EnergyAustralia

EnergyAustralia's submission to

Australian Competition & Consumer Commission

Response to ACCC's Draft Determination for EnergyAustralia's Revenue Cap 2004-2009

Energy

OVERVIEW

ACCC released its draft determination for EnergyAustralia's transmission business in May 2004 to meet notification requirements for transmission pricing as required by the National Electricity Code.

The ACCC's review of EnergyAustralia's revenue application has been a challenging process for both EnergyAustralia and ACCC. This is the ACCC's first review of the prudence of past capital and fundamental flaws in the process and an absence of clear criteria for the review have led to this process being far from satisfactory.

In order to ensure that this revenue reset process delivers a fair balance between the interests of customers, TNSPs and the community at large, the following issues must be addressed in the ACCC's final decision:

- The framework within which the ACCC is conducting this reset is currently being reviewed, with almost every element of the framework subject to change. While EnergyAustralia supports a review of regulatory principles to ensure their relevance, we believe it grossly inappropriate that such a review should be conducted at the same time as this revenue reset.
- The draft is critical of the information provided by EnergyAustralia to date and has identified a number of areas where further information is required. EnergyAustralia believes that the source of these information gaps is the inability of ACCC and its consultant to specify their information requirements and investment criteria in a timely manner. *EnergyAustralia is committed to filling any information gaps in order to demonstrate the prudence and efficiency of our expenditure programs*.
- ACCC's criticisms are totally at odds with the independent reviewers (Meritec and Burns and Roe Worley) used by IPART in their better planned review process. This claim is expanded in some detail in the body of our submission.
- ACCC is attempting to apply investment criteria after capital has been sunk. This breaches every fundamental investment principle and highlights the significant level of regulatory risk facing TNSPs in Australia. Non-regulated businesses that do not face similar statutory obligations to supply customers would simply not invest under such uncertainty.
- EnergyAustralia strongly believes that all past expenditure was prudent, efficient and in the public interest to ensure reliable electricity supply and should be added to the RAB in full. In the case of Homebush, EnergyAustralia believes that 15% of its $10M costs related to the replacement of the 200/201 circuits should be included in the RAB, on the basis that this circuit would have required replacement in 2003 if it had not been replaced earlier.
- The ACCC recognises that its approach of "penalising" TNSPs for past capex inefficiencies by not allowing the return on any "inefficient" expenditure as adopted in the draft has no basis in economic theory. Despite this admission the ACCC has still adopted the approach as a simplistic penalty without a basis or context. We do not support this approach and believe its arbitrary nature sets a dangerous regulatory precedent.
- EnergyAustralia has developed detailed expenditure programs based on an expert understanding of the operation and maintenance of our network. Basing operating expenditures solely on the level of past expenditures, as proposed by GHD and ACCC, entirely misses the fundamental issue that, in order to maintain current network

performance standards, a higher level of activity will be undertaken in the next regulatory period than has occurred in the 1999-2004 period. This increased activity is to cover the growth of assets on the system, and to cater for the increased level of corrective and emergency maintenance caused by asset ageing.

- Applying a “general efficiency” factor for future expenditures without providing evidence as to the reasons for the reductions in expenditure proposals or the impact the cuts may have on system performance is not acceptable to EnergyAustralia’s customers, its employees or our shareholder. The ACCC’s advises have not demonstrated that they have undertaken the detailed analysis to support their proposed cuts.
- EnergyAustralia’s expenditure programs were prepared as an integrated package, with any reductions in expenditures likely to have a material impact on service standards. EnergyAustralia believes that the ACCC is “double dipping” by reducing our future operating expenditure while at the same time not providing a corresponding adjustment to proposed service standard targets. In this context, and recognising the increased number of assets deemed to be transmission, we do not support the introduction of monetary “incentives” for service standards at this time. EnergyAustralia commends ACCC to consider the approach recently taken by IPART to adopt a “paper trial” over the regulatory period at issue.
- The WACC in the draft decision, while similar to previous decisions made by the ACCC in electricity transmission, is still considerably lower than that implicit in comparable decisions adopted by overseas regulators. Errors in the ACCC’s financial analysis have compounded this effect by understating the allowed returns.

INTRODUCTION

The ACCC's review of EnergyAustralia's revenue application has been a challenging process for both EnergyAustralia and ACCC. This is the ACCC's first review of the prudence of past capital and fundamental flaws in the process and an absence of clear criteria for the review have led to this process being far from satisfactory.

ACCC released its draft determination for EnergyAustralia's transmission business in May 2004 to meet notification requirements for transmission pricing as required by the National Electricity Code. The draft is critical of the information provided by EnergyAustralia to date and has identified a number of areas where further information is required. EnergyAustralia is committed to providing this information to ensure that ACCC is satisfied that our investments during the 1999-2004 regulatory period were prudent and were delivered efficiently.

In order to ensure that this revenue reset process delivers a fair balance between the interests of customers, TNSPs and the community at large, EnergyAustralia believes the following issues must be addressed in the ACCC's final decision:

- ACCC's processes to obtain information have not enabled EnergyAustralia to respond adequately to address any potential concerns regarding our expenditure programs. Only once we (and ACCC) understood what these requirements were, have we been in a position to address these concerns. Unfortunately, the ACCC's timetable did not cater for this information to be considered as part of the draft decision.
- EnergyAustralia is confident that it can address any outstanding concerns.
- ACCC is attempting to apply investment criteria *after* capital has been sunk. This breaches every fundamental investment principle and highlights the significant level of regulatory risk facing TNSPs in Australia. Non-regulated businesses that do not face similar statutory obligations to supply customers would simply not invest under such uncertainty.
- EnergyAustralia strongly believes that all past expenditure was prudent, efficient and in the public interest to ensure reliable electricity supply and therefore should be added to the RAB in full. In the case of Homebush, EnergyAustralia believes that 15% of its $10M costs related to the replacement of the 200/201 circuits should be included in the RAB, on the basis that this circuit would have required replacement in 2003 if it had not been replaced earlier.
- Given that EnergyAustralia has met all industry standards for its past investment, it is incumbent on ACCC to accept all of EnergyAustralia's past capex. This is particularly the case when ACCC had not specified its criteria for establishing prudence or efficiency prior to the commitment of capital. In the absence of any guidance from ACCC on this matter, it is unacceptable to place more onerous tests on us than were in place at the time of the investment. Continuation of this approach in our view would be irresponsible and should be expected to severely dampen incentives to invest in much needed electricity infrastructure.
- We believe that ACCC drastically underestimated the complexity of the task of undertaking a second round review, and its ill-planned, information-intensive approach has only exacerbated the problem. TNSPs should not be penalised for this oversight.

- EnergyAustralia believes that the arbitrary efficiency penalty reduction applied by the ACCC to some of EnergyAustralia's projects is fundamentally flawed, creates significant concerns at the potential for "black box" regulation and creates unsustainable levels of regulatory risk.

THE ACCC'S UNCERTAIN FRAMEWORK

The framework within which the ACCC is conducting its review of NSW TNSPs revenues for the 2004-2009 period is currently being reviewed. In fact, almost every element of the framework is subject to change. While EnergyAustralia supports review of regulatory principles, we believe it to be grossly inappropriate that such a review should be conducted at the same time as the principles of regulation are being applied to us, prior to appropriate consultation and debate. EnergyAustralia made strong representations to the ACCC about the inappropriateness of the concurrent framework review at the time the DRP Discussion Paper was released in mid 2003. It should go without saying that the ACCC has five years to review its so called "draft" regulatory principles since they were last applied to NSW TNSPs in 1999.

The most significant aspects of the framework that are uncertain include:

- The ACCC has decided to pursue a roll-forward methodology to establish the opening asset value instead of maintaining its previous support for an ODRC methodology. In making the decision in favour of roll-forward, the ACCC did not recognise the extent to which their framework was silent in relation to the ex-post assessment of prudent capital.
- ACCC began its review without clear criteria for determining prudent and efficient investment, without an approach outlined and without sufficient detailed information requirements established to allow EnergyAustralia to deliver the required information.
- GHD, the ACCC's consultants, did not meet the terms of reference for conducting the review of expenditures as they did not reach any meaningful conclusions in their review. This has left the ACCC with unfettered ability to form views on transmission planning matters that we believe falls well outside their (or any Regulator's) knowledge base. EnergyAustralia finds this situation totally unacceptable, and believes that GHD's review has made a mockery of the regulatory review process
- The ACCC appears to be pursuing a framework for future capital expenditures that is a complete overhaul of the existing framework. EnergyAustralia will work with the ACCC to explore whether such a framework can be applied to us. However we believe that making some key, but limited improvements to the existing framework is a superior solution. The threat of wholesale changes to the fundamental basis upon which our capital is treated every five years not surprisingly places strong disincentives to invest. This is not the objective of the Code.
- The ACCC is continuing to explore modifications to its service standards framework as it is being applied to EnergyAustralia. We believe it is unreasonable to reduce our future expenditure programs while at the same time tightening the targets and attaching monetary "incentives" to the framework.
- The review of the Draft Statement of Regulatory Principles raises many other issues that are the subject to a separate review process. It is not clear to EnergyAustralia to what extent the ACCC will try to adopt and apply issues raised in that separate process to this reset process to EnergyAustralia. We are deeply concerned that this may occur, and believe that any application of new policy decisions to EnergyAustralia would need to be the subject of extensive consultation specifically as it applies to this review.

CAPEX EFFICIENCY "PENALTIES"

The ACCC recognises that the approach of "penalising" TNSPs for alleged past capex inefficiencies by not allowing the return on any inefficient expenditure as adopted in the draft determination has no basis in economic theory. Despite this admission, the ACCC has adopted this approach as a simplistic penalty and has not provided a basis or context in which to rectify the arbitrary nature of the adjustment. The manner in which ACCC has indicated that the penalty is to be applied suggests that the "return" of inefficient capital investment will not only be removed, but that it will also be removed from the RAB, thereby removing any return over the life of the asset.

EnergyAustralia is concerned that the approach has been applied without any direct relationship being developed between the penalty and the efficient levels of expenditure. EnergyAustralia notes that neither the ACCC nor its consultant has identified any inefficiency in our expenditures. Nor does it appear that the ACCC advisers have addressed the normative question of what our expenditures should be relative to targeted outcomes and the age and condition of our assets. However, should the ACCC demonstrate that some inefficiency has taken place in past capital expenditures, the ACCC has not demonstrated that the approach they have adopted to penalise TNSPs would withstand scrutiny (i.e. does the penalty fit the crime?).

PAST CAPITAL EXPENDITURE

The uncertain framework has created a number of problems for EnergyAustralia, particularly in the area of establishing the prudence of historic capex. The ACCC has identified a number of areas where information gaps remain. EnergyAustralia has responded by providing detailed information as part of this submission to demonstrate its firm belief that all investment undertaken in the past regulatory period has been both prudent and delivered efficiently.

This submission contains a discussion of each of the projects constructed by EnergyAustralia. Where ACCC has indicated its satisfaction at the information provided to date, a short summary of the project is included. However, where substantial information was still required by ACCC, the information provided is in depth.

OPERATING EXPENDITURE

EnergyAustralia is disappointed with the ACCC's treatment of our operating cost program. EnergyAustralia has developed detailed expenditure programs based on an expert understanding of the operation and maintenance of our network. Basing operating expenditures solely on the level of past expenditures, as proposed by GHD and the ACCC, entirely misses the fundamental issue that more activity will need to be undertaken in the next regulatory period than has occurred in the current period.

Applying a "general efficiency" factor for future expenditures without providing evidence as to the reasons for the reductions or the impact the cuts may have on system performance is not acceptable to EnergyAustralia's customers, its employees or our shareholder.

The ACCC has made what appear to be arbitrary and unsubstantiated cuts to various parts of EnergyAustralia's operating program which EnergyAustralia believes set a dangerous precedent for arbitrary cuts to operating costs in the future. While a considerable volume of information was provided to ACCC and its consultant, we do not see evidence that all of the information was interpreted properly, or in many cases was examined at all. We are concerned that engineering consultants have formed views on the appropriateness of matters such as superannuation, areas in which we are not convinced they are qualified to comment.

In any case, the high level “driver analysis” adopted by GHD appears to be an attempt to achieve reductions in future operating expenditures without requiring a robust justification for the reductions. The following summarises our main concerns with the operating expenditure section of the ACCC’s draft decision:

- GHD questions the allocation of costs across our network businesses. We find this perplexing, given that EnergyAustralia has provided annual regulatory accounts to ACCC; we have diligently provided all cost allocation methodologies to both ACCC and IPART to ensure no “double dipping” has occurred; we sought, and were granted, a transmission ring-fencing waiver from ACCC which endorsed our application that the net public benefits of further systems and legal separation of our networks would be far outweighed by the additional costs; and we approached ACCC to seek a change to the interpretation of the definition of transmission assets to enable the improved reporting of costs (which was denied). We believe GHD’s comments in this regard are entirely unsubstantiated.
- Approximately $90m of EnergyAustralia’s distribution assets will fit the definition of transmission assets from 1 July 2004 due to changes in the configuration and operating of the network. These assets have been transferred from the distribution asset base (and revenue cap) to the transmission asset base. The change to the size of the transmission asset base has necessarily resulted in the increased size of the operating program.
- The lack of detailed review by GHD or ACCC of our operating proposals has resulted in the simplistic application of future operating expenditures based on historical expenditures to set a “starting point” for future expenditures. This is clearly inappropriate as it ignores the fundamental issue that more activity will need to be undertaken in future.
- The calculation of future operating expenditures based on a starting point and the application of a “general efficiency” factor is again a simplistic approach that enables GHD and ACCC to make unsubstantiated reductions without any accountability for the impact that the reductions may have on outcomes. This is totally unacceptable.
- In GHD’s calculation of the starting point, we note that the GHD report has taken superannuation costs from EnergyAustralia’s Annual Report which reports the costs of the entire group, including the Distribution, Retail and External Businesses, none of which are the subject of this review. Notwithstanding, superannuation represents an ordinary and legitimate business expense and the ACCC’s approach of not recognising the full costs of superannuation should be concerning to many.
- In calculating the “general efficiency” factor, ACCC has made comments in relation to future savings that can be expected from further consolidation of EnergyAustralia. Over the past 10 years, EnergyAustralia has undergone significant organisational consolidation, however we believe it is extremely unlikely that further consolidation of distribution or transmission businesses will continue in NSW. Nor do we believe it appropriate for a regulator to speculate on possible changes that no-one has flagged and are matters for our owners to decide. In the context of EnergyAustralia’s significant increase in staff numbers during the next regulatory period it is difficult to see how “consolidation” savings will eventuate.

- No compliance costs associated with FRC (Full Retail Contestability) have been allocated to EnergyAustralia's transmission business. These costs were clearly identified in EnergyAustralia's Distribution submission to IPART and reviewed as part of the Distribution review process.
- ACCC has incorporated staffing and productivity considerations into its "general efficiency" adjustment. As outlined in ACCC's draft decision, EnergyAustralia is facing a continued high level competition for skilled staff in the NSW electricity sector. This has resulted in increasing staff costs. Furthermore, the significant increase in the size of EnergyAustralia's future program of capital works and maintenance has prompted the company to recruit a large number of new staff as apprentices, engineers and technicians.
- Given the flawed basis upon which GHD has recommended savings in these areas, EnergyAustralia argues that the "general efficiency" adjustment have no basis and double count efficiency savings achieved in other areas.
- GHD's comments that efficiency gains having not been pursued by EnergyAustralia is baseless and misrepresents the significant amount of work undertaken to improve systems. It also overlooks the substantial gains made since the corporatisation reforms of 1995. GHD then reported a table of data comparing forecast maintenance costs under both time based and condition based regimes. This data illustrates a total real ($'2003/04) saving of $6M (7%) over the next regulatory period. By the last year of the regulatory period the condition based maintenance regime achieves a saving of around 15% in maintenance costs as compared to a time based approach.
- Given GHD's scathing comments in relation to EnergyAustralia's information systems, it is entirely inconsistent for GHD to subsequently recommend cuts to our proposed program. While we accept that the last regulatory period was characterised by under-investment in Network related IT, this is explained by the group being focussed on FRC and market reforms and the requirement to meet national market and NSW Government objectives. IT spending in the current (2004-2009) period is a crucial component in ensuring that the business is able to meet its regulatory, safety and financial obligations as a publicly owned company. It is also unclear how expenditures on systems to meet the increasing obligations could result in operating expenditure efficiencies, as indicated by GHD.
- ACCC has removed an allowance of $20,000 per annum for current insured risks held by EnergyAustralia from transmission opex and has instead included insurance as a pass-through item. EnergyAustralia believes that the ACCC has under-compensated EnergyAustralia for the true costs.

WACC

The WACC in the draft decision, while similar to previous decisions by the ACCC in electricity transmission, is still considerably lower than that implicit in comparable decisions adopted by overseas regulators. EnergyAustralia makes the following observations with respect to WACC:

- While EnergyAustralia supports the ACCC's decision to base the risk free rate on the 10-year Commonwealth Bond, we are not convinced that the ACCC has embraced the unequivocal nature of the Australian Competition Tribunal's decision on GasNet on this matter.
- The ACCC's approach to the debt margin will understate the required debt margin for an efficient benchmarked transmission business. In addition, errors in the ACCC's credit rating calculations understate the required debt margin. Correcting for these errors results

in a benchmark credit rating of “BBB+”, not “A” as stated in the draft decision, and an increase in the debt margin of 20 basis points.

- EnergyAustralia believes that the 10.5 basis points allowed by ACCC in its draft decision for debt issuance costs does not adequately recognise the 25 basis points allowed by Australian Competition Tribunal for GasNet (which we are advised should represent a lower bound on a reasonable estimate).
- The ACCC notes that its allowances for the equity beta have been “generous” and “biased in favour of the service provider” compared with market data on beta. EnergyAustralia strongly disagrees with this suggestion. Regardless of the merit of arguments in relation to the systematic risk of TNSPs compared to other companies on the ASX, the systematic risk as measured by the asset beta (0.40) is already significantly lower than that for an average firm on the ASX (currently 0.62-0.65).

SERVICE STANDARDS

EnergyAustralia believes it is inappropriate to reduce our future expenditure programs without a corresponding reduction to expected service outcomes. This price / service relationship was an essential component of EnergyAustralia’s revenue cap application, where an integrated package of expenditure programs and the maintenance of existing service outcomes was proposed. We see no evidence that the ACCC’s technical advisers have acquired any understanding of the relationship between proposed expenditures and service outcomes. It is not appropriate for the ACCC to, on one hand, reduce our expenditure programs without any detailed justification, while on the other hand, fail to make a corresponding adjustment to service level targets. We see this as regulatory opportunism and are concerned that the ACCC’s public statements suggest a bias towards funding cuts.

EnergyAustralia commends the approach recently taken by IPART to adopt a “paper trial” over the upcoming regulatory period in order to develop and test a framework that delivers the desired incentives. Given the new framework proposed, the additional assets that now form part of ACCC’s service standard framework, and the proposed reduction in expenditure programs, we believe it is inappropriate to attach any monetary incentives to this framework over the next five years.

PASS THROUGH MECHANISM

EnergyAustralia welcomes the ACCC’s decision to allow for pass-through of costs associated with specific events that are outside the control of the TNSP. However, we are disappointed that ACCC has not accepted the suggestion put forward for an “External Event” and a “Fees Event” to be considered as a pass through item.

ACCC'S UNCERTAIN FRAMEWORK

The ACCC's framework for regulation of transmission network service providers is in a state of disarray. Almost every aspect of the regime is under review, being developed further or has been signalled to be replaced by a new proposal. At the same time the framework is being applied to EnergyAustralia and to TransGrid for a period of five years which is set to begin on 1 July 2004. The uncertainty of the regime has made it difficult for the ACCC to apply its framework to TransGrid and EnergyAustralia and has in fact caused it to delay its final decision for both companies in order to establish the new framework prior to its application.

EnergyAustralia has been highly critical of the ACCC's timing for review of the framework. The ACCC for its part admits that the timing is not ideal for EnergyAustralia and TransGrid but says that no time would have been a good time to review the framework. This may be the case, but we submit that the ACCC's decisions need to take account of this. In addition, its "draft" principles have been in place for 5 years!

The following section highlights the incompleteness of the current framework and the areas of the regime that have become subject to review since EnergyAustralia put forward its initial submission just nine months ago. It highlights the extraordinary level of investment and operational uncertainty faced by EnergyAustralia and TransGrid in this revenue cap process.

1.1 DRP REVIEW PROCESS

The ACCC released its Draft Statement of Regulatory Principles (DRP) in May 1999. In August 2003, the ACCC released a discussion paper relating to its review of this document which incorporated suggested changes to the regime. EnergyAustralia was advised of the impending review of the DRP in mid 2003, just weeks before we made our initial submission to the ACCC for the revenue cap for the 2004-2009 period.

Prior to release of ACCC's discussion paper, EnergyAustralia raised its strongly held concerns about the timing of the DRP's review and the consequent uncertainty that such a review would bring to the revenue cap review process for NSW TNSPs. Despite EnergyAustralia's concerns about the process and the substance of the review, the ACCC continued in its review of the framework.

The review of the DRP has now been in train since August 2003. By the end of the 1999-2004 regulatory period, ACCC has not yet released a follow up paper on its review. In fact, the regime remains more uncertain than ever as the capital expenditure framework is now also under fundamental review. We understand such a paper will be forthcoming, however, it was not available prior to the closing date for submissions on ACCC's draft determination.

EnergyAustralia has raised its concerns relating to due process many times with the ACCC. EnergyAustralia continues to believe that it is inappropriate to change the framework while applying the framework to regulation of our business. Despite the ACCC's assurance in a letter dated 27 August 2003 that with the exception of the asset base, the 1999 DRP framework would be applied in the case of EnergyAustralia revenue cap for 2004-2009, it appears that this is now not the case with ACCC delaying its final decision on EnergyAustralia's revenue cap until the DRP review process has been completed.

The ACCC sought agreement from EnergyAustralia that it would assist in the development of the new capital expenditure framework. EnergyAustralia agreed to assist in the regime's development. However, we have not accepted the new framework as there is not sufficient detail upon which we could make an informed decision. As stated in our separate submission on the subject, EnergyAustralia is not against an ex-ante review of expenditure at the time that the investment is about to be made. However, we strongly object to a 'firm cap' and the absence of an opportunity for ex-post review of prudent expenditures. We hold the view that such a concept is not consistent with recognition of prudent investment as required by the Code.

The review of the framework has made the process of the revenue cap review very difficult. Not only are resources stretched in dealing with framework and revenue cap issues, the uncertainty created by the changing framework has undermined EnergyAustralia's confidence in the regulatory regime.

1.2 ACCC CRITERIA TO DETERMINE PRUDENT INVESTMENT

The ACCC released its DRP Discussion paper in August 2003. In that Discussion paper, it stated that the ACCC's preferred treatment of the asset base was to roll-forward the asset base rather than establish the asset base by an ODRC methodology. This decision was made just weeks before EnergyAustralia made its initial submission to ACCC in September 2003.

The decision to use a roll-forward approach was a significant decision that had ramifications for other parts of the framework, which EnergyAustralia believes the ACCC did not fully understand at the time that it made this decision. The 1999 DRP was written with the understanding that periodic revaluation of assets under an Depreciated Optimised Replacement Cost (DORC) framework would occur[1]. The Commission considered that a well-defined ODRC approach had some significant advantages as a valuation methodology on economic efficiency grounds. It suggested that an ODRC approach seeks to "….*replicate the desirable outcomes of a competitive market*."

It also stated "… *any value that is in excess of DORC is likely to imply pricing of services that will expose the service provider to being by-passed* …." therefore "… *a DORC valuation actually is attempting to measure…the maximum price that a firm would be prepared to pay for 'second hand' assets with their remaining service potential* ...."

The optimisation of the network as part of the valuation process under an ODRC approach would automatically determine whether investment was required:

> *The ODRC is calculated based on the gross current replacement cost (GCRC) of modern equivalent assets, that are adjusted for over-design, over-capacity and/or redundant assets, less an allowance for depreciation…*
>
> *The ODRC of electricity transmission and distribution assets has been described as representing the minimum cost of replacing or replicating the service potential embodied in the network with modern equivalent assets in the most efficient way*

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[1] Optimised Depreciated Replacement Cost (ODRC) and Depreciated Optimised Replacement Cost (DORC) refers to the same methodology, and can be used interchangeably.

possible from an engineering perspective, given the service requirements, the age and condition of the existing assets and replacement in the normal course of business. [2]

The ODRC approach is a widely accepted and well documented methodology with guidelines that have been largely accepted, previously in Australia and New Zealand and more recently in other countries such as Singapore, the Philippines, and other south east Asian countries. These countries are moving towards an ODRC approach to valuing their assets as their electricity market reforms and deregulation requires them to disaggregate their electricity asset bases.

The application of ODRC to the electricity industry in Australia has been inconsistent, with various regulators (notably ESC, IPART and now ACCC) choosing to move to a "roll-forward" approach after the initial application of ODRC to determine the RAB. It is EnergyAustralia's contention that this move has been premature, given the lack of a framework to determine the prudence and efficiency of subsequent capital project expenditure.

More recently, the Australian Tax Office has issued Guidelines for the determination of "fair market value" of assets for the purposes of the consolidation of taxation and financial reporting, and a number of companies have adopted the ODRC methodology for the determination of "fair market value" for these purposes.

The decision to use a roll-forward methodology removed the in-built mechanism that recognised prudent investment at its efficient cost. Instead, the roll-forward methodology requires the Regulator to determine whether an investment is prudent and efficient, and therefore requires an exercise of judgement. In exercising its judgement, the Regulator must establish criteria to help it determine whether the investment was prudent.

The ACCC made its decision to pursue a roll-forward approach without establishing the criteria it would use to determine prudence of investment. For EnergyAustralia and TransGrid whose investments are being judged for prudence, the criteria remained unclear until the release of the ACCC's Draft Determinations.

EnergyAustralia has repeatedly asked ACCC to establish the criteria it would use to determine whether investment has been prudent. EnergyAustralia believes it is inappropriate to apply criteria ex-post and emphasises that the absence of published criteria has made it extremely difficult to determine the information required by ACCC and therefore to debate the appropriateness of investments. EnergyAustralia believes that the assessment of the prudent capex (and indeed the entire revenue cap process) has been equivalent to playing a game with only one team (we assume the Regulator) knowing the rules.

The ACCC's draft decision for EnergyAustralia and TransGrid has at last outlined the criteria the ACCC is using to establish whether an investment is prudent. The ACCC has also outlined its approach to the review. In the case of TransGrid's large portfolio of investments, ACCC has divided capex into categories depending on whether the investment was forecast in 1999 and whether TransGrid has spent more or less than it forecast it would spend on these investments in 1999. In assessing the investments in each category varying depths of examination of efficiency have been carried out.

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[2] Valuation of Electricity Network Assets - A Policy Guideline for New South Wales Distribution Network Service Providers. February 2004. Issued by NSW Treasury.

In contrast, for EnergyAustralia and its smaller investment portfolio, the ACCC has undertaken an in depth investigation of *each* project. This approach has required a far greater amount of detailed information than EnergyAustralia had first envisaged would be required. No explanation has been given as to why every project needed to be assessed and EnergyAustralia suggests that the detail required by ACCC has gone far beyond what would be expected from a Regulator undertaking "light-handed" regulation and indeed has gone far beyond that required by IPART and its consultant (Meritec) in conducting a similar analysis on EnergyAustralia's distribution assets. EnergyAustralia notes that through two consultant's reviews (GHD and Meritec), all of its past capex has been thoroughly examined with <u>no</u> investments found to be imprudent

1.2.1 Impact of GHD's approach

The lack of criteria at the outset of the review also impacted GHD's ability to undertake its review of EnergyAustralia's capex and opex. In the absence of criteria laid down by ACCC, GHD established its own criteria, which it applied to EnergyAustralia's capex. GHD's criteria was not relayed to EnergyAustralia until February 2004, some three months after GHD's review had begun.

The criteria used by GHD are supported by EnergyAustralia. GHD attempted to assess three key questions:

- Was the need for the investment established?
- Did the option chosen address the need in the optimal way?
- Was the project delivered efficiently?

Once this criteria had been made explicit to EnergyAustralia, it was clear that GHD was satisfied with the first two questions, but that more information was required before a view on the third question could be formed.

To put these three criteria into the context of the investment in electricity industry infrastructure, it is a broadly accepted principle that the overall magnitude of capital expenditure to major projects such as substations and transmission lines is made in three distinct phases of the projects, as follows:

1. Project inception – 80%
2. Project design and procurement – 15%
3. Project construction and project management – 5%.

That is to say that 80% of the capital cost of the solution to a constraint of condition is determined at the time of developing the concept plans of the preferred solution, and these costs become "locked in". After that, 15% of costs are determined by the engineering, environment, procurement, and design decisions that are made. By the time that the project arrives at the construction and project management phase, only 5% of the final costs can be influenced by decisions made, including whether certain work should be outsourced or not.

The limited opportunity provided to us to deliver appropriate information to GHD, and the fact that the criteria was made explicit at such a late stage in the review not surprisingly led to GHD not having time to satisfy itself in regard to the efficient delivery of our projects. We were extremely disappointed that ACCC forced GHD to release its final report prior to being able to assess all of the addition information that had been provided to them by EnergyAustralia in response. We question the basis of this approach, given the importance of the report's findings (or lack thereof) particularly in light of the fact that the release date of the report (29 March 2004) was 12 months before the intended release date of the final determination.

1.2.2 ACCC / GHD criticisms unfounded

EnergyAustralia believes it has been made the scapegoat for a process that has not been well managed by ACCC and has resulted in our circumstances being misinterpreted or misrepresented. It is within this context that EnergyAustralia is accused by ACCC (and GHD) of not providing sufficient information and not demonstrating prudence and efficiency of its past and future capital expenditure programs.

It is instructive to compare the ACCC's / GHD's comments with those of IPART's consultant (Meritec), which recently completed a similar review of EnergyAustralia's distribution assets[3]. In relation to the co-operation and level of information provided, Meritec stated:

- *"The willing co-operation and assistance of the DNSPs' management and staff during the course of the review is gratefully acknowledged especially in light of the tight time frames for their responses." (p xii)*

- *"The assistance of [EnergyAustralia] in correcting errors and resolving inconsistencies put the analysis on a sound footing. We acknowledge their assistance during this period." (p 21)*

- *"We obtained from EA information on its documented network planning criteria for sub transmission systems, high voltage distribution systems and low voltage distribution systems. We also asked for and obtained information on the length of planning period assumed in its long-term network planning process. We asked when the criteria had last been reviewed, whether the security of supply criteria were deterministic, probabilistic or both, and what plant rating criteria were applied. EA provided us with comprehensive information in response. We considered the criteria reasonable." (p 47)*

- *"We were provided with data to prepare our own forecast of future demand but, on review of EA's own forecast, noting its comprehensiveness and its use by other outside parties, we concluded that (a) we could not improve on the accuracy of EA's own forecast with the data available to us; and (b) EA's forecast was in our opinion reasonable for the purpose of this review." (p 42)*

- *"We noted that EA's capex covered the full range of network and non-network expenses including the replacement of obsolete gear, installation of new equipment to improve voltage conditions on the network and to meet load growth,*

[3] See Meritec "*Review of Capital and Operating Expenditure of the NSW Electricity Distribution Network Service Providers – Final Report*" September 2003. As commissioned by IPART.

new customer connections, metering and load control equipment, the modification of mobile plant to comply with current requirements and other items." (p 46)

Further, in relation to the issue of whether past capital expenditures were prudent and efficient, Meritec stated:

- *"Our opinion is that, based on the information made available to us and on our own assessment, notwithstanding the comments made above,* ***we had no reason to judge any material component of EA's actual capex during the period FY 1999-2003 imprudent".*** [emphasis added] *(p 47)*

- *"We took the view that the responsibility for ensuring that adequate allowances were made in their 1998 submissions for their non-system capex and other needs lay with the DNSPs and that overruns should have reason. After receiving explanations of the additional expenditures we found no reason to judge the individual project and programme expenditures incurred during the period imprudent.*" *(p 23)*

- *"We reviewed the capex evaluation and approval processes followed from project identification to approval and considered them appropriate for the purpose of this review, noting that they had been reviewed by the PA Consulting Group." (p 48)*

- *"We were asked by IPART to look specifically at the Sydney CBD reinforcement project in terms of whether non-network solutions should have been adopted. The impression given to us by the correspondence we received was that the project might have overrun in either cost or time in a way that might have justified non-network solutions. We were advised that non-network options may have compared favourably with the network solution finally recommended and adopted. To examine this matter we obtained from EA the NERA report of February 2000 on the cost-effectiveness of the options available and noted, as best we could judge, that: the report we received was apparently the most recent in of a number of reports on the subject; under all options the lowest cost options involved network augmentation in the first stage of development; the cogeneration and demand side management options were projected to become relatively more attractive in the second stage of development (relative to the results excluding carbon dioxide emissions) compared to pure network alternatives; and, when subsequent augmentation is considered, it would be important to assess demand side management options in light of any updated information that is available at the time.*

  EA reported to us that its costs on the project were still expected to be substantially in accordance with budget and that the project was running substantially on time. We therefore have no reservations about the project form the standpoint of this review and consider it a desirable addition to the Sydney CBD supply."

EnergyAustralia was also subject to a review by IPART's consultants Burns and Roe Worley (BRW) in respect of asset lives.[4] The desk-top study was supplemented with an inspection of a number of key installations to determine the condition of assets and the rational for applying different asset lives. The report highlighted the very positive aspects of EnergyAustralia's practices and knowledge of its network, as evidenced by the following BRW comments:

- *"…it is BRW view that EnergyAustralia has a comprehensive and through understanding of their asset base. EnergyAustralia has used sound methodologies to determine the age of assets, which have been audited by SKM for the 2002 NSW Treasury Valuation." (p 16)*

- *"Through these maintenance practices EnergyAustralia has gained a detailed understanding of the condition of their assets and specific maintenance strategies have been developed for particular assets." (p 16)*

- *"EnergyAustralia's assets are the oldest in New South Wales and the design reflect[s] this. Most of the substations in the CBD of Sydney are underground and classified confined spaces. A significant part of the system is within the CBD and appropriate design and equipment is used to reflect the need for very high levels of reliability, which EnergyAustralia's system delivers." (p 16)*

- *"BRW accepts that this extension is reasonable and adequately reflects the age profiles and conditions of the EnergyAustralia's assets. EnergyAustralia's knowledge of the rating and the actual loading of the assets in this category [Distribution lines and cables] is comprehensive providing [e]ffective utilisation management … EnergyAustralia's policies, strategies and guidelines for maintenance and life extension for this asset category are comprehensive and effective." (p 17)*

- *"BRW accepts that this extension [of asset lives] is reasonable and adequately reflects the age profiles and conditions of EnergyAustralia's assets. EnergyAustralia's policies, strategies and guidelines for maintenance and life extension for this asset category [Low Voltage Lines and Cables] are comprehensive and effective." (p 18)*

- *"BRW has found that a substantial and impressive effort has been made to determine these lives given the legacy records of previous organisations and the mass of data involved. BRW points out that records of thousands of items of equipment are involved, stretching back over fifty years of installations." (p 22)*

- *"BRW is of the view EnergyAustralia has employed logical and defensible methodologies to determine their asset lives and that no inappropriate biases have been detected." (p 22)*

EnergyAustralia believes that any assertions by GHD or ACCC as to EnergyAustralia's provision of information, knowledge of its network or internal practices are unfounded and inconsistent with recent independent reviews conducted by another Regulator's recognised

[4] Burns and Roe Worley - Review of EnergyAustralia's Asset Lives. Commissioned by IPART as part of the 2004 Review of DNSP Pricing.

experts. The only reasonable conclusion that can be drawn is that the GHD / ACCC believe that some higher level of investment criteria should have been in place. This is not reasonable given that EnergyAustralia was at the forefront of the industry in its practices and that the ACCC had not outlined the criteria against which it would assess prudence and efficiency.

On this matter, the following discussion from Meritec highlights the attention given by IPART as to the importance of setting ex ante investment criteria.[5]

> *"IPART advised the DNSPs in November 2001 that for capex to be judged prudent the expenditure option and its timing should be consistent with good industry practice given:*
>
> - *current and projected capacity;*
> - *current condition of assets and renewal requirements;*
> - *alternatives of contracting for support through demand management and distributed generation (taking into account emerging trends in technology and costs);*
> - *current safety standards for the distribution network and accepted planning standards;*
> - *current and foreseeable policies in regard to factors such as environmental requirements and contestability;*
> - *current demand and reasonable projections for demand; and*
> - *analysis of the risks attached to the above elements.*
>
> *IPART also noted at that time that past experience with prudence tests highlighted that such tests start from an assessment of the quality of, and commitment to, planning and evaluation procedures of the DNSP. It expressed the view that a benchmark for that was 'best practice' within the industry for the planning, provision and utilisation of assets and service standards and that it included the integration of these processes with pricing strategies and 'market testing' for alternatives …*
>
> *We applied our tests in accordance with these concepts. Efficiency was tested by considering the expenditures in accordance with accepted power planning concepts, risk analysis and operational practice: prudence was considered in respect of prior expenditures only, modifying the efficiency approach based on our understanding of the information available at the time and taking account of the particular points noted by IPART above." (pp 5-6)*

Given that the ACCC had not specified its criteria for establishing prudence or efficiency <u>prior</u> to the commitment of capital, it is incumbent on ACCC to adopt a similar approach. To do otherwise is to penalise NSW TNSPs without justification and to significantly increase the regulatory risk faced by TNSPs.

[5] Ibid.

1.3 ACCC INFORMATION REQUIREMENTS

The ACCC has been critical of the information that EnergyAustralia has provided throughout the review. As mentioned above, depending on the approach and criteria used to assess investment prudence, the level of detailed information required can differ substantially. EnergyAustralia argues that the lack of clear information requirements relating to prudent capex at the beginning of the review and the ACCC's inability to detail the criteria it was using has materially effected the success of this review process.

1.3.1 ACCC reliance on 1999 DRP

ACCC has continued to rely on its 1999 DRP as the basis for its review and continues to assert that all the guidance required by EnergyAustralia to deliver the appropriate information was contained in that document. EnergyAustralia rejects this assertion.

The DRP refers to prudent investment in Statement 5.16. It refers to good industry practice, and states that investments that generate revenues that exceed project costs, or that are required on reliability or safety grounds, or that the ACCC is satisfied have system wide benefits should be included in the regulatory asset base. While Statement 5.1 is somewhat informative, it leaves the ACCC with substantial discretion in its interpretation. It does not on any objective analysis, detail information that TNSPs will need to produce in order to justify their investments. This can be starkly contrasted to IPART's "template" approach which set out the information required well in advance of the EnergyAustralia's initial submission being made.

The 1999 DRP contains a list of information requirements to be included in the TNSPs revenue application. However, the information requirements do not relate to establishing prudence of capex.[7] This is due to the fact that the DRP was drafted on the premise that periodic revaluation would occur, and that the prudence of investment would be established via the optimisation process. Therefore when the ACCC moved from the ODRC approach to the roll-forward approach it should have ensured that the necessary changes to the information requirements and policies to facilitate the roll-forward were made.

The 1999 DRP discusses information asymmetry facing the regulator and considers that there is a need to reach a middle-ground in determining the appropriate level of information that should be made available to the Regulator.[8] The DRP goes on to state that the initial TNSP application should not necessarily contain all the relevant information but rather be a starting point for the process from whence the Regulator is able to make further information requests.

EnergyAustralia would suggest that the absence of criteria or clear approach to the review of prudent capex has driven the ACCC to continually seek further information. EnergyAustralia has found this process of information gathering to be time-consuming and has in many cases, resulted in repeated questions asked by their own consultants. EnergyAustralia strongly

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[6] Draft Statement of Regulatory Principles (DRP), May 1999, ACCC, p 63.

[7] The information requirements in the 1999 DRP can be found in Appendix 3 to the DRP. The information requirements relate to: analysis of budgeted versus actual capital expenditure for the previous period, TNSP's estimation of their required revenue path for the next period, and justification of this path on the basis of WACC, CAPM and the asset base, accounting assumptions behind the statements, demand forecasts, details of proposed financing arrangements, and a map of the network. At no point do the information requirements in Appendix 3 of the DRP explain the criteria and information required to demonstrate prudent investment under a roll-forward approach.

8 DRP p 111.

believes that had the ACCC set out the key criteria it was going to use, the key questions it was seeking to answer, the level of source documentation it was expecting, and issued these things some months prior to EnergyAustralia's initial submission being made, the ineffectual process that EnergyAustralia has experienced may have been easier to manage and lead to a reasonable conclusion.

While ACCC has acknowledged that the process undertaken in respect of our revenue cap has been less than ideal, ACCC is still yet to acknowledge that its lack of adequate planning of the review process and advance speculation of the information requirements has fundamentally affected the success of the process.

1.3.2 EnergyAustralia – regulated by two regulators

EnergyAustralia is in an unenviable position of having its single network regulated by two separate regulators. The arbitrary boundary of transmission assets in the Code makes separation of the information for both regulators extremely complex. This complex split of costs impacts capital costs where transmission capital projects have distribution connections and permeates almost all areas of operating costs.

The current definition of transmission assets in the Code removes the option for EnergyAustralia to split its network between distribution and transmission on a voltage basis. This means that identical assets, often in close proximity may be regulated by different regulators depending on whether they are being operated radially or in parallel to other transmission assets. Operating costs that are typically assigned to asset classes must then be split between IPART and ACCC regulatory accounts. Furthermore, asset management strategies that are based on asset classes such as replacement become complex to deliver as an appropriate split must be maintained to ensure correct information is provided to the two regulators.

The complexity of the information split between EnergyAustralia's distribution and transmission business has made it extremely difficult for EnergyAustralia to present information that is clearly reconcilable to information presented to the ACCC in 1999. Furthermore, the fact that EnergyAustralia's 1999 transmission determination was made in such haste (during a six week period in 1999) has impacted on our ability to adequately report against the 1999 determination.

The ACCC has acknowledged the difficulty that EnergyAustralia has in separately recording its distribution and transmission businesses. The complexity is made worse as assets can change classification from distribution to transmission due to changes in the network configuration and operation. In addition, assets which are constructed for the sole purposes of supplying end-use customers, and for reinforcing existing distribution and sub-transmission systems are classified as transmission assets, even though they serve no transmission function. As demonstrated in the Macquarie Park project, the vagaries of large spot loads appearing, and then disappearing, due to the general economic environment and business decisions by third parties, are not uncertainties that any other TNSP operating in the NEM has to deal with.

ACCC has written to EnergyAustralia about the transmission definition and has signalled its intention to find a solution to the dual regulation currently experienced by EnergyAustralia.[9]

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[9] Letter to G Maltabarow, EA dated 6 August 2003.

EnergyAustralia faces significant extra costs due to the dual regulation and is keen to find a solution that allows our business to be subject to a single set of rules and a single regulatory regime. (The additional twelve months that we are undertaking the ACCC review after the final IPART Determination has been released is a case in point).

The current reforms to the regulatory arrangements in the energy sector proposed by the Ministerial Council on Energy present a clear opportunity for the dual regulation of EnergyAustralia's network to be addressed. However, the costs of complying with two different regulatory regimes will not be materially changed by having a single regulator assess both the distribution and transmission aspects of EnergyAustralia's network business. While the move to a national regulatory regime was strongly advocated by EnergyAustralia and seen as a positive development, the fact that there are different regimes that apply to distribution and transmission networks and different Code requirements means that a single regulator on its own will not be sufficient to end the unnecessary complexity of EnergyAustralia's current regulatory framework.

EnergyAustralia hopes that a solution will be found that provides for a single regime to apply to all of EnergyAustralia's network assets.

1.4 ACCC ROLL-FORWARD

The valuation of the RAB is one of the critical elements for determining the future revenue stream for a TNSP. It is also key in determining what incentives to invest, if any, are provided to the TNSPs from the regulatory regime. Given the critical nature of the ACCC's policy position on this issue and its implications for both the long-term investment incentives and the subsequent long-term customer outcomes, EnergyAustralia is deeply concerned with the process undertaken by the ACCC in developing its roll-forward methodology to date.

The ACCC has applied its roll-forward approach to both EnergyAustralia and TransGrid's revenue decisions. The approach adopted by ACCC has not been publicly consulted on, and in fact, has not been the subject of specific consultation with EnergyAustralia. Instead, ACCC has discussed the roll-forward methodology with TransGrid at length and has subsequently applied it to EnergyAustralia. Furthermore, the roll-forward approach has been set out in the draft decision for TransGrid and EnergyAustralia has merely been referred to the relevant chapter in TransGrid's decision. We do not believe it appropriate that ACCC has failed to consult on the framework that will apply to us on the basis that "EnergyAustralia argued for an ODRC approach".

While EnergyAustralia is less than impressed with the lack of consultation, the roll-forward approach adopted by the ACCC appears at first glance to not be unreasonable. However, EnergyAustralia has a number of concerns on specific issues within the roll-forward methodology as discussed below.

1.4.1 Delivery of financial capital maintenance

The ACCC states in the TransGrid draft decision that:

> "The calculation of the closing RAB combined with the subsequent calculation of the Maximum Allowable Revenue in the PTRM must ensure that over the life of the regulated assets, the present value of revenue equals the present value of the sum of

the allowed operating expenditure plus return on and return of capital (discounted at the allowed rate of return)."[10]

In making this statement the ACCC has clearly articulated that the roll-forward calculations must preserve Financial Capital Maintenance (FCM) over the life of the regulated assets.

The concept of maintaining FCM is critical for ensuring that the regulatory regime provides certainty regarding the expected revenues that prudent and efficient expenditure can expect to earn both now and over the life of long term investments. Whilst the ACCC's roll-forward calculations appear to preserve FCM in regards to capital expenditure[11], it does not appear to maintain the same incentives and certainty regarding operating expenditure despite contrary advice having been provided to the ACCC by its own consultant Darryl Biggar. The findings of the paper commissioned by the ACCC from Biggar on this issue are particularly clear as shown in the quote below.

> *"33. In my view the simplest answer to this question is that any legitimate over- or under-spend which the Commission wishes to compensate should be "brought forward" and capitalised into the regulatory asset base."*[12]

EnergyAustralia notes that the framework proposed by ACCC does not exclude present value of past operating expenditure that exceeds that which has been allowed in the determination and can be demonstrated to be both prudent and efficient from being included in the closing RAB. It is critical that the regulatory regime maintains parity between capital and operating expenditure and therefore maintains the overall economic and customer outcome objectives. This highlights but one of the unanswered questions that EnergyAustralia has in regards to the roll-forward.

The choice between investing in capital or operating expenditures to achieve the required service outcomes for customers must remain with the TNSP. By treating one form of network investment "better" than the other the ACCC is imposing a value judgement on the relative value of the types of investment. The TNSP must be provided with equal incentives to invest in either capital or operating expenditures if the regulatory regime is to deliver the optimal economic and customer service outcomes.

If TNSPs are not afforded such incentives, their investment decisions will be skewed towards capital investments regardless of the relative customer and economic benefits that may otherwise be available from opex.

EnergyAustralia is not proposing that the regulatory regime should be changed to a cost-plus framework. However, EnergyAustralia is advocating a framework that provides enhanced incentives for operating expenditure investment in two ways:

1. The ACCC's Determination should set ex-ante operating expenditure targets that provides the TNSPs with incentives to extract efficiencies and thus achieve outcomes better than those forecast, which can then be shared with customers in future periods; and

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[10] ACCC, NSW and ACT Transmission Network Revenue Cap – TransGrid: Draft Decision, p 41.
[11] This statement relates purely to the mathematical calculations used in the roll-forward, and does not necessarily relate to the ACCC's decisions regarding the prudence or efficiency of past capital expenditure which is discussed below.
[12] Darryl Biggar, Approach to depreciation and treatment of asset base roll forward and total revenue, 23 October 2003, p 6.

2. The regulatory regime should provide ex-post protection against unforseen circumstances that require the TNSP to invest more operating expenditure than initially forecast and that this additional operating expenditure should be included in the RAB at its present value. It is of course essential that the TNSP can demonstrate that such expenditure was prudent and efficient in the circumstances, and should take into account any trade-offs that have occurred between capital and operating expenditures.

When used in conjunction the two aspects of investment incentives described above provide the TNSPs with the incentives to seek efficiencies where possible. However, it also ensures that TNSPs are not penalised for maintaining their infrastructure at a level consistent with expected customer outcomes, despite potential forecast errors or unforseen events occurring.

EnergyAustralia submits that the ACCC review its calculation of the roll-forward to explicitly include the present value of all efficient and prudent capital and operating investments made by EnergyAustralia regardless of the level that was allowed in the 1999 Determination.

1.4.2 Asset Lives

EnergyAustralia is concerned that the ACCC appears to have adopted a purely mathematical approach to determining the remaining lives of assets instead of EnergyAustralia's proposed asset life estimates.

As part of the normal accounting requirements and indeed good asset management principles, EnergyAustralia reviews the assumptions of remaining economic life of its assets at least every 5 years. This review takes into account information that is gathered over the period that may impact the expected remaining life of its assets.

The types of information that EnergyAustralia is gathering and uses in its assessment of the remaining economic lives of its assets includes:

- asset condition;
- experiences with specific technologies including, equipment behaviour in specific circumstances and resulting failure modes;
- environmental changes and impacts on asset condition over time;
- changes to legislative or environmental requirements that impact on the viability of specific technologies;
- the ongoing costs to maintain the assets in operating condition; and
- potential for economic stranding.

In regard to the distribution review undertaken by IPART, EnergyAustralia used this information and provided IPART with revisions to the expected economic lives of its assets. Generally, these lives did not accord with the lives that would be calculated from rolling-forward the weighted average remaining lives for the opening RAB and new capital expenditure.

Indeed, EnergyAustralia's assessments generally resulted in extensions in the assumed remaining lives for its asset categories, although there were some reductions for specific categories. IPART engaged BRW to review EnergyAustralia's approach and the subsequent proposals. With one exception BRW agreed that EnergyAustralia's revisions to the assumed remaining life of its assets were appropriate.

> "*BRW accepts that this extension is reasonable and adequately reflects the age profiles and conditions of the EnergyAustralia assets. EnergyAustralia's knowledge of the rating and the actual loading of the assets in this category [Distribution lines and cables] is comprehensive providing [e]ffective utilisation management…EnergyAustralia's policies, strategies and guidelines for maintenance and life extension for this asset category are comprehensive and effective.*"[13]

EnergyAustralia believes that this approach is important for ensuring that inter-generational equity is preserved and that the TNSP is able to recover the full economic cost of the assets by the end of its economic life. It should be noted that revisions of the economic lives of assets do not impact on the value of those assets under the roll-forward methodology, merely the time period over which the remaining asset value is recovered.

EnergyAustralia submits that the ACCC should ensure that the assumed remaining economic lives of assets included in the opening RAB are based on the most recent asset information that is available, as was accepted by IPART, and not simply the application of a mathematical formula.

1.4.2 Penalties for "unproven" efficiency in capital expenditure

The ACCC has stated in its draft decision that, for capital expenditure projects where efficiency has not been demonstrated, it will disallow any return on the investment during the relevant period of construction. Although EnergyAustralia has significant concerns regarding this approach, as detailed in the historic capital expenditure chapter below, it is also disturbing that the calculations used by the ACCC in arriving at the closing RAB do not reflect the stated decisions on this matter.

Further EnergyAustralia submits that the modelling approach adopted by the ACCC generates errors that result in an understatement of EnergyAustralia's RAB in the order of $6.5 million. The sections below discuss the ACCC's current modelling approach, and the approach that EnergyAustralia believes is required to align the calculations with the draft decision.

The ACCC's modeling approach

In a calculation exogenous to the roll-forward model, the ACCC determines a percentage reduction for investments where it feels that efficiency has not yet been demonstrated. This percentage reduction is then brought into the roll-forward model.

The percentage reduction is then applied to the total capitalised value for the specific project. In other words the ACCC discounts both the return on capital and the initial capital investment in the calculation of the roll-forward RAB. The ACCC's approach leads to the removal of $13M in actual capital expenditure, and $7M in associated returns, resulting in a total reduction in the RAB of $20 million.[14]

This approach does not make intuitive sense, and furthermore does not reflect statements made by the ACCC in its draft decision such as,

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[13] Burns and Roe Worley – Review of EnergyAustralia's Asset Lives. Commissioned by IPART as par of the 2004 Review of DNSP Pricing.

[14] Ignoring any adjustments for the Homebush project, which is to be examined separately.

"the ACCC considers that EnergyAustralia has failed to provide sufficient information to demonstrate that these projects were efficient investments. Without sufficient information the ACCC is unable to ascertain an efficient level of expenditure for these projects; therefore, the ACCC's draft decision is to also disallow any return on EnergyAustralia's investment in these projects during the period of construction for the draft decision."[15]

EnergyAustralia therefore undertook its own modelling, based on the approach described in the draft decision, to assess the accuracy of the ACCC's modelling. EnergyAustralia's modelling approach and results are set out below.

EnergyAustralia's modeling approach

Rather than attempting to arrive at overall percentage rate as calculated by the ACCC, EnergyAustralia separated the various capital costs into discrete elements:

- Actual capital expenditure – this amount is rolled into the RAB in its entirety; and
- Allowed return on investment – only those investment projects where efficiency has been deemed to have been demonstrated is allowed a return using the "return on overspend" mechanism in the ACCC model.

By separating out the return on capital from the underlying investment the application of the penalty adjustments as described by the ACCC in the draft decision becomes transparent and repeatable.

Using this information EnergyAustralia's modelling reduced the return on capital to zero for those specific projects where the ACCC had deemed that EnergyAustralia was yet to prove were efficient. Using this approach to modelling the adjustment reflects clearly the ACCC's intentions as described in the draft decision.

When all of the capital expenditure and the return on capital for "efficient" projects is included into the roll-forward calculations, it is clear that the RAB should only be discounted $13.5 million based on the ACCC's decision; $6.5 million less than calculated by the ACCC.[16]

EnergyAustralia's modeling recommendations

As previously stated EnergyAustralia does not support the current approach taken by the ACCC to address concerns of inefficient capital investment. However, should the ACCC persist with such an approach EnergyAustralia submits that the ACCC must review its financial modelling in light of EnergyAustralia's findings to ensure that the decision taken by the ACCC is actually reflected in its financial modelling.

1.5 NEW CAPEX FRAMEWORK

The review of the DRP has heightened the uncertainty implicit within the regulatory framework. However, the discussion paper released by ACCC raised very few new issues. Instead it put

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[15] ACCC, NSW & ACT transmission network revenue caps – EnergyAustralia: Draft decision, 28 April 2003, p 40.

[16] Ignoring any adjustments for the Homebush project, which is to be examined separately.

the ACCC's position on several issues on the public record. Previously, many of the policy decisions that were included in the DRP discussion paper had been implemented in other determinations.

In contrast, the late inclusion of a fundamental review of the capital investment framework has been a very new and revolutionary development. The ACCC's proposal to set a firm ex-ante cap for capital expenditure is highly controversial and in EnergyAustralia's view is not appropriate for transmission investment.

1.5.1 EnergyAustralia's submission to ACCC on investment framework

In its submission on the issue, EnergyAustralia put its strong view that ACCC has not made a case for a fundamental review of the capex framework and that the review of the capital framework has been an extreme reaction driven, at least in part, by the problems experienced in the current NSW reviews.

EnergyAustralia explained its disappointment that the ACCC had stated in various forums that the over-spend in NSW on transmission capex has prompted it to rethink the framework. EnergyAustralia believes that spending capex over the amount allowed in the initial determination does not signal a failure of the framework. Nor is the over-spend in itself a reason to disallow investment on the grounds of it being imprudent of inefficient. Instead, it is likely to be the result of a range of factors including the robustness of the initial forecasts, the accuracy of forecast demand growth in each geographic area, movements in GDP, changes to regulations, application of conditions on planning approvals, environmental considerations and the experience of utilities in responding to regulatory regimes.

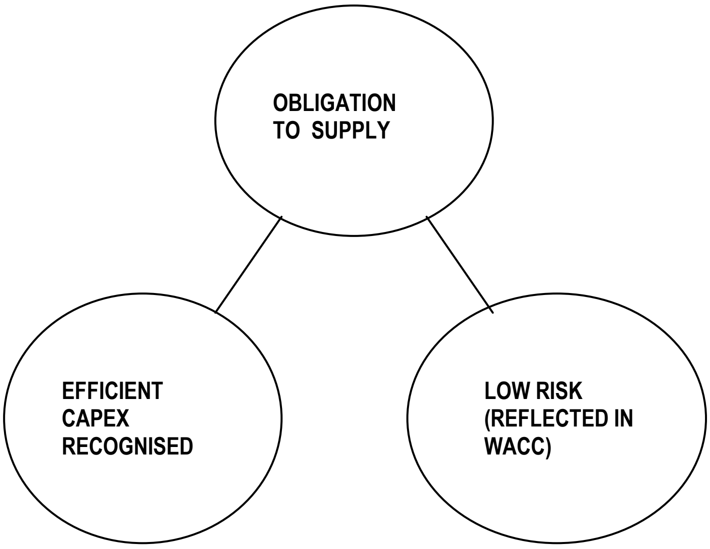
EnergyAustralia argued in favour of the existing framework as it has the potential to be both flexible and to allow circumstances that vary from initial forecasts to be taken in to account. Given the myriad of factors that can influence out turn costs for transmission investments, particularly in densely populated areas such as Sydney's metropolitan area, EnergyAustralia believes the existing framework (with some adjustments) is more appropriate than a firm ex-ante cap.

The fundamental philosophy of monopoly regulation in Australia and overseas has for many years revolved around three co-dependent (and necessary) conditions:

- An obligation to supply (backed up by rigorous reliability requirements)
- An understanding that prudent and efficient capital investments will be recognised
- Consequently a low risk business environment, and hence WACC with relatively low risk weighting.

This is illustrated below, showing the links between the three conditions, and hence why it is not reasonable to alter one of these conditions in isolation.

Figure 1 - Philosophy of monopoly regulation



Imposing an ex-ante capital cap 5 years in advance effectively negates the second of these conditions. Where capital investments above what was anticipated 5 years in advance are required to satisfy the obligation to supply,[17] TNSPs face the risk that these investments will not be recognised. Either the obligation to supply must be relaxed,[18] or the risk profile of the TNSP is significantly altered, and the very low risk WACCs applied in the past will no longer be appropriate.

Commercial entities manage the allocation of capital in response to dynamic market conditions, with both the size and priority of capital allocations subject to constant changes in the business environment. Well run businesses do not lock in the overall level or specific items of capital expenditure 5 years in advance (nor would be able to forecast within the error bands being sought by the Commission and GHD), and it is unreasonable to impose such requirements on TNSPs that also face dynamic market conditions.

This situation is exacerbated when the ACCC or its consultants reviews and adjusts the capital forecasts submitted by a TNSP. In effect the Commission has assumed planning and capital budgeting responsibility, while the TNSP retains the obligation to supply and risk that unanticipated capital expenditures will not be recognised. This is clearly an unreasonable and unsustainable environment to expect TNSPs to operate under and continue to invest in reliable transmission links vital to the economy.

EnergyAustralia has acted in good faith in determining its capital forecast for this and other previous regulatory submissions. Our capital forecast represents its best estimate of its capital requirements over the coming 5 years, without inflation for unforseen events. In this regard, it

[17] Networks business are also obligated to meet (changing) environmental and OH&S requirements, which can become drivers for capital investments in their own right, or affect the acceptable design and hence cost of other capital projects.
[18] Most commercial entities do not face an obligation to supply. Where they are capital constrained, or supplying marginal peaks in demand is not considered attractive, they can choose to limit supply (through availability, pricing, or other means). Regulated TNSPs are obliged to supply all new loads, and provide sufficient capacity to meet the highest expected peaks in demand.

can be considered a likely outcome, rather than the expected value for each aspect of the program when taking into consideration the probability of all potential events occurring. It is therefore necessarily a lower value. It is also based on current health, safety and environmental requirements, and does not build in risk weighting for future legislative change. Under the existing capex framework, this is considered a reasonable approach, but relies on good faith and reasonableness from regulators at subsequent reviews to recognise unforseen capital requirements.

A firm cap on allowable capital expenditure also dramatically increases the incentives for networks to attempt to “game” their capital forecast. Under the current regime, forecasting errors may result in marginally higher or lower allowed revenue for return on capital during the subsequent regulatory period, though with an expectation that there would be an NPV adjustment at the next reset if this amount was material. Under a firm cap, every marginal dollar included in the forecast will affect allowable revenue for up to 50 years, introducing a strong incentive to push up the forecast. This does not assist the ACCC nor TNSPs, and only serves to raise the stakes in the inevitable TNSP vs consultants review of reasonable capital forecasts. As stated in tis submission on the review of the Draft Statement of Regulatory Principles (and as referred to in our discussion of operating expenditures), EnergyAustralia’s approach to this regulatory “game” is to refuse to play. We hope that such an adversarial regulatory environment is not institutionalised.

EnergyAustralia argued that the criteria for changing the capital investment framework needs to refer to the certainty of investment, and the flexibility of allowing a business to innovate and choose the most efficient project, rather than be based on the regulator’s desire to minimise infrastructure investment overall or minimise resources required to regulate it. EnergyAustralia does not believe that a new framework is the only way to address perceived problems with the current ex-post review and given the largely untested outcomes of the current framework, we believe it is too soon to make wholesale changes. EnergyAustralia argues that the costs of poor and inflexible regulatory decisions that could take place under an inflexible firm ex-ante cap are likely to far outweigh the costs of regulation under the more flexible ex-post framework. EnergyAustralia argues that it is also appropriate to evaluate regulatory costs against the cost of regulatory failure which could have significant societal impacts if investment is inappropriately discouraged.

EnergyAustralia drafted a comprehensive response to the ACCC’s call for submission in relation to its capital investment proposals. To avoid repeating all of the other issues raised in that document, we refer the reader to our submission, which should be available on the ACCC’s website.

In conclusion, EnergyAustralia does not believe that a new capital investment framework is necessary, and believes that the one put forward by ACCC contains serious flaws that have the potential to undermine any perceived benefits of changing the framework. While supportive of discussion of framework issues, EnergyAustralia would again question the manner in which the issue has been raised and the timing for its review. EnergyAustralia strongly contends that while framework issues are debated, they should not be applied until such time as a final policy decision has been made. To apply policies before this point increases the regulatory risk faced by TNSPs and unnecessarily increases the uncertainty of the regime being applied.

It should be noted that EnergyAustralia has, at the ACCC’s request, agreed to assist the ACCC in further development and refinement of its ex-ante capex framework. The purpose of this agreement is to explore whether such a framework could be made appropriate for

EnergyAustralia's circumstances. While EnergyAustralia has agreed to assist the ACCC, we have reserved our judgement as to whether we will choose to have the new framework applied to EnergyAustralia's transmission business in the 2004-2009 period.

1.6 NEW SERVICE STANDARD REGIME

The ACCC has had an ongoing investigation of service standards and the role service standards should play in the regulatory framework. SKM's report helped to establish service standard guidelines which were released in November 2003 and which set a common set of measures whereby TNSPs performance could be compared against each other and against set targets.

The ACCC has applied these guidelines in its draft decision for EnergyAustralia and has set a target for the relevant service standard measure. One percent of revenue has been placed at risk to incentivise EnergyAustralia to meet the target service standards. A failure to reach or beat target levels will result in a penalty up to one percent of EnergyAustralia's transmission revenue.

ACCC has recently canvassed a more sophisticated service standard regime that would link market outcomes to TNSP service standards. While this issue is in its early stages of development, it represents a further development of the framework and creates yet further uncertainty.

From EnergyAustralia's perspective, it is unclear how service standards being linked to market outcomes is likely to impact our transmission business, particularly as EnergyAustralia does not control interconnecting assets. Furthermore, EnergyAustralia's transmission assets do not impact the market dispatch of generators within NSW under first order conditions and therefore does not contribute to NEM market outcomes per se. Given the uncertainty of the new service standard regime and its application to us, our comments relate merely to the decision to change the regime again before the existing regime has had time to be bedded down.

While EnergyAustralia welcomes the concepts of continued evaluation of the regime, it is difficult to understand the behaviour changes that the ACCC is seeking to deliver through its regime change. At this point, it appears that establishing modes of operation that respond to the old regime appear to be of short term value only given that the regime itself may change again soon.

1.7 DEROGATION

The uncertain framework surrounding the ACCC's revenue cap reviews has obliged the ACCC to delay the finalisation of the revenue caps until the review of both the DRP and the future capex framework has been completed. This has had the effect that neither TransGrid nor EnergyAustralia will have final determinations in place until April 2005.

The ACCC had previously indicated that TransGrid and EnergyAustralia should set prices on the basis of its draft decision, which was released in May 2004. TransGrid and EnergyAustralia were concerned that the Code does not envisage prices being set on the basis of a draft decision, and that it does not provide the ACCC with the ability to make its final decision retrospectively. This has financial implications for EnergyAustralia and TransGrid in terms of allowing recovery of any revenue difference between draft and final decisions, and has implications for the term of the ACCC's decision.

To address these issues, the NSW Minister for Energy and Utilities has sought a derogation under Chapter 9 of the National Electricity Code on behalf of TransGrid and EnergyAustralia to address the legal problems caused by the absence of a final determination. The purpose of the derogation is to provide a firm and legal basis upon which transmission prices will be set in the absence of a final determination. The derogation will also allow the ACCC's final decision to take effect for a period of five years beginning on a date prior to the date of its final decision.

The ACCC has acknowledged the benefit of the proposed derogation and has granted interim authorisation to ensure that it takes effect prior to 1 July 2004. While we acknowledge the ACCC's cooperation on this matter, we nonetheless are disappointed that the ACCC's process did not accommodate a final decision by 1 July 2004, thereby requiring TransGrid and EnergyAustralia to seek such a remedy.

HISTORIC CAPEX

This section addresses the ACCC's comments made in its draft determination in relation to capital expenditure that occurred during the 1999-2004 regulatory period. Expenditure must be deemed prudent and efficient by the ACCC before it will allow the expenditure to be included in the regulatory asset base, and thereby allow EnergyAustralia to receive a regulated return on that investment.

EnergyAustralia has provided extensive information to the ACCC and to the ACCC's consultants in regard to transmission projects built in the 1999-2004 regulatory period. The ACCC believe a number of information gaps remain. EnergyAustralia is committed to providing sufficient information to ensure that the projects built during the 1999-2004 period are recognised as prudent and as having being delivered efficiently.

EnergyAustralia explained in its original submission that the documentation and governance procedures used during the 1999-2004 period could be improved, and therefore, a significant project is under way to improve the transparency and accountability of investment decisions made in both our transmission and distribution network businesses. The new governance process has been developed over a number of years and is due for implementation in the next few months.

The ACCC commented in its draft determination that it had seen very little evidence that EnergyAustralia's new governance program had been applied. This is not surprising as the new governance procedures were never intended to apply in the 1999-2004 regulatory period. This point was made clearly in our submission to IPART and represented part of our contribution to ensuring greater investment certainty going forward. It is EnergyAustralia's intention that all investment decisions made in the 2004-2009 will be consistent with the new governance procedures.

In its report, GHD made a number of comments regarding the relatively weak systems that EnergyAustralia had in place at the beginning of the regulatory period that could have reduced EnergyAustralia's decision making ability. While EnergyAustralia acknowledges that better systems will improve EnergyAustralia's ability to respond to information requests more quickly, we make the following observations. First, the state of our systems was known when the 1999 Determination was established and no requirements relating to system improvements were laid down by ACCC in the intervening period. Second, EnergyAustralia believes that these statements represent an ex-post attempt to change the rules after investments have been made.

EnergyAustralia does not believe that the investment decisions made during the past regulatory period have been poor. On the contrary, EnergyAustralia's technical staff remain at the forefront of their field and the decisions made by these experts have consistently stood up to scrutiny by both IPART and ACCC and their relevant consultants. Furthermore, EnergyAustralia does not accept that our systems and processes are of a lower standard than those of other Australian TNSPs.

EnergyAustralia remains committed to improving its IT systems to ensure greater transparency of decision making and of asset information in the future. IT improvement is a significant driver of non-system expenditure in the next five years. Therefore, it is very disappointing that the ACCC has made arbitrary cuts to the proposed IT program for the next period given the strong criticism it has made of current systems. This issue is discussed in more detail in the opex section of this submission.

The information included in the next sections responds to the ACCC's comments made in its draft determination in relation to specific projects that were constructed in the 1999-2004 period where the ACCC has identified information gaps. EnergyAustralia has not commented further on projects where the ACCC has indicated it is satisfied with information provided to date.

The next two sections outline general errors made by ACCC in drafting its draft decision. Project specific information then follows.

1.1 SKM INDEPENDENT REVIEW OF PROJECT EFFICIENCY

EnergyAustralia has requested that Sinclair Knight Merz ("SKM") review and comment on the draft ACCC determination with respect to historical capital expenditure on a number of EnergyAustralia projects. The findings of this analysis are presented in Attachment 2.

In undertaking this review, SKM has referred to the GHD assessment of these projects, per the GHD report titled "*EnergyAustralia Regulatory Review – Capital Expenditure and Asset Base, Operational Expenditure and Service Standards*" dated March 2004. In particular, EnergyAustralia has requested advice from SKM, as to issues of capital efficiency associated with the following projects:

- Macquarie Park 132/11kV substation,
- Beresfield 132/33kV STS and associated works,
- CBD augmentation associated with Haymarket 330/132kV substation, and
- Homebush 132kV cable replacement.

It is understood that there is general acceptance by ACCC and GHD that the justification for, and the timing of, these projects was appropriate given the magnitude and nature of the various system constraints and overloading that might occur on the EA system under contingency situations. The advice sought by EnergyAustralia from SKM was whether the scope and capital cost of the solutions implemented may reasonably be considered to be "capital efficient" solutions.

It is SKM's findings and conclusions that:

- The Macquarie Park 132/11kV project was selected as the least cost (NPC) option from six alternatives that represented the most likely technically and economically viable scenarios. The final project cost of $20.49 million ($12.0 million allocated as transmission) was comparable with the original Board Approval of $14.25 million (plus 132kV cable cost approved by the EnergyAustralia Board at $5.3 million). The transmission component of $12.0 million of the final costs compare favourably with the benchmarked industry costs of $16-17 million (excludes 11kV feeder works).
- The Beresfield 132/33kV STS project is currently timed for 2005, which is somewhat overdue by all reasonable electricity industry planning standards. The preferred option has been selected as the least cost (NPC) option of the three logical solutions. As each stage of project authorisation has been reached, EnergyAustralia has reviewed the NPC comparisons to validate the preferred option. The extent of concept design information, preliminary designs and estimates, and estimated costs for the various stages of the

project are as good as one would expect for this type of project, given the vagaries of public consultation processes. SKM is of the view that the approvals process, and staged authorisations, documentation and regular review of NPC's of alternatives represents a "Model Case Study for the Corporate Governance of Capital Works Projects".

- The Homebush Bay 132kV overhead transmission line undergrounding was undertaken in 1998 and 1999 at the request of the Olympic Coordination Authority, who contributed most of the $37 million cost of the project, with EnergyAustralia contributing the remaining $10 million. It appears this project was not necessary for electrical / network reasons, and delivers little benefit to electricity consumers during the period of the remaining life of the overhead lines that were replaced. Some of these lines were, however, apparently in poor condition and may have required replacement around 2005 anyway, with the others expected to remain serviceable until 2015. It appears reasonable that the (depreciated) cost of the new underground assets be included in EnergyAustralia's regulatory assets from the date when replacement of the old assets would have been necessary.
- The CBD Haymarket / Campbell St project was initiated to add new transmission capacity to the Sydney CBD and inner suburbs required by 2004 to maintain supply reliability and cater for strong load growth. The expected cost of delivering the CBD substation and transmission projects of approximately $94 million are significantly above initial estimates and the $46 million[19] cost used in the 1999 regulatory test. The overruns are mostly due to underestimating the actual costs ($34.8 million), followed by externally imposed scope changes ($9.3 million).

  In general, the selected option and project costs appear reasonable for an undertaking of this nature in a dense CBD location. While noting a formal re-evaluation of project alternatives was not undertaken, SKM suggests it is likely EnergyAustralia would have experienced similar increases in most of the other options, as the variation has been shown to be overwhelmingly due to systemic underestimating of costs. The final delivered cost of the project appears reasonable, and it can be expected that the competitive procurement processes that applied to over 80% of costs would deliver efficient market prices for those items.

On balance, SKM considers the costs for Macquarie Park, Beresfield, and the CBD projects are likely to be efficient. In each case the lowest cost option from a suite of alternatives has been chosen, and the costs for project delivery appear to be in line with independent estimates.

For Homebush, SKM considers the undergrounding project was not required in 1998 for network reasons, and customers should not fund the costs of undergrounding while the existing assets would have remained serviceable. EnergyAustralia estimates that one of the three tower lines would have required replacement at around 2003 (15% of the total cost), while the remaining two tower lines would have required replacement at around 2015. On this basis, it would appear reasonable that the depreciated value of the replacement assets (less capital contribution) be included in the regulated asset base from the date when they would otherwise be required. This implies 15% of EA's costs should be included now (depreciated by 6 years), with the remaining 85% included from 2015 (depreciated by 17 years).

[19] Slightly different cost estimates are quoted in different source documents, reflecting incremental changes in the design and costing of the project as it was developed.

Finally, SKM notes that while EnergyAustralia has a number of assets that are classified as transmission, their characteristics in terms of planning, function, and utilisation much more closely resemble distribution assets than transmission assets. Variability and uncertainty in local network loads will be significantly higher than those experienced in the backbone transmission network where there is much greater diversity of loads. Individual projects can be expected to vary in cost, timing and scope to a much greater degree than traditional transmission assets, and this should be considered an inherent characteristic of electricity (particularly distribution) networks. As EnergyAustralia's long term strategy of 132kV sub-transmission is gradually realised over the coming decades, and EnergyAustralia's 132kV network becomes increasingly meshed, there will emerge an issue of "classification creep", where significant amounts of assets providing an essentially distribution function will be classified as transmission. This will require either a more flexible approach to transmission regulation, or a definition that better classifies these assets as distribution.

1.2 ACCC ERRORS IN RECORDING PAST CAPEX

ACCC has made several errors in its summary of EnergyAustralia's capex allowance in 1999-2004 and subsequent comparisons of actual and predicted capex.

Table 3.2 in the ACCC's draft determination does not contain an allowance for the Haymarket project and understates the substation replacement allowance by $1m. Correct details are shown below.

Table 1 - Correct representation of EnergyAustralia's past capex

	Total 1999 – 2004	1999 -00	2000 -01	2001 -02	2002 -03	2003 -04	2004 -05
Load Growth							
Uprate Feeder 910 & 911	**10**	3	7				
Tuggerah-Munmorah Feeder	**3.5**	3.5					
Ourimbah-Gosford feeder	**7**	0.2	0.3	4.5	2		
Sydney Central connections	**25**			5	15	5	
Other	**0.9**	0.2	0.1	0.2	0.2	0.2	0.2
Replacement							
Replacement Mains	**24.9**	3.2	6.7	7.1	5.9	2	2.5
Replacement Subs	**8.7**	1.2	1.5	2	2	2	1.9
Total	**80**	**11.3**	**15.6**	**18.8**	**25.1**	**9.2**	**4.6**

It should also be noted that an allowance of $10m for Macquarie Park substation was contained in the 1999 IPART submission. EnergyAustralia consider that reference to the inclusion of Macquarie Park in the IPART determination would be appropriate.

1.3 CAPITAL EXPENDITURE "EFFICIENCY" PENALTY

EnergyAustralia believes that the arbitrary efficiency penalty reduction applied by the ACCC to some of EnergyAustralia's projects is fundamentally flawed, inconsistent with the requirements of the Code and arguably beyond power. The approach raises significant concerns at the potential for "black box" regulation and unsustainable levels of regulatory risk.

The ACCC recognises that the approach adopted in the draft has no basis in economic theory.

> *"The ACCC notes that there is nothing sacrosanct about disallowing the full return on investment, it could just as well be half the return on investment or even twice the return on investment."*[20]

Despite this admission of the arbitrariness of the ACCC's policy, it has still adopted the approach as a simplistic penalty and has not even provided a basis or context in which to justify the adjustments it has imposed.

EnergyAustralia is very concerned that the penalty has been applied without any direct relationship being developed between the penalty and the allegedly inefficient levels of expenditure. Hence it can not be demonstrated that the magnitude of the penalty is commensurate with any degree of actual inefficiency, particularly as the ACCC has yet to determine that inefficiencies in expenditure actually exist. Therefore, the penalty being applied by the ACCC appears to have been imposed on the basis of the presumption of "guilt" rather than the actual demonstration of inefficiencies. EnergyAustralia submits that the ACCC's decisions on this aspect should be based on proper and relevant consideration, known facts and expert opinion and advice, not mere presumptions or arbitrary assertions.

A more appropriate administrative process and economically sound assessment for such issues must be adopted in the final determination if the regulatory regime is to meet the ACCC's objectives and obligations under the Code. The section below sets out EnergyAustralia's views on what it believes is a more appropriate and robust approach to conduct the review, and how any subsequent adjustments should be managed and calculated for inclusion in the final determination.

Clauses 6.2.3(4)(iv) and 6.2.4(c)(5) of the Code operate to impose a very clear obligation upon the ACCC to ensure that its revenue determination delivers a fair and reasonable risk-adjusted cash flow rate of return on efficient investment, including sunk assets. The proposed capital expenditure "efficiency" penalty is directly contrary to this obligation because it imposes a penalty in relation to "inefficient" investment without determining what level of investment would have been efficient and in fact denies part of the appropriate return on efficient investment.

EnergyAustralia submits that the ACCC's decision on this issue must be consistent with the above provisions of the Code and based on proper and relevant considerations including known facts and expert opinion and advice, not mere presumptions or arbitrary assertions

Further, this assessment must take into consideration the degree to which the costs of the project are attributable to the market conditions and prices prevailing at the time the project was being undertaken for competitively sourced components etc. Should this assessment determine the existence of inefficiencies in the project design or delivery they must be fully quantified to ensure that EnergyAustralia is able to recover the costs associated with efficient capital expenditure as foreseen by the Code.

Once the efficient level of capital expenditure is determined EnergyAustralia submits that the financial modelling should be changed such that expenditure for the project in question is restated at its efficient level. Therefore if the capital expenditure included in the ACCC's financial modelling is the efficient expenditure, EnergyAustralia would expect that the return on

[20] ACCC, NSW and ACT Transmission Network Revenue Caps – TransGrid 2004/05-2008/09, p 61.

capital calculations would be corrected to ensure that the full return on that expenditure is recognised, including interest during construction, and that these costs would be included in the opening RAB.

1.4 SYDNEY CBD AND INNER SUBURBS AUGMENTATION

The CBD and inner suburbs augmentation is a joint project between EnergyAustralia and TransGrid. The project is a significant upgrade to the security of supply and to the capacity supplying the CBD and inner metropolitan area. The CBD project was forecast in the 1999 Determination. However, a number of changes to the project have occurred since its inclusion in 1999 which makes the assessment of prudence more complicated.

EnergyAustralia and TransGrid commissioned NERA to assist with running the Regulatory Test for this project. NERA found that the Haymarket 330kV augmentation in 2003/04 was the least cost investment as a first stage.

ACCC believes that EnergyAustralia has justified the need for the CBD project and that under the Regulatory Test, EnergyAustralia's capital expenditure would have only increased had another option been selected. The ACCC has therefore accepted the costs as put forward in the Regulatory Test.

ACCC is naturally concerned at the significant increase in cost of this project. However, ACCC has noted a number of factors that contributed to the change in scope and cost of the project including the need for a new site for the substation, the decision to use a tunnel rather than pit and duct style cable installation, and some minor changes in cost due to additional feeder bays. These issues are discussed in further detail in the following sections.

1.4.1 New substation site

At the time the Regulatory Test analysis was conducted, it was believed that EnergyAustralia would build a substation in the Surry Hills area. However, no site had been identified at that stage.

EnergyAustralia entered into an agreement with TransGrid to exchange a site in Goulburn Lane, Surry Hills for the Haymarket site which TransGrid subsequently used but was at that stage owned by EnergyAustralia. This agreement was conditional on EnergyAustralia receiving planning approval for the development of this site. However, approval for use of the site at Goulburn Lane was not forthcoming.

The Lord Mayor of Sydney undertook to coordinate ministerial discussions on an alternative proposal for siting the substation in conjunction with the creation of a park on land previously occupied by the Sydney Police Centre car park. It was agreed that EnergyAustralia would purchase a portion of the site, adjacent to the Police Centre for the construction of the Campbell Street substation. The Sydney City Council agreed to purchase the balance of the site for redevelopment as a park.

The EnergyAustralia purchase price for the site was $8m. This was $3m higher than the original cost of the Goulburn Lane site.

The Campbell Street site was slightly larger and allowed better access for tunnel construction equipment. Given the proximity of the Campbell Street site to Goulburn Lane (one city block), EnergyAustralia believes that the subsequent changes to cable route did not materially impact on the costs of the cable or the tunnel.

1.4.2 Tunnel construction versus pit and duct

As part of the joint CBD project review by EnergyAustralia and Transgrid, GHD were engaged to “assess and evaluate the alternatives of providing underground access for the installation of 132kV circuits between the nominated locations in the CBD area.” Their report “ Goulburn Lane Project, Cable Access Route – Feasibility Study” dated December 2000 investigated in great deal a range of options for the cable access system, including pit and duct, direct burial, accessible tunnel, directional drilling, overhead cables, and various combinations of them all.

The GHD report noted (p2) that :

“The recommended scheme to be documented for tender purposes is therefore the accessible tunnel option for Sections 1, 2 and 3 with provision for an alternative offer of a pit and duct system for Sections 2 and 3.”

The budget estimate for the preferred option (tunnel) was $40.5M (excluding the ductline, cable supply/ installation in Transgrid tunnel, commissioning and internal EA costs, and substation works.)

1.4.3 Additional feeder bays and other factors

The initial regulatory test submission provided four feeder bays at Campbell Street. These were allocated to provide the following connections:

- Campbell St-Beaconsfield- (Beaconsfield-Haymarket Interconnector)
- Campbell St –Haymarket - (Beaconsfield-Haymarket Interconnector)
- Campbell St – Double Bay - (replaced existing connection)
- Campbell St - Surry Hills - (replaced existing connection)

It was subsequently decided to increase the available connections from Campbell St to cater for connection of a future CBD zone substation and to provide an additional 132kV connection to Surry Hills subtransmission substation. The work involved an additional feeder bay at Campbell St and installation of about 500m of additional cable through the proposed tunnel. The cost of this work ($350k GIS bay and $530k feeder) was relatively minor and represents an advancement of future work rather than additional work.

EnergyAustralia considers that the additional feeder bay represents appropriate future planning. A more detailed explanation can be found at Attachment 5.

1.4.4 SKM Review of CBD Project.

EnergyAustralia has asked SKM to review at a high level the overall scope, system design, and final costs of the CBD augmentation project. Specifically, SKM were asked to address three fundamental questions:

1. Was the project scope and design efficient (ie the right solution)?
2. What were the reasons for the cost increases?

3. Are the final costs considered reasonable for what was delivered?

The SKM report is attached, and the main findings of that report can be summarised as follows:

- The project costs were significantly underestimated at the regulatory test stage, contributing 74% of the variations.
- Externally imposed scope changes (site changes, environmental requirements, etc) contributed 20% of the project overrun.
- Internal EA scope changes contributed to 6% of the project cost variation.
- The tunnel costs and 132kV connections increased 84% over the original estimates for the tunnel and connections, and this increase contributed 80% of the total project cost variation.
- A comparison of the costs of a number of international tunnelling projects for electricity infrastructure purposes shows that the estimated EA cable tunnel costs were comparable with a number of international tunnelling projects, particularly given the relatively short length of the EA tunnel compared with others.
- For the full scope of the CBD augmentation project, 83% of all project costs were competitively procured.

Further, the SKM report notes:

> *"While SKM has not reviewed the design, scope or costs in detail, in general the selected option and project costs appear reasonable for an undertaking of this nature in a dense CBD location. While a formal re-evaluation of project alternatives would have been preferable when the likely cost increases became known, it is likely that EnergyAustralia would have experienced similar increases in most of the other options, as the variation has been shown to be overwhelmingly due to systemic underestimating of costs, and externally imposed changes.*
>
> *Further to this, and depending on the time during the project that EA became aware that there was likely to be a substantial cost overrun, consideration would have to be given to the impact on the security of supply to the CBD if the project were suspended for re-evaluation of options, and possible implementation of an alternative project strategy.*
>
> *The final delivered cost of the project appears reasonable where SKM has a basis for comparison, and it can be expected that the competitive procurement processes that applied to over 80% of costs would deliver efficient market prices for those items."*

1.5 MACQUARIE PARK

The Macquarie Park zone substation was required to meet significant load growth in the local area and capacity constraints on nearby substations at Epping and North Ryde that exceeded EnergyAustralia's objectively measurable service standard.[21]

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[21] EnergyAustralia applies a risk based service standard to their suburban zone substations. This means that:
- With all zone transformers or sub-transmission feeders network elements in service, the loading on each element is not to exceed the continuous rating of that element.

The Macquarie Park 132/11kV zone substation was established in 2001 to relieve N-1 contingency overloads on Epping and North Ryde zone substations. The timing of the project was advanced from 2005 to accommodate anticipated customer proposals for an additional 10MVA of loading by the end of 2001. Some of the specific customer spot loads did not proceed as expected but general load growth and the promotion of the area as a high technology industrial park necessitated the establishment of a zone substation in the area.

The ACCC considers that EnergyAustralia has not met its Code obligations in relation to the Macquarie Park substation augmentation. The ACCC has written to NECA alleging a Code breach and this matter is currently being investigated by NECA. EnergyAustralia will respond to this alleged code breach in the appropriate forum but can indicate that it believes that the ACCC may not have correctly interpreted EnergyAustralia's Code obligations in relation to Macquarie Park.

The following material is provided to demonstrate that EnergyAustralia's investment in Macquarie Park was efficient and should be allowed in full.

1.5.1 Background

The Macquarie area is supplied at 66kV from Integral's Carlingford substation. The area is supplied by zone substations at Epping and North Ryde. As a result of rapid load growth the loading at both these substations was above firm capacity in Summer 99-00.

The constraint in this area arose from:

- Loading on Epping and North Ryde zone substations exceeding the firm capacity of the substations;
- Loading on the 66kV network supplying Epping, Hunter's Hill and North Ryde zone being loaded to capacity in 2001;
- EnergyAustralia's load on Integral Energy's Carlingford sub-transmission being forecast at 97.5% of allocated capacity in 2001.

1998 Value Management Study recommendation.

A Value Management (VM) study proposed the minor upgrades of capacity at Epping detailed above and the installation of capacitors at North Ryde and Epping zones at a further cost of \$800k. This capacitor work would have provided an increase in capacity of about 9.5 MVA. This minor work was to be followed by the construction of a 132/11kV zone in 2005.

The forecast prepared in 1998 for Epping and North Ryde predicted a total load of 118MVA in 2005. The combined ratings of Epping (75MVA) and North Ryde (42MVA) following work at Epping was expected to be 117MVA.

- The chance in any season is less than 1% that following outage of any one network element, loading will exceed the sustained emergency capacity of remaining system elements.
In terms of reliability standards as defined by the Code, this constitutes a slight reduction in reliability from an "N-1" reliability criterion (as described in S5.1.2.2 (b) (4)).
A deterministic (N-1) criteria is used for subtransmission substations.

Higher than expected load growth load meant that load at the two zones reached 118MVA in summer 1999-00, with forecast load in 2000-01 being 129MVA (excluding requested new loads from two major customers PRL and Exodus). It is estimated that capacitors would have reduced the forecast 2000-01 load to 120MVA, which is still above the rating of Epping and North Ryde substations (without the PRL or Exodus load).

This load increase made deferral of the new zone to 2005 unacceptable from a load perspective, particularly given the load applications from PRL and Exodus for 8MVA in 2002 and 10MVA in 2003.

Forecast capacity deficits were in 2002 ranged from 10MVA (without PRL or Exodus) up to about 20MVA if Exodus was considered). This shortfall in capacity required urgent action to provide a large amount of capacity.

1.5.2 Assessment of Augmentation Options

The recommended action from the VM in 1998 was to provide a 132kV/11kV zone. This option was proposed because options involving other supply voltages were plainly uneconomic. A review of other supply voltage options follows to confirm this fact.

66kV Supplied Alternative

In 2000 the existing 66kV zone substations and feeder networks to the area were loaded to their design capacity. In addition EnergyAustralia had already fully utilised its capacity from Integral's Carlingford substation. The expected deficit in capacity by 2005 was between 30MVA and 55MVA, could only have been met by the construction of a new zone substation.

A new 66kV substation would have required the construction of a new 3 transformer substation ($8m) and new 66kV feeders from Carlingford to the Macquarie area. Assuming a feeder length of 10km and that 75% of feeders would be underground the feeder cost would be expected to be about $18m.

A 66kV zone substation would provide sufficient capacity to meet load growth until 2008 when it would be necessary to establish another 132kv zone substation in the area.

If a 66kV Macquarie Park substation was established it would result in Carlingford's allocation being exceeded in 2002. Previous discussion with Integral Energy had indicated that there was no ready way to expand capacity from Carlingford .

Given the expected costs of the 66kV option, it was considered that further development of 66kV supply was not warranted. Cost comparisons are provided to demonstrate this point. The costings for this option did not include an allowance for Exodus or PRL.

33kV Supply Option

The closest 33kV supply point is Kuringai sub-transmission substation (STS). This has insufficient capacity to supply a new zone substation unless it was augmented. A capacity increase of about 60MVA could be provided by uprating a transformer. This would only provide sufficient capacity to meet expected load growth until 2006. As there is no further scope to uprate Kuringai STS it would be necessary to provide additional capacity in 2006 by establishing a new 132/33kV substation, or converting one of the 33/11kV zone substations supplied from Kuringai STS to 132kV operation, or establishing a new 132/11kV zone to meet load growth in the Kuringai supply area. The least cost alternative would be to upgrade a zone substation, with Turramurra zone being the most likely candidate. (There is insufficient space at the other zone substation sites)

A three transformer Macquarie 33kV zone substation would reach its capacity (assuming power factor correction is installed) in 2007. Further upgrades could not be suppled from Kuringai STS. When Macquarie 33kV zone substation reached capacity it would be necessary to establish a 132kV zone substation to meet load growth in the Macquarie area.

Supply to Macquarie zone from Kuringai STS would be by UG cables involving a route length of about 7km. These cables would require a crossing of the North Shore rail line and the Lane Cove River. There are no spare ducts in deBurgh's bridge thus the feasibility of cable connections is doubtful.

Given the expected costs of the 33kV option, it was considered that further development of 33kV supply was not warranted. Cost comparisons are provided to demonstrate this point. The costings for the this option did not include an allowance for Exodus or PRL

132kV Options

Option 1 - Establish a Zone Substation in 2001

A high capacity double circuit tower line runs along the Lane Cove river adjacent to the Macquarie industrial area . A 132/11kV substation could be supplied by a relatively short tee (~1km) connection to this line. The distances involved make the connection costs of a 132kV zone substantially less than for other supply voltages.

A 132/11kV zone could be initially established with 2 x 50MVA transformers providing 65MVA of firm capacity. With power factor correction this should provide adequate capacity to meet expected load growth up to 2008 (assuming Exodus did not proceed). Upgrading to a 3rd transformer would provide capacity until about 2014.

Other 132kV options

A number of 132kV development options were considers by the original VM.

> VM Option A, D, & C – Assumed deferral of Pennant Hills - As work at Pennant Hills was already in progress these options were no longer possible at the time the decision to accelerate Macquarie was made.
>
> VM Option B & E – Proposed 11kV load transfers to Pennant Hills to defer Macquarie Zone substation

Load transfers to other zones are limited by 11kV system capacity and zone substation capacity. Transfer of up to 15MVA of load to Pennant Hills would be possible at an estimate cost of $6m. This comprises $2.5m Epping Macquarie and $3.5m Pennant Hills Epping. (This was reflected in Option B of the VM by expenditures in 2001, 2005 and 2008). When combined with capacitors this transfer would have potentially delayed the establishment of Macquarie Park until 2002 (assuming that Exodus and PRL did not occur). By 2008 load would need to be moved back to Macquarie Park to relieve loading on Pennant Hills hence this work would not delay the need for long term augmentation of Macquarie Park.

Further 11kV expenditure would be required to supply PRL or Exodus Stage 2 ($2m exodus, $4m PRL). This would have further increased benefits of accelerating a new zone substation.

Table 2 - Cost Comparison

Option		Total Capital Cost # $m	NPC $m	Comments
1	66kV	$48.5	$25.2	Not possible due to lack of capacity from Carlingford
2	33kV	$59.6	$28.8	
3	132kV zone in 2001	$32.3	$11.6	
4A	11kV work then 132kV zone in 2002 (without Exodus/PRL)	$39.1	$15.7	Deferral of zone to 2002 by 11kV load transfers (excluding Exodus/PRL supply issues)
4B	11kV work then 132kV zone in 2002 (with Exodus/PRL)	$45.1	$21.7	Deferral of zone to 2002 by 11kV load transfers (including supply to Exodus/PRL)
4C	Sensitivity to 11kV work deferring zone to 2003 (without Exodus/PRL)	$39.1	$15.5	Sensitivity analysis considering cost benefit of further deferral

Total zone and subtransmission costs to 2014. 11kV costs common to all options have been excluded.

Least Cost Strategy

The least cost strategy comprises the establishment of a 132kV zone substation at Macquarie in 2001. This is consistent with what was constructed by EnergyAustralia.

- 2001 132kV zone substation at Macquarie park with 2 x transformers $12.8m
- 2007 11kv capacitors at Macquarie Park $ 0.4m
- 2009 Uprate Macquarie Park by installation of a 3rd transformer $ 3.5m
- 2014 A second 132kV zone substation $15.6m
-

In summary, the Macquarie Park 132/11kV substation project was selected as the least cost (NPC) option from six alternatives that represented the most likely technically and economically viable scenarios. The optimum timing of the project was disrupted by some “committed” large customer loads which did not proceed, but that did not result in the preferred augmentation option being delivered in an inefficient manner. An independent cost estimate by SKM for Macquarie Park “transmission” assets, places the value of the assets at between $16m and $17m, substantially higher than the $12m being sought by EnergyAustralia.

1.5.3 Regulatory Test

The ACCC considers that EnergyAustralia has not met its Code obligations in relation to the Macquarie Park substation augmentation. ACCC has written to NECA alleging a Code breach and this matter is currently being considered by NECA.

EnergyAustralia will respond to this alleged code breach in the appropriate forum but can indicate that it believes that the ACCC may not have correctly interpreted EnergyAustralia's code obligations in relation to Macquarie Park.

1.5.4 SKM Review of Macquarie Park

The details of SKM's analysis of Macquarie Park is provided in Attachment 2. This provides a summarised history of the project costs from inception to completion (on the current date). From this summary the following key findings emerge:

- The 132/11kV supply option was selected as offering the lowest NPC cost from a range of options including deferment through 11kV augmentation.
- The optimum timing of the project was disrupted by a number of large customer loads which did not eventuate.

SKM's independent cost estimate for Macquarie Park substation (transmission component) is comparable with the original Board approval and higher than the proposed transmission allocation of $12M.

1.6 BERESFIELD

The Beresfield sub-transmission substation forms a critical part of the development strategy for Tarro-East Maitland area. This strategy incorporates several transmission and distribution augmentations required to meet dramatically increasing loads in the surrounding regions.

The ACCC has alleged that EnergyAustralia did not meet its Code obligations in relation to the Beresfield augmentation.

EnergyAustralia considers that compliance with the Code planning process is a separate issue to the efficiency of the relevant investment. While EnergyAustralia will respond to the ACCC's allegations, in the appropriate forum we note that this issue will not affect consideration of the prudence and efficiency of this investment. The section below concentrates on demonstrating the efficiency of the Beresfield investment to justify its inclusion in EnergyAustralia's regulated asset base.

1.6.1 Background

This area is serviced by two zone substations, one at East Maitland and one at Tarro and lies between two 132/33kV subtransmission substations, Kurri & Tomago. Load at both zone substations is currently exceeding firm capacity. In 2003, the load at Kurri STS was 29.7MVA above firm capacity in summer and is expected to exceed it's Winter firm rating in 2005. Tomago STS is expected to exceed it's firm rating in the summer of 2004/05 and the winter of 2008.

The key constraint driver is the increase in commercial load, the operation of air conditioning systems during peak summer periods and ongoing residential & industrial developments. Load is forecast to grow at approximately 5 % per annum and summer loads are approximately 21% higher than winter loads.

There is a need for an additional 53 MVA of zone substation capacity and an additional 140MVA of sub-transmission capacity for year 2010 loads. This situation applies to East Maitland and Tarro substations with Tarro having limited opportunity for improvements in capacity or load transfer.

A detailed planning study has been carried out to help determine a preferred supply strategy for the short and longer term. The study has attempted to ensure any immediate supply developments are compatible with the preferred longer-term augmentation strategy.

The study identified 22 options as being feasible and that would fit the long-term supply requirements for the area. There was an analysis of the options to form a list of strategies (38 strategies), each strategy consisted of a set of individual options which addressed the key issues and as many other issues as possible and also satisfy as many constraints as possible.

These strategies have been taken into further analysis that included technical, environmental and financial issues and three primary strategies were identified that would meet the short and long term supply requirements for the area.

The three strategies are:

- Construct a new Beresfield 132/33 subtransmission substation (STS) and associated works.
- Build 132/11kV Zones for East Maitland, Thornton and Tarro.
- Upgrade 66kV capacity from Kurri STS for East Maitland, Thornton and Tarro.

Due to the high growth rates there is a need to undertake works in the short term while still encompassing the long-term outcomes.

The need for augmentation in this area is so critical that, if the substation is not operational before summer 2004/05, load shedding is the likely outcome for customers. From EnergyAustralia's perspective, the real constraint of customers being faced with inadequate total capacity was the driving factor behind the investment.

1.6.2 Demand Management

EnergyAustralia has investigated demand side options in the East Maitland, Thornton and Tarro areas.

The investigation found that the absolute volume of DM required is large. The value available for DM is moderate at best. Based on the findings and EnergyAustralia's experience with other investigations, it is considered highly unlikely that sufficient effective DM options would be identified in an investigation to enable a cost-effective deferral of any part of this investment strategy. A copy of the DM scoping study is attached to this submission as Attachment 4.

Based on this analysis it is considered unreasonable to expect that it would be cost-effective to postpone the expansion by implementing demand management strategies. The investigation recommended that no further specific investigation of demand management options be pursued with respect to the proposed Beresfield STS and Thornton Zone Substation Projects.

1.6.3 Conclusions

Strategy 1, a 33kV solution is EnergyAustralia's preferred option. Detailed works associated with this strategy are listed in Table 3.

Table 3 - Preferred strategy costs and timing

Measure	Asset	Cost	Timing
New 132/33kV STS at Beresfield	Transmission	$20.6m	2004
33kV feeders	Distribution	$13.5m	2004/7
New zone substation Thornton	Distribution	$9.2m	2005
Capacitors at East Maitland	Distribution	$0.7m	2005
Capacitors (12MVAr) at Tarro	Distribution	$0.7m	2006
Replace Tarro Switchroom	Distribution	$2m	2007/8
Replace Transformers at Tarro	Distribution	$0.6	2011
Transformers & switchgear at East Maitland	Distribution	$3.4m	2011

Key elements of this strategy are the construction of Beresfield and Thornton substations and associated feeder works. Accordingly, EnergyAustralia plan to carry out the following works:

- Construction of a 120MVA firm capacity sub-transmission substation at Beresfield to be completed in November 2005 ($20.6m).
- Construction of a 33/11kV zone substation at Thornton to be completed in August 2005 ($9.2m).
- 33kV feeder works associated with the above substation works which are to be completed in two stages between 2005 and 2007($13.5m).

1.6.4 Regulatory test

In order to demonstrate that the investment decision can be justified under the principles of the Regulatory Test, EnergyAustralia has recently prepared a report which sets out the results of the application of the Regulatory Test on the basis of the information available to EnergyAustralia at the time the investment decision was made. This document is attached to this submission as Attachments 3.

In summary, the application of the Regulatory Test demonstrates the need for, and efficiency of, the investment and the fact that the Beresfield STS is one component of an overall least cost strategy to deliver reliability of supply to the Lower Hunter. The Demand Management Scoping study referred to in section 1.7.2 demonstrates that based on information available to EnergyAustralia at the time the investment options were being considered, the magnitude of the supply shortfall was so large that demand management was not a viable option and that further pursuit of a demand side solution would not have been recommended at the time.

1.6.5 Independent review

EnergyAustralia has asked SKM to review the system constraints, planning process, and technical and economic analysis to alternative supply options in the areas currently supplied from the Kurri and Tomago STSs, and their comments are contained in the attached report (Attachment 2). We draw the ACCC's attention to the following comments made in that report:

> *"A significant value of energy at risk and contribution to system vulnerability (SAIDI) by 2004/05 has been identified" (p 7)*
>
> *"…the Beresfield 132/33kV STS project and asssociated works is not only prudent and efficient, but is overdue by all reasonable electricity industry planning standards." (p 7)*
>
> *"SKM is of the view that the approvals process, and staged authorisations, documentation and regular review of NPC's of alternatives represents a "Model Case Study for the Corporate Governance of Capital Works Projects" (p 2)*

1.7 HOMEBUSH

In preparation of the Olympic Games site in Homebush Bay, EnergyAustralia together with SOCOG and OCA agreed to replace tower lines that crossed the site with underground cables to the site. Not only did the undergrounding of feeders 90X, 92F(2), 926/2, 927/3, 200, and 210 deliver a more cosmetic alternative for the Olympic site, a number of these tower lines directly crossed land that was to be used for the Olympic sites that hosted hockey, tennis, the Showground, the Olympic Village and car parking. It was therefore necessary from a construction perspective for the tower lines to be re-positioned or undergrounded.

1.7.1 Homebush assets

During 1998 and 1999, three double circuit 132kV steel tower lines were removed from Homebush Bay and were replaced with underground 132kV cables. Each tower had two 132kV overhead feeders attached to it with the asset ages varying between 25 to 38 years.

Table 4 - 132kV Tower Assets (Old - Replaced)

Tower Line 1	Feeder Description	Age	Removal Year	Length	Conductor Type
Feeder 90X	MASON PARK STSS –Homebush Bay TP	25	1998	3.86km	54/3.53 ACSR BUND 60H
Feeder 92F(2)	MASON PARK STSS –Homebush Bay TP	25	1998	3.86km	54/3.53 ACSR BUND 60H
Tower Line 2	Feeder Description	Age	Removal Year	Length	Conductor Type
Feeder 926/3	926 TEE –Mason Park STSS	27	1998	4.1km	54/3.53 ACSR BUND 60H
Feeder 927/3	927 TEE –Mason Park STSS	27	1998	4.1km	54/3.53 ACSR BUND 60H
Tower Line 3	Feeder Description	Age	Removal Year	Length	Conductor Type
Feeder 200	MASON PARK STSS –Flemington Zn	38	1998	1.32km	54/3.53 ACSR BUND 60H
Feeder 201	MASON PARK STSS –Flemington Zn	38	1998	1.38km	54/3.53 ACSR BUND 60H
11kV Feeder	Flemington Zn – Silverwater area	38	1999	3km Approx	54/3.53 ACSR BUND 60H Estim.

Note 1: Treasury Guidelines indicate that lattice towers have an assumed life of 60 years.
Note 2: 46 tower structures were removed.

In 1998, the condition of Tower Line 3 (22 tower structures) was in poor condition and was expected to be replaced within 5 years. However Tower Line 1 & 2 (24 tower structures) were both in good condition and replacement (due to condition) would not of occurred until 2015.

When the towers were replaced with underground cables, 63 hectares of land was made available for other uses. This land enabled the various Olympic Games venues to be built.

The above mentioned overhead feeders were replaced with the following underground 132kV cables.

Table 5 - 132kV Underground Assets (New)

	Feeder Description	Install Year	Length	Conductor Type
Feeder 90X	MASON PARK STSS --Homebush Bay TP	1998	4.1km	1600 AL1 G XQ G FE YQ
Feeder 92F(2)	MASON PARK STSS --Homebush Bay TP	1998	4.1km	1600 AL1 G XQ G FE YQ
Feeder 926/3	926 TEE –Mason Park STSS	1998	4.1km	1600 AL1 G XQ G FE YQ / 2 cab / ph
Feeder 927/3	927 TEE – Homebush Bay	1998	1.1km	1600 AL1 G XQ G FE YQ / 2 cab / ph
Feeder 935	Homebush Bay –Mason Park STSS	1998	3.0km	1600 AL1 G XQ G FE YQ / 2 cab / ph
Feeder 200	MASON PARK STSS –Flemington	1998	1.5km	630 AL1 G XQ G FE YQ
Feeder 201	MASON PARK STSS –Flemington	1998	1.5km	630 AL1 G XQ G FE YQ

* Also approximately 3km of underground 11kV cable were installed to replace the 3km of overhead 11kV that was connected to Tower Line 3.

There was no change in the system configuration with the undergrounding of feeders 200, 201, 90X, 92F(2) and 926/3. All these feeders start and finish at the same locations as when they were overhead feeders. However when feeder 927/3 was undergrounded, it 'looped' into Homebush Bay zone substation, forming feeders 927/3 and 935. Homebush Bay zone substation was established in order to cater for the new loads associated with development of the Homebush Bay area.

1.8 GOSFORD – OURIMBAH

The Gosford - Ourimbah project was an integrated strategy comprising of the following elements:

- Construction of a 132kV line from Gosford to Ourimbah via West Gosford zone substation;
- Construction of 132kV feeder bays at Gosford and Ourimbah subtransmission substations; and
- Conversion of West Gosford zone substation from 33kV to 132kV operation.

The line work associated with this project was included in the 2000 ACCC transmission determination, whilst an allowance for conversion of a zone substation at Lisarow to 132kV operation was included in the 1999 IPART determination.

1.8.1 132kV Feeder and Associated Works

The Gosford –Ourimbah line is a 132kV feeder which links two parts of EnergyAustralia's distribution network. EnergyAustralia considers that this could not reasonably be considered to be a transmission asset and that it was incorrectly included in the 2000 ACCC determination. Accordingly the costs associated with this project during the period 1999-2004 were allocated to the IPART regulatory accounts rather than the ACCC accounts.

With the subsequent change in classification of 132kV assets on the Central Coast from distribution to transmission, the Gosford-Ourimbah 132kV lines and West Gosford zone substation will be classified as transmission assets from 1 July 2004.

In its draft determination, the ACCC has compared the original cost submissions for the Gosford projects to actual costs without inflating for cost increases over time.

The impact of inflation is shown in Table 6 below.

Table 6 - Costings for the ACCC portion of Gosford projects (including inflation)

Component	Submission $1999 $m	Submission $2003-4 $m	Projected spend $2003-4
Line Construction	5.4	6.1	10.5
132kV feeder bays at Ourimbah and Gosford	1.6	1.8	2
Total submission	7	7.9	12.5

The original estimates were based on conversion of an existing 33kV line to 132kV operation and the estimate assumed that the total line route would be overhead.

In 1997-98 EnergyAustralia had carried out route selection and community consultation for the much longer Tuggerah-Munmorah line and had experienced little community interest. This suggested to EnergyAustralia that reconstruction of the existing 33kV lines between Ourimbah and Gosford was the most likely route for the proposed new line.

EnergyAustralia commenced consultation over the proposed Gosford-Ourimbah feeder in June 1999. The proposal resulted in considerable community opposition. A community working group was established to consider possible line options. The consultation process resulted in the identification of 4 major route options and 17 variations to the major options. After approximately 18 months of consultation and analysis a preferred route was announced in January 2001. An EIS followed in June 2001 and planning approval for the project was granted in March 2002.

As a result of the consultation process and associated environmental issues the final line route selected was more than 25% longer than the route envisaged at the time of the ACCC submission and required a short section of UG cable which was not anticipated at the time of the submission.

The new route also comprised a significant length of new 132kV construction, which required:

- additional expenditure for diversion of existing infrastructure; and
- acquisition of new easements.

These costs would not have arisen if the existing 33kv line had been upgraded to 132kV operation. The total cost increases associated with the change in routes is estimated to be $2m.

The extensive EIS and consultation process took almost three years from commencement of consultation to granting of approval. This added a further $700k to project costs.

1.8.2 Zone Substation Works

The work associated with the conversion of West Gosford zone substation to 132kV operation was not included in the 1999 ACCC submission as this work was a distribution augmentation.

The 1999 IPART determination included an allowance of $9.5m in 1998 dollars to convert Lisarow zone substation to 132kV operation. This is equivalent to $11.1m in $2003-4.

Subsequent to the determination a decision was made to convert West Gosford zone substation to 132kV operation, rather than Lisarow substation. This decision arose from a number of considerations.

- Detailed investigations found that major uprating work at Lisarow could be deferred by load transfers and minor works until about 2008-9. It was not possible to defer the augmentation of West Gosford.
- West Gosford substation adjoins a number of highly loaded zone substations and the provision of additional capacity allowed 11kV load transfers to be implemented which enabled the deferral of work at other locations.

The conversion of West Gosford zone substation to 132kV operation was carried out instead of the work proposed at Lisarow substation in the 1999 IPART Determination. Whilst the two projects are similar in scope they involve different sites. A direct comparison between the submission and the actual project is thus invalid except as a high level benchmarking exercise. When the 1999 submission is appropriately indexed the cost increases from the IPART submission are within the accuracy limits of the high level estimates used in the submission.

OPEX

EnergyAustralia rejects the ACCC's treatment of our operating cost program. The ACCC has made what appear to be arbitrary and unsubstantiated cuts to various parts of EnergyAustralia's operating program which EnergyAustralia believes sets a dangerous precedent for arbitrary cuts to operating costs in the future.

Arbitrary reductions such as those recommended by the ACCC add an unfortunate and inefficient element to the regulatory framework. These arbitrary cuts incentivise the business to play a regulatory "game", in which cost forecasts are arbitrarily inflated in anticipation of arbitrary cuts by the Regulator. As stated in its submission on the review of the draft Statement of Regulatory Principles, EnergyAustralia's approach to this regulatory "game" is to refuse to play.

EnergyAustralia has developed and proposed an integrated operating program that is designed to meet both the current needs of the transmission network and facilitate long-term improvements in asset management, operating costs and customer outcomes. Any reduction in the forecast operating budget will necessarily result in some aspect of the integrated program not proceeding. The integrated nature of the program invariably means that any cancellation of a component of the program will have consequential effects on other parts of the program.

It should be noted that the increase proposed in our operating expenditure program for the 2004-2009 period relate to the need to stabilise our service standards. EnergyAustralia has experienced a deterioration in performance of some asset classes recently which needs to corrected in the next regulatory period. Part of this strategy is the introduction of condition based maintenance. The increased proposed allows for corrective action to be carried out along side planned maintenance. It is only when the corrective action is completed that there will be certainty in the delivery of service standards.

EnergyAustralia is particularly disappointed by the specific reductions proposed by the ACCC in relation to information technology (IT) costs. EnergyAustralia is astounded that the ACCC has demanded a higher volume of more detailed information than ever before, and yet is not prepared to fund the IT systems required to produce that information.

More importantly, however, information provides the foundation of the network management programs. Reductions in the IT budget therefore have significant implications for EnergyAustralia's ability to deliver the targeted network performance and expenditure outcomes that form the basis of its submission.

IT is a facilitating expenditure program, and as such, reductions in the level of operating investments in this area will limit the benefits that can be derived from the systems currently in place and of those being developed. This can lead to reductions in the volume, level and integrity of data contained in the various systems, thereby reducing EnergyAustralia's ability to strategically manage its network performance through targeted maintenance and capital expenditure. Without robust information to support strategic asset management, EnergyAustralia believes that network costs could increase beyond those predicted due to the need to undertake corrective actions that would have otherwise been predicted through the condition based asset management system. EnergyAustralia submits that the forecast IT expenditure will ultimately deliver lower cost outcomes to customers.

The ACCC's draft Determination relies heavily on the work conducted by GHD in reviewing EnergyAustralia's operating program. EnergyAustralia is surprised that the ACCC would choose to rely upon high level judgemental analysis rather than EnergyAustralia's detailed integrated cost forecasting process. The combination of the high level judgemental cost driver analysis on one hand, and the arbitrary reductions to the opex program on the other, can only act to undermine all stakeholders confidence in the ACCC's findings on EnergyAustralia's operating and maintenance expenditures.

EnergyAustralia's following comments will address the particular flaws that have been identified with the ACCC's methodology and findings in the draft determination.

1.1 ACCC'S APPROACH TO BENCHMARKING

EnergyAustralia notes that the ACCC, on a seemingly arbitrary basis, has savagely cut EnergyAustralia's opex over the period (based at least in part on GHD's report). Notwithstanding its comment that:

> *The ACCC recognises that differences in operating conditions and scale may explain why some [opex] ratios are higher or lower. As such, [the ratios] can only provide a measure of reasonableness. Accordingly, the ACCC does not use benchmarking to establish opex allowances but rather as a guide to whether the allowance is within a reasonable range.*[22]

the ACCC has undertaken considerable analysis to benchmark EnergyAustralia's opex against that of its compatriot transmission businesses.

There appears to be little debate that three key drivers of opex are:

(i) number of assets that are required to be maintained;

(ii) the environment in which those assets operate, particularly the extent of surrounding urbanisation; and

(iii) the age of a network.

For the most part, the analysis and graphs provided in the ACCC's Draft Determination are consistent with these principles.

In Figure 5.4 included in the ACCC's Draft, it is completely reasonable to expect that EnergyAustralia's opex per line length would be significantly greater than the other Australian TNSP's. But this is not, as suggested by the ACCC, because EnergyAustralia has a compact network and therefore a small line length "denominator". Rather, this reflects the degree of urbanisation in which the EnergyAustralia transmission system operates. The metropolitan environment has profound implications for the operation of the network, ranging from fault location to crew mobilisation and traffic control.

In EnergyAustralia's view, this high level benchmark has produced reasonably anticipated results. Here again, EnergyAustralia's forecast reflected the increased opex spend relative to the prior period, which is graphically exacerbated by the low line length.

[22] Draft Determination p 76.

The ACCC's Figure 5.5 places EnergyAustralia in the middle of the pack in terms of opex per substation. In a compact transmission system, there will be relatively more substations per kilometre of transmission line than in a long haul system (note the comparable results for TransGrid and SPI PowerNet). Dividing EnergyAustralia's relatively higher urban opex over a relatively larger number of substations results in an averaging of the benchmark results.

Figure 5.6 also delivers anticipated results with respect to opex per GWh, with ElectaNet and Transend outstanding by virtue of their relatively low loads. In EnergyAustralia's case, the load reflects the population and load density of the urban area.

The relative operating environments also drive the results in Figure 5.7. It would be expected that, for a given level of opex, a transmission business with a relatively peakier load would tend to show lower opex per unit of system peak. Again, the transmission businesses in the states with the most significant air conditioning load, Victoria and Queensland, appear at the bottom of the pack in this analysis. The more stable the load, the higher the measure of opex per unit of peak demand would be expected to be, and this is shown with Transend at the top of the graph.

However, one of the graphs is outstanding in its analysis. EnergyAustralia draws ACCC's attention to its benchmarking as provided in Figure 5.3 of the draft decision, in which EnergyAustralia's opex to asset base ratio is compared to that of other TNSPs. This Figure is reproduced below.

Figure 5.3 Comparison of TNSP's opex per asset base

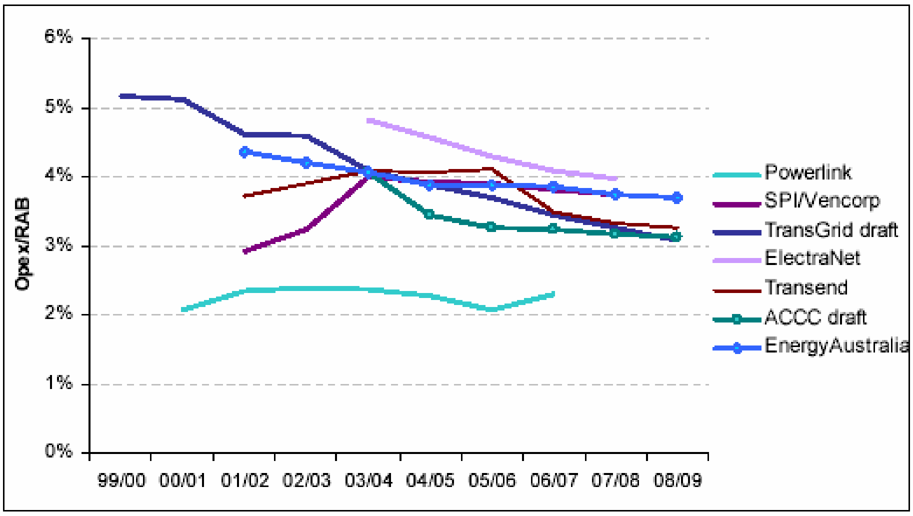

Figure 5.3 shows that EnergyAustralia proposed a program resulting in a ratio of opex to asset base that would deliver modest efficiency gains. While EnergyAustralia reclassified some assets from distribution to transmission, it would be reasonable to expect that the opex associated with those assets should also be transferred from distribution to transmission, as was the case. We refute the claim that the movement of assets from distribution to transmission should result in a lower opex to asset base ratio due to the operating costs associated with the greater number of transmission assets.

The ACCC's analysis attempts to analyse the relationship between the number of assets to be maintained and the level of anticipated operating expenditures. From the analysis, there are a number of conclusions that can be drawn:

- The ACCC has significantly reduced EnergyAustralia's opex proposals;
- With the exception of Powerlink, the ACCC's allowed opex ratio for EnergyAustralia is the lowest of all TNSP's in all future years.
- In 2008/09, the ratio is the lowest for the NSW TNSP's compared with other states.
- The ACCC's proposed opex ratio line brings forward efficiency expectations at a much greater rate than for all other TNSP's (with the exception of ElectraNet), significantly impacting on cash flows, particularly in the early years.
- EnergyAustralia had demonstrated significant "efficiency gains" in its past opex and had proposed future additional efficiency gains, as observed from the ratio line.

What has not been factored into the ACCC's analysis is the impact of the age of assets. The age of the transmission system, as indicated in the ACCC's Draft Determination, would suggest that companies with older assets would have relatively higher operating expenditures. The ACCC's allowances as provided in the above analysis do not reflect this.

A case in point is the ACCC's recent TransEnd decision. TransEnd has a similar size of asset base (approx $570 million) compared with ACCC's view of EnergyAustralia's opening asset base as contained in the Draft Determination ($629 million). In addition, the Tasmanian Department of Treasury and Finance Valuation of Transmission Assets dated August 2003, indicated that "Transend outlined the age profile of its assets, which are some of the oldest transmission assets in Australia, with transmission lines averaging 43 years and substations 32 years."

EnergyAustralia has long maintained that its assets are also among the oldest in Australia and, in fact, when reviewing previous information provided to ACCC, it is apparent that TransEnd's asset ages are very similar. Table 9 below has been taken from EnergyAustralia's original submission to ACCC.[23]

Table 9 - Projected ageing of asset classes with base case capital expenditure

Weighted Average Age at year start (yrs)			
Asset Class	1999	2004	2009
Underground Transmission Circuits	36.2	40.0	42.6
Overhead Transmission Lines	33.0	37.3	41.7
Zone substations	31.55	33.74	36.31

However, the opex to asset base ratios for EnergyAustralia and TransEnd are quite different, particularly in the early years of the determination. Applying the opex to asset base ratio provided for TransEnd to EnergyAustralia's asset base, would result in additional opex for EnergyAustralia of approximately $7 million over the first two years alone. While an element of the difference in the early years relates to costs for TransEnd entering the NEM, the earlier opex allowances are still substantially above those for EnergyAustralia.

[23] See Table 9 of EnergyAustralia's submission to ACCC dated September 2003.

Also at odds with the ACCC's analysis in this area is the relative amount of opex to asset age for ElectraNet. ElectraNet has stated that its average asset age is 28 years,[24] considerably 'younger' than EnergyAustralia's. It should follow from the ACCC's analysis therefore that ElectraNet's opex cost ratio should be considerably lower than for the other transmission networks, particularly Transend and EnergyAustralia. It is apparent from the ACCC's Figure 5.3 reproduced above, that age of the network has not been adequately considered. Applying the opex to asset base ratio allowed for ElectraNet to EnergyAustralia's asset base would result in an additional $13 million over the first two years of the upcoming regulatory period.

It should be noted that the higher opex numbers calculated by adopting the ratios applied to TransEnd and Electranet produces directionally consistent results when compared with SKM's operating and maintenance report. This report shows that during the 1999-2004 period EnergyAustralia has underspent operating and maintenance expenditures and is looking to correct this trend in 2004-2009. This clearly indicates that the opex per asset value should indeed be higher in the forecast period than the historical period. Instead of recognising this, the ACCC's Draft Determination provides for a decrease in opex per asset base over the forecast period. This feature alone accounts for over 75% of the reductions to EnergyAustralia's opex program.

The age of EnergyAustralia's network, combined with its stated need to increase opex relative to the previous period, suggest that the EnergyAustralia forecast opex is more consistent with the balance of the ACCC's benchmarking results than the level adopted by the ACCC in its draft decision. In addition, the lack of analysis provided by GHD (or ACCC) to support such significant reductions is concerning and has led to what appear to be arbitrary cuts.

1.2 ACCC'S TREATMENT OF OPEX

EnergyAustralia is disappointed with the ACCC's treatment of our operating cost program. EnergyAustralia has developed detailed expenditure programs based on an expert understanding of the operation and maintenance of our network. Basing operating expenditures solely on the level of past expenditures, as proposed by GHD and the ACCC, entirely misses the fundamental issue that more activity will be undertaken in the next regulatory period than has occurred in the current period.

Applying a "general efficiency" factor to the starting point that reduces all future opex without providing evidence as to the reasons for the reductions or the impact the cuts may have on system performance is not acceptable to EnergyAustralia's customers, our employees or our shareholder. While we note the ACCC's comment that even though a general efficiency factor of 2.5% of opex in 2003/04 has already been applied to the opex starting point, "…the ACCC considers that applying a further general efficiency factor to EnergyAustralia's opex for 2004-2009 is not required."[25] We would certainly expect not.

The ACCC has made what appear to be arbitrary and unsubstantiated cuts to various parts of EnergyAustralia's operating program which EnergyAustralia believes set a dangerous precedent for arbitrary cuts to operating costs in the future. While a considerable volume of information was provided to ACCC and its consultant, we do not see evidence that all of the

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[24] ElectraNet SA Transmission Network, Revenue Cap Application 2003 – 2007/08, 16 April 2002, p8-11.

[25] ACCC Draft Determination for EnergyAustralia, p71.

information was interpreted properly, or in many cases was examined at all. We are concerned that engineering consultants have formed views on the appropriateness of matters such as superannuation, which we are not convinced they are suitably qualified to comment.

In any case, the high level "driver analysis" adopted by GHD appears to be an attempt to achieve reductions in future operating expenditures without requiring a robust justification for the reductions. Basing operating expenditures solely on the level of past expenditures, as proposed by GHD and ACCC, does not take into account the fact that more activity will be undertaken in the next regulatory period than has occurred in the current period. The following summarises our main concerns with the operating expenditure section of the ACCC's draft decision:

- GHD questions the allocation of costs across our network businesses. We find this perplexing, given that EnergyAustralia has provided annual regulatory accounts to ACCC; we have diligently provided all cost allocation methodologies to both ACCC and IPART to ensure no "double dipping" has occurred; we sought, and were granted, a transmission ring-fencing waiver from ACCC which endorsed our application that the net public benefits of further systems and legal separation of our networks would be far outweighed by the additional costs (discussed in section 1.2.1); and we approached ACCC to seek a change to the interpretation of the definition of transmission assets to enable the improved reporting of costs (which was denied). We believe GHD's comments in this regard are entirely unsubstantiated.
- Approximately $90m of EnergyAustralia's distribution assets will fit the definition of transmission assets from 1 July 2004 due to changes in the configuration and operating of the network. These assets have been transferred from the distribution asset base (and revenue cap) to the transmission asset base. The change to the size of the transmission asset base has necessarily resulted in the increased size of the operating program.
- The lack of detailed review by GHD or ACCC of our operating proposals has resulted in the simplistic application of future operating expenditures based on historical expenditures to set a "starting point" for future expenditures. This is clearly inappropriate as it ignores the fundamental issue that more activity will be undertaken in future.
- The calculation of future operating expenditures based on a starting point containing a "general efficiency" factor is again a simplistic approach that enables GHD and ACCC to make unsubstantiated reductions without any accountability for the impact that the reductions may have on outcomes. This is totally unacceptable.

1.2 ENERGYAUSTRALIA'S ALLOCATION METHODOLOGY

EnergyAustralia operates a combined distribution and transmission business. Transmission assets contribute approximately 12 percent of EnergyAustralia's total network assets.

The National Electricity Code defines EnergyAustralia's transmission assets to be those assets that are operating at a voltage of 66kV and above which are operated in parallel to other transmission assets. Prior to the revenue cap review process, EnergyAustralia requested the ACCC to deem EnergyAustralia's transmission assets to be those assets that have a voltage of 66kV and above only. EnergyAustralia believed that this voltage-based definition would simplify the way it could attribute costs to the distribution and transmission networks and make the allocation of joint costs more transparent for both regulators.

In July 2002, ACCC rejected EnergyAustralia's request to change the definition of transmission assets for EnergyAustralia. This has resulted in the existing definition continuing into the 2004-2009 regulatory period. The reasons for the ACCC's decision were included in the introduction to EnergyAustralia's initial submission and therefore are not repeated here.

The transmission definition in the Code enables similar assets to exist in both the distribution and transmission networks. They are allocated to one regulator or the other on the basis of the network's configuration at a point in time. Not only does the definition allow assets to change classification from one period to the next, the definition also allows assets to change classification within periods.

While EnergyAustralia has a number of assets that are classified as transmission, their characteristics in terms of planning, function, and utilisation much more closely resemble distribution assets than transmission assets. Variability and uncertainty in local network loads will be significantly higher than those experienced in the backbone transmission network where there is much greater diversity of loads. Individual projects can be expected to vary in cost, timing and scope to a much greater degree than traditional transmission assets, and this should be considered an inherent characteristic of electricity (particularly distribution) networks. As EnergyAustralia's long term strategy of 132kV sub-transmission is gradually realised over the coming decades, and EnergyAustralia's 132kV network becomes increasingly meshed, there will emerge an issue of "classification creep", where significant amounts of assets providing an essentially distribution function will be classified as transmission. This will require either a more flexible approach to transmission regulation, or a definition that better classifies these assets as distribution.

EnergyAustralia and ACCC have agreed that for the purposes of regulation, EnergyAustralia assets will maintain the classification as at the beginning of the period for the five year period and will be reviewed at the end of the period, therefore ensuring consistency within any one regulatory period. We believe this to be a pragmatic solution to a potentially complex arrangement, and we welcome the ACCC's acceptance of this approach.

Most transmission businesses are able to allocate direct operating costs to asset classes. EnergyAustralia is also able to do this. However, due to similar assets being present in both networks, these direct costs must also be allocated to one set of regulatory accounts or the other. Similarly, where joint costs arise for the network, these cost must be allocated to one regulator or the other. Further allocation occurs at the corporate level where joint administration costs are allocated to the Network business (distribution and transmission) and the other businesses that EnergyAustralia operate such as our Retail and External businesses.

EnergyAustralia has gone to great lengths to explain the complexity of the allocation process. The ACCC's Draft Determination accurately reflects EnergyAustralia's move to a new method of allocating costs which, EnergyAustralia believes will better represent the true costs of the transmission network. However, the fact remains that EnergyAustralia's transmission opex is difficult to calculate with accuracy and therefore difficult to compare with the 1999 forecasts of transmission opex.

It is within this complex environment that EnergyAustralia has produced information for ACCC and its consultants in relation to opex for the transmission network. EnergyAustralia does not believe that the 1999 and 2004 forecasts for opex can be easily compared due to the changes in asset base, and the changes to the allocation methodology.

Transmission Ring-Fencing waiver

EnergyAustralia received a waiver from its obligations to legally separate its transmission and distribution networks under the ACCC's transmission ring-fencing requirements in December 2003. EnergyAustralia submitted a waiver application on 29 October 2002 following the release of the ACCC's guidelines in August 2002. The application sought a permanent waiver of the requirement for legal separation of EnergyAustralia's transmission and distribution businesses on the basis that the costs and difficulties in complying with the guidelines far outweighed any public benefit in doing so.

In its application, EnergyAustralia explained the substantial costs involved in legally separating the two network businesses. Not only would there be difficulties in operating the two integrated networks separately, the legal and financial issues involved in separation are also significant and would require shareholder agreement. The most significant costs are likely to involve duplication of IT systems and licenses, and duplication of operations including network control, network billing and the customer contact centre. These are areas where significant savings have been achieved in the past.

The ACCC agreed that the separation of EnergyAustralia's transmission and distribution businesses was not in the public interest and therefore granted a waiver to EnergyAustralia in regard to the legal separation requirements contained in the Ring-Fencing Guidelines. The ACCC stated that "there will be significant costs associated with meeting this particular ring-fencing requirement"[26] and there appeared to be "no apparent benefit in enforcing the ring-fencing requirement that (EnergyAustralia's) transmission service be a separate legal entity."[27] In making this decision, the ACCC noted IPART's ring-fencing requirements that were in place in relation to competitive and monopoly services carried out in the distribution business which would prohibit cross-subsidisation between the two.

1.3 GHD'S APPROACH

GHD reviewed EnergyAustralia's operating program, but GHD did not conduct a line-by-line assessment of the proposed program. Instead GHD undertook what it described as a 'top-down' driver analysis. In using the top-down driver analysis, GHD looked at EnergyAustralia's overall network operating costs, made simplistic assumptions about the drivers of these costs and then recommended (downward) adjustments to EnergyAustralia's operating program on the basis of high level observations about how the drivers might effect the operating program moving forward.

EnergyAustralia does not believe that GHD's approach is appropriate for a sophisticated and integrated network service provider. EnergyAustralia is also extremely disappointed that a change of approach for the review was agreed upon between GHD and ACCC and was not communicated to EnergyAustralia until GHD's report was completed.[28]

Furthermore, GHD used information that was not appropriate, such as EnergyAustralia's Annual Report, which included cost information for the Retail, Trading, Distribution and External

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[26] *Application for Waiver of Ring-Fencing Arrangements by EnergyAustralia*, ACCC 10 Dec 2003, p 6.
[27] ibid p 6.
[28] The clarification of GHD's terms of reference was not provided to EnergyAustralia. EnergyAustralia became aware of the clarification after GHD had provided an advanced copy of their final report to EnergyAustralia just prior to its release.

businesses, none of which are the subject of the ACCC's review. EnergyAustralia believes that GHD's approach was flawed and that the conclusions reached by GHD were arbitrary and are not based on substantive evidence.

EnergyAustralia is also critical of the ACCC's decision to apply GHD's recommendations given that they were based on high level estimates of how the identified drivers might affect EnergyAustralia's operating program.

1.4 GHD DRIVER ANALYSIS – STARTING POINT

In order to establish whether EnergyAustralia's level of operating costs was a reasonable starting point for opex in 2004, GHD assessed EnergyAustralia's actual 1999-2004 operating costs to establish a view of whether inefficient expenditure had occurred. Once GHD had established what they considered to be an efficient starting point, GHD then reviewed the forecast opex to determine whether the levels of opex sought for the 2004-2009 period were efficient.

EnergyAustralia believes that GHD made fundamental errors in their analysis of the appropriateness of the starting point. The following section addresses the drivers GHD investigated and which the ACCC has applied to EnergyAustralia's forecast operating program.

1.4.1 Comparison of historic opex with 1999 forecasts

Purpose of comparing forecasts with actual costs

Comparing historic operating costs with those forecast in 1999 is not a simple task in the context of EnergyAustralia's transmission business. Not only has the method of allocating costs changed, the number of assets considered to be transmission assets has also changed. In these circumstances, one must choose the basis upon which to compare actuals to forecasts.

However, prior to making such a comparison, one needs to question the purpose of such analysis. In comparing actuals with forecasts, GHD has assumed that the 1999 forecasts of transmission opex represented an efficient level of opex spending. It is not clear to EnergyAustralia on what basis such a conclusion could be reached. To EnergyAustralia the results of such analysis merely explain that there are differences between forecasts of costs and actual costs incurred. Any value judgement relating to the efficiency or otherwise of either number must be based on other information.

Basis of comparing forecasts with actual costs

GHD and ACCC have chosen to compare EnergyAustralia's historic performance on the basis of EnergyAustralia's global allocation method which exacerbates the difference between forecast costs and historical spend. This choice is disappointing because GHD and ACCC have both acknowledged that the new method of cost allocation is likely to be a more accurate reflection of the true cost of the transmission business.

The choice made by ACCC and GHD to compare 1999-2004 forecasts with 1999-2004 actuals was based on the assumption that the forecasts for opex in 1999 were developed using a global allocation methodology. This is in fact <u>not</u> the case. The operating costs for the last regulatory period were projected on a basis equivalent to that proposed for the next regulatory period. Thus, the 1999-2004 forecasts were prepared on a largely consistent basis as the 2005-2009 forecasts.

Past transmission operating costs have been reported for regulatory purposes on the basis of the more simplistic global allocation methodology. This means that it is not possible to meaningfully compare the 1999-2004 *forecasts* with 1999-2004 *actuals*, or the 1999-2004 *actuals* with the 2005-2009 *forecasts*.

If the ACCC remains convinced that comparison of forecast and actual opex is relevant, the most accurate allocation method upon which to compare operating costs for the last regulatory period is on the basis of the revised allocation method. This is because it more accurately reflects the method used for projecting opex costs at the time of the last regulatory period and is consistent with the methodology used for future expenditure. As a result of using the revised allocation methodology as the basis for comparison, the average difference between allowed and actual operating costs has averaged approximately 12 per cent.

1.4.2 Superannuation

The GHD report has taken superannuation costs from EnergyAustralia's Annual Report which reports the costs of the entire group, including the Distribution, Retail and External Businesses, none of which are the subject of this review. The use of the Annual Report information to adjust for allegedly inefficient costs in the transmission business is completely inappropriate and has led to erroneous outcomes.

EnergyAustralia's superannuation is part of the Energy Industries Superannuation Scheme. The costs of the scheme are projected on the basis of annual independent actuarial assessments of the projected performance and liabilities of the fund.

As ACCC points out, ordinary superannuation costs have risen markedly in the last regulatory period due to the increasing rate of superannuation required to be paid by employers (now 9%) and the increased number of employees at EnergyAustralia.

There are many employees at EnergyAustralia who remain on a Defined Benefits Scheme for superannuation and who have entitlements that are determined on the basis of a formula that takes into account the employee's salary and years of service, amongst other things. It is the responsibility of EnergyAustralia to ensure that sufficient funds are set aside to meet the benefit required.

Under a defined contribution (superannuation) plan the employer makes a fixed contribution to the employee's superannuation fund (a "defined contribution"). This contribution is generally specified in terms of a fixed percentage of salary. The minimum federal required contribution rose from 8% of salary to 9% of salary during the last regulatory period. Under this arrangement, the employee bears the risk that there will be sufficient earnings in the superannuation fund to finance the employee's retirement.

Under a defined benefit plan, the employee's retirement benefits are stated in specified terms, for example 80% of the average of the last 5 years salary before retirement. It is incumbent on the employer to ensure sufficient resources are available in the fund to finance these stated retirement benefits. The required balance in the fund at any time is determined by actuarial analysis taking into account the age of the employees, expected post-retirement lifespan, salary calculations etc. If the fund performs well, the amount of employer contributions will be small. However, if the fund performs poorly, as has been the common experience in the last few years, the employer must make larger contributions to ensure the balance of the fund does not fall below its actuarially determined liabilities.

These defined benefit plan contributions are the main driver of increased superannuation costs relative to the forecast.

The additional superannuation costs questioned by GHD and ACCC were the result of a shortfall between fund earnings and liabilities. The expenses associated with movements in the provisions account of superannuation defined benefit scheme are not abnormal. Rather, they represents an exposure to volatile performance of securities, interest rates and other variables.

Without the funds moving forward, EnergyAustralia will not be in a position to cover ongoing defined benefit superannuation liabilities. The ongoing long run expense associated with this represents an ordinary and legitimate business expense that should be recognised by ACCC. Over the past regulatory period, the annualised difference between EnergyAustralia's stake in the defined benefit scheme and the gross liability has been $13.8m, which when allocated to transmission, is approximately $1.38m.

The most sensible treatment of this normal superannuation expense in light of its fluctuating nature, is to substitute an annualised amount for the actual amount expensed for 2004. This produces a more appropriate starting point for a future assessment of opex.

This treatment is consistent with GHD's approach that attempted to 'smooth' the expenses associated with falling liability provisions. In doing so, GHD recognised that these expenses were not abnormal, but rather reflect the ongoing deficiency of an unfunded superannuation liability.

ACCC must recognise the legitimate expense of funding superannuation and must not arbitrarily disregard costs that constitute EnergyAustralia's legal obligations of continuing to fund the Defined Benefit Scheme.

1.4.3 Purchasing policies

EnergyAustralia notes that GHD has recommended imposing a reduction to the starting point of opex on the basis that EnergyAustralia has in the past used purchasing policies that have been based on least cost without appropriate regard for the life-cycle or cost of the diversity within the portfolio of assets.

EnergyAustralia rejects this proposal put by GHD and state that purchasing decisions have always been made with the total costs of the assets in mind. EnergyAustralia, as a prudent business, reviews its purchasing policies regularly to ensure that the most efficient purchases are being made.

EnergyAustralia notes that ACCC has not made an explicit adjustment to the opex starting point on the basis of GHD's spurious recommendation. However, ACCC had not ruled out doing so in the final decision. EnergyAustralia asserts that we have carefully reviewed the timing of expenditures and we maintain that our current approach to purchasing is efficient. Furthermore, the programs included in our submission already take these efficient costs into account.

1.4.4 Insurance

ACCC and GHD have both questioned the significant increase in insurance costs faced by EnergyAustralia in 2001/02. While GHD and ACCC have accepted EnergyAustralia's arguments regarding general insurance cost increases following the events of September 11, 2001, ACCC has failed to understand the significant impact that the collapse of HIH Insurance had on EnergyAustralia.

EnergyAustralia's original submission explained that a major factor accounting for the significant increase in insurance costs in 2001/02 related to a provision for expenses relating to the collapse of HIH Insurance. The amount of this provision was determined by an independent actuarial estimate. The total provision was $8.6 M of which $5.1M related to the Network business.

1.4.5 Consolidation of EnergyAustralia

ACCC has made comments in relation to future savings that can be expected from further consolidation of EnergyAustralia. These remarks come as a surprise to EnergyAustralia and have not been based on information provided by us. We note that ACCC has not made a specific adjustment for efficiency savings in this area but has included them in its consideration of "general" opex efficiency.

Over the past 10 years, EnergyAustralia has undergone significant organisational consolidation. However, EnergyAustralia believes it is extremely unlikely that further consolidation of distribution or transmission businesses will continue in NSW in the future.

In contrast, the recent discussion paper released by the NSW Government on the possible restructure of retail trading arrangements may lead to changes to the organisation. However, EnergyAustralia believes that any changes will not be in the form of consolidation, but rather may be a separation of parts of EnergyAustralia's business. If a separation was to occur, EnergyAustralia's network business is likely to sustain increased costs in the form of administration and corporate overheads which are at the present time shared between the Network and Retail lines of business. While providing overall benefits to the market, it may result in high network costs depending on the approach adopted.

In this context, and in the context of EnergyAustralia's significant increase in staff numbers during the next regulatory period (discussed below) it is difficult to see how consolidation savings will eventuate.

1.4.6 Full Retail Contestability (FRC)

ACCC commented in its draft determination that costs associated with Full Retail Contestability should not be included in the transmission operating costs.

No compliance costs associated with FRC (Full Retail Contestability) costs have been allocated to EnergyAustralia's transmission business. These costs were clearly identified in EnergyAustralia's Distribution submission to IPART and reviewed as part of the Distribution review process.

1.4.7 Staffing and productivity

GHD made recommendations to ACCC to adjust the opex starting point to take account of efficiencies that should have been achieved through staffing and productivity improvements during the last period. EnergyAustralia notes that ACCC has not made a specific adjustment for this factor but has included any improvements in the 'general efficiency' adjustment.

EnergyAustralia believes that GHD has failed to recognise the real costs of labour to its business. EnergyAustralia is in the process of increasing its staff numbers in primarily in recognition that past maintenance levels have been inadequate. Furthermore, the size of EnergyAustralia's future program of capital works has prompted the company to recruit a large number of new staff as apprentices, engineers and technicians. As outlined in ACCC's Draft Determination, EnergyAustralia is facing a continued high level of competition for skilled staff in the NSW electricity sector which has resulted in increasing staff costs.

GHD has also failed to recognise the increasing costs of existing staff. GHD's analysis makes no allowance for the increases in labour costs associated with the progression through the Award structure of older employees. EnergyAustralia has calculated that the impact of progression adds approximately one percent to labour costs per annum.

EnergyAustralia also refutes GHD's contention that recruitment and training costs for new staff can be offset with the lower salaries of trainee staff. Enerserve, EnergyAustralia's service provider, has undertaken analysis that shows the *net* cost to EnergyAustralia of apprentices to be $150,000 over four years of training. This figure takes into account the salaries paid to apprentices, the cost of training and the value of work performed by apprentices during the four-year period. GHD's comments that the costs of recruiting and training new staff is offset by lower salaries "and hence have no overall impact on opex costs"[29] is simply erroneous.

GHD also noted that expected productivity improvements were not been identified by EnergyAustralia and that future productivity gains from Reliability Centred Maintenance (RCM) (see below) will not occur in the 2004-2009 regulatory period. EnergyAustralia does not believe that GHD has provided an accurate description of EnergyAustralia's circumstances.

As mentioned above, EnergyAustralia notes that ACCC has not made an explicit adjustment to opex for productivity but has incorporated the expected efficiencies in its 'general efficiency' adjustment. Given the flawed basis upon which GHD has recommended savings in these areas, EnergyAustralia argues that the 'general efficiency' adjustment is also flawed and in fact double counts efficiency savings achieved in other areas.

1.4.8 Maintenance

EnergyAustralia notes that it appears to have receive the support of both ACCC and GHD for its Reliability Centred Maintenance (RCM) program. The RCM program is expected to deliver long-term efficiencies to the maintenance of the network. However, it should be recognised that EnergyAustralia is at the commencement of this program and that initially costs are expected to increase before long-term efficiencies are achieved.

[29] ACCC Draft Determination, p 62.

ACCC claims that costs of moving to RCM have not been shown (see following section for a description of these efficiency gains already incorporated). EnergyAustralia is concerned by these comments given the comprehensive set of briefings that were undertaken for the benefit of ACCC and its consultants.

EnergyAustralia explained that the RCM program would deliver long-term efficiencies to the network but that in the initial stages of implementation there was likely to be a catch up period where the costs of the RCM program were likely to be higher than the current maintenance costs. This is in keeping with the experience of other organisations that have made this transition and GHD would do well to research this point. EnergyAustralia explained that it had forecast costs to settle to a more normal level after the catch-up phase had been completed.

1.4.9 General opex efficiency

ACCC in its draft determination referred to GHD being surprised that they "did not find any evidence that such gains were pursued or achieved by EnergyAustralia". EnergyAustralia strongly refutes this claim as simplistic and not consistent with information provided to ACCC and with GHD's own conclusions on various aspects of spend.

As mentioned in the sections above, EnergyAustralia was able to achieve efficiencies in corporate overhead costs and is in the process of implementing a system that will generate long run efficiencies in maintenance practices (RCM). GHD acknowledged the work undertaken by EnergyAustralia to improve the long-term costs of purchasing equipment and also acknowledged the significant increase in costs EnergyAustralia has sustained as a result of the changing OH&S environment and the insurance market.

EnergyAustralia therefore finds GHD's comments in relation to evidence that efficiency gains having not been pursued by EnergyAustralia as baseless and as misrepresenting the significant amount of work undertaken by this business to improve systems. This appears to us to confirm the ACCC's general presumption that arbitrary cuts need to be found.

ACCC has unfortunately taken GHD's recommendation to impose a reduction in the efficient level of opex of 0.5 percent per year. ACCC writes that

> "The case for the efficiency gain recommended by GHD is supported by the fact that there are some additional areas where efficiency gains could have been expected, but for which no specific adjustment has been made to the amount that should have been spent by EnergyAustralia in the 1999-2004 regulatory period."[30]

EnergyAustralia has refuted the basis for GHD claims for further achievable efficiencies in the following areas – superannuation, insurance, purchasing policies, consolidation of EnergyAustralia, FRC and staff productivity. GHD's recommendations for a general efficiency reduction has no basis and if implemented, double counts efficiencies already taken into account by EnergyAustralia in future operating costs forecasts. It is somewhat alarming to EnergyAustralia that the ACCC would use such arbitrary estimates of achievable efficiencies to impose real operating cost reductions which could materially impact the ability of the network to meets its obligations.

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[30] ACCC Draft Determination for EnergyAustralia p 63.

1.5 DRIVER ANALYSIS – EFFICIENCIES IN OPEX 2004-2009

The calculation of future operating expenditures based on a starting point that contains a "general efficiency" factor is again a simplistic approach that enables GHD and ACCC to make unsubstantiated reductions without any accountability for the impact that the reductions may have on outcomes. The impact on future opex is totally unacceptable.

Given the flawed basis upon which GHD has recommended savings in these areas, EnergyAustralia agrees that the "general efficiency" adjustment is flawed and double counts efficiency savings achieved in other areas.[31] The effect of the general efficiency adjustment to the starting point, however, is a much more severe penalty as it lowers the "base" for all future years.

1.5.1 Reliability Centred Maintenance (RCM)

EnergyAustralia is pleased that ACCC has accepted GHD's recommendation to accept costs associated with EnergyAustralia's RCM program. It is a significant step for EnergyAustralia and will deliver industry best practice systems to manage our aging and critical infrastructure.

GHD dealt specifically with the issue of the move to Reliability Centred Maintenance (RCM) in their report and stated that:

> "The move to RCM provides substantial long-term benefits to the organisation as a whole and will deliver ongoing opex efficiencies. However, the savings tend to apply to the most significant assets and as such the same savings are not apparent within the Transmission figures provided."

GHD then reported a table of data comparing forecast maintenance costs under both time based and condition based regimes. This data illustrates a total real ($2003/04) saving of $6M (7%) over the next regulatory period. By the last year of the regulatory period the condition based maintenance regime achieves a saving of around 15% in maintenance costs as compared to a time based approach.

GHD's own work demonstrates the real efficiency gains embodied in RCM and it is extremely disappointing that GHD have misrepresented EnergyAustralia's proposed operating program as not already including efficiency improvements.

1.5.2 Information Technology (IT)

GHD commented that EnergyAustralia should focus its IT spending in the next regulatory period on achieving efficiencies by consolidating existing systems. GHD states that such savings could be expected to be in the range of 1-5 percent per annum with a one year lag. This recommendation is not supported by information provided by EnergyAustralia to ACCC and GHD. EnergyAustralia must therefore conclude that the savings estimates are the result of separate analysis of similar IT savings in other businesses (such analysis has not been provided to EnergyAustralia nor sourced in GHD's report) or may be a simple estimation of savings in this area.

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[31] The ACCC notes (p 71 Draft Determination) that such a factor was applied to Transend in the ACCC's final decision and to TransGrid in the ACCC's draft.

EnergyAustralia has a substantial IT expenditure program planned for the coming regulatory period. The forecast program corrects the under-investment in network IT systems which has occurred during the 1999-2004 period. This was a result of the organisation giving priority to IT spending associated with FRC and national market compliance during the last regulatory period.

As stated by ACCC, IT spending will be focussed on delivering compliance and risk management. EnergyAustralia's IT strategy for the next five years will concentrate on delivering the following:

- Provision of integrated asset management systems which support the determination of optimum asset life cycle performance and risk trade-offs aligned with community expectations;
- Review and establishment of billing and accounting systems which ensure capture of network revenue and appropriate allocation of costs;
- Maintenance of contemporary telecommunications, service order management, outage management and dispatch systems which address customer service requirements, community safety standards, and duty of care;
- Provision of project and works management systems which support the effective management of the network maintenance and capital works programs; and
- Enhancement of efficient reporting systems which meet business and regulatory needs.

A key aspect of the strategy is the development of the existing SAP enterprise architecture and the Smallworld GIS. Also, considerable effort is envisaged in the definition, capture and cleansing of appropriate data in the appropriate format.

While EnergyAustralia will seek to improve the efficiency of its IT spending over the regulatory period, its current position with regard to appropriate business systems makes it imperative that appropriate investment occurs. Given GHD's scathing comments in relation to EnergyAustralia's information systems, it appears entirely inconsistent and opportunistic for GHD to subsequently recommend cuts to the program. From EnergyAustralia's perspective, IT spending is a crucial component in ensuring that the business is able to meet its regulatory, safety and financial obligations as a publicly owned company. Any cuts in the area of IT spending may compromise the company's ability to deliver such outcomes. EnergyAustralia considers that GHD's recommended funding reductions are ill considered and contradictory.

Furthermore, it is apparent that both ACCC and GHD have recommended and accepted cuts to forecast opex on the basis of supposed efficiencies generated by IT spending. However, EnergyAustralia believes it is naïve to suggest that savings are likely to be delivered as a result of introducing and maintaining the IT projects listed above. An improved reporting information system, an outage management system and a better asset management system will enable EnergyAustralia to better understand the needs of its network, and will allow EnergyAustralia to respond better to customers needs. It is not clear how the maintenance of these systems will deliver cost savings equivalent to 3 percent per annum over a five year period.

EnergyAustralia notes that the ACCC chose 3 percent as a mid-point between 1-5 percent savings estimated by GHD. EnergyAustralia argues that the1-5 percent savings proposed by GHD have not been substantiated by GHD and therefore, the ACCC's use of a mid-point of such an estimate is equally baseless. EnergyAustralia would expect to see better analysis from GHD before making such significant cuts to forecast spending in such a crucial area as IT.

EnergyAustralia is disappointed that ACCC has relied on GHD's unjustifiable recommendations to arbitrarily slash spending.

1.5.3 Customer service levels

ACCC made several comments in its Draft Determination which are of concern to EnergyAustralia in relation to customers. While the ACCC has not suggested making an efficiency adjustment for this issue, the comments suggest that ACCC does not understand the costs imposed by customers on a network business.

> "The ACCC considers that most of EnergyAustralia's customer service costs should be excluded from the regulatory activity, as customer service operations should form part of EnergyAustralia's retail activity."[32]

The statement appears to be based on a misunderstanding of the functions carried out by the Customer Service division of EnergyAustralia. The functions undertaken for the network business are set out below.

EnergyAustralia's Customer Service division manages the delivery of most connection services as an integral part of the network line of business. EnergyAustralia's network business has 1.4 million customers within its franchise network. While most of these customers connect to the distribution network, a number of customers connect directly to the transmission network. Both the transmission and distribution networks use the services rendered by the Customer Services division.

Customer Service becomes involved in the conceptual stage of a customer's connection. This may involve considerable community consultation and general planning input as well as dealings with consultants, and local and state government. The typical process involves initial discussions and assessment of demand and profile followed by preparation of design briefs of acceptable connection options to enable the customer to prepare a design of the connection asset.

Customer Service also coordinates the construction process with the customer, and Enerserve and or an external service provider. Customer Service's inspectors also inspect the work of external service providers for compliance with Safety, Environmental and Network Standards.

Customer Service also handles all requests for major asset relocations and this often entails transmission assets. This work also requires extensive communications, design preparation, arranging of estimates and project coordination, including management of the contestable process and inspection of works if carried out by external service providers.

The ACCC's statement above that customer costs should be borne by EnergyAustralia's Retail business reveals no understanding of the real costs that customers pose to a network business, particularly in relation to a network's NEM obligations. It is relevant to note that approximately 60% of the costs of EnergyAustralia's Customer Service division are charged to the Network line of business as a result of Network specific activities undertaken by Customer Service.

[32] ACCC Draft Determination for EnergyAustralia, p 69.

1.5.4 Corporate and contractor costs

EnergyAustralia welcomes the ACCC's decision not to make an adjustment to forecast operating costs for future changes to corporate and contractor costs. As mentioned in section 1.3.5 above, EnergyAustralia does not believe the trend for overhead costs will be downward if steps are taken at a NSW Government level to separate EnergyAustralia's Retail business. If such a move were to take place, EnergyAustralia's network business would face higher corporate costs than is the case under the current shared arrangement.

1.5.5 Confidential project

GHD was provided with information in relation to a procurement project that is in the initial stages of development. The purpose of providing this information to GHD was to demonstrate EnergyAustralia's active pursuit of efficiencies in the area of procurement.

The information provided by EnergyAustralia was indicative only and had not been tested. Furthermore, the program which is in the early stages has not been implemented. EnergyAustralia believes it is therefore inappropriate that $5.6m of proposed savings (or 30% of ACCC's total opex cuts) should be imposed on EnergyAustralia on the basis of such incomplete information. We note that GHD did not undertake any subsequent analysis to determine whether such efficiency savings were achievable or not.

EnergyAustralia believes that efficiency benefits achieved from this type of strategy should be shared between the business and customers. GHD's recommendation for aggressive reductions to transmission opex up front **do not** meet the objectives of incentive regulation, particularly as they appear to have ignored the risks of project implementation let alone benefit sharing. EnergyAustralia believes that the ACCC should review this matter in light of both the uncertainty of the expected savings and as well as the lack of incentive EnergyAustralia has to undertake the project at all.

1.6 SELF-INSURANCE

EnergyAustralia submitted a comprehensive report from Trowbridge Deloitte that actuarially assessed the cost of self-insured risks currently borne by EnergyAustralia's network. Trowbridge allocated $0.44m of the self-insurance costs to the transmission network. The remaining $5.58m was allocated to EnergyAustralia's distribution network.

ACCC, as set out in its draft determination, requires EnergyAustralia to provide formal advice from its Board that confirms EnergyAustralia's intention to self-insure for the risks set out in the Trowbridge report. This formal advice will be forwarded separately.

EnergyAustralia notes that ACCC has removed an allowance of $20,000 per annum for current insured risks held by EnergyAustralia from transmission opex and has instead included losses under insurance deductibles as a pass-through item. EnergyAustralia is concerned that by making this change the ACCC has under-compensated EnergyAustralia for the true costs of this risk.

This issue is discussed in more detail in the chapter on the ACCC's treatment of the Pass Through Rules. In summary, EnergyAustralia believes that by removing this part of the premium from the self-insurance premium, the ACCC has left EnergyAustralia exposed to bearing claims of less than $10m itself without having any way of recovering these costs (ie no pass through, and no self-insurance allowance).

EnergyAustralia believes that this has been an inadvertent mistake made by ACCC and believes that the removal of the allowance from the self-insurance premium should be reversed to ensure that EnergyAustralia is able to cover Trowbridge Deloitte's calculation of EnergyAustralia's liability.

WACC

1.1 LOW BY INTERNATIONAL COMPARISONS

EnergyAustralia engaged NECG to review and provide advice to EnergyAustralia on the positions taken by the ACCC in its draft determination. NECG's report is included as Attachment 1 to this submission.

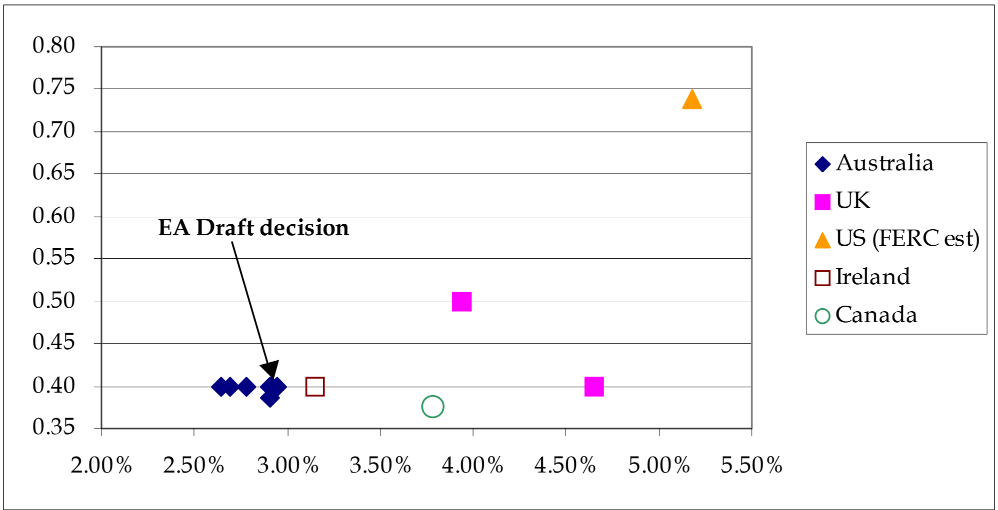
The NECG report focuses on four key areas of difference between the parameters proposed by EnergyAustralia and the draft determination, namely:

- the risk free rate;
- the debt margin;
- debt issuance costs; and
- beta.

This limited focus reflects the fact that the WACC model used by the ACCC and a number of the parameter values are identical or similar to those initially proposed by EnergyAustralia.

The WACC in the draft decision, while similar to previous decisions by the ACCC in electricity transmission, is still considerably lower than that implicit in comparable decisions adopted by overseas regulators. Figure 2 - sets out the margin of the vanilla WACC over the prevailing 10 year Government bond for various electricity transmission decisions, with these all reflecting the outcome that would have occurred had the relevant overseas regulator adopted a market risk premium of 6%. In NECG's opinion this is the most credible approach to comparing international WACC allowances.

Figure 2 - Comparison of electricity transmission decisions



Source: NECG submission to the Productivity Commission, September 2003 (Number 56). ACCC decisions since this date have been added (Murraylink, Transend, Transgrid/EnergyAustralia).

NECG notes that while this approach to comparing regulatory decisions has been criticised by the ACCC and its consultants, the Allen Consulting Group, neither party has provided a superior approach to analysing WACC allowances in regulatory decisions. The only alternative provided by the ACCC was the comparison of total returns. However, this approach is a more restrictive measure as it assumes that investors expect the real exchange rate to remain constant and that there is no country risk premia embedded in risk free rates.[33]

1.2 WACC PARAMETERS

The following sections summarise the main findings in the NECG Report (Attachment 1) concerning the WACC parameters contained in the ACCC's draft decision.

1.2.1 Risk free rate

In the case of the risk free rate, it is not the actual allowance that is of concern, but rather the ACCC's statements indicating that its "preferred position" is significantly lower than the value provided. EnergyAustralia believes this exposes it to transparent regulatory risk arising from the ACCC exercising "regulatory judgement".

NECG also supports the ACCC's decision to base the risk free rate on the 10-year Commonwealth Bond. However, despite the unequivocal nature of the Australian Competition Tribunal's decision on GasNet, NECG is concerned that the ACCC may still argue in favour of matching bond maturity with the length of the regulatory period. Furthermore the ACCC does so without providing supporting justification – at least in the draft decision. To reduce the risk of unpredicted changes to the regulatory regime, the ACCC should more explicitly set out its reasons for choosing the 10-year bond rate in its final decision.

1.2.2 Debt margin

The ACCC's approach to the debt margin will understate the required debt margin for an efficient benchmarked transmission business. Inclusion of Government owned comparators in the list of benchmark companies violates principles of competitive neutrality, systematically biases the credit rating upwards and systematically biases the allowance downwards.

This implies the ACCC should consider other approaches to determining a credit rating, such as consideration of a wider sample of similar private companies or consideration of the underlying cash flows of the business in greater detail. While the ACCC does this to some extent in its calculation of financial ratios, errors in the calculation of EBIT means that the figures in the draft decision overstate the credit rating derived from the draft decision. Correcting for this error results in a benchmark credit rating of "BBB+", not "A" as stated in the draft decision.

Mathematical errors in calculating the debt margin

In reviewing the draft determination EnergyAustralia identified that the ACCC made some fundamental errors in calculating key ratios and cashflows used in its assessment of EnergyAustralia's credit rating against the criteria of Standard & Poors. The net impact of the errors identified by EnergyAustralia lowers the average credit rating for EnergyAustralia under

[33] For further details see NECG's submission to the Productivity Commission Review of the Gas Code in March 2004 (DR97).

the ACCC's draft determination from "A" to "BBB+", which EnergyAustralia understands is the determining factor for the ACCC's decision for EnergyAustralia's debt margin. ACCC stated in its draft decision:

> *"(I)n determining EnergyAustralia's WACC, the ACCC benchmark EnergyAustralia's gearing at 60% and set the debt margin based on a benchmark credit rating of 'A'"* [34]

EnergyAustralia submits that the ACCC must review its calculation of the WACC in light of the errors discussed below. Furthermore, EnergyAustralia believes that prior to the finalisation of the determination that the ACCC provides its financial analysis to stakeholders to ensure that the modelling used in its analysis is technically correct and does not contain further errors.

Calculation of EBIT and the debt margin

In determining a value for EBIT the ACCC has failed to deduct depreciation and amortisation expenses. This leads to overstated values for all of the earnings, profitability and dividend measures used in the financial analysis that the ACCC relies on to determine WACC parameters such the debt margin.

EnergyAustralia submits that the ACCC must ensure that calculations of EBIT include the required deduction for depreciation expenses, if not the ACCC is not using the appropriate financial concept for its analysis and is instead using EBITDA. The effect of using EBITDA instead of EBIT is that the subsequent calculations are based on overstated returns, thereby producing a credit rating that is higher than the cash flows should suggest. Given the ACCC's reliance on its credit rating calculations as noted above, correcting for this error would result in a higher WACC *a priori* as the debt margin would need to increase by approximately 20 basis points to reflect the lower credit rating.

Calculation of transmission cashflows

The ACCC's approach to modelling EnergyAustralia's cashflows is a simplistic extrapolation of historic information. EnergyAustralia believes there are two major problems with this approach.

Firstly, the WACC is developed in a forward looking framework, and therefore the ACCC should have adopted an approach that models cashflows based on expected cash outcomes. Secondly, the ACCC has erroneously used historical information relating to EnergyAustralia's total network business, rather than its transmission business as regulated by the ACCC.

EnergyAustralia submits that both of these errors can be easily corrected when the appropriate conceptual framework is applied for assumptions of future cashflows. EnergyAustralia believes that the ACCC should simply use the expected closing cash balance for the 2003/04 financial year and "roll-forward" this balance annually by adding the net assumed future cashflows. The net forecast cashflows is most appropriately calculated as the difference between the smoothed and unsmoothed revenues contained in the draft determination.

The rationale for this approach is simply that all allowed revenues for a TNSP are for specific purposes, and as a result the regime is theoretically cash neutral in the long term. Each of the

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[34] See ACCC Draft Decision – NSW and ACT transmission Network Revenue Caps – EnergyAustralia 2004/05-2008/09 p 124.

building blocks can be explicitly linked to an equal assumed cash outflow as set out in the table below.

Table 7 - Regulatory parameters and their related cash outflows

Regulatory cashflow parameter	Related cash outflow
Return on capital	Dividends and interest expenses
Return of capital	Repayment of the principal of borrowings and share buy-back[35]
Operating expenditure	Operating expenditure arising in the year
Income taxes payable	Income taxes attributable to profits for the year
Capital expenditure and gearing	These two concepts when viewed together demonstrate that when capital is invested there is a precisely equivalent raising of finance to support the investment, and is therefore theoretically neutral.

Therefore the only changes in the cash position of TNSPs that should be observed in the conceptual framework adopted by the ACCC, is where the notional and allowed revenues differ annually due to revenue smoothing considerations.

The assumed profile of cashflows over the regulatory period is an important aspect of developing the financial indicators used to derive the overall credit rating the TNSPs. Given that these calculations will influence the returns allowed, EnergyAustralia believes that the adjustment outlined above is necessary to ensure that the ACCC's modelling of financial indicators, and therefore the debt margin, is based on the most technically correct estimate of forecast net cashflows, and annual cash position.

1.2.3 Debt issuance costs

- While EnergyAustralia supports the ACCC for recognising that debt issuance is a significant cost that needs to be recognised, we believe that the allowance for debt issuance costs in the draft decision understates the cost to the firm of issuing debt.
- The allowance in the ACCC's draft decision (equivalent to 10.5 basis points on the cost of debt) is consistent with research initiated by the ACCC in the public debt market and similar to the allowance proposed by EnergyAustralia (12.5 basis points). NECG, however, believes there is credible evidence to support margins well in excess of these levels.
- In NECG's view, the empirical evidence that is available is consistent with a total debt issuance cost in the order of up to 0.50% on the cost of debt (or equivalent amount in the cashflows). We believe that the 25 basis points allowed by the Tribunal for GasNet is a lower bound on a reasonable estimate. For a medium-sized company such as EnergyAustralia that does not issue large amounts of debt, the issuance costs are more

[35] It is understood that the latter is a conceptual aspect of the regime and that such buy-backs would not necessarily occur annually but is necessary to ensure that the assumed level of equity investment is matched to the TNSP's contribution to the RAB.

likely to be in the range of an amount equivalent to 30 to 50 basis points on the cost of debt.

- With regulatory support for 25 basis points, NECG believes this represents a more appropriate allowance at this time.

1.2.4 Beta

The CAPM assumes all non-systematic (specific) risks are diversifiable and hence are not provided an expected return in a competitive market. The systematic risk (or beta) of a firm is the only risk factor incorporated in the CAPM.

The asset beta represents the risk arising from the sensitivity of the operating cash flows generated by an entity's assets compared with the market in general, that is, the market risk associated with an entity's business. Asset betas vary with the volatility of free cash flows and are driven by the sensitivity of those cash flows to fluctuations in the economy.

Some of the considerations that should be examined when estimating an appropriate asset beta for a regulated TNSP include:

- an assessment of comparable companies in Australia and overseas;
- regulatory decisions; and
- an assessment of the factors that impact on the sensitivity of the TNSP's returns to movements in the economy.

As was highlighted at the ACCC pre-determination conference on 18 June 2004, when assessing a TNSP's beta and in comparing results to international comparators, normalisation of the data is critical to ensure that the basis upon which the comparisons being made are in fact appropriate.

When attempting to derive an equity beta, this type of analysis would require the asset beta to be normalised on the basis of the relative gearing of the individual TNSP and the market to ensure that the differences in capital structure and risks are appropriately accounted for. Similarly, international comparisons require the relative natures of the markets to be accounted for as the reported asset beta for a comparator is its relative risk to the market in which it operates, and as such the profiles and compositions of the international markets are likely to be materially different to the Australian market, and must therefore be adjusted for.

Conclusion on asset beta

The ACCC notes that its allowances for the equity beta have been "generous" and "biased in favour of the service provider" compared with market data on beta. While the headline numbers in regulatory decisions are clearly higher than asset and equity beta values derived from listed infrastructure companies on the ASX, such a simple analysis does not take into account the statistical properties of the estimates.

The available evidence from the ASX does not support the ACCC's arguments for setting an equity beta for an electricity transmission business below one. Regardless of the merit of arguments in relation to the systematic risk of TNSPs compared to other companies on the ASX, the systematic risk as measured by the asset beta (0.40) is already significantly lower than that for an average firm on the ASX (currently 0.62-0.65).

1.3 WACC ISSUES RAISED AT ACCC'S PUBLIC FORUM

1.3.1 Market Risk Premium (MRP)

One of the key issues relating to WACC raised at the ACCC's pre-determination conference was the MRP. In preparing its response to the concurrent ACCC and IPART network regulatory reviews, EnergyAustralia engaged NECG to prepare a number of independent reports covering WACC framework issues and specific WACC parameters including the MRP. The following comments have been drawn from these reports and EnergyAustralia's own stated positions.

International regulatory precedent

A concern raised by customer advocates at the pre-determination conference was the ACCC's refusal to adopt an international MRP, based on the view that "UK regulators have all adopted [an MRP of] (around) 3.5%"[36].

These values relate to only two regulators' opinions of the MRP in the UK, and we note that there is not a consistently held view within the UK as to the appropriate value. For example, Oftel has applied a MRP of 5% in its decisions. In fact, the most comprehensive historical study of international MRPs by Dimson, Marsh and Staunton reports that the MRP for the UK for 1900-2002 was 5.5%.[37]

More importantly, however, is that on the surface the argument mounted by the customer representatives seems to suggest that it is appropriate to apply the seemingly low MRP value adopted by regulators in the UK to Australian businesses. EnergyAustralia has many concerns over the robustness of this approach and without any attempt to adjust for factors between the two markets accounting for market risk, these results say little about the MRP in Australia.

In comparing MRPs, it is necessary to consider the related issue of the appropriateness of applying an International CAPM ("ICAPM") more generally to a domestic business. There have been many versions of an ICAPM in economic literature, but there are two that have received serious consideration as practical alternatives:

- Simple CAPM with international MRP
- ICAPM incorporating exchange rate risk

NECG notes that the available evidence suggests that the domestic CAPM is only marginally different from the multi-factor ICAPM in explaining historical returns. A recent empirical test by Koedijk, Kool, Schotman and van Dijk investigates the extent to which international and domestic asset pricing models lead to different estimates of the cost of capital for an individual firm.[38] They find that "even though the ICAPM is theoretically preferable to the domestic

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[36] See Joint Customer Presentation – Australian Business, Australian Consumers Association, Energy Action Group, Energy Users Association of Australia, and National Farmers Federation. ACCC pre-determination conference 18 June 2004.
[37] NECG, Response to IPART draft decision OP-18 – Comments on weighted average cost of capital, February 2004, p 15.
[38] K. Koedijk, C. Kool, P. Schotman and M. van Dijk, 2001, "The Cost of Capital in International Financial Markets: Local or Global", Working Paper No. 3062, Centre for Economic Policy Research.

CAPM, a firm's beta calculated using the domestic CAPM does not necessarily provide a worse estimate of the cost of capital."[39]

The evidence also indicates that the single-factor ICAPM is an inferior model.[40] However, one of the major challenges with adopting an ICAPM that incorporates exchange rate risk (which is required to address issues of purchasing power parity) is the problem of estimating a "world MRP" and the obvious question of which countries should be included in the sample (i.e. benchmarking the MRP off the US market results in estimates of around 7% for a US MRP).[41] In addition, what data should be analysed and over what period should the analysis be conducted?

Even if the problem of estimating a world MRP could be overcome, the fact remains that the single-factor ICAPM model does not provide an improvement over the domestic CAPM. To achieve a significant improvement it is necessary to apply an ICAPM that incorporates exchange rate risk. To achieve this we must estimate a firm's sensitivity to exchange rate risk across all countries in the world economy. We are far from having a reasonable basis for such estimation.

Given the problems associated with the ICAPM, we can conclude that the predictive properties of the domestic CAPM should be at least as good as the ICAPM. If this is combined with significant support and precedent for the domestic version of the CAPM, there appears no benefit in moving away from the domestic version of the CAPM. Given the availability of a domestic CAPM, adopting the ICAPM results in additional complexity and imprecision without commensurate benefits.

Undertaking the necessary research to do a robust analysis of the appropriateness of an ICAPM would be an extraordinarily complex task. However, before international comparisons can be considered in the regulatory context, this research would need to be undertaken and subjected to extensive stakeholder consultation. EnergyAustralia would of course be interested in commenting on any such research when (or if) it becomes available.

Conclusion on MRP

EnergyAustralia reiterates its stated position that there is "no substantial evidence to justify (the) claim that the appropriate value of the MRP is below 6%. In our opinion a value of 6% is at best at the low end of a plausible range for the MRP. Historical estimates of MRP typically fall within a range of 6-8%, while other approaches such as benchmarking the MRP off the US market results in estimates around 7%.[42] As a result, we believe it is impossible to conclude that a value below 6% is justified, let alone conservative."[43]

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[39] These tests are of the standard CAPM against the Solnik-Sercu ICAPM with exchange rate risk. In an earlier version of the paper (1999) they also included tests of the single-factor ICAPM, and found that it perform significantly worse than the CAPM against the multi-factor ICAPM.

[40] See NECG Response to IPART Discussion Paper (DP56) on behalf of EnergyAustralia, September 2002.

[41] The historic and benchmarking approaches are outlined in detail in NECG's submission to IPART, included in EnergyAustralia' s original submission to IPART.

[42] The historic and benchmarking approaches are outlined in detail in NECG's submission to IPART, included in EnergyAustralia' s 10 April 2003 submission to IPART.

[43] NECG, Response to IPART draft decision OP-18 – Comments on weighted average cost of capital, February 2004, p 16.

1.4 SUMMARY

Based on the considerations outlined in the NECG Report, it is concluded that as of the time of the draft decision the appropriate vanilla WACC for EnergyAustralia should be 9.14% - or 9.06% if issuance costs are to be included in the cash flows.[44]

NECG's estimates are detailed in Attachment X and set out below in Table 8.

Table 8 - WACC estimates for EnergyAustralia (as of 28 April 2004)

Variable	ACCC draft decision	NECG/EA (with issuance costs in WACC)	NECG/EA (issuance costs in cashflows)
Nominal risk free rate	5.89%	5.89%	5.89%
Debt margin	0.87%	1.06%	1.06%
Cost of debt issuance	NA	0.125%	NA
Cost of debt	6.76%	7.075%	6.95%
Market risk premium	6.00%	6.00%	6.00%
Gamma	0.50	0.50	0.50
Effective tax rate	27.15%	27.15%	27.15%
Asset beta	0.40	0.425	0.425
Equity beta (debt beta =0)	1.00	1.06	1.06
Cost of equity	11.86%	12.23%	12.23%
Vanilla WACC	8.80%	9.14%	9.06%

[44] Note this is based on a conservative estimate of issuance costs equivalent to 12.5 basis points on the cost of debt.

SERVICE STANDARDS

1.1 DRAFT DECISION

The ACCC has applied performance targets for service standards for EnergyAustralia in the 2004-2009 period. The targets are consistent with the recommendations made by GHD that:

- target for transmission circuit availability be set at 96.1% with collar and cap applying at 95.3% and 96.7% respectively;
- that 1% of revenue be subject to risk of meeting the service standard target.

In addition, EnergyAustralia is required to measure its transmission circuit availability with the inclusion of:

- transformers and reactive plant, in accordance with the proposed standard definition;
- significant lengths of new 132kV lines and other equipment, resulting from the re-classification of some assets from distribution to transmission during the 1999-2004 regulatory period.

Finally, the ACCC in its draft determination required EnergyAustralia to report on the other relevant performance measures contained in the ACCC's service standard guidelines.

1.2 IMPACT OF REDUCED REVENUE ON SERVICE STANDARDS

As discussed earlier, EnergyAustralia's initial submission is based on an integrated package of opex and capex to deliver customer outcomes. Therefore any changes made by the ACCC necessarily impacts the outcomes that can be expected and vice versa.

EnergyAustralia has proposed an increase in our operating expenditure for the 2004-2009 period to address the need to stabilise service standards. EnergyAustralia has experienced a deterioration in performance of some asset classes recently which needs to corrected in the 2004-2009 regulatory period. Part of this strategy is the introduction of condition based maintenance. The increased proposed allows for corrective action to be carried out along side planned maintenance. It is only when the corrective action is completed that there will be certainty in the delivery of service standards.

EnergyAustralia believes that the aggressive reductions made by ACCC to the transmission opex budget, which are in the order of 15 percent, will have a material impact on EnergyAustralia's ability to meet the service standard targets set by ACCC in its draft determination which does not appear to have been recognised by the ACCC to date. It is not clear what the ACCC's treatment of capex will be, but failure by ACCC to provide a revenue stream to cover critical capex projects in the 2004-2009 regulatory period also has the potential to fundamentally impact EnergyAustralia's ability to meet its service standard targets.

It is within the context of significant reductions to revenue as proposed in the draft determination that EnergyAustralia believes that an additional one percent revenue penalty for failure to meet service standard targets results in a double revenue impact on EnergyAustralia which could compound its ability to meet targets set in subsequent periods.

When establishing the programs for the next regulatory period for both its distribution and transmission businesses, EnergyAustralia targeted areas of the network that were performing relatively poorly. The programs put up by EnergyAustralia were not a complete list of all the possible programs that could be included to improve reliability and quality of supply across the network, but reflected a prioritisation and selection from a much larger list of projects and strategies.

EnergyAustralia believes that it is therefore not reasonable for ACCC to make cuts to operating and capital programs without expecting that there will be a corresponding negative impact on the condition of network assets and/or the operation of the network and the level of service it delivers. In contrast, it would not be unreasonable for ACCC to expect that additional funds would be channelled in to additional projects and strategies that would improve services standards further.

In its distribution review EnergyAustralia notes that IPART specifically sought expenditure information to support a base and alternate service level. EnergyAustralia put forward indicative cases for both a constrained and enhanced service standard case on the basis of varying budgets for capital and operating programs. The ACCC has not requested this information therefore this analysis was not conducted for transmission service standards on their own. However, the fact remains that should transmission revenues fall, a fall in transmission service standards over the longer term will be the outcome.

EnergyAustralia contends that if the ACCC continues on its current course and imposes significant cuts to revenues, EnergyAustralia would seek the ACCC's involvement in negotiating an acceptable trade-off between acceptable service standards and the operating and capital budgets. EnergyAustralia would expect that such discussions would necessarily involve an adjustment to the service standard target set by ACCC or the revenue placed at risk.

1.3 TECHNICAL ISSUES ASSOCIATED WITH ACCC'S DECISION

EnergyAustralia believes that there are a number of issues that have not been adequately clarified in the ACCC's draft decision in relation to the practical application of the service standards regime.

1.3.1 Transmission circuit availability

EnergyAustralia understands that when the original Service Standards Scheme was devised and implemented it was found that even though the scheme adopted a suite of standard measures (eg circuit availability), each of the TNSP's had been historically recording their performance in slightly different ways. (i.e. some defined a circuit as either an overhead or underground circuit, while others included transformers, reactors, capacitor banks, etc). It was decided at the time to accept the differences in historical reporting methods, and to set targets that were based on there being no change to the reporting methods. That is to say, the targets are unique to the TNSP's recording and reporting system. EnergyAustralia believes that no change should be made to the recording method unless targets are also reviewed. It also follows that if a change is made to the recording of data, there will need to be an elapsed period of time in order to collect sufficient data to establish meaningful forward looking targets.

As explained in our original submission, EnergyAustralia has collected performance data in relation to transmission circuit availability on a manual basis. At this point, the data collected incorporates the performance of feeders only and does not include the performance of other network elements such as transformers or reactive plant.

EnergyAustralia argued in its original submission that the target set on the basis of historical data would not be relevant for future data if the future data included the performance of additional network elements (transformers and reactive plant). This is also the case if the assets newly classified as transmission assets are required to be included in the performance data.

Should the ACCC continue to accept GHD's recommendations for changes to the reporting of transmission circuit availability, EnergyAustralia proposes that two sets of data be recorded – one that measures performance as per GHD's recommendations (and the ACCC's requirements in the draft decision), and another set of data that records transmission circuit availability in the same way as data has been recorded in the past. This will allow the performance targets that have been set by ACCC (based on historic data) to be compared with data collected from the same set of assets and the same network elements.

EnergyAustralia believes that is unnecessary for ACCC to require a change to the current recording practice in order to establish a target or compare EnergyAustralia's subsequent performance against this target. However, EnergyAustralia's proposal for two sets of data allows data to be recorded in a consistent manner with other TNSPs over the next period[45] but also allows financial cost/benefits to be applied in the 2004-2009 regulatory period on the basis of accurate like-with-like comparisons, thereby ensuring that EnergyAustralia is not unreasonably penalised in revenue terms for events that have not been captured by limited data used to set the target.

GHD's recommended targets

EnergyAustralia does not believe that EnergyAustralia has recorded sufficient data in relation to transmission circuit availability to have revenue penalties applied. The targets recommended by GHD and accepted by ACCC rely on three years of data. While this is sufficient data to take an average, EnergyAustralia does not believe that this is sufficiently robust analysis upon which to allocate approximately a million dollars worth of revenue. Given that the final report will not be made for some time, EnergyAustralia believes that it is appropriate that data for the 2003/04 year be taken into account prior to targets being set.

Furthermore, EnergyAustralia is very concerned that the current service standard targets do not take into account the future program of capital works that will occur during the forthcoming regulatory period. EnergyAustralia strongly contends that the effect of the future capital program on the service standards should be taken into account in the finalisation of the future targets. As such until the future capital program is agreed then the EnergyAustralia would argue the need to review and reset any service target at the point of finalising the future capital program.

1.3.2 Outage duration

EnergyAustralia agrees with the ACCC's treatment of outage duration in its draft determination. EnergyAustralia understands the desire of the ACCC to have more than one service standard

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[45] EnergyAustralia questions why this is necessary.

by which to compare network performance. However, the lack of data available at the present time and the uniqueness of EnergyAustralia's network poses problems for any comparison of service standards between EnergyAustralia and any other TNSP.

EnergyAustralia outlined a number of reasons why it believes that outage duration is not an appropriate measure of EnergyAustralia's network performance. These issues are repeated below:

- Average restoration period does not impact on EnergyAustralia's customers because of the inherent security of the network (use of double circuits etc).
- The repair times for assets such as underground cables can be significant (weeks or months) and can vary substantially depending on the type of cable. EnergyAustralia has a large proportion of underground cables in its transmission network and is not able to easily control the incidence of outages on underground cables through changes to operational and maintenance programs. Incidences on underground cable can be impacted by a change in the type of cable used – replacing a pressure type cable to a solid dielectric cable. However, a choice to change the type of cable through new installations or replacement would be part of a major capital works program which EnergyAustralia believes is outside the scope of a performance standard incentive mechanism.
- The long duration of repaid times could introduce significant volatility in the measurement of outage duration from year to year (ie a single incident could dramatically change the performance measure).

EnergyAustralia maintains that due to these issues, outage duration is an inappropriate measure of performance for its transmission network.

EnergyAustralia welcomes the ACCC's decision not to link financial impacts to this measure for the 2004-2009 revenue cap. EnergyAustralia will collect this data over the next regulatory period.

1.3.3 Capped event

In its draft decision, ACCC has not recognised EnergyAustralia's request that the impact of a single event be capped at a period of 7 days. As mentioned in the section above, the presence of underground cables makes it likely that events that result in an outage of 7 days are likely to be out of service for several weeks or months while the problem is located and fixed. A cap of 14 days, while consistent with the ACCC guidelines, is not appropriate for underground cables because it is very unlikely that the fault will be fixed within this period.

EnergyAustralia requests that the ACCC reconsider its decision and reduce the cap for events for EnergyAustralia to 7 days.

1.4 RESPONSE TO COMMENTS MADE BY INTERESTED PARTIES

EnergyAustralia notes that a number of comments have been made by interested parties in relation to market outcomes and the services standard regime applied to EnergyAustralia. Interested parties believed that the impact of transmission outages on market outcomes should be taken into account and applied to EnergyAustralia.

EnergyAustralia’s transmission network has a primarily distribution function. EnergyAustralia is a TNSP because it operates assets considered by the Code to be transmission assets. It meets the Code’s definition of transmission because parts of the network operate in parallel and provide support to other transmission assets. Outages on EnergyAustralia’s network do not have a direct impact on market outcomes. The virtual node used for the purposes of establishing the regional price in NSW is located at TransGrid’s Sydney West substation. EnergyAustralia’s network does not connect to this point. Furthermore, outages on EnergyAustralia’s network do not directly effect the dispatch of generators on to the national electricity grid. Therefore to require EnergyAustralia’s service standards to be linked to market outcomes would effectively benefit or penalise EnergyAustralia for constraints that occur outside of its network.

Interested parties also commented that TNSPs that claim increases in opex and capex over time should be required to deliver improved service standards. While this statement appears to be reasonable on the surface, it does not take into account the changes faced by the TNSPs in relation to their networks. EnergyAustralia is required to maintain a larger number of assets that are on average aging faster than they are being replaced. An aging asset profile increases maintenance costs due to the level of maintenance required for each asset. Furthermore, as technology becomes obsolete and as additional safety, environmental and regulatory requirements are established, costs of maintaining networks increases.

EnergyAustralia’s network is the oldest in Australia and some of the assets currently in operation are over 70 years old. The next five year period signals the start of a significant asset replacement phase. The last time a similar replacement program was initiated was during the rapid network expansion that occurred during the 1970s.

Within this context, EnergyAustralia believes that the suggestion that service standards should be required to improve simply due to increasing capital and operational spending is simplistic. EnergyAustralia is committed to providing high quality transmission services, but does not accept that this can be done without increases in operating and capital budgets.

EnergyAustralia believes that the incentive based service standard regime designed by ACCC has been established to drive better performance in operational areas and is not designed to drive changes in network augmentation or replacement of assets.

PASS THROUGH MECHANISM

EnergyAustralia welcomes the ACCC's decision to allow for pass-through of certain costs associated with specific events that are outside the control of the TNSP. However, we are disappointed that ACCC has not accepted the suggestion put forward for a "Fees Event" or an "External Event" to be considered as a pass through item.

1.1 RELEVANT FACTORS

1.1.1 Financial effect

The ACCC has deleted clause (1) which requires the ACCC to take into account the financial effect on EnergyAustralia associated with the provision of revenue capped services attributable to the pass through event and the time at which the financial effect took place or will take place.

The clause has been removed with no explanation. EnergyAustralia notes that a similar clause was included in the SPI Powernet Pass Through Rules and therefore we seek its reinstatement to ensure consistency across TNSPs.

1.1.2 Deletion of sub-clauses in relation to insurance

The ACCC has deleted a number of subclauses under section 2.3 clause (6) on the basis that they may be deemed to be within the control of EnergyAustralia.

EnergyAustralia considers that the deleted clauses are useful in providing guidance as to the circumstances where additional costs may arise that are outside the control of EnergyAustralia. EnergyAustralia notes that these clauses were used in the Pass Through Rules for SPI Powernet and EnergyAustralia believes that the clauses are appropriate in this case.

1.2 INSURANCE EVENT

1.2.1 ACCC requests copies of insurance policies

The ACCC has included two additional clauses (5) and (6) in the definition of Insurance Event. EnergyAustralia does not believe that these clause are appropriate to fall within the definition.

ACCC's new clause (5) in the Insurance Event definition that states,

> *(5) EnergyAustralia has provided the ACCC with a copy of insurance premium at least 50 business days before the state of the financial year, regardless of if a pass through event has occurred.*

EnergyAustralia renews its insurance policies in September each year. To meet the requirement of clause (5) above, EnergyAustralia would accept a separate provisions requiring EnergyAustralia to provide insurance policies to the ACCC each April that were renewed in September the previous year. Alternatively, EnergyAustralia could provide details of premiums when they are renewed each September.

1.2.2 Interaction with self-insurance

The ACCC also included clause (6) in the Insurance Event definition as set out below:

> *(6) where an insurance benefit payment to EnergyAustralia under its insurance for risk of bushfire liability is reduced by a deductible amount.*

EnergyAustralia understands this clause to be related to the ACCC's decision not to include $20,000 in the self-insurance premium which Trowbridge Deloitte calculated as an appropriate premium to cover losses under deductibles. This issue has been briefly discussed in relation to self-insurance in section 5.1 of the Opex chapter.

When Trowbridge Deloitte assessed EnergyAustralia's self-insurance liabilities, it included a premium of $20,000 for current insurance risks relating to bushfire liability. EnergyAustralia is liable to pay the first $10m of each claim made under the policy. By removing this premium and including clause (6) above, EnergyAustralia is concerned that ACCC has only recognised part of the costs that were included in the self-insurance premium as a legitimate pass through cost.

While clause (6) allows EnergyAustralia to claim a pass-through for any claim that is made for damages as a result of bushfire liability over $10m where EnergyAustralia pays the first $10m, it is not clear that the clause allows EnergyAustralia to claim a pass through for costs for bushfire liability damage where the total damage is less than $10m and therefore where no insurance payment is received.

According to Trowbridge Deloitte "EnergyAustralia can still have a material exposure under its insurance policies". In removing this premium, EnergyAustralia is left exposed to bearing claims of less than $10m without having any way of recovering these costs (i.e. no pass-through and no self-insurance allowance).

EnergyAustralia believes that this clause should be removed from the Pass Through Rules and that the $20,000 premium should be reinstated in the self-insurance premium.

1.3 CHANGE IN TAXES EVENT

EnergyAustralia notes the ACCC's acceptance of a Change in Taxes Event as a legitimate Pass Through Event with minor variations.

However, EnergyAustralia requests that the wording of the clause be changed to cover the scenario where a Change in Taxes Event may occur after 1 July 2004 and prior to the final determination being made. EnergyAustralia therefore requests the ACCC to replace the current wording that refers to the "date of the decision" with the words "1 July 2004" to ensure that EnergyAustralia is able to pass through the financial effect of a Change in Tax should it occur prior to the final determination being made. This will ensure that EnergyAustralia is not disadvantaged by the ACCC's decision to delay making its final determination with respect to EnergyAustralia's revenue cap until April 2005.

1.4 EXTERNAL EVENT

In its original submission to ACCC, EnergyAustralia proposed that the financial effects of unforeseen or very rare events be considered as a Pass Through Event. EnergyAustralia called such circumstances "External Events". In our original submission, EnergyAustralia argued that there are some events that are so rare or unforeseen that a prudent business would not insure against them. To do so would unnecessarily increase the operational costs of the business and raise prices. However, there are a range of events that could potentially occur which could dramatically impact the business and where it would be prudent to pass these costs through to parties better able to bear the risks. The example given by EnergyAustralia of an “External Event” was a terrorist attack in the CBD.

The ACCC rejected EnergyAustralia’s proposal for an “External Event” on the basis that the definition was ambiguous and broad in scope. The ACCC argued that a Pass Through Event must be “identified in advance with its scope precisely defined”[46]. The ACCC went on to argue that pass through events should be defined as specifically as possible to ensure that the provision does not lead to later uncertainty over whether an event is admissible of not. In lieu of accepting EnergyAustralia’s External Event proposal, ACCC has accepted a more tightly defined “Terrorism Event”.

In suggesting an External Event, EnergyAustralia had two types of events in mind – terrorism events and force majeure events (i.e. acts of God). EnergyAustralia notes the ACCC’s acceptance of a Terrorism Event, but believes that by removing reference to an External Event, the ACCC has denied EnergyAustralia an ability to pass through the costs associated with legitimate external events such as ‘acts of God’.

EnergyAustralia therefore seeks a change to the Pass Through Rules to incorporate a clause that would capture events similar to those that would normally be included in a contractual Force Majeure clause. Given the accepted nature of force majeure events in contract law, EnergyAustralia believes that the ACCC’s concerns in regard to the ambiguous nature of the External Event definition would be removed while providing EnergyAustralia with appropriate protection against potentially catastrophic financial consequence of external and uncontrollable events.

EnergyAustralia therefore proposes the following clause to define an External Event.

*“**External Event**” means any of the following events:*

(1) act of God, flood, explosion, landslide, action of the elements, force of nature, storm or natural disaster;

(2) a Terrorism Event;

(3) war (whether declared or not), riot, civil disorder, rebellion, revolution, insurrection, vandalism, sabotage, malicious damage or epidemic;

which:

(4) is beyond the control of the EnergyAustralia;

(5) occurs without the fault of negligence of the EnergyAustralia;

(6) has not been included in estimation of EnergyAustralia’s claim for self-insurance;

[46] ACCC Draft Determination for EnergyAustralia, p 104.

(7) *results in EnergyAustralia incurring (or being likely to incur) materially lower or higher costs in providing capped revenue transmission services than those contemplated as at 1 July 2004."*

1.5 FEES EVENT

EnergyAustralia is disappointed that ACCC has not recognised the legitimate costs that may be imposed through the application of fees. EnergyAustralia is concerned that a change in NEM fees or the impost of an industry wide levy to fund the new regulatory agencies such as the Australian Energy Regulatory and the Australian Energy Market Commission could impose material costs on EnergyAustralia which under the ACCC's Pass Through Rules would not be captured or allowed to be passed through.

EnergyAustralia is concerned that the ACCC has misinterpreted the purpose of including a Fees Event in the Pass Through Rules. The purpose was to capture externally levied fees that were unavoidable and uncontrollable by the TNSP that had a material impact on the costs of the business. The purpose was not to pass on the legitimate impost of environmental fines, should they occur.

EnergyAustralia notes that the Fees Event definition put forward specifically captured events that were not already captured under the Regulatory or Changes in Tax Event as it was not clear that an industry levy or changes to NEM fees would be covered by these events.

EnergyAustralia rejects the ACCC's argument that the legitimacy of a fee to be passed through is linked to whether it is imposed across the industry or not. In the case of competitive businesses, higher costs are often passed through to customers by all competitors. The $10 fuel levy currently being applied to airline tickets to cover increased costs of jet fuel is a relevant example of such cost pass through. Unfortunately, regulated business are not able to reflect a change of costs in pricing within the period with such ease and must instead seek a pass through to allow any additional costs to be reflected.

EnergyAustralia therefore seeks the ACCC's reconsideration of this event in light of the energy industry levy that is due to come into force in 2005.

LIST OF ATTACHMENTS

Attachment 1 – NECG report on WACC

Attachment 2 – SKM report on historic capex

Attachment 3 – Beresfield Regulatory Test

Attachment 4 – DM Scoping study for Beresfield

Attachment 5 – Additional feeder bays for Campbell Street