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EnergyAustralia™ We're on it

16 February 2009

Ms Michelle Groves
Chief Executive Officer
Australian Energy Regulator
GPO Box 520
MELBOURNE VIC 3001

Email to: Aerinquiry@aer.gov.au

Dear Ms Groves

EnergyAustralia's Further Submission

I am pleased to submit EnergyAustralia's *Further Submission on the AER's Draft Determination, February 2009* in response to the AER's draft determination and decisions with respect to EnergyAustralia that was published on 28 November 2008. This submission is in addition to EnergyAustralia's *Revised Regulatory Proposal and Interim Submission, January 2009* submitted to you on 14 January 2009.

This further submission is provided on two DVDs. The material on DVD 1 contains the submission document and all other non-confidential material. The material on DVD 1 can be made publicly available. DVD 1 also includes a document index for attachments to this submission and a document index for other reference material, and identifies confidential documents. DVD 2 only includes confidential material. We request that the AER contact EnergyAustralia before disclosing any material on DVD 2.

The structure and approach of this further submission is explained in detail in the document itself, but briefly the submission has two main purposes:

1. To make further submissions with respect to certain aspects of the AER draft decision and determination. The submission itself is on DVD 1 as file, 'Further submission: February 2009'. We note that attachments to the submission are within the folder, 'Attachments to further submission' of DVD 1.
2. To submit reference material relied upon by our experts in their reports submitted as part of the revised proposal and interim submission. This was foreshadowed in the covering letter to you of 14 January 2009. Non-confidential reference material is located within the folder, 'Additional reference material' of DVD 1 while confidential material is on DVD 2.

EnergyAustralia has engaged PricewaterhouseCoopers to externally review the accuracy of the models and spreadsheets submitted as part of our revised proposal as mentioned in the covering letter to you of 14 January 2009. We are yet to receive the final report and therefore we are not in a position to provide you with advice as to the accuracy of those models, or the impact of any change if such a change is identified as

Partner

being required. We expect the final PricewaterhouseCoopers report to be available in the coming days and will work to provide this information together with its impacts to you as quickly as possible.

EnergyAustralia has also prepared a separate submission with respect to the AER's draft decisions for Integral Energy, Country Energy, ActewAGL, TransEnd and TransGrid and the revised proposals submitted by those network service providers.

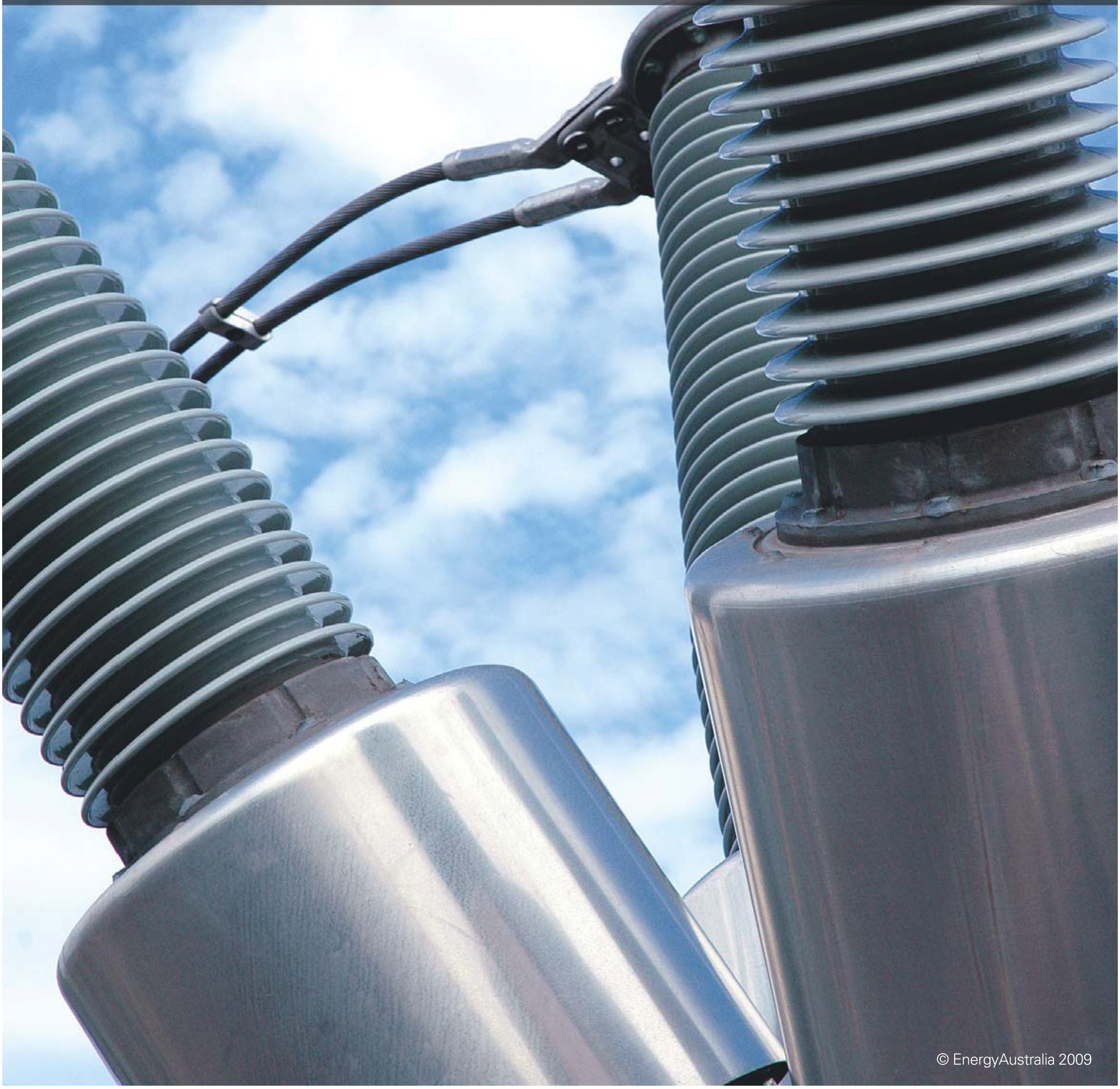
Please do not hesitate to contact Catherine O'Neill, Executive Manager, Network Pricing & Regulation on 02 9269 4171 should you wish to discuss any aspect of our submissions.

Yours sincerely

TREVOR ARMSTRONG
Executive General Manager (Acting)
System Planning and Regulation

Further Submission on the The AER's Draft Determination

February 2009

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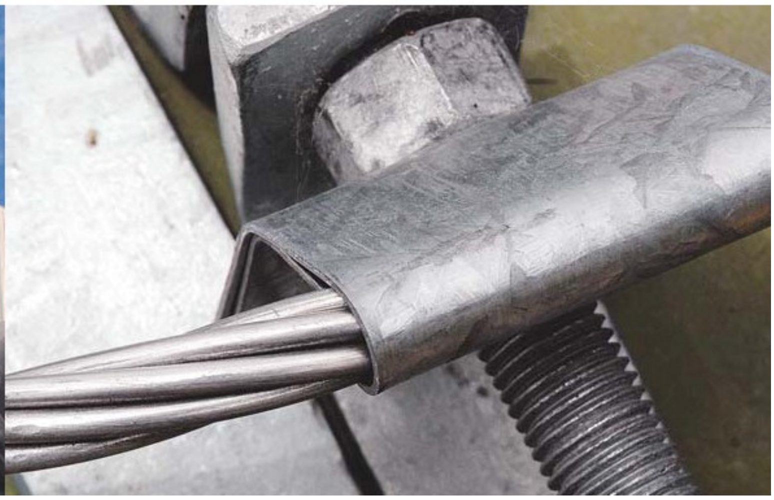

Contents

Overview comments

Purpose of this document

This document is EnergyAustralia's further submission in response to the Australian Energy Regulator's (AER's) Draft distribution determination and Draft decision with respect to EnergyAustralia published on 28 November 2008.

EnergyAustralia submitted an interim submission with its revised proposal on 14 January 2009. The matters raised in this submission, together with those raised in our revised proposal and interim submission should all be considered as matters raised in EnergyAustralia's submission to the AER with respect to EnergyAustralia's distribution determination.

Structure and Approach

This document provides additional submission in relation to the AER's Draft determination and Draft decision with respect to:

- Capital Expenditure, specifically the impact of the AER's draft transmission determination for equity raising costs.
- Rate of Return.
- Operating Expenditure, specifically Step Changes.
- X Factors.
- Incentive Mechanisms.
- Pass through events.

Also included within this submission is further material in support of EnergyAustralia's revised proposal and submissions. This majority of material is mainly supporting material that was referenced in expert reports attached to the revised proposal and interim submission.

However there are also additional attachments referred to in this further submission which have been provided, together with the supporting material referenced in those attachments. For ease of reference, a list of all attachments to the revised proposal and submissions (interim and further) is attached to this submission and indicates the additional attachments and where additional supporting material has now been submitted with respect to an attachment.

All chapter references are to chapter numbering used in EnergyAustralia's June 2008 Regulatory Proposal and its January 2009 Revised Regulatory proposal

Further submission on chapter 3: capital expenditure

Equity Raising Costs

Cash Flow Modelling

EnergyAustralia's revised proposal and interim submission outlined concerns with the AER's decision to amend cash flow modelling in respect of the calculation of dividends. We submitted that the AER's final determination must demonstrate consistency between its decision on dividend payment assumptions and the economic value and timing assumptions in the PTRM. This submission provides further information demonstrating inconsistencies between the cash flow modelling and the PTRM used by the AER in its draft decision for EnergyAustralia. These inconsistencies relate to:

- the cash flows used to calculate the amount of new equity required and the cash flows used to demonstrate the returns to equity holders; and
- the amount of dividend payment required to fully distribute the imputation credits.

Inconsistency in the amount of equity required

In its draft decision, the AER determined that the amount of new equity required by EnergyAustralia for the 2009-14 regulatory period is $1,388 million. The AER used a dividend payout ratio of 70% to calculate an assumed forecast dividend payment of $608 million for the period.

The AER's assumptions mean that over the 2009-14 regulatory period, equity investors are expected to inject an additional $780 million, being the amount over and above the dividend of $608 million they expect to receive.

Using the same data, the AER calculated the cash flow to equity holders to demonstrate that these investors achieved their benchmark equity returns of 11.34%. This cash flow modelling, however, resulted in equity holders needing to inject $1,157 million over the period.

There appears to be inconsistency in the AER's cash flow modelling for the purpose of determining the cost of equity raising and the cash flow used to demonstrate the returns on equity, even though the same set of data is used.

This inconsistency appears to result from the fact that the cash flows used to demonstrate return on equity includes a cash outflow for the repayment of debt whereas the cash flows used to calculate additional equity for the purpose of determining cost of equity raising does not.

As a consequence of this inconsistency, it appears that the amount of additional equity used to calculate the cost of equity raising is understated by $377 million, which therefore understates the cost of equity raising calculated by the AER.

Inconsistency in the distribution of imputation credits

In its draft decision, the AER applied a dividend payout ratio of 70%. The AER considers that the dividend payout of 70% is consistent with a gamma of 0.5, assumed in the Rules.

In its explanatory statement on WACC parameters [1], the AER states that it "intends to define gamma as the value of imputation credits created by the payment of corporate tax. This implies a payout ratio of one for the purpose of estimating gamma".

In the cash flow calculation used to demonstrate the returns to equity holders, the total value of imputation credits for the 2009-14 period is $292m. To fully distribute these imputation credits - consistent with a payout ratio of one adopted by the AER in the WACC review - implies that a total dividend payment of $1,365 million is required. This is $757 million above the amount of dividend payment calculated in the cash flow modelling used for the calculation of equity raising costs.

Therefore, it appears that the AER's assumed dividend payments used to determine equity raising costs in the draft determination are inconsistent with the underlying assumptions used in the PTRM. The dividend payment calculated in the cash flow modelling to determine the cost of raising equity understated the amount of additional equity required and hence the cost of raising equity.

Further discussion highlighting inconsistencies outlined above is provided in Attachment 3P, submitted with EnergyAustralia's revised regulatory proposal[2]. Also included in this further submission is a supplementary report, also prepared by Tony Carlton, to further clarify the issue of distribution of imputation credits. This supplementary report is at attachment 'I' to this further submission.

Implications for the AER's decision

EnergyAustralia submits that prior to its final determination being made, the AER should undertake further analysis of the cash flow modelling used in the draft decision to calculate the cost of equity raising to ensure that its modelling is consistent with the underlying assumptions used in the calculation of revenue, i.e. the PTRM.

Further submission on chapter 8: rate of return

Introduction

EnergyAustralia's revised regulatory proposal included revised values for the nominal risk free rate and debt risk premium based on a revised averaging period of 15 business days commencing 18 August 2008.

EnergyAustralia's revised averaging period is in response to the AER's decision to withhold agreement to EnergyAustralia's proposed averaging period and to instead specify its own period. The AER's decision to reject EnergyAustralia's original proposal was based on a premise that applying an averaging period which is closely aligned to the date of the final determination provides an unbiased rate of return which is

[1] " Electricity transmission and distribution network service providers – Review of the weighted average cost of capital (WACC) parameters – December 2008"p298

[2] Tony Carlton: Indirect Costs of Equity and Debt Raising, January 2009.

consistent with market conditions at the time of the final determination.

Our revised proposal outlines why we believe the AER's decision to withhold agreement to our original proposal was unreasonable. In addition we provided evidence that suggests the AER's premise is unsound, particularly in the context of current market circumstances. We also demonstrated how our revised averaging period is more likely to result in an unbiased estimate of the rate of return than that specified by the AER.

EnergyAustralia relies on analysis undertaken by Dr Tom Hird of CEG[3] (the CEG report) to substantiate our proposed averaging period. This was provided to the AER as Attachment 8B to our revised proposal.

To further substantiate the matters raised in our revised proposal and interim submission, this further submission includes:

- an independent expert opinion by Robert Officer on the CEG report in the context of EnergyAustralia's circumstances;
- supporting information on current market conditions that was provided to the AER as part of its review of WACC parameters for distribution and transmission businesses;
- further information supporting an approach to reconsider the observation of the risk free rate during a period of financial crisis.

Robert Officer Report

EnergyAustralia engaged Robert Officer to undertake a peer review of the CEG Report.

Robert Officer is Professor Emeritus of the University of Melbourne and an Honorary Professor of the University of Queensland. He has extensive experience in the areas of corporate finance and the cost of capital. Officer's report is attached to this submission at attachment 'II'

Officer's report substantiates the opinion provided by CEG:

> I do not consider that such an estimate is likely to provide an unbiased value for the current cost of capital for a company. I do not think that current market conditions are requiring a below average cost of capital, in fact, quite the reverse when we look at the discount being required for rights and similar attempts at raising equity capital..[4]

Officer notes that the current environment is producing extreme observations. At a time when 10 year government bonds are at 50 year lows, MRPs are at record highs. Officer notes JF Capital Partners' analysis which suggests that MRP in the current climate could be in excess of 20%[5].

Officer notes, as does CEG, that specifying a period of observation where the proxy of the risk free rate is lower than the average and the 'average MRP' is fixed, is likely to give an inaccurate (low) estimate of the MRP and result in a lower cost of equity for the current period than is required by providers of equity capital.

Officer's review departs from the CEG in that while he prefers an observation for corporate debt close to the start of the period, there is little option but to accept an alternative estimate of corporate bond yields. This may involve a considerable degree of subjectivity of an appropriate rate for company debt.

Officer notes that evidence such as that provided by UBS may better inform the AER as to the real cost of debt in the current market compared to observation of similar debt in "normal" periods which is likely to inappropriately understate the true cost of debt.

[3] CEG "Rate of Return and the averaging period under the National Electricity Law" dated January 2009.

[4] Officer report, p12

[5] We have included JF Capital Partners' report as an additional reference material to this submission

Submissions to the AER review of WACC parameters

The AER is currently reviewing the WACC parameters under the National Electricity Rules. While many of the issues raised in the AER's review are not relevant for our determination process (as many of the parameters are already locked in for EnergyAustralia's current process) the AER's WACC review has nevertheless resulted in the production of various submissions and evidence which are relevant to the AER's considerations of the rate of return aspect of EnergyAustralia's revised regulatory proposal, in particular, current market conditions.

Set out below is a summary of those submissions provided to the AER as part of its WACC review and the reasons why EnergyAustralia considers they contain relevant information which the AER should take into account in determining EnergyAustralia's rate of return under the National Electricity Rules. Specifically, the Rules require that the rate of return be measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the distribution business.[6]

FIG submission to the AER Explanatory Statement

The financial investors group (FIG) comprising eight major investors in around $30 billion of transmission and distribution networks made a submission to the AER's review of WACC parameters. Their submission provides relevant insight into investors expectations of rates of return under current market conditions. FIG's submission is provided at attachment 'III' of this submission.

The FIG submission provides evidence demonstrating the impact of tightening global debt and equity markets on our industry. It also provides evidence to suggest that current financial conditions will take considerable time to improve. Any economic recovery is likely to be tempered by a structural change in the appetite for investment and there is unlikely to be a return to the conditions of the recent past[7].

The entirety of this evidence leads to a conclusion that the returns required by investors have increased in the current environment. The FIG provides analysis of prospective trading yields for utility companies as at December 2008, and demonstrates that there has been a significant increase in these trading yields compared to two years ago[8]. The FIG submission concludes that there is sufficient evidence from the market as a whole and the performance of regulated businesses in particular to conclude that expected returns for equity investors have increased:

> The evidence from the market suggests that both the market risk premium and the equity beta of energy network businesses have increased in recent times. This is evident from the market's performance as a whole and the performance of regulated businesses in particular. The cost of equity resulting from the AER's CAPM analysis is well below the prevailing cost of equity in the market.. and risk free rates are being impacted by Government efforts to negate the effects of the crisis. These market conditions are likely to persist over the medium term and thus affect investment levels for at least the next 5 years.
> The FIG acknowledges that the cost of equity resulting from a mechanical application of the CAPM will not necessarily capture the prevailing cost of equity in the market. The FIG also notes, however, that in these circumstances, the principles underpinning the National Electricity Objective should prevail, as they do in market practice.[9]

Macquarie Research Equities submission to AER Explanatory Statement

Also relevant to the AER's decision on EnergyAustralia's rate of return is the Equity Market Participant's submission to the AER's review of WACC parameters. This submission provides useful insight of market analysts' expectations around rate of

[6] National Electricity Rules, clause 6.5.2(b)

[7] Financial Investor Group Submission to the AER's WACC Parameter review – the investors perspective, page 28

[8] ibid,p35

[9] ibid, p4

return. This is particularly valuable in the context of the AER's comments that:

> "The cost of capital has fluctuated from around 9 per cent in early 2007 up to around 11 per cent in mid 2008. However, since then the cost of capital has fallen to 9.72 per cent, as at 17 October 2008....If global financial conditions improve in the interim period, and the commercial debt risk premium subsequently declines, this will be reflected in a lower cost of capital"[10]

In its revised proposal, EnergyAustralia has outlined why this statement is incorrect. It is also clear that global financial conditions have not improved but, despite this, the cost of capital calculated using the AER's proposed averaging period continues to fall. The outcome of the AER's decision,, compared to the opinion of market participants generally, and utility investors specifically, are clearly opposed. This is very concerning and is further evidence that the AER must revisit its draft determination in respect of cost of capital in light of recent financial events.

Macquarie Research Equities canvassed a number of domestic fund managers who are ultimately responsible for allocating capital to the energy networks sector. Of importance to this review is the response from equity market participants to the following question:

> What return on equity would you require from investing in a regulated electricity distribution network asset (assume internally managed, clean structure)

The answers to this question are found in the Macquarie Research Equities submission (Attachment 'IV'). Some specific responses are found below:

> In an environment of 1) de-leveraging, 2) a shrinking pool of available capital to fund investment, 3) a fundamental re-pricing of risk and 4) credit market dislocations, it beggar's belief that the regulator should conclude that...the cost of equity has declined..[11]

> Experience from previous episodes of major market and economic dislocation suggests that a full recovery from prevailing market conditions could take upwards of five years... We expect difficult debt and equity capital raising conditions to persist for the foreseeable future.[12]

> Expecting investors to allocate capital to this sector given current market conditions (volatility, cost and availability of debt) with a lower return on equity does not make sense[13].

Joint Industry Association submission

The Joint Industry Associations (JIA) Submission[14] includes analysis and evidence that can assist the AER in its decision on the averaging period for EnergyAustralia.

Of particular importance is the JIA's response to the AER's assumptions on the timing of borrowings which is an issue related to the AER's decision on the averaging period for our business. The AER's draft determination states:

> On the basis of the available evidence it appears reasonable to expect that interest rate exposure on a large existing debt portfolio can be largely hedged away over the averaging period[15]

The Joint Industry Association noted, and we agree that these statements are not accurate and misrepresent what actually occurs when energy network businesses hedge interest rate risk[16]. The JIA submission and additional attachments from Treasurers of network businesses focus on the simplification of the AER's assumption and the fact that such assumptions would need to be backed with acceptance of considerable costs associated with hedging arrangements. It is also worth noting that such an approach would, in some cases be both inefficient and imprudent, particularly where large amounts of hedging cover was required from a thinly traded market in a very short time period.

In such circumstances, the price obtained for such coverage is likely to be significantly above the average price obtained if

[10] AER draft determination p xv
[11] Macquarie research equities submission to the AER, p4
[12] ibid p6
[13] ibid, p11
[14] Joint Industry Association's submission to the AER's review of WACC Parameters, 2 February
[15] AER draft determination p104
[16] JIA submission p74

hedging was undertaken over a longer period, in smaller tranches and staggered to smooth exposure to market conditions.

EnergyAustralia would add that in the context of its own circumstances, where a significant capital program needs to be financed in a tightening market, the assumption is unlikely to hold. In general, and in the current market circumstances in particular, the AER cannot conclude that a DNSP is indifferent to the risk free rate, particularly if the observation of this rate is at historic lows.

The report by CEG entitled "Overview of CEG analysis", provided under the AER's WACC review as part of the JIA submission, provides further supporting evidence that the required rate of return for investors is not declining in the current market conditions but is in fact increasing. CEG notes that there has been a significant repricing of equity risk in general and utillity stocks have not been immune from this repricing[17].

Based on this CEG analysis in support of the JIA submission, any assumption that equity returns are reducing and are significantly lower than in June 2008 does not reflect reality.

The Joint Industry Association submission and attachments from CEG and Treasurers of NSPs are provided at Attachment 'V'.

Additional Independent Information

Industry developments with CGS observations

In the final ACCC decision for the Roma to Brisbane pipeline access arrangement, the AER considered other industry and accounting practice when making its decision on the costs of the pipeline:

> Insurance industry practice also recognises that the value of the liability does not change with the company's cost of capital by requiring that liabilities be discounted by the risk free rate.[18]

In applying other industry and accounting practice to our circumstance, we note that, due to the financial crisis, valuations across industries have been affected by using (lower) current CGS yields as a proxy for a risk free discount rate. Revisiting the use of CGS observations in the current market as proxy for the risk free rate is supported by developments in accounting standards for the general insurance industry and recent guidance, in the form of an Information Note, in relation to those standards from the Institute of Actuaries of Australia (IAA). This discussion note is attached at attachment 'VI'.

Under revised AASB 1038 (effective 1 January 2005) insurers are required to value their future liabilities using a risk free discount rate. Even at the time of its inception, it was acknowledged that CGS yields were not necessarily a perfect proxy for the risk free rate. In a recent practice note, the IAA has stated:

> The concept of 'risk-free' discount rates extends beyond the government bond rates of appropriate duration. Paragraph 8.8.2 of AASB 1038 clearly states that although government bond rates may, in some cases, provide appropriate discount rates, in other cases they may only be a starting point.
>
> This is further reinforced by the 23 August 2004 letter from the Chairman of the AASB to the then President of the Institute (see Appendix 1) which makes it clear that the AASB included paragraph 8.8.2 to ensure that the phrase "risk-free rates" was not narrowly interpreted to be government bond rates. [19]

However, consistent with the views expressed by EnergyAustralia in its revised proposal, the problems with using CGS yields as a proxy for the risk free rate have been heightened with the advent of the global financial crisis.

[17] CEG Overview of CEG analysis – a report for the JIA, Feb 09

[18] Attachment VI ACCC Revised Access arrangement for the Roma to Brisbane Pipeline December 2006, p21

[19] LIFE INSURANCE & WEALTH MANAGEMENT PRACTICE COMMITTEE Information Note: Risk-free Discount Rates under AASB 1038 October 2008

These events have largely triggered the need for the October 2008 IAA guidance quoted from above. Indeed, that guidance states:

> The determination of risk-free discount rates became particularly topical following the investment market turmoil in late 2007 and early 2008. This led some market observers to question conventional thinking regarding the allowance for risk and liquidity in market yields. The conclusions in this Information Note reflect consideration of those developments.

CEG has provided evidence from Deloitte to confirm the direction of the IAA. The additional evidence provided by CEG and the associated IAA Information Note is provided at attachment 'VII'.

The key conclusions of the Information Note are that in current market circumstances something above the CGS yield should be used as a proxy for the risk free rate reflecting both a shortage of supply and a liquidity premium paid for CGS. The Information Note proposes a number of possible alternatives to the use of CGS yields. These include starting with corporate debt or swap rates and removing a fair estimate of the true expected value of default and any associated risk premium. If CGS yields are to be used as a starting point then the Information Note recommends an upward adjustment to reflect a relative shortage of supply and a liquidity premium paid for CGS (depressing CGS yields relative to other riskless assets).

Consistent with the advice of CEG, any such adjustment for the liquidity premium post September 2008 would need to be very significant.

Approach to adjusting forward revenues if agreed period unchanged

If, against EnergyAustralia's proposals and submissions, the AER proceeds with its original specified averaging period to determine the rate of return, the AER will need to make adjustments to other constituent decisions or inputs to ensure that the 10 year estimate of inflation and the 10 year nominal risk free rate are applied consistently in the PTRM.

We note that two alternatives may be available for the AER:

- adopt the CGS break even inflation rate as its best estimate of expected inflation; or
- use indexed bonds as a proxy for market observations of the risk free rate and add the AER's best estimate of inflation when calculating revenue returns.

The AER has noted in recent decisions that use of indexed CGS yields is not appropriate because "since late 2006 a downward bias in the indexed CGS has become evident due to a limited supply of these securities"[20].

We also submit that neither option represents the ideal solution for the AER's decision on the rate of return, which would instead be to select a period unaffected by the financial crisis (which EnergyAustralia says can be achieved by selecting the 15 business days commencing from 18 August 2008), but represents the minimum needed to ensure the real revenue returns and forecast inflation are internally consistent in the event the AER decides not to alter its original specified period.

Further submission on chapter 9: operating expenditure

NERA report on AER draft Determination

In its draft determination for EnergyAustralia, the AER determined that a reduction in EnergyAustralia's forecast network operating expenditure forecast to remove certain step changes as recommended by Wilson Cook would reflect the efficient costs that a prudent DNSP in the circumstances of EnergyAustralia would require to achieve the operating expenditure objectives[21].

In reaching this conclusion, the AER agreed with Wilson Cook's definition of step changes as including only those changes that result in a benefit to the customer in terms of the product delivered or to the business in terms of efficiency[22]

In particular, Wilson Cook concluded that:

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[20] AER draft determination p226
[21] AER draft determination p599
[22] Ibid, p598

> The proposed step changes are reviewed in section 9.5 but we note the following general points. First, in a competitive market, businesses do not normally add to their own costs unless they are satisfied that there is a benefit to customers in terms of the product delivered or to the business in terms of efficiency. Regulation presumably ought to incentivise natural monopolies in a similar way. Second, businesses are dynamic, with variations occurring from year to year. Such variations ought not to form the basis of a claim for a step change, as the effect of that would be to allow costs to be passed on readily in contravention of the efficiency objective implicit in the regulatory framework.
> We consider that a methodology such as that used by EnergyAustralia that starts with a base year and then applies cost escalators, workload escalators and step changes (which apart from some adjustments for abnormal items in the base year are almost all additional costs) without any explicit consideration of business efficiency improvements or potential cost savings is likely to lead to a forecast of future costs that is above an efficient level. We therefore consider that for acceptance as a step change, a cost ought to relate to a fundamental change in the business environment arising from outside factors or be offset by cost efficiencies in other areas[23].

EnergyAustralia's revised proposal and interim submission:

- provides detailed explanation as to why Wilson Cook's analysis is incorrect ;
- demonstrates why AER's decision to accept Wilson Cook's analysis and reduce forecast operating expenditure accordingly is not consistent with Rule requirements; and
- provides evidence in support of our response as well as independent expert analysis and advice from Concept Economics and PWC to support our conclusions. These were provided as attachments to our revised proposal and interim submission.

Following the submission of our revised regulatory proposal, we asked NERA to review our response to the AER's draft determination and particularly the general points raised in Wilson Cooks analysis. NERA has considerable experience in regulatory and economic advice and has assisted EnergyAustralia in understanding how to demonstrate that our operating expenditure is consistent with Clause 6.5.6 of the Transitional Rules.

NERA found that expenditure that provides benefits to customers (now or in the future) may be considered prudent and efficient (and therefore are consistent with the expenditure criteria in the National Electricity Rules) even in the absence of off-setting cost efficiencies. This is consistent with Wilson Cook's general findings. NERA also found that:

> … it is important that the AER explicitly consider evidence presented on the nature of any off setting efficiencies that may be expected, and the timeframe over which those efficiencies may be achieved. A blanket assumption that there will be off setting efficiencies and that these efficiencies will occur within the same regulatory period may not be correct in all cases. If forecast expenditure is disallowed or reduced on this basis, expenditure that is otherwise consistent with the operating expenditure criteria set out in the National Electricity Rules, may be disallowed.[24]

NERA's report is found at Attachment VIII to this further submission. NERA's analysis supports the conclusions raised in our revised proposal and interim submission that our operating expenditure forecasts give due consideration to prudence and efficiency in accordance with the Rules requirements.

Self Insurance

In its decision to reject EnergyAustralia's operating expenditure forecast, the AER rejected EnergyAustralia's forecast operational costs for self insurance. In rejecting our forecast self insurance costs, the AER gave the reason that the costs of insuring for certain self insurance events went beyond a 'realistic expectation of the costs of self insurance required in the next regulatory period'[25] on the basis that the probability of those events occurring was too low for insurance against those events to be prudent.

The AER identified a number of events where it did not accept the forecast self insurance premium, including:

- terrorism events;
- earthquake of a magnitude of 6;

[23] Wilson Cook & Co Review of Proposed Expenditure of ACT & NSW Electricity DNSPs volume 2 p51

[24] NERA report p14

[25] AER draft determination p 624

- bushfires ignited by a DNSP's own assets;
- minor and major bushfires ignited by third party; and
- non-terrorist impact of planes and helicopters[26].

The AER concluded that the fact that, for some insurance events, the event had not (to date) occurred in EnergyAustralia's network, was an indicator that the event was improbable and therefore that the proposed self insurance premiums of the risk of that event did not reflect the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives.

Our revised proposal and interim submission noted that the fact that an event has not occurred to date is not a justifiable reason to assign zero probability of it occurring in the future and therefore not a valid reason to conclude that insuring against that event is not reasonable, prudent and efficient.

An example where the AER applied this reasoning was in relation to the risk of an aircraft hitting and damaging our powerlines. The AER stated:

> EnergyAustralia had never experienced an incident of wire strike given the largely urban nature of EnergyAustralia's network[27]

Since the draft determination, EnergyAustralia has recorded an instance of an aviation wire strike.[28] This demonstrates the AER's conclusion that a zero probability for events that have not previously occurred is incorrect. Further information on this instance can be provided upon request.

In other instances the AER rejected the assumptions or methodology applied by SAHA and therefore substituted zero compensation for those self insured risks. For example, it rejected self insurance premiums in relation to bushfires, both those ignited by a third party and those ignited by EnergyAustralia for the following reasons:

- that the probability of occurrence and associated costs have not been reasonably determined; and[29]
- The probability of the occurrence and the costs associated with the event are not sufficiently robust to be used to determine the self insurance premiums.[30]

We note that while our network spans CBD and urban areas, EnergyAustralia's network is also exposed to densely vegetated areas. On 12 January 2009, the Daily Telegraph reported bushfires in the Killara region, which is part of EnergyAustralia's network area. The front page of the newspaper displayed a photo that illustrates the diversity of topography within EnergyAustralia's network area. It shows the CBD in the background and bushland in Killara in the foreground. It also shows a helicopter flying around network infrastructure to manage a bushfire in densely vegetated bushland[31].

The amount of bushfire activity that has occurred this summer indicates that the AER's decision to substitute a zero premium for self insurance for this risk is incorrect and contrary to what is required by the Rules when the AER substitutes an amount value or methodology[32].

EnergyAustralia stands by its regulatory proposal with respect to the risks of events. We note that the amounts and methodologies required to estimate the expected cost of these asymmetric risks require judgement because of their nature. That is, they are generally low probability and high cost consequence events.

EnergyAustralia engaged SAHA International to estimate the costs of certain asymmetric risks. SAHA has considerable experience in undertaking this type of estimation for regulated networks and its estimates were reviewed and agreed to by an accredited actuary.

[26] Note the costs proposed by EnergyAustralia that were not accepted by the AER represented the residual risk not covered by external insurance providers

[27] AER draft determination p630

[28] We provide details of the event at attachment IX

[29] AER draft determination p630

[30] AER draft determination p629

[31] The photograph appearing in the Daily Telegraph on 12 January is provided at attachment "X"

[32] Clauses 6.12.1(4)(ii) & 6.12.3(f)(2)

SAHA's method established a non-zero probability and insurance premium for future events based on the frequency of similar events, in some cases events outside our network area.

If the AER disagrees with the values, amounts or methodologies used, it should only amend those amounts values or methodologies to the extent necessary to enable it to be approved in accordance with the Rules.

The AER did not amend the values and methodologies that it expressed concerns about. Rather, it dismissed the cost entirely. This is akin to amending all values to zero. These zero probability assumptions are intrinsically incorrect and should be rectified.

EnergyAustralia stands by its regulatory proposal and considers that the AER must revisit its decision to apply zero probabilities and premiums to events. If it still has concerns about the values, amounts or methodologies, it should justify what should be applied in their place and recalculate its allowance for self insurance using a forward looking assessment of probability of occurrence.

Further submission on chapter 13: X factors

Updated economic projections provided by KPMG Econtech

The economic growth projections relied on by EnergyAustralia in its revised regulatory proposal were a combination of the ANZ Bank's 11 November 2008 short-term projections (for 2008/09 and 2009/10) and KPMG Econtech's October 2008 projections for the period 2010/11 to 2013/14.

The rationale for adopting the ANZ Bank projections for the near-term forecasts was that the projections were more current than the KPMG Econtech projections, and therefore more likely to have factored in the ongoing emergence of actual and anecdotal evidence which suggested that the impact of the global financial crisis was becoming increasingly more severe.

On 3 February 2009 KPMG Econtech released its latest update of projections for NSW economic growth. EnergyAustralia notes that KPMG Econtech has significantly revised downward its outlook for NSW economic growth. The table below compares relevant recent sets of NSW economic projections.

Table: Recent NSW Economic Growth Projections (%)

	FY09	FY10	FY11	FY12	FY13	FY14	Ave FY09 to FY10	Ave FY09 to FY14
KPMG Econtech Oct-08	1.40	1.40	2.80	3.30	3.00	2.00	1.4	2.3
EA Revised Proposal (see note)	0.50	1.25	2.78	2.78	2.78	2.78	0.9	2.1
KPMG Econtech Feb-09	0.40	1.10	3.30	2.00	2.00	2.10	0.8	1.8

Note: EnergyAustralia's revised proposal relied on ANZ Bank projections for 2008/09 and 2009/10, and on the average of the KPMG Econtech projections for 2010/11 to 2013/14.

The KPMG Econtech report is provided at Attachment 'XI'[33].

EnergyAustralia contends that the updated KPMG Econtech economic projections demonstrate that EnergyAustralia's decision to rely on the then more recent ANZ Bank projections for the short-term economic outlook has been proven to have been prudent. KPMG Econtech's latest short-term outlook is in fact marginally lower than the outlook assumed in EnergyAustralia's revised regulatory proposal.

In addition, the significant difference between KPMG Econtech's latest projections and those prepared a matter of months earlier demonstrates the level of uncertainty that surrounds the economic outlook. As economic growth is a key driver of electricity consumption, it would be appropriate that forecasts be reviewed again prior to the final determination.

33 KPMG Econtech's Australian National, State and Industry Outlook, 23 January 2009.

EnergyAustralia submits that this forecasting uncertainty adds credence to EnergyAustralia's proposal for a G-factor to be incorporated into the framework to cater for the uncertain economic and policy environment that will characterise the beginning of the 2009-14 period.

As noted in our revised proposal, the G-factor places a collar/cap on revenues by providing a mechanism whereby volume forecasts are updated during the period where revenues significantly diverge from forecast revenue. This mechanism ensures that neither customers nor distributors are penalised by the level of uncertainty that is present at the beginning of our regulatory period. The proposed G-factor also provides the AER with a relatively safe option to set volumes, and avoids the need to take a firm position on forecast volumes which is likely to be incorrect and may lead to the national electricity objective not being achieved. EnergyAustralia considers that it would be unreasonable for the AER to fail to take advantage of such a mechanism in the current environment when both the stakes and the uncertainty are high.

Additional analysis on the impact of electricity price changes on peak demand

For the purposes of incorporating electricity price impacts into the volume forecasts for its revised proposal, EnergyAustralia relied on price elasticities which had been published by NEMMCO. The NEMMCO price elasticity publication contained the important qualification that the estimated elasticities "refer to consumption per year, not instantaneous or average short run demands (e.g. half hourly)".

EnergyAustralia notes that while the AER's forecasting consultants, MMA, considered in some detail the impact of price changes on annual energy consumption, MMA made no mention of price impacts in the report which considered EnergyAustralia's peak demand forecasts (a separate report from MMA's report on energy). Accordingly, it can be inferred that MMA consider that electricity price changes are not an important driver of peak demand.

EnergyAustralia has undertaken analysis based on NEMMCO market data of recent electricity growth trends in South Australia which supports the contention that peak demand is less sensitive to price changes than annual consumption. The South Australian experience is relevant, as the small to medium (<160 MWh per annum) customer base were exposed to a significant price increase, of approximately 25%, from January 2003.

Between summer 2003/04 and summer 2007/08 South Australia's peak demand has grown at an average 4.4% per annum. Annual energy consumption over the same period has grown at the much lower rate of 0.8% per annum. It should be noted that the Adelaide daily average temperature on the system peak days in both 2003/04 and 2007/08 was identical at 33.2 degrees.

EnergyAustralia suggests that the recent South Australian trends noted above support the argument that retail energy price levels have a disproportionately higher impact on energy consumption than on peak demand.

EnergyAustralia's forecast energy volumes compared to other distribution businesses

With regard to the volume forecasts that underpin the NSW DNSP revised proposals of January 2009, EnergyAustralia wishes to bring to the AER's attention the following matters relating to Integral Energy's and Country Energy's treatment of electricity price movements over the 2009-2014 determination period.

The three NSW DNSPs have made different assumptions in the preparation of energy forecasts in light of the economic slow down and the implementation of the CPRS. EnergyAustralia considers the approach it has taken to be robust, but acknowledges that there is a variety of opinion in relation to the impacts of both lower economic growth and the future impact of climate change policy.

The variance in opinion is such that EnergyAustralia considers the proposed G-factor to be the only sensible option available to the AER which acknowledges the uncertain environment, allows the opportunity to recover at least the efficient cost and doesn't unduly penalise network provider or customer. As mentioned earlier, the proposed G-factor provides a mechanism whereby the AER can accept the variety of forecasts put forward by the DNSPs and still have confidence that if actual volumes are significantly different from forecasts, a mechanism will be triggered that ensures consumers will be protected. Without this mechanism or something similar, the

AER is forced to make a judgement about the three NSW forecasts, and in so doing, place its own bet in the energy volume lottery. If that bet proves to be wrong, the AER risks failing to provide businesses with adequate opportunity to recoup revenues to cover approved and prudent costs, and in so doing, fail in its duty under the National Electricity Law.

Further submission on chapter 14 incentive mechanisms

EnergyAustralia responded to the AER's draft determination on incentive mechanisms in chapter 14 of its revised proposal and interim submission. This submission provides further response to the AER in the context of two specific areas:

- the AER's revised Demand Management Incentive Allowance; and
- the AER's national service target performance incentive scheme

Demand Management Innovation Allowance

We note that in its Draft Determination, the AER sought EnergyAustralia’s written confirmation that the original DMIA be replaced by the replacement DMIA (required by clause 6.6.3(c) of the transitional chapter 6).

Our revised proposal and interim submission supported the AER’s general direction outlined in the draft determination. We noted it was a reasonable approach and most of the issues raised will achieve the objectives of the DMIA.

We also have some issues surrounding the application of the DMIA in the next regulatory period, and in future periods which we would like to clarify with the AER before agreeing with the revised scheme.

We also note in our revised proposal that we were disappointed that our proposed I Factor arrangements were not considered appropriate.

We also note that the AER’s intention that this be a modest scheme. As such, EnergyAustralia believes it will deliver only modest outcomes. Our preference would be for the AER to apply a broader and more meaningful incentive for innovation in demand management particularly in a political climate of reducing energy use etc.

In summary, we support the general direction given to the replacement of the original scheme with the one proposed by the AER as part of its draft determination, subject to further confirmation of the application of the scheme to the existing framework..

Service Target Performance Incentive Scheme

EnergyAustralia is required to implement a data collection and analysis exercise based on the national STPIS (placing no revenue at risk) for the 2009-14 regulatory control period. In February 2009, the AER published proposed amendments to the Service Target Performance Incentive Scheme (STPIS) to apply to electricity DNSPs.

EnergyAustralia will be providing a separate submission to the AER on the proposed amendments to the STPIS in accordance with the AER’s timelines for consultation. To the extent that the reporting requirements in the national STPIS directly impact on EnergyAustralia’s 2009-14 regulatory determination, we would like to provide specific comments on these requirements as part of this further submission. This will provide the AER with sufficient opportunity to consider our submission on reporting requirements in the national STPIS.

In our revised proposal we submitted that the STPIS should specify definitions, methods and exclusions for NSW DNSPs that are consistent with those set out in the NSW distribution licence conditions. We note that the proposed amendments to the STPIS indicate that the AER has made some progress in resolving the issues raised by EnergyAustralia in its revised proposal. For instance, EnergyAustralia supports the AER’s proposed amendments for the major event day definition including:

- deleting step 2 from the methodology for establishing the major event day boundary in appendix D of the STPIS;
- amending Appendix D to reflect that the major event day boundary will be calculated annually using the last 5 years SAIDI data; and

- clarifying Appendix D to exclude the entire duration of those outages originating within the midnight to midnight period of a major event day.

We note the AER has still not addressed many of the definition and method issues that apply to reporting arrangements in the STPIS. These issues result in the inconsistencies with the existing DWE Licence Conditions framework and will require EnergyAustralia to develop two sets of similar, but different, reliability statistics.

These issues were raised in EnergyAustralia's response of 26 September 2008 to the AER's proposed STPIS reporting arrangements. Based on these concerns, we submit that the proposed STPIS should be further amended as follows:

- The AER should ensure that the definition of CBD feeders to apply to NSW DNSPs in the national STPIS is consistent with the DRP licence conditions. This could be achieved through a footnote, which applies the definition used in the DWE licence conditions. DWE explicitly limits the CBD definition to feeders supplied by the City of Sydney's triplex 11kV cable system.
- The dataset to be used for the major event day (TMED) calculation and application should be consistent with the DRP licence conditions. Two different TMED methodologies will inevitably result in two different TMED thresholds with the potential for days to be considered 'valid' major event day exclusions under one jurisdiction and not in the other. This in turn will lead to different statistics that are calculated by subtracting the major event days. For NSW DNSPs, the AER should use the definition used in the NSW Licence Conditions, which specifically clarify that the TMED methodology is based on unplanned data after allowed exclusions with the exception of planned outages are removed.
- The AER should apply the exclusions framework for NSW DNSPs to be consistent with the DRP Licence Conditions framework. Specifically emergency services directed load shedding and customer caused interruptions (Licence Conditions Schedule 4 exclusions b(ii) and e) are excluded under the DWE framework but included under the AER framework.

We request that the AER make these adjustments to the National STPIS.

Further submissions on chapter 15: Pass through events

The Transitional Rules provide for the distribution determination made by the AER to provide for additional pass through events to apply for a regulatory control period, see clause 6.12.1(14).To support this decision, Sch 6.1.3(2) required a building block proposal to contain a proposed pass through clause with a proposal as to the events that should be defined as pass through events. These provisions are replicated in the main Chapter 6 rules.

This is a clear acknowledgement from the MCE policy makers who developed both the Transitional Rules and the general Chapter 6 rules that there would be circumstances relevant to individual DNSPs that would give rise to pass through event that may not be caught by the general definitions of pass through events in the Rules. The material in support of this is referred to in our revised regulatory proposal at p140 and footnotes 260 and 261. EnergyAustralia reiterates its previous proposal and submissions that the AER determine appropriate additional pass through events to meet the circumstances of EnergyAustralia.

We make further submissions here in support of EnergyAustralia's proposed Joint Planning Event and Customer Connection Event. We also submit why the AER's approach in relation to Alternative Control Services is legally incorrect and should be reconsidered.

Joint Planning Event

The AER's rejection of TransGrid's proposed CBD contingent project illustrates why EnergyAustralia considers it necessary to include a pass through event for joint planning.

A key assumption underlying Energy Australia's capital expenditure forecast is the retirement of the 132kV cables from Lane Cove to Dalley Street zone which requires work by TransGrid to advance 330kV supply to the CBD. The AER's draft decision not to allow this work by TransGrid to be included as a contingent project means that TransGrid will be unable to recover its efficient capital costs if required to carry out this work in the 2009-14 regulatory period.

EnergyAustralia is concerned that if TransGrid did not agree to undertake the investment, EnergyAustralia could be required to undertake a less efficient investment to replace the 132kV feeders within the 2009-14 regulatory period without an opportunity to recover the efficient costs of the investment.

This type of situation was raised in our revised regulatory proposal, where we noted that disincentives to efficient network development can arise where the various regulatory determinations for the participants involved in joint planning do not provide the requisite funding for all parties involved in the development of the project.

Customer Connections Event

EnergyAustralia sought a pass through for a customer connection event to ensure the costs associated with a large an unforeseen customer connection would be recognised as prudent expenditure under the regulatory regime.

EnergyAustralia endeavoured to incorporate known large future customer connections into its planning (within the Area Plans). However, there are circumstances that may occur that lead to a new and previously unknown connection being brought forward. Where such a connection is made to a part of the network that has sufficient capacity, there is limited additional cost to EnergyAustralia. However, where such a connection is made to a capacity constrained part of the network, the costs of meeting our obligation to connect a customer may be significant. Whilst direct connection costs are recovered via capital contributions, costs of upgrading shared assets must be funded by EnergyAustralia.

Since finalising the Area Plans and submitting them as part of EnergyAustralia's capital expenditure forecast there have been developments with respect to several major customer projects on the fringes of the Sydney CBD. It now seems likely that several major customer projects which were not included in EnergyAustralia's capital expenditure forecasts are likely to proceed during the 2009-14 period.

These connections are largely driven by construction of infrastructure projects as well as private developments and involve more than 90MVA of additional demand. This load is equivalent to more than half of the capacity of a large zone substation, and has not been catered for in existing forecasts. On the basis of information provided by the relevant proponents, EnergyAustralia considers that these are firm proposals which are likely to proceed. At this stage the details of these projects are subject to confidentiality arrangements, but further details could be provided to the AER, on a confidential basis if required, to further support the need for the proposed customer connection event.

EnergyAustralia requests that the AER reconsider its rejection of a customer connection event in light of such events occurring. It is particularly important given the significance and purpose of the loads being sought.

EnergyAustralia is committed to serving its community, but we consider that this should be not be at the expense of a reasonable return to shareholders.

Alternative Control Services

EnergyAustralia proposed that the pass through provision of the transitional Chapter 6 rules apply to alternative control services as well as standard control services[34].

The AER appears to have agreed in principle that these provisions should apply[35], but has formed the view that they already apply because the "NER relating to pass through events refer to direct control services which include both standard and alternative control services"[36].

In EnergyAustralia's view the existing Rule provisions do automatically allow or require positive or negative pass through amount to be determined by the AER with respect to alternative control services. There are a number of reasons for this:

Firstly Rule 6.6 is headed "Adjustments after making of building block determination" and is located in Part C of the

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[34] EnergyAustralia June 2008 Proposal, Chapter 7 of Part II, p 200-201.

[35] AER Draft Determination for NSW DBs at p 286.

[36] Ibid

Transitional Rules which relates to building block determinations for standard control services. This would appear to indicate that these provisions apply in the context of a building block determination only. This is supported by the provisions themselves; note that clauses 6.6.1(j)(2) (3) refers to "standard control services" and clause (j)((7) refers to "the provider's annual revenue requirement".

Secondly the references to "direct control services" are in the definitions of the various events not in the provisions in Rule 6.6 which allow an application for pass through to be made. This is appropriate so that that pass through arrangements are capable of being applied to alternative control services, but this does this does not result a right to seek to approval for the pass through of a positive pass through amount or an ability for the AER to require a negative pass through amount to passed through.

Finally and most conclusively, it is clear from clause 6.2.6 of the transitional rules that the policy intent of the rule makers was that Rule 6.6 would not automatically apply to alternative control services. Clause 6.2.6 imposes requirements in relation to the control mechanism for alternative control services. It provides that the control mechanism for alternative control services may utilise elements of Part C. A note to that provision indicated that the control mechanism might be based on the building block approach and the distribution determination might provide for the application of clause 6.6.1 to pass through events with necessary adaptations and specified modifications. It is therefore clear that the intention of the rules was that if any element of Part C, including the pass through arrangements, was to apply to the control mechanism for alternative control services, then that had to be specified in the part of the distribution determination that specified the control mechanism for those alternative control services.

In light of the above EnergyAustralia strongly submits that the AER should reconsider its decision in relation to the application of the pass through provisions to EnergyAustralia's public lighting services. The AER should include in that part of its distribution determination which decides on the control mechanism for alternative control services a provision which applies clause 6.6.1 of the Transitional Rules to any pass through event which occurs with respect to the provision of public lighting services as was set out in section 7.7.1 of EnergyAustralia's June 2008 proposal. A pass through event should include the following pass through events which were proposed in Chapter 15 and Attachment 15.1 of EnergyAustralia's June 2008 proposal and as further supported by our Revised Regulatory Proposal submitted on 14 January 2009:

- Pass Through events occurring prior to 30 June 2009 (Dead Zone Event);
- Force Majeure Event;
- Compliance Event; and
- Cost or Demand Input Variance Event.

The following adaptations should apply to the application of Clause 6.6.1:

- Any reference to Standard Control Services should be read as a reference to alternative control services being the construction and maintenance of public lighting.
- The reference to annual revenue requirement in Clause 6.6.1(j) should be read as a reference to the *Schedule of Fixed Prices.*

Modelling and financial information in support of our revised proposal

PwC review

EnergyAustralia's capital and operating expenditure forecasts were built using a large number of complex and integrated set of models. These models have proven to be a challenge to EnergyAustralia, particularly at the point where real cost escalation has been applied in order to meet the input requirements of the PTRM issued in February 2008.

Both EnergyAustralia and the AER have identified a number of modelling errors in the models provided with our June 2008 submission. Since then, EnergyAustralia has worked with the AER to fix these errors and confirm the integrity of the forecasts.

EnergyAustralia revised both its capital and operating expenditure forecasts to take account of a variety of factors including more up to date forecasts of real cost movements. As a result, the exercise of checking the integrity of models is again required.

To provide confidence to the AER that EnergyAustralia's methodology is robust and has been consistently and accurately applied, EnergyAustralia has engaged PwC to independently review the mechanics of the models and confirm that data and escalators in particular have been correctly applied.

EnergyAustralia has not yet received the final report from PwC in relation to its review. EnergyAustralia will provide the report and any outcomes to the AER as soon as the work is complete.