will present its results back to the MAC.	**IMO**
5	**GENERAL BUSINESS** There was no general business raised.	
6	**NEXT MEETING** Mr Ruthven noted that the members would be advised of the details of the next Working Group meeting closer to the date, depending on the status of the Consultants' work on the two reports on transmission connection and the WACC.	
7	**CLOSED:** The Chair declared the meeting closed at 4.20 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
29	Meeting 4	IMO	The IMO to consider a briefing session on scope of works with IMO or Working Group with the Consultant if required.	Briefing sessions held with the IMO. Western Power also involved for Deep Connection Costs project. Completed.
32	Meeting 4	IMO	The IMO to issue the review on deep connection costs scope of work document for tender.	Completed.
35	Meeting 5	IMO	The IMO to make the agreed amendments and publish Meeting 4 minutes on website as final.	Completed.
36	Meeting 5	IMO	The IMO to update the Market Procedure to allow for the inclusion of inlet cooling in the power station costs, with the ability for the Consultant to specify the cost-effective technology type.	Pending. Updated Market Procedure to be provided at subsequent meeting.

#	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.	Pending.
39	Meeting 5	IMO	The IMO to seek clarification from SKM on the components included and excluded in its assessment and seek advice on whether they consider there is a better way to determine Margin M.	SKM to provide advice at Meeting 6.

Agenda Item 4: Weighted Average Cost of Capital Methodology – Draft Report by Pricewaterhouse Coopers

1. BACKGROUND

The IMO appointed Pricewaterhouse Coopers (PwC) to undertake a review of the methodology for determining the Weighted Average Cost of Capital (WACC). PwC has prepared its draft report, which is attached as Appendix A.

The review by PwC builds on the similar review of the WACC by the Allen Consulting Group in 2007[1]. In considering the constituent WACC parameters, PwC has noted any changes in the regulatory environment that have occurred since the 2007 review and, where deemed appropriate, has recommended revisions to the methodology. PwC has also considered the way in which the WACC is applied within the calculation of the Maximum Reserve Capacity Price (MRCP) to compensate investors for incurred costs.

The draft report also includes proposed amendments to the *Market Procedure for: Determination of the Maximum Reserve Capacity Price*.

The draft report is provided to the MRCPWG for its evaluation and consideration.

2. RECOMMENDATIONS MADE BY PwC

Within the draft report, PwC recommends that:

- the current WACC equations in the Market Procedure should be retained, while providing commentary around the options for the treatment of taxation and inflation within the WACC equations;
- the current methodology for determining the nominal risk free rate should be retained;
- the methodology for determining the inflation rate should be amended in line with recent regulatory practice;
- the methodology for determining the debt margin (debt risk premium) should be amended in response to changes in the availability of bond data;
- the values of the market risk premium, debt issuance costs, taxation rate, gamma and asset beta determined in the 2007 review should be retained;
- the assumptions for gearing and credit rating should be changed based on recent observations from comparable businesses and the availability of bond data;
- the equity beta value should be changed in line with the revised gearing assumption; and

[1] The Allen Consulting Group, November 2007 (corrected September 2008), *Review of the Weighted Average Cost of Capital for the Purposes of Determining the Maximum Reserve Capacity Price*, available at http://www.imowa.com.au/f3326,857170/IMO01_WACC_Review_FinalCorrected080922.pdf

- the application of the WACC within the calculation of the MRCP should be changed in order to more accurately estimate the financing costs in the power station project.

3. RECOMMENDATIONS

The IMO recommends that the MRCPWG:

- **Discuss** the PwC draft report and the recommendations contained within; and
- **Provide out of session feedback** on the PwC draft report and recommendations to the IMO (system.capacity@imowa.com.au) by 5pm Thursday, 3 February 2011.

Maximum Reserve Capacity Price - WACC methodology

Independent Market Operator of Western Australia

DRAFT REPORT

11 January 2011

pwc

What would you like to grow?

Contents

Executive Summary

Introduction

PricewaterhouseCoopers ('PwC') has been engaged by the Independent Market Operator of Western Australia (IMO) to review the appropriate parameters, assumptions, calculations and application of the weighted average cost of capital (WACC) that is applied in determining the maximum reserve capacity price (MRCP). These are set out in the *Market Procedure for: Determination of the Maximum Reserve Capacity Price Version 2* ('Market Procedure').

The scope of PwC's engagement is to:

- review any changes in the regulatory environment that have occurred since the 2007 Review and. if appropriate, recommend an appropriately revised methodology to calculate the WACC;
- review the values of parameters applied in the estimation of the WACC;
- consider how the WACC should be applied in calculating the amount of compensation within the MRCP for costs incurred in the "construction phase" of the generic power station project.

A previous review of the WACC determination was undertaken by the IMO in 2007 ('2007 Review'), involving provision of advice by the Allen Consulting Group.[1]

Conclusions and recommendations

WACC methodology

In advice to the IMO for the 2007 Review, the Allen Consulting Group set out the WACC formulae for calculation of both a real or nominal post-tax WACC (the 'Vanilla WACC') and a real or nominal pre-tax WACC (the 'Officer WACC').

These WACC formulae remain the most commonly applied formula for determination of WACC values amongst finance practitioners. PwC considers that they remain the preferred WACC formula for the IMO to apply in determining the WACC.

Which of these forms of WACC should be applied is ultimately a decision of the IMO. Considerations relevant to this decision are as follows.

- Whether to use a nominal or real WACC is largely incidental as long as the consistency is maintained between the form of WACC and other elements of the calculation of the MRCP.

[1] The Allen Consulting Group (November 2007), *Review of the Weighted Average Cost of Capital for the Purposes of Determining the Maximum Reserve Capacity Price*, Report to the Independent Market Operator.

- Use of a post-tax WACC (in combination with specification of the cost of taxation in the cash flows for the generic power station project) will tend to produce a MRCP that more accurately reflects the cost of taxation to the investor in the generic power station project, although this introduces some additional computational complexity in derivation of the MRCP.
- The Economic Regulation Authority maintains a convention of using a real WACC in its functions of access and price regulation of other infrastructure services in Western Australia, including electricity network services provided by Western Power. The Authority is required to approve the MRCP and use of a real pre-tax WACC may facilitate the ERA's approval. Also, the use of a real pre-tax WACC allows for stakeholders to readily compare the value of the WACC applied in the MRCP and WACC values applied in other Western Australian regulatory determinations.

In this report, indicative values of the WACC are presented as all combinations of nominal and real and pre-tax and post-tax values.

Whichever of these forms of WACC are adopted, PwC recommends that there be no change from the current Market Procedure in the basic methods used to estimate the cost of equity and the cost of debt. That is:

- the cost of equity should continue to be estimated using the Sharpe Lintner capital asset pricing model (CAPM), and
- the cost of debt should continue to be estimated as a margin over the risk-free rate, with the margin derived from observations of costs of debt in capital markets.

WACC parameters

The Market Procedure distinguishes between a set of WACC parameters for which values should be estimated on an annual basis (minor components) and a set of parameters for which the values determined in this review of the WACC should be applied each year until the next review (major components).

Minor components

The minor components comprise:

- nominal risk free rate;
- forecast rate of inflation;
- real risk free rate of return; and
- debt margin (which should be re-named the debt risk premium).

PwC's recommended methods for annual determination of the values of these parameters are set out below.

- Nominal risk free rate. The 10 year Commonwealth Government Security (Government bond) yield should be applied as the proxy for the nominal risk free rate. This is consistent with the current Market Procedure.
- Forecast rate of inflation. A forecast rate of inflation should be estimated as a forecast rate over 10 years based on short to medium term rates as forecast by the Reserve bank and longer term rates at the mid point of the Reserve Bank's target range for inflation.

- Real risk free rate of return. The real risk free rate of return is not directly applied in determination of the WACC but, if stated for illustrative purposes, should be calculated from the nominal yields on 10 year Government bonds and the forecast rate of inflation (calculated through the Fisher equation).
- Debt risk premium. The debt risk premium and should be established for a notional 10 year BBB rated bond estimated as an extrapolation of the fair value yield curve for 7 year BBB rated bonds published by Bloomberg, based on the rise in the Bloomberg AAA debt risk premium. The debt margin should be derived as the sum of the debt risk premium and debt issuance costs.

The values of these parameters determined at 30 November 2010 are:

- nominal risk free rate – 5.48 percent;
- forecast rate of inflation – 2.57 percent;
- real risk free rate of return – 2.84 percent; and
- debt risk premium – 466 basis points.

Major components

The major components:

- market risk premium;
- equity beta;
- debt issuance costs;
- corporate tax rate;
- value of imputation credits (*gamma*); and
- financial structure (gearing).

PwC's recommended values of these parameters are set out below.

In summary, the recommended values of these parameters are:

- market risk premium – 6 per cent;
- equity beta – 0.77;
- debt issuance costs – 12.5 basis points;
- corporate tax rate – 30 per cent;
- value of imputation credits (*gamma*) – 0.50; and
- financial structure (gearing) – 35 per cent.

Indicative WACC value at 30 November 2010

An indicative estimate of the WACC is indicated in Table E.1 taking into account values of risk free rates and inflation at 30 November 2010. For comparison purposes, Table E.1 also shows the estimate of the WACC that would result from values of WACC components derived in the 2007 Review.

Table E.1 WACC estimates derived from PwC's recommended parameter values, including risk-free rate and inflation values at 30 November 2010

Parameter	Notation		
Nominal risk free rate of return (%)	R_{fn}	5.48	5.48
Expected Inflation (%)	i	2.62	2.62
Real risk free rate of return (%)	R_{fr}	2.79	2.79
		2007 review	**2010 Review**
Market Risk Premium (%)	*MRP*	6.00	6.00
Asset beta	β_a	0.50	0.50
Equity beta	β_e	0.83	0.77
Debt risk premium (%)	*DRP*	1.60	4.66
Debt issuance costs (%)	d	0.125	0.125
Corporate tax rate (%)	T	30	30
Gamma	γ	0.5	0.5
Gearing	*D/V*	0.40	0.35
Nominal pre-tax cost of debt (%)	R_{fr+DRP}	7.21	10.27
Nominal post-tax cost of equity (%)	$R_{fr} + \beta_e \text{ x MRP}$	10.46	10.10
Nominal post-tax WACC (%)	**Vanilla WACC**	**9.16**	**10.16**
Real post-tax WACC (%)	**Vanilla WACC**	**6.37**	**7.35**
Nominal pre-tax WACC (%)	**Officer WACC**	**10.27**	**11.32**
Real pre-tax WACC (%)	**Officer WACC**	**7.45**	**8.47**

Compensation for financing costs during construction

The construction phase of the generic power station project is the time period commencing when investors in the generic power station project first commit significant funds to the project and ending when revenues from the project commence. Although revenues are not received during the construction phase, there is still a cost of equity and debt funds committed to the project. This cost is typically referred to as the "allowance for funds used during construction" (AFUDC).

The current market procedure allows for AFUDC in the maximum reserve capacity price by including two years of return on the total investment cost of the generic power station project in the capital cost of the project.

PwC considers that the current market procedure provides for too high a value of the AFUDC substantial over-compensation of investors for the financing costs during the construction period.

It is PwC's view that, for the purposes of simplicity in the market procedure, a rule-of-thumb method for determining the AFUDC provides a reasonable estimate of the AFUDC for the generic power station project, which is to determining the AFUDC as a return on the total investment cost for half of the construction period, which can be assumed to be in the order of one year. This rule of thumb would reduce the AFUDC by approximately 75 per cent from that which would be determined under the current market procedure.

This rule of thumb method can be implemented in the market procedure by a change to the CAPCOST formula in the market procedure as follows:

$$CAPCOST[t] = (PC[t] \times (1 + M) \times CAP + TC[t] + FFC[t] + LC[t]) \times (1+ WACC)\hat{}\,{}^{1}/_{2}$$

Recommended revisions to the Market Procedure

Recommended revisions to the Market Procedure are set out in Appendix A of this report.

1 Introduction

1.1 Background

The method currently applied by the IMO in setting the maximum reserve capacity price ('MRCP') is set out in the IMO document *Market Procedure for: Determination of the Maximum Reserve Capacity Price Version 2* ('Market Procedure').

The method to be applied by the IMO in determining the MRCP is set out in section 1.14 of the Market Procedure. Under this method, the MRCP is calculated as an annualised cost over a 15 year period of a generic power station project.

The discount rate used in the calculation of the annualised cost is an estimate of the weighted average cost of capital ('WACC') for the generic power station project 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.

The WACC is also used to determine an element of cost in the MRCP that is an amount of compensation to the investor in the generic power station project for costs incurred in the approximately two-year period between when the reserve capacity auction is held and when the payment stream for capacity credits is expected to be realised. At present, this amount is calculated as two years return on the capital cost of the generic power station project, with the annual rate of return equal to the WACC.

Under section 1.13 of the Market Procedure, the IMO is required to determine the value of the WACC on an annual basis. Clause 1.13.7 provides for the IMO to determine the WACC on the basis of:

- using the capital asset pricing model (CAPM) as the basis for calculating the return to equity;
- specification of the WACC on a pre-tax basis; and
- calculating the WACC using the standard Officer WACC method.

Clause 1.13.3 of the Market Procedure contemplates that the components of the WACC are classed as a set of 'minor' components that require review annually (risk free rate of return, forecast inflation, debt margin and debt issuance costs) and a set of 'major' components that require review less frequently (market risk premium, beta, corporate tax rate, value of franking credits, financial structure).

The IMO most recently undertook a review of the method used to calculate the WACC and the values of major components in 2007 ('2007 Review'). In doing so, the IMO obtained advice from the Allen Consulting Group.[2]

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[2] Allen Consulting Group, November 2007, *Review of the Weighted Average Cost of Capital for the Purposes of Determining the Maximum Reserve Capacity Price*, Report to the Independent Market Operator.

1.2 Scope of this study

PwC has been engaged by the Independent Market Operator of Western Australia (IMO) to provide advice to assist the IMO in a new review of the method of calculation of the WACC and some other elements of the procedure to determine the MRCP.

The scope of the current review is to:

- review any changes in the regulatory environment that have occurred since the 2007 Review and. if appropriate, recommend an appropriately revised methodology to calculate the WACC;
- review the values of parameters applied in the estimation of the WACC;
- consider how the WACC should be applied to compensate the investor in the generic power station project for costs incurred in the approximately two-year period between when the reserve capacity auction is held and when the payment stream for capacity credits is expected to be realised.

2 Relevant features of the reserve capacity mechanism

2.1 Reserve capacity cycle and reserve capacity auctions

Under the reserve capacity mechanism, market customers (i.e. electricity retailers and some loads) are required to purchase capacity credits in proportion to their energy demand. Capacity credits may be purchased directly from generators or providers of a demand-side-management (DSM) facility through bilateral contracts, or capacity credits are purchased by the IMO and on-sold to market customers.

The set of events and activities governing the procurement of capacity and subsequent delivery of that capacity is termed the 'reserve capacity cycle'. Each reserve capacity cycle occurs over an approximately four year period, with a new reserve capacity cycle being initiated each year. The timing of events in the reserve capacity cycle is set out in clause 4.1 of the Market Rules and details of events set out in the remainder of section 4.

The key events in a reserve capacity cycle and the timing of these events are shown in Table 2.

Table 2 Key events of the reserve capacity cycle

Timeline	Actions
Year 1 – January to May	The IMO issues a request for expressions of interest to provide capacity with an indication from existing and potential new market participants of the amount of new generation and new Demand Side Management capacity they are willing to offer to make available as Reserve Capacity (Market Rules clause 4.2.4). Capacity providers submit expressions of interest.
Year 1 – July	The IMO publishes the Statement of Opportunities Report including specification of the reserve capacity requirement for the reserve capacity year commencing in October of year 3 of the reserve capacity cycle.
Year 1 – 5 August	Notification of certified reserve capacity
Year 1 – 10/11 August	Market participants notify the IMO of how much of their certified reserve capacity will be traded bilaterally and how much will be offered to the IMO in the reserve capacity auction. The IMO confirms amounts with each market participant.
Year 1 – 18 August	The IMO confirms the holding or cancellation of a reserve capacity auction. If a reserve capacity auction is to be held, the IMO publishes the amount of reserve capacity required to be procured by the auction and receives reserve capacity offers.
Year 1 – September	The IMO runs the reserve capacity auction and publishes results.
Year 3 – 1 October	"Reserve capacity year" commences Supply of capacity commences and payments from the IMO to suppliers of capacity commence.
Year 4 – 1 October	Reserve capacity year terminates.

Source: Market Rules, section 4.

Within the reserve capacity cycle, a capacity provider must have capacity certified by the IMO prior to notification of the IMO that the capacity is to be bilaterally traded or offered to the IMO in a reserve capacity auction. In general terms, certified capacity needs to comprise either capacity in existence or capacity proposed or under construction, with network access secured and evidence provided that environmental approvals have been granted or will be granted in time for the facility to meet its reserve capacity obligations.

If the amount of certified capacity indicated by market participants to be traded bilaterally exceeds the reserve capacity requirement, the IMO will cancel the reserve capacity auction.

If the amount of certified reserve capacity indicated by market participants to be traded bilaterally is less than the reserve capacity requirement, the IMO will hold the reserve capacity auction to purchase an amount of certified capacity to meet the shortfall.

Under the process of the reserve capacity auction, market participants offer a price-quantity offer for each generator or DSM facility, where the offered price must be less than or equal to the maximum reserve capacity price. The IMO will accept offers in ascending order of the offered price until sufficient certified capacity is secured to meet the reserve capacity requirement. All market participants that sell capacity to the IMO through the reserve capacity auction receive the price of the last offer accepted.

A provider of capacity purchased by the IMO by the reserve capacity auction has the option of entering into a “long term special price arrangement” with the IMO for that capacity to be priced at the reserve capacity price determined by the reserve capacity auction (with annual escalation for inflation) for a period of 10 years.

2.2 Determination of the maximum reserve capacity price

The method currently applied by the IMO in setting the MRCP is set out in the IMO document *Market Procedure for: Determination of the Maximum Reserve Capacity Price Version 2*.

Under the Market Rules, the MRCP is used as the price cap for the reserve capacity auction, in the event that an auction is held. The price cap operates by the MRCP being the maximum offer price that can be submitted in a reserve capacity auction.

The method to be applied by the IMO in determining the MRCP is set out in section 1.14 of the Market Procedure. The MRCP to apply for a reserve capacity auction held in calendar year t is PRICECAP[t] where this is to be calculated as:

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

Where:

PRICECAP[t] is the MRCP 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 the WACC as determined as part of the 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;

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, expressed in Australian dollars in year t, per MW per year.

The value of CAPCOST[t] is to be calculated as:

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

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;

M is a margin to cover legal, approval, and financing costs and contingencies;

TC[t] 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 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 cost of land purchased in year [t]; and

WACC is the Weighted Average Cost of Capital.

The escalation factor applied to CAPCOST[t] of (1 + WACC)^2 is the amount of two years return on the capital cost of the generic power station project to compensate the investor in the generic power station project for the costs incurred in the approximately two-year period between when the reserve capacity auction is held and when the payment stream for capacity credits is expected to be realised. In effect, this amount of compensation assumes that the investor incurs all costs of the generic power station two years prior to commencement of the payment stream. The amount of compensation is the financing cost of holding this asset for two years before the payment stream commences.

2.3 Determination of the WACC

The method currently applied by the IMO in determining the WACC is set out in section 1.13 of the Market Procedure. This method is for determination of the WACC on the following basis:

- use of the CAPM as the basis for calculating the return to equity;
- specification of the WACC on a pre-tax basis;
- use of the standard “Officer WACC” method as the basis for calculation of a pre-tax real WACC.

The Officer WACC method is stated in the Market Procedure as:

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

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

Where

(a) R_e is the nominal return on equity (determined using the CAPM) 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) $R_d = R_f + DRP$

where:

R_f is the nominal risk free rate for the capacity year;

DRP is the debt risk premium for the capacity year.

(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 & Poors and a maturity of 10 years and the nominal risk free rate:

- using the predicted yields for corporate bonds published by Bloomberg; and 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 bonds with a maturity of 10 years on any day in the period referred to in steps (g) and (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 used in Step (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.

(k) *i* is the forecast rate of inflation. In establishing a forecast of inflation, the IMO is to have regard to the forecasts of the Reserve Bank of Australia, the Western Australian Department of Treasury and Finance, and financial market participants.

3 Method of estimation of the weighted average cost of capital

3.1 What is the cost of capital?

The cost of capital is the return that investors would expect to receive from a project in order to justify committing funds to that investment. It is a level of return on invested capital that is sufficient to motivate the capital investment in a particular asset and attract the capital away from alternative investments. In this sense, the cost of capital is the *opportunity cost* of capital – the return on capital available to investors in the next-best investment opportunities, taking into account the expected return and risk.

The role of the IMO in setting an appropriate cost of capital to set the Reserve Prices is similar to that of an economic regulator using the cost of capital to determine regulated prices. In setting regulated prices, the regulator determines an appropriate cost of capital to ensure that the prices are sufficient for the regulated business to be able to recover all its costs (operating and maintenance, and depreciation), as well as earn a rate of return on existing and new capital investment that is sufficient to attract investment funds for that investment.

From a regulator's perspective, ensuring that regulated revenue provides a commercial return for the regulated business is important because where revenue falls below commercial returns, future investment in infrastructure is compromised, undermining the quality of service provided to users. Conversely, if regulated returns are set too high, the business would earn a return in excess of their cost of capital. This would distort price signals to consumers and investors, resulting in a misallocation of resources and sub-optimal economic outcomes.

3.2 How the cost of capital is estimated

The cost of capital is usually estimated as the weighted average of the costs of equity and debt finance (the WACC), with the weighting being the proportion of equity and debt finance in the capital structure of the relevant business entity. Estimating the cost of capital requires estimating the costs of equity and debt and making a judgement about the optimal capital structure.

The cost of debt is directly observed from capital market data. Both the interest payable on loans and the implied return on traded debt instruments (such as corporate bonds) can be observed as the cost of debt.

In contrast, the required returns to equity providers cannot be observed but must be estimated. While the market value of any share-market listed equity can be observed at any time, the returns that investors expect to receive from that share – in dividends and capital gains – cannot be observed. The cost of equity must be estimated using a model drawn from finance theory and practice.

3.3 Estimating the cost of equity

Four alternative approaches to the estimating the cost of equity were identified and described in the 2007 Review by the Allen Consulting Group.

- Capital Asset Pricing Model – Also known as the CAPM, and is used extensively in corporate finance as well as by Australian state and federal regulators. It is a forward looking model that estimates the required return for an asset to be a combination of the risk free rate, and the required yield to compensate for the asset's systematic risk.[3]
- Arbitrage Pricing Theory – This theory postulates that the expected return of an asset is linearly related to its sensitivity to various macroeconomic factors. Therefore, the theory states that the return on an asset is the risk free rate, plus the sensitivity to the identified macroeconomic factors multiplied by yield premium of each factor in excess of the risk free rate. This methodology is information intensive, and varies with time because the factors that influence returns may change through time.
- Fama-French model – This model can be considered an extension of the CAPM discussed above. The Fama-French model augments the CAPM by adding two additional variables – The difference in the return for small compared to large capitalisation companies, and the difference in the return for stocks with high compared to low book to market equity ratios.
- Dividend Growth Model – This model estimates a return on equity based on the company's stock price, as well as dividend payments. It states that the required return on a particular asset is dependent on tomorrow's dividend yield, plus the expected dividend yield growth rate.

Since the 2007 Review was undertaken there has been an examination of the Fama-French model by the Australian Energy Regulator ('AER') in the context of a determination on the rate of return applied in gas distribution prices for Jemena Gas Networks (NSW) Limited ('Jemena').

Jemena proposed a rate of return that incorporated a return on equity estimated using the Fama-French model and that that was significantly higher than would have been derived by the Sharpe-Lintner CAPM. In support of this proposal, Jemena provided the AER with the following.

- A report by NERA that applied the Fama-French model to derive the estimate of the cost of equity and that sought to demonstrate that, for specific Australian energy utilities, the Fama-French model provides a better estimate of the cost of equity than the CAPM;[4]
- A second report by NERA providing evidence that the Fama-French model is consistent with the requirements of the National Gas Rules that the estimate of the rate of return be conducted using a 'well accepted' methodology and

3 Systematic risk refers to risk that is not unique to a particular asset. It reflects risk that cannot be removed through portfolio diversification, and is common throughout the relevant market.

4 NERA (12 August 2009), *Cost Of Equity – Fama-French Three-Factor Model*, p. lii.

that any forecast or estimate be ‘arrived at on a reasonable basis’.[5] This report cited evidence of the strong reputation of Fama and French, the teaching of their model in universities, and the fact that Morningstar (a commercial provider of investment research) publishes Fama-French betas for the US.

- A report by UK consulting firm Oxera that:
  - verified the analysis undertaken by NERA;
  - indicated that there is evidence supporting, and evidence raising concerns about both the CAPM and Fama-French models; and
  - concluded that there is mixed evidence from Australian studies on the relative performance of the CAPM and Fama-French models.[6]

The AER rejected the proposal for use of the Fama-French model on the grounds that it is not consistent with the requirements of the National Gas Rules that the estimate of the rate of return be conducted using a well accepted methodology and that any forecast or estimate be arrived at on a reasonable basis. The AER expressed concerns that the Fama-French model is empirically driven, lacks a firm theoretical foundation, and provides unstable parameter estimates.[7] The AER also pointed to the findings of the Oxera report that in 25 of the 33 studies comparing the CAPM to the Fama-French model the results could not be statistically distinguished at the 10 per cent level, and the remaining 8 cases provided more support for the CAPM.

Despite the proposal by Jemena for application of the Fama-French model, there has been no change in regulatory practice in Australia. In view of this, PwC recommends that the IMO continue to use the CAPM.

3.4 Form of the WACC

As indicated in the previous section of this report, the Market Procedure currently requires that the IMO determine the WACC as a real, pre-tax value that is calculated using the Officer WACC formula. Relevant considerations in reviewing this approach are the treatment of taxation, the treatment of inflation and the WACC formula.

Treatment of Taxation

In advice provided for the 2007 Review, the Allen Consulting Group set out the options for the IMO in adopting a pre-tax or post tax form of the WACC.

In the pre-tax form of the WACC, an allowance is made in the WACC for the cost of taxation to the business entity by scaling up the return on equity.

5 NERA (19 March, 2010), *Jemena Access Arrangement Proposal for the NSW Gas Networks: AER Draft Decision*, a report for Jemena.

6 Oxera (28 April, 2010), *Estimating the cost of equity from the Fama-French model*, Prepared for Jemena Gas Networks (NSW) Ltd.

7 AER (10 February, 2010), pp.138-140.

In the post tax form of the WACC, taxation liabilities of the business entity are determined separately from the WACC and provision made for these liabilities through, for example, a separate cost allowance in the MRCP.

The Allen Consulting Group correctly identified that the pre-tax approach has an advantage of computation simplicity, but involves making simplistic assumptions about the cost of tax and tends to overstate the cost of taxation, and hence provide over-compensation for the cost of taxation. For this reason, a post-tax form of WACC is preferred by most economic regulators in Australia, including the Australian Competition and Consumer Commission and the Australian Energy Regulator. However, the Economic Regulation Authority in Western Australia maintains a convention of using a pre-tax WACC in its functions of access and price regulation of other infrastructure services in Western Australia.

It is the view of PwC that there has been no change in regulatory theory and practice since the report of the Allen Consulting Group that would change the consideration of whether to use a pre-tax or post-tax WACC; that is:

- a post-tax specification of the WACC would generally be preferred for reason of greater accuracy in allowing for a cost of taxation in the costs of the generic power station project, and this specification would be relatively easy to implement; but
- the IMO may prefer to use a pre-tax specification of the WACC for consistency with other regulatory decisions in Western Australia.

Both a pre-tax and post-tax WACC calculations are presented in this report.

Treatment of inflation

In advice provided for the 2007 Review, the Allen Consulting Group set out the options for the IMO in adopting a real or nominal form of the WACC.

The Allen Consulting Group correctly identified that relevant considerations in selecting a real or nominal form of the WACC relate to issues of consistency in the treatment of inflation in the form of the WACC and other elements in the calculation of the MRCP. PwC is of the view that the following guidance provided by the Allen Consulting Group for consistency in the choice of a nominal or real WACC and other elements of the calculation of the MRCP is still valid.

> *Some simple rules for consistency are that where cash flows are to be discounted:*
>
> - *if those cash flows are forecast in nominal (or 'money of day') terms, then a nominal WACC must be employed; and*
> - *if those cash flows are forecast in real (or 'constant price') terms, then a real WACC must be employed:*
>   - *cash flows will be in constant price terms where the revenue is subject to CPI escalation (with that escalation being ignored in the forecasts) and where expenditure is expected to rise with the CPI (again, with that escalation being ignored in the forecasts).*
>
> *Alternatively, if a revenue requirement is to be created (and prices determined), then:*

- *if asset values are to be carried forward at their original cost (that is, following a historical cost accounting type approach) then a nominal WACC must be used; but*
- *if asset values (and, in parallel, prices) are to be escalated for outturn inflation (that is, following a current cost accounting type approach) then that escalation already compensates investors in the asset for inflation and so a real WACC must be used.*

As with the treatment of taxation, it is the view of PwC that there has been no change in regulatory theory and practice since the report of the Allen Consulting Group that would change the consideration of whether to use a real or nominal WACC.

WACC Formula

In advice provided for the 2007 Review, the Allen Consulting Group set out the WACC formulae for calculation of both a real or nominal post-tax WACC (the 'Vanilla WACC') and a real or nominal pre-tax WACC (the 'Officer WACC').

These WACC formulae remain the most commonly applied formula for determination of WACC values amongst finance practitioners. PwC considers that they remain the preferred WACC formula for the IMO to apply.

The Officer WACC formula is that currently specified in the Market procedure and reproduced in section 2.3 of this report. The Vanilla WACC formula is set out in Appendix B of this report.

Which of these forms of WACC to apply is ultimately a decision of the IMO. Considerations relevant to this decision are as follows.

- Whether to use a nominal or real WACC is largely incidental as long as the consistency is maintained between the form of WACC and other elements of the calculation of the MRCP;
- Use of a post-tax WACC (in combination with specification of the cost of taxation in the cash flows for the generic power station project) will tend to produce a MRCP that more accurately reflects the cost of taxation to the investor, although this introduces some additional computational complexity in derivation of the MRCP.
- The Economic Regulation Authority maintains a convention of using a real WACC in its functions of access and price regulation of other infrastructure services in Western Australia, including electricity network services provided by Western Power. The Authority is required to approve the MRCP and use of a real pre-tax WACC may facilitate the ERA's approval. Also the use of a real pre-tax WACC allows for ready comparison between the value of the WACC applied in the MRCP and WACC values in other Western Australian regulatory determinations.

In this report, indicative values of the WACC are presented as all combinations of nominal and real and pre-tax and post-tax values.

4 Cost of capital – market wide parameters

4.1 Introduction

The parameters used to estimate a WACC consists of two groups – the first group represents parameters that are applicable to the market as a whole, and therefore is independent to the type of company or project that is being assessed. The second group represents parameters specific to the company or project, and must be considered based on the nature and risks of the company or project.

The purpose of this chapter is to consider the market wide parameters. In estimating a regulatory WACC, the market wide parameters refer to the following parameters:

- the risk free rate;
- the Market Risk Premium;
- debt and equity issuance costs; and
- taxation and the value of imputation credits (gamma).

The determination of each of these parameters is addressed below. In each case, the consideration of each of the parameters is addressed by:

- definition of the parameter
- a summary of the method of determination adopted from the 2007 review and incorporated in the Market Procedure;
- new developments in regulatory and finance theory and practice, and market conditions, that are relevant to the determination of these parameters; and
- PwC's recommendation on either maintaining or changing the current method of determination.

4.2 Risk free rate

Definition

The risk free rate is the return an investor would expect from an asset with no risk. Both the cost of equity and the cost of debt are expressed as margins over and above the risk free rate, with the margin reflecting a compensation for the risk borne by the provider of funds.

The risk free asset is a notional asset and proxy assets with very low levels of risk are usually used to approximate the risk free rate. Finance practitioners and Australian regulators have used implied returns on traded Commonwealth Government Securities (Government bonds) as a proxy measure of the risk free rate.

- A nominal risk free rate can be derived by observing the implied yields of nominal Government bonds.

- A real risk free rate can be derived by either observing the implied yields of inflation indexed Government bonds, or by scaling of the nominal risk free rate by a forecast of inflation using the Fisher equation.[8]

Current Market Procedure and 2007 Review

The current Market Procedure provides for determination of the real risk-free rate by estimating a nominal risk free rate as the annualised yield on Government bonds with a term to maturity of 10 years using average mid-rates published by the Reserve Bank of Australia averaged over a 20 trading day period (and there are no bonds with a maturity of 10 years for a relevant trading day period, determining the nominal risk free rate 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).

A real risk free rate is not applied directly in determination of the real WACC, Rather, a nominal WACC is determined and adjusted to a real risk free rate using a formula equivalent to the Fisher equation and applying a forecast rate of inflation determined having regard to the inflation forecasts of the Reserve Bank of Australia, the Western Australian Department of Treasury and Finance and financial market participants.

In advice provided for the 2007 Review, the Allen Consulting Group recommended against estimating the real risk free rate by observed yields on inflation-indexed Government bonds due to a suspect downward bias, at the time, of yields on inflation-indexed Government bonds. Instead, the Allen Consulting Group recommended determining a forecast of inflation by reference to inflation forecasts of the Reserve Bank of Australia, financial institutions and governments; and deriving a real risk free rate by use of the Fisher equation.[9] The Allen Consulting group has subsequently changed this approach to estimating a real risk free rate from observations of annualised yields on inflation-indexed Government bonds, and determining an implied forecast of inflation by applying the Fisher equation and the nominal and real risk free rates.[10] The reasons for this change are not stated.

8 $R_f^{real} = \frac{1 + R_f^{nominal}}{1+i} - 1$ where R_f^{real} is the real risk free rate, $R_f^{nominal}$ is the nominal risk free rate i is the inflation rate.

9 Allen Consulting Group, November 2007, *Review of the Weighted Average Cost of Capital for the Purposes of Determining the Maximum Reserve Capacity Price*, Report to the Independent Market Operator, p. 28.

10 Allen Consulting Group, October 2010, Update of WACC Minor Parameters f9or the Purpose of Determining the Maximum Reserve Capacity Price, Report to the Independent Market Operator, pp. 8, 9.

New developments

Nominal risk free rate

During the five year period leading up to the 2007 Review, capital markets world-wide exhibited the lowest levels of volatility for several decades. The global financial crisis has materially raised perceptions of risk in all markets, including the market for Government bonds. This raises the question of whether the yield on Government bonds remains an acceptable proxy measure of the risk free rate.

This question is examined below addressing, in turn:

- whether there has been an impact of the global financial crisis on government-bond yields; and, if so
- whether this effect is currently material.

The global financial crisis unfolded over the 2007/08 financial year, with its worst effects extending through calendar 2009. During this period the Australian bond market was virtually closed down, with no issuance of new corporate bonds for some time. As prices in share markets tumbled, there was a ‘flight to quality’, with very high investor demand for Government bonds with the effect of driving up the bond price and reducing yields. At the height of the crisis the 10 year government bond yield was below 4.5 percent, which was 1 to 1.5 percent lower than in the previous 5 year period.

From 2007 to 2009 a number of reports by NERA and CEG questioned the appropriateness of the yield on Government bonds as a proxy for the risk free rate.

NERA argued that the yield of CGS securities is biased downwards on account of the fact that CGS have particular benefits (e.g. greater liquidity and ‘convenience yield’) than other similar default-free securities.[11]

CEG argued that the CGS yield was downwardly biased citing evidence of:

- an increase in the spread between Commonwealth Government Securities and state government debt yields;
- a large spread between the yield on Commonwealth Government Securities and Commonwealth Government guaranteed debt; and
- a large drop in the spread between Commonwealth Government Securities and inflation-indexed Commonwealth Government Securities.[12]

During the past year Government bond yields have risen to levels that are comparable with yields that existed prior to the global financial crisis. During the global financial crisis the convenience yield (measured as the difference

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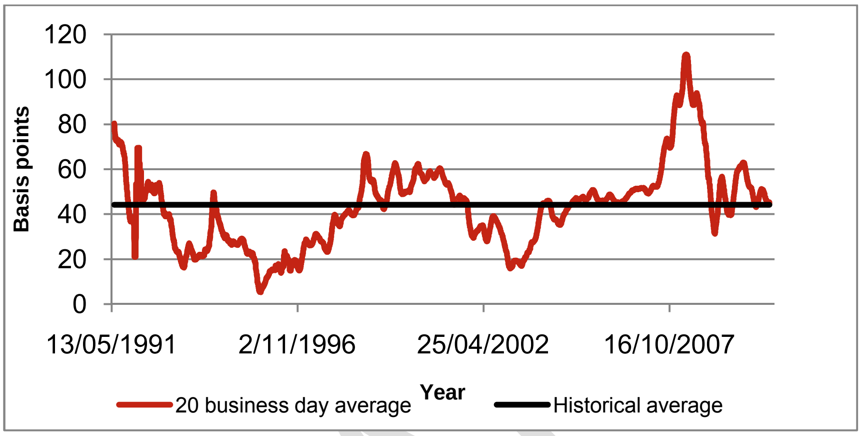
[11] NERA, *Bias in Indexed CGS Yields as a Proxy for the CAPM risk free rate,* March 2007

[12] CEG, *CGS as a proxy for the risk free rate – A report for the JIA,* January 2009

between the yield on 10 year Commonwealth Government Securities and the 10 year Credit Default Swap) rose to 120 basis points, which was 76 basis points higher than the historical relationship measured over the period from 1991 to 2010. In these circumstances, an adjustment to the risk free rate was potentially justified. However, the current differential between the yield on 10 year Commonwealth Government Securities and the 10 year Swap yield is now close to the historically average differential (Figure 4.1). As such, it appears that the distortion of the market for Government bonds during the period of the global financial crisis has diminished.

Figure 4.1 CGS yield less Credit Default Swap (CDS) yield for 10 year maturity



Source: Bloomberg

Inflation rate and real risk-free rate

The current market procedure provides for determination of a forecast of inflation by reference to inflation forecasts of the Reserve Bank of Australia, the Western Australian Department of Treasury and Finance and financial market participants. A real risk-free rate is not directly applied in determination of the real WACC, but may be derived for illustration purposes by adjusting the nominal risk free rate for inflation using the Fisher equation.

The use of this approach to determine the inflation rate and the real risk free rate developed in regulatory practice at around the time of the 2007 Review in response to concerns by regulators over a decline in issues of inflation-indexed bonds and the possibility of a downward bias in observed yields on these bonds.

In PwC's view, there has been no change to this situation. There has also not been any change to regulatory practice. PwC therefore recommends that the IMO maintains the current approach in estimating the real risk-free rate.

Regulators generally estimate future inflation rates by reference to Reserve Bank of Australia forecasts. For example, in the recent decision on the Victorian electricity distribution network service providers (DNSPs), the AER derived a 10 year inflation forecast of 2.57 percent based on the Reserve Bank of Australia's August 2010 *Statement on Monetary Policy*, which set out a medium term forecast of inflation of 2.75 per cent to December 2011 and 3.00 per cent to December 2012, and a longer term forecast of inflation at 2.5 per cent.

Recommendation

PwC recommends that IMO:

- continue to estimate the annual nominal risk free rate by taking a 20 business day average of annualised yields of ten year term to maturity Government bonds (which was 5.48 percent for the 20 business days to 30 November, 2010); and
- estimate an inflation forecast by reference to other published inflation forecasts.

In regard to the sources of information used to estimate an inflation forecast, PwC recommended that the IMO have primary regard to the medium term inflation forecast of the Reserve Bank of Australia and a longer term inflation forecast at the mid-point of the Bank's target range for inflation. This is consistent with the practice of most regulators throughout Australia. As the Reserve Bank of Australia has regard to a range of factors and information sources in deriving its medium-term forecast, PwC considers than provision in the market procedure for the IMO to also have regard to a range of information sources does not add to the rigour of deriving a forecast.

In its latest Statement on Monetary Policy (November 2011), the Reserve Bank of Australia makes medium term forecasts of inflation of 2.75 per cent to December 2011, 3.00 per cent to Dec 2012, and 3.00 per cent to June 2013. Taking the Banks June 2013 forecast as a forecast for the whole of 2013, the 10-year inflation forecast is derived as a geometric average of forecast annual rates as shown in Table 4.1.

Table 4.1 Calculation of forecast inflation (percent)

Dec 2011	Dec 2012	June 2013	Dec 2014	Dec 2015	Dec 2016	Dec 2017	Dec 2018	Dec 2019	Dec 2020	Geom. Ave.
2.75	3.00	3.00	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.62

Source: RBA, (November, 2010) *Statement on monetary policy*, p.62

Parameter values for the nominal risk free rate, forecast inflation rate and the implied real risk free rate as of 30 November 2010 are shown in Table 4.2.

Table 4.2 Risk free rate estimation

Parameter	Estimate
Nominal risk free rate	5.48%
Forecast Inflation rate	2.62%
Real risk free rate	2.79%

Note: The value estimated is based on 20 business days ending 30 November 2010. We recommend that IMO update this figure when it is setting its Maximum Reserve Price based on the latest market data on the nominal risk free rate

Source: RBA and PwC's analysis

4.3 Market risk premium

Definition

The Market Risk Premium (MRP) measures the price of risk in the market. That is, it provides a measure of how much compensation in excess of the risk free rate investors require in order to accept average market risk. The MRP is a major determinant of the WACC. It is a variable that is not observable, and is difficult to quantify. In theory the MRP should reflect forward-looking market expectations, but as these are difficult to measure, reliance is often placed on historical data, in particular the historical differential between realised market returns and the risk free rate.

Current Market Procedure and 2007 Review

The current Market Procedure provides for application of a MRP of 6.0 percentage points.

In advice provided for the 2007 Review, the Allen Consulting Group recommended the MRP of 6.0 based on:

- capital market observations of historical returns to equity;
- studies attempting to estimate imputed expectations of the MRP;
- surveys of opinions and assumptions of capital-market participants; and
- qualitative considerations of factors that may cause the expected MRP to change over time and to vary from historically observed returns, in particular suggesting that the forward-looking MRP may be lower than suggested by historical measures.

New developments

The Australian Energy Regulator (AER) undertook a review of WACC parameters during the global financial crisis, publishing its final decision in May 2009.[13] This included an extensive discussion of evidence for the MRP that caused the AER to raise the value for the MRP from 6.0 to 6.5 for reason of a consideration that a high level of stock-market volatility post GFC had resulted in an increase in investors' expected MRP. While the AER considered that an MRP of 6 percent was the best estimate of the MRP prior to the global financial crisis, it felt that conditions at that time were reflective of one of two scenarios:[14]

- That the prevailing medium term MRP is above the long term MRP, but will return to the long term MRP over time, or
- That there has been a structural break in the MRP and the forward looking long term MRP (and consequently also the prevailing) MRP is above the long term MRP that previously prevailed.

Whilst not being able to distinguish these two scenarios, taking account of the weight of evidence at that time, the AER concluded that there was persuasive evidence to depart from the previously adopted MRP of 6 percent, and proposed an MRP of 6.5 percent for the period of the determination (2009 to 2015).

More recently, the ACCC has reversed this position on the MRP, with the ACCC in its recent final decision on Australia Post arguing that post GFC market conditions have improved and that a MRP of six percent is now appropriate.[15]

Recommendation

PwC recommends a value of the MRP of 6.0 per cent taking into account emerging regulatory position for a reversion to a long-standing position of adopting an MRP of 6.0 per cent after raising the value of the MRP to 6.5 for a period in response to the GFC

4.4 Debt and equity issuance costs

Definition

Debt and equity issuance costs refer to costs of securing debt and equity finance.

In keeping with the regulatory benchmarking approach applied in Australia, debt and equity issues costs are typically considered by regulators as representative or benchmark costs, rather than the actual costs incurred by businesses.

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13 AER (May, 2009), *Final decision – Electricity transmission and distribution network service providers: Review of the weighted average cost of capital (WACC) parameters.*

14 AER (May, 2009), p.238.

15 ACCC (May, 2010), Australian Postal Corporation – Decision, p.80.

Current Market Procedure and 2007 Review

The current Market Procedure contemplates debt issuance costs being included as a parameter in the WACC as a percentage increment to the cost of debt, with the value treated as a minor parameter with a value determined annually.[16] It is observed, however, that the formulae for the WACC and the nominal return on debt as set out in the Market Procedure do not explicitly include the debt issuance cost as an increment in the cost of debt.

In advice provided for the 2007 Review, the Allen Consulting Group recommended a value of debt raising transaction costs of 12.5 basis points be added to the debt margin based on regulatory precedent, although this value was indicated to be conservatively generous given empirical evidence for debt raising costs of 8 to 10.4 basis points per annum when expressed as an increment to the debt margin.[17]

The Allen Consulting Group recommended that equity raising costs be addressed in the Maximum Reserve Capacity Price as a direct component of capital cost. The Allen Consulting Group observed more generally that the capital cost used to calculate the Maximum Reserve Capacity Price includes a margin 'M' for "legal, approval and financing costs and contingencies" noting that debt issuance and equity raising costs are already provided for in the Maximum Reserve Capacity Price as a direct cost rather than an element of the WACC. The Allen Consulting Group's conclusion was that inclusion of debt raising costs in the WACC should be subject to the IMO excluding this cost from the margin 'M' in the capital cost of the generic power station project.

New developments

In considering debt and equity raising costs under the provisions of the current Market Procedure, a distinction can be made between construction and operating periods of the generic power station project.

- *Construction period* - debt and equity raising transaction costs form part of the capital cost of the generic power station project and are capitalised into the capital cost of the project.
- *Operating period* – during the operating period of the generic power station debt raising transaction costs will be incurred. These will be on-going debt raising transaction costs associated with re-financing of debt.

The on-going debt raising transaction costs relate to ongoing operation of the generic power station and are appropriately compensated for through the WACC.

Since the Allen Consulting Group's 2007 report, most Australian regulators apart from the AER and ACCC have continued to apply the 12.5 basis points assumption for debt raising transaction costs.

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[16] *Market Procedure for: Determination of the Maximum Reserve Capacity Price Version 2*, p. 10.

[17] ACG (2007), p.31.

The AER has recently re-estimated the costs of debt-raising costs (as a mark up on the cost of debt) at 10.7 to 10.9 basis points per annum for one standard sized bond issue of $250 million, and lower values down to a range of 8.9 to 9.1 basis points for a bond program of 10 issues raising $2,500 million in debt.[18]

Recommendation

The capital cost of the generic power station project is likely to be less than $600 million, and require only one standard bond issue of less than $250 million for debt finance. The AER's recent estimates of debt raising costs indicate that an appropriate allowance for debt raising costs would be close to 11 basis points.

PwC considers that a margin of 11 basis points is not materially different from the currently adopted value of 12.5 basis points and recommends that the value of 12.5 basis points continue to be applied.

PwC also recommends that:

- the formula for the nominal return on debt in the market procedure be revised to explicitly include the increment for the debt issuance costs, with the debt margin defined as the sum of the debt risk premium and the debt issuance cost; and
- the parameter for the debt issuance costs be defined as a major component, and hence not be subject to annual determination.

4.5 Taxation and imputation credits

Definition

Compensating for the costs of taxation and the benefits of imputation credits – known as gamma - can occur through cost modelling (in a post-tax WACC) or alternatively through the WACC (in a pre-tax WACC). Imputation credits, or franking credits, are received by Australian resident shareholders for corporate tax paid at the company level when they are determining their personal tax liability. This occurs due to Australia's dividend imputation system, and is used to prevent double taxation of distributed corporate profits

Under the regulatory approach applied in Australia, the value of imputation credits as a proportion of their face value (gamma, γ) is defined as the product of the imputation credit 'distribution ratio' (F), and the 'utilisation rate' (theta or θ):

$$\gamma = F \times \theta$$

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[18] AER (October, 2010), *Final decision – appendices: Victorian electricity distribution network service providers, distribution determination 2011 – 2015*, p.479.

If the costs of taxation and benefits of imputation credits are compensated through the WACC, assumptions need to be made about the effective corporate tax rate and the value of franking credits. This will be reflected through an adjustment in the final WACC figure to determine the appropriate cost of capital.

Current Market Procedure and 2007 Review

The current Market Procedure provides for estimation of a pre-tax WACC on the basis of a taxation rate of 30 per cent and a gamma value of 0.5.

In advice provided for the 2007 Review, the Allen Consulting Group recommended a taxation rate of 30 per cent, equal to the statutory corporate income tax rate and a gamma value of 0.5 based on capital market evidence supporting use of a gamma value of between 0.4 and 0.8 and regulatory precedent for a value of 0.5.

New developments

Taxation rate

Australian regulators that specify rates of return as a pre-tax WACC (including the Economic Regulation Authority) have continued to apply the corporate taxation rate as the cost of tax, which remains at 30 per cent.

It would be open to the IMO to estimate an effective rate of tax and apply that rate rather than the corporate tax rate. In this regard, it is observed that a recent study of new entry and generation costs in the National Electricity Market assumed an effective tax rate of 22.5 percent.[19] To apply an effective tax rate of less than the corporate tax rate would, however, depart from Australian regulatory practice.

Imputation credits

Extensive consideration was given to the value of imputation credits by the AER in its review of WACC parameters that was concluded in May 2009.[20]

The AER concluded that a value of 0.65 is the most reasonable estimate of gamma, based on:

- adoption of a distribution ratio of 1, which was held to be consistent with the Officer WACC framework; and
- a utilisation rate (theta) of 0.65 determined as the average of a lower bound estimate of 0.57 based on the 'dividend drop-off' study by Beggs and Skeels[21] and an upper bound estimate of theta of 0.74 based on Handley

[19] ACIL Tasman (April, 2009), *Final Report – Fuel resource, new entry and generation costs in the NEM*, Report prepared for the Inter-Regional Planning Committee (AEMO), p. 22.

[20] AER (May, 2009), pp. 393-469.

[21] D. Beggs and C.L. Skeels, (September, 2006), 'Market arbitrage of cash dividends and franking credits,' *The Economic Record*, Vol. 82, No. 258.

and Maheswaran's study of the utilisation of imputation credits from Australian Taxation Office statistics.[22]

This determination of the AER has been bought into question by an appeal to the Australian Competition Tribunal ('the Tribunal') by Energex Limited, Ergon Energy Corporation Limited, and ETSA Utilities.[23] In the determination of the Tribunal:

- the AER conceded that had erred in assigning a value of 1 to the distribution ratio and accepted that the distribution ratio of 0.71 derived from Hathaway and Officer (2004) is the average annual ratio of the amount of credits distributed in a year to the amount of credits created in a year.[24]
- the Tribunal came to the view that there is persuasive evidence to justify a departure from the AER's value of 0.65 for the utilisation ratio on the basis that the AER made a material error of fact and exercised its discretion incorrectly.

The Tribunal did not correct the errors, but directed the AER to re-examine the values of the distribution ratio and utilisation ration, and hence the value of imputation credits. This has not yet been undertaken.

Recommendation

PwC recommends that a tax rate of 30 per cent be applied in determination of a pre-tax WACC, consistent with the current Market Procedure.

PwC recommends that a gamma value of 0.50 should continue to be applied consistent with the current Market Procedure pending the AER's redetermination of this value in accordance with the direction of the Australian Competition Tribunal.[25]

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22 John C. Handley and Krishnan Maheswaran, (March, 2008), 'A measure of the efficacy of the Australian imputation tax system,' *The Economic Record*, Vol. 84, No. 264.

23 Application by Energex Limited (No 2) [2010] ACompT 7 (13 October 2010)

24 N. Hathaway and B. Officer, (November, 2004), *The Value of Imputation Credits – Update 2004*, Capital Research Pty Ltd.

25 The AER has not issued a redetermination as of 10 January 2010.

5 Cost of capital – project specific parameters

5.1 Introduction

This chapter addresses the second group of WACC parameters – project-specific parameters. These parameters must be estimated taking into account the risks and characteristics of the project or asset in question.

The project-specific parameters refer to the following parameters:

- gearing and credit rating;
- cost of debt; and
- equity beta.

The project specific parameters either comprise or reflect benchmark assumptions about the generic power station project. Determining values for these parameters involves determining settings for these benchmark assumptions informed by current practices in financing similar projects and relevant capital market data.

Determination of each of these parameters is addressed below. In each case, the consideration of each of the parameters is addressed by:

- definition of the parameter
- a summary of the method of determination adopted from the 2007 review and incorporated in the Market Procedure;
- new developments in regulatory and finance theory and practice, and market conditions, that are relevant to the determination of these parameters; and
- PwC's recommendation on either maintaining or changing the current method of determination.

5.2 Gearing and credit rating

Definition

The financial structure of the investment in the generic power station project is the proportions of debt and equity finance in the funding of the investment. More specifically, gearing is the proportion of debt to total asset value, typically determined as the ratio of the book value of debt to the sum of the book value of debt and market value of equity. The level of gearing is determined as a benchmark assumption for an efficient business undertaking the investment activity.

The credit rating of the generic power station project refers to the notional credit rating that would be expected to apply to the owning business by a reputable credit rating agency if that business were geared at the benchmark level of gearing.

Current Market Procedure and 2007 Review

The current Market Procedure provides for an assumed financial structure of 40 per cent debt to assets and for determination of a debt margin based on an assumed credit rating of BBB+.

In the advice provided for the 2007 Review, the Allen Consulting Group recommended these parameter values on the basis of:

- an average of observed levels of gearing for listed generation businesses of 35 per cent and a range of credit ratings of B to BBB+; and
- a judgement that the total risk associated with investment in capacity for sale under the Reserve Capacity Mechanism would be less than for a typical generation business that only sells into an energy market, thus supporting a higher level of gearing and higher credit rating than a typical generation business.

New developments

PwC has reviewed the assumptions of financial structure and credit rating by examining evidence from entities comparable to the business of the generic power station project.

A sample of 38 electricity generation businesses has been compiled, drawn from a number of Western economies. The main characteristics of each business are described in Appendix C. The sample is dived into baseload and intermediate/peaking groups. Gearing levels and average current credit rating were determined for pre and post GFC periods. The summary of results is provided in Table 5.1, and full results provided in Appendix D.

Table 5.1 Gearing estimates and credit rating

Type of generator	Average credit rating	Post-GFC		Pre-GFC
		10 yr average	5 year average	
Baseload	BBB-	36%	36%	35%
Intermittent / Peaking	BBB	36%	30%	23%

Source: Bloomberg

The results show that post the global financial crisis (defined as post July, 2007), both baseload and intermediate/peaking plant have gearing levels of 36 percent. Pre- global financial crisis, intermittent/peaking generators had a lower gearing level (being only 23 percent as a five year average). This is to be expected, given that intermittent/peaking generators are likely to have less contracted loads and therefore less stable revenue streams than baseload generators, and hence be less capable of supporting greater debt. It is counter-intuitive that in the post GFC period, the gearing of intermittent/ peaking generators has risen, unless there has been a relative reduction in the equity values of intermediate/ peaking firms relative to baseload firms.

Credit ratings were available for 23 of the sample businesses and indicate average credit rating levels of BBB- for baseload generators and BBB- for intermediate/ peaking generators.

PwC considers that firms receiving 10 years of contracted revenue under the Reserve Capacity Mechanism will have cash-flow characteristics closer to baseload than intermediate/peaking generators. Current evidence suggests a level of gearing of approximately 35 per cent, rather than 40 per cent as applied under the current Market Procedure, and a credit rating of BBB- rather than BBB+ as applied under the current market procedure.

Recommendation

PwC recommends changing the assumptions for gearing and credit rating in accordance with the market evidence presented in this report to a gearing of 35 per cent and a credit rating of BBB. The credit rating of BBB (rather than BBB-) is recommended taking into account the availability of data from Bloomberg for estimating the debt margin (see below).

5.3 Cost of debt

Definition

The cost of debt refers to the return investors require to provide debt finance to the business. The cost of debt is typically expressed as a margin above the risk free rate.

For regulated entities and long-term investments, such as the generic power station project, the cost of debt is typically estimated as the cost of long-term debt instruments, such as fixed coupon bonds with a 10 year term to maturity.

Current Market Procedure and 2007 Review

The current Market Procedure provides for determination of the debt margin as the margin (the debt risk premium) between the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a BBB+ (or equivalent) credit rating from Standard and Poor's and a maturity of 10 years and the nominal risk free rate:

- using the predicted yields for corporate bonds published by Bloomberg; and
- the nominal risk free rate and Bloomberg yields averaged over the same 20-trading day period.

In advice provided for the 2007 Review, the Allen Consulting Group recommended this method for determining the debt margin, and estimated a debt risk premium of 159 basis points.[26]

New developments

Since the 2007 review, Bloomberg has ceased providing an estimate of the 10 year fair value curve for bonds in the BBB range. The longest term data

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26 ACG (November, 2007), p.38.

available from Bloomberg is for 7 year BBB bonds. A possible alternative source of data, CBASpectrum, ceased publishing fair value yield curves in September 2010.

In response to the limitations on data from Bloomberg, Australian regulators have derived estimates of yield bonds in the BBB range by various methods of extrapolation of the fair value curve for 7 year BBB.

Most recently, the AER derived the debt margin for a 10 year BBB+ bond by applying:

- 75 percent weight to the 7 year Bloomberg BBB debt risk premium extrapolated to 10 years using the rise in the Bloomberg AAA bond from 7 to 10 years; and
- 25 percent weight to the observed debt risk premium for the recently issued Australian Pipeline Trust (APT) BBB rated (approximately) 10 year bond. [27]

While the AER reaffirmed that the Bloomberg curve is 'a reasonable source of information' that can be used in setting the debt risk premium, the AER considered that the observation of a lower debt risk premium on the APT bond indicated that the 7 year BBB Bloomberg debt risk premium is likely to overstate the debt margin.

PwC does not support the AER's approach, considering that there is no demonstrated justification for scaling the Bloomberg data on the basis of an observed yield of another single bond.

Recommendation

PwC recommends that the debt risk premium be estimated from the 7 year Bloomberg BBB debt risk premium extrapolated to 10 years using the rise in the Bloomberg AAA bond from 7 to 10 years. For an average of the 20 trading day period to 30 November 2010, this derives a debt risk premium of 466 basis points.

PwC also recommends that the "debt margin" be re-defined in the WACC formulae as the sum of the debt risk premium and the debt issuance costs.

5.4 Equity beta

Definition

The systematic risk (beta) of a business is the measure of how the changes in the returns of the business's stock are related to changes in the returns of the market as a whole. The beta reflects the business's exposure to non-diversifiable risk.

[27] Australian Energy Regulator (October, 2010), Final Decision - *Victorian electricity distribution network service providers, Distribution determination 2011 - 2015*, p.509.

The asset beta of a stock refers to the systematic risk of the firm if it had no gearing. It is estimated by de-levering the equity beta through a de-levering formula.

Current Market Procedure and 2007 Review

The current Market Procedure provides for equity beta value of 0.83.

These value were based on asset beta data estimated by the Allen Consulting Group for 12 Australian and internationally listed generation businesses with asset beta values ranging from 0.06 to 0.95 and averaging 0.50, and a corresponding average equity beta (at 40 per cent gearing) of 0.83. The asset beta was obtained from equity beta estimates by de-levering through the simple form of the Harris and Pringle formula:

$$\beta_a = \frac{E}{V} \cdot \beta_e$$

Where,

β_a is asset beta

β_e is equity beta

$\frac{E}{V}$ is the value of equity as a proportion of total asset value.

New developments

PwC has reviewed the equity beta value by examining evidence for the same sample of 28 companies that was used in estimating the gearing level. As with consideration of the gearing level, the sample has been split into pre and post global financial crisis periods, and into intermittent/peaking and baseload generation businesses.

The summary of results is provided in Table 5.2, and full results are provided in Appendix E.

Table 5.2 Asset beta estimates

Type of generator	Post-GFC		Pre-GFC[1]
	10 yr average	5 yr average	
Baseload	0.44	0.49	0.51
Intermittent/Peaking	0.66	0.63	0.47

[1] Pre-GFC is defined as before July 2007.

Source: Bloomberg and PwC's analysis

Recommendation

PwC considers that the systematic risk characteristics of a business whose capacity is procured by the IMO will be closer to that of a baseload generator than an intermittent/peaking generator. Taking account of both the post-GFC and pre-GFC beta data PwC recommends that an asset beta of 0.50 be adopted, consistent with the outcome of the 2007 Review.

At a gearing of 35 per cent, the asset beta of 0.50 corresponds to an equity beta of 0.77.

6 Compensation for financing costs during construction

6.1 Introduction

The final element of the scope of PwC's engagement is to consider how the WACC should be applied in calculating the amount of compensation within the MRCP for costs incurred in the "construction phase" of the generic power station project.

The construction phase of the generic power station project is the time period commencing when investors in the generic power station project first commit significant funds to the project and ending when revenues from the project commence. Although revenues are not received during the construction phase, there is still a cost of equity and debt funds committed to the project. This cost is typically referred to as the "allowance for funds used during construction" (AFUDC).

In this chapter, a first-principles approach is taken to estimation of AFUDC consistent with common practices applied in project finance. The method for determination of AFUDC thus derived is compared with the method applied under the current market procedure and a "rule-of-thumb" method for a reasonable assumption of the length of construction period for the generic power station project.

6.2 Current method of determining the allowance for funds used during construction

The current market procedure allows for AFUDC in the MRCP by including two years of return on the total investment cost of the generic power station project in the capital cost of the project, derived by escalation of the total investment cost by the factor "(1+ WACC)^2" in the following formula:

CAPCOST[t] = (PC[t] x (1 + M) x CAP + TC[t] + FFC[t] + LC[t]) x (1+ WACC)^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;

M is a margin to cover legal, approval, and financing costs and contingencies;

CAP is the capacity of the power station in MW;

TC[t] 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 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 cost of land purchased in year [t]; and

WACC is the Weighted Average Cost of Capital.

Where the total investment cost, TIC is defined as:

TIC = (PC[t] x (1 + M) x CAP + TC[t] + FFC[t] + LC[t])

then

CAPCOST[t] = TIC x (1 + WACC)^2

The AFUDC provided in this formula is the amount of escalation, which is the difference between CAPCOST[t] and the unescalated value of expenses:

AFUDC = TIC x [(1 + WACC)^2 – 1]

This method for determining the AFUDC implicitly assumes that investors in the generic power station project have incurred the full cost of the generic power station project two years prior to the commencement of revenues from capacity payments.

6.3 First principles approach to determining the allowance for funds used during construction

Construction assumptions – the 'S curve'

Construction costs for the generic power station project would include costs to acquire and prepare the land for the power station; the cost of materials and plant; and costs of labour.

The key parameters of construction costs that determine the requirements for funds are:

- the total value of the construction costs,
- the total time taken for construction; and
- a time path of cumulative expenditures.

The time path of cumulative expenditures for a construction project typically (for a construction project) follows an "S-curve" form. That is, costs are incurred at a relatively low rate at the commencement of construction (typically in a phase of planning and design), at a higher rate in the middle of the construction period (as most equipment is purchased and work is undertaken), and at a lower rate at the end of the construction period (typically in a phase of testing and commissioning).

For an open cycle gas turbine, construction times have been indicated in a range of reports and studies of generation costs as six to nine months,[28] eight and a half months,[29] one year,[30] and between 24 and 30 months.[31]

With a construction time of, say, one year, an open cycle gas turbine has a short construction period. With such a short period, a typical project financing assumption for the time path of costs is for a linear time path rather than and S-curve.

Types of financing costs

The financing costs that would typically be incurred in the construction phase of a project comprise;

- debt and equity issuance costs and debt commitment fees – the cost charged by debt and equity arrangers for the amount of finance required, and the costs charged by debt issuers for making funds available to borrowers to use; and
- financing cost during construction – the return investors require for committing capital before the asset is fully constructed and is being utilised.

The current market procedure provides for the notional investor in the generic power station project to recover “financing costs” as part of the capital cost of the project (as parameter “M” in the CAPCOST function). This is assumed to mean the costs of initial raising of debt and equity finance. As such, in this study the estimation of AFUDC is concerned only with the financing cost during construction. This is estimated as rate of return of the WACC on accumulated costs.

Estimation of AFUDC

The first principles approach to estimating AFUDC assumes that construction costs are incurred in a smooth manner over the construction period. Since the cumulative value of costs incurred increases as construction progresses, the return on costs incurred at the start of the construction period will be considerably lower than the return on constructed assets at the end of the construction period.

$$\mathrm{AFUDC} = \left(\sum_{t=1}^{n} C_t * (1 + \mathrm{WACC})^{\frac{(n-t)}{p}}\right) - \sum_{t=1}^{n} C_t$$

28 McLennan Magasanik Associates, 19 March 2009, *Rule Change #35 Re-imposition of Seasonal Caps on Capacity Payment Refunds*, Report to Independent Market Operator of Western Australia, p. 6

29 Creamer Media’s research Channel, 18 May 2007, *OCGT Stations Fuel Eskom’s Winter Fire* (http://www.researchchannel.co.za)

30 Acil Tasman, April 2009, *Fuel resource, new entry and generation costs in the NEM*, report Prepared for the NEMMCO Inter-Regional Planning Committee, p. 56.

31 IEA ETSAP - Technology Brief E02 – April 2010 (www.etsap.org), *Gas-Fired Power*, p. 4.

Where:

- C_t is the cost incurred in construction sub-period t and $\sum_{t=1}^{n} C_t$ is the total investment cost across n construction sub-periods;
- p is the periodicity of the analysis undertaken, for example, if the analysis is undertaken in months, then the periodicity is 12;
- t refers to one sub-period of the construction period based on the periodicity used.

6.4 Rule-of-thumb approach to determining the allowance for funds used during construction

A simple "rule of thumb" to determining the AFUDC for a project is to determine a return on the construction cost for half of the construction period. That is:

AFUDC = TIC x [(1+ WACC)^(n/2) – 1]

Where n is the length of the construction period in years.

This is equivalent to an assumption that all investment costs are incurred at the half way point of the construction period.

6.5 Comparison of methods

The three methods for determination of the AFUDC are compared below on the assumptions of:

- the total investment cost of the generic power station project is $150 million, incurred in even incremental amounts over a 12 month period; and
- the value of the WACC is 7.45 per cent.

Values of the AFUDC derived by each method are indicated in Table 6.1.

Table 6.1 Illustrative comparisons of AFUDC values derived by alternative methods for a total investment cost of $150 million, a construction period of one year, and a WACC of 7.45 per cent

Estimation method	AFUDC estimate
Current market procedure	$23.18 million
First-principles method	$5.06 million
Rule-of-thumb method	$5.49 million

The AFUDC values derived by the first-principles method and rule-of-thumb method are substantially less than the value that would be derived under the current market procedure. This is an expected result given that the first-principles method and rule-of-thumb method provide for a return on investment costs over a substantially shorter period.

The rule-of-thumb method gives a value close to the first principles method, which is an outcome of an assumption of the “linear S curve” for construction costs.

6.6 Recommendation

It is PwC’s view that, for the purposes of simplicity in the market procedure, the rule-of-thumb method provides a reasonable estimate of the AFUDC for the generic power station project given that the project would be characterised by a short construction period. This rule of thumb method can be implemented in the market procedure by a change to the CAPCOST formula as follows:

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

Appendices

Appendix A Recommended revisions to the market procedure

This appendix sets out recommended revisions to sections 1.13 and 1.14 of the *Market Procedure for: Determination of the Maximum Reserve Capacity Price Version 2*.

The recommended revisions to section 1.13 are drafted on the presumption that the IMO determines to maintain application of a real pre-tax WACC.

The recommended revisions to section 1.4 address the change in method used to compensate the investor in generation capacity for costs of finance during construction.

1.13. Weighted Average Cost of Capital

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.

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.

3 The methodology adopted by the IMO to determine the WACC may involve a number of components that require review. These components will normally be 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).

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

5 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.

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

7 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.

8 The pre-tax real Officer WACC shall be calculated using the following formulae

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

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

Where

(a) R_e is the nominal return on equity (determined using the CAPM) 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:

$$R_d = R_f + DM\cancel{DRP}$$

where:

R_f is the nominal risk free rate for the capacity year;

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

~~*DRP* is the debt risk premium for the capacity year.~~

(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 & 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 ~~and~~ 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 step~~s~~ (g)~~ and (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 Bloomberg does not published predicted yields for 10 year BBB-rated corporate bonds as referred to in step (h), the IMO must estimate a predicted yield for 10 year BBB rated bonds by extrapolation of the published predicted yields for the longest term BBB-rated corporate bond for which predicted yields are published applying the rise in predicted yields for AAA rated corporate bonds from 7 to 10 years.

(~~j~~k) If the ~~methodology~~ methods used in ~~Step~~ steps (i) and (j) 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.

(~~k~~l) *i* is the forecast rate of inflation. In establishing a forecast of inflation, the IMO is to have regard to the forecasts of the Reserve Bank of Australia~~, the Western Australian Department of Treasury and Finance, and financial market participants~~.

9 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	β_e	Major	~~0.83~~0.77
Debt ~~margin~~ risk premium (%)	~~DM~~DRP	Minor	TBD
Debt issuance costs (%)	d	Major	~~TBD~~0.125
Corporate tax rate (%)	t	Major	30
Franking credit value	γ	Major	0.5
Debt to total assets ratio (%)	D/V	Major	~~40~~35
Equity to total assets ratio (%)	E/V	Major	~~60~~65

1.14. Determination of the Maximum Reserve Capacity Price

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

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:

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 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;

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, expressed in Australian dollars in year t, per MW per year.

The value of CAPCOST[t] 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;

M is a margin to cover legal, approval, and financing costs and contingencies;

TC[t] 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 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 cost of land purchased in year [t]; and

WACC is the Weighted Average Cost of Capital.

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 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.

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.

Appendix B Post tax Vanilla WACC Formula

The Vanilla WACC is an estimate of the total return that the asset owners demand, and requires all potential costs and benefits (such as cash tax payments, net of the tax deductibility of interest and the non cash value of franking credits) to be reflected in the cash flows. It is the simplest form of WACC, hence its name, and is expressed as:

$$WACC = R_e \frac{E}{V} + R_d \frac{D}{V}$$

where Re is the cost of equity, Rd is the cost of debt, and E/V and D/V are the shares of equity and debt, respectively, in the financing structure (also referred to as the level of gearing).[32]

[32] Reproduced from Allen Consulting Group, November 2007, *Review of the Weighted Average Cost of Capital for the Purposes of Determining the Maximum Reserve Capacity Price*, Report to the Independent Market Operator.

Appendix C List of comparator companies

Table C.1 Comparator companies

Company name	Type of generator	Country	Market capitalisation ($millions of local currency)
Algonquin Power Income Fund	Intermittent/Peaking	Canada	461
Boralex Inc.	Baseload	Canada	325
Brookfield renewable power fund	Intermittent/Peaking	Canada	2,241
EDF Energies Nouvelles S.A	Intermittent/Peaking	France	2,325
EDP Renovaveis	Intermittent/Peaking	Spain	3,549
Energy Developments Ltd	Intermittent/Peaking	Australia	399
Greentech Energy Systems A/S	Intermittent/Peaking	Denmark	790
IdaCorp, Inc	Baseload	US	1,772
Infigen Energy	Intermittent/Peaking	Australia	491
Northland Power Income Fund	Baseload	Canada	1,170
Novera Energy PLC	Intermittent/Peaking	UK	N/A
Plambeck Neue Energien AG	Intermittent/Peaking	Germany	69
Renewable Energy Generation Ltd	Baseload	Guernsey	47
Renewable Energy Holdings PLC	Intermittent/Peaking	UK	11
Theolia	Intermittent/Peaking	France	123
AES Corporation	Baseload	US	8,882
Allegheny Energy Inc	Baseload	US	3,987
American Electric power	Baseload	US	17,285
Calpine Corp	Baseload	US	5,397
Constellation Energy Group	Baseload	US	5,873
Drax Group PLC	Baseload	UK	1,366
Dynegy Inc	Baseload	US	621
Electric Power Development	Baseload	Japan	429,916

Company name	Type of generator	Country	Market capitalisation ($millions of local currency)
Caital Power Income LP	Baseload	Canada	1,000
International Power PLC	Baseload	UK	6,610
NRG Energy Inc	Baseload	US	4,840
Pinnacle West Capital	Baseload	US	4,453
PNM Resources	Baseload	US	1,068
Progress Energy Inc	Baseload	US	12,919
RRI Energy	Baseload	US	1,297
Scottish and Southern Energy	Baseload	UK	10,872
AGL Energy	Intermittent/Peaking	Australia	7,102
Contact Energy	Baseload	NZ	3,641
Trust Power	Baseload	NZ	2,332
Fortum Oyj	Baseload	Finland	18,451
Centrica	Baseload	UK	16,981
Arendals Fossekomani	Baseload	Norway	3,584
Innergex Power Income Fund	Baseload	Canada	N/A

Source: Bloomberg

Appendix D Gearing and credit rating of comparator companies

Table D.1 Gearing pre and post GFC, and credit ratings of comparator companies

Company	Type of generator	Credit rating	Gearing		
			Pre-GFC		Post GFC
			10 year	5 year	
Algonquin Power Income Fund	Intermittent /Peaking	BBB-	45%	30%	23%
Boralex Inc.	Baseload	N/A	33%	29%	26%
Brookfield renewable power fund	Intermittent /Peaking	BBB	42%	38%	38%
EDF Energies Nouvelles S.A	Intermittent /Peaking	N/A	-	-	-
EDP Renovaveis	Intermittent /Peaking	N/A	-	-	-
Energy Developments Ltd	Intermittent /Peaking	N/A	43%	38%	34%
Greentech Energy Systems A/S	Intermittent /Peaking	N/A	19%	12%	7%
IdaCorp, Inc	Baseload	BBB	47%	47%	47%
Infigen Energy	Intermittent /Peaking	N/A	50%	-	-
Northland Power Income Fund	Baseload	BBB-	19%	13%	11%
Novera Energy PLC	Intermittent /Peaking	N/A	34%	-	-
Plambeck Neue Energien AG	Intermittent /Peaking	N/A	33%	30%	38%
Renewable Energy Generation Ltd	Baseload	N/A	9%	-	-
Renewable Energy Holdings PLC	Intermittent /Peaking	N/A	45%	-	-
Theolia	Intermittent /Peaking	N/A	38%	-	0%
AES Corporation	Baseload	BB-	60%	66%	69%
Allegheny Energy Inc	Baseload	BBB-	40%	51%	58%
American Electric power	Baseload	BBB	49%	50%	48%

Gearing and credit rating of comparator companies

Company	Type of generator	Credit rating	Gearing		
			Pre-GFC		Post GFC
			10 year	5 year	
Calpine Corp	Baseload	B	-	-	-
Constellation Energy Group	Baseload	BBB-	32%	37%	36%
Drax Group PLC	Baseload	N/A	9%	-	-
Dynegy Inc	Baseload	B-	62%	61%	68%
Electric Power Development	Baseload	AA	70%	-	-
Caital Power Income LP	Baseload	BBB	36%	23%	15%
International Power PLC	Baseload	BB	46%	37%	32%
NRG Energy Inc	Baseload	BB-	48%	-	-
Pinnacle West Capital	Baseload	BBB-	48%	47%	45%
PNM Resources	Baseload	BB-	61%	54%	50%
Progress Energy Inc	Baseload	BBB+	48%	49%	49%
RRI Energy	Baseload	B	41%	50%	64%
Scottish and Southern Energy	Baseload	A-	24%	21%	17%
AGL Energy	Intermittent /Peaking	BBB	15%	-	-
Contact Energy	Baseload	BBB	16%	20%	19%
Trust Power	Baseload	N/A	19%	11%	9%
Fortum Oyj	Baseload	A	22%	32%	31%
Centrica	Baseload	A-	11%	9%	10%
Arendals Fossekomani	Baseload	N/A	21%	11%	5%
Innergex Power Income Fund	Baseload	N/A	32%	-	-

Source: Bloomberg

Appendix E Asset betas

Table E.1 Asset betas pre and post GFC of comparatorcompanies

Company name	Type of generator	Asset betas		
		Pre-GFC		Post GFC
		10 year	5 year	
Algonquin Power Income Fund	Intermittent/Peaking	0.63	0.56	0.31
Boralex Inc.	Baseload	0.61	0.62	0.52
Brookfield renewable power fund	Intermittent/Peaking	0.22	0.18	0.34
EDF Energies Nouvelles S.A	Intermittent/Peaking	-	-	-
EDP Renovaveis	Intermittent/Peaking	-	-	-
Energy Developments Ltd	Intermittent/Peaking	0.47	0.53	0.82
Greentech Energy Systems A/S	Intermittent/Peaking	1.66	1.37	0.95
IdaCorp, Inc	Baseload	0.25	0.29	0.36
Infigen Energy	Intermittent/Peaking	0.62	-	-
Northland Power Income Fund	Baseload	0.18	0.26	0.42
Novera Energy PLC	Intermittent/Peaking	0.49	-	-
Plambeck Neue Energien AG	Intermittent/Peaking	0.54	0.51	0.48
Renewable Energy Generation Ltd	Baseload	0.63	-	-
Renewable Energy Holdings PLC	Intermittent/Peaking	0.60	-	-
Theolia	Intermittent/Peaking	1.02	-	(0.08)
AES Corporation	Baseload	0.55	0.63	0.28
Allegheny Energy Inc	Baseload	0.53	0.47	0.38
American Electric power	Baseload	0.30	0.30	0.44
Calpine Corp	Baseload	-	-	-
Constellation Energy Group	Baseload	0.70	0.52	0.35
Drax Group PLC	Baseload	0.42	-	-
Dynegy Inc	Baseload	0.43	0.61	0.64
Electric Power	Baseload	0.16	-	-

Development				
Capital Power Income LP	Baseload	0.20	0.22	0.13
International Power PLC	Baseload	0.66	1.00	1.34
NRG Energy Inc	Baseload	0.43	-	-
Pinnacle West Capital	Baseload	0.31	0.32	0.45
PNM Resources	Baseload	0.38	0.45	0.40
Progress Energy Inc	Baseload	0.20	0.18	0.33
RRI Energy	Baseload	1.01	1.07	0.82
Scottish and Southern Energy	Baseload	0.29	0.19	0.08
AGL Energy	Intermittent/Peaking	0.40	-	-
Contact Energy	Baseload	0.79	0.76	0.84
Trust Power	Baseload	0.50	0.65	0.91
Fortum Oyj	Baseload	0.60	0.39	0.29
Centrica	Baseload	0.39	0.56	0.73
Arendals Fossekomani	Baseload	0.29	0.36	0.42
Innergex Power Income Fund	Baseload	0.24	-	-

Note: Some companies did not have a full 5 or 10 year set of asset beta figures, and as such were not represented in the sample. They however were useful in identifying the credit rating of the benchmark generator, and as such were left in the sample

Source: Bloomberg

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pwc.com.au

DRAFT

Agenda Item 5: Deep Connection Cost Methodology – Interim Discussion Report by Sinclair Knight Merz

1. BACKGROUND

The IMO appointed Sinclair Knight Merz (SKM) to undertake a review of the calculation methodology to be applied in determining Deep Connection Costs (DCC). SKM has prepared an interim discussion report, which is attached as Appendix A.

The intent of this report is to advise the MRCPWG of SKM's preferred solution for the determination of DCC and initiate discussion on this preferred solution and other potential methodologies discussed within the report. The IMO notes that as SKM's preferred solution represents a significant departure from the current methodology it considers it to be prudent to present this to the MRCPWG prior to undertaking further development of the methodology.

The report provides detailed background commentary on the meaning and role of connection costs within the WEM, evaluation of the existing DCC methodology against a defined set of assessment criteria and comparison of the proposed alternative methodologies against the same assessment criteria.

The draft report is provided to the MRCPWG for its evaluation and consideration.

2. RECOMMENDATIONS

The IMO recommends that the MRCPWG:

- **Discuss** the SKM interim discussion report and the recommendations contained within.

SINCLAIR KNIGHT MERZ
SKM

imo
Independent Market Operator

Calculation Methodology to be Applied in Determining Deep Connection Costs

INTERIM DISCUSSION REPORT

- Rev 0
- 11 January 2011

Calculation Methodology to be Applied in Determining Deep Connection Costs

INTERIM DISCUSSION REPORT

- Rev 0
- 11 January 2011

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1. Executive Summary

The intent of this Interim Discussion Report is to advise the Maximum Reserve Capacity Price Working Group of the solution for the calculation of Deep Connection Costs (DCC) preferred by SKM and to engage in a discussion on this proposed solution. This Interim Discussion Report was considered prudent as the preferred solution is a material departure from the existing methodology. In light of this the IMO, Western Power and SKM believed it appropriate to receive the Working Group's feedback on the solution before the calculation methodology itself is finalised.

The scope of this study was to undertake the following:

- Analyse any assumptions made by Western Power and the IMO in the estimation of the DCC used in the Maximum Reserve Capacity Price (MRCP) calculation for the 2010 Reserve Capacity Cycle and recommend adopting or replacing those assumptions. Where an assumption is recommended to be replaced SKM will, if required, propose alternative assumptions. SKM will comment on both stated and implied assumptions; and
- If appropriate, propose an alternative methodology for estimating the DCC used in the MRCP, whilst also explicitly stating all assumptions made in the methodology.

In undertaking this review SKM analysed the assumptions made by Western Power in the estimation of the DCC against the following criteria broadly grouped into 5 areas:

- Accuracy – Extent to which the estimated DCC (as an input to the MRCP) drives the correct level of new capacity investment and supports the correct mix of generation technologies in the market.
- Certainty / Repeatability – Stability and repeatability of the methodology over time.
- Simplicity – Ease of understanding, management burden and cost associated with the calculation.
- Resilience – Extent to which methodology would be impacted by changes in Western Power's Access Arrangement or changes to other Market Rules or procedures.
- Flexibility – Extent to which the methodology can adapt to changes in technology and market conditions.

These criteria were selected as indicators of the extent to which the DCC calculation best meets the Market Objectives, consistent with work previously undertaken by MMA on issues to be addressed when considering Rule Changes. Different weightings were given to each criterion, these are:

Factor	Weighting
Accuracy	50%
Certainty	20%
Simplicity	20%
Resilience	5%
Flexibility	5%

In undertaking the analysis SKM, identified that the existing methodology has significant shortfalls against many of the criteria.

To address these shortfalls the report considers 3 alternative calculation methodologies, these being:

- A fixed annual allocation for the DCC based on an average cost of providing capacity on the network.
- A calculation of total connection cost based on a historic per MW connection cost for selected generators with different weightings on different years.
- A process that modelled a 160 MW new entrant generator as the number 1 queue applicant in which Western Power's Application and Queuing Policy and Capital Contribution Policy is accurately and fully applied, as if a real world connection.

In these options there is an inherent tension between accuracy, stability and simplicity. The report recommends a calculation methodology that uses historic DCC to reflect the likely level of future connection costs which are then used as a proxy for setting an appropriate MRCP. In adopting this approach the calculation methodology must consider the following issues with this methodology:

- Ability to respond to rapid changes in actual connection costs due to network limitations.
- Balance between reflecting long run and short run marginal costs.
- Reflecting the connection cost of the efficient capacity providers.
- Confidentiality of actual connection cost data.
- Selection of financial escalators.
- Establishing a conservative forecasting error margin in the calculation.

SKM believe these issues can be successfully addressed in the calculation methodology.

2. Introduction

2.1. Scope of Report

The IMO is currently reviewing the Market Procedure for: Determination of the Maximum Reserve Capacity Price (MRCP). As part of this review, it has been identified that the assumptions and methodology behind the calculation of the Deep Connection Costs (DCC) require further analysis. The intent of this report is to provide an analysis of the existing methodology used to calculate the DCC and recommend a methodology for moving forward. The review and the recommendations focus on the assumptions that underpin the calculation of the DCC and the extent to which these assumptions best support the Wholesale Energy Market (WEM) Market Objectives. The result of the analysis is a specific calculation methodology for Western Power to follow in future DCC reviews.

The calculation methodology is required to take into account:

1. Related legislation such as the Access Code, the Metering Code, the Technical Rules etc and any other relevant regulatory considerations;
2. Possible outcomes and implications of the application of the New Facilities Investment Test (NFIT);
3. Western Power's Capital Contributions Policy;
4. Appropriate tariff charges to include, i.e. the most up to date tariffs are in the 2010 Western Power Price List should Western Power scale these up when applying the Capital Contributions policy, if so how;
5. Application of GST;
6. The appropriateness of applying an escalation for locations outside the metropolitan area; and
7. The nature of the current capacity based market and the associated need for unconstrained network access;
8. Any other considerations the Consultant deems should be taken into account.

2.2. Purpose of this Report

Specifically, this purpose of this report is to:

- Analyse any assumptions made by Western Power and the IMO in the estimation of the DCC used in the MRCP calculation for the 2010 Reserve Capacity Cycle and recommend adopting or replacing those assumptions. Where an assumption is recommended to be replaced we will propose a different assumption. SKM will comment on both stated and implied assumptions; and
- If appropriate, propose an alternative methodology for estimating the DCC used in the MRCP, explicitly stating all assumptions made in the methodology.

2.2.1. Report Deliverable

The main deliverables for this report are:

1. A document which plainly states each parameter that should be used by Western Power in calculating an estimate of DCC under both the Western Power methodology (including details of any amended assumptions and assumptions associated with the Western Australian regulatory regime) and the alternative methodology, the calculation methodology for each parameter, and the assumptions inherent in each calculation. This document will need to be worded such that it can either be incorporated directly into the Market Procedure or be used as a subsidiary document to the Market Procedure. This document will in effect provide a definition of DCC;

2. Details of the costs associated with the DCC that should be included in the MRCP, e.g. the capital contributions estimated by Western Power in the 2010 MRCP review or another cost variable to take into account potential changes to tariffs etc.; and

3. Details of the relevant recommendations and analysis undertaken in determining the information provided in the document referred to above.

2.3. Definitions and Interpretation of Terms

The definition of the terms within this report are as specified in the Market Procedure for the Determination of the Maximum Reserve Capacity Price and in the Western Power Contribution Policy and the regulatory frameworks that support these documents.

In support of the documents detailed above and the analysis in this report the terms Shallow Connection Costs and DCC are defined in section 4.3 of this report.

3. Background

The IMO provided the following background information as part of its Request for Quotation for the services relating to this report:

The Wholesale Electricity Market Rules[1] (Market Rules) and the Market Procedure for the Determination of the Maximum Reserve Capacity Price[2] (the Market Procedure) require the IMO to calculate a Maximum Reserve Capacity Price (MRCP) each year. The MRCP sets the maximum offer that can be made in a Reserve Capacity Auction and is used as the basis for determining an administered Reserve Capacity Price if no auction is required and capacity refunds.

The Reserve Capacity Mechanism is designed to incentivise the provision of a sufficient amount of reliable capacity within the SWIS. The MRCP is one of the elements of this mechanism which estimates the annualised cost of building a 160 MW OCGT that is entered into the RC Auction.

In particular, the Market Procedure outlines the principles to be applied and the steps to be taken by the IMO in order to develop and propose the MRCP. Section 1.8 details the methodology that Western Power must follow in determining the cost of connecting the Power Station to the SWIS.

Section 1.8.2(i) specifies that "An estimate of DCC must be included". However, the Market Procedure does not include either a detailed methodology for how this should be calculated or a definition of DCC. To date the IMO has defined DCC as the capital costs passed on to the connecting generator that are associated with upgrading/ augmenting the transmission system to allow for the generator to connect to the SWIS.

As part of the 2010 MRCP determination, Western Power provided an analysis in support of their calculation of transmission costs associated with the proposed power station. The estimates provided, and the methodology which supported them was a recurring topic in a number of the submissions the IMO received in response to the draft report. These submissions can be found on the IMO website[3].

In accordance with clause 4.16.9 of the Market Rules, the IMO is currently reviewing the Market Procedure. As part of this review it has been identified that the assumptions and methodology behind the calculation of the DCC require further review.

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[1] Available on the IMO website: http://www.imowa.com.au/market-rules

[2] Available on the IMO website: http://www.imowa.com.au/f711,482994/482994_Market_Procedure_for_Maximum_Reserve_Capacity_Price.pdf

[3] Available on the IMO website: http://www.imowa.com.au/mrcp

To guide this review this report provides a methodology including the appropriate definition (including the reasons for inclusion and exclusion of each cost), parameters, assumptions and calculation of estimates of deep connection charges associated with connecting a Power Station to the SWIS. This report will need to be in the context of the Western Australian Wholesale Electricity Market and be able to be followed by Western Power in calculating an estimate of deep connection charges.

The IMO anticipates that the outcomes of this work will feed into its wider five year review of the determination of the MRCP.

4. Connection Costs and the Wholesale Market

A review of the assumptions and methodology behind the calculation of DCC ultimately requires an understanding of the term, including its meaning, purpose and use within the market and regulatory arrangements. While the term conveys a general meaning that is common across many jurisdictions, its precise definition and required interpretation is affected by the manner of its use within the functions and processes of the Market Rules, and given the related procedures, systems and guiding objectives that together give direction and effect to these Market Rules.

This section therefore considers the meaning, purpose and use of the term DCC within the market and regulatory arrangements. It defines the required basis of an assessment framework that will be used to assess the effectiveness of Western Power's Capital Contributions Policy, insofar that it provides an appropriate input into the operation of the Reserve Capacity Mechanism of the Market Rules.

4.1. A general understanding of the term 'Connection Cost'

The term connection cost generally covers the costs associated with infrastructure or supporting services that facilitate the connection of an electric facility, such as a generator or load, to a network, in a manner that maintains system reliability and other applicable standards, that is consistent with good practice and that is least cost.

Recognised cost components typically include the design, procurement and installation costs for three classes of investment:

1. Direct costs that provide for the physical connection of a new facility with the existing assets of the network.

   Examples of costs include: Substations; transmission / distribution lines; and communication and control infrastructure.

2. Indirect costs associated with the reinforcement of existing network assets, or service levels, to accommodate the load characteristics, or to support the deliverability of supply, as the case may be, of the connecting electric facility.

   Examples of costs include: Reinforcement or upgrade of existing transmission / distribution line, substations or terminal stations. Installation of new lines, substations or reactive power support at sites removed from the electric facility.

3. Indirect costs associated with upgrading or augmenting the network, or service levels, such that the costs facilitate actual or anticipated load growth, load patterns, or other changes in the network that are not specific to the connecting facility.

   Examples of costs are similar to those in item 2 above.

4.2. Connection Costs in the Physical and Market Systems

The SWIS is the major interconnected electricity network in Western Australia (WA). It supplies the bulk of the South West region, extending to Geraldton in the north, Albany in the south, and Kalgoorlie in the east.

The network assets of the SWIS are owned and managed by Western Power, and facilitate the physical operation of the power system. Electric facilities that connect with the SWIS are subject to Western Power's Capital Contributions Policy that specifies the extent and nature of costs that are payable to facilitate a physical connection to the SWIS. The Capital Contribution Policy is part of Western Power's Access Arrangement which is to meet the requirements of the Electricity Network Access Code 2004 (ENAC).

The Wholesale Electricity Market of Western Australia (WEM) is a feature of the SWIS, providing for the organised dispatch and trade of electricity, and electricity related services, between industry participants that operate in the energy supply sector. The organised markets of the WEM, together with bilateral contract markets for capacity, define the market relations that facilitate transactions in capacity and related services.

Although the connection costs of a new electric facility do not directly feature in trading arrangements of WEM, they do indirectly feature as a component of the MRCP, which operates as a calculated cap on offers and on prices in the market for Reserve Capacity.

The market and regulatory arrangements of the WEM can be defined as the market rules, procedures, systems and related regulatory provisions that together give effect to the trading arrangements and operations of the wholesale market, and the behaviour of its participants.

4.3. Deep Connection Costs vs Shallow Connection Costs

The IMO Market Procedure for the calculation of the MRCP includes a requirement for the calculation of Transmission Connection Cost Estimate (item 1.8). In the calculation of this estimate the procedure calls for the cost estimate to consider 9 items, the last of these items is that an "An estimate of Deep Connection Costs shall be included". The other 8 items define the nature of the connection of the generator to the network and the technical assumptions that should be made in calculating the estimate.

The existing Western Power Access Arrangement does not make a distinction between Deep and Shallow Connection Costs. It should also be noted that the definition of Deep vs Shallow Connection Costs do not necessarily with align with Western Power's definition of Connection Assets and Shared Network Assets in all circumstances.

In jurisdictions where the definition is widely used, the DCC typically pertain to the costs described in items 2 and 3 of section 4.1 of this report. The purpose of having the costs met by the entity connecting to the network is to provide a price signal that reflects the scarcity of network capacity at a given location. This investment signal is considered important in driving economically efficient investment in generation and load development on a network.

Shallow Connection Costs typically represent the costs associated with network assets required to connect the user to the existing or planned network assuming adequate network capacity at the point of connection. In this report, the sum of the Deep and Shallow Connection Costs represent the Transmission Connection Cost Estimate consistent with the Market Procedure.[4]

For the purposes of this report, shallow connection costs will be defined by the 2 km of transmission line and the 330 kV breaker and a half substation specified in items 1.8 a-h of the Market Procedure for the calculation of the MRCP. Deep Connection Costs will be defined as the total connection costs established by the existing methodology applied by Western Power minus the shallow connection costs.

It is noted that using this definition of the calculation of shallow connection costs places technical bounds around the calculation of the broader connection costs that may result in a technical outcome that is removed from the efficient technical solution for a given location. This is particularly the case where connection costs calculations are undertaken for locations that are significantly removed from the existing 330kV network requiring significant extension of the 330kV network in the DCC Calculation (such as at Kalgoorlie). However, by defining the Shallow Connection Costs in this manner the consideration of DCC in effect becomes a study of the determination of Total Connection Costs by Western Power.

As a result, this review of DCC determination methodology effectively becomes a review of the manner in which Western Power is applying its Capital Contribution Policy in response to the bounds provided by the IMO Market Procedure.

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[4] Some jurisdictions defined Deep Connection Costs as inclusive of Shallow Connection Costs. For example a pure Deep Connection Cost policy would result in the network user paying all attributable network reinforcement costs (as is the case with the Western Power Capital Contribution Policy). To remain consistent with the MRCP Market Procedure this report defines Deep Connection Costs as separate costs to the Shallow Connection Costs.

4.4. The Regulatory Context

The existing DCC calculation methodology applied by Western Power occurs at the intersection of two major regulatory regimes defining actives in the WEM, the Electricity Network Access Code 2004 (ENAC) and the WEM Market Rules. The following summarises the impact of these market and regulatory arrangements.

4.4.1. Arrangements relevant to the physical networks

4.4.1.1. The Electricity Network Access Code

The ENAC governs the activities of any Covered Network in Western Australia, including that provided by Western Power. The ENAC defines the bounds under which a Network Operator can levy connection costs through the definition of the requirements for a Capital Contribution Policy. In effect, this policy describes the extent to which the cost of infrastructure required to facilitate a connection can be recovered from a user as an upfront charge (connection cost) and the extent to which the cost is rolled into the regulated asset base to be recovered through regulated tariffs. In defining this division, the ENAC states that any Capital Contribution Policy

(a) must not require a user to make a contribution in respect of any part of new facilities investment which meets the new facilities investment test; and

(b) must not require a user to make a contribution in respect of any part of noncapital costs which would not be incurred by a service provider efficiently minimising costs; and

(c) may only require a user to make a contribution in respect of required work;

and

(d) without limiting sections 5.14(a) and 5.14(b), must contain a mechanism designed to ensure that there is no double recovery of new facilities investment or non-capital costs

The above dictates that any DCC charged by Western Power must be on the basis of infrastructure developed in an efficient manner and not include infrastructure to the extent that it meets the requirements of the New Facilities Investment Test.

The ENAC does not require Western Power to differentiate between deep and shallow connection costs.

Also of note is that the ENAC defines that all Access Contracts for capacity services be for a defined capacity and that under normal operation a user will not be restricted below this capacity. This requirement is otherwise referred to as unrestricted access.

4.4.2. Capital Contribution Policy

The Western Power Capital Contribution Policy has been determined by the ERA as consistent with the requirements of the ENAC. The Capital Contribution Policy defines the capital contribution as the Allocated Forecast Costs minus Network Access Charges plus Other Applicable Costs.

Where allocated forecast costs include:

- Minimum practical works to provide the connection
- Shared networks costs
- Future applicants
- Current applicants
- Costs brought forward
- Temporary supplies

4.4.3. Arrangements relevant to the Wholesale Market

4.4.3.1. The role of Connection Costs in the design of the WEM

DCC ultimately contribute to the design and implementation of the organised wholesale market via their contribution to the determination of the MRCP that is a feature of the Reserve Capacity Mechanism. Indeed, it is this context that guides the focus of this review.

A review of the WEM Market Rules identifies that the MRCP undertakes the following roles

1. Provides for the mitigation of actual or potential market power (Clause 2.26.3)
2. Provides for the management of commissioning risk specific to a new electric facility that is assigned Certified Reserve Capacity (Clause 4.13). This process underpins the Security of the Reserve Capacity.
3. Defines an upper bound for the Reserve Capacity Price (Clause 4.16)
4. Defines an upper bound for Reserve Capacity Offers in the Reserve Capacity Auction (Clause 4.18)
5. Defines a settlement price for Capacity Credits in the absence of a Reserve Capacity Auction (Clause 4.29.1)
6. Defines the financial implications of failing to satisfy Reserve Capacity Obligations in the absence of a Capacity Auction (Clause 4.26.1)

7. Sets bounds for administrative processes related to Long Term Special Price Agreements (Clause 4.22.2)

The Market Rules are also clear that the MRCP is to act a market signal with a general requirement to be published (Clause 10.5.1.e) and a requirement to be included in the information that forms the Expression of Interest in the Reserve Capacity Auction (Clause 4.3.1).

This review of the Market Rules indicates that the general function of the MRCP is to provide a benchmark or reference price to facilitate the management of risk, market power or other administered market processes. Moreover, it is defined as one unique benchmark or reference price that is applied commonly across the reach of the Market Rules; it therefore does not differentiate in application or calculation with respect to location, time or technology.

The role of the MRCP in the market design is also indicated via the associated Market Procedures, in particular, the *Market Procedure for: Determination of the Maximum Reserve Capacity Price. Version 2*. Specifically:

1. Section 1.5 defines the technical characteristics of a hypothetical Power Station that is to be used in the calculation of the MRCP;
2. Section 1.6 defines the cost factors that are to be used in the calculation of the MRCP; these explicitly include costs associated with the connection of the Power Station to the bulk transmission system (Clause 1.6(d));
3. Section 1.14 defines the formulae to determine the MRCP, for which no precise methodological detail is provided for the determination of connection costs; and
4. Section 1.15 defines requirements for the periodic review of the methodology that is used to determine the MRCP.

A review of the Market Procedure therefore indicates that the calculation of the MRCP is to be based on a hypothetical generation asset using contrived assumptions that are deemed to be reasonable by virtue of the consultative provisions of the Market Rules, and of the periodic reviews that are required by the Market Procedure.

4.4.3.2. The Role of Connection Costs in the Bilateral Market

As a published metric and instrument of the market for Reserve Capacity, the MRCP represents a significant market signal for the installation and procurement of capacity. The direct impact is via the operation of the organised market for Reserve Capacity, including the Reserve Capacity Auction and arrangements for the procurement of Supplementary Reserve Capacity. It has indirect impact on the bilateral contract market for capacity, insofar that the organised market complements the contract market by providing alternative facilities for the procurement of capacity, for trading out of contractual exposures, for the refinement of contracted positions, and as a price reference in the negotiation and operation of bilateral contracts. Moreover, the performance of both the bilateral and organised markets provide price and dispatch signals that feature in decisions to invest in physical capacity, or in associated services.

4.4.3.3. Interaction of the MRCP with the Energy Market

In the broader context of the WEM, the Reserve Capacity Mechanism represents one of two major revenue streams for generators. The second major stream of revenue is the sale of electricity, whether through the bilateral market, the short term energy market (STEM) or as a balancing or ancillary service. The Reserve Capacity Mechanism is intended to cover a portion of the fixed cost associated with installing new capacity. The portion of that cost depends on the generation technology being installed as the fixed and variable cost base of generation technologies vary widely, from diesel generators (with low fixed and high variable costs) to wind and other renewable generation (with high fixed and low variable costs).

As a metric not largely determined by market mechanisms[5] the MRCP has limited ability to respond dynamically to incentivise efficient outcomes within the market. This suggests that the portion of participating generators revenue met by the MRCP through the Reserve Capacity Mechanism should be minimised. However, the WEM market is a day before market and therefore cannot respond dynamically (in real time) to periods of generation shortfall. This is reflected by the low Maximum Energy Price Limits on the WEM compared to those in real time energy markets such as the NEM. The impact of this is that peaking generation technologies, that form and integral part of an efficient energy solution, do not see the high energy price that incentivise their participation in real time energy markets. Thus, the MRCP must be set high enough to incentivise the participation of low fixed cost peaking technologies.

[5] Notwithstanding the scaling made by the Excess Capacity Adjustment that is linked to the relationship between supply and demand for Capacity Credits.

5. Assessment Approach

5.1. An Assessment Framework to support the evaluation task

5.1.1. What is the subject of the assessment?

The subject of the assessment is defined by the IMO in its terms of reference for this review. In particular, the IMO requests the following:

To guide this review the IMO requires a report on the appropriate definition (including the reasons for inclusion and exclusion of each cost), parameters, assumptions and calculation of estimates of deep connection charges associated with connecting a Power Station to the SWIS. This report will need to be in the context of the Western Australian Wholesale Electricity Market and be able to be followed by Western Power in calculating an estimate of deep connection charges.

SKM therefore interprets the subject of the assessment as the substance and application of the calculation methodology for DCC, as prescribed by the Capital Contributions Policy of Western Power.

5.1.2. Benchmark criteria and attributes that should inform the assessment

The IMO requires the assessment to consider what is ‘appropriate’ with respect to the substance and application of the calculation methodology for DCC.

A consideration of what is appropriate necessarily requires reference to the Market Objectives, insofar that they prescribe what is required for an effective and appropriate set of rules to guide the operation of the WEM in the context of the SWIS.

In determining what is appropriate, however, SKM recognises that the Market Rules, including their Market Objectives, are but one element of a suite of market and regulatory arrangements that ultimately influences the operation of the market. Other elements include related systems, procedures, guidelines, regulatory instruments, institutions, assets and processes of change and reform. Together these shape decisions, implement processes and guide the behaviour of participants in the market. Accordingly, while the Market Objectives can provide some specific guidance of what is appropriate in the context of the WEM, on their own they are not sufficient. For a market design to best achieve the Market Objectives, additional and more general attributes also guide what is ‘appropriate’. Examples include the following:

- Resilience to anticipated scenarios of change, reform, investment and innovation.
- Consistent with the realities of operational practices, technological constraints and prevailing contracts.

- Consistent with the broader market and regulatory arrangements that influence market behaviour and outcomes.
- Processes of change are manageable in terms of time, cost and risk.

SKM has therefore broadened the set of criteria and attributes that it considers relevant to the assessment and development of the calculation methodology for DCC.

Appendix A describes how SKM has developed a set of assessment factors to assist the review.

The following summarises the assessment factors that have been used in this review.

5.1.3. Summary of Selected Assessment Criteria

The following summarises the criteria that SKM has utilised to assess Western Power's calculation of DCC:

Criteria 1: Accuracy

For the purpose of this review, we define accuracy as the extent to which the DCC calculation methodology drives the correct level of new capacity investment and supports the correct mix of generation technologies in the market as prescribed by the Market Objectives. The level of new capacity must therefore achieve the Market Objectives of economic efficiency, reliability and fair competition.

As a component in the calculation of the MRCP, the estimate of DCC should represent an upper limit on the connection cost of Reserve Capacity, estimated in marginal cost terms for application across the SWIS. Ultimately the economic intent of the MRCP is to provide a price constraint that is approximately consistent with the system marginal cost of new peaking (liquid fuelled) capacity when the market is in long-run equilibrium. It follows that the DCC estimate should similarly reflect the system marginal connection cost for new peaking capacity in this long-run equilibrium state. With respect to this ideal, the following clarifying observations are made:

- The long-run equilibrium state refers to circumstances when the market is in a long-run equilibrium, meaning that in the context of the Market Rules, the market best achieves the Market Objectives. In part, this requires the market to achieve ideals of economic efficiency, competitiveness and non-discrimination, in circumstances when system assets exactly deliver the requirements of the reserve margin, and associated reliability and system security objectives. When actual capacity varies from the exact requirements of the reserve margin, it is not in a long-run equilibrium. If the market is performing well, this will then cause system marginal prices to incentivise changes to market behaviour towards the achievement of the requirements of the long-run equilibrium. When actual capacity is in excess of the requirements of the Reserve Margin, for example, a competitive market would produce energy and capacity price outcomes that are less than the long-run total cost of new capacity, thereby acting as a disincentive for new investment. Conversely, when actual capacity is short of the requirements of the Reserve Margin, the MRCP combines with higher energy prices to reflect a scarcity of capacity, thereby resulting in prices at or above the marginal cost of new capacity in this long-run equilibrium state, and encouraging increased investment.

- As a system marginal cost, the DCC estimate in the MRCP should reflect the cost of the last increment of new capacity that just achieves the requirements of the Reserve Margin for the SWIS. The appropriate size of this increment is 1 MW, with costs measured on an annual basis. It follows that estimates of DCC should similarly reflect an annualised measure of the additional total cost of connecting the last MW of new capacity that is required to achieve the system's Reserve Margin.

Criteria 2: Simplicity

The calculation methodology represents an overhead burden ultimately borne by customers on the SWIS. Further, more complicated methodologies may introduce uncertainty or modelling difficulty amongst potential investors. For these reasons it is necessary that any methodology be simple to understand, implement, manage and be repeatable. To the extent that it is feasible, participants other than Western Power should be able to independently apply the methodology, therefore supporting their own investment modelling.

Criteria 3: Certainty

The methodology must be stable over time, therefore promoting regulatory certainty, and as a consequence, minimal investment risk.

Because the MRCP is both a default price, and a price cap that affects payments to assets with long-lives, this volatility can be the cause of revenue risk in investment decisions. The consequence is that the market may delay new investment longer than is optimal and/or, the technology of the ultimate capacity investment may be inappropriate given the needs of an economically efficient system and market.

Criteria 4: Resilience

The methodology is expected to continue to deliver the intent of the Market Rules given anticipated scenarios of industry change, development and reform.

Criteria 5: Flexibility

The methodology must accommodate variations in the character of connection costs, and in the scenarios that may be used to establish the benchmark.

5.1.4. Weighting of Criteria

The above criteria are not considered of equal importance within the assessments in this report. Criteria that directly support multiple Market Objectives (as discussed in Appendix A) are given a greater weighting than criteria that support more general attributes. Table 1 provides a weighting out of 100% as a guide to the relative importance of each criteria.

Table 1 Weighting of Assessment Criteria

Factor	Weighting
Accuracy	50%
Certainty	20%
Simplicity	20%
Resilience	5%
Flexibility	5%

5.2. The assessment approach

The assessment will undertake the following steps:

1. Summarise existing methodology.
2. Review existing methodology and assumptions against criteria.
3. Review interactions or complexities with other market and regulatory requirements.
4. Propose a range of options.
5. Consider the proposed methodology options against Criteria.
6. Recommend a methodology

6. Summary of Existing Methodology

6.1. Our approach

This section summarises the existing DCC methodology by considering the following aspects of the DCC:

1) How the DCC is used in the broader MRCP calculation.
2) The context prescribed by the IMO to Western Power for the calculation of the DCC.
3) The methodology and assumptions used by Western Power to apply the Capital Contribution Policy to the context prescribed by the IMO.

The methodology and assumptions summarised in this section form the basis of the analysis in Section 7 of this report.

6.2. Documents Referenced in the Review

The summary outlined in this section references the following documents:

- Interview with Western Power by SKM on 28 October 2010.
- Western Power Capital Contribution Policy Summary[6].
- Appendix 3 of the current Western Power Access Arrangement[7].
- Spreadsheet from the IMO titled “MRCP_CALC_2012_2013 - OPTIMISED V5 -Including easements and updated WACC and updated M and updated transmission costs”.
- Spreadsheet provided by Western Power titled “MRCP - Capital Contribution Calculator - Collie Shared Assets Only.xls”.
- Wholesale Electricity Market Rules[8] (Market Rules).
- Market Procedure for: Determination of the Maximum Reserve Capacity Price[9].
- Various submissions to the IMO on the DCC calculation methodology[10].

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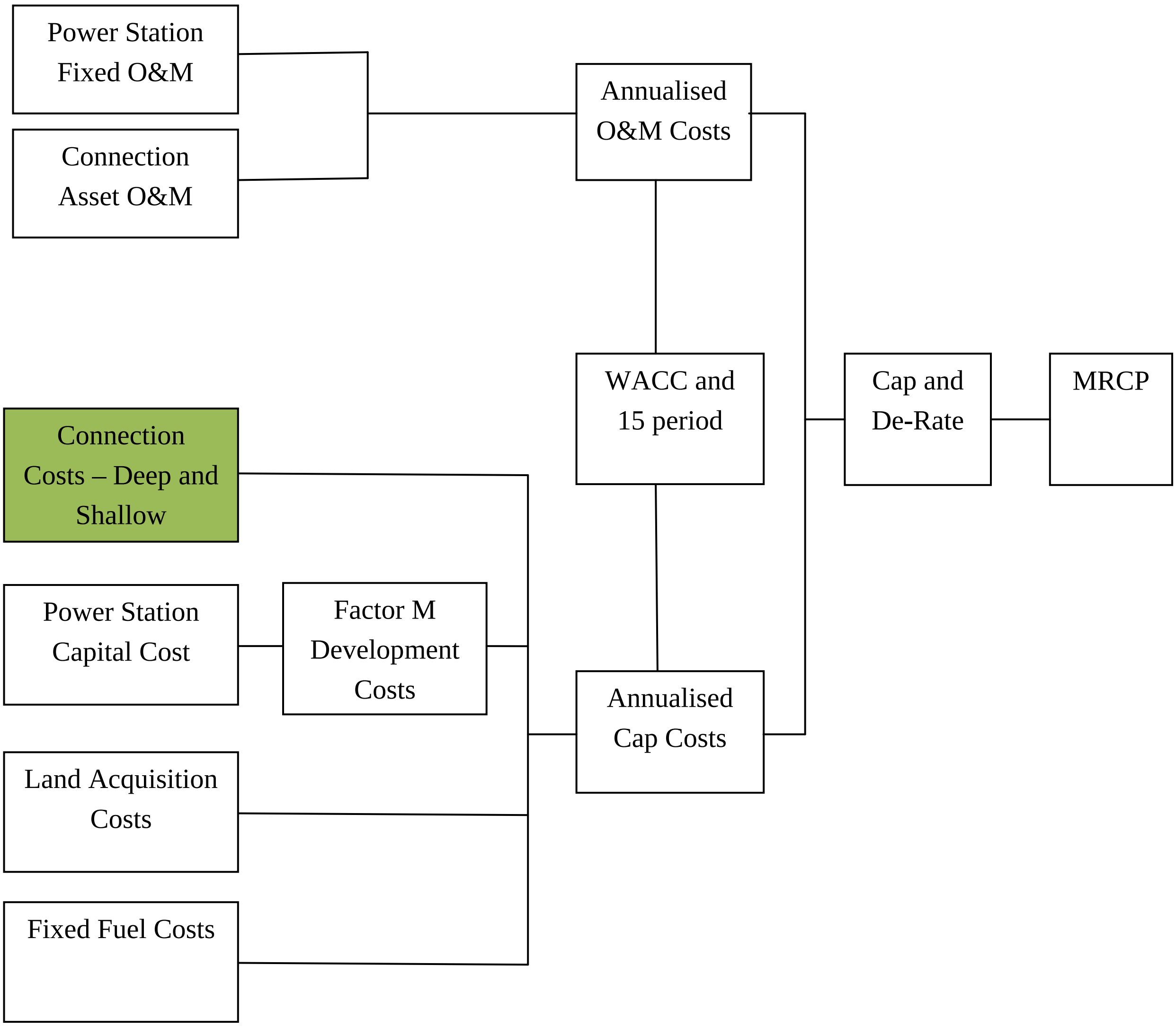
[6] http://www.westernpower.com.au/documents/infoPacks/CapitalContributionPolicy.pdf
[7]http://www.westernpower.com.au/documents/aboutus/accessarrangement/2010/WE_n5012829_v14A_AA2_Appendix_3_-_Contributions_Policy.pdf
[8] http://www.imowa.com.au/market-rules
9http://www.imowa.com.au/f711,482994/482994_Market_Procedure_for_Maximum_Reserve_Capacity_Price.pdf
10 Available on the IMO website: http://www.imowa.com.au/mrcp

6.3. DCC as part of the MRCP

The role of the DCC in the determination of the broader MRCP is detailed in the formulae contained with the Market Procedure for MRCP, this formulae is summarised diagrammatically in Figure 1 below. The DCC component of the MRCP is highlighted in green.

- **Figure 1 Components of the MRCP**



The IMO typically requests the parties that calculate the component parts of the MRCP determination to commence work in July of each year with the results to be with the IMO for compilation by October of the same year.

6.4. The prescribed context for the DCC calculation

The IMO, through the Market Rules and Market Procedures, prescribes the calculation scenario that Western Power is required to use in its estimation of DCC for input into the MRCP calculation. Specifically, the connection scenario considers the connection of the following generator to the SWIS:

a) 160 MW open cycle Gas Turbine.

b) Connected at 330 kV.

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

The connection scenario also requires a consideration to the ollowing locations for connection:

- Pinjar
- Kwinana
- Kemerton
- Collie
- Geraldton
- Eneabba
- Kalgoorlie

These locations are consistent with the regions stipulated in section 1.8 of the Market Procedure.

This calculation is requested in current dollars and assumes a 2 year construction period. The steps Western Power currently takes to calculate the DCC within this scope are detailed below.

6.5. Western Power's application of their Capital Contribution Policy

In determining the DCC consistent with the preceding prescribed context, Western Power seeks to address the general requirements of the Western Power Capital Contribution Policy. These are:

- Allocated Forecast Costs, including:
  - Definition of minimal practical works.
  - Level of contribution to the connection costs from current and future third parties.
  - Extent to which the costs are an acceleration of investment that would have met the NFIT.
- Period (up to 15 years) and forecast quantum of the Network Access Charges.

- Other Applicable Costs, including:
  - Non capital costs.
  - Non standard construction.
  - Other costs incurred to ensure Western Power complies with all technical rules.

The current approach to each of these aspects, as determined through discussions with Western Power, is detailed below.

6.5.1. Determining Minimum Practical Works

6.5.1.1. Definition of Minimum Practical Works

In defining the required Minimum Practical Works for the DCC calculations, Western Power depends largely on studies undertaken for previous access applicants and experience and knowledge of what is likely to be the most effective arrangement for new facilities. For some connection points, like Kalgoorlie, the requirement for a 330 kV connection results in works that are significantly disconnected from that which would be considered efficient.

In determining the Minimum Practical Works Western Power does not follow the procedures for processing real new connections, most significantly:

1) Western Power does not undertake any specific steady state or dynamic analysis to determine the Minimum Practical Works for the model generators at each of the locations.
2) No specific options analysis is undertaken beyond the information drawn from previous connection studies.
3) Likely future users are not considered in determining the Minimum Practical Works requirement at each location.

The use of information from previous studies and experience in establishing the Minimum Practical Works for each of the connection points is a reasonable approach in the time frame provided for the study and the expected expenditure. To complete a comprehensive options analysis for each of the locations would require an extended program of work that would need to exist in parallel with Western Power's network planning process and processing of "real world" Access Applications.

6.5.1.2. Estimating the Cost of defined Minimum Practical Works

In determining the cost of the Minimum Practical Works, Western Power uses a cost "building blocks" approach consistent with the first stage of the Western Power estimating framework. This approach involves no application specific design and limited project definition. SKM believe this is consistent with a class 4 estimate under the Association for the Advancement of Cost Engineering international (AACEi) recommended practice of estimate classification (Refer

Appendix B). SKM believes the expected accuracy of this estimate would be in the order of ±30-50%, this is consistent with Western Power's view of this estimating process.

6.5.2. Level of contribution to the connection costs from current and future third parties

In defining the costs contribution by third parties, Western Power assumes that any "spare" capacity produced by the minimum practical works will be utilised by third parties and therefore allocate a pro –rata cost to the model 160 MW. This pro rata is on the basis of the portion the required 160 MW takes of the capacity created by the minimum practical works. This approach represents what would be a "best case" for a real connection.

6.5.3. Extent to which costs are an acceleration of investment that would have met the NFIT

Western Power have advised minimum required works developed for the DCC are not considered in the context of the Western Power 10 year plan for the SWIS network. In this way this aspect of the Capital Contribution Policy is not considered.

6.5.4. Calculation period

The calculation period of 15 years is used by Western Power in the calculation of the DCC.

6.5.5. Forecast quantum of the Network Access Charges;

Western Power use the existing Network Access charges with no escalation in real terms in their capital contribution model.

6.5.6. Other applicable costs

Western Power applies the operating and maintenance costs of the minimum practical works on the basis of:

- 3.1% of distribution asset capital cost.
- 2.1% of transmission asset capital cost.

SKM has not identified any other applicable costs applied by Western Power.

6.5.7. Payment Terms

Clause 6 of the Capital Contribution Policy allows provision for payment terms, and prescribes the circumstances when alternative payment terms are available. These payment terms are not applied in the determination of the DCC.

6.5.8. Western Power's application of the applications and Queuing Policy

Western Power does not take into account any impact on the DCC from the Applications and Queuing Policy.

7. Review of Existing Approach and Assumptions against Criteria

This section reviews the methodology and assumptions summarised in section 6 against the criteria detailed in section 5 of this report.

7.1. Review of Existing Approach to Calculating the DCC

This section provides a review of the existing approach of basing the DCC calculation on an estimate of the actual cost of a model connection at various sites against the assessment criteria.

Factor	Impact of Assumption
Accuracy	The approach should produce a cost estimate that is consistent with the system marginal connection cost of the efficient new entrant capacity provider when the market is in a long-run equilibrium, and therefore when it is fully achieving the market objectives (eg. the new capacity exactly achieves the requirements of the reserve margin). The approach does not produce costs that are consistent with this requirement, in part because it considers the current context of the network, and not a context that reflects long-run equilibrium conditions. What this means is that the estimated costs may be volatile, and subject to current system constraints, and the effect of over or under network investment. When feeding through to the MRCP, this may then produce a price/bid cap that contributes to cycles of over or under capacity investment. Due to the constrained nature of the network there may be periods where this approach results in costs significantly higher than those seen by capacity providers using technologies that differ from the model connection size.
Certainty	The approach to a model connection provides certainty to market participants that the DCC should reflect the actual cost of new entrant capacity within the accuracy constraints introduced by the assumptions used discussed further in section 7.2.
Simplicity	The model connection is an approach that is easily understood by market participants. The resulting methodology could be very complicated and requires a range of detailed assumptions. Western Power has adopted a methodology that uses existing data and experience to simplify the approach. This approach represents a practical solution to what could be a significant time and resource intensive process. It does however introduce a range of repeatability concerns.
Resilience	The use of a model scenario for the Calculation of DCC is an approach that can be applied independently of changes in the regulatory context within the WEM. It does however make the calculation methodology subject to changes in both the ENAC and the WEM Market Rules. Therefore, although the approach is resilient the resulting methodology may be impacted by changes to a wide range of market mechanisms.
Flexibility	The current approach has flexibility to respond to the locations within the network that may represent the most cost effective connection site but cannot respond to changes in the nature of the efficient new entrant capacity provider over time.

7.2. Assumptions prescribed by the Market Procedure

This section reviews the following assumptions summarised in section 6.4 of this report against the assessment criteria.

160 MW Capacity Requirements

Factor	Impact of Assumption
Accuracy	The optimal scale for the efficient new entrant capacity provider will change over time. For example, embedded generation may have a lower connection cost but this may be offset by lower capital efficiency in the generation. Alternatively, larger scale generation may deliver a higher economy of scale. Fixing the size of the model new connection means that the DCC cannot adjust to reflect the changes in the nature of the efficient new entrant capacity provider. We note however that a medium-sized OCGT is a benchmark generator that is often used in similar markets around the world to estimate a capacity cost benchmark for the capacity market when in balance with the needs of the reserve margin.
Certainty	Fixing the model size to 160 MW should result in a relatively stable outcome for the DCC over time within a large network. However physical constrains in the SWIS may result in step change in costs as network connection opportunities at this size are consumed. This is discussed further in location assumptions.
Simplicity	The model 160 MW connection is an approach that is easily understood by market participants and simplifies the calculation methodology.
Resilience	The 160 MW connection assumption is resilient to changes in the market.
Flexibility	The efficient new entrant capacity provider will change over time. Fixing the size of the model new connection means that the DCC cannot adjust to reflect the changes in the nature of the efficient new entrant capacity provider.

330kV Connection Voltage

Factor	Impact of Assumption
Accuracy	Setting the voltage of the connection avoids the efficiencies that may be introduced by other approaches to connection. The most pressing example of this is the model connection in Kalgoorlie that results in the minimum practical works being a circa 400 km 330 kV transmission line. It is unlikely this is the most cost effective connection solution. This connection voltage assumption will likely drive the DCC calculation to overstate the cost of connection.
Certainty	Fixing the model voltage of connection to 330 kV should result in a relative stabile outcome for the DCC over time within a large network.
Simplicity	The model 330 kV connection is an approach that is easily understood by market participants and simplifies the DCC calculation methodology. It removes many of the options Western Power may have otherwise needed to consider from the calculation of the DCC.
Resilience	The 330 kV connection assumption is resilient to changes in the market.
Flexibility	Fixing the voltage of the model new connection means that the DCC cannot adjust to reflect the changes in the nature of the efficient new entrant capacity provider.

7 Connection Sites

Factor	Impact of Assumption
Accuracy	The seven sites selected represent a reasonable cross section of the likely connection sites on the SWIS and would likely therefore capture a site selected by an efficient new entrant capacity provider at the scales considered.
Certainty	In the 2009 MRCP calculation the Western Power calculations for MRCP varied between $35 million and $350 million across the 7 sites considered with an average of $129 million. This is a very wide range in costs that could have a significant impact on the stability of the DCC calculation.
Simplicity	Attempting to calculate the actual connection costs for 7 sites introduces a significant complexity. The DCC calculation for the 7 sites makes the management of the DCC calculation troublesome. Not only must the calculations be undertaken for each site, a consistent approach to the calculation must be maintained for each site. Western Power's use of previous studies and experience makes this difficult to achieve. Further the interaction between the DCC and other components of the MRCP must be considered in the selection of the model lowest cost new entrant.
Resilience	The seven sites are selected independent of market arrangements.
Flexibility	The seven sites would likely effectively respond appropriately to changes in the network configuration over time.

7.3. Assumptions determined by WP to guide the application of the DCC calculation

This section reviews the following assumptions summarised in section 6.5 of this report against the assessment criteria.

Assumptions in the Definition of Minimum Practical Works

Factor	Impact of Assumption
Accuracy	In not using a dedicated options analysis or other planning activities, the existing approach introduces the possibility that the minimum practical works have not been identified. A sub optimal technical solution could significantly increase the cost associated with a particular connection site. To produce a cost estimate that corresponds to a long-run equilibrium state, then some form of network reference scenario would be desirable, to hypothesise the network state when it is in a long-run equilibrium, and therefore not subject to inefficient pockets of congestion or constraint that may otherwise introduce a transmission scarcity cost component to the DCC estimate that is used in the MRCP.
Certainty	The dependence on experience may undermine market certainty on the outcome of the DCC .
Simplicity	The existing approach is a simplification of the activities undertaken in a full access application process. However, it relies heavily on previous real access applications and the experience of Western Power's staff. This represents a risk to the ongoing repeatability of the existing methodology.
Resilience	Is directly linked to the Western Power capital contribution policy and would be directly impacted by changes in this policy.
Flexibility	Can respond to changes in the market and changes in the physical network. However, this response is based on historic access applications and the experience of Western Power staff.

Assumptions in Cost Estimation

Factor	Impact of Assumption
Accuracy	Estimate will likely be ±50% of the actual cost to build the connection assets.
Certainty	The accuracy of the estimating methodology has a direct impact on the market's certainty and confidence of the DCC.
Simplicity	This approach represents the simplest approach to cost estimating as detailed in Appendix B and utilises existing Western Power processes and does not therefore represent a significant management burden.
Resilience	The cost estimation process is based on Western Power's wider cost estimation process and would be impacted by changes in this process.
Flexibility	The estimating approach can respond to any defined Minimum Practical Works.

Assumed Contribution from Third Parties

Factor	Impact of Assumption
Accuracy	Represents the best case for an access applicant. Thus an actual applicant may see a cost above that determined under this approach by up to the pro rata amount.
Certainty	Represents a consistent approach to a complicated variable in the calculation of real access charges.
Simplicity	Is a simplifying assumption to a complicated variable.
Resilience	Could be heavily impacted by changes in management of Western Power's regulated network.
Flexibility	N/A

Lack of Integration with Western Power 10 Year Strategic Planning

Factor	Impact of Assumption
Accuracy	Introduces the possibility of significantly overstating the actual DCC.
Certainty	N/A
Simplicity	Is a simplifying assumption.
Resilience	Is in conflict with Western Power's existing Capital Contribution Policy and therefore the impact of any changes would be uncertain.
Flexibility	N/A

7.4. Summary Key of Issues / Gaps

From the analysis detailed above the following issues / gaps have been summarised:

7.4.1. Accuracy

The review of the DCC methodology, as it is applied to the context of determining the MRCP, has found that in some circumstances, the DCC calculation methodology will not correctly measure the system marginal connection cost of new capacity in an assumed state of long-run equilibrium, thereby distorting efficient investment behaviour. The following details the basis of these concerns.

- The existing approach to calculating the DCC applies to real investments in the physical system. It then determines and allocates connection costs that are relevant for the time and place of that real investment. When applied to the context of the MRCP calculation, an assumed investment scenario is provided, defining the technology and guiding the location of a hypothetical investment. This assumed investment scenario does not however require Western Power to estimate a connection cost in a circumstance when the system is assumed to be in long-run equilibrium. This means that the estimated connection cost will be reflective of short-run conditions in the system. In practice, this means that if transmission investment has been insufficient in the past, which in many jurisdictions is the case, then the DCC calculation methodology may over-estimate the connection and system augmentation costs for the hypothetical 160 MW generation investment. This means that the system marginal connection cost may capture costs that are required to recover from insufficient investment in the past (reflected as a cost of transmission scarcity), thereby over-measuring the estimate of MRCP. Such a circumstance would typically be coincident with higher energy prices, caused by higher marginal costs of system constraints and system losses, which when combined with a higher MRCP, may cause the combined market revenues to be inefficiently high, and potentially encouraging a cycle of over-investment in generation plant.

- The existing estimating methodology represents an opportunity for significant inaccuracy in the order of ± 30-50% of the actual completed cost of the connection asset.
- The lack of integration with Western Power's 10 Year Planning introduces significant inaccuracies and further disconnects the DCC estimate from a long run equilibrium position.
- The lack of dedicated options analysis has the opportunity to introduce significant inaccuracies and disconnects the determination of the MRCP from a long run equilibrium position.
- Whether the hypothetical 160 MW and a 330 kV connection continues to be the correct scale for a least cost capacity provider given the cost impact of increasing DCC.

7.4.2. Simplicity

- The existing methodology is a simplification of the process that is undertaken for a real applicant that relies heavily on the experience of Western Power's technical staff and on historic analysis. This reliance means that the process cannot be completed by non Western Power staff and undermines the repeatability of the process.
- Modelling the Actual Connection Costs for 7 sites represents a significant management burden.

7.4.3. Certainty

- The DCC is becoming an increasing portion of the MRCP over time and under the current assumptions may change dramatically year to year due to increasing network constraints.
- In the 2009 MRCP calculation the Western Power calculations for MRCP varied between $35 million and $350 million across the 7 sites considered with an average of $129 million. The $35 million DCC represents 17% of the total capital cost whereas the average $129 million would represent 41%. As the more cost effective sites continue to be utilised and restrictions on medium and large scale generation in central areas continue to increase over time the DCC will likely trend toward the average. This trend will be supported by the increasing restrictions on medium and large scale generation in developed areas. This is reflective of a methodology that is disconnected from a long run equilibrium cost.

- Indeed this a key concern raised in responses to the 2010 MRCP determination. This has the effect of producing a DCC estimate that can be very different between Reserve Capacity Cycles, ultimately causing volatility in the measure of MRCP.

7.4.4. Resilience

- The current approach to calculating the DCC requires an implementation of Western Power's Capital Contribution Policy. Thus any methodology and associated assumptions must be framed with reference to this policy. This policy is reconsidered at each review of Western Power Access Arrangement (approximately every three years). Any methodology framed under the existing approach will be impacted by this review or by many other changes under the ENAC.

7.4.5. Flexibility

- Fixing the connection size and voltage undermines the ability of the methodology to respond to changes in the position of the technical nature of the efficient new entrant generator within the market.

8. Options Considered

8.1. Key Observations

Critical to the concept of Accuracy, is the differential treatment of connection costs within the network regulatory and market arrangements, as they apply to either the trading arrangements of the WEM, or to physical investments that occur in the SWIS.

Currently, Western Power's Capital Contribution Policy is used to allocate the actual connection costs of real assets and services to industry participants, and is also used by the IMO to guide its estimate of DCC that feature as a component in the determination of the MRCP.

The critical distinction lies in between these two applications of the Capital Contribution Policy:

- The policy must calculate and allocate the costs of actual investments in real assets and services to industry participants.
- The policy is also used to calculate the expected costs of hypothetical assets to support a contrived MRCP mechanism using proxy data that is intended to provide an economic signal or reference benchmark to support administered purposes.

When considering the role of the MRCP, it becomes obvious that the logical requirements of a connection cost calculation methodology may at times depart from what is required to allocate the costs of real investments. Some of these departures may imply a need for contradictory outcomes.

In terms of real investments in physical assets, and the calculation and allocation of related connection costs, methodological requirements will necessarily accurately reflect the efficient marginal cost of cost of the connection. This determination of the efficient marginal cost should feature a prudency assessment that links with formal planning processes, including the scenario modelling and options assessment that features therein.

As a mechanism for setting the DCC, the Capital Contributions must seek to provide a pricing constraint or default price related to actual and potential investments in reserve capacity. For it to promote the achievement of economic efficiency, it must be set with reference to appropriate long-run and short-run pricing signals as discussed in section 5.1.3 of this report. This consideration to short and long run investment signals results in a calculation that necessarily varies from that required for the allocation of costs related to actual investments in real assets and services.

The use of a single estimate of a MRCP for a single region and multi-period market means that the calculation of connection costs will ultimately be static, approximate and representative based on what is deemed reasonable. Given that the MRCP is used primarily as a market constraint and default price in particular circumstances, the need for accuracy becomes less critical.

It follows therefore that the methodological requirements for the calculation of DCC may, under some options to be considered, become largely divorced from the methodology defined under the Capital Contributions Policy.

8.2. Options

To address the issues discussed in section 7.4 this section considers a range of options against the assessment criteria.

To determine the range of options to be considered, reference is made to the discussion section 8.1 of this report. From these discussions it is clear that the options, insofar that they produce a cost estimate for inclusion in the MRCP, must seek to produce appropriate short and long run investment signals that have the effect of promoting the achievement of the Market Objectives. In doing this the approach does not necessarily need to result in an application of the Capital Contribution Policy.

The Options proposed below are best considered on a continuum of increasing complexity; the options also vary in the extent to which the long run or short run marginal are best reflected.

Option 1

Calculate an "average cost" based on the cost of providing network capacity and the quantity of network capacity provided as the basis of the DCC and adjust this annually to capture market changes. This option is a reflection of the long run average (not marginal) cost of capacity on the network.

Option 2

Use historic connection cost data to forecast likely future DCC. This approach may place bounds around the historic connection cost data to only include connection costs for technologies consistent with an efficient new entrant capacity provider. The approach to forecasting may take into account trends over time or other market data. The extent to which historical data is used in the forecasting process should provide a balance of historic long run marginal costs and short run marginal costs.

Option 3

Continue with the existing methodology and revisit and adjust the main assumptions to attempt to address some issues.

Option 4

Continue with the existing approach of the modelling of the connection of a model generator and reinforce the methodology to undertake analysis more consistent with that undertaken for an access applicant. This would include options analysis, integration with Western Power long term planning and perhaps consideration of the impact of the Applications and Queuing Policy.

This approach would most accurately reflect the short run marginal cost of connection.

8.3. Options Comparison

In considering the above approaches the pros of each approach is contrasted against the existing approach (Option 3) against the assessment criteria in section 5.1.3 of this report . This information is provided symbolically in Table 3 with a tick representing an improvement compared to Option 3 for that criteria and a cross representing a worse outcome against that criteria.

- **Table 2 Comparison of alternative DCC calculation methodology (Options 1,2 and 4) approaches against the existing methodology (Option 3) - Detailed**

Criteria	Average Cost (Option 1)	Forecast DCC based on Historic Connection Costs Data (Option 2)	Reinforced Existing Approach (Option 4)
Accuracy	This approach would not reflect short run or long run marginal costs and, as such, may disconnect from an appropriate outcome over time.	This approach would likely result in a more accurate outcome than the status quo as it does not include the opportunities for inaccuracies introduced by assumptions. It would also pick up changes in the optimal technology for the efficient new entrant over time.	On the basis that the appropriate investment was made to implement this approach, this approach should yield DCC that closely reflect that experienced by the efficient new entrant capacity provider using the modelled technology.
Certainty	This approach would provide significant certainty in the market of the likely outcome of the DCC calculation.	This approach would in effect “smooth” changes in the cost of connecting over time. The extent of the smoothing would be impacted by the forecasting mechanism used. This mechanism may impact market certainty.	This approach would respond appropriately to any network constraints that may impact the model generator size. This may impact market certainty.
Simplicity	Will require limited management and could likely be undertaken independent of Western Power.	Will require Western Power to undertake calculations (as confidential data will be used) but the methodology can be automated with new data added in each year’s review. This approach is significantly simpler than the existing approach.	This would be more complex than any that is used for any calculation currently undertaken by the IMO. It would likely require 1-2 technical staff full time to fully implement.
Resilience	Will disconnect the DCC from the major market mechanisms making the approach more resilient.	Will reflect changes in market mechanism albeit after a delay. The methodology will not be directly affected by changes in market and regulatory mechanisms.	This will result in an increased linking of the DCC calculation to the Access Queuing Policy and the Capital Contribution Policy.
Flexibility	This approach would not effectively reflect changes in the market.	This approach could reflect changing trends in the market. Step changes in the market would be reflected on a year behind basis.	This approach could reflect changes in the market before they were experienced by market participants making the DCC a lead indicator for the market.

▪ **Table 3 Comparison of DCC Calculation Methodology Approaches against Option - Symbolic**

Criteria	Average Cost	Forecast DCC based on Historic Connection Costs Data	Reinforced Existing Approach
Accuracy	✗	✓	✓
Certainty	✓	✓	✗
Simplicity	✓	✗	✗
Resilience	✗	✓	✗
Flexibility	✓	✓	✗

From the summary provided in Table 2 and Table 3, Option 2 “Forecast DCC based on Historic Connection Costs Data” is the preferred option, the discussion below expands on this preference.

SKM are of the view that reinforcing the existing model connection approach (Option 4) will increase the accuracy of the DCC calculation against the short run “real world” connection costs. With a range of assumptions on the long term “stable” nature of the network taken from Western Power’s long term system planning information this approach may also be manipulated to provide a long run marginal cost view. However, SKM are of the opinion that the increased complexity, management cost and certainty issues outweigh any benefit in accuracy that could be achieved through this approach.

The Average Cost (Option 1) approach significantly simplifies the existing approach. It is not however a reflection of marginal cost (short run or long run) and cannot therefore be considered an accurate determinate of the DCC.

The option to forecast DCC based on historic connection costs (Option 2) will produce a more accurate outcome than the existing approach as it avoids many of the assumptions and simplifications the existing approach adopts. The extent to which historic data is used in the forecasting process can be used to provide a balance between the need for the DCC to reflect short run and long run marginal costs by weighting recent and historic data. That is, a heavier weighting on more recent data would result in an increased focus on the short run marginal cost in the DCC determination. This approach is also significantly simpler than the existing approach. For these reasons, Option 2 is the preferred approach.

8.3.1. Issues to be addressed with the preferred approach

SKM has identified the following issues with Option 2 that must be addressed in the methodology to effectively implement the approach:

1) Ability to Respond to Rapid Changes in Actual Connection Costs

   Western Power has indicated that they believe increasing constraints on the SWIS will result in a rapid increase in connection costs and have raised concerns that that using historic data may not be able to capture this. SKM is less concerned with this issue for reasons:

   a) The requirement for applicants for Capacity Credits to have an Access Offer means that data will be available for the actual access offer costs for the year the capacity credits are required.

b) The requirement for the DCC to reflect the long run marginal cost of connection to best achieve market objectives means it need not respond to short term under investment in the network at a given location.

In developing the methodology it is intended that the Access Offer data for the year the capacity credits are required will be included in the calculation at an appropriate weighting.

2) Balance between reflecting long run and short run marginal costs

The balance between reflecting long run marginal costs and short run marginal costs will be reflected in the weighting between historic actual connection cost data and access offer data for the year the capacity credits are required.

3) Reflecting Connection Cost of Efficient Capacity Provider

As discussed in section 5.1.2, the DCC should be set to reflect the long run marginal cost of new peaking (liquid fuelled) capacity. The location of liquid fuelled peaking capacity is less dependent on the location of energy sources (coal, gas pipes, solar, and wind resources) than other generation technologies and as such these technologies are less constrained in their ability to avoid areas of network constraint. For this reason the methodology will only use historic capital contribution cost data for generators that are capable of liquid fuel operation.

4) Confidentiality of actual Connection Cost data

The historic access cost data held by Western Power is considered confidential information and cannot be released to external parties except in aggregate form. This represents a challenge in developing the details of the methodology that SKM and Western Power are working through.

- Selection of financial escalators

Given that the proposed methodology uses financial data across years, an appropriate discount rate will be required to provide an appropriate result in today's dollars. SKM believe that the WACC used within the MRCP calculation would be the most appropriate for this purpose.

- Establishing a conservative forecasting error margin in the calculation

The general practice by organised markets, when estimating or forecasting values for benchmark or reference prices, is to apply some conservatism in managing estimation or forecasting risks. This conservatism is often generous to market participants when these prices are used as a bid or price cap. This is particularly the case in the WEM where:

a) The use of the Excess Capacity Adjustment to adjust the settlement cost of capacity credits in the case of oversupply partially mitigates the risk of conservatism in the calculation of the MRCP.

b) A MRCP set too low in the event of a Capacity Auction could result in an undersupply of capacity in the market.

Given the above SKM will consider a margin in calculating the DCC in the context of other risk margins introduced elsewhere within the MRCP calculation.

9. Recommended Methodology

The recommended methodology will be finalised after discussion with the working group.

Appendix A Assessment Criteria

The following summarises the benchmark criteria and attributes that have been used to guide the assessment:

General Criteria and Attributes:

Criterion or Attribute	How we consider it as part of this assessment
Resilience to anticipated scenarios of change	We will consider the appropriateness of the methodology in terms of the current context of the market, and with respect to our view of how the market and industry may evolve given anticipated scenarios of change, reform, investment and innovation. A consideration of resilience to potential scenarios of change is of particular relevance to the planning process, especially with respect to the planning assumptions and options that contribute to the assessment of shared connection costs and system augmentation or reinforcement costs. **Criteria: Resilience**
Consistent with the realities of operational practices, technological constraints and prevailing contracts	Given that the starting point of our assessment is to review the existing DCC calculation methodology of Western Power, we will assume that it achieves this attribute unless we identify participant concerns indicating the contrary in industry submissions to the IMO's 2010 MRCP determination. Where we identify weaknesses in the existing calculation methodology, we will explicitly consider this attribute in our recommendation of improvements to the calculation method.
Consistent with the broader market and regulatory arrangements that influence market behaviour and outcomes	Given that the starting point of our assessment is to review the existing DCC calculation methodology of Western Power, we will assume that it achieves this attribute unless we identify participant concerns indicating the contrary in industry submissions to the IMO's 2010 MRCP determination. Where we identify weaknesses in the existing calculation methodology, we will explicitly consider this attribute in our recommendation of improvements to the calculation method.
Processes of change are manageable in terms of time, cost and risk	Given that the starting point of our assessment is to review the existing DCC calculation methodology of Western Power, we will assume that it achieves this attribute unless we identify participant concerns indicating the contrary in industry submissions to the IMO's 2010 MRCP determination. Where we identify weaknesses in the existing calculation methodology, we will explicitly consider this attribute in our recommendation of improvements to the calculation method.

Specific Criteria and Attributes:

Criterion or Attribute	How we consider it as part of this assessment
Market Objective # 1 *To promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system.*	Economic Efficiency: Economic efficiency in the context of the power market is associated with the production of electricity and electricity related services at minimum cost, and in a manner that fully reflects the preferences of market participants and end-users. The calculation methodology used for determining DCC contributes to an assessment of economic efficiency in the power market via its effect on investment, and its contribution to the pricing and investment signals intrinsic to the MRCP determination. Connection, augmentation and reinforcement assets that are determined to be economically efficient will typically be unique to a particular location, technology and time-frame, they will have a particular usage profile, and they will be determined to be optimal given a particular expectation of current and future market operation. The IMO's consideration of what is 'appropriate' with respect to the substance and application of the calculation methodology for DCC, in the context of the MRCP determination, must therefore consider not just the quality of the calculation parameters and processes, but also the planning basis and choice of options and assumptions that together influence the locational, technology, temporal and usage aspects of related assets. As a cost component to the calculation of the MRCP, the methodology for calculating DCC can be a significant influence on reserve capacity prices. This influence acts directly through the definition of the settlement price in the Reserve Capacity Mechanism and indirectly as a market signal impacting bilateral trade negotiations. Thus, to support the economic efficiency of the market the DCC Calculation must establish a cost that supports the correct level of investment in generation over the long term. Safety and Reliability: In the context of this review, safety can be interpreted in a financial sense, given effect by the Maximum Reserve Capacity Price (MRCP) that in part protects the industry from excessive price outcomes that may raise market risk, and potentially weaken the solvency of some participants. Reliability can be interpreted in terms of the adequacy and availability of capacity, particularly via the reserve and availability margin that is achieved in the wholesale market. . ▪ Connection costs that are too high, may raise the MRCP, and therefore subject participants to potentially higher prices for reserve capacity; this can reduce solvency, raise financial risk, and diminish the achievement of the safety aspect of this Market Objective. ▪ Connection costs that are too low may weaken investment and market participation signals, thereby potentially reducing the reserve and availability margin over time, and also diminish the achievement of this aspect of the

	Market Objective. We consider that the following criteria can assist the achievement of this objective: ▪ **Accurately reflect the cost borne by the efficient new entrant capacity provider** - Costs that are too low may dampen investment and market participation signals by reducing the extent that prices will recover generation costs. This will discourage competition and distort market outcomes. Further, in the event that costs are too high, investment signals may be excessive, causing over-investment which in the future may pose solvency issues for investors, and/or cause prices to be lower than may be efficient.
Market Objective # 2 *To encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors.*	The extent of competition in a market is in part determined by industry structure, which is beyond the scope of this review. However, the extent to which the market and regulatory signals encourage and provide for market participation and investment has a direct impact on the number of participants in the market and therefore the level of competition. In terms of this latter point, and given the constraints of this review, we therefore consider that the following criteria assist the achievement of this objective: ▪ **Accurately reflect the cost borne by the cheapest new entrant capacity provider** - As above **Certainty for Investors -** As a significant market signal the stability of the DCC over time drives investment confidence increasing the spectrum of investors prepared to participate in the market.
Market Objective # 3 *To including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions.*	The MRCP works alongside the energy based markets within the WEM as a package to incentivise appropriate generation development and dispatch. Given the low maximum energy prices and the day before nature of STEM the MRCP plays a major role in incentivising low fixed cost peaking plants that only sell energy during periods of constrained supply and/or high demand. Thus the DCC must be adequate to facilitate investment in this generation technology. However, if the DCC is set too high it is likely the MRCP will over encourage the installation of cheap fixed cost plant to the detriment of generation technologies that fulfil other roles within the market. This will result in a suboptimal economic outcome. We consider that the following criteria assist the achievement of this objective: **Accurately reflect the cost borne by the cheapest new entrant capacity provider**. As above **Be flexible enough to capture changes in the location and technology of the cheapest new entrant capacity provider over time** The most efficient manner of delivering new peaking capacity to the WEM is likely to vary in location and technology over time. Ideally the DCC calculation methodology would be flexible enough to capture this change in location and

	technology as it varies over time to ensure that new, more competitive, peaking generation arrangements are not incentivised beyond their efficient contribution to the generation mix. That is, efficient peaking generation does not displace renewable generation beyond that which is efficient in the generation mix.
Market Objective # 4 *To minimise the long-term cost of electricity supplied to customers from the South West interconnected system.*	Ultimately the long-term cost of electricity is minimised when investments in industry assets and infrastructure occur in a manner that is timely, and with a location and technology that is economically optimal, and that combines with a market structure that is competitive. In terms of the constraints of this review, we note that timely investments occur when investment risk is minimised, implying a need for accurate market signals, a competitive market context, and the minimisation of regulatory and market risk over time. We therefore interpret this market objective in terms of the following criteria: ▪ **Accuracy of the cost calculation methodology** –As above ▪ **Simplicity of calculation** – The calculation of the DCC represents a direct overhead burden on the long term cost of generation in the market. More simple methodologies cost less to undertake and administer reducing the impact of market overheads on the cost of electricity.
Market Objective # 5 *To encourage the taking of measures to manage the amount of electricity used and when it is used.*	Given that the review is constrained to the context of power generators connecting to the SWIS, and the costs thereof, we do not consider this Market Objective as part of our assessment.

Appendix B AACEi Cost Estimating Classes

The AACEi (Association for the Advancement of Cost Engineering) international recommended practice of estimate classification is outlined in the table below.

- **Table 4 Generic Cost Estimate Classification Matrix (Summary)**

	Class 4 Order of Magnitude/Concept	Class 3 Pre-Feasibility Study (PFS)	Class 2 Feasibility Study (FS)	Class 1 Definitive Estimate
Basis Of Capital Cost Estimate – Purpose & Criteria				
Purpose	Preliminary economic and technical Investigation. Project screening. Comparison of alternatives, configurations and options	Economic Feasibility of one or more chosen options.	Project Approval and basis of securing financing. "Bankable " study	Detailed Control. Target measurement. Change/Variation. Monitor and control of implementation phase.
Expected Estimate Contingency Range	25% to 40%	15% to 20%	10% to 15%	5% to 10%
Accuracy - Indicative Range	-30% to +100%	-20% to +25%	-10% to +15%	-5% to +10%
Level of Project Definition	0% to 5%	10% to 30%	30% to 70%	70% to 100%
Level of Engineering (% of total Eng.)	0% to 2%	2% to 5%	1.1. 15% to 30%	.1.2. 30% to 100%