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Troy Forward
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Dear Troy,

RE: Submission to 2009 MRCP Review.

Griffin Energy welcomes the opportunity to make a submission on the 2010 MRCP Draft Report. The price of capacity is a very important factor in driving the functionality of our capacity market. Generally, investment in electricity markets (particular those with a capacity market component) is seen as low risk in comparison to other industrial sectors (such as petrochemical and oil and gas). In order to contain regulatory risk, price regulation within the sector should be managed in a manner that is both transparent and which lends itself to stable and easily predictable price fluctuations. Given the rationale for a capacity market in the first place – that of providing a secure income stream to enable timely investment in new peaking capacity – the process for setting the annual MRCP should be especially robust. While market participants and future investors must expect some degree of market risk due to movements in the cost structures of investing in new capacity, this should not be compounded by additional regulatory risk brought about by changing methodologies or by changing the interpretation of particular cost components. The implication for fluctuating capacity prices is the inability to accurately predict both revenues, but more importantly, costs on a forward basis. While a significant increase to the MRCP may be beneficial to some generation proponents that are exposed to the merchant price of capacity year on year, it will have a negative impact on those generators that have bilaterally contracted their output (a combination of energy and capacity) at a Long Run Marginal Cost (LRMC) basis, as well as retailers with medium to long term supply contracts. The bilaterally contracted generators do not benefit from an increase in the administered capacity price. Implicit in their LRMC is their own capacity cost. The fluctuating administered capacity price is passed through to customers. However, capacity market penalties (refunds) and prudential costs, which are related to the administered capacity price, are borne by generators. Additionally, retailers are directly exposed to higher IRCR costs as the MRCP increases.

Having performed a cursory analysis comparing the 2010 MRCP (draft) determination to earlier determinations, Griffin is of the opinion that far too much uncertainty exists in the current process. Figure 1 below shows the variation in the MRCP since market inception. The differential from the low point ($122,500 in 2008/09) to the high point of the current draft determination ($231,300) is almost 90%, occurring over a period of only 4 years.

Figure 1. MRCP since market start.

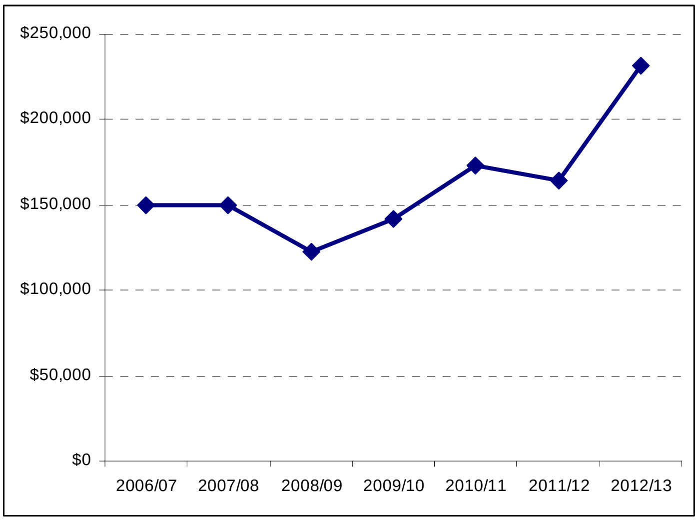
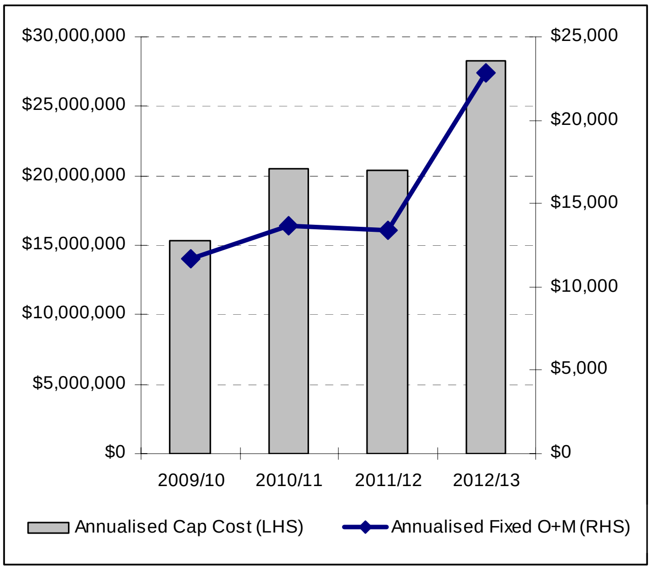


Figure 2 compares the Annualised Cap Cost and Annualised Fixed O+M from the last 4 MRCP determinations (i.e. those not prescribed under the rules as both the 2006/07 and 2007/08 MRCPs were). It is quite clear that both components of the latest draft determination are significantly higher than the previous determinations. Attachment 1 compares all cost components in the last 4 MRCP determinations (including the latest draft determination).

Figure 2. Annualised Cap Cost and Annualised Fixed O+M.



From Attachment 1, it is clear that a number of the individual cost components have moved substantially. Most evident is the increase in component TC[t] – the transmission costs. Griffin provides further comment on this below. Another substantial cost increase is to the margin M, for which the dollar value[1] doubled from the first two MRCP settings to the last

[1] M is set as a % value. The 'dollar value' is obtained by applying the % margin to the capital cost of the OCGT.

two. This represents an increase in owner's costs for the OCGT development from around $13M to $26M. While not commenting directly on the accuracy of either value (I would opine that a more reflective value of M would lie somewhere in the middle), the point that the value of M could exhibit such a step change over the short history of MRCP determinations does not auger well for containing volatility in the administered capacity price. Lastly, the Annualised Fixed O+M increases by over 75% in this draft determination from the average of the previous three determinations. Griffin provides further comment on this issue below.

Comment on specific issues

Griffin makes comment on three specific issues:

1. The increase in transmission costs;
2. The increase in Annualised Fixed O+M costs; and
3. The treatment of the WACC.

1. Transmission Costs

Griffin believes that the management of transmission regulation in the WEM is poor. In its submission to the IMO, Western Power estimates its cost of augmenting the shared transmission network in order to connect generation to specific locations on the SWIN, then applies part of that cost to a 160MW generator based on its proportional use of the new capacity. This is an overly simplified method of applying costs and comes with the caveat that it "…assume[s] (conservatively) that augmentation costs are allocated fully to generators only..." This method has increased the estimated cost of transmission augmentation dramatically from previous MRCP determinations. While the estimations of total transmission costs for previous MRCP determinations were well below those which, in reality, Western Power were quoting to prospective generators, this does not necessarily imply that those previous cost estimates were incorrect. Griffin is of the opinion that Western Power is not properly managing its regulatory obligations under the Access Code. New transmission augmentation should be subject to a New Facilities Investment Test (NFIT). This is irrespective of whether it is primarily required to service existing loads or new generation, which seems to be a distinction Western Power has been happy to make. As has been recognised in the NEM, where transmission regulation is treated somewhat more seriously, the nexus between new generation being required to service loads is made[2]. If the NFIT is applied to new transmission augmentation, especially transmission augmentation required to strengthen the existing network in areas of high load, such as Pinjar, Kwinana, Kemerton and Collie, then it is likely that a significant portion of the augmentation costs will be added to the Regulated Asset Base of Western Power and not be levied directly on generators as a capital contribution. Griffin has raised this important issue a number of times in separate forums without much progress, including directly with the ERA (who also cannot explain Western Power's reluctance to properly apply the NFIT). While there seems to be an irrational intransigence to apply regulatory obligations to the transmission network from Western Power, we do not believe that the IMO should weaken its own regulatory structures by allowing this failure to flow through to the MRCP setting process. Griffin strongly suggests either engaging a consultant familiar with the *Electricity Networks Access Code 2004* to perform a review of the likelihood of the estimated augmentation costs meeting the NFIT or (given the late stage of the current MRCP Review), reverting to the previous determination's value on transmission costs.

[2] AEMC Rule Determination (Pricing of Prescribed Transmission Services) Rule 2006 No. 22.

2. Annualised Fixed O+M costs

The increase in the Annualised Fixed O+M costs in the draft determination (by over 75% from the average of the previous three determinations) seems to stem directly from the inclusion of a cost component for the annual fixed network access tariff (comprising a use of system charge, control system service charge and the metering charge). This new component appeared for the first time in the SKM report for the current (draft) determination and seems to have been omitted from previous determinations. While it appears sensible to include the previously omitted cost component (as it clearly represents an annual fixed operating cost), Griffin believes it is not in the interest of regulatory certainty to merely allow a previous omission to be rectified in a single price determination. In the interest of regulatory certainty, Griffin suggests that this new cost component be introduced on a glide path basis over a period of, say, five years. That is, in the current determination, 20% of the new cost component will be included in the final Annualised Fixed O+M costs. In next year's MRCP determination, 40% of that year's annual fixed network access tariff cost component would be included and so on until 100% of the cost component is included.

3. The WACC.

As has been recently discussed, the WACC should represent a stable value which is representative of the return on capital in our market. The MRCP Market Procedure requires certain (Minor) elements of the WACC to be reviewed annually. Other (Major) elements do not have this requirement. However the MRCP Market Procedure does not stipulate when the Major components should be reviewed, only that they "require review less frequently". A logical timeframe for doing this would be along with the Major Review of the methodology for determining the MRCP (at least once every five years). ***This does not mean that those components of the WACC labelled 'Major' components cannot be reviewed at any other time if a justifiable reason were found to do so.*** In the case of the recent review by the Allen Consulting Group (ACG), in response to the potential effects of the global financial crisis, there appears no reason why such a review should not proceed. The most significant financial event in generations provides justification to review financial return parameters.

On a broader note, Griffin would welcome a review (post the final determination on the current MRCP review) of how the WACC has been applied in previous determinations. There appears to be significant variability over the last four determinations (including the current draft determination). For instance,
Figure 3 below shows the WACC over the last four determinations. In the first two determinations, the level of gearing was set at 60%. That was changed to 40% for the last two determinations (this is discussed below). One would expect, all things being equal, that there would be an increase in the WACC as it moved from a higher gearing (60%) to a lower gearing (40%). Intuitively, if you move to a lower gearing, then you are applying a lower multiple (0.4x) to the lower return (on debt) and a higher multiple (0.6x) to the higher return (on equity). This should increase the weighted average cost of capital. The fact that, instead of increasing, the WACC has moved (quite considerably) in the opposite direction would suggest that there have been significant changes to the return on debt and (especially) the return on equity components. Griffin believes that in the interest of transparency, an independent third party review of how the WACC has been applied in previous MRCP determinations is warranted. Ideally, this would form part of the ongoing MRCP Market Procedure review as it may lead to new insights in setting the process of identifying the WACC in future determinations.

Figure 3. WACC for the last four MRCP determinations (including the current draft determination)

Capacity cycle	2007	2008	2009	2010
Capacity year	2009/10	2010/11	2011/12	2012/13
Gearing ratio	60	60	40	40
WACC	9.35%	9.61%	7.78%	7.09%

More specifically, Griffin believes the current capital structure identified for proposed generation investment in the WEM is not appropriate. A previous review by ACG recommended the original capital structure of 60% debt to 40% equity be replaced by a 40% debt to 60% equity structure. The change appears to have been accepted with little debate, which is surprising as this capital structure bears little semblance to that of current market participants. And given new entrants into our market are likely to use a project financed SPV to finance a new OCGT investment, it almost certainly will not represent the likely capital structure of a new entrant. The ACG analysis is too dependent on international comparisons. In many cases (especially the Canadian based Trusts and Income Funds), entities may adjust their capital structure to take advantage of local taxation schemes (see Box 1).

Box 1. The Canadian Tax Act and Mutual Funds

For example, the Canadian Tax Act allows distributions from registered mutual funds to be included as investments for Registered Retirement Savings Plans (RRSPs), Registered Retirement Income Funds (RRIFs), Registered Education Savings Plans (RESPs) and Deferred Profit Sharing Plans (DPSPs). Under the Canadian Income Tax Act, an eligible mutual fund is entitled to claim various deductions from its net income for tax purposes including, for example, Canadian Oil and Gas Property Expense (COGPE), resource allowance and expenses of issuing Trust Units. Such deductions will generally result in a portion of the fund’s distributions being considered a "return of capital" for income tax purposes. Such amounts reduce the cost base of the Units acquired and thus defer the related tax for Canadian resident Unitholders until the Units are sold.

While financial theory is helpful, we question the relevance of its application in this case. A bias should be given to empirical evidence. In the case of investors in generation assets in Australia (and especially in the SWIS), this suggest a higher gearing level. At a minimum, Griffin strongly recommends the immediate return of this (Major) WACC component to a capital structure of 60% debt and 40% equity. We see no impediment in doing so under the current Market Rules. This would likely entail a revaluation of the equity beta.

Setting a transparent and predictable MRCP is fundamental to maintaining the value of the capacity market as a driver for timely investment. We urge the IMO to carefully consider all sources of potential variation to the MRCP and manage these in a manner which minimises the volatility and maximises the predictability of the administered price going forward.

Yours sincerely

Shane Cremin
GM – Policy & Strategy

Attachment 1

Parameter	2007	2008	2009	2010	Capacity Cycle	Description
	2009/10	2010/11	2011/12	2012/13	Capacity Year	
FFC[t]	$3,243,500.00	$2,635,900.00	$3,374,305.00	$2,590,280.00	A$	Fixed fuel costs
LC[t]	0	0	$313,500.00	$761,250.00	A$	Land cost
TC[t]	$16,908,800.00	$20,707,300.00	$14,081,877.08	$56,092,145.58	A$	Total transmission (shared and connection) costs
M	15.00%	12.72%	22.50%	21.60%	%	Margin (legal and owners costs)
M ($ component)	$12,410,448.00	$14,424,724.22	$26,371,959.12	$26,928,996.48	A$	Margin (legal and owners costs)
PC[t]	$517,102.00	$708,762.00	$732,554.42	$779,195.50	A$	Capital cost of OCGT ($/MW)
CAPCOST[t]	$120,952,306	$159,276,503	$185,040,905.07	$245,159,806.27	A$	CAPCOST
WACC	9.35%	9.61%	7.09%	7.78%	%	WACC
ANNUALISED_CAP_COST[t]	$15,316,607	$20,476,662	$20,432,138.81	$28,258,314.64	A$/Year	Annualised CAPCOST
CAP	160	160	160	160	MW	OCGT size (fixed in MR)
SDF	1.18	1.18	1.18	1.18	N/A	Summer derating factor (fixed in MR)
ANNUALISED_CAP_COST[t]	$15,316,607	$20,476,662	$20,432,138.81	$28,258,314.64	A$/Year	Annualised CAPCOST
ANNUALISED_FIXED_O&M[t]	$11,713.00	$13,669.00	$13,431.03	$22,856.60	$AUD/MW/Year	Annualised FIXED O+M
PRICECAP[t]	$142,200.00	$173,400.00	$164,100.00	$231,300.00	$AUD/MW/Year	PRICECAP