Australian Competition and Consumer Commission

EnergyAustralia Regulatory Review

Capital Expenditure and Asset Base, Operational Expenditure and Service Standards

Report

March 2004

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Executive Summary

The Australian Competition and Consumer Commission (the Commission) is conducting an inquiry into the appropriate revenue cap to be applied to the non-contestable elements of the transmission services provided by EnergyAustralia for the Regulatory Period (RP) from 1 July 2004 to 30 June 2009.

This report presents GHD's review of the EnergyAustralia Revenue Reset Application in relation to Capital Expenditure (Capex), Opening Asset Base, Operating Expenditure (Opex) and Service Standards, as part of the Commission's review process.

The review has been undertaken within the Commission's clarified scope and is to be used only for the purposes of the Commission's Revenue Cap Decision. The review relies on information provided by EnergyAustralia and does not include verification of the information by GHD.

The key findings of the review are:

Business Related Expenditure Systems

EnergyAustralia started the previous RP with generally weak systems and data, with a correspondingly reduced capacity to make decisions. The level of performance in this respect was below that which would be expected of a prudent operator. The weaknesses have been identified and steps are underway to rectify some of these inadequacies, with some definite improvements currently in evidence. The Asset Management system and the procurement strategy being introduced are expected to reap significant benefits for EnergyAustralia in the long term, with some of the effects impacting during the upcoming RP, however it should be noted that the benefits of the systems being introduced have not yet been observed.

Capex

GHD are not able to form a firm conclusion of the overall efficiency of EnergyAustralia's Capex program, both historic and forecast for the reasons outlined below. Consequently, GHD is also not able to conclude on the prudency of the opening RAB.

Reasons GHD are not able to respond effectively to the Terms of Reference are:

- The linkage between Board Approval and inclusion of a project in the ACCC application has not been demonstrated.
- The documentation to fully support capital cost estimates has not been provided.
- Working papers and Board submissions that can demonstrate rigour of justification for any particular project to be included in the ACCC application have not been provided.
- For future projects, GHD can find no evidence that the new capital governance framework has been rigorously followed.

It is noted that GHD have found demonstrated ability to proactively identify system limitations and initiate an investigation into options for overcoming those limitations. For most of the Demand Related Capital Expenditure projects, both historic and future, there was evidence of a clear understanding by the Planning personnel of the assets, the capacity of the assets and current and projected loadings.

The Value Management Studies or Planning Reports provided to GHD indicated that many alternatives are considered before a proposed solution is adopted. However, in line with the reasons outlined above on the difficulty in making a firm conclusion on EnergyAustralia's Capex program, it is not clear how the adopted alternative is selected out of the range of possibilities. On the assumption that cost is a factor in choosing an option, there was no evidence to indicate whether the Value Management Study or Planning Report selection process is re-visited as designs and cost estimates are developed. In other words if the cost increases as information becomes more accurate would one of the other alternatives have been adopted.

For replacement projects the assessment of appropriateness would be assisted if contemporary condition assessment were provided.

There is evidence from the Business Cases that Final Cost Estimates, Board Approval, Development Approval and Detailed Civil and Electrical Designs are prepared as part of the process, however GHD has not been provided with a reasonable level of documented project details.

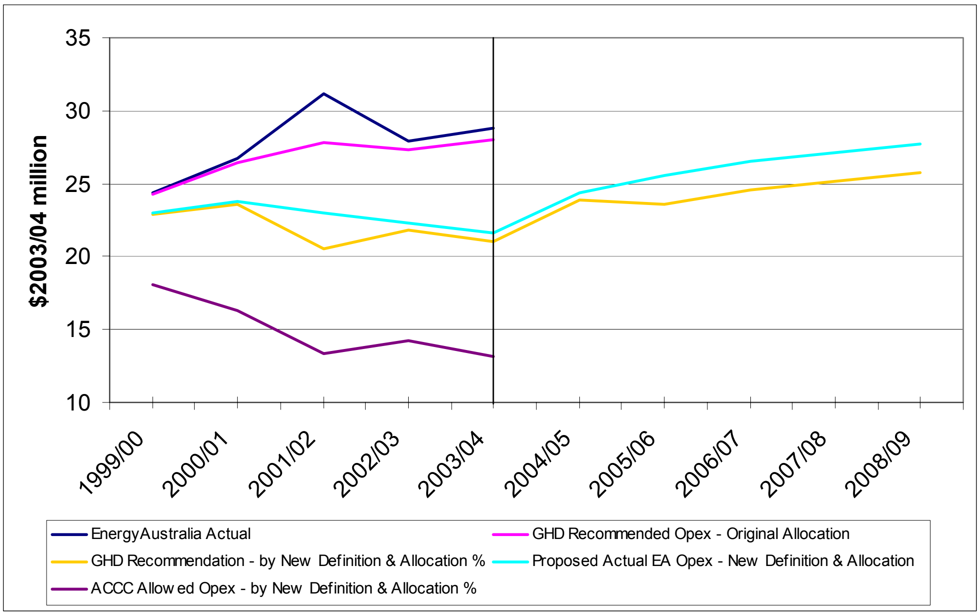
GHD recommends that an efficiency saving of $1.419m p.a. be removed from the EnergyAustralia forecast Capex starting in 2005/06.

Opex

GHD was not able to access a suitable level of linked data to enable a detailed evaluation of EnergyAustralia's past and future Opex. As such, GHD undertook a driver analysis and applied the findings for those drivers to EnergyAustralia's actual and proposed Opex figures, thus generating a recommended level of Opex.

Figure 1 summarises the Opex recommendations and observations over a 10-year period covering both the previous and upcoming regulatory periods.

Figure 1 10-Year Summary of Opex Findings



Service Standards

The level of data available for an evaluation of suitable service standards for EnergyAustralia is low. An incentive scheme that incorporates an asymmetric cap and collar during the upcoming RP has been recommended, providing EnergyAustralia an opportunity to review their performance and implement improvement plans as desired. In addition it is recommended that EnergyAustralia be required to record Average Outage Durations during the upcoming RP, which will enable a more substantial evaluation at the next revenue cap review.

The primary outcomes of the proposed incentive scheme are outlined below:

- Target of 96.1% Transmission Circuit Availability
- Asymmetric collar and cap set, of 95.3% and 96.7% respectively.
- Require EnergyAustralia to measure Average Outage Duration over the upcoming RP to develop a reasonable data history from which future service standards decisions can be based

1. Introduction

1.1 Introduction

Under the National Electricity Code (NEC), the Commission is responsible for regulating the non-contestable services of the transmission network service providers (TNSPs).

The Commission is conducting an inquiry into the appropriate revenue cap to be applied to the non-contestable elements of the transmission services provided by EnergyAustralia for the period from 1 July 2004 to 30 June 2009, referred to herein as the Regulatory Period or RP.

EnergyAustralia has made its Application to the Commission proposing a revenue cap.

To assess performance of EnergyAustralia relative to the NEC, the Commission requires a capital expenditure (Capex), asset base, operational expenditure (Opex) and service standards review to be undertaken. In particular, Part B of Chapter 6 of the NEC requires, *inter alia*, that:

- In setting the revenue cap, the Commission must have regard to the potential for efficiency gains in expected operating, maintenance and capital costs, taking into account the expected demand growth and service standards.
- The regulatory regime seeks to achieve an environment that fosters efficient use of existing infrastructure, efficient operating and maintenance practices and an efficient level of investment.
- In setting the revenue cap, the Commission must have regard to the provision of a fair and reasonable risk-adjusted cash flow rate of return on efficient investment including sunk assets
- The regulatory regime provides reasonable recognition of pre-existing policies of governments regarding transmission asset values, revenue paths and prices but with the limitation that such valuation must not exceed the deprival value of those assets.

In this context, GHD was engaged to inform the Commission on the:

- Adequacy and efficiency of EnergyAustralia's forecast Capex to meet its future service requirements, including the likelihood that proposed augmentation Capex will pass the *regulatory test*, and the appropriateness of non-augmentation Capex.
- The opening regulatory asset valuation as at 1 July 2004, including review of augmentation and non-augmentation Capex undertaken by EnergyAustralia over the previous regulatory period.
- Adequacy, efficiency and appropriateness of the Opex stated by EnergyAustralia as being necessary to meet its present and future transmission service requirements.
- Appropriate service standards and performance targets to apply to EnergyAustralia over the forthcoming RP.

1.2 Terms of Reference

The Terms of Reference for this review are provided in Appendix A. The Commission further clarified these Terms of Reference and the significant requirements are described below.

Capex Review

A specific requirement was to focus on the efficiency of proposed investment, and how EnergyAustralia has taken account of the impact of endogenous and exogenous factors in future Capex. The principles of the *regulatory test* were to be used to assess the efficiency of augmentation investment, rather than specific application of the *regulatory test*. Non-augmentation Capex was required to be assessed to meet agreed needs at least cost.

Asset Base and Historic Capex Review

Advice was required on asset lives and depreciation profiles to assist the Commission in determining the opening asset base. The efficiency of EnergyAustralia's historic Capex was to be reviewed overall, and advice provided in order for the Commission to compare EnergyAustralia's Capex spent against the Commission's approved Capex program. As EnergyAustralia has not specifically applied the regulatory test, in place of reviewing three *regulatory test* applications, a detailed review of the extent to which EnergyAustralia's investment has been assessed through the regulatory test for three projects has been undertaken. This will especially relate to the application of the planning standard, quality and objectivity of analysis of costing and design of alternative projects, and appropriateness of timing of the project. For non-augmentation Capex, the focus was on EnergyAustralia's methodology and approach to assessing the need for investment and then for choosing the investment to meet the need at least cost.

Opex Review

EnergyAustralia's proposed Opex model was to be evaluated in detail. In addition to this GHD should develop its own analysis of Opex costs, considering the various drivers of these costs and how these drivers are likely to affect the efficient level of expenditure in the future. Benchmarking of EnergyAustralia's Opex forecast was to be undertaken if required by the Commission, to provide input to the forecast Opex review. The Opex evaluation is not required to define the allocation of expenditure between different activity types. This is further defined in Section 6.1.1.

Service Standards

No clarification to the Terms of Reference.

1.3 Review Methodology

The review was undertaken in accordance with the clarified Terms of Reference (ToR) and on the basis of the general tasks outlined below:

- Review of application and appropriate Commission documentation.

- Provision of a list of indicative questions and subsequent information requests to EnergyAustralia.
- Review of documentation and responses provided by EnergyAustralia.
- Conduct of discussions and interviews with relevant EnergyAustralia staff to develop understanding and analyse the information provided to meet the ToR.
- Further communication and information requests to clarify and justify the information provided.
- Preparation of a draft report for review by the Commission and EnergyAustralia.
- Consideration of review comments and incorporation of appropriate amendments into a final report.
- Communication with stakeholders and provision of responses as required.

1.4 Glossary of Terms

A Glossary of Terms and Acronyms is included as Appendix B.

1.5 Statement of Limitations

This report is only to be used for the exclusive purposes of the Commission's Revenue Cap Review of EnergyAustralia and cannot be used or referenced for any other purpose. This report is supplied in good faith and reflects the knowledge, skills and experience of the consultants involved. GHD accepts no responsibility whatsoever for any loss occasioned by any person acting or refraining from action as a result of reliance on the report, other than the Commission.

The review has relied upon the information supplied by EnergyAustralia during the course of the review process. The review has not involved the verification by GHD of data or information supplied by EnergyAustralia except in limited instances.

GHD does not make any warranties or representation, whether expressed or implied regarding the accuracy of the source information and shall not be held accountable or responsible in the event of errors or omissions in the source material.

The appraisals, comments and findings presented in this report pertain to conditions judged to be pertinent at the time the assessment was performed. The report is not intended for use in future evaluations and no obligation is assumed to revise this report to reflect events or conditions or further information that occurs or becomes available subsequent to the completion of this revenue reset.

A list of reference material supplied by EnergyAustralia is provided in Appendix D.

1.6 Acknowledgements

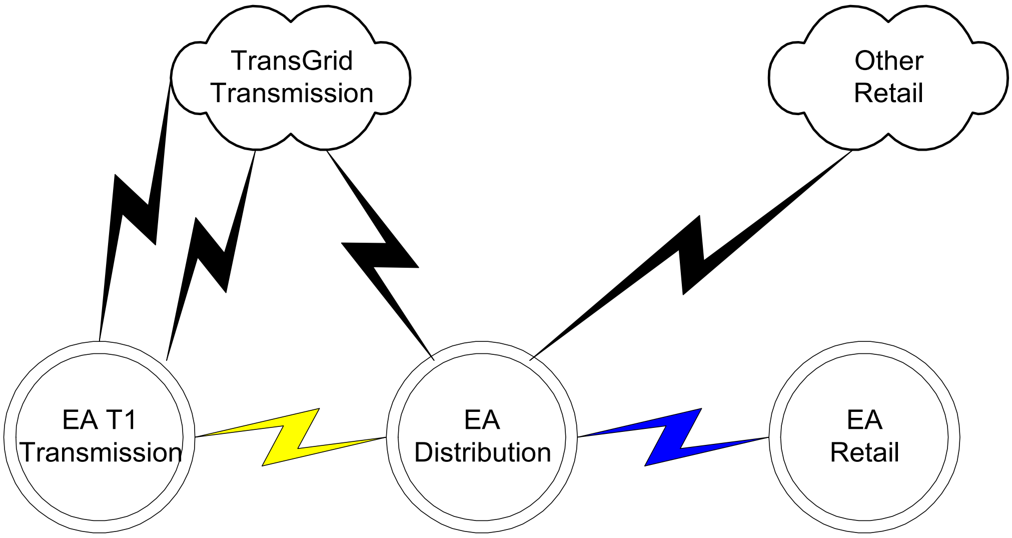
GHD acknowledges the assistance provided by the Commission and numerous senior staff of EnergyAustralia in undertaking this review.

2. EnergyAustralia And Its Application

2.1 Transmission in the Bigger Picture

The following figure shows the role of EnergyAustralia's Transmission network. EnergyAustralia's transmission network is bordered by TransGrid's network and EnergyAustralia's distribution network.

Figure 2 EnergyAustralia Schematic



The distribution network carries around 25,000 GWh. Of this, 63% is carried by EnergyAustralia's transmission system, as in a number of locations EnergyAustralia's distribution network connects directly to TransGrid's transmission network.

Flows through EnergyAustralia's T1 transmission network (ACCC regulated transmission assets) to the distribution network are 15,715 GWh. Looping flows through EnergyAustralia's T1 network and out to TransGrid are 640 GWh. Thus the total flow on the T1 network are 16,457 GWh including losses of 102.3 GWh.

2.2 External Operating Environment

EnergyAustralia and TransGrid were the first TNSPs to have revenue caps established under the Commission and the first to undergo the current "reset" of their revenue cap. Consequently there is some interest from stakeholders in the outcomes of this review, including from other TNSPs and customer groups in terms of the precedents that may be formed.

The regulatory regime has evolved considerably over the current RP, with the development of the Draft Statement of Regulatory Principles, now undergoing further review. The National Electricity Code and other State and national regulatory instruments have developed with numerous changes made.

There are still uncertainties with numerous aspects of the regulatory regime, and further changes are expected. These will include the formation of a National Energy Regulator encompassing both electricity and gas, and include regulation of transmission and distribution businesses nationally over a period of time.

The National Electricity Market (NEM) has developed significantly over the current RP, and now includes all Eastern States, the Australian Capital Territory, and South Australia, with Tasmania proposed for connection with the completion of the Basslink project in 2005. EnergyAustralia primarily operates a distribution network in NSW. However, under the current definition of transmission assets in the National Electricity Code, some of their network assets are classified as transmission. It is these assets that are regulated by the Commission, and are the focus of this review. The distribution network of EnergyAustralia is regulated by IPART. A separate submission was presented to IPART for the distribution business on 10 April 2003 and a draft decision has already been made and published.

Total electricity loads are steadily growing in all jurisdictions, and in NSW the summer demand growth has outstripped winter demand growth to the extent that maximum summer demands are forecast to exceed maximum winter demand over the next RP. This shows a similar trend to other southern States, and is largely due to the increased demand for air conditioning.

The expected demand growth gives rise to a need for enhancements and new transmission capacity as well as new generation capability. This may be located within NSW over the next RP. There is considerable uncertainty over the location of any future generators, and this creates significant uncertainty in planning for future transmission asset augmentations to connect these generators to the network.

The Olympics was also a major factor in the period. EnergyAustralia was a corporate sponsor. There was a considerable focus on ensuring that the Olympics received a totally reliable energy supply. This did divert attention from other areas.

There has been a continual increase in environmental and safety requirements over the current regulatory period. These regulations have in some areas significantly raised costs as many facilities were designed long before such regulations were even thought of. Infrastructure security has become a major concern since 2001.

Technology within the Electrical Transmission sector continues to develop. The developments in general are enabling improved efficiencies and improved decision making. The following technology developments are indicative of the common trend within this sector:

- Software and Hardware advancements enabling improved network analysis, planning, design and monitoring.
- Design enhancements through piled footings enabling better pole support in soft soils.
- An industry wide focus on Asset Management, incorporating topics such as Optimised Renewal Decision Making and the evaluation of optimal maintenance practices.

- Improved condition monitoring capabilities, e.g. constant, in-situ circuit breaker condition monitoring provided Just-In-Time maintenance feedback.

The technology developments are providing a much wider range of options that should be considered when considering the maintenance / renewal / replacement decision, and should enable improved decision-making.

Productivity improvement opportunities abound for EnergyAustralia, based upon the level of their current systems relating to business expenditures and performance. These are further discussed in Section 3, and the associated implications incorporated where possible into the Capex and Opex evaluations.

Pressures to reduce costs for energy provision also continue in order to assist in maintaining Australia's competitive international trade position, recognising that energy costs vary widely as a proportion of industry production costs and are very significant for some industries, eg. mineral processing.

In summary, the external operating environment of EnergyAustralia has considerably changed over the current RP and will continue to change during the upcoming RP.

2.3 Corporate Environment

EnergyAustralia is a State owned corporation of the New South Wales government. It commenced operation in 1996, created from the merger of Orion Energy and Sydney Electricity.

Over the last regulatory period from 1999/00 to 2003/04, key EnergyAustralia statistics are:

- Peak demand growth expected to average 3.5% and 2% for summer and winter respectively during the RP
- The regulated asset base has increased from $864.9 million to $953.5 million (nominal)
- Transmission asset actual historic Capex of $146.4 million compared to an allowed spend of $89.2 million for that RP (real $2003/04)
- Transmission based actual Operating expenses averaged $27.5 million per year, compared to an allowed expenditure of $88.66 million for the period. The EnergyAustralia proposed Opex model incorporates a revised allocation of transmission assets that effectively increase the allowed average to $23.1 million over the RP. The proposed revision is planned to become effective for the upcoming RP. (All real $2003/04, and averaged from 1999/00 to 2002/03)
- Direct staff numbers have increased from 3089 in 1999/00 to 3527 in 2002/03

The structure of the Network Line of Business consists of five core areas:

1. ***Investment & System Performance***. Made up of the Asset & Investment Management group and the Network Engineering group;
2. ***Regulation and Customer Connection***. Made up of the Regulatory Strategy Group and the Network Pricing & Customer Connections group;

3. ***Operations***. Consisting of a Commercial arm and a Network Control arm;
4. ***Support Functions***. Made up of the Network Business Systems group and the Network Finance & Support Services group, and
5. ***Demand Management & Non Regulated Business***. Contained within the Network Venture Development group.

2.4 The Application

EnergyAustralia's Revenue Reset Application comprises:

- Revenue Reset Application for the period 1 July 2004 to 30 June 2009
- Supporting Attachments to the application

The Application generally provides an extensive description of the business, its service obligations, the service delivery capability and a descriptive basis for EnergyAustralia's expenditure proposal over the RP. The Application and supporting documents provides information on historic and expected costs and revenues at a high level.

The Application did not include detailed breakdowns of historical or forecast costs to enable the reader to gain a strong appreciation of proposed cost element magnitudes, or the justification supporting projects and programs. This information was sought from EnergyAustralia and some responses were provided to GHD for the review. The supporting attachments contained details of some of the key documents utilised in developing their application.

2.5 Key Issues Summary

The challenge for EnergyAustralia is to manage growth and change in their business while delivering a reliable and efficient service to the community. The Transmission service supports the primary focus of the organisation on distribution.

Key issues to be considered in reviewing the Application, relating to EnergyAustralia and its operating environment, include:

- EnergyAustralia's primary role as a distribution business.
- A strong need for EnergyAustralia to ensure planning for network augmentations for uncertain future generation is robust and flexible, while demonstrating that the proposed investments are prudent and efficient.
- Consideration of providing benefits to customers in terms of reduced prices for energy services and/or increased service performance. This will necessitate a focus on optimising the trade-off between risk, timing, cost and service level, and between new investment and maintenance, to justify selected outcomes.
- Changes in those assets that will be regulated by the ACCC, and the impact of those changes on the levels of both Opex and Capex.

3. Expenditure-Related Business Systems Review

3.1 Basis of Business Systems Review

This section reviews EnergyAustralia's business systems and practices relating to the development of both Capex and Opex programs, and covers both historic and forecast expenditure. The focus is on whether the systems and activities within the business have delivered or will deliver the appropriate service levels in the most cost-efficient manner. This section is separate from the specific Capex and Opex review sections as it provides an overall business context and relevant inputs to each subsequent section, and specifically addresses those matters that contribute to both Capex and Opex.

Utility businesses have large infrastructure asset bases relative to other businesses, and hence asset-related expenditure dominates total corporate expenditure. The business systems review has thus considered all relevant activities by EnergyAustralia from inputs (business drivers, demand growth, existing asset base) to outputs (historic and forecast expenditures and strategies). The systems are reviewed against a "best practice" level considered by GHD to be most appropriate for a TNSP or more particularly for EnergyAustralia, and whether they are considered "efficient".

Overall business systems and practice activities of relevance include:

- Efficiency of organisation structure.
- Efficiency of service/project delivery systems.
- Asset management planning.
- Asset management strategies, including maintenance and renewal decision processes.
- Capitalisation Policy.
- Opex efficiencies resulting from Capex investment.

This approach is a development of analysis processes extensively used by GHD to undertake asset management and expenditure reviews, and draws from the approach detailed in the International Infrastructure Management Manual 2001, which was endorsed by the relevant Ministers of the Australian and New Zealand governments as appropriate for use by infrastructure businesses.

The review has been undertaken using information received from EnergyAustralia, GHD's knowledge of business systems and practices relating to Capex and Opex program development, and relevant information from external sources.

3.2 Efficiency of Organisation Structure

No significant change in structure has occurred during the previous RP, and no evidence of a focussed review of the structure was identified. There has been in the last two years reviews and reports in some areas aimed at improving decision-making and governance. There was a significant increase in the employee base, rising by 12.4% from 1999/00 to 2002/03.

It was clear from the documentation provided and through the interview process that EnergyAustralia now believes the regulators, (both ACCC & IPART) to be key stakeholders. The reporting systems and decision making protocols that are clear, traceable and enable EnergyAustralia to show regulators clear linkages between their data and the decisions made, are only now starting to be put in place.

In general, the information does not exist to enable GHD as advisers to the ACCC to say with complete assurance that EnergyAustralia's expenditure has been fully appropriate, prudent and efficient in the current RP or that EnergyAustralia's proposals for the coming RP are appropriate, prudent and efficient. Whilst systems are presently being put in place, EnergyAustralia are let down in part by the lack of any traceable history. The systems that have been incorporated, in general, should improve the efficiency of the Opex and Capex programs, particularly as the history of available data increases.

Prior to the development of these new systems, what was in place in general appeared rudimentary with a low level of traceability. This will have restricted the business performance of EnergyAustralia, particularly in the early part of the previous RP. However, it should be noted that with EnergyAustralia being primarily a DNSP, that is where the majority of their focus would lie, as such it would be expected that the systems evaluated as part of this transmission review would tend to be weaker than those in place for the distribution portion of the organisation although some areas should overlap.

3.3 Efficiency of Service/Project Delivery Systems

Up until now, purchase decisions were made on the basis of lowest cost. This meant that EnergyAustralia had components from every manufacturer throughout the world. The maintenance costs of this policy were large in terms of spares and the necessary skilled and experienced maintenance staff. We understand that this policy is under review.

EnergyAustralia utilise both internal and external resources for the delivery of projects, services and maintenance. When outsourcing, competitive tendering is always utilised. The internal service providers have been evaluated for their performance against industry benchmarks. Internal resources are primarily responsible for project management work. No clear risk evaluation or decision-making process was observed regarding the evaluation of whether internal or external resourcing should be selected.

Internal work is managed via internal supervisors, and at a higher level by regional managers. Work that is outsourced is the direct responsibility of the contractor, with KPI's utilised to manage performance in key areas such as progress, safety, quality and environment. Contractors undertaking work for EnergyAustralia may also be managed through the auditing of the contractors systems. Contractors are required to have appropriate management systems that cover Quality, Environment and OHS&R. These are audited to ensure contractor compliance.

Much of the investigation and design undertaken by external consultants, and civil engineering and design work is generally outsourced. Electrical design is done both internally and externally dependent upon the availability of internal resources.

EnergyAustralia is certified to AS/NZ ISO 9001:2000, and have quality audits carried out as a part of the maintenance of this certification.

A recently developed (2002) Capital Governance Process incorporates a stage-gate type process that requires capital projects to undergo a set of phases designed to ensure that the best decision is made. This process sets up a reasonable framework, however a more substantial focus on the option analysis and evaluation stage could further enhance the program.

Summarising these inputs, EnergyAustralia have had reasonably poor systems and processes in place, although there is now clear evidence that many of the weak points have been identified and solutions being implemented. This suggests that decisions made over the last 5 years will not have had the same level of rigour as would be expected for the next RP, as such the decisions made have a higher risk level due to the input of poorer data quality.

3.4 Overall Asset Management Planning

EnergyAustralia has made some significant positive moves with regards to their overall Asset Management. The following areas are now incorporated into the EnergyAustralia Asset Management program and decision making processes:

- A renewed capital investment program,
- Replacement capital to be decided based up asset condition and performance, and
- The inclusion of Capital / Operating Cost Trade-offs.

The majority of these overall Asset Management Planning processes have been developed and implemented since 2001, as such the level of detail held within the associated spreadsheets and documentation is not high, and there are not extensive examples available to provide evidence that they are in common use throughout the business. While tangible evidence is not yet available, a review of the procedures developed indicates that they should provide long-term improvements for EnergyAustralia through improved knowledge and understanding leading to better business decisions.

Prior to this recent focus on Asset Management, there was little evidence of a clearly considered approach. The previous systems were based upon historically built up methods and techniques, with past experiences and knowledge in conjunction with manufacturers' guidelines leading to the development of time based maintenance routines. The additional decision making benefits, and increased awareness and levels of data that are incorporated into sound asset management plans, extending them beyond the maintenance regime are not in evidence. The implication being that over a 5 – 7 year period, (assuming that EnergyAustralia continue upon their current path), they should transform from an organisation will relatively poor asset systems and decision making tools to a near best practice Asset Management organisation.

The implications of the level of asset management prior to this change is that the decisions made would have been based upon the best information at hand, and that the full ramifications of those decisions would not have been fully understood at the time of those decisions. EnergyAustralia were lagging the industry in this.

GHD has seen evidence of significant amounts of work being undertaken to improve these systems, however there was no clear evidence of the results or benefits of this work to date – apart from an improved understanding of their assets. Based on industry experience, GHD believes that with a continued focus on Asset Management, the decisions EnergyAustralia make with respect to their assets is expected to be much improved.

At present EnergyAustralia does not have a single document that outlines the Asset Management Plan for the entire organisation – a sign that the development of their asset management program is still underway. These documents typically show the linkages between the business goals of the organisation and the implications of these for the asset decisions, as well as providing a single reference document that details the policies, priorities and practices expected by the organisation. Asset Management Plans also generally provide details as to the responsibilities and accountabilities within the organisation for the management and performance of their assets.

3.5 Asset Management Strategies including Maintenance and Renewal Decision Processes

In line with the recent developments in EnergyAustralia's overall asset management planning, the asset level maintenance and renewal strategies have undergone significant revision. This review, completed through a combination of internal resources and external consultancy papers, has increased the level of understanding within the organisation with respect to an improved maintenance regime for their assets.

The key notable changes include:

- The introduction of Life Cycle Costing (LCC), Condition Based Maintenance (CBM) and Failure Mode Effects Analysis (FMEA) into asset decision-making. LCC, CBM and FMEA are vital tools in optimising the value that an asset category delivers. They enable an evaluation of the repair, replacement and renewal options available for a particular asset class, models the associated expenditure and levels of performance, taking into account particular asset conditions and hence enables near-optimal decisions to be made.
- Development of a Capex/Opex trade-off model. This model has recently started to be incorporated into the capital investment decision-making process. This should improve the decision-making and aid in the optimisation of overall expenditure.
- Reviews of their asset categories identifying asset conditions and performance. This information and the knowledge of their assets that is derived from these reviews will support the LCC and Capex/Opex trade-off items above. This information additionally will identify priority focus areas and provide a direction for further improvements.

It should be noted that it is still early in the implementation program for all of the above points and no clear results can as yet be determined. The steps taken show an improved level of thought and consideration, and it would be expected that long-term efficiencies, either through cost or more efficient outcomes, should be derived from the full implementation and utilisation of this program.

Through the evaluation of the performance of current maintenance practices, an awareness of the requirement to bring forward a number of maintenance activities to minimise ongoing expenditure has been identified. The appropriateness of the costs associated with this brought forward maintenance is discussed within Section 4 of this report.

The asset management strategies are at an early stage of development. The steps taken to date will provide significant long term benefits to the organisation, however with their relative recency and the current 'development and implementation' phase underway, there should be further efficiencies possible within this area over the upcoming RP.

The implications of limited Asset Management Strategies is primarily linked to the decision being made on poor information and without a full understanding of the ramifications of that decision for the asset base, and the ongoing costs and expenses. These issues have now been identified and actions are underway to rectify deficiencies, which based on GHD's industry experience will place EnergyAustralia into a leading role within the TNSP industry if the current direction and developments are continued.

3.6 Capitalisation Policy

The capitalisation policy is important because it can materially affect operating expenditure and the affect the revenue cap. We note that the Auditor (September 03) has evaluated the accounting policies of the EnergyAustralia Board in preparing the accounts and that they are in accordance with applicable Accounting Standards. Accordingly, we consider that any Capitalisation will be consistent with Accounting Standards and will be result in an appropriate allocation of costs.

GHD have not undertaken a full review of the allocation data utilised within the EnergyAustralia submission, as this was outside the scope of the report.

3.7 Opex Efficiencies from Capital Investment

GHD consider that with its new maintenance approach, and the detailed investigation of the organisations assets that is underway, EnergyAustralia is well placed to understand the Capex / Opex tradeoffs especially in regards to replacement Capex. However, these systems have yet to be put in place to make sure that this happens.

During the interview process, and within supporting documentation to the EnergyAustralia submission, it was identified that a model has been developed by EnergyAustralia to quantify the Capex / Opex relationship which would enable the incorporation of Opex implications into the Capital decision making (governance) program. Conclusive evidence of the model or of its use in the evaluation of projects to date has not been sighted.

3.8 Capital Governance Framework

EnergyAustralia provided to GHD a presentation on their new Capital Governance Framework during interviews in December 2003. It was indicated that this process will be adopted in the future for new projects.

Key elements of the Framework are as follows for each phase of the Project Lifecycle:

Project Phase	**Assess Potential Solutions**	**Develop Feasible Options**	**Justify & Plan**	**Execute Project**		**Evaluate & Operate**
Decision Maker	Manager A & IM	Executive Team & Board SC	Board SC or Nominated Officer	Nominated Officer	Sponsor	
Deliverables	VMS Options Report	Preliminary Design incl Funding & Resource requirements	Full Business Case incl. PIP Project Specification	Project Status Report Milestone Report	Asset Complete and Ready for Handover	Post Implementation Review Beneficial operation of asset
Objectives of Each Stage	Identify a set of Options to address a need and ensure alignment with business strategy	Further Develop Options for consideration in portfolio	Finalise Scope, cost and schedule and get project funded	Produce an operating asset consistent with scope, cost and schedule		Start up, Operate and Evaluate asset Ensure performance Specifications and maximum Return to Business

EnergyAustralia has not yet fully adopted this system and it was not in place for past projects. For future projects it has not been formally adopted or used. However, some of the steps are fundamental phases in all projects and it would not be unreasonable for the process to be followed and documentation to be available to demonstrate progress.

In a preamble to the Framework the following observations are some of the Core Principles:

- Project options to be identified, analysed, assessed and reviewed to ensure the development of an optimised portfolio.
- Each phase of a project is to be transparent, verifiable & requires an assurance check before progressing
- Funding of projects conditional upon the achievement of targeted outcomes with any significant change requiring the project to be resubmitted for approval.

- The portfolio comprises projects extending over multiple years requiring forecasts for;
  - The current year & next years budget
  - The 5-year determination period
- The framework is to be simple to assist in understanding of the priorities and implications of decisions made."

3.9 Summary of Findings

The following points summarise the expenditure related business systems that EnergyAustralia have had in place during the previous RP and the changes that have occurred:

- Performance levels below what would be expected of an organisation such as this early in the RP.
- These performance levels will have resulted in decision-making based on inadequate levels of data.
- Poor traceability within the previous RP, this is improving as systems are introduced, but requires extensive work.
- Weaknesses have been identified, prioritised and systems and processes are being developed and implemented to rectify the immediate deficiencies, further development of these will improve performance into the future.
- In some areas (AM) a substantial change is underway, moving EA from lagging the industry to a position whereby they will be above the industry average.
- Significant opportunities exist for EnergyAustralia to improve their performance levels over the upcoming RP, and improve overall efficiency levels.

In conclusion, EnergyAustralia started the previous RP with generally weak systems and data, with a correspondingly reduced capacity to make decisions. The level of performance in this respect was below that which would be expected of a prudent operator. The weaknesses have been identified and steps are underway to rectify some of these inadequacies, with some definite improvements currently in evidence. The Asset Management system and the procurement strategy being introduced are expected to reap significant benefits for EnergyAustralia in the long term, with some of the effects impacting during the upcoming RP.

4. Regulatory Asset Base and Historic Capital Expenditure

4.1 Basis for Review

This review component was required to ascertain the efficiency of EnergyAustralia's historic Capex and provide advice in order for the Commission to compare EnergyAustralia's Capex spent against the Commission's approved Capex program. This advice forms inputs to the Commission's PTRM model in establishing the starting regulatory asset base (RAB) for the forthcoming RP. This review component also provides advice on asset lives and depreciation profiles to assist the Commission in determining the starting RAB.

This review was to be based on assessment of information provided by EnergyAustralia, including:

- Historical Capex information, in particular, Attachment F of the Application, covering information on the 1999-2004 capital expenditure and project-specific details;
- EnergyAustralia's capital expenditure process, plans and programs as described in the Application and further clarified during the Review process;
- EnergyAustralia's forecasting process;
- Individual sampled project reports;
- Miscellaneous supporting information; and
- EnergyAustralia's responses to queries during the Review process.

To date, only some of the information has been provided in written format.

(Note: In this section, where a lack or absence of information from EnergyAustralia is mentioned, GHD have submitted requests for such information as documented in Appendix C of this Report).

The review was carried out within the following framework:

- Reviewing adequacy of EnergyAustralia's Capex methodology with a focus on efficiency of expenditure. Consideration was given to internal and external factors impacting on project identification, development and implementation;
- Reviewing the link between EnergyAustralia's load forecasting, load monitoring and individual timing of implementation and the capacity of the augmentation;
- Review of regulatory test application principles that have been applied to three projects selected by the Commission, including reviewing the application of the planning criteria, modeling, justification and assumptions in project selection, quality of analysis of options and costing, and appropriateness of timing of the projects;
- For non-augmentation projects, selecting key investment categories/projects and reviewing the relevant business case justification or asset management strategy from which the program/project derived.

EnergyAustralia have not specifically applied the regulatory test, other than as part of a joint application with TransGrid in the case of the Sydney CBD upgrade. Accordingly, ACCC have directed GHD to conduct a detailed review of three projects in lieu of the three regulatory test applications specified in ACCC's original brief. The three projects are as follows:

- The Sydney CBD project. In respect of this project, the review will cover the extent to which EnergyAustralia's investment in this project has been assessed through the regulatory test and whether the investment by EnergyAustralia, following TransGrid's investment, is justified and efficient;
- Beresfield 132/33kV sub-transmission substation;
- Macquarie Park 132kV substation.

4.2 Regulated and Non-regulated Capital Expenditure

Some of the elements of EnergyAustralia's network are classified under the Code as transmission assets and as such, are all regulated assets under the ACCC. Under the Code, EnergyAustralia's transmission assets are those "operating at nominal voltages between 66kV and 220kV that operate in parallel to and provide support to the higher voltage transmission network".

EnergyAustralia have no non-regulated transmission assets.

EnergyAustralia primarily operate a distribution network in NSW and are therefore regulated by both IPART and ACCC. EnergyAustralia have identified a number of network elements whose function will change from that of distribution to one of transmission due to augmentation work changing the configuration and operation of the network.

For the 1999-2004 RP, EnergyAustralia's transmission assets are understood to be as defined within the report developed by Erldunda Associates in May 2003[1].

Further, EnergyAustralia have submitted the following information to both IPART and ACCC on its closing RAB for 1999-2004 and the assets that will be re-classified as transmission for the 2004-2009 RP:

Table 1 Asset Re-Classification

1999-2004		
Region	**Asset**	**Re-classification**
Hunter	None	
Inner Sydney Metropolitan	9SA	Distribution to transmission

[1] Erldunda Associates, May 2003, *Transmission Assets owned by EnergyAustralia a report for the Australian Competition and Consumer Commission as Regulator of Electricity Transmission Assets*

1999-2004

Region	Asset		Re-classification
Central Coast	957	Vales Point – Ourimbah	Distribution to transmission
	95C	Ourimbah – Tuggerah	Distribution to transmission
	951	Ourimbah – West Gosford	Distribution to transmission
	958	Tuggerah – Gosford	Distribution to transmission
	956	West Gosford – Gosford	Distribution to transmission
	95E	Gosford – Somersby	Distribution to transmission
	95Z	Somersby – Mt Colah	Distribution to transmission
	Ourimbah sub-transmission substation		Distribution to transmission
Central Coast	Gosford sub-transmission substation		Distribution to transmission
	West Gosford zone substation		Distribution to transmission
	Somersby zone substation		Distribution to transmission
	Mt Colah switching station		Distribution to transmission
2004-2009			
Hunter	None		
Inner Sydney Metropolitan	Feeder 900		Transmission to distribution
	Feeders 916 and 917 – not confirmed		Distribution to transmission
	Kurnell 132/33kV		Distribution to transmission
	Feeder 240 and 24? – not confirmed		Distribution to transmission

4.3 Overall Historical Capital Expenditure

EnergyAustralia's actual capital expenditure for the current Determination period 1999 – 2004 is set out in Table 2 below:

Note: The figures presented in the following sections are in 2003 dollars.

Table 2 Historical Capital Expenditure (2003/04 $ million)

Financial Year	Augmentation Capex	Refurbishment Capex	Other	Total Capex
2000	11.1	18.7	0.03	29.8
2001	19.3	1.6	1.0	21.9
2002	30.2	2.4	0.5	33.1
2003	27.3	0.7	0.2	28.2
2004 (forecast)	29.6	3.7		33.3
		Total Capex 99-04		146.4

Table 3 provides a comparison of the Capex spent by EnergyAustralia in 1999/00 to 2003/04 with the 1999 Allowance:

Table 3 Comparison of Capex spent in the current RP vs. Capex allowed in 1999

ID	Description	Historic ($M)	1999 Allowance ($M)	Variance ($M)
1	**Augmentation Projects**			
1.1	Projects identified in 1999 Determination and completed in the current RP	10.2	15.2	-5.0
1.2	Projects identified in 1999 Determination but not completed in the current RP	63.8	28.2	+35.6
1.3	Projects not identified in 1999 Determination but Capex spent and project completed in the current RP	36.2[2]	N//A	+36.2
1.4	Projects not identified in 1999 Determination, Capex spent but project not completed in the current RP	7.4	N/A	+7.4
	Total (Augmentation)	117.6	43.4	+74.2

[2] This figure includes the Macquarie Park Project which was brought forward from 2005 and Wyong and Charmhaven zone substations which were previously included in the IPART accounts.

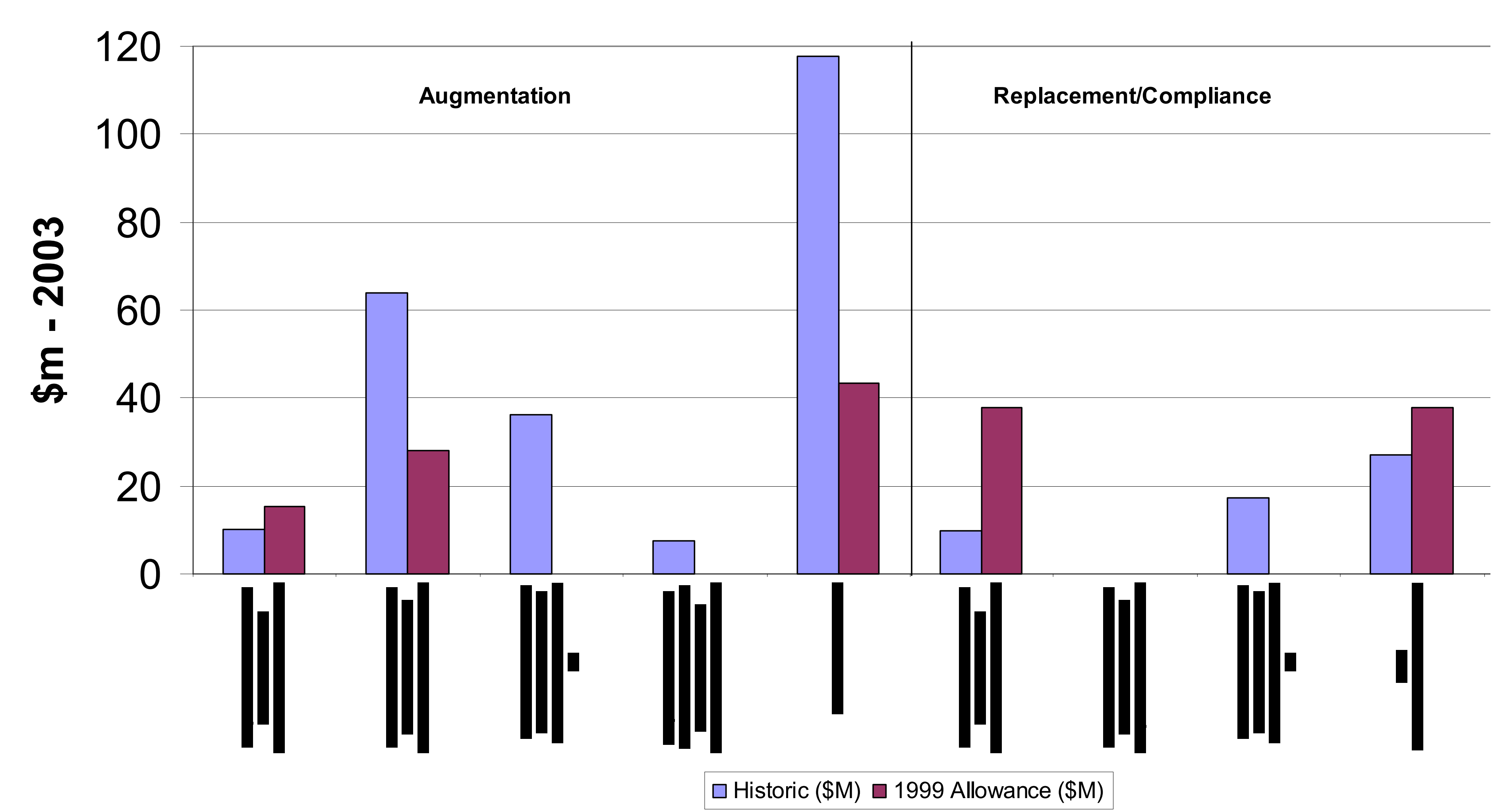
ID	Description	Historic ($M)	1999 Allowance ($M)	Variance ($M)
2	**Replacement/Compliance**			
2.1	Projects identified in 1999 Determination and completed in the current RP	9.9	37.9	(-28.0)
2.2	Projects identified in 1999 Determination but not completed in the current RP	None		
2.3	Projects not identified in 1999 Determination but Capex spent in the current RP	17.2	N/A	+17.2
	Total (Replacement/Compliance)	27.1	37.9	(-10.8)
3	**Other Projects (not classified)** Note 1 below	**1.7**	**7.9**	**(-6.2)**
	Grand Total (Augmentation + Replacement + "others")	***146.4***	***89.2***	***+57.2***

Notes:

1 The Gosford to Ourimbah project was identified and allowed in the 1999 Determination, classified under "others". However, there was no actual spend in the ACCC regulatory accounts. EnergyAustralia are advising IPART and ACCC that this project will be transferred from distribution to transmission. EnergyAustralia have clarified the amount of $1.7M spent under "others" in its regulatory accounts to be a figure relating to miscellaneous projects that did not fit within the project listing of Attachment F of its submission. This figure is not the amount spent for the Gosford-Ourimbah project that has been classified under "others" in the Allowed Capex project listing.

A comparison of the historical Capex against the Capex allowed in the 1999 decision is provided in Figure 3.

Figure 3 Comparison of Historical Capex against Capex Allowed in 1999 Decision



The above comparison indicates:

- A total overspend of **$57 million** from the total allowed Capex for the current (1999-2004) Regulatory Period;
- An overspend of **$74 million** for augmentation projects;
- An underspend of **$11 million** for refurbishment projects;
- An underspend of **$6 million** for miscellaneous projects, details of which have not been provided;
- Of the 6 augmentation projects undertaken in the current RP, only 3 had been identified in the 1999 decision;
- Of the 3 that had been identified in the 1999 Decision, only one (Tuggerah-Munmorah 132kV line) came close to its allowed Capex ($4.5M spent versus $3.9 allowed);

The above observations are considered in further detail below.

4.4 Augmentation Capex

4.4.1 Introduction

The projects identified in EnergyAustralia's 1999-2004 Capex are summarised in the following table:

Table 4 Transmission Projects 1999-2004

Project ID	Description
1	Tuggerah-Munmorah 132kV Feeder and Conversion of Wyong and Charmhaven Substations
2	Uprating of feeders 910/911
3	Macquarie Park
4	Sydney CBD Haymarket and Campbell Street
5	Beresfield Sub-transmission Substation
6	Additional 132kV capacity in the Lower Hunter

The analysis of Projects 3, 4 and 5 are detailed separately (further in this report) as part of the review of the application of the Regulatory Test Principles. Analysis of Projects 1, 2 and 6 is described below.

4.4.2 Project ID 1 Tuggerah-Munmorah 132kV Feeder

The reported actual expenditure of this project was $4.473M spread across 2000 to 2002, against an approved Capex of $3.945M to be spent in 2000, that is, an overspend of $0.528M.

This project was one of three in a works program totalling $25.3M included in EnergyAustralia's 1997 submission to IPART as follows:

Table 5 Works Program in EnergyAustralia's 1997 IPART Submission

Project ID	Description	Expenditure ($M)
1	Construction of a 132kV line from Tuggerah to Munmorah	5.0
2	Construction of a 132/11kV zone substation at Wyong	9.9
3	Construction of a 132/11kV zone substation at Charmhaven	10.4
	Total	**25.3**

EnergyAustralia stated in Attachment F of its 2004-09 submission to ACCC that whilst the construction of the 132kV line from Tuggerah to Munmorah was subsequently included in its 2000-04 submission to the ACCC, the other two projects (2 and 3) above were not, although they were transmission exit points. In August 2003, EnergyAustralia provided advice to both IPART and ACCC, of EnergyAustralia's closing distribution RAB for 1999-2004 and changes in asset classification from distribution to transmission. The two zone substations at Wyong and Charmhaven were not included in this advice. Subsequently EnergyAustralia have advised GHD that as the Tuggerah-Munmorah 132kV feeder had been constructed as a transmission asset, it naturally meant that Charmhaven and Wyong must also be regarded as transmission assets as they were transmission exit points. Hence, they were not specifically mentioned in the August 2003 advice to the two regulators. At the time of this report, EnergyAustralia have since written to the ACCC with an updated Capex spend for the current RP, adjusted to include the Wyong and Charmhaven substations.

Data source

- EnergyAustralia Value Management Study Report, December 1996 – Supplying Central Coast (Northern Sector Sub-transmission & Zone Substation Capacity);
- EnergyAustralia/TransGrid Final Report, March 2003 – Development of Electricity Supply to the Central Coast;
- Attachment F of EnergyAustralia 2004-09 submission to ACCC;
- EnergyAustralia letter of 11 August 2003 to IPART and ACCC – Subject: "EnergyAustralia's closing Regulatory Asset Base for period 1999-2003 and information relating to changes in operational classification of network assets (i.e. asset moves from distribution to transmission)"[3];
- EnergyAustralia Annual Electricity System Development Review (AESDR), May 2003;

[3] The information on moving assets is also included in EnergyAustralia's submission as Attachment 2

- Attachment 6 of EnergyAustralia 2004-09 submission to ACCC - SKM Report on Project Prudency;
- System Diagram – "Existing Gosford STS, Vales Point BSP & Munmorah BSP 132kV, 66kV & 33kV Load Areas" (Arrangement of Central Coast 132kV System prior to Tuggerah-Munmorah);
- 5 November 1996 Network Division (Sub-transmission Planning) File Note – Summary of analysis for outage of 33kV feeder Wyong-Berkeley Vale (showing feeder overloading and unsatisfactory voltage);
- 21 November 1997 Spreadsheet of Berkeley Vale and Wyong SCADA information (showing comparison of loadflow and actual voltage levels following an outage of 33kV Wyong-Berkeley Vale feeder);
- 1998 Loadflow analysis on Munmorah 33kV network supplying Charmhaven;
- 1997 Charmhaven Forecast (Spreadsheet dated 15 May 1998);
- 1997 Extracts of Central Coast Summer and Winter Sub-Transmission Forecasts;
- 1996 Wyong Forecast (Spreadsheet dated 5 June 1997); and
- Four (4) Reports - Risk Assessments of EnergyAustralia Zone Substations for Winter 1999, Summer 2000/2001, Winter 2000 and Summer 2000.

Brief Description

The project was driven by the need to improve network reliability, reduce system losses, replace aged substation equipment and accommodate growth in the Central Coast area of approximately 4% over the next 10 to 15 years.

Planning Criteria

N-1 criterion applies to supply to this area. However, risk management is implemented for predominantly residential substation loads such that at times, some zones could be non-firm for part of the time. The risk management approach employs the criteria that "development work should only be planned if the firm rating of the substation (based on current rating practices) is forecast to be exceeded for more than 1% of the time in any year, or if the annual probability of failure(s) which would require load shedding to prevent equipment damage is forecast to exceed 1%"[4]

Options Considered

The construction of a 132kV line between Tuggerah and Munmorah was one of numerous options that were identified to address the problems of:

- Firm capacity constraint at Munmorah Bulk Supply Point;
- Capacity of various sub-transmission feeders in the Central Coast area;
- Loading on Ourimbah Sub-transmission Substation, Charmhaven and Wyong zone substations;

[4] Risk Management Analysis, Charmhaven Risk Analysis, Appendix 4 of VM Study for the Central Coast 1996

EnergyAustralia have provided documentation relating to joint planning activities with TransGrid, which indicate that strategic options for the long-term development of the supply to the Central Coast Region were specifically discussed in late 1994/early 1995. A series of Value Management Study sessions were held by EnergyAustralia from June to December 1996, attended by TransGrid Planning.

The outcome of this value management process was a series of system development proposals for the Central Coast of which the Tuggerah-Munmorah 132kV Project was one. The value management study included a Net Present Cost analysis which encompasses all of the development proposals considered during the study.

The total cost for the components that eventuated as the Tuggerah-Munmorah 132kV Project was estimated at the value management study to be $14M[5].

The Project was included in the IPART submission as previously described at a cost of $25.3M, of which $4.5M (the 132kV line) was subsequently included and allowed in the ACCC submission. The cost of this line was estimated at the Value Management Study to be $3M.

Assessment

EnergyAustralia have provided working papers and other supporting information on joint planning discussions, relevant load flows, substation forecasts and risk assessments that clearly demonstrate:

- Forecast loads exceeding firm ratings at Wyong and Charmhaven;
- Loadings of the interconnected systems and bulk supply points which in turn, support the justification that:
  - conversion of the Charmhaven substation to 132kV will assist in minimising load "dumping" within the existing 33kV network configuration;
  - the 132kV interconnection between Tuggerah and Munmorah is a strategic solution, providing relief to the Munmorah BSP and Ourimbah STS.

It is unclear at this stage as to how the costs estimated during the value management process developed into the figures submitted to IPART and subsequently to ACCC for the current RP. During the 15-17 December 2003 interviews with EnergyAustralia, they advised that cost estimates were further fine-tuned and confirmed as the design progressed. This is considered to be standard practice in industry.

GHD have requested and have not received details of engineering estimates or detailed scope of work. The only costing details that were available for review for this project were the cost estimates of a 132kV zone substation, which GHD have found to be comparable with their database.

Conclusions

The component of the project specifically identified and allowed for in the 1999 Determination (the 132kV line) was overspent by approximately $0.6M or 10%.

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[5] Value Management Study, December 1996, cost of items C2, E1 and F1 on page 23.

At the December presentations to GHD, EnergyAustralia have also advised that the 10% overspend was due to construction and final line design issues. With only this information at hand however, GHD is unable to determine if the magnitude of the investment was prudent.

GHD would need to review further detailed analysis of the options (if this was carried out following the high level value management study) and further development and justification of the costing for the project leading up to Board approval of the project and/or inclusion of the budget in the 1999 submission to the ACCC.

In respect of this project and on the basis of the load forecasts, load flow data, loading details and risk assessment reports provided by EnergyAustralia, GHD can conclude that there was a need for a solution to address the load constraints demonstrated by the information supplied by EnergyAustralia and this project will provide a solution.

The findings on this project are summarised against the review framework in the following table.

Table 6 Summary of Findings for Tuggerah-Munmorah 132kV Project

	Criteria	Pass (√) / Fail (X)	Reasons for pass/fail assessment
1	Timing:		
	Linkage to load forecasting, load monitoring	√	Evidence from working papers illustrating load constraints and other such details.
	Application of planning criteria, modelling, justification and assumptions in project identification	√	Evidence from working papers illustrating load constraints and other such details.
2	Magnitude of investment		
	Quality of analysis of options	X	High level options analysis at the value management stage – GHD is seeking information on further options analysis/justification leading up to Board approval of the project.
	Quality of costing	X	High level cost comparison – no information sighted on detailed cost estimates and costing development following project identification.

4.4.3 Project ID 2 Feeder 910/911

The reported actual expenditure of this project was $5.674M spread across 2000 to 2002, against an approved Capex of $11.272M to be spent in 2000 and 2001, that is, an underspend of approximately $5.6M.

Data Source:

- EnergyAustralia Value Planning Study Report, 29 April 1998 – 132kV Supply to the CBD;
- Attachment F of EnergyAustralia 2004-09 submission to ACCC;
- May 1998 Correspondence with TransGrid on planning issues for discussion at joint meeting of the time;
- September 1998 recommendation of joint meeting for EnergyAustralia to implement a 132kV augmentation to improve the utilisation of TransGrid supply points by November 2001;
- December 1998 facsimile from TransGrid regarding feasibility of upgrading feeder 910/911;
- August 2000 extracts of joint planning meeting relating to 910/911 work by TransGrid;
- Summary of load flow studies;
- Various extracts of performance details of 910/911 in summer 00/01 and in 2003/04 indicating performance of inner metropolitan network with and without 910/911.

Brief Description

Feeders 910 and 911 were up-rated, which required re-conductoring of about 15km of double circuit transmission line. The up-rating of these feeders forms part of an overall program to improve the supply to the CBD, involving, inter alia, relief of the loading on TransGrid's Beaconsfield West Substation.

Planning Criteria

Information supplied to GHD for the review of this project does not specifically state the criterion but this project was one of several identified to improve supply to the CBD under a N-1 planning criterion.

Options Considered

This project was one of several identified for the improvement of supply to the Sydney CBD and inner suburbs, in particular, to address the relief of Beaconsfield West which in turn would help to defer TransGrid's 330kV augmentation to the CBD.

The VM study considered 3 options to address the relief of Beaconsfield West:

- Uprating of feeders 910/911 (estimated to be $9M);
- Transfer of 100MW of peak load from Sefton and Greenacre Park to Bankstown (estimated to be $15M);
- Installation of a link between Kurnell and Bunnerong (estimated to be $30-$40M).

Assessment

EnergyAustralia have provided working papers and other supporting information on joint planning discussions as well as loadflow studies showing constraints and limitations on the 132kV elements relating to the discussion on the option of re-conductoring 910/911 feeders.

It is unclear at this stage as to how the costs were estimated for the value management study.

A cost of $9.5M (nominal) was stated in the Value Planning Study dated 29 April 1998. A subsequent memo dated 11 March 1999 from the Transmission Section of Enerserve estimated the cost of re-conductoring the 910/911 feeders to be $7.2M (nominal). This presumably was a further refined estimate for the works. The 1999 Allowed Capex was $11.3M (2003$), which is approximately $10M nominal.

EnergyAustralia advised that the underspend of $5.6M (2003$) was due to the fact that the cost estimate was based on internal prices but that contract prices had come in significantly less.

From a technical perspective, the option of re-conductoring the 910/911 feeders appears to be prudent. In providing relief to the loading of the critical TransGrid Cable 41 under certain failure scenarios and in providing additional capacity at Chullora when Cable 41 is out of service, this project provided a cost effective option for the deferral of expenditure by TransGrid associated with the 330kV augmentation to the CBD.

Conclusions

In respect of this project and on the basis of the load flow data and loading details provided by EnergyAustralia, GHD are of the opinion that the issues identified in relation to the relief of Beaconsfield West and ultimately, supply capacity to the inner suburbs are valid and that technically, the project was an appropriate option to address these issues.

The options comparison in the 1998 Value Management Report was a high level study with insufficient economic analysis to enable GHD to form a firm conclusion on whether the investment, as a whole, is prudent.

The findings on this project are summarised against the review framework in the following table.

Table 7 Summary of Findings for Feeder 910/911

	Criteria	Pass (√) / Fail (X)	Reasons for pass/fail assessment
1	Timing:		
	Linkage to load forecasting, load monitoring	√	Evidence from working papers illustrating load constraints and other such details
	Application of planning criteria, modelling, justification and assumptions in project identification	√	Evidence from working papers illustrating load constraints and other such details
2	Magnitude of investment		
	Quality of analysis of options	X	Uprating of feeder 910/911 was one of three options considered at the value management stage to address the relief of Beaconsfield West. – GHD is seeking information on further analysis/justification of this option leading up to Board approval of the project. There are no details of how the costs used for option comparison have been derived.
	Quality of costing	X	No information sighted on the development of the costs of the options considered. GHD had also previously requested details on the tendered price to gauge the advice given that this price came in significantly lower than EnergyAustralia's internal cost estimates. This information was not received.

4.4.4 Project ID 6 Additional 132kV Capacity in the Lower Hunter

The reported expenditure of this project was $1.5 million forecast to be spent in 2004. This project was not included in the 1999 Determination.

Data Source

Attachment F of EnergyAustralia 2004-09 submission to ACCC.

Brief Description

GHD submitted a general request to EnergyAustralia on 16 January 2004 to provide "the original working papers that have been prepared in support of each project for example, board papers, supporting information in the form of load flow results, costing spreadsheets, etc…"

At the meeting of 24 February 2004 to further clarify to EnergyAustralia the information being sought, GHD advised that they did not have any information on this project and EnergyAustralia said that they would look for this information. At the time of this report, information sought during this meeting has not been received.

Insufficient information available

Planning Criteria

Insufficient information available

Options Considered

Insufficient information available

Assessment:

Insufficient information available

Conclusions:

Insufficient information available

4.5 Refurbishment Capex

Table 8 Refurbishment Capex Summary

Project ID	Description
8	Refurbishment of transmission mains
9	Transmission Mains undergrounding at Homebush
10	Oil containment and environment
11	Green Square with augmentation later
12	Substation replacement

4.5.1 Preliminary View

The underspend on refurbishment Capex was approximately $11M. At the presentation of 15-17 December 2003, EnergyAustralia identified a lack of robustness in the derivation of the refurbishment Capex of $28M submitted to the ACCC for the 1999 Determination. Insufficient information is available to draw reasonable conclusions or recommendations for this item.

4.5.2 Green Square

This project was initiated during the current RP and will continue onto the next RP. The assessment of this project is covered in the following section under “Forecast Capex”. Although they are in the context of future Capex, the issues discussed in the next section are relevant to the historical spending in that:

- The documentation supplied to GHD by EnergyAustralia does not clearly detail the scope of work or the basis on which the estimates have been prepared.
- Following supply of supplementary documentation on 16 March 2004, GHD has formed the view that the project is probably prudent for the reasons outlined in 5.3.3 below.

4.6 Review of Regulatory Test Application Principles

The Commission has selected the following projects to be reviewed against regulatory test application principles, including the application of the planning criteria, modeling, justification and assumptions in project selection, quality of analysis of options and costing, and appropriateness of timing of the projects:

- Haymarket Project;
- Macquarie Park;
- Beresfield

4.6.1 Haymarket Project

The reported actual expenditure of this project stands at $63.8M against an allowed ACCC Capex of $28.2M.

The Haymarket project was one of three in a works program totalling $75.5M that was included in EnergyAustralia’s 1997 submission to IPART:

Table 9 Works Program in EnergyAustralia’s 1997 IPART Submission (2003 $)

Project ID	Description	Expenditure ($M)
1	Connection to Sydney Central (Haymarket)	28.2
2	Broadway Zone Substation	13.5
3	Taylor Square Zone Substation	33.8
	Total	**75.5**

Subsequently, the Sydney Central connections were included in the submission to the ACCC.

This project was subject to the Regulatory Test which has been comprehensively documented. The scope of the project has evolved from both the concept assumed for the test as well as the 1999 submissions and can be summarised as follows:

- A new zone substation at Campbell Street at Surry Hills which took the place of the Taylor Square and Broadway zone substations, including the purchase of the land;
- The connection of the new zone substation to the Haymarket supply point.

The written information available to support and trace the increase in expenditure is lacking and what has been provided to GHD for review for this report has been prepared specifically in response to GHD's request for a detailed cost reconciliation. This response attributed the main reasons for the increase in cost to:

- The change to the Campbell St site resulting in land cost;
- Two additional feeder bays due to revised network configurations;
- The construction issues of using ducts under the city streets and the subsequent installation of the cable tunnel.

In their specific response for this report, EnergyAustralia also stated that the Regulatory report was issued at a time when the design was at a conceptual stage and "that the accuracy of estimates would normally have been in the order of… +/- 25%". EnergyAustralia also went on to quote the Ewbank Preece report to the ACCC that suggests that expected cable costs could be 40% higher than used in the Regulatory estimates, as well the subsequent NERA' s sensitivity analysis of the Regulatory Test figures.

Irrespective of the most efficient option for TransGrid from the application of the Regulatory Test, EnergyAustralia, on their part, would still need to establish a zone substation in the area.

GHD have requested information that would allow them to review the movement in the budget from $28M to the Regulatory Test figure of $46M, thence to the $68M spent. To date, the information received on this Project consists of:

- An explanation of the cost development that was prepared specifically in response to GHD's request;
- Various extracts from the Ewbank Preece Review, the NERA Cost Effectiveness Analysis and Feasibility Study for the Cable Access Route.

Unfortunately, the above do not contain the detailed scope of work, detailed engineering estimates, associated board approvals, and other original working papers (i.e. not specifically prepared in response to GHD's request) that would allow GHD to conduct a proper review of the cost increase.

4.6.2 Macquarie Park

In 1998, a Value Management Study was undertaken to address the problems of loading on Pennant Hills Zone Substation, Epping/North Ryde Zone Substations, Hornsby Zone Substation and at various feeders in Galston, Epping, North Ryde and Hunters Hill.

The Value Management Study indicated a range of alternatives to address the problems. The study was a high level report, which did not delve into the details of the basis of costing and the development of the "creative" ideas to the selected option of a zone substation at Macquarie Park.

A subsequent planning report (dated September 2000) contained further details on the selected option. GHD have reviewed this report and agree with the technical justification of the project, which was based on the following reasons:

- The proximity of the site to existing 132kV lines;
- The load growth in the area (EnergyAustralia have provided load details which GHD have reviewed);
- A standard 132/11kV substation would have an ultimate capacity to accommodate the forecast loads, compared with a 33kV or 66kV substation.

Table 10 Summary of Findings for Macquarie Park

	Criteria	Pass (√) / Fail (X)	Reasons for pass/fail assessment
1	Timing:		
	Linkage to load forecasting, load monitoring	√	See note 1 below
	Application of planning criteria, modelling, justification and assumptions in project identification	X	See note 1 below
2	Magnitude of investment		
	Quality of analysis of options	X	In spite of the high level nature of the value management study, the recommended option would appear to be an obvious choice from a technical perspective. However, GHD are seeking further information that can demonstrate any further analysis/justification and detailed costing leading to Board approval.
	Quality of costing	X	High level cost comparison – no information sighted on detailed cost estimates and costing development

Notes:

1. EnergyAustralia have supplied load details which indicate that the investment was needed to address the load growth in the area. If the assessment could be based on this information and EnergyAustralia's presentation of the project at the interviews, GHD would also conclude that the investment was needed. However, with little information on costings and detailed options analysis, GHD cannot form a conclusion on the efficiency of this investment.

4.6.3 Beresfield

This project was initiated during the current RP and will continue onto the next RP. The assessment of this project is covered in the following section under "Forecast Capex". Although they are in the context of future Capex, the issues discussed in the next section are relevant to the historical spending in that:

- The documentation supplied to GHD by EnergyAustralia does not clearly detail the scope of work or the basis on which the estimates have been prepared.
- The rationale covered by the planning reports seems to be appropriately based on the loading and rating information supplied. Without a clear understanding of the scope of work and appropriateness of the expenditure GHD are unable to form an opinion on whether the expenditure is prudent.

4.7 Conclusions on Historic Capex

For the 1999 determination, the process used by EnergyAustralia for identifying and selecting augmentation projects over $5M would commence with a high level Value Management Study with attendees from planning, network control, customer service, asset management and field personnel, as well from TransGrid. In reviewing the projects undertaken for the current RP, GHD found that the linkages between the initial Value Management phase and subsequent phases of the Capex program were not easily traceable and there was not a coherent documentation process in place.

During its opening presentation at the interviews of 15-17 December, EnergyAustralia did acknowledge that they had had concerns with the existing capital process. Some of these concerns include:

- Lack of a direct linkage between decision criteria and high level objectives;
- Difficulty in assigning priorities between Capex drivers and projects;
- Difficulty in quantification of overall impact of Capex program; and
- Performance expectations do not match allocated resources[6]

To overcome these concerns, a new capital governance process is being put in place that will improve the traceability of the key elements in the Capex program.

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[6] EnergyAustralia presentation to ACCC and GHD, 15 December 2003

During the interviews held in December, EnergyAustralia gave a presentation on their Capex programme including explanations on the individual projects. Initial supporting documentation provided for review did not reflect the clarity of the verbal presentation and there was some difficulty in seeing this detail (and linkages in the Capex process) in the documentation. Following further requests for information, EnergyAustralia have now provided additional working papers that suggest that EnergyAustralia have a strong knowledge of demands for services and existing asset capabilities expected of a TNSP.

However, while EnergyAustralia have provided these additional working papers that demonstrate their ability to identify the need for investments, the linkage between the initial project identification process (VM study phase) and Board Approval through to the inclusion of a project in the ACCC application has not been demonstrated.

Our findings can be summarised as follows:

- Variances between 1999 Allowed and actual Capex:
  - An overall overspend of **$57 million** from the total allowed Capex for the current (1999-2004) Regulatory Period;
  - An overspend of **$74 million** for augmentation projects;
  - An underspend of **$11 million** for refurbishment projects;
  - An underspend of **$6 million** for miscellaneous projects, details of which have not been provided;
  - Of the 6 augmentation projects listed for the current RP, only 3 had been identified in the 1999 decision;
  - Of the 3 that had been identified in the 1999 Decision, only one (Tuggerah-Munmorah 132kV line) came close to its allowed Capex ($4.5M spent versus $3.9 allowed);
  - There was also the complication of the Gosford to Ourimbah project which was allowed in the 1999 Determination but actually included in the IPART asset base. The $1.5M figure under “others” in Attachment F of EnergyAustralia’s submission relates to Capex spent on miscellaneous projects not specifically identified for the 1999 submission.
- EnergyAustralia report to IPART as a DNSP and to ACCC as a TNSP. The nature of electricity networks and the definition of transmission assets under the code are such that assets could be re-classified between distribution and transmission. The function of the asset is sometimes not evident at the time of submission to the Regulator. As a result, there has been an adjustment to the historic capex and corresponding re-classification of assets between distribution and transmission;
- Working papers provided by EnergyAustralia relating to load forecasts, load flows, loading details, capacity constraints and risk assessment reports do demonstrate that the key issues on the need for investment have been addressed;
- For all historic projects, GHD have not received the details on the development of the costings for each project and as such, is unable to form an opinion on whether the expenditure was prudent.

- There is a lack of robustness in the linkage of the capital process to the ACCC regulatory framework. Project justification is not easily traceable through a structured process.

On the basis of the above findings:

- GHD is of the opinion that EnergyAustralia have a strong knowledge of demand for services and existing asset capabilities and particularly in respect of Projects 1 and 2, have been able to demonstrate the need for the investments. However, this is not necessarily evident in all cases due to the lack of traceability to documented justification and other supporting information/processes;
- GHD can also conclude that EnergyAustralia are aware of the deficiencies in their Capex processes to date and are making improvements to these processes;

In all cases, there is a lack of information on the development of costings (although GHD have requested this information – refer Appendix C). GHD have also requested but have not received information that would demonstrate a detailed or robust economic analysis/appraisal of options. Consequently, GHD are not able to form an opinion on the efficiency of the expenditure and therefore cannot conclude on the overall efficiency of the historic Capex program nor provide validated advice on the opening asset base.

5. Forecast Capital Expenditure

5.1 Basis for Review

The review for this Section was to be based on assessment of information provided by or sought from EnergyAustralia, including:

- Category break up of Capex amounts shown in the Application;
- Detailed listing of projects and amounts;
- Load forecasts;
- Overall strategies and programs for Capex,
- Individual sampled project planning and justification reports and project summaries,
- Support information and reports, and
- EnergyAustralia's responses to enquiries arising during the review.

To date, only some of the above information has been provided in written format.

Although the formal Board approval process of individual projects is carried out after consideration by the Capital Investment & Utilisation Sub-Committee [as outlined in advice from Energy Australia dated 22 March 2004], it would seem reasonable for the Board or its Sub-Committee to have a role in deciding which projects were to be included in the ACCC application for future Capital Expenditure.

It is understood that many projects have both a transmission and distribution component. In providing justification for **the transmission part of the project to be included in the ACCC application** GHD would have expected the whole project to be presented together with the **basis** on which the Transmission component was justified and its costs segregated from the total project.

The written information provided in support of these projects is limited. It was not provided during the discussion phase in December.

None of the proposed projects was supported initially by a comprehensive series of documents highlighting:

- The basis on which the project was initiated.
- Detailed load analysis before and after the project will be completed.
- Detailed cost estimates showing the assumptions used and the basis on which the cost had been include in the ACCC application
- A rigid analysis of alternatives other than an initial value management study considering option (with only some priced). After accepting an option at the value management there was no reconsideration of alternatives as more detailed costing became available that may have changed the ranking of the adopted scheme.
- An audit trail of documents showing how the proposed projects received Board approval to be included in the ACCC application.

- The regulatory test has not yet been formally applied in any of the future projects. It is understood that it will be applied within a year of the projects being implemented.

The review process was intended to include:

- Reviewing adequacy of EnergyAustralia's Capex methodology with a focus on efficiency of expenditure. Consideration was given to internal and external factors impacting on future Capex requirements.
- Checking the link between EnergyAustralia's load forecast and individual growth projects, and how this affects the timing of implementation and the capacity of the augmentation.
- Specific review of regulatory test applications selected by the Commission for augmentation projects, including reviewing the modeling, justification and assumptions in project selection, cost and timing of the projects.
- For non-augmentation projects, selecting key investment categories/projects and reviewing the relevant business case justification or asset management strategy from which they derive and whether this meets needs at least cost.
- Checking the consistency between the Capex allowance provided in the Application and the documentation supplied.

The process did not include independent analysis or verification of EnergyAustralia's load forecasts.

As indicated above, information to satisfy these processes was not available for any of the projects.

5.2 Demand Related Capital Expenditure

The projects included in the EnergyAustralia ACCC application in September 2003 for Demand Related Expenditure are included in the following table.

Table 11 Demand Related Expenditure Projects

Project	Expenditure ($m)
Inner Metropolitan	36.5
Beresfield and East Maitland/Tarro	5.9
Lower Hunter 132 kV	10.5
Newcastle W Corridor	2.4
TOTAL	**55.30**

For each of the above projects a verbal explanation was provided during interviews with GHD in December 2003. At the interviews EnergyAustralia was requested to supply detailed documentation about each of the projects. An Outline Business Case - Summary for each of the above (updated to reflect IPART/ACCC splits at the request of GHD on 23/12/03; 24/12/03; 24/12/03 & 23/12/03 respectively) was supplied during January 2004.

These Business Cases were in some cases supplemented by additional documentation that provided at high level planning rationale and general descriptions of the works to be performed.

In no cases was there any clear statement of the detailed scope of work with lists of equipment to be supplied or detailed engineering estimates provided.

Similarly, because of the lack of the detailed estimate, there was no clear method by which the split of cost estimates between distribution (IPART) and Transmission (ACCC) could be verified.

5.2.1 Inner Metropolitan Project

The Business Case describes this project as “Provision of Additional Transmission Capacity and connection to New TransGrid Substations in Sydney.”

The driver for this project is Load at Risk.

The main thrust is stated as: ”Provide adequate transmission capacity to meet then needs of Sydney by optimising network utilisation until a new 330/132kV supply point is established and providing capacity to the supply point after its establishment”

On 19 February 2004 EnergyAustralia provided supplementary documentation that clarified the planning criteria for the Inner Metropolitan project. This data including projected critical loading on feeders at each stage of the project and provided the technical justification of the project. The cost estimating data, however, was at a high level with no back up material to clarify the scope of work and assumptions made. The internal processes by which load planning analysis and associated budget estimates, lead to the inclusion of these projects in the ACCC application were not evident.

The work associated with this project will allow existing transmission capacity to be more fully used once Haymarket is operational. The aim is to control load flow through the existing 132 kV transmission assets linking Sydney North and Sydney South when either cable 41 or 42 (from Sydney South to Beaconsfield and Haymarket respectively) or a transformer in Sydney North or Sydney South is out of service to provide N-2 reliability to the inner metropolitan area.

The existing inner metropolitan load is expected to grow at about 80 MW per year and the proposed works would allow the existing transmission assets to handle the load growth with N-2 reliability from 2007. The proposal assumes that in 2008 to 2009 a new TransGrid 330/132 kV supply point will be established in the Mason Park area. It is not clear what would happen if this bulk supply point is not established. In other words, will the N-2 reliability of the Inner Metropolitan supply be maintained for loads after 2008 if no new TransGrid supply is established with increased loading on the system?

The only alternative considered in the documentation provided has been the deferral by one year resulting in load shedding by demand management or use of generation.

The alternative of bringing forward the new TransGrid bulk supply point to 2007 has apparently been considered but no documentation has been provided to indicate whether this would result in there being no need to install quadrature reactors at a cost of $13.8 million.

In this case the costing information provided has been at a high level with no detailed estimating back-up. There is a risk that when final designs are complete that the costs will be different.

Without a clear understanding of the scope of work and appropriateness of the proposed expenditure GHD is unable to form an opinion on whether the expenditure is prudent. The need for quadrature reactors needs to be clarified with reference to the timing of the new TransGrid bulk supply point.

The reasons GHD has not been able form an opinion on this project can be summarised as follows:

- Although the proposed changes to reactors at various stages have been shown to provide N-2 security under various scenarios as the load increases, there is no clear indication that these changes will be needed after the new TransGrid bulk supply point is commissioned. In other words no load flows and forecasts have been provided beyond the year in which the TransGrid bulk supply point is commissioned.
- The documentation to support the capital cost estimates has not been provided.
- GHD would have expected to see some working papers and Board submissions prior to this project being included in the ACCC application. No such papers have been provided[1].
- With the doubt raised above about the long-term need for the quadrature reactors, GHD would have expected this to have been addressed as part of the project approval process and appropriate cost/benefit analyses to be provided.
- There is no evidence that any of the new capital governance processes as summarised in 3.8 above has been formally followed on this project. Based on the information provided the project is close to the Justify & Plan stage and certainly has passed through the Develop Feasible Options stage. At this point there should be some evidence of Approval by the Manager, Asset & Investment Management or Board Sub committee. No such approval has been provided
- GHD would expect at least to see preliminary designs and estimates and some form of engineering scope documentation. Only the Outline Business Case has been provided and specific answers to GHD questions.

[1] See 5.1

5.2.2 Beresfield and East Maitland/Tarro

The Business Case describes this project as: "Provision of increased sub-transmission network and zone substation capacity to support existing and future residential and light industrial development along the major transport corridor between Newcastle and Maitland."

The key driver for the project is "Loss of Load". This is due to existing and projected load growth effecting Kurri STS and East Maitland and Tarro Zone sub-stations being in excess of the installed capacity at these sites.

A large number of alternatives were considered as outlined in the following reports by EnergyAustralia: "Hunter Planning Report 41B-99 East Maitland/Thornton/Tarro Area" dated 2 April 2002 including Attachment 1 to the Board Report.

"Hunter Planning Report 85-00 Lower Hunter 132 kV Network Supply Development Strategy Options" dated 16 April 2002.

The options considered have been identified with load impacts from future growth taken into account. The decision to adopt Strategy 1 – Beresfield 132/33 STS has been based on among issues the lowest NPV of $20,087,000 as outlined in Table 15 of Hunter Planning Report 41B-99 dated 2 April 2002. (In this report an amount of $13m has been assumed for Beresfield STS in 2006)

The preferred option is establishment of a new 132/33 kV substation near Beresfield with a Planning Estimate of $19 m. This estimate includes 2 x 120 MVA transformers and associated 132 kV and 33 kV connections.

The Business Case dated 24/12/03 identifies the ACCC Capital as $18.3m covering $12.4m by 2004 and the balance by 2005/06. In the spreadsheet attached to EnergyAustralia's letter of 4 February 2004 the project cost is shown as $20.609m with $7.36m by 2004 and the balance by 2006. In Attachment 1 there is an estimate from Enerserve of $20.552m covering this project. Documentation provided on 16 March 2004 clarifies some of the project cost variations and refers to an amount of $20.6m as authorised by EnergyAustralia Board.

The initial application to ACCC in September 2003 identified $5.9m during the 2004-09 period. The 4 February 2004 spreadsheet has identified $13.25m during the 2004-09 period.

The documentation supplied to GHD by EnergyAustralia does not clearly detail the scope of work or the basis on which the estimates have been prepared.

The rationale covered by the planning reports seems to be sensible based on the loading and rating information supplied. Without a clear understanding of the scope of work and appropriateness of the proposed expenditure GHD is unable to form a firm opinion on whether the expenditure is prudent.

The reasons GHD has not been able form an opinion on this project can be summarised as follows:

- Although the various Planning reports have identified a large number of options and arrived at recommended capital projects that overcome short and long-term limitations in handling increased loads in the area, there is a lack of rigour in the cost estimates.
- The documentation to support the overall capital cost estimates has not been provided.
- GHD would have expected to see some working papers and Board submissions prior to this project being included in the ACCC application. No such papers have been provided[1].
- There is no evidence that any of the new capital governance process as summarised in Section 3.8 above has been formally followed on this project. Based on the information provided the project is at the Justify & Plan stage and certainly has passed through the Develop Feasible Options stage. At this point there should be some evidence of Approval by the Manager, Asset & Investment Management or Board Sub committee. No such approval has been provided
- GHD would expect at least to see preliminary designs and estimates and some form of engineering scope documentation. The 2002 Planning Reports and the Outline Business Case dated 24/12/03 is the only documentation provided to GHD.

5.2.3 Lower Hunter 132 kV

The Business Case summary describes this project as – “Provision of Additional 132 kV Capacity in the Lower Hunter” – last updated 24/12/03

The key driver for this project is “Loss of Load”.

As with the East Maitland/Tarro project the rationale is covered in the Hunter Planning Reports referred to above. Due to current and forecast load growth a number of items in the transmission network will exceed their installed rating in the next few years.

The work covered by the Business Case includes mostly distribution assets that are not the subject of the ACCC determination.

The capital works that are part of the transmission assets include 132 kV Beresfield feeder augmentation, Tomago 132 kV feeder augmentation and part of the work associated with the 330 kV conversion of Waratah West.

The steps in implementing this project include:

- TransGrid installation of a 330/132 kV Transformer at Waratah West 330/132 kV Substation.
- Establishment of Beresfield 132/33 kV EnergyAustralia substation (covered in 5.2.2 East Maitland/Tarro above).

[1] See 5.1

- Disconnection of TransGrid feeder 95W to relieve load on the Newcastle 330/132 kV TransGrid 132 kV busbar.
- Construction of a new 132 kV feeder from Newcastle 330/132 kV TransGrid. Substation to Beresfield 132/33 kV Substation.
- Construction of a new 132 kV feeder from Beresfield to Tomago.
- Re-arrangement of Feeder 963 to Taree at Tomago.
- Construction of a new 132 kV feeder fro TransGrid Waratah West 330/132 kV Substation to EnergyAustralia Waratah 132/33 Substation.
- Re-arrangement of Feeders 950 and 9N9/1 around Waratah 132/33 kV Substation.

Based on a spreadsheet supplied by EnergyAustralia on 3 February 2004 it is understood the work covered by this project is as follows:

Capital $m (ACCC)	**ACCC Share**	**2000 – 04**	**2004 -09**
Beresfield 132 kV Feeder Augmentation	100%	0	5.0
Tomago 132 kV Feeder Augmentation	100%	0.5	4.5
Waratah West 330 kV Conversion	50%	1.0	1.0
TOTAL		1.5	10.5

It is understood that the Argenton substation (not part of ACCC determination) has been delayed. It is not clear whether this will delay the transmission work outlined above or whether difficulty in creating a substation in the Argenton area will mean that some of the transmission work will be handled differently.

The documentation supplied to GHD by EnergyAustralia does not clearly detail the scope of work or the basis on which the estimates have been prepared.

The rationale covered by the planning reports seems to be based on the loading and rating information supplied. Without a clear understanding of the scope of work (in particular Waratah West) and appropriateness of the proposed expenditure GHD is unable to form an opinion on whether the expenditure is prudent.

The reasons GHD has not been able form an opinion on this project can be summarised as follows:

- Although the various Planning reports have identified critical issues of loading on the Tomago, Newcastle and Waratah substations and arrived at recommended capital projects that overcome short and long term limitations in handling increased loads in the area, there is a lack of rigour in the cost estimates.
- The documentation to fully support the capital cost estimates has not been provided.

- GHD would have expected to see some working papers and Board submissions prior to this project being included in the ACCC application. No such papers have been provided[1].
- There is no evidence that any of the new capital governance process as summarised in 3.8 above has been formally followed on this project. Based on the information provided the project is beyond the Justify & Plan stage and certainly has passed through the Develop Feasible Options stage. At this point there should be some evidence of Approval by the Manager, Asset & Investment Management or Board Sub committee. No such approval has been provided
- GHD would expect at least to see preliminary designs and estimates and some form of engineering scope documentation. The 2002 Planning Reports and the Outline Business Case dated 24/12/03 is the only documentation provided to GHD.

5.2.4 Newcastle West Corridor

The Business Case describes this project as “Supplying Increasing Demand Newcastle West Corridor” dated 23/12/03

The Key Driver is “Loss of Load”.

The scope of work is broadly described as “Provision of increased sub-transmission zone substation capacity to support existing and future residential and industrial/mining development in the Newcastle West Corridor.”

The project is briefly covered in the Hunter Planning Report 85-00 Lower Hunter Network supply Development Strategy Options dated 16 April 2002 in Section 3.4.24. An estimated amount of $11m has been used as a planning estimate.

Since this is proposed as a future 132/11 kV substation in the transmission network it is included in the ACCC determination. A total figure of $8.4m has been used in the Business Case with $2.4m in 2006-09 and $6.0m in 2009-14.

No explanation for the difference between $11m and $8.4m has been given except that during interviews in December mention was made the project has been proposed using modular design standards so the costs have been reduced.

The documentation supplied to GHD by EnergyAustralia does not clearly detail the scope of work or the basis on which the estimates have been prepared. The Planning Report (3.2.24) indicates it will be connected to feeder 96Z or 950 (from TransGrid’s Newcastle Substation). The Business Case indicates it will be connected to feeder 9NA (from Newcastle to Beresfield). The drawings attached to the document “Project ID: Beresfield Sub-transmission Substation Part 1” show the new West Wallsend Zone Substation cut into the new feeder between Newcastle and Beresfield (Section 5.2.3 above).

[1] See 5.1

The rationale covered by the planning reports suggests a new 132/11 kV substation in the western corridor is necessary based on the loading and rating information supplied. Without a clear understanding of the scope of work and appropriateness of the proposed expenditure GHD is unable to form an opinion on whether the expenditure is prudent.

The reasons GHD has not been able form an opinion on this project can be summarised as follows:

- Although the various Planning reports have identified issues of loading in the West Newcastle corridor and arrived at recommended capital projects that overcome short and long-term limitations in handling increased loads in the area, there is a lack of rigour in both the planning options and cost estimates.
- The documentation to support the scope of work and capital cost estimates has not been provided.
- GHD would have expected to see some working papers and Board submissions clearly identifying this specific project prior to it being included in the ACCC application. No such papers have been provided[1].
- There is no evidence that any of the new capital governance process as summarised in 3.8 above has been formally followed on this project. Based on the information provided the project is probably at the Develop Feasible Options Stage. At this point there should be some evidence of Approval by the Manager, Asset & Investment Management. No such approval has been provided
- GHD would expect at least to see preliminary designs and estimates and some form of engineering scope documentation. The 2002 Planning Reports and the Outline Business Case dated 23/12/03 is the only documentation provided to GHD.

5.3 Replacement Related Capital Expenditure

In addition to the above Demand Related projects, Replacement Related Capital Expenditure from 2004 to 2009 was foreshadowed as shown in the following table.

Table 12 Replacement Related Capital Expenditure from 2004 to 2009

Project	Expenditure ($m)
Feeder 908/909 replacement	36.1
Ourimbah Refurbishment	16.1
Green Square	10.5
Transmission Substations	8.6
TOTAL	**71.3**

[1] See 5.1

5.3.1 Feeder 908/909 Replacement

The Business Case describes this project as: "Kurnell-Bunnerong (circuits 908/909 replacement) dated 22/12/03

The key driver for this project is: "Load at Risk"

The existing gas filled cables from Canterbury STS to Bunnerong STS are 45 years old, have a history of failure and are becoming more difficult to repair. Alternatives to new cables along a similar route ($48.6 m) have been compared to submarine cables from Kurnell to Bunnerong ($36.2 m)

Some supporting reports on cable failure were provided but it is believed from discussions with EnergyAustralia staff that future cable failures are a significant risk. As far back as 1991 there was a recommendation that the cables be replaced. There are difficulties in identification of the location of faults and repairs to the gas-filled cables are time consuming and expensive.

The documentation supplied to GHD by EnergyAustralia does not clearly detail the scope of work or the basis on which the estimates have been prepared. A high level estimate of $4,000 per metre has been provided for supply and installation of the submarine cable - but no supporting documentation for this figure has been supplied.

The financial accuracy of the submarine cable cost estimate needs to be justified more fully. The technical risk of two submarine cables across the mouth of a busy port at Botany has not been addressed.

Other options such as embedded generation at Botany have not been mentioned although, from industry knowledge, GHD is aware they have been considered and not adopted by the proponents for environmental or economic reasons. Issues that have made the projects uneconomic have included the national market price for electricity being too low to allow a new gas fired cogeneration plant to be economically viable. Environmental issues have been concerns at air pollution in the Sydney basin requiring expensive emission controls to be added to the plant making the projects even less viable. The availability of an economic reliable source of gas has also been of concern due its inherent single point of failure. (These comments on embedded generation would also apply to other network deferral projects in the Sydney Basin region).

They are made in connection with this project since a reliable embedded generator near Bunnerong with an appropriate network support agreement may have been a viable alternative to replacing these cables.

The rationale covered by the Business Case and verbal reports would indicate that the submarine cable option is appropriate.

The replacement of these cables seems justified. The submarine cable option from Kurnell to Bunnerong seems to be significantly cheaper than the alternative of like for like from Canterbury.

GHD believes that this project is prudent but would like more work to be done in justifying the cost estimate, especially for the submarine cables.

Remaining areas of concern include:

- The documentation to fully support the capital cost estimates has not been provided[1].
- GHD would have expected to see some working papers and Board submissions prior to this project being included in the ACCC application. No such papers have been provided.
- There is no evidence that any of the new capital governance process as summarised in 3.8 above has been formally followed on this project. Based on the information provided the project is close to the Develop Feasible Options stage. At this point there should be some evidence of Approval by the Manager, Asset & Investment Management. No such approval has been provided
- GHD would expect at least to see preliminary designs and estimates and some form of engineering scope documentation. Only the Outline Business Case has been provided.
- The regulatory test needs to be applied before the project is implemented.

5.3.2 Ourimbah Refurbishment

The Business Case describes this project as: "Supplying Increasing Demand and replacing Aged Infrastructure on the mid-Central Coast (Wyong Shire)

The key driver for this project is: "Load at Risk"

The scope of work covered by the ACCC application appears to be Reconstruction of Ourimbah STS to 2 x 120 MVA 132/66 kV and 1 x 60 MVA transformers, replacement of outdoor 132 kV busbar, replacement of 4 x 33 kV circuit breakers and extension of 66 kV busbar. The cost estimate is shown as $16.1m from 2006 to 2009.

This solution provides 60 MVA of non-firm capacity at 33 kV and 120 MVA at 66 kV compared to 110 MVA firm capacity at 33 kV and 15 MVA capacity at 66 kV. Associated work involves upgrading and refurbishment of Long jetty substation to operate at 66 kV.

The age of the equipment has, in 2004, reached its standard life of 45 years, and some condition assessment reports were provided to support its replacement during the regulatory period.

The arguments in favour of the replacement and upgrading to suit increasing demand seem plausible.

An alternate strategy involves reconstruction of Ourimbah at 33 kV with an estimated cost of $18.6m with apparently no increase in capacity. It is understood that associated 33 kV costs at Ourimbah would make the project uneconomic.

The only other alternative considered was a 132 kV line, which was rejected due to expected community opposition without examining any cost benefit that may arise.

[1] See 5.1

The documentation supplied to GHD by EnergyAustralia does not clearly detail the scope of work or the basis on which the estimates have been prepared.

Without a clear understanding of the scope of work and appropriateness of the proposed expenditure GHD is unable to form an opinion on whether the expenditure is prudent.

The reasons GHD has not been able to form an opinion on this project can be summarised as follows:

- The Outline Business Case is the only documentation provided specifically supporting this project. The 1996 "Supplying Central Coast Value Management Study" and the 2003 "Final Report on Development of Electricity Supply to the Central Coast" provides good background information on load growth and associated distribution projects.
- GHD would have expected to see some working papers and Board submissions prior to this project being included in the ACCC application. No such papers have been provided[1].
- There is no evidence that any of the new capital governance process as summarised in 3.8 above has been formally followed on this project. Based on the information provided the project is close to the Justify & Plan stage and certainly has passed through the Develop Feasible Options stage. At this point there should be some evidence of Approval by the Manager, Asset & Investment Management or Board Sub committee. No such approval has been provided
- GHD would expect at least to see preliminary designs and estimates and some form of engineering scope documentation. Only the Outline Business Case has been provided.

5.3.3 Green Square

The Business Case describes this project as: "Replacement of aged zone substations and 33 kV cables with new 132 kV zone substations."

The key driver for this project is: "Load at Risk"

The statements about the age of the equipment exceeding the standard lives are quite strong and replacement is probably appropriate on that basis. However, it would be easier to accept the proposition if condition assessment reports were available to support replacement. The arguments to use 132/11 kV substation in lieu of replacing 33 kV seem plausible but have not been supported by documentation.

The problem of age of equipment and loading during reconstruction is a driver for this project effecting existing substations at Alexandria, Zetland and Mascot. In the Consultation Paper 3 Options were considered:

[1] See 5.1

- Option 1 Develop a new substation at Bourke Street Alexandria in 2006 and retire Alexandria zone substation (work includes 2 x 50 MVA transformers with capacity to increase the load on the 132 kV cables beyond 2015)
- Option 2 Refurbishment of Alexandria as 33/11 kV Substation (involving transfer of loads to Mascot and Zetland before work commenced) Also involved in this project was extensive 33 kV replacement that would reach load capacity limits by 2014.
- Option 3 Reconstruct Alexandria Zone substation as 132/11 kV substation 2004-2006. This option was dismissed due to cost and the limited size and location of the existing site.

In the consultation paper produced in 2003 the capital cost of the new 132 kV Zone at Bourke Street Alexandria is estimated at $19.5 m. The September 2003 ACCC application estimates Green Square at $ 18.2 m. The 3 February 2004 spreadsheet shows the total cost of Green Square at $24.4m with $4.2m by 2004 and the balance from 2004-09.

The documentation initially supplied to GHD by EnergyAustralia did not clearly detail the scope of work or the basis on which the estimates have been prepared.

Supplementary documentation was provided on 16 March 2004, which has clarified the scope of work, loading and to some extent condition of equipment.

Based on this more comprehensive documentation GHD believes the proposed expenditure is probably prudent.

The reason GHD has some reservation is that:

- Detailed condition assessment reports have not been provided on equipment at Alexandria substation.
- Cost estimates of refurbishment versus replacement have not been given
- The project has not yet been subject to a regulatory test and other processes have not been demonstrated:
- GHD would have expected to see some working papers and Board submissions prior to this project being included in the ACCC application. No such papers have been provided[1].
- There is no evidence that any of the new capital governance process as summarised in 3.8 above has been formally followed on this project. Based on the information provided the project is at to the Justify & Plan stage and certainly has passed through the Develop Feasible Options stage. At this point there should be some evidence of Approval by the Manager, Asset & Investment Management or Board Sub committee. No such approval has been provided

5.3.4 Transmission Substations

Insufficient details have been provided on the proposed $8.6m expenditure and therefore GHD is unable to form any opinion on this item.

[1] See 5.1

A series of documents was provided on 16 March 2004, which showed various projects such as replacement of reactor at Chullora, transformers at Tomago, Canterbury and Kurri, spares, batteries and buildings totalling $8.64 M.

Other documents in the package refer to mains expenditure of $2.0 M.

In addition other documents refer to business cases for replacement of outdoor bulk oil circuit breaker replacements, ageing distance relays and some transformer condition assessment.

The problem in assessing this documentation is to see how it translates to a figure of $8.6 M.

5.3.5 Non System Capital Expenditure

GHD has not analysed the rationale of the whole of Network Non System Capital Expenditure of $45m per year leading to a transmission component of $5.6 m.

The proportional split of 12.4% for non-direct capital seems reasonable to be consistent with the approach taken for allocating non-direct operating expenditure.

5.4 Overall Capital Expenditure in Revenue Application

In a letter from EnergyAustralia to ACCC dated 3 February 2004 the amount of Forecast Transmission System Capex for the 2005 to 2009 Financial Years is shown as $156.2m plus $27.7m Non-system Capex = **$183.9 M**. These figures are considerably higher than the $55.3 + $71.3 = **$126.6m** in the September 2003 Submission to ACCC plus Non-system Capex of $27.7m = **$154.3 M**.

The only explanation to these changes are notes in Table 4 and Appendix 1 to the letter which include:

- Figures take account of asset transfer from Distribution to Transmission
- Figures take into account improved cost estimates for Green Sq, Beresfield & updated Haymarket commissioning
- Project estimates for East Maitland – Tarro have increased from $18m to $20 m
- Total expenditure on Green Square increased from $15.5 to $21.4 m
- WIP changed for Haymarket and Green Square to reflect commissioning in 2004-2009 period
- WIP adjusted for 132 kV connections to reflect an arithmetic error.

All of the above information makes it very difficult to analyse and comment on the appropriateness of the forecast Capex. The fact that significant changes have occurred between September 2003 application with projects totalling $126.6m to a figure on 4 February 2004 of $183.9m does not provide confidence in the overall planning and forecasting process. (Non-system Capex was not included in the original figures.)

In order to move forward on the analysis and comments on future Capex it will be necessary for EnergyAustralia to provide:

- More complete details of preliminary engineering designs, including preliminary layout and schematic drawings;
- Initial budget estimates with scope of work and high level list of equipment to be supplied;
- Load information to support the project;
- Detailed breakdown of costs between distribution and transmission.

It would be desirable if this information was supported by internal memos, board submissions etc to show how theses projects were singled out for inclusion in future Capex budgets and how they came to be included in the September 2003 and February 2004 applications to ACCC.

None of the past or future capital expenditure projects have been formally reviewed in accordance with the steps outlined in the Capital Governance Framework as outlined in 3.8 above. There is no evidence of any projects being subjected to a post implementation review.

GHD recommends that an efficiency saving of $1.419m p.a. be removed from the EnergyAustralia forecast Capex starting in 2005/06. Details and calculations for the generation of this efficiency saving are discussed in Section 6.9, under the sub-title of 'Confidential Project".

5.5 Summary of Findings

For most of the Demand Related Capital Expenditure projects there was evidence of a clear understanding by the Planning personnel of the assets, the capacity of the assets and current and projected loadings. As a result of this knowledge there was a demonstrated ability to proactively identify future system limitations and initiate an investigation into options for overcoming those limitations.

The Value Management Studies or Planning Reports provided to GHD indicated that many alternatives are considered before a proposed solution is adopted. In all cases where Value Management Studies were provided the analysis was at a high level and rarely supported by schematic or layout drawings that allowed a clear understanding of the detailed scope of work proposed.

It is not clear how the adopted alternative is selected out of the range of possibilities.

On the assumption that cost is a factor in choosing an option, there was no evidence to indicate whether the Value Management Study or Planning Report selection process is re-visited as designs and cost estimates are developed. In other words if the cost increases as information becomes more accurate would one of the other alternatives have been adopted.

For replacement projects the assessment of appropriateness would be assisted if more comprehensive project specific contemporary condition assessments were provided.

There is evidence from the Business Cases that Final Cost Estimates, Board Approval, Development Approval and Detailed Civil and Electrical Designs are prepared as part of the process. Despite numerous requests for this information from GHD, EnergyAustralia has not provided the details to assist GHD in forming an opinion.

The linkage between Board Approval and inclusion of a project in the ACCC application has not been demonstrated[1].

GHD recommends that an efficiency saving of $1.419m p.a. be removed from the EnergyAustralia forecast Capex starting in 2005/06.

[1] See 5.1

6. Operational Expenditure

6.1 Basis for Review

6.1.1 Terms of Reference

The ACCC Terms of Reference and their future clarification are as follows, please note the full ToR and Clarification are in Appendix A, the following is a version abridged by GHD:

Table 13 Opex Clarification

	Terms of Reference	Clarification
1	Benchmarking EnergyAustralia's Opex forecasts against other transmission network service providers both nationally and internationally	Depending on the available information, it may be better that time that would have been spent on this would be better spent on developing a better response to item 2 below.
2	Assess EnergyAustralia's forecast Opex costs for each year of the regulatory period, looking at endogenous and exogenous cost drivers and whether there is scope for additional efficiency gains.	EnergyAustralia's Opex forecast appears based on a model of maintenance costs related to asset age, plus other Opex. The "other Opex" is based on the proportion of Transmission ODRC in relation to the total network ODRC. Evaluate EnergyAustralia's proposed Opex model in detail developing an analysis of Opex costs, consider the drivers of these costs, and how these drivers affect the efficient level of expenditure in future and GHD's opinion of the efficient level of Opex for each year of the coming period.
3	Comparing the Opex program approved by the Commission at the previous regulatory reset with the actual Opex spent during the regulatory period and identify the endogenous and exogenous factors driving differences between the two	The work required to complete this requirement should form part of the work required to complete item 2 above. We would expect a reconciliation of EnergyAustralia's claimed historic Opex with the numbers recorded in their financial accounts and in their proposals to IPART.
4	Review the allocation of Opex costs to specific activities, including the distinctions between regulated and non-regulated activities, between routine maintenance and renewals, and the treatment of joint and common costs, especially corporate administration expenses, financing charges and depreciation	An assessment of (functional/business activity) operating expenditure and common costs is likely to be helpful. The fulfilment of this requirement should contribute significantly to the completion of the second issue above.
5	Assess the efficiency of EnergyAustralia's operating practices and asset management systems in ensuring that only necessary and efficient Opex expenditure occurs, with reference to the acceleration or deferral of capital expenditure.	We would envisage that this would be a sub-activity of item 2 above. There will obviously need to be strong interaction with GHD's Capex analysis – particularly in relation to capitalisation policies and business practices – in completing this work.

6.2 Data Issues

Data issues dominate this regulatory review. GHD have concluded that EnergyAustralia do not collect the information useful and necessary to undertake a regulatory review to meet the requirements of the Terms of Reference above. An organisation operating within a regulatory environment such as this should be able to access and provide this information.

Accordingly, the review of EnergyAustralia's Transmission Opex has proven a substantial challenge. The terms of reference provided by the ACCC, summarised within Section 6.1.1, have been very difficult to meet.

GHD found that EnergyAustralia has a "whole of business" approach to recording information in its systems. EnergyAustralia do not have an activity based costing system nor do they record information specifically for each regulatory authority. The transmission activities are not ring fenced. Refer Section 3 for details.

Moreover, EnergyAustralia informed GHD that maintenance was not accurately recorded against assets. EnergyAustralia do keep maintenance information by Opex activity.

GHD would have expected that EnergyAustralia would keep records to demonstrate to the regulators that EnergyAustralia were operating a prudent and efficient business, and that EnergyAustralia could explain and justify the differences between the approved and actual Opex and how joint costs were allocated.

In preparation for the reviews of both IPART and the ACCC, EnergyAustralia engaged SKM to undertake a comprehensive review of the historic and future Opex. SKM worked with EnergyAustralia to clarify their Opex figures and advise on a proposed forecast. Clearly, SKM faced exactly the same set of issues. The following quote was included within the SKM report (page 7):

"The study does not attempt a reconciliation of EnergyAustralia's O&M actuals and budgets for the current regulatory period (1999/00 to 2003/04) with the IPART approved forecast. While this was originally envisaged, it transpired that neither the IPART determination nor the EnergyAustralia figures provided sufficient information to enable a worthwhile reconciliation. The reconciliation was therefore removed from the scope of the study with the approval of EnergyAustralia."

6.3 Approach

To overcome the data issues and provide some reasonable assessment, GHD has undertaken an analysis of the Opex drivers and applied the noted variations to the actual and proposed figures. This is explained in detail in the following sections.

The situation was discussed with ACCC and it was agreed that GHD would, taking a whole of business approach to the predicted future Opex:

- Determine the drivers of operations, maintenance and overhead.
- Consider the drivers of these costs, and how these drivers affect the efficient level of expenditure in future.

- Form an opinion of the efficient level of Opex for each year of the coming period.
- Use EnergyAustralia's Opex model to reallocate costs.

GHD's conclusions are based on the material presented to us by EnergyAustralia, their answers to the questions we raised and our assessment of that information. In addition, GHD have reviewed the information in the SKM "Operational and Maintenance Expenditure Review and Projection for the 2004/05 – 2008/09 Regulatory Period" and the Meritec report to IPART "Review of Capital and Operating Expenditure of the NSW Electricity Distribution Network Service Providers – Final Report".

This report is based on the information GHD have received from EnergyAustralia, which includes the SKM Report. GHD note that not all our questions have been answered and it may be that information that has not been provided could materially affect our conclusions. Accordingly, GHD cannot accept responsibility if full disclosure has not been made or any consequential error on our part.

6.4 The SKM Review for EnergyAustralia

EnergyAustralia engaged SKM to review its current RP Opex, and with that in mind develop a forecast Opex for the upcoming RP. The historic review undertaken failed to reconcile between the EnergyAustralia and IPART values (see quote in Section 6.1) and hence the reconciliation was subsequently removed from the scope of the engagement. The historic review did include a reasonably detailed break-up of the overall business expenditures, with the reasons of that level of expenditure included. The Opex forecast developed by SKM was the basis of the forecast included within the submission of EnergyAustralia to the ACCC.

Some sections of the SKM report were deemed commercially sensitive and as such were removed from the document provided to GHD. The key findings relevant to the ACCC review were:

- Observations regarding Enerserve:
  - Marginally higher pricing than 'Deemed Market Prices" developed by SKM through a survey evaluation and comparison
  - Second highest direct labour costs of all companies surveyed (13 in total)
  - Highest labour on-costs of all companies in survey
- O&M (Opex) forecast is based on a substantial increase in Capex and the relationship between asset age and Opex
- Breakdown of Enerserve costs – main increase (20%) is due to Opex increase for increasing asset age – the spreadsheet that justifies this was not provided
- Maintenance graph showing an increasing backlog, rectification of this backlog is built into the forecast Opex model

The information within the SKM report was frequently used to crosscheck the points and issues raised by EnergyAustralia within the interviews and subsequent communications.

6.5 The Meritec Review for IPART

Meritec was engaged by IPART to assess the prudence of each DNSP's Opex and Capex for the previous RP, and to evaluate the efficiency of each DNSP's future Opex and Capex. Because of the significant scope of this engagement, it was undertaken at a fairly high level.

Meritec's opinion, regarding the EnergyAustralia submission, was as follows:

a. *We found no reason to conclude that Opex during the period FY 1999-2003 was imprudent;*

b. *We considered the FY 2003 Opex figures as agreed with us and presented in the later sections of the report to be a reasonable and balanced starting level in all cases for the determination of future Opex in accordance with the recommendations that follow;*

c. *We saw no reason for Opex movements in real terms from FY 2003 onwards to exceed a reasonable allowance for increase in scale of operation, given adequate capital investment;*

d. *We noted that Opex increases were projected to be less than this in the case of some DNSPs;*

e. *We were not able to quantify possible efficiency gains based on the scope of our work although our work suggested the prospect of some; and*

f. *We recognised that Capex reductions might make it harder for DNSPs to achieve their targets without a corresponding increase in Opex.*

We recommend for IPART's consideration the following actions in respect of projected Opex for the period FY 2004-2009:

- *The implicit re-positioning of EnergyAustralia's Opex not be agreed to;*
- *To give effect to (i) above EnergyAustralia's Opex be adjusted to reflect an increase of no more than 10% in nominal terms from FY 2003 to FY 2009;*
- *Opex for the other DNSPs be accepted as projected;*
- *Before automatically adjusting the projections in future assessments for notional changes in the cost of materials, labour or plant, the cost of Opex should be examined to check that DNSPs are maintaining cost-effective operational structures and practices and that their overheads are reasonable.*

6.6 Allocation of Costs

EnergyAustralia have two approaches to allocating costs. The current regulatory period saw costs allocated by ORC of the assets involved. GHD call this the Global ORC framework.

For the coming regulatory period EnergyAustralia has allocated costs by asset class as follows:

- Maintenance is taken from the Opex activity to the asset class by the ratio of ODRC valuation multiplied by age in each asset class (e.g. Transmission) to the sum total of ODRC valuation multiplied by age for that asset class;
- Overhead is allocated to asset class by the percentage of direct costs in that asset class to total direct costs;
- Asset class costs are then allocated to Transmission (ACCC), Distribution (IPART) and street lighting by the percentage of ODRC assets in that area (Transmission etc.).

Accordingly, by default, all costs in the regulated area are allocated.

6.7 GHD Reconciliation of EnergyAustralia's Historic Opex

The review of historic Opex is intended to establish the reasonableness of both the starting point for projected future Opex and the path of the projected future Opex. There are three sets of figures in existence.

- Figures based on the original definition of Transmission assets agreed to by the ACCC in 1998. These figures are based on a global allocation framework
- Figures based on the original definition of Transmission assets agreed to by the ACCC in 1998. These figures are based on an allocation framework based on asset class
- Figures based on the revised definition of Transmission assets agreed to by the ACCC in 2003. This definition will apply from 1 July 2004. These figures are based on a allocation framework founded on asset class

These three sets of figures are detailed below.

Original Asset Definition; Global ORC Allocation

The following table and graph represents the nominal values associated with the Original asset definition when allocated using the global ORC method, as was in place at the beginning of the 1999 RP.

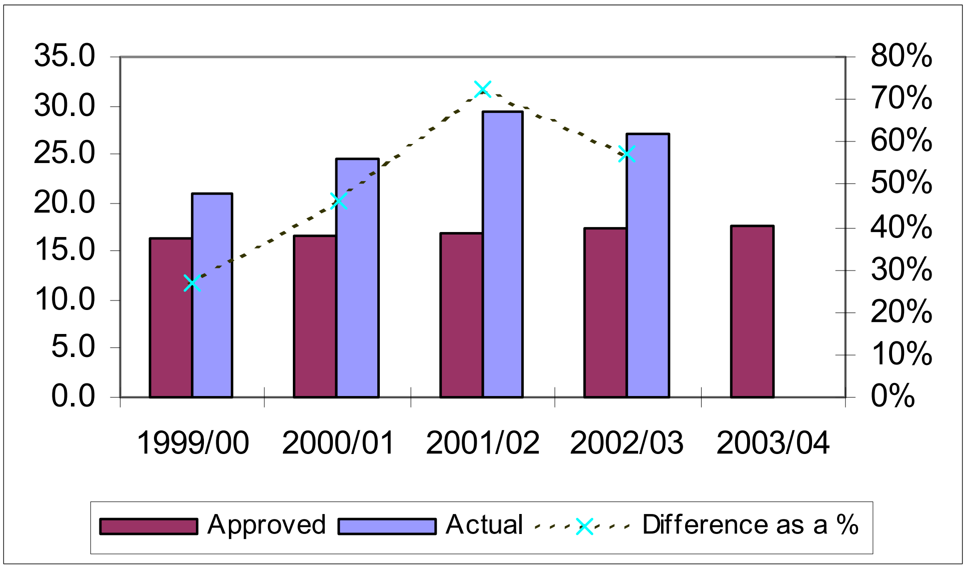
Table 14 Opex; Original Asset Definition; Global ORC Allocation

Year	1999/00	2000/01	2001/02	2002/03	2003/04
Approved	16.45	16.71	16.98	17.25	17.53
Actual	20.90	24.40	29.30	27.10	NP
Difference	-4.45	-7.69	-12.32	-9.85	NP

Nominal dollars, $ million: 2004 forecast; source EnergyAustralia; NP = Not provided in original asset definition and allocation method.

The average difference between the actual and the approved Opex was 51%. This is clearly far above what GHD would have expected and on face value it is not reasonable. We have explored these differences below.

Figure 4 Original Asset Definition; Global ORC Allocation



Nominal dollars, $ million: 2004 no forecast actual outturn; source EnergyAustralia

Original asset definition; Allocation by Asset Class ODRC

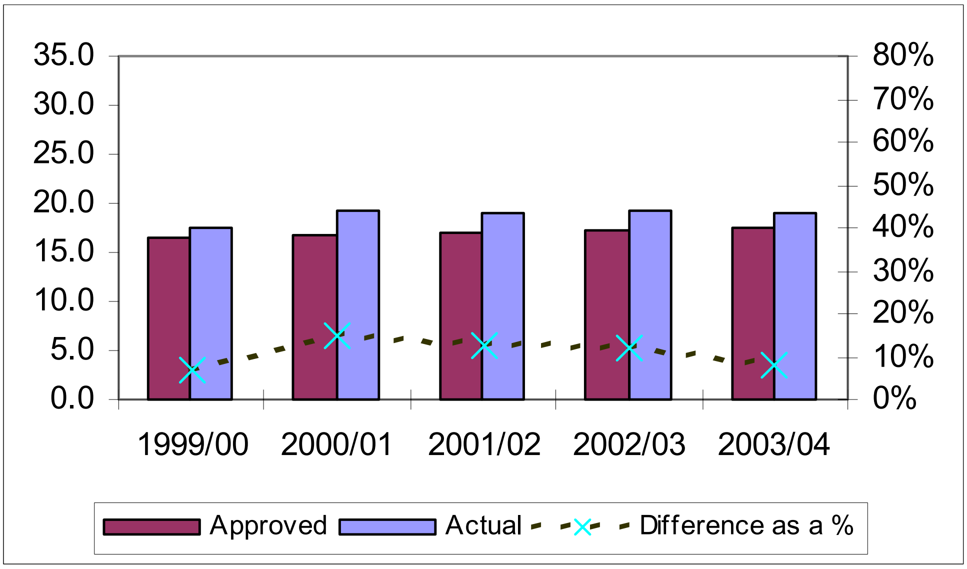
The following table represents the nominal values associated with the Original asset definition when allocated using the Asset class ODRC method, as is proposed by EnergyAustralia for the upcoming RP.

Table 15 Opex; Original Asset Definition; Allocation by Asset Class ODRC

Year	1999/00	2000/01	2001/02	2002/03	2003/04
Approved	16.45	16.71	16.98	17.25	17.53
Actual	17.54	19.23	19.10	19.30	18.98
Difference	-1.09	-2.52	-2.12	-2.05	-1.45

Nominal dollars, $ million: 2004 forecast; source EnergyAustralia

Figure 5 Original Asset Definition; ODRC Asset Class Allocation



The average difference as a percentage for the global allocation process was 51% and for the asset class allocation process it is 12%. This is much more acceptable than 51%.

There is then the choice between which of the different costs allocation models to use as the basis for GHD's review of the Current Regulatory Period Opex. GHD considers that since the ACCC made its 1999 decision based on the original asset definition and used the global allocation of costs by ORC to make that decision then that should be the basis on which the Opex in the Current Regulatory Period is reviewed. GHD's role is to review (as per the TOR) approved Opex in comparison with actual Opex, this has to a comparison of like with like. While, as set out above, the revised allocation process results in a far more favourable outcome for EnergyAustralia, the 1999 decision may well have been significantly different if the allocation was by asset class rather than global ORC.

Opex Components Current RP; New transmission asset definition; Allocation by Asset Class ODRC

The following table identifies the historic Opex of EnergyAustralia, based upon the asset definition and allocation processes that are proposed for the upcoming RP. This information was not available using the current definition and global ORC allocation.

Table 16 Opex; Current Period; New Definition; New Allocation method

Year	1999/00	2000/01	2001/02	2002/03	2003/04
Approved	16.45	16.71	16.98	17.25	17.53
Actual	19.74	21.77	21.66	21.66	21.58
Maintenance	12.86	13.17	9.96	10.87	11.53
Coms & other	6.88	8.60	11.70	10.82	10.05

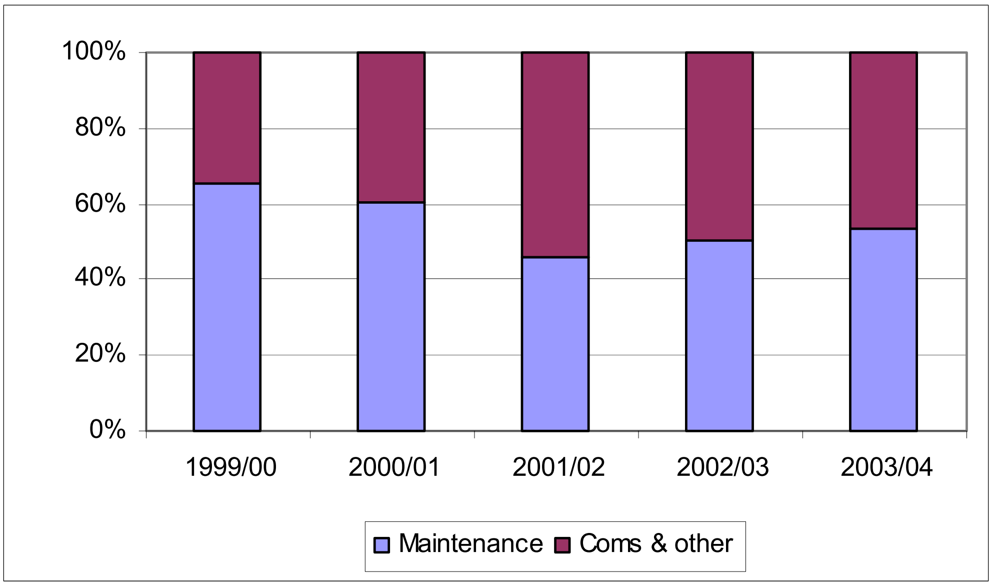
Year	1999/00	2000/01	2001/02	2002/03	2003/04
Difference	-3.29	-5.06	-4.68	-4.41	-4.05

Nominal dollars; 2004 forecast; new definition of Transmission

Source Original Data EnergyAustralia;

There are a number of aspects that clearly need explanation. Such as why maintenance is high in 2000 and 2001 and then drops by over $3 million and why communications and other increased by around 50% and appears to have stabilised 25% higher than in 2000. These issues are explored below.

Figure 6 Opex by Percentage; New Asset Definition; Allocation by Asset Class



Summary of approach given the varied definitions and allocations

GHD is undertaking a review of the historic Opex utilising the Original asset definition and global ORC allocation method as was utilised for the previous ACCC determination.

An evaluation of the starting point will be included, that will identify the impact of the change between definitions and allocation methods. See Section 6.8.

The review of future Opex will be based upon the new asset definition and new allocation method by asset class. See Section 6.9.

6.7.1 Review of historic Opex drivers

It was clear from the EnergyAustralia presentation that during the current regulatory period EnergyAustralia both faced and put in place significant change. The changes included:

- The Olympics, which lead to a focus on ensuring the power supply to Olympic facilities was risk free. This meant that other maintenance elsewhere in the network was deferred.
- One-off superannuation costs were very significant.
- Rapid load growth especially summer load growth and impact of distribution growth.
- Purchase Policies
- Consolidation of the organisations led to costs in merging disparate systems. This occupied significant management time.
- Impact of Environmental and OH&S legislation. Many of the facilities were designed when these regulations were not contemplated. This means that servicing costs are now significantly higher to accommodate the necessary safety margins.
- Impact of Full Retail Contestability diverted management attention and development of new systems to separating off that side of the business.
- Staff attrition is a concern as staff with skills and experience are valuable and there is competition to attract staff.
- Issues of productivity (potential surplus staff etc.)
- A radical change in the approach to maintenance with a move to Reliability Centred Maintenance and Failure Mode Effects Analysis and away form time based maintenance. This approach is also influencing the approach to selecting assets for replacement. It also drives purchasing policy. This is such a fundamental change that it is covered separately below.
- Change in the definition of ACCC regulated assets and thus Opex.
- General Opex Efficiency improvements

Each of these categories is briefly assessed below.

Olympics

EnergyAustralia was a sponsor of the Sydney Olympic 2000. In their 2000-01 Annual Report (pages 6/7), EnergyAustralia said that it had invested $120 million in new infrastructure and spent a significant amount of time and money. GHD would see this money as a donation and not a charge on Opex. Unfortunately, GHD have not been able to establish how much was spent. Table 17 would imply that in real terms maintenance during 1999-2000 and 2000-01 was around $3 million higher than in later periods.

GHD do not have any firm information and to suggest a more accurate figure would be inaccurate. GHD suggest that the amount to be deducted ranges from zero to $3 million dollars for each of the two years; 1999/2000 & 2000/01.

Superannuation

EnergyAustralia has incorporated into the Opex model superannuation costs that were significant during the previous RP. There was no discussion within the SKM historical Opex review regarding justification of this expenditure.

GHD consider that these should have been seen as extra-ordinary expenses and not included in Opex. GHD recommend that the ACCC modify the final figures by the amounts in the row headed “GHD Recommended variation $2003/04”.

Table 17 Impact of Superannuation on Opex (nominal $ unless specified)

	1999/00	2000/01	2001/02	2002/03	2003/04
Transmission ORC / Network ORC	10.10%	9.80%	9.90%	9.10%	NA
Costs in Nominal dollars					
Impact of Superannuation[7]	0	16.9	41.5	20.4	NA
Costs after allocation by ORC ratio					
Impact of Superannuation after allocation	0	1.656	4.108	1.856	NA
Impact in $ 2003/04	0	1.813	4.366	1.912	NA
GHD Recommended variation $2003/04 (Smoothed)	0	+0.0495	-2.5035	-0.0495	NA

NA = Not available;

The GHD recommended variation is introduced to smooth this expense in order to gain an understanding of a suitable level of expenditure for EnergyAustralia. This smoothing has been achieved by taking the average of the 2000/01 and 2002/03 expenditure for superannuation and averaging these based on the assumption that they represent a reasonable annual level of expenditure. The recommended variation is the difference between this average and the actual impact over those years.

Rapid Load Growth / Distribution Growth

The rapid growth of Sydney led to significant demand for scarce resources to accommodate the growth. It is evident from Figure 8-1, on page 33 of the SKM report, that the maintenance expenditure had not been sufficient to meet the maintenance tasks required for completion. EnergyAustralia does not have the required information available to judge the prudency in this area.

Purchase Policies

During presentations there was discussion about the policy of buying from the cheapest tenderer. The variety of plant and equipment resulting from purchase policies in the past meant that spares costs were higher than they should have been and skills and experience for the many unique items were in short supply. It is understood that the introduction of RCM has highlighted the costs of such purchase policies and the move to standardisation should lead to lower maintenance costs.

The savings that will be seen are incorporated into the procurement strategies improvements and are introduced into the forecast Opex. EnergyAustralia’s systems do not make it possible to say what the costs of such a purchase policy have been. GHD consider that costs from such a policy should be disallowed.

[7] Taken from EnergyAustralia Annual Reports, not accounting for regulated and non-regulated splits. GHD has utilised this value as the best available data at the time of review.

GHD suggest that while there is no conclusive information available, that efficiency savings in the range of at least 1% per annum should have been possible from following appropriate purchase policies. These saving should continue on into the forecast period. These have been incorporated into the "General Opex Efficiency" category.

Consolidation of Organisation

EnergyAustralia have made recent cuts to their corporate budget resulting in 3.5% savings being achieved through a recent restructure including twelve redundancies. These savings are reflected within the provided Opex claim. EnergyAustralia has experienced a variety of mergers in the last decade, and with these comes the complexity of system integration and optimisation of the remaining organisational structures.

GHD would expect some further rationalisation within the EnergyAustralia organisation over the upcoming RP, however are unable to place a figure on the level of improvement.

Insurance

Insurance expenditure increased substantially within the previous RP. EnergyAustralia demonstrated an appropriate level of consideration and risk management in minimising the associated costs. A substantial increase occurred in 2001/02, significantly outside the expected level of increase consistent with the utility industry.

GHD deem all years with the exception of 2001/02 as prudent, and would have expected a prudent organisation to have minimised the almost 9-fold increase in that year. A reasonable expenditure level in 2001/02, in line with the step increase that would have been experienced due to the September 11 attack would be equivalent to the 2002/03 expenditure.

The following table indicates the scale of this expenditure during the period. We recommend that the ACCC deduct the amounts in the row headed "Difference".

Table 18 Impact of Insurance on Opex

	1999/00	2000/01	2001/02	2002/03	2003/04
Transmission ORC / Network ORC	10.10%	9.80%	9.90%	9.10%	NA
Costs in 2003/04 dollars					
Insurance expenditure	1.049	0.766	6.589	3.19	4.7
GHD Recommended Insurance expenditure	1.049	0.766	3.19	3.19	4.7
Costs after allocation by ORC ratio					
Insurance expenditure	0.1059	0.0751	0.6523	0.2903	
GHD Recommended Insurance expenditure	0.1059	0.0751	0.3158	0.2903	
Difference	0	0	-0.3365	0	0

OH&S legislation

The following OH&S related items have been identified within EnergyAustralia's application:

- Asbestos management:
  Training relevant staff, provision of asbestos kits where a risk of asbestos dust exists
- Confined spaces:
  Increased cost of working in confined spaces due to a WorkCover requirement for internal resourcing of rescue capability
- Fall arrest:
  Training in application and use of harnesses when employees are exposed to heights of greater than 2 metres
- Safe work method statements:
  The documentation of safe work method statements for each electrical-related service. This requirement applies to members of the High Risk Construction Industry in which EnergyAustralia operates
- System restrictions:
  A move towards conducting outages and performing services outside of normal working hours in order to minimise risk when servicing live equipment

It should be noted that in general all organisation are required to meet these legislative requirements. No specific costing was provided for these items, and as such no conclusion can be reached regarding the appropriateness of these expenses.

GHD also note that Meritec in its report on page 54 stated, with respect to various points, including expenditure associated with OH&S Regulation, *'we had no reason to judge any material component of EA's actual Opex during the period FY 1999-2003 imprudent'.*

Environmental legislation

Multiple legislative acts have come into place during the previous RP, each of which has impacted on the operating expenses of EnergyAustralia. EnergyAustralia claim the following costs have been incurred during the previous RP due to compliance with this legislation.

Table 19 Opex Impact of Environmental Legislation

Legislation	Approximate cost ($m real) during past RP
Pesticides Act	4
Protection of the Environment Operations Act	25 (5m p.a.)
Contaminated Land Management Act	6 (2m p.a. starting from 2000/01)
Total	35

GHD has only briefly reviewed these figures, however they appear appropriate for an organisation such as EnergyAustralia, and are comparable to other organisations. GHD recommend that these are prudent.

Full Retail Contestability (FRC)

The costs associated with Full Retail Contestability were specifically tracked within a specific category. This was incorporated into the ‘Other’ category along with the expenses due to Franchise Metering Maintenance, Customer Supply Systems and Processes, Special Meter Reads/Disconnects and Reconnects and Network Mapping. A break-up of the FRC associated costs only was not available, however it is stated within the SKM report that in general transmission related FRC costs were to be reduced to zero, and not incorporated after the 2002/03 budget. Clear evidence of this was not available, it was not possible to clarify whether the undefined associated costs were prudent in nature.

Staff attrition

EnergyAustralia state that a strong level of competition for electrical staff within NSW has made staff attrition a driver of historic costs. In response EnergyAustralia has increased its recruitment of trainees to ensure sufficient staffing levels.

While there are increased recruitment costs, training costs and higher employee numbers associated with utilising less experienced staff, GHD expects that the significantly lower salaries that apply would offset this. As such no significant variation is expected in the Opex as a result of staff attrition. GHD would expect that even with staff attrition, any increase would be at Wage Cost Index (WCI) rate. No specific data relating to the costs associated with staff attrition have been accessed.

GHD have incorporated any savings here in the “Productivity and Surplus Staff” category below.

Productivity & Surplus Staff

GHD would have expected that as productivity improvements were put in place and the workplace changed that some staff would have become surplus to requirements. It has not been possible to track such changes or make any estimate of productivity improvements. GHD suspect from what we were told at the presentation that before the introduction of RCM there were no productivity improvements. GHD understand that no productivity improvements from the introduction of RCM will be seen in the current RP.

GHD would have expected a productivity gain in the range of at least 1% per annum and potentially much more, taking into account the Capex growth during that period. These savings would cover amalgamation savings, staff attrition savings and general productivity and surplus staff savings. These have been incorporated into the “General Opex Efficiency” Category.

Transformation of maintenance regime from time based

EnergyAustralia undertook a review of their maintenance regime during the previous RP. Operating expenses have occurred through both internal resourcing and external consultancy fees.

GHD is of the opinion that all funds expended by EnergyAustralia with regards to this transformation would equate to prudent spending, particularly given the long-term benefits that result from the comprehensive implementation of life cycle costing and asset management practices.

The level of expenditure associated with this transformation has not been provided or identified during this review.

Changing definition of Transmission assets

This item is discussed in detail in Section 6.8. The implications of this changing definition are not being evaluated as part of the historical Opex.

General Opex Efficiency

From the discussions, interviews and data received from EnergyAustralia, it was apparent that there had been very little focus on the introduction of systems or system modifications to reduce Opex, other than the work undertaken regarding RCM that has not yet begun to impact the Opex. GHD would have expected that a prudent business would have been able to introduce at least some Opex savings during this period. As such GHD recommends that a percentage reduction be applied to the EnergyAustralia Historic Opex that ramps up during the period as follows:

Table 20 Implied efficiency to Historic Opex

Year	1999/00	2000/01	2001/02	2002/03	2003/04
Implied efficiency (%)	0.5	1.0	1.5	2.0	2.5

GHD believes that this is a conservative improvement, and should have been readily achievable.

6.7.2 Impact of Historic Opex Drivers

Table 21 Summary of Historic Opex drivers and their impact

Item	GHD Observations	GHD Recommendations
Olympics	Insufficient evidence to prove that up to $3 million in 1999-2000 and 2000-01 should be deducted	
Superannuation	Firm evidence available	Add to Opex $0.0495 in 2000/01; Deduct from Opex, $2.5035m 2001/02 and $0.0495m 2002/03
Rapid Load Growth / Distribution Growth	Significant growth – RCM has highlighted high procurement costs. Ramifications are included into forecast Opex	

Item	GHD Observations	GHD Recommendations
Purchase Policies	Insufficient evidence to prove that a 1% per annum efficiency saving should be deducted	
Consolidation of Organisation	Recent 3.5% Opex savings from restructure. Ongoing consolidation opportunities may exist	
Insurance	Spend increased in line with general rises. Substantial glitch in 2001.02 not consistent with prudent management	Reduce 2001/02 Opex by $0.3365m
OH&S legislation	Reasonable changes evident within the previous RP. No break-up provided to justify expenditure	
Environmental legislation	Appropriate expenditure, based upon textual documentation and discussions	
Full Retail Contestability	FRC not in budget as a separate item from 2002/03 onwards – no evidence of associated costs available	
Staff attrition	No values available to gauge impact of attrition. GHD would expect growth to be in line with WCI	
Productivity and Surplus Staff	Insufficient evidence to prove that a 1% per annum productivity saving should be deducted. Potentially much larger if & Consolidation of Organisation are included	
Transformation of maintenance regime from time based	Intent of expenditure is in line with prudent operations. GHD supports this approach and the funds that it required	
General Opex Efficiency	Improvements were expected, very little evident	Introduce efficiency as per Table 20

6.7.3 Historic Opex Recommendations

It should be noted that where it is unclear whether expenditure is prudent or not, or where an appropriate and reasonable assessment could not be made, no variation has been recommended by GHD.

Table 22 Historic Opex Summary ($2003/04m)

Year	1999/00	2000/01	2001/02	2002/03	2003/04
ACCC Approved	19.17	18.28	18.05	17.77	17.53
EnergyAustralia Actual	24.35	26.70	31.14	27.91	28.78[1]
GHD Recommended Variation					

Year	1999/00	2000/01	2001/02	2002/03	2003/04
Superannuation	0	(0.0495)	2.5035	0.0495	0.0510[1]
Insurance	0	0	0.336	0	0[1]
General Opex Efficiency	0.122	0.267	0.467	0.558	0.748
GHD Recommended Opex *(EA Actual less GHD Recommended Variation)*	24.228	26.483	27.833	27.303	27.976[1]

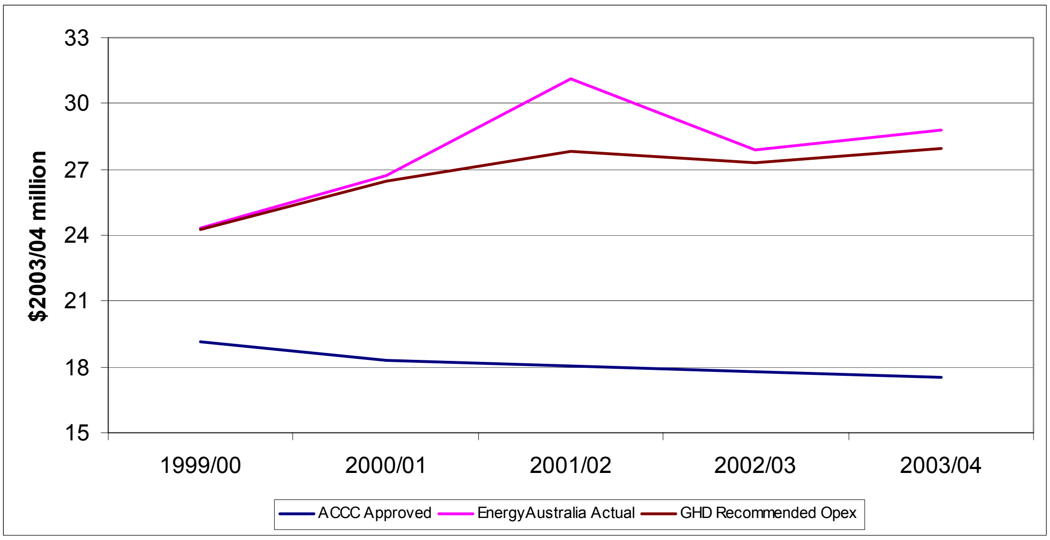
$2003/04 million; source EnergyAustralia;

[1] These forecast figures not provided in original definition and allocation methodology, thus assumed at straight line of 2002/03 figures including an assumed CPI of 3.1%.

All values based upon original definition and ORC allocation methodology.

The GHD recommended Opex figure represents the EnergyAustralia actual Opex with individual GHD recommendations applied where these could be clearly justified. The GHD Observations that have been made represent issues that GHD have identified, but could not find reasonable levels of evidence to justify. These observations are areas that the ACCC may wish to further consider as the revenue cap

Figure 7 Historic Opex Summary Graph



6.8 Review of Proposed Starting Point

EnergyAustralia, as part of their submission, have incorporated a new starting point for the upcoming RP. This proposed starting point is the result of two key drivers as follows:

- A change in allocation methodology, and
- Assets ‘re-defined’ as transmission.

These two drivers are evaluated for appropriateness within this section, and a recommended starting point for the upcoming RP derived.

6.8.1 Review of the Drivers of the modified starting point

Change in Allocation Methodology

EnergyAustralia has proposed a change in allocation methodology from global ORC to asset class ODRC. The global ORC allocation methodology was agreed upon for the last RP and is utilised within the regulatory accounts that EnergyAustralia has to date submitted. The move to asset class ODRC is aimed at better allocating the costs and expenses between the distribution and transmission sections of the business. Where costs cannot be clearly allocated to the asset classes they have been globally allocated as per the original methodology.

This new allocation method has been applied to both regulators of the business (IPART and ACCC).

This allocation method is deemed appropriate by GHD, with a better representation of the actual transmission costs being available through it. However, in-depth evaluation of Operating expenditure would require either a full assessment at a whole of business level, passed through the agreed allocation process, or a separate set of accounts splitting all the expenditure of EnergyAustralia between Transmission and Distribution, based upon an agreed asset base.

Assets 're-defined' as transmission

During the previous RP a number of EnergyAustralia assets that did not originally fall under the transmission definition, have become transmission assets due to changes in the network, which have directly impacted the roles of those assets.

This re-definition of assets has been accepted previously by the ACCC. As such the impact of this re-definition will be incorporated into the starting point.

Impact of the drivers

The following table describes the difference between the current and proposed methodologies, including the impact of the two drivers to the historic Opex.

Table 23 Build-up of proposed starting point (Real $m 2003/04)

	1999/00	2000/01	2001/02	2002/03	2003/04
Original Allocation Method					
ACCC Allowed Opex[8]	19.17	18.28	18.05	17.77	17.53
Actual EA Opex[9]	24.35	26.70	31.14	27.91	28.77[1]
GHD Recommended Opex	24.228	26.483	27.833	27.303	27.976[1]
Impact of Drivers					
Impact of changed allocation method on Actual EA Opex	(3.91)	(5.66)	(10.84)	(8.03)	(9.79)[10]

[8] Opex allowed by the ACCC in the 1999 determination, using the original global ORC allocation method and based upon the original asset definition.

[9] Actual Opex of EnergyAustralia as per the ACCC regulatory accounts

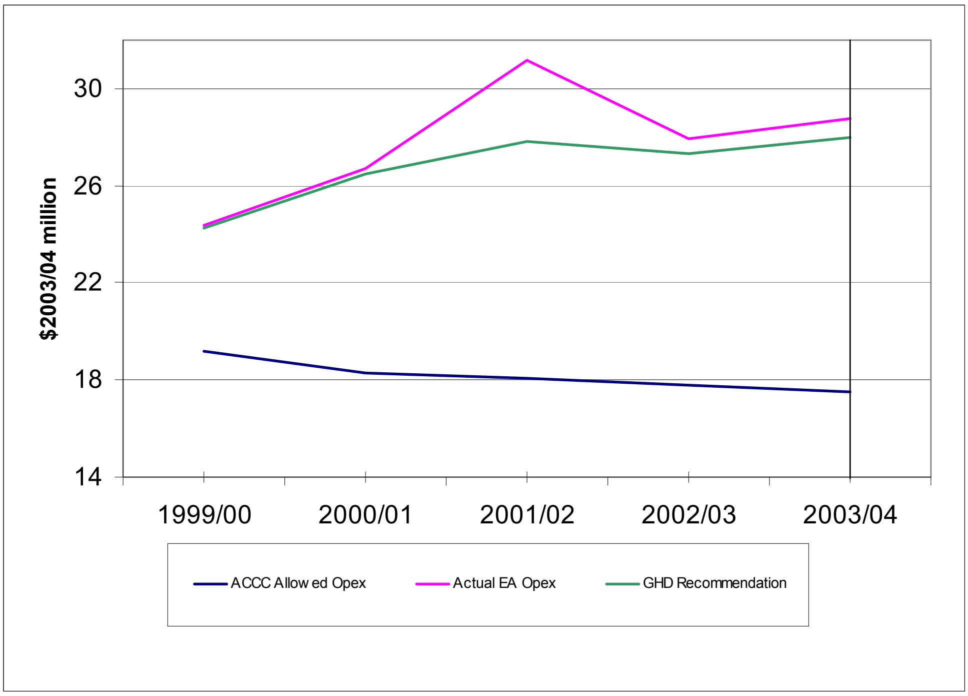
[10] Calculated using GHD recommended Opex

	1999/00	2000/01	2001/02	2002/03	2003/04
Impact of new asset definition on Actual EA Opex	2.56	2.78	2.72	2.43	2.60
New Allocation Proposal and Ratio					
Proposed Actual EA Opex *(including new allocation method and new asset definition)*	23.00	23.82	23.02	22.30	21.59
Ratio of proposed EA Actual (proposed definition) to the original EA Actual (original definition) (%)	94.46%	89.23%	73.92%	79.92%	75.01%[1]
New Allocation Method					
GHD Recommendation - by New allocation %	22.885	23.629	20.573	21.819	20.986
ACCC Allowed Opex - by New allocation %	18.108	16.311	13.342	14.201	13.150[1]

[1] These forecast figures not provided in original definition and allocation methodology, thus assumed at straight line of 2002/03 figures with a CPI allowance of 3.1% for final year

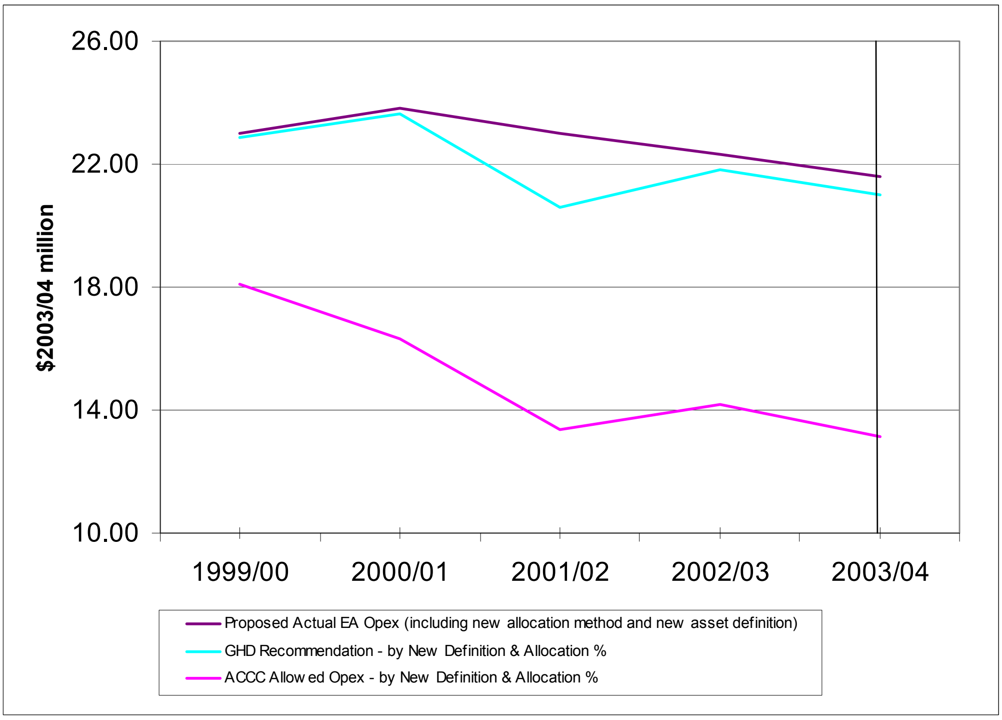
To simplify the data within Table 23, the values presented in the original allocation method are combined into one graph, and the values presented in the proposed allocation method are placed into a second graph as follows.

Figure 8 Historic Opex and Starting Point: Original Allocation Method



Note: The ACCC allowed Opex represented in the above figure is based on the Actual ACCC allowance for the previous RP, multiplied by the ratio identified in Table 23, to provide a reference point.

Figure 9 Historic Opex and Starting Point: Proposed Allocation Method



To develop these figures, GHD have simply applied the percentage difference between the original and proposed allocation methods to the 2004 forecast figures in order to develop a proposed starting point.

6.8.2 GHD identified inefficiencies

GHD has identified potential efficiency improvements for the upcoming RP, however believes that it is most appropriate for the future efficiencies identified to be applied as they would occur within the upcoming RP. As such no inefficiency reduction is being applied to the starting point by GHD other than those identified within the historic Opex review.

6.8.3 GHD recommended starting point

The GHD recommended starting point aligns with the GHD recommended historic Opex. While GHD has identified potential efficiency gains, these will be applied over the upcoming RP and are detailed within Section 6.9.

The GHD proposed starting point is $20.986m using the new asset definition and allocation methodology. The GHD proposed starting point variation is $0.604m less than the proposed EnergyAustralia starting point. This is displayed graphically in Figure 9.

6.9 GHD Review of EnergyAustralia's Future Opex

The transmission Opex proposed by EnergyAustralia consisted of three core categories: Maintenance, Communication & Control and Other. Similar to the historic Opex, it was not possible in many cases to evaluate in detail the appropriateness of the expenditure within these categories. As such a driver analysis was undertaken and the implications of those drivers used to modify the EnergyAustralia proposed future Opex.

As GHD has identified a different starting point, the entire EnergyAustralia proposed Opex has been shifted by the difference between the proposed starting point and the GHD recommended starting point. This is completed after the driver analysis.

The following table summarises the future Opex proposal of EnergyAustralia. It should be noted that all future Opex is considered in terms of the proposed transmission asset definition and the revised allocation of expenditure by asset class ODRC.

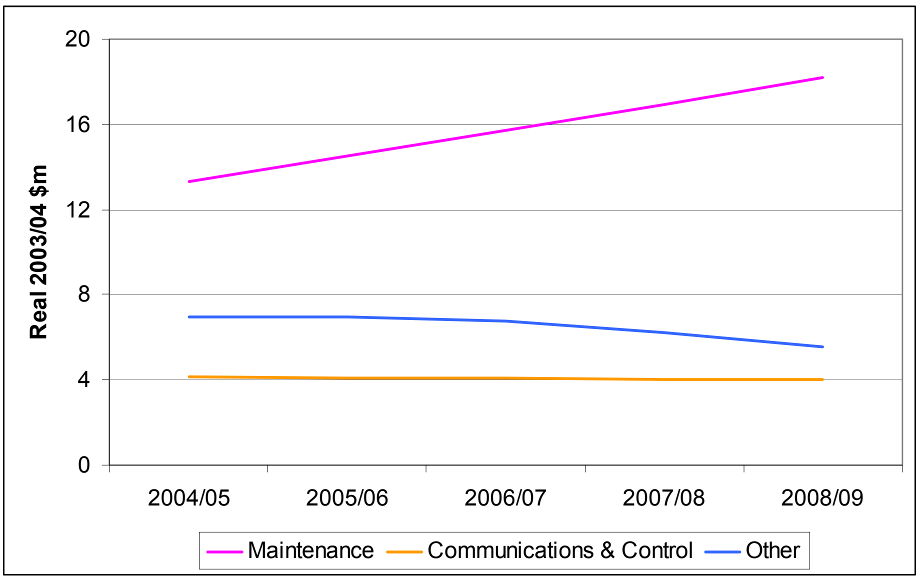
Table 24 EnergyAustralia Proposed Future Opex

Year	2004/05	2005/06	2006/07	2007/08	2008/09
Total	24.370	25.751	26.559	27.143	27.729
Maintenance	13.282	14.511	15.742	16.893	18.201
Communications & Control	4.151	4.109	4.064	4.024	3.986
Other	6.937	6.951	6.753	6.226	5.542

Real 2003/04 $m

The figures are represented in the following graph to show the underlying trends of the three main categories.

Figure 10 Graph of EnergyAustralia's Forecast Opex & Break-up



As is evident from the table and graph above, the core driver of increase in EnergyAustralia's future Opex is the expenditure associated with maintenance, and their move to Reliability Centred Maintenance.

In addition to the maintenance related costs, various other drivers have been identified. These drivers are assessed within Section 6.9.1, and the implications of these drivers identified and reviewed where possible.

6.9.1 Review of Future Opex Drivers

The following drivers were identified during interviews with EnergyAustralia and subsequent questionnaires. These drivers represent the key areas that will affect the future Opex of EnergyAustralia.

- Information technology
- Move to Reliability Centred Maintenance
- Insurance
- Corporate and Contractor costs
  - Enerserve
  - Corporate Procurement
- Consolidation of organisation
- Customer service levels
- Capitalisation policy
- Environmental legislation

Information Technology

EnergyAustralia has a forecast expenditure on IT systems within the range of $25m p.a. and $33m p.a. in Capex and Opex respectively during the upcoming RP. To date the expenditure has not been aimed at delivering any savings, with a primary focus on risk management and compliance.

Given the level of expenditure and the potential within this field, GHD would expect a prudent organisation to take advantage of the potential opportunities and deliver operational expenditure efficiencies through savings within this next period.

The opportunities are significant, particularly considering the recent merger and the efficiency improvements that can be obtained through the selection of the best systems and the subsequent consolidation of these. EnergyAustralia should include a focus on potential efficiencies within their IT program, and this may become evident through the current benchmarking process being undertaken with KPMG.

The scale of the potential savings is not possible without a detailed review of the EnergyAustralia IT system, which is outside the scope of this review. However, it would be expected that a reasonable level of savings would be within a range of 1-5% p.a. and would likely lag the initialisation of such a program by 1 year.

Move to Reliability Centred Maintenance (RCM)

The Maintenance category of the transmission Opex proposed by EnergyAustralia experiences a significant increase over the forecast period from $11.5m to $18.2m in real 2003/04 dollars. This increase is primarily driven by the move from Time Based Maintenance to Reliability Centred Maintenance (RCM).

In moving towards RCM, the current high-level of maintenance backlog requires rectification in the short-term, to enable long-term benefits to be delivered.

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.

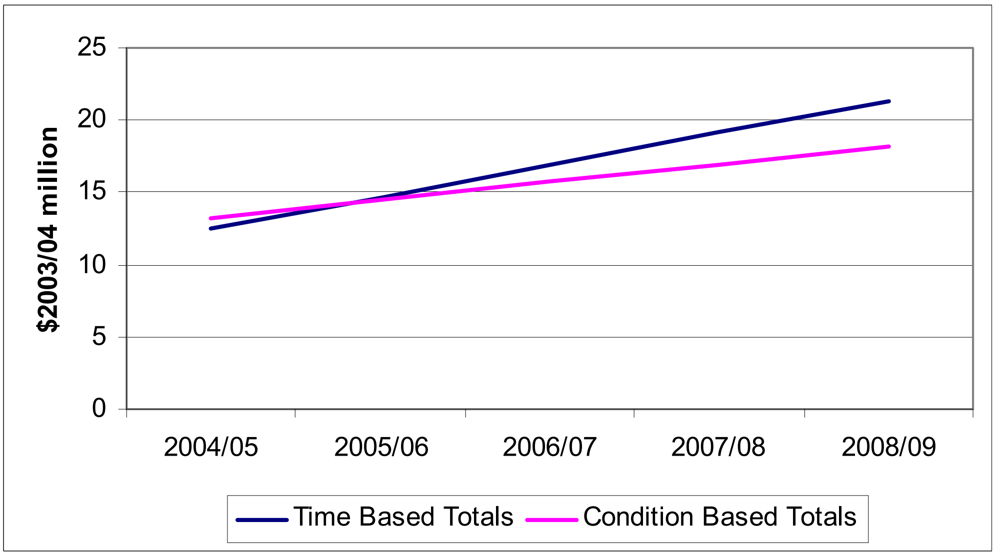
Table 25 Comparison between Time base forecast and Condition Based forecast

	2004/05	2005/06	2006/07	2007/08	2008/09
Time Based Totals	12.48	14.70	16.92	19.14	21.35
Condition Based Totals	13.28	14.51	15.74	16.89	18.20

Real $ 2003/04

These figures are represented for further understanding in the following figure.

Figure 11 Comparison of Time Based and Condition Based Forecasts



GHD supports the move by EnergyAustralia to RCM, and supports the forecast put forward by EnergyAustralia.

Insurance

The review process identified insurance as a key driver of Opex into the upcoming RP, while this has been claimed, the Opex proposed by EnergyAustralia has assumed that the current spend level will not increase during the period, in fact it has been flat-lined over the coming RP. This treatment appears reasonable given current insurance industry trends.

The level of insurance costs can be affected substantially by global events, as has recently been the case, which may have insurance levels currently at a premium. This current level of costs may lead to reductions over the upcoming period as long as no further global events occur.

The last financial year has not seen the same level of insurance cost increase, and as such the forecast 2003/04 expenditure of $4.7m may be over-estimated. No further information has been identified that points to a revised 2003/04 expenditure.

Corporate and Contractor Costs

Corporate costs within EnergyAustralia were reduced by 3.5% due to a recent restructure, and are evidence of one of the efficiencies that become available during the consolidation period post business mergers. Opportunities will exist within other areas to undertake efficiency / business process reviews and achieve further savings.

Enerserve

A particular opportunity exists within the labour resources associated with the Enerserve contract, with the SKM review identifying that on a weighted average basis (weighted by quantities), the total Enerserve pricing is marginally high at +0.36%.

In addition, SKM found that Enerserve has the second highest direct labour costs of the 13 companies surveyed, and that Enerserve have the highest labour on-costs of all companies in the survey. The size of the Enerserve contract and the fact that the agreement between Enerserve and EnergyAustralia makes up 19% of Enerserve's annual budget suggests that diligent negotiations and contractor research should result in relative savings post the contractual negotiations stage.

The associated savings are likely to be minimal, and would probably lie within a 0.5 – 1% p.a. improvement.

Corporate Procurement

EnergyAustralia undertook an extensive and detailed internal review of their Corporate Procurement Strategy, with a completed document submitted in December 2002. The procurement strategy identified many cost saving opportunities for the organisation.

Consolidation of Organisation

As identified within the historic Opex review, EnergyAustralia have made recent cuts to their corporate budget resulting in 3.5% savings being achieved through a recent restructure including twelve redundancies. EnergyAustralia has experienced a variety of mergers in the last decade, and with these comes the complexity of system integration and optimisation of the remaining organisational structures.

A review of the potential opportunities and the scope of those opportunities is outside the scope of this review, however GHD would expect that further opportunities with regards to organisational consolidation would exist. This may return overall Opex savings of between 0.5 and 1% p.a. post implementation.

Customer Service Levels

The expenditure associated with customer service grew by 9.7% over the previous RP, and is forecast to grow by a further 24.8% in the upcoming RP. The forecast growth in customer service expenditure is significant, and GHD was not able to determine whether this growth level was incorporated into the Opex proposed by EnergyAustralia.

Capitalisation Policy

SKM report notes that under a new capitalisation policy being introduced (March 2003) approximately $2.2m of expenditure relating to new installation inspections will be capitalised. SKM did not include the impact of this into the outputs of the report. GHD have not been able to identify this expenditure is within the Opex model provided by EnergyAustralia, or how it was allocated to the Transmission line of business.

Environmental Legislation

An increasing environmental focus at a legislative level, particularly with respect to site-decontamination and noise reduction, is considered a significant driver of Opex within the EnergyAustralia submission. The submission states that based on the historic expenses (identified in Section 6.7.1) incurred across the whole business, an amount of $6m p.a. in real terms has been included into the transmission submission in the total O&M costs for 2004-2009.

This inclusion into the Opex claim of $6m p.a. for the upcoming RP, based upon the historical expenditure and the expected levels of legislative change within the upcoming RP, is an appropriate allowance.

Confidential Project

A project was identified during the review that EnergyAustralia believes to be confidential. As such the project is not discussed in this section, only the implications of that project.

Table 26 Costs and Benefits of Confidential Project

Item	Costs	Benefits (tangible only identified – substantial intangible benefits also, not included)
Item 1	$600k p.a. resourcing cost	$23.2m p.a. (based on conservative figure contained within EA report)
Item 2	$100k Capex, $60k Opex (training)	No dollar figure associated
Item 3	$1m – Capex (in existing budget)	7.8% of Opex, approx. $0.3m
Financial summary of items	***$1.1m Capex ($1m in existing budget)*** ***$600k Opex p.a. resourcing cost*** ***$60k once off Opex expense***	***Est. $23.5m p.a.***

Resource issues were identified as a restraint to implementation – as such the financial summary of items line includes additional annual funding for resources to support the project and enable implementation above and beyond that identified in the documentation reviewed.

The Net Benefit per annum for the remaining years = $23.5m - $0.6m = $22.9m (ignoring the negligible non budgeted Capex and once-off Opex).

Applying this per annum benefit to the transmission assets by ORC (12.4%) results in annual savings of $2.839m. This project was scheduled for completion in March 2005, as such the associated efficiencies should take effect as of the following year (2005/06), thus allowing time for full implementation.

Of these annual savings, a proportion will be split between Capex and Opex. This has been allocated based upon the approximately even split of spend over the previous RP between Opex and Capex.

This results in both Opex and Capex savings of $1.419m p.a. each, starting in 2005/06. The proportion associated with Opex is included in this section, and the proportion associated with Capex is included into Section 5.4.

12.4% of the resourcing costs will be included into the first year of the upcoming RP, to support initial implementation costs.

6.9.2 Impact of Future Opex Drivers

The following table summarises the observations and recommendations of GHD with regards to the future Opex drivers that have been identified.

Table 27 Summary of Future Opex drivers and their impact

Item	GHD Observations	GHD Recommendations
Information Technology	This level of spend should drive Opex savings of 1-5% p.a.	
Move to Reliability Centred Maintenance	GHD supports this move and the associated expenditure	No variation to proposed maintenance Opex
Insurance	Level of insurance flat-lined for upcoming RP. Starting point not justified	
Corporate and Contractor costs	Opportunity for 0.5-1% p.a. savings on Enerserve related labour	
Consolidation of Organisation	Opportunity for 0.5-1% savings p.a. post implementation	
Customer service levels	9.7% growth historically, 24.8% growth forecast	
Capitalisation policy	$2.2m in overall Opex to be capitalised – unsure of inclusion into proposed forecast	
Environmental Legislation	Prudent – leave in forecast	No variation
Confidential Project	Positive project that will drive substantial savings for EnergyAustralia. Additional resourcing costs incorporated to support the implementation	$0.074m p.a. transmission increase in 2004/05 for resources to support implementation $1.419m p.a. transmission Opex reduction from 2005/06

6.9.3 Future Opex Recommendations

The following table summarises the EnergyAustralia proposed forecast Opex, and the GHD recommended forecast, with the associated variations.

It should be noted that where it is unclear whether expenditure is prudent or not, or where an appropriate and reasonable assessment could not be made, no variation has been recommended by GHD. If possible, an indicative range has been included as a GHD Observation.

Table 28 Future Opex Summary

Year	2004/05	2005/06	2006/07	2007/08	2008/09
EnergyAustralia Proposed Opex	24.370	25.570	26.560	27.140	27.730
EA Proposed Opex less GHD Recommended starting point variation ($0.62m)	23.771	24.971	25.961	26.541	27.131

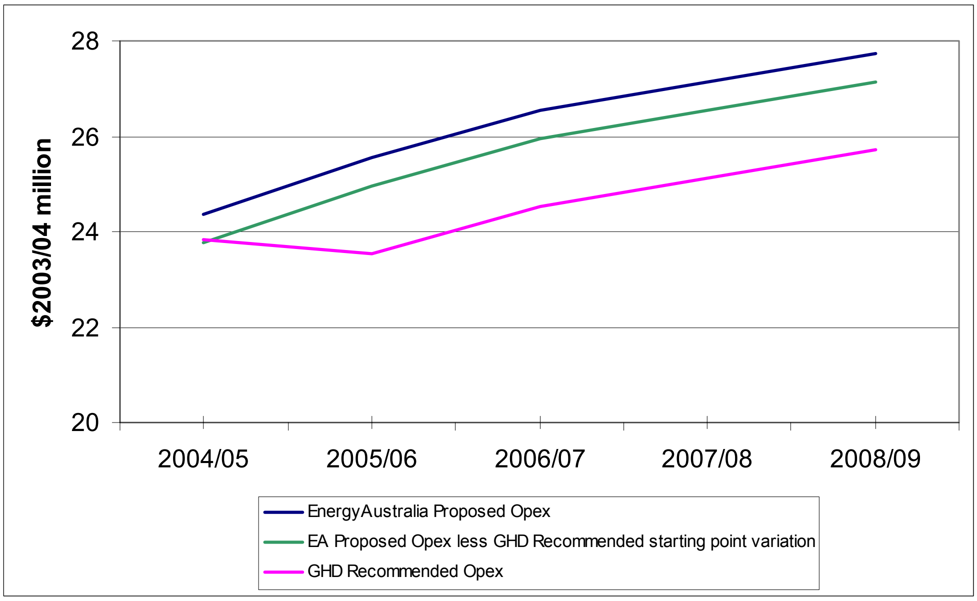
Year	2004/05	2005/06	2006/07	2007/08	2008/09
GHD Recommended Variation	0.074	-1.419	-1.419	-1.419	-1.419
GHD Recommended Opex (EA Actual less GHD Recommended Variation)	23.845	23.552	24.542	25.122	25.712

$2003/04 million;

All values based upon new asset definition and ODRC allocation by asset class

This is further represented in the following figure.

Figure 12 Summary Diagram: Impact of Drivers on Future Opex



6.10 Summary of Opex Recommendations 1999/00 – 2008/09

Figure 13 summarises the Opex recommendations and observations over a 10-year period covering both the previous and upcoming regulatory periods.

Figure 13 10-Year Summary of Opex Findings

The GHD recommendation is still significantly above the 1999 ACCC Opex decision, with many observations not being included into the GHD recommendation due to a lack of evidence to conclude that expenditure as wither prudent or non-prudent.

7. Service Standards and Performance Incentives

7.1 Basis for Review

GHD has been tasked with the recommendation of appropriate service standards and performance targets based upon the following information:

- Information provided by EnergyAustralia as part of their application;
- Supplementary information provided by EnergyAustralia following an interview process and documentation review;
- Report titled 'The Commission Network Service Provider (TNSP Service Standards), March 2003[11]';
- Statement of principles for the regulation of transmission revenues. Service standards guidelines – released by the commission in November 2003[12]

In undertaking this review, the measures proposed by EnergyAustralia and Sinclair Knight Merz will be discussed and evaluated against actual performance over the previous regulatory period to review the reasonableness of the proposed measures. In addition to this, items that are expected to impact upon the performance of EnergyAustralia against the proposed measures in the upcoming regulatory period will be taken into account when developing a recommended set of service standards.

7.2 Selection of Service Indicators

EnergyAustralia are proposing that no Service standards be introduced at the start of the upcoming RP and that the Transmission Circuit Availability measure be reviewed mid-way through the RP once at least 3 years worth of data in available on which to make a valid decision. EnergyAustralia have not proposed or discussed potential caps, collars or deadbands for this measure.

EnergyAustralia propose that only the transmission feeder availabilities be measured, and that transformer and reactive plant not be included as they claim that these have no material impact on feeder availability.

SKM proposed two potential service measures for EnergyAustralia, further reflected in the Commissions draft service standards guidelines, being:

- Transmission Circuit Availability, and
- Average Outage Duration

Of these, SKM recommended that the Circuit Availability measure be phased in due to a lack of historical data, and that the Average Outage Duration measure is applicable for EnergyAustralia however insufficient data is available and that this measure be incorporated in the future. There are no caps, collars or deadbands proposed within the SKM report for EnergyAustralia.

[11] Report by Sinclair Knight Merz, available on the ACCC website

[12] Available from the ACCC website, www.accc.gov.au

7.3 Historic Performance Comparison

A comparison of the performance of EnergyAustralia against the proposed measure of Transmission Circuit Availability is limited by a lack of available data. The following table summarises the data made available within the previous RP.

Table 29 Historic Performance of EnergyAustralia

Measure	1999/00	2000/01	2001/02	2002/03	2003/04
Transmission Circuit Availability (%)	NA	96.55	94.60	96.30	NA
Average Outage Duration	NA	NA	NA	NA	NA

NA = Not Available

The target proposed by SKM for this measure is 95.50%. Thus in the three years for which data is available, EnergyAustralia would have returned results of +1.05%, -0.9% and +0.8% respectively had this proposed target been in place.

Based upon the available information and taking into consideration the limited historical data available, GHD recommends the following configuration of caps, collars and deadbands for the upcoming RP. This configuration of service standards would have returned a near revenue neutral result of the previous RP if it had been applied.

Table 30 Service Standards proposed by GHD

Performance Measure	Unit of Measure	Revenue at Risk (%)	Collar	Dead Band Knee 1	Target	Dead Band Knee 2	Cap
Transmission Circuit Availability	%	1	95.3	-	96.1	-	96.7
Average Outage Duration	Data to be measured by EnergyAustralia during the upcoming RP						

These proposed service standards would represent a relatively straightforward basis of assessment for the upcoming RP. It would be preferable to have multiple measures over which to spread the revenue placed at risk in order to provide a better balance and spread of risk, however given that only one measure has some historic data available this considered to be the most appropriate approach.

To further evaluate the historic performance of EnergyAustralia against these proposed service standards, they will be

The following calculation method is identified within the Commissions service standards guidelines.

$$FI_{ct} = \left[\frac{\left(AR_{t-1} + AR_{t-2}\right)}{2} \times S_{ct} \right]$$

$$i.e.FI_{01January2004} = \left[\frac{\left(AR_{01July04} + AR_{01July03}\right)}{2} \times S_{01January04} \right]$$

Where:

FI = Financial Incentive
AR = Annual Revenue
ct = time - calendar year
t = time - financial year

To provide an indication of the dollar impact for EnergyAustralia of these standards, the total revenue from financial statements has been allocated to the transmission asset base (12.4%) and then 1% of that used as the MAR. This is only an indicative value, as values in the annual reports will incorporate non-regulated parts of EnergyAustralia's business as well.

The results of applying this equation against the available data points for EnergyAustralia is summarised in the following table.

Table 31 Summary of EnergyAustralia Historic Performance against GHD proposed service standards

Six months beginning	1 % of Annual Transmission Revenue 'AR' (12.4% of total AR) $m	Performance 'S'	Financial Incentive 'FI', for EnergyAustralia $m
01 July 1999	2.32		
01 January 2000		NA	NA
01 July 2000	2.65		
01 January 2001		0.917	2.43
01 July 2001	2.73		
01 January 2002		(1.0)	(2.73)
01 July 2002	2.89		
01 January 2003		0.5	1.44
01 July 2003	3.01		
01 January 2004			

For the available historical data, when evaluated against the proposed service standards, EnergyAustralia would have received a net bonus of $1.14m over the three years.

The GHD proposed incentive scheme raises the targets set by SKM, yet still results in a net benefit to EnergyAustralia over the three years of evaluation possible. GHD believes that this higher target is reasonable based upon the historic data available.

7.4 Summary of Findings

The findings with regards to EnergyAustralia's Service Standards are summarised as follows:

- *Limited data is available.* The data provided is insufficient to set substantial, restrictive service standards.
- *Target proposed by EnergyAustralia of 95.5% Transmission Circuit Availability.* This matches the target recommended by SKM.
- *No data available for Average Outage Duration measure*, however SKM recommend that data be collected as this may be a suitable future measure of EnergyAustralia's performance. GHD also recommend that data should be collected.
- *No caps, collars or deadbands proposed by EnergyAustralia.* A proposed incentive scheme with caps and collars has been proposed, with an increased target level of 96.1% and asymmetric reward/penalty loading.

7.5 Suggested Performance Incentive Scheme

To facilitate the implementation of a reasonable incentive scheme, the measures identified in Table 30 are proposed. An incentive scheme based upon one single measure is not an ideal situation, however with a small amount of MAR apportioned, the risks are deemed moderate.

The primary outcomes of the proposed incentive scheme are outlined below:

- Target of 96.1% Transmission Circuit Availability
- Asymmetric collar and cap set, of 95.3% and 96.7% respectively.
- Require EnergyAustralia to measure Average Outage Duration over the upcoming RP to develop a reasonable data history from which future service standards decisions can be based

It is outside the scope of this review for GHD to undertake a full review of the service standards. As such the above recommendations are based upon the available sources of information detailed within Section 7.1.

Appendix A

Terms of Reference and Clarifications

Consultancy Terms of Reference

EnergyAustralia - capital expenditure, asset base, operating and maintenance expenditure and service standards review

Background

The Australian Competition and Consumer Commission (Commission), in accordance with its responsibilities under the National Electricity Code (code), is currently conducting an inquiry into the appropriate revenue cap to be applied to the non-contestable elements of the transmission services provided by EnergyAustralia, from 1 July 2004.

To assess the performance of EnergyAustralia relative to the requirements of the code, the Commission requires reviews of:

- capital expenditure (Capex)
- the asset base
- operational and maintenance expenditure (Opex) and
- service standards

In particular, Part B of Chapter 6 of the code requires *inter alia* that:

- in setting the revenue cap, the Commission must have regard to the potential for efficiency gains in expected operating and maintenance costs, taking into account the expected demand growth and service standards
- the regulatory regime seeks to achieve an environment which fosters efficient use of existing infrastructure, efficient operating and maintenance practices and an efficient level of investment
- in setting the revenue cap, the Commission must have regard to the provision of a fair and reasonable risk-adjusted cash flow rate of return on efficient investment including sunk assets
- the regulatory regime provides reasonable recognition of pre-existing policies of governments regarding transmission asset values, revenue paths and prices but with the limitation that such valuation must not exceed the deprival value of those assets.

Terms of reference

Capital expenditure

The consultant is to review the Capex proposal by EnergyAustralia for the forthcoming regulatory period and is required to:

- review the adequacy of EnergyAustralia's methodology and planning processes in arriving at a forward estimate of the efficient level of future investment needs, looking at the exogenous and endogenous factors affecting projected future Capex performance

- assess the assumptions underlying any trade-offs between Capex and Opex

- compare EnergyAustralia's Capex proposal, asset management policies and quality of service standards, with industry best practice

- assess the likelihood that proposed non-reliability augmentation Capex will pass the regulatory test including:

  - the benefits
  - the costs
  - probability of proceeding and
  - timing of construction

- assess the likelihood that proposed reliability augmentation Capex will pass the regulatory test including:

  - demonstrated need for such investment to meet the requirements set out in schedule 5.1 of the code and/or relevant legislations and regulations in NSW
  - the costs
  - probability of proceeding and
  - timing of construction

- assess the need for proposed non augmentation Capex works as well as consider:

  - the costs
  - probability of proceeding
  - timing of construction

- review the allocation of capital expenditure between contestable and non-contestable services

The consultant must, based on its analysis, provide a Capex program for EnergyAustralia contingent on various factors i.e. demand growth and weather for the forthcoming regulatory period, listing individual Capex proposals, likely timing and probabilities of proceeding.

Asset base

The consultant must advise on an opening regulatory asset valuation to apply to EnergyAustralia as at 1 July 2004. This should be done by rolling forward the asset base by using the Commission's PTRM electricity model; the actual rate of inflation during the appropriate period and efficient Capex. The consultant will also consider alternative approaches to asset valuation as required.

The consultant must provide a schedule listing the assets categorised into classes, their standard replacement costs, relevant asset lives and depreciation profiles. In determining an opening asset valuation to apply to EnergyAustralia, the consultant is required to review augmentation and non-augmentation capital expenditure undertaken by EnergyAustralia over the previous regulatory period. In particular the consultant must:

1. Undertake a review of 3 (three) regulatory test applications, as directed by the Commission, conducted by EnergyAustralia during the previous regulatory period and advise the Commission on whether the regulatory test application was conducted in accordance with the process outlined in the Code and methodology outlined in the regulatory test. In particular, the review must advise the Commission on:

a. In the event that the reliability augmentation was proposed to meet an objectively measurable service standard linked to the technical requirements set out in schedule 5.1 of the code and/or relevant legislations and regulations in NSW at the time that the regulatory test was undertaken, in particular:

i. Whether the augmentation relates to an objective criteria set out in schedule 5.1 of the code and/or relevant legislations and regulations in NSW

ii. Whether the alternatives were justifiably excluded

iii. Whether the costing for the alternative projects (including embedded generation, cogeneration, demand side responses and other non-build options) was in accordance with industry practice;

iv. Whether the timing of the construction was appropriate

v. Whether the market development scenarios were reasonable

2. As set out in statement 5.1 of the draft Regulatory Principles, undertake an audit of 1 (one) non-augmentation capital expenditure, as directed by the Commission, and advise whether:

a. the amount invested by EnergyAustralia exceeded the amount that would be invested by a prudent TNSP acting efficiently in accordance with good industry practice and to achieve the lowest sustainable cost of delivering services

b. In the event that it does not the consultant must advise the Commission on whether

i. the anticipated incremental revenue generated by the capital expenditure exceeds the investment cost;

ii. the capital expenditure has system wide benefits

iii. the new capital expenditure is necessary to maintain safety, integrity or is approved under the code and/or the relevant legislations and regulations in NSW.

3. The consultant is to compare EnergyAustralia's Capex program approved by the Commission at the previous regulatory reset with EnergyAustralia's actual Capex spent during the regulatory period and identify the endogenous and exogenous factors driving differences between the two.

The consultant is also to provide advice on other such matters as are necessary to enable the Commission to make a valuation of the non-contestable assets of EnergyAustralia expected to be in service on 1 July 2004.

Operating and maintenance expenditure

The consultant is to analyse and comment on the following matters in relation to the contribution of Opex to EnergyAustralia's delivery of transmission services:

- benchmarking EnergyAustralia's Opex forecasts against other transmission network service providers both national and internationally

- conducting an assessment of EnergyAustralia's forecast Opex costs for each year of the regulatory period, looking at endogenous and exogenous cost drivers and whether there is scope for additional efficiency gains

- comparing EnergyAustralia's Opex program approved by the Commission at the previous regulatory reset with EnergyAustralia's actual Opex spent during the regulatory period and identify the endogenous and exogenous factors driving any differences between the two

- reviewing EnergyAustralia's allocation of Opex costs to specific activities, including the distinctions between regulated and non-regulated activities, between routine maintenance and renewals, and the treatment of joint and common costs, especially corporate administration expenses, financing charges and depreciation

- assessing the efficiency of EnergyAustralia's operating practices and asset management systems in ensuring that only necessary and efficient Opex expenditure occurs, with reference to the acceleration or deferral of capital expenditure

Service Standards

The consultant must recommend appropriate service standards and performance targets, based on EnergyAustralia's historical performance and the previous review by Sinclair Knight Merz, [13]and other obligations contained in legislation, the Code, regulations and directions or licence requirements issued as provided for within such instruments.

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[13] Sinclair Knight Merz, *The Commission Network Service Provider (TNSP – Service Standards)*, March 2003, ACCC website

Consultation Process

The consultant will be required to consult extensively with EnergyAustralia during the course of the review. These consultations will involve the consultant requesting information from EnergyAustralia which is in addition to that submitted in EnergyAustralia's original application as well meetings with EnergyAustralia and possible site visits, expected to be a minimum of three days duration.

The Commission is simultaneously conducting an inquiry into the appropriate revenue cap to be applied to the non-contestable elements of the transmission services provided by TransGrid, from 1 July 2004. Given the similar inquiry timeframe, the need to ensure a consistent approach and the shared network planning and development undertaken by the two companies, the consultant reviewing EnergyAustralia's application will be required to work closely with the consultant chosen to review TransGrid's application. In addition, the consultant may be required to liaise with TransGrid as directed by Commission staff.

Source Materials

In undertaking the review the consultant source materials must include the following documents:

- The Commissions responsibilities as set out in the Code, in particular Chapter 6 Part B;
- Commission's previous revenue cap decision for EnergyAustralia from 1999-2004 and its other recent revenue cap decisions;
- Commission's *Draft Statement of Principles for the Regulation of Transmission Revenues (Draft Regulatory Principles);* and
- Commission's *Discussion Paper 2003 – Review of the Draft Regulatory Principles*
- *The Regulatory test for new interconnectors and network augmentations –* 15 December 1999
- *Sinclair Knight Merz, The Commission Network Service Provider (TNSP – Service Standards)* - March 2003
- Other relevant legislation, Codes, regulations and directions issued in accordance with such instruments that set our and/or determine EnergyAustralia's performance obligations

Timing and outcomes

The successful consultant will be required to sign the Commission's standard contract.

The Commission expects to receive EnergyAustralia's application in mid September 2003.

The Commission expects to release a draft decision in March 2004. Given this timeline the draft consultancy report must be provided to the Commission no later than 17 November 2003 and the final report no later than 8 December 2003.

The final consultancy report will be made available to the public. It will also form the basis of a discussion to be held with key stakeholders, which is expected to take place in March 2004. The consultant is to be available for this discussion.

The consultant should also expect to make a number of presentations to staff of the Commission and EnergyAustralia regarding the contents of the report.

The Commission may need to discuss issues with consultants after the consultant's final report.

Historic capital expenditure: Clarification of ACCC's requirements of GHD in respect of the review of EnergyAustralia

	Terms of reference requirement	Elaboration and clarification of the terms of reference
1	The consultant must advise on an opening regulatory asset valuation to apply to EnergyAustralia as at 1 July 2004. This should be done by rolling forward the asset base by using the Commission's PTRM electricity model; the actual rate of inflation during the appropriate period and allowable Capex. The consultant will also consider alternative approaches to asset valuation as required.	We will not require GHD to undertake a roll-forward analysis for us using the PTRM model.
2	The consultant must provide a schedule listing the assets categorised into classes, their standard replacement costs, relevant asset lives and depreciation profiles. In determining an opening asset valuation to apply to EnergyAustralia, the consultant is required to review augmentation and non-augmentation capital expenditure undertaken by EnergyAustralia over the previous regulatory period.	We are unlikely to require GHD to provide standard costs, but are likely to require GHD's advice on asset lives and depreciation profiles. We will require that GHD provides an opening asset valuation based on their review of the efficiency of EnergyAustralia's historic capital expenditure program. This is the core requirement of the analysis of historic capital expenditure and the completion of all elements of this part of the terms of reference we would expect would be reflected in GHD's response to this item. For the avoidance of doubt, we expect a detailed justification from GHD on their recommendation of the efficient level of historic expenditure with reference to well-supported engineering and economic facts and judgements.

	Terms of reference requirement	Elaboration and clarification of the terms of reference
3 & 4	3. The consultant must undertake a review of 3 (three) regulatory test applications, as directed by the Commission, conducted by EnergyAustralia during the previous regulatory period and advise the Commission on whether the regulatory test application was conducted in accordance with the process outlined in the code and methodology outlined in the regulatory test. In particular, the review must advise the Commission on: a. In the event that the reliability augmentation was proposed to meet an objectively measurable service standard linked to the technical requirements set out in schedule 5.1 of the code and/or relevant legislations and regulations in NSW at the time that the regulatory test was undertaken in particular: i. Whether the augmentation relates to an objective criteria set out in schedule 5.1 of the code and/or relevant legislations and regulations in NSW ii. Whether the alternatives were justifiably excluded iii. Whether the costing for the alternative projects (including embedded generation, cogeneration, demand side responses and other non-build options) was in accordance with industry practice; iv. Whether the timing of the construction was appropriate v. Whether the market development scenarios were reasonable	EnergyAustralia have not specifically applied the regulatory test, other than as part of a joint application with TransGrid in the case of the Sydney CBD upgrade. Accordingly in place of the three regulatory test applications, we would like GHD to complete the following: 1. A detailed review of the extent to which EnergyAustralia's investment in the Sydney CBD project has been assessed through the regulatory test. To avoid duplication of effort we do not require GHD's EA team to focus on whether or not TransGrid's installation of a 330KV cable to Haymarket is justified. Rather we would like GHD to assess whether the investment by EA - following TransGrid's investment - is justified; whether it was comprehensively assessed as part of the regulatory test and whether the investment that they have actually undertaken is efficient. The framework set out in Attachment A should be a guide to the nature of the analysis that we expect GHD to undertake. 2. A detailed review of the Beresfield 132/33kV sub-transmission substation investment. The framework set out in Attachment A should be a guide to the nature of the analysis that we expect GHD to undertake 3. A detailed review of the Macquarie Park 132 kV substation. Again, the framework set out in Attachment A should be a guide to the nature of the analysis that we expect GHD to undertake. As described, Attachment A provides the framework for the analysis of capital expenditure that we would like GHD to follow. However, for the avoidance of doubt, we have specifically described the analysis that we expect GHD to undertake in answering Item 3a of the Terms of Reference: · ◗ In completing requirement 3(a)(i) we will seek GHD's assessment of precisely how the relevant planning standard was applied by EnergyAustralia, and whether EnergyAustralia had fairly assessed the need for the investment against the planning standard. We would expect that the analysis by GHD would consider a study of load flows (and the generation and demand forecasts underlying them) and the assessment of the network capacity and of other factors as necessary.

	Terms of reference requirement	Elaboration and clarification of the terms of reference
		◗ In completing requirements 3(a)(ii) and (iii) we are seeking GHD's assessment of quality and objectivity of the analysis underlying EnergyAustralia's costing and design of the project that it has developed and of the other alternative projects that it considered, and of possible obvious alternatives that EnergyAustralia may have failed to consider. ◗ In completing requirement 3(a)iv we are seeking GHD's assessment of whether the proposed timing of the project is appropriate or whether it could not be deferred.· In respect of requirement 3(a)v, since EnergyAustralia has not applied the regulatory test we expect GHD to consider market development scenarios (in a general sense) in as far as they relate to assessing the need for the investment (requirement 3(a)i).
	4. As set out in statement 5.1 of the draft Regulatory Principles, undertake an audit of 1 (one) non-augmentation capital expenditure, as directed by the Commission, and advise whether: a) the amount invested by EnergyAustralia exceeded the amount that would be invested by a prudent TNSP acting efficiently in accordance with good industry practice and to achieve the lowest sustainable cost of delivering services b) In the event that it does not the consultant must advise the Commission on whether i. the anticipated incremental revenue generated by the capital expenditure exceeds the investment cost; ii. the capital expenditure has system wide benefits iii. the new capital expenditure is necessary to maintain safety, integrity or is approved under the code and/or the relevant legislations and regulations in NSW.	With respect to requirement 4, non-augmentation investment by EnergyAustralia relates either to investments needed to support the business or investment required to maintain the capacity of the network (replacement and refurbishment). We would suggest that GHD focus its effort on developing an objective and thorough assessment of the range of replacement projects developed by EnergyAustralia. We would expect that this would focus particularly on EnergyAustralia's methodology/approach to assessing the need for replacement of the network and then for choosing the investment to meet that need at least cost. The relevant benchmark in this assessment would be as stated in item 4(a) – "a prudent TNSP acting efficiently in accordance with good industry practice". With regard to the specific requirement to assess one non-augmentation project, we would like GHD to assess the Green Square project. Again, the framework in Attachment A should provide guidance on the nature of the investigation we expect GHD to complete. It should be noted that the Commission will be evaluating EA's historic capital expenditure independently of GHD and we will be looking to GHD to assist us on ad-hoc technical issues as they arise.
5	The consultant is to compare EnergyAustralia's Capex program approved by the Commission at the previous regulatory reset with EnergyAustralia's actual Capex spent during the regulatory period and identify the endogenous and exogenous factors driving differences between the two.	This analysis is central to the work to be done in response to items 2 to 4 of the terms of reference and we would expect that GHD would incorporate this work in response to those items of the Terms of Reference. It should be noted that it will be valuable to the Commission to obtain GHD's independent assessment in this area, but we will also be looking to GHD to assist the Commission in providing ad-hoc advice on technical issues as they arise.

	Terms of reference requirement	Elaboration and clarification of the terms of reference
5	The consultant is also to provide advice on other such matters as are necessary to enable the Commission to make a valuation of the non-contestable assets of EnergyAustralia expected to be in service on 1 July 2004.	This is likely to relate mainly to work identified under items 4 and 5 identified above.

Forecast capital expenditure: Clarification of ACCC's requirements of GHD in respect of the review of EnergyAustralia

The consultant is to review the Capex proposal by EnergyAustralia for the forthcoming regulatory period and is required to:

Terms of reference requirement	Elaboration and clarification of the terms of reference
Review the adequacy of EnergyAustralia's methodology and planning processes in arriving at a forward estimate of the efficient level of future investment needs, looking at the exogenous and endogenous factors affecting projected future Capex requirements.	It should be stressed that the ACCC is not seeking a "process-based" review of EnergyAustralia's proposals. Generic conclusions on the quality of planning processes can provide useful context to EnergyAustralia's proposed investment. But the specific issue here is to ensure that any conclusions on these processes can be explicitly translated into conclusions on the efficiency of proposed investment – and hence the efficient level of spending. Conclusions on the "technical feasibility" of their investment program for example, are unlikely to be helpful to the Commission. GHD's comments and conclusions on EnergyAustralia's Capex projection methodology should be provided. All conclusions on this should be clearly justified. In addition, we would like GHD's recommendation to clearly focus on how EnergyAustralia have taken account of the impact of endogenous and exogenous factors on the future Capex program.
Assess the assumptions underlying any trade-offs between Capex and Opex.	The focus here should be on concluding whether EnergyAustralia's capitalisation policy and planning/business practices result in distorted projections of Capex and Opex and if so, to quantify such distortions.
Compare EnergyAustralia's Capex proposal, asset management policies and quality of service standards, with industry best practice.	In a sense, the evaluation of the Capex proposal needs to have regard to industry best practice in order to inform judgements on EnergyAustralia's Capex projection. We expect that GHD will have regard to this throughout their assessment of EnergyAustralia Capex and that GHD's opinion will explicitly take account of this.

Terms of reference requirement	Elaboration and clarification of the terms of reference
Assess the likelihood that proposed non-reliability augmentation Capex will pass the market benefits limb of the *regulatory test* including: the benefits the costs probability of proceeding and timing of construction	None of EnergyAustralia's Capex is proposed under the market benefits limb; however, GHD should review the appropriateness of EnergyAustralia's classification of capital projects. If GHD determine that any proposed projects are more appropriately classified as being non-reliability augmentations, GHD should consider the market benefits limb in its assessment of any such projects. If GHD agree with EnergyAustralia's classification, none of the work envisaged here will be required.
Assess the likelihood that proposed reliability augmentation Capex will pass the reliability limb of the *regulatory test* including: demonstrated need for such investment to meet the requirements set out in schedule 5.1 of the code and/or relevant legislations and regulations in NSW; the costs probability of proceeding; and timing of construction.	The reliability limb of the regulatory test establishes the principles for assessing the efficiency of investment. Our requirement here is that GHD use these principles and in particular the approach described in Attachment B in assessing EnergyAustralia's future Capex program, but that no specific "application" of the regulatory test is required.
Assess the likelihood that the proposed non-augmentation Capex will pass the reliability limb of the *regulatory test* including: the costs probability of proceeding and timing of construction review the allocation of capital expenditure between contestable and non-contestable services.	With regard to non-augmentation Capex, this is not formally required to pass the regulatory test. However in line with the intent of the regulatory test we would like GHD to assess the need for non-augmentation investment and whether the proposed investment meets agreed needs, at least cost (again Attachment B provides the framework for the analysis we expect GHD to conduct in this regard). Since non-augmentation Capex accounts for the majority of EnergyAustralia's proposed Capex, it will be essential that GHD carefully review EnergyAustralia's proposal. Again GHD should determine the appropriateness of EnergyAustralia's classification of projects between augmentation and non-augmentation and advise the Commission accordingly.

Operating and maintenance expenditure: Clarification of ACCC's requirements of GHD

The consultant is to analyse and comment on the following matters in relation to the contribution of Opex to EnergyAustralia's delivery of transmission services:

	Terms of Reference requirement	Clarification and elaboration of the terms of reference
1	Benchmarking EnergyAustralia's Opex forecasts against other transmission network service providers both national and internationally	Depending on GHD's experience in this area, and access to information, it may be better that time that would have been spent on this, will be better spent on other activities. Specifically our concern is that unless GHD are able to produce a high quality and rigorous benchmark assessment, this time would be better spent on developing a better response to item 2 of the terms of reference.
2	Conducting an assessment of EnergyAustralia's forecast Opex costs for each year of the regulatory period, looking at endogenous and exogenous cost drivers and whether there is scope for additional efficiency gains.	It is now clear that EnergyAustralia have not developed a "bottom-up" Opex forecast, but rather have based it on a model of maintenance costs related to asset age, plus other Opex – which is determined as the remainder after subtracting the maintenance cost from the calculation of Opex based on a proportion of Transmission Optimised Replacement Cost in proportion to the total network Optimised Replacement Cost. We would therefore expect GHD to evaluate EnergyAustralia's proposed model in detail. Subsequently we expect GHD to develop its own analysis of Opex costs., considering the various drivers of these costs, and how these drivers are likely to affect the efficient level of expenditure in future. The specific output that we expect from GHD in this area, is GHD's opinion of the necessary efficient level of Opex for each year of the coming period. We expect GHD's opinion to be supported by engineering and economic fact and judgement.
3	Comparing EnergyAustralia's Opex program approved by the Commission at the previous regulatory reset with EnergyAustralia's actual Opex spent during the regulatory period and identify the endogenous and exogenous factors driving any differences between the two	We would envisage that the work required to complete this requirement would form part of the work required to complete item 2 above. We would expect a reconciliation of EnergyAustralia's claimed historic Opex with the numbers recorded in their financial accounts and in their proposals to IPART.
4	Reviewing EnergyAustralia's allocation of Opex costs to specific activities, including the distinctions between regulated and non-regulated activities, between routine maintenance and renewals, and the treatment of joint and common costs, especially corporate administration expenses, financing charges and depreciation	We do not require GHD's evaluation of Opex to necessarily define the allocation of expenditure between different types of activities. But an assessment of (functional/business activity) operating expenditure and common costs is likely to be helpful. More generally, we would see the fulfilment of this requirement as contributing significantly to the completion of the second issue above.
5	Assessing the efficiency of EnergyAustralia's operating practices and asset management systems in ensuring that only necessary and efficient Opex expenditure occurs, with reference to the acceleration or deferral of capital expenditure.	We would envisage that this would be a sub-activity of item 2 above. There will obviously need to be strong interaction with GHD's Capex analysis – particularly in relation to capitalisation policies and business practices – in completing this work.

Appendix B

Glossary of Terms and Acronyms

Glossary of Terms and Acronyms

Acronym	Term
ACCC	The Australian Competition and Consumer Commission
AESDR	Annual Electricity System Development Review
Capex	Capital Expenditure
CBD	Central Business District
CBM	Condition Based Maintenance
Commission	The Australian Competition and Consumer Commission
DNSP	Distribution Network Service Provider
EA	EnergyAustralia
EH&S	Environmental, Health and Safety
ESAA	Electricity Supply Association of Australia
IPART	Independent Pricing and Regulatory Tribunal of NSW
KPI's	Key Performance Indicators
LCC	Life Cycle Costing
NEC	National Electricity Code
NEM	National Electricity Market
NEMMCO	National Electrical Market Management Company
O&M	Operations and Maintenance
ODRC	Optimised Depreciable Renewal Cost
Opex	Operating Expenditure
ORC	Optimised Renewal Cost
PI	Performance Incentive
PTRM	Post Tax Revenue Model
RAB	Regulatory Asset Base
RP	Regulatory Period

Acronym	Term
SCADA	System Control and Data Acquisition
SKM	Sinclair Knight Merz
TG	TransGrid
TNSP	Transmission Network Service Provider
ToR	Terms of Reference
WACC	Weighted Average Cost of Capital

Appendix C

GHD Questions and EnergyAustralia Response Status

EnergyAustralia Revenue Cap Review Supplementary Questions – Interview Preparation

27th November 2003

1 Basis for this document

These questions are provided to enable an understanding of the types of questions likely to be asked within the interviews. Some of the questions will overlap between areas and interviews. Included within the text are sections that identify likely directions and examples of questions that may be asked during the relevant interviews.

2 Opex Questions

2.1 Interviews

During the Opex interviews, we will be asking multiple questions with the intent of developing an improved understanding of the facts, drivers and main impacting issues relating to EnergyAustralia. The questions below are indicative of the questions that are likely to be asked during the interviews, and provide a background for the EnergyAustralia representatives regarding the types of questions and issues that may be discussed. The interview topics and questions are not limited to the questions below.

There are bound to be overlaps between the subjects and also the knowledge of the EnergyAustralia members – as such the interviews will vary to get the best available information.

2.2 Opex – General

We note that some international studies have shown that by adopting best practices in all areas, transmission companies have been able to reduce Opex by up to 30%.

1. What drivers does EnergyAustralia use to improve Opex efficiency?

Answer Provided

- *Enerserve (currently transferring to an outcome-based SLA based around the RCM Framework discussed with GHD)*
- *Customer Service (primarily activity/functionally based)*
- *Property (primarily activity/functionally based)*
- *Corporate Finance (Activity/Functionally Based)*
- *Information Technology (Activity/Functionally Based)*
- *Legal (Functionally Based and direct cost allocation for external legal advice)*

The SLAs in the corporate area are predominantly activity based. This provides a direct link between costs and services provided for each business unit within the NLOB and for the NLOB as a whole.

Examples of SLAs can be made available if this is required.

2. Has an Activity Based Analysis been undertaken to identify main Cost Drivers? Eg Operator errors, inadequate capacity? Under/over utilisation, inadequate/inappropriate maintenance,
3. If so, has a Pareto Analysis been undertaken?

4. Overall is there a Board directed requirement to analysis Capex/Opex on a cost/benefit trade off?
5. Is there a Capital Investment Program (CIP) post installation benefits audit undertaken for major projects?
6. If so, how are the efficiency gains tracked?

Answer Provided

7. What outsourcing reviews have been undertaken?
8. What non-core activities have been outsourced?
9. What was the impact of major outsource contracts? Were they effective/efficient?
10. What evidence is available?
11. Does EnergyAustralia employ KPI's?

Answer Provided

12. Are these benchmarked against other Transmission companies in Australia / International? What are the results of this benchmarking?
13. Is there a formal business risk management plan?
14. Has it been reviewed by an independent group?
15. If installed how extensive is the Activity Based Costing program?
16. Were any issues raised in the most recent external audit that is likely to have significant financial costs that impact on Opex?
17. What programs have been undertaken or are proposed to improve the corporate cost structure?

Answer Provided

18. Has a supply costs review been undertaken to optimise costs of supplies?

Answer Provided

2.3 Opex – Corporate

1. What are the changes in Head count over the last five years and projected 5 years?

Answer Provided

2. An aging workforce would tend to imply a lower cost of labour as younger less experienced staff is employed. The application claims there is expected to be a cost increase? Why?
3. What costs are associated with Training & Education? Is there evidence of an efficiency gain from this?
4. What is the capitalisation policy? Is there evidence that it is used properly?

2.4 Opex – Operations

5. Have independent reviews or audits of maintenance best practice management strategies been undertaken?

6. If so what were the outcomes? What supporting evidence can be provided?
7. To what extent is Condition Based Assessment used to manage maintenance?
8. How is this linked to forecast Opex?
9. What Capex has been partially or in total justified on reduction in Opex?

Answer Provided

10. Have senior technical staff periodically attend international symposiums to ensure they are aware of Best Practice?
11. To what extent have best practices been implemented?
12. Can specific evidence be provided to show the impact of introducing a new practice?
13. Provide details of the justifications identified when deciding on 2 Capital Investments. What were the justifications, and were those justifications met by the projects.
14. What Opex efficiencies or costs are expected, resulting from the capital investments over the past or in the future?
15. What are the major Opex risks? What are the mitigation strategies?

Answer Provided

16. What major reviews have been undertaken in the last 5 years? How will they impact on Opex in the next five?

Answer Provided

2.5 Opex – Network Systems

1. What new Information Systems have been installed over the last 5 years? What Information Systems are proposed for the next 5 years? What was the CIP and what were/are the anticipated savings?

Answer Provided

2. Has an Information Technology Security Review been undertaken? Are their any significant issues that may adversely impact on Opex?
3. Is there a business continuity plan? When was it last updated? Has it been tested? Has it been reviewed by an external party?

Answer Provided

4. Are there any other potential material factors that may positively or negatively impact on Opex over the next five years?

Answer Provided

3 Capex Questions

3.1 Capex – Overall

1. What are the core drivers for the Capex program? What evidence is there of these?
2. What efficiencies have occurred in the Capex program?

3.2 Capex – 00-04 Augmentation, Refurbishment, Support the business

These three interviews will focus on the Historic Capex considerations. Each interview will be primarily focussed on either Augmentation Capital projects, Refurbishment Capital program or the Capital invested in additional 'Support the Business' areas.

The questions are likely to cover the following areas:

A. Is investment needed now?

1. What planning criteria applies to this investment?
2. Is the planning criteria appropriate for the investment?
3. Why is the planning criteria expected to be breached? To answer this question it is necessary to consider:
   - demand and generation forecasts and their translation into forecast load flows;
   - information on the capacity and performance of the existing network and how this is expected to change if there is no investment. Included in this assessment of this should be an analysis of how the capacity of the network is likely to be affected by expected changes in exogenous variables (such as the weather, asset age etc.) and endogenous variables (operation and maintenance procedures, line ratings etc.)
   - whether all plausible opportunities to mitigate the need for the investment were considered?

B. Has the right project been proposed to meet the need?

4. What options were considered in the assessment?
5. Was this a comprehensive list of options, if not, what other options could there be? In particular, were alternative projects sufficiently clearly defined? Were alternative configurations (routes, type of assets, capacity of assets) considered that could have met the need?
6. Were the alternative options objectively and rigorously assessed? In particular:
   - Were the alternatives accurately costed?
   - In the case of investment justified on reliability grounds, were "benefits" taken into account in the regulatory test assessment which had a bearing on the outcomes of the regulatory test? If so, were these benefits fairly costed? Were the appropriate benefits considered for all other alternatives?
   - Is the proposed augmentation optimal (capacity, timing etc.) in view of the need for the investment?

C. Has the project that "passed" the regulatory test been developed?

7. How does the proposed project compare to the project defined in the regulatory test? In particular:
   - Did the scope/design of the project substantially change (from what was proposed in the regulatory test application) and if so how and why?
   - Are there substantive differences in the cost of a project determined in the regulatory test and the actual cost of development and if so why?

– Was the project delayed, brought-forward or deferred (compared to the timing established in the regulatory test)? If so, why?
– Is there anything in 1 or 2 that should have been foreseeable when the regulatory test was undertaken and hence which would have affected the decision on the appropriate investment.

3.3 Capex – 05-09 Augmentation, Refurbishment, Support the business

These three interviews will focus on the Future Capex considerations. Each interview will be primarily focussed on either Augmentation Capital projects, Refurbishment Capital program or the Capital invested in additional 'Support the Business' areas.

A. Is investment needed?

1. What planning criteria applies to this investment?
2. Is the planning criteria appropriate for the investment?
3. Why is the planning criteria expected to be breached? To answer this question it is necessary to consider:
   – demand and generation forecasts and their translation into forecast load flows;
   – information on the capacity and performance of the existing network and how this is expected to change if there is no investment. Included in this assessment of this should be an analysis of how the capacity of the network is likely to be affected by expected changes in exogenous variables (such as the weather, asset age etc.) and endogenous variables (operation and maintenance procedures, line ratings etc.)
   – whether all plausible opportunities to mitigate the need for the investment have been considered?

B. Is the right project proposed to meet the need?

4. What investment options have been considered?
5. Is this a comprehensive list of options, if not, what other options could there be? In particular, are alternative projects sufficiently clearly defined? Were alternative configurations (routes, type of assets, capacity of assets) considered that could have met the need?
6. Have the alternative options been objectively and rigorously assessed? In particular:
   – Have the alternatives been accurately costed?
   – In the case of investment justified on reliability grounds, were "benefits" taken into account in the regulatory test assessment which had a bearing on the outcomes of the regulatory test? If so, were these benefits fairly costed? Are the appropriate benefits considered for all other alternatives?
   – Is the proposed augmentation optimal (capacity, timing etc.) in view of the need for the investment?

Further Opex Question: Why is there a difference between the forecast starting point and the transmission Opex, including the new definition of assets?

Single Answer Provided to cover these

EnergyAustralia Revenue Cap Review
Supplementary Questions

19th December 2003

As discussed yesterday, please find below a list of the information we have requested since our interviews of this week:

- Business cases of all the projects discussed during the interviews;
- Further information in the audit trail from the NERA report relating to the $ overspend on the Haymarket/Campbell St project;
- Further supporting information relating to the justification for the acceleration of Macquarie Park;
- System diagrams associated with all the projects that were discussed;

With item 3, if this is not practical to collect the various documentation within a reasonable time frame, we are happy to come in and have a detailed "walk through" with Terry, the sources of the inputs that were used for the Macquarie Park VM study, in a similar way to the "walk through" for the Green Square refurbishment project (eg looking at typical outputs of load flow studies, etc).

EnergyAustralia Revenue Cap Review Supplementary Questions

16th January 2004

1 Questions

1.1 General

During the presentation/interviews in December, the explanations given were quite clear and coherent and we had expected the supporting documentation to reflect the verbal presentation with greater detail. However, we have some difficulty in seeing this detail (and linkages in the Capex process) in the documentation received to date.

The questions on the specific projects (see Section 1.2 below) illustrate the gap in the information received to date. These questions are intended to illustrate the nature of the information flow for which we are seeking. Therefore, whilst these questions relate only to a selected number of projects, we are seeking similar supporting information for the other projects in the historic and future Capex.

In summary, we find it difficult to trace the linkages between the Capex (past and future) figures and the justification/substantiation of these figures through a coherent documentation process. We take note of EnergyAustralia's comments made during its opening presentation at the interviews of 15-17 December, that it had concerns with the existing capital process and that it is now establishing a new capital governance process which will improve the traceability of the key elements in the Capex program. We therefore understand that it may not be possible to provide evidence of the structured documentation process that we are seeking. However, we would expect EnergyAustralia to have the original working papers that have been prepared in support of each project for example, board papers, supporting information in the form of load flow results, costing spreadsheets, etc – these do not have to be re-organised or re-formatted specifically for our review.

In all cases, we would like to see a reconciliation between the distribution (IPART) and transmission (ACCC) assets as part of project costing.

Also, as the specific questions indicate, there appear to be inconsistencies between the different sets of documentation that have been provided. The following provides a sample of the inconsistencies found:

- AESDR does not indicate any historical or future constraints for both Wyong and Charmhaven, yet the 1996 Value Management Study Report for the Supply to the Central Coast states in various places that there are high loadings on Charmhaven and Wyong Zone substations;
- In Attachment F, EnergyAustralia stated that the conversion of Wyong and Charmhaven substations were not recognised as transmission exit points at the last submission. In August 2003, EnergyAustralia provided advice to both IPART and ACCC, of EnergyAustralia's closing distribution RAB for 1999-2004 and changes in asset classification from distribution to transmission. The two zone substations at Wyong and Charmhaven appear to have been omitted from the list of substations to be re-classified from distribution to transmission (document entitled "Changes to the configuration of EnergyAustralia transmission network assets – New Parallel and Supporting Assets at 1 July 2004").

- In respect of Macquarie Park, the AESDR indicate no constraints at Pennant Hills Zone substation contrary to the statements made in the Value Planning Study;
- The SKM prudency report mentions a figure of $42 million for the sub-transmission portion of the Haymarket project whereas the spreadsheet emailed to GHD on 12 January 2004 ("Haymarket spend.xls") shows a base case Regulatory Test forecast of $46.4 million;

1.2 Specific Questions & Missing Information

1.2.1 Historic Capex

Project ID 1 Tuggerah-Munmorah 132kV Feeder:

- Evidence of joint planning with TransGrid specifically in relation to the augmentation of the Central Coast 132kV network and leading to the development of the Tuggerah-Munmorah 132kV line option – note that we have a copy of the development report for the Munmorah-Sterland-Tuggerah 330kV line dated in March 2003 (post project);
- Load flow figures supporting statements on loading and capacity constraints;
- Forecast figures supporting the stated 4% growth;
- Why weren't Charmhaven and Wyong mentioned in the re-classification of assets advice to IPART and ACCC?
- Explain why the AESDR report does not list any constraints for Charmhaven and Wyong.

Project ID 2 Feeder 910/911

- Documentation to support the linkage between the joint planning with TransGrid of the 330kV supply to the CBD that has led to the options for Feeders 910/911;
- Supporting information of load forecast figures, results of load flow studies, if not contained in the above;
- Costing spreadsheets;
- Tender report for the Contract (we would like to have a feel for the price submitted by the successful tenderer).

Project ID 3 Macquarie Park

- Planning reports or planning group working papers that triggered the identification of this project;
- Supporting information of load forecast figures, results of load flow studies, if not contained in the above;
- Costing spreadsheets;
- Why does the AESDR indicate to the contrary in relation to the loading constraints on Pennant Hills Zone substation mentioned in the Value Planning Study?

Project ID 4 Haymarket & Campbell Street

- The key issue with the documentation received on this project is that there does not appear to be specific information relating to the movement in the budget, from $28 million to the Regulatory Test figure of $46 million, thence to the $67 million spent.

1.2.2 Future Capex

Inner Metropolitan Project

GHD's current understanding

Attachment D to EA Application lists this project at $36.5m from 2004 to 2009. Justification is to avoid overloading on the interconnected 132 kV system. Constraint by TransGrid Cable 41 when Cable 42 out of service. Proposes optimising power flow by use of reactors together with increased transformer capacity at Sydney South by TransGrid. Long-term new TransGrid 330/132 kV substation in Homebush / Chullora area.

Discussion with EA on December 16 clearly explained the role of series reactors to increase load flow and use of quadrature reactors (a first for EA) in controlling load flow. It made sense as a verbal presentation with diagrams on the table.

Specific Questions:

The only other information provided is the Business case, which does not include sufficient supporting details. We need to have information on:

- where the work is to be carried out
- actual loadings compared to feeder ratings
- linkage to load growth data
- copy of any estimating data for the Capex. (During discussions a figure of $5 to 6m for each of 2 quadrature reactors = $13.8m was mentioned)

From the Business Case we assume the work to be as follows for the base case:

- In 2005 install series reactors – $500 k *Where and on which feeder?*

Answer Provided

- In 2006 install shunt reactors - $1.5 m Where, in which substation? What switchgear is included?
- in 2007 install reactors to tune the network power flows - $2.7 m Where? What is is the aim of tuning the network? Where is power flow to be diverted to and from? What is the projected loading on the affected feeders?

Answer Provided

- In 2007 install Quadrature Regulators at Chullora - $ 13.8 m Since this is apparently the first time EA has used quadrature regulators some detail would be appropriate. What is the rating and characteristics? How are they connected to the Chullora bus?

Answer Provided

- 2008-2009 ACCC submission, connection to new 330/132 kV supply point at Mason Park - $18m - What is the scope of work? New switchyard? New overhead or underground circuits? New switchgear? New transformers?
- 2007 – 2010 Dist *(Presumably distribution work)* Connection to new 330/132 kV supply point at Mason Point - $11.5 m. *What is the scope of work*?
- After 2010 Connection to the next 330/132 kV supply point.

Fundamental issues to clarify are that apparently Items 1 to 5 above are transmission to be included in ACCC application. For the period 2005 to 2009 these items total $36.5 m. The Business Case Base strategy shows the same amount but spread over the years in a different time frame. The difference is probably project cash flow. However, there is no written explanation in the Business Case.

It is also unclear as to how the estimates have been prepared and costs allocated between transmission and distribution.

Answer Provided

In order to make the Business Case clearer to understand it would be helpful if the following had been included:

- Schematic system diagrams showing where each item of equipment is to be installed
- Detailed load analysis of the existing feeders and equipment now and in the future.
- Detailed load analysis after each of the proposed works is completed
- Basis of load estimates
- Basis of equipment and project cost estimates listing at least the major equipment and activities.

  (All of the above should be available at least as working papers for internal use and do not have to be in presentation format.)

Answer Provided

The only alternatives considered in the Business Case were deferral by 1 year or load shedding 80 MW of load. *(Why 80 MW?)* Neither of these is analysed in detail.

Answer Provided

The whole project is based on TransGrid having 330 kV capacity at Mason Park. *(How much? When? Are there copies of joint planning meetings covering this?)*

Answer Provided

Replacement of Feeder 900 is needed to allow this work to proceed. *(Where is Feeder 900 replacement shown in future Capex?)*

Answer Provided

The ability to delay the project *(which part?)* to 2008 depends on Feeder 908/909 being replaced.

Answer Provided

Hunter Area Western Corridor Project

The Business Case (dated 24/12/03) does refer to the preferred strategy study but there are no back-up estimates anywhere

As with others we cannot see how the ACCC figures are segregated from the overall project budget. ($12m out of $58.5 m)

The Business Case refers to a number of Deliverables that should have been completed by now including:

- Final Strategy Proposal Public Report Sep03
- Cable/Feeder Route Determination Aug 03
- Community acceptance (Argenton) Aug 03; Final Cost Estimates (Argenton) Aug 03
- Cost Estimates Oct 03
- Project (Board Approval) Dec 03.

We have not seen any of the above documents.

Answer Provided

Additional EA Response subsequently provided

EnergyAustralia Revenue Cap Review
Supplementary Questions for Report

22nd January 2004

1 Basis for this document

These questions are being asked in order to assist the GHD team in completing the review currently underway. In general, the questions are designed to either further explore areas or have been generated so that a better understanding of the business is gained.

2 Opex Questions

1. What systems are in place to ensure that suitable value is obtained for expenditure undertaken? (This question would in part be answered through the Strategic Procurement Document discussed by phone). What is the structure of the Procurement group and how is efficient spending managed?

Answer Provided

2. To simplify things for us can you provide a breakdown and reconciliation between historic Opex, the numbers in your financial accounts and the past and proposed Opex in your proposal to IPART?

Answer Provided

3. As regards usage of your T1 network, can you let us know what proportion of past and future usage (by year) is driven by your retail and distribution business, how much for other retail businesses and how much is for other TNSPs?

Answer Provided

4. The very first presentation by Matt Cooper to GHD and ACCC has a number of tables with relevant information on Transmission Opex. Could you go through the presentation and make it clear which figures relate to the past accepted definition (by the ACCC) of transmission assets and which figures relate to the current accepted definition (by the ACCC) of transmission assets. We need to be very clear on these points. In addition, could you tidy up and resend the table on page 4

Answer Provided

5. What effect is demand management likely to have on Opex?

Answer Provided

6. What is the relationship between service delivery performance and Opex?

Answer Provided

What KPIs do they report on to the Board (or to senior management) for the Transmission business? Could we have copies of those reports for all the periods of interest and forecasts

Answer Provided

7. For IPART, you gave faults per 100 km of overhead line. Do you have similar information on the Regulated Transmission Business for above and below ground cables for all the periods of interest?

Answer Provided

3 Capex Questions

No further questions. Still awaiting responses from questions dated 16th January 2004 as per discussion with Catherine O'Neill on the 21st of January 2004. Neil Wyles is expecting contact from Terry Fagan to discuss progress.

4 General/Other Questions

4.1 Delivery of Projects/Services/Maintenance

1. Does EnergyAustralia use outsourced or in-sourced people for the actual doing of work? Have these been reviewed recently?

Answer Provided

2. How does EnergyAustralia manage the teams that do the work? Do you utilise internal/external supervisors? Or are KPI's used to manage performance on an outcome basis? (See following question).

Answer Provided

3. Describe the processes used for contract management of projects (eg. Full contract supervision and inspection, partial supervision and audit, audit only, or a mixture)?

Answer Provided

4. Is there a Quality system in place for internal & external teams? Are quality audits undertaken?

Answer Provided

5. What proportion of investigation and design is undertaken by external resources?

Answer Provided

6. What process(es) does EnergyAustralia use to optimise the scope, equipment and construction methods used for any particular project? To what extent are internal resources, external consultants and/or contractors used to assist this process?

Answer Provided

7. What management systems are required of contractors and to what extent are they required to be applied?

Answer Provided

EnergyAustralia Revenue Cap Review
Supplementary Questions for Report

23rd January 2004

1 Basis for this document

These questions are being asked in order to assist the GHD team in completing the review currently underway. The questions follow from our review of your 2003 Annual Report.

2 Opex Questions

1. On page 10/11 of your 2002/3 Annual Report in the graph of Electricity supplied in GWH (repeated below in the table, you supply in formation for 2000 to 2003 June year inclusive. However, supplied energy may not be the same as the amount of energy carried by your Transmission Network. If the difference between supplied and carried energy is significant, can you supply the carried information? In addition, can you provide the anticipated outturn for 2004 and the forecast outturn for the next regulatory period 2005 to 2009?

Answer Provided

Supporting comments from GHD and additional question

In answering our Opex questions, especially the ones about the Cost Allocation spreadsheet you may care to answer some along the lines of:

- Costs that have been driven as the Transmission business changed due to incorporation of other transmission businesses or divestment and set out what those costs were (big picture only)
- Costs driven by one off or a step change in the regulatory or legal framework under which EnergyAustralia operates
- Costs driven by events in the market place (superannuation and insurance come to mind)

6. Do you have any comments on economies of scale and can you trace them as your business has expanded or are the other drivers more influential and crowd out the economies of scale?

Appendix D

Reference Material Supplied by EnergyAustralia

No.	Document Title	Description	Date placed into GHD system	Source	Confidential
001	EA Trans Final Report	Report re: which asset are classified as 'transmission' by independent consultant	29/09/2003	ACCC	N
002	ACCC Submission.pdf	The current submission	26/09/2003	ACCC	Y
003	EA Attachments.zip	The attachments for the EA submission, 1 through 14	26/09/2003	ACCC	Y
004	Application Attachment Sheets – placed into single folder.	Doc titles are: Attachment 1 (cover); Attachment 11 – NECG (WACC) cover; Attachment 12 (Cover); Attachment 4 (cover); Attachment 5 – (cover); Attachment 6 (cover); Attachment 7 (cover); Attachment 9 (cover) All other covers should be with the actual submission.	30/09/2003	ACCC	N
005	EnergyAustralia Annual Report 2002		07/10/2003	ACCC	N
006	EA PSR 2002 Final 04m.zip	Pricing strategy information (included in e-mail from Harry Colebourn – EA)	14th Oct 2003	EA	Y
007	Network_Price_List+2003_04_final.pdf	Pricing strategy information (included in e-mail from Harry Colebourn – EA)	14th Oct 2003	EA	Y
008	2003-04 pricing & losses 19 5%.pdf	Pricing strategy information (included in e-mail from Harry Colebourn – EA)	14/10/2003	EA	Y
009	PTRM (EA Version)exs		22nd October	ACCC	Y
010	99 Valuation (model provided by EA).xls		22nd October	ACCC	Y
011	Cover letter for information request.doc	EA response to 1st round of questions from ACCC	5th November	EA	Y
012	Attachment B - Asset valuation doc.doc	EA response to 1st round of questions from ACCC	5th November	EA	Y
013	Attachment A - Service Standards (availability).doc	EA response to 1st round of questions from ACCC	5th November	EA	Y
014	Cover letter for information request (2).doc	EA response to 1st round of questions from ACCC	17th November	EA	N
015	Attachment C - Depreciation.doc	EA response to 1st round of questions from ACCC	17th November	EA	N
016	Attachment D - Capital Expenditure Forecasts.doc	EA response to 1st round of questions from ACCC	17th November	EA	N
017	Substation spatial forecast (IPART Att 05).doc	EA response to 1st round of questions from ACCC	17th November	EA	N
018	Attachment E - ACCC proforma.xls	EA response to 1st round of questions from ACCC	17th November	EA	N

019	Attachment G - Opex.doc	EA response to 1st round of questions from ACCC	24th November	EA	N
020	Attachment F - Economic tests applied to transmission (web version).doc	EA response to 1st round of questions from ACCC	24th November	EA	N
021	Cover letter / summary - includes docs 019 and 020.	EA response to 1st round of questions from ACCC	25th November	EA	N
022	NSW DM Code of Practice & Working Group Final Report	EA response to 1st round of questions from ACCC	25th November	EA	N
023	Sinclair Knight Merz Report on Project Prudency	EA response to 1st round of questions from ACCC	25th November	EA	N
024	Project ID: 1 Tuggerah / Munmorah 132kV Feeder and Conversion of Wyong and Charmhaven Substations	EA response to 1st round of questions from ACCC	25th November	EA	N
025	Supplying Central Coast - Northern Sector Subtransmission & Zone Substation Capacity	EA response to 1st round of questions from ACCC	25th November	EA	N
026	Project ID: 2 Uprating of feeders 910 / 911 - Value Planning Study	EA response to 1st round of questions from ACCC	25th November	EA	N
027	Project ID: 3 Macquarie Park Reports	EA response to 1st round of questions from ACCC	25th November	EA	N
028	Gosford / Ourimbah 132kV Feeder and West Gosford Substation	EA response to 1st round of questions from ACCC	25th November	EA	N
029	Project ID: 4 CBD Upgrade	EA response to 1st round of questions from ACCC	25th November	EA	N
030	Project ID: 5 Beresfield Subtransmission Substation Part 1 (& Part 2)	EA response to 1st round of questions from ACCC	25th November	EA	N
031	Network (level 3) Organisational Chart.doc	EA response to request for Org Chart	27th November	EA	Y
032	Asset Invest Mgmt Org Chart.pdf	EA response to request for Org Chart	27th November	EA	Y
033	Pricing & connection organisational chart.pdf	EA response to request for Org Chart	27th November	EA	Y
034	RSG org chart.doc	EA response to request for Org Chart	27th November	EA	Y
035	ea_full 2003.pdf	EA annual Report	12th December 03	N/A	N
036	ea_full 01-02.pdf	EA annual Report	13th December 03	N/A	N
037	EA_full 00-01.pdf	EA annual Report	14th December 03	N/A	N
038	Ea~2000 99-00.pdf	EA annual Report	15th December 03	N/A	N
039	99annualreport 98-99.pdf	EA annual Report	16th	N/A	N

			December 03		
040	eafins98 97-98.pdf	EA annual Report	17th December 03	N/A	N
041	EA procedures	Screen capture of Lotus Notes System	17th December 03	EA	Y
042	Value Management Study Report	Inner Suburbs Load Area Development Items	17th December 03	EA	Y
043	R&R Policies v0.2 171203.doc	Refurbishment & Replacement Policies	17th December 03	EA	Y
044	Consultation Paper	Establishment of a Zone substation at Alexandria	17th December 03	EA	Y
045	Report HPR83-01 3 April 2002	Hunter Planning Report 83-01 - Western Corridor Supply Development Strategy Options	16th December 03	EA	Y
046	Age Profile Information Summary (as at 30 June 2002)	EXCEL Spreadsheet prepared for 2002 ODRC Valuation by the Strategic Asset Management Group - See doc 069	17th December 03	EA	Y
047	ACCC Asset Age Profile Information Summary (as at 30 June 2004)	EXCEL Spreadsheet prepared for 2004 ACCC Submission from the 2004 SKM ACCC ODRC Valuation - See doc 069	17th December 03	EA	Y
048	EnergyAustralia Sydney 132kV System	Diagram	15th December 03	EA	Y
049	EnergyAustralia Central Coast 132kV System - 1998	Diagram	15th December 03	EA	Y
050	Lower Hunter 132kV Network Selected Projects	Diagram	16th December 03	EA	Y
051	ACCC TNSP Disclosure Requirements Guideline - Appendix A 'Statement of Capex', Issue No. 1	Table	17th December 03	EA	Y
052	Outline Business Case - Summary	Replacement of Aged Infrastructure & Supplying Increasing Demand in Alexandria and Botany	17th December 03	EA	Y
053	EnergyAustralia Annual Electricity System Development Review May 2003		17th December 03	EA	Y
054	Overview Presentation	2004 Transmission Determination EnergyAustralia Presentation	5th January	EA	N
055	EnergyAustralia's Moving Assets	EnergyAustralia's closing Regulatory Asset Base for period 1999-2003	5th January	EA	N
056	Confirmation letter from ACCC	Network assets owned by EnergyAustralia moving from distribution to transmission	5th January	EA	N
057	Presentation on Opex- John Hardwick (updated version)	ACCC OPEX Submission - 2003	5th January	EA	N

058	Chart from story board- "Initial ODRC Values per Asset"	Initial ODRC Values per Asset	5th January	EA	N
059	Chart from story board- "Average ages of asset groups with proposed Capex"	Average Ages of Asset Groups with Proposed CAPEX	5th January	EA	N
060	Chart form story board- "Summary of ACCC splits for both Time & Condition Based Maintenance Projections"	Summary of ACCC % Splits for both Time and Condition Based Maintenance Projections	5th January	EA	N
061	Erldunda Report by John Kaine - EA Transmission assets	Transmission assets owned by EnergyAustralia report for ACCC by Erldunda Associates	5th January	EA	N
062	Matt Cooper's Presentation- Opex overview	2004 Transmission Determination EnergyAustralia Presentation to ACCC & GHD	6th January	EA	N
063	Capital Governance Presentation	Key Issues with Existing Capital Process	7th January	EA	N
064	Process flow diagram from John Hardwick summarising story board	(a) High level process view of the ACCC Submission as Detailed on the OPEX Storyboard; (b) Detailed Level Process View of the ACCC Submission as Detailed on the OPEX Storyboard	8th January	EA	N
065	Hunter CAPEX presentation	Hunter 132kV Network Development Plan 2003/12 Key Issues and Projects Overview	9th January	EA	N
066	Hunter Planning Report 83-01- "Western Corridor Supply Development Strategy Options"	Hunter Planning Report 83-01- "Western Corridor Supply Development Strategy Options"	10th January	EA	N
067	EnergyAustralia's Sydney 132kV system	Map of EnergyAustralia's Sydney 132 kV system	11th January	EA	N
068	EnergyAustralia's Central Coast 132kV System - 1999	Map of EnergyAustralia's Central Coast 132kV System- 1998	12th January	EA	N
069	ACCC age profiles information summary 2002(Total network) and 2004 (ACCC only)	(a) ACCC Asset Age Profile Information Summary 2004; (b) Age Profile Information Summary 2002 Replicates documents 046 & 047	13th January	EA	N
070	Presentation - Steve Buncombe - asset ages & ORDC data	EnergyAustralia Network Engineering, 2002 ODRC Asset Valuation & ACCC 2004 ODRC Asset Valuation	14th January	EA	N
071	EA Trans Final Report	EA Trans Final Report' Transmission Assets owned by EnergyAustralia- a report for ACCC'	16/12/2003	EA	N
072	OPEX MODEL COST ALLOCATION 090104.xls	Network System Assets spreadsheet, costs and percentages	12/01/2004	EA	N

073	Explanatory notes regarding Opex allocation model v2.doc	Explanatory notes regarding Opex allocation model, which have been extracted from EA's regulatory model and copied for GHD.	12/01/2004	EA	N
074	BC 908_909 132KV Cablev2-3ACCC.doc	Outline Business Case - Summary of Kurnell-Bunnerong (circuits 908/909 replacement), date 22/12/03, Version 2.3ACCC	12/01/2004	EA	N
075	BC Alex-Botany v1.4ACCC.doc	Outline Business Case-Summary (Replacement of Aged Infrastructure & Supplying Increasing Demand in Alexandria and Botany, Version 1.4ACCC	12/01/2004	EA	N
076	BC EMait-Tarro v1.5ACCC.doc	Outline Business Case - Summary of Supplying Increasing Demand in the East Maitland/ Tarro Corridor, date 24/12/03, Version 1.5ACCC	12/01/2004	EA	N
077	BC Lower Hunter 132kV v1.6ACCC.doc	Outline Business Case-Summary Provision of Additional 132kV Capacity in the Lower Hunter, date 24/12/2003, Version 1.6ACCC	12/01/2004	EA	N
078	BC Ourimbah 2-2ACCC.doc	Outline Business Case - Summary 'Supplying Increasing Demand and Replacing Aged Infrastructure on the mid-Central Coast (Wyong Shire), date 23/12/2003, version 2.2ACCC	12/01/2004	EA	N
079	BC Sydney Transmission v1.3ACCC.doc	Outline Business Case- Summary ' Provision of Additional Transmission capacity and Connection to New TransGrid Substations in Sydney', date 23/12/2003, Version 1.3ACCC	12/01/2004	EA	N
080	BC Western Corridor v1.4ACCC.doc	Outline Business Case - Summary 'Supplying Increasing Demand Newcastle Western Corridor', date 23/12/2003, version 1.4ACCC	12/01/2004	EA	N
081	Haymarket Spend.xls	Haymarket and Campbell St Costs, comparison $03-04	12/01/2004	EA	N
082	Macquarie.doc	Macquarie Park Zone Substation	12/01/2004	EA	N
083	Attachment E - ACCC proformaV2.xls	Setting the Revenue Cap Forecast - Forecast Capital Expenditure (gross)	12/01/2004	EA	N
084	Overview Flowcharts.doc	ORDC Asset Valuations Executive Summary and Asset Valuations Overview	12/01/2004	EA	N
085	GHD questions and responses 090104.doc - updated, see doc 087	Questions asked by GHD (I.e. 1/ What are the changes in the headcount in the last 5 years and projected 5 years?)	15/01/2004	EA	N

086	Benchmarking of EA IT Costs	IT Benchmarking information and a recent IT business case enclosed, demonstrating the level of scrutiny that is applied to IT and to show that levels of IT spending overall are in line with industry trends.	16/01/2004	EA	C
087	GHD questions and responses 090104 (updated for IT).doc	Questions asked by GHD (I.e. 1/ What are the changes in the headcount in the last 5 years and projected 5 years?) updated from doc 085	19/01/2004	EA	C
088	Response from EA to Capex Questions: Attachments: **Project ID1:** TM-1.1, TM-1.2, TM-1.3,TM-2.1, TM-2.2, TM-2.3, TM-2.4, TM-2.5, RA1-4,TM-3.1, TM-3.2; **Project ID2:** ID2-1.1, ID2-1.2, ID2-1.3, ID2-1.4, ID2-1.5; ID2-2.1, ID2-2.2, ID2-2.3, ID2-2.4; **Project ID3:** ID3-1.1, ID3-2.1, ID3-2.2, ID3-2.3, ID3-2.4, ID3-4.1	Response specifically to Capex questions.	27/01/2004	EA	C
089	Future Capex-Hunterv2 03.02.04.doc	Hunter Are Western Corridor Project- GHD questions regarding a business case dated 24/12/03.	04/02/2004	EA	C
090	Hunter ACCC Transmission CostsGHD 03.03.04.xls	23 Lower Hunter 132kV NetworkDevelopment, 30 East Maitland/ Tarro Corridor Supply Development, 37 Newcastle Western Corridor Supply Development- CAPEX ALL	04/02/2004	EA	C
091	Response from EA to Capex Questions on Project ID4 Haymarket & Campbell Street Attachments: ID4.1.1, ID4.1.2, ID4.1.3, ID4.1.4, ID4.1.5, ID4.1.6 (ID4.1.1 is spreadsheet emailed on 12 Jan); ID4.2.1, ID4.2.2, ID4.2.3, ID4.2.4;	Response specifically to Capex questions.	06/02/2004	EA	C

092	Response to ACCC letter of 1 Dec 03 FINAL.doc	Letter to Aaron Murray (ACCC) dated 4/2/2004, regarding information req by ACCC from George Maltabarow- GM Network. Subheadings are; * Adjustment to historic distribution and transmission Capex, *Recovery of revenue for the 1999-2003 reg period, * Reconciliation between distribution and transmission applications *Forecast Capex on commissioning data basis, *Tax remaining lives, * Working Capital, *Opex ratios	06/02/2004	EA	C
093	tax depreciation extract.jpg	EnergyAustralia- Asset History Major Categories Report (dated 30.06.2003)	06/02/2004	EA	C
094	Attachment E - ACCC proforma - revised costs inc Haymarket (22.01.04).xls	Setting the Revenue Cap Forecast - Initial Regulatory Assets (gross)	06/02/2004	EA	C
095	Roll Forward Calcs V17 - Revised D to T info (Wyong & Charmhaven) 02-02-04.xls	Roll forward adjustments to reach closing distribution RAB for 30 June 2004	06/02/2004	EA	C
096	Letter to IPART (Wyong & Charmhaven).doc	Letter to Dr Tom Parry(chairman IPART) regarding adjustment to historical Capex from George Maltabarow GM Network	06/02/2004	EA	C
097	DOC 1 - Documents relating to Haymarket DOC 2 - EA Goulburn Lane Project Report on Cable Access Route - Feasibility Study	DOC (1) Historical Capex- Project ID 4 - Haymarket & Campbell Street "Key Issue with the doc received on this project is that there doesn't appear to be specific info relating to the movement in the budget, from $28m to Reg Test fig of $46m, thence to the $67m spent. DOC(2) EA - Goulburn Lane Project Report On Cable Access Route - Feasibilty Study by GHD "need for augmentation of the power transmission networks for Sydney's CBD and Inner Suburbs."	10/02/2004	EA	C
098	Historic opex.xls	Excel workbook, consisting of Transmission Opex (nominal), Transmission Opex (Real), Breakdown of transmission Opex, Transmission Opex 1999-2009	16/02/2004	EA	C

099	Responses to ACCC Qs 6.02.04.doc	q" Regarding the past Capex reconciliation table (Att F), can EA now provide a table showing actual Capex incurred on a cash spend basis in the last regulatory period listed project ie incorporating changes to CBD, Green Sq and Beresfield projects?"	16/02/2004	EA	C
100	ACCC non-system Capex subm.doc	The purpose of this doc is to provide info to support EA claim for non-system capex for transmission of approximately $5.6m per annum during the 2004/09 regulatory period.	16/02/2004	EA	C
101	PTRM (MOD VER) 120204.xls	Post tax revenue model - electricity module	16/02/2004	EA	C
102	Future Capex 'Inner Metropolitan Project'	Future Capex 'Inner Metropolitan Project', GHD's current understanding with specific questions	23/02/2004	EA	C
103	EA Strategic Sourcing	EA Strategic Sourcing Approach, Rationale and Toolkit	23/02/2004	EA	C
104	Corporate Procurement Strategy	Driving business performance strategic sourcing, commercial contracting, integrated supply- 11Dec2002 Version 1.1	23/02/2004	EA	C

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