CAPITAL EXPENDITURE (1999-2004)

Statutory Requirements

In NSW the *Electricity Supply Act* 1995 requires an electricity distributor operating in New South Wales to hold a licence. The licences are subject to conditions imposed by the *Act* and by the Minister for Energy.

The *Act* requires that the Minister for Energy impose a condition on each licensed electricity distributor to conduct investigations on the cost effectiveness of implementing demand management strategies that may permit distribution network augmentation work to be deferred or avoided. In terms of the *Act* all activities of the 'electricity distributor', in this case EnergyAustralia, are subject to the licence guidelines including those activities which may be considered, under the NEC definition, as 'transmission' works.

Specifically, Schedule 2(6)(5) of the *Electricity Supply Act* states:

(5) Without limitation, the Minister must impose the following conditions on each electricity distributor's licence:

(a) a condition requiring the holder of the licence, before expanding its distribution system or the capacity of its distribution system, to carry out investigations (being investigations to ascertain whether it would be cost-effective to avoid or postpone the expansion by implementing demand management strategies) in circumstances in which it would be reasonable to expect that it would be cost-effective to avoid or postpone the expansion by implementing such strategies,

(b) a condition requiring the holder of the licence to prepare and publish annual reports in relation to the investigations carried out by it as referred to in paragraph (a).

In accordance with the *Act*, the Minister has imposed Licence Condition 3.1 in all electricity distributors' licences. This condition substantially repeats the wording from the *Act*. The *NSW Code of Practice - Demand Management for Electricity Distributors* is a voluntary code that provides guidance on implementing the requirements in the *Act* and licence condition 3.1.

Additionally, 'distributors' must comply with the *Environmental Planning and Assessment Act* as administered and interpreted by Planning NSW (the Department of Planning). This *Act* specifies development requirements for supply system activities but also allows the Director to impose further conditions on any capital works (for example financing of a $10M Demand Management fund as an approval condition for the Sydney CBD development).

We also must comply with the National Electricity Law and the National Electricity Code that specifically refers to the ACCC *Regulatory Test* for economic evaluation.

These statutory/regulatory instruments are not entirely consistent in their consultative and assessment procedures and accordingly EnergyAustralia has adopted an approach which we believe satisfies their principle intent and clearly demonstrates prudent outcomes from our capital planning process and project economic evaluations.

Planning Process

As a TNSP EnergyAustralia is required to carry out an annual planning review with DNSP's connected to its transmission system in accordance with Clause 5.6.2 of the NEC. EnergyAustralia as a DNSP is involved in annual planning reviews with both its own transmission business and TransGrid. Where the necessity for augmentation or extension is identified in this review, joint planning must be undertaken to determine plans that can be considered by code participants and interested parties. There are regular meetings between TransGrid and EnergyAustralia planners so that anticipated works can be planned and implemented in a timely manner consistent with the wider strategic aspirations of the two network businesses.

Emerging constraints (timing, magnitude, location, planning options and cost) are documented in the Annual Electricity System Development Review (AESDR). The AESDR scope is all of EnergyAustralia's prospective growth driven capital works and separately identifies those works related to the deemed transmission system (ie the AESDR includes the NEC required Annual Planning Report). The AESDR is a public document and is specifically sent to interested parties who may be able to use the information to suggest alternative development options.

It is a responsibility of EnergyAustralia to ensure that the network provides a supply of adequate reliability and quality in accordance with the requirements of the National Electricity Code.

Major Infrastructure development projects at EnergyAustralia are assessed through the Value Management process in accordance with the Australian/New Zealand standard AS/NZS 4183:1994. At EnergyAustralia this process includes the consideration of alternatives to network construction such as demand management.

Schedule 5.1.2.2. of the NEC specifies a range of possible minimum service standards that may be applied to a power system taking account of specific design, locational and seasonal influences which may affect performance. EnergyAustralia has developed guidelines that indicate the expected performance standards that should be applied in different situations. These guidelines act as a filter that indicates the need for further action or analysis. The guidelines are for each specific component of the system (eg zone substations, 132kV network etc) and are designed so that the whole stream of arrangements for supply from the generators down to the low voltage system produce real customer outcomes in accordance with the standards specified in our ES2 document. The ES2 document defines a holistic 'product' provided by our distribution and transmission networks and is called up by our nominal customer connection agreement.

Apart from NEC requirements, EnergyAustralia also complies with jurisdictional requirements set out in the NSW Demand Management Code of Practice and any development approval criteria imposed by determining authorities or PlanningNSW under the EPA Act. The DM Code was developed to give guidance to network service providers on satisfying their licence requirements. EnergyAustralia is required to have in place a formal process for providing information 'to the market' that might facilitate non-network supply augmentation options. There is a formal obligation to consider such options in an open and transparent manner - on the same basis as our own network augmentation options.

A significant example of DA Approval outcomes, associated with the jointly planned cable tunnels required for augmenting supplies to the Sydney CBD, is the PlanningNSW determination that TransGrid and EnergyAustralia jointly finance a $10M Demand Management and Planning Project (to be managed by PlanningNSW) and follow specified rules for its application.

Evaluation Process

EnergyAustralia's investment decisions are intended to ensure the Network meets required technical standards required in section 5.1.2.2 of the National Electricity Code (NEC). Under the NEC assessment of options must consider whether the investment is economically cost effective. (Specifically, for intra region developments it is sufficient that the development be the least cost investment required to meet an objectively measured service standard linked to Schedule 5.1 of the NEC). In 1999 IPART undertook a review of EnergyAustralia's ten year capital expenditure program including transmission projects, and in its Section 12 Report to the Premier of NSW, outlined a proposed process that would see the full capital program for the upcoming regulatory period recognised in the current determination. The process envisaged actual investments being reviewed at the end of the upcoming regulatory period to determine the capital value (deemed to be economically efficient) that would be allowed in the regulated asset base for subsequent periods.

It was widely understood that all investment, endorsed by the 1999 review, provided it proves to be required to meet appropriate network service standards and provided its implementation costs are efficient, will be allowed at full value into the regulated asset base.

Thus the deciding criteria for EnergyAustralia in making network investment decisions are:

- Whether the option proposed is the most economically cost effective option to address the projected limitations of the relevant transmission system or distribution system. Demand Side Management initiatives, alternative generation or co-generation projects are considered in addition to supply side options.
- Whether the investment is necessary to meet reasonable customer and community expectations regarding the nature of the infrastructure and quality and reliability of supply, represented by the broadly enunciated design standards endorsed by the 1999 review These design standards are not linkable to Section 5.1 of the Code. The demonstration of their prudence therefore relies upon their previous endorsement by IPART through the Worleys review, the Section 12 enquiry and the 1999 pricing review; and
- For investment not endorsed by the 1999 IPART Capex Review (or any subsequent review) it is important that the *Planning Process and the evaluation* should be robust and defensible in terms of the provisions of the National Electricity Code and the Regulatory Test defined by the ACCC or the Evaluation Protocol as defined in the Ministry of Energy and Utilities endorsed NSW Demand Management Code of Practice.

Application of NEC and DM Code Requirements

It was a consensus of the DM Code working group (and as indicated, subsequently endorsed by the MEU) that application of the DM Code process by 'distributors' would satisfy the NEC requirements.

Accordingly, the following process was proposed for growth driven capital projects:

- EA will carry out the NEC 'annual planning review' jointly with TransGrid who will then produce their 'annual planning report' (APR)
- The 'Annual Electricity System Development Review' (AESDR) under the DM Code will incorporate our 'internal' APR (as EA is also a transmission network service provider)
- Consultation with Code participants and interested parties will be considered equivalent to the DM Code Specification Protocol consultation requirements
- The Regulatory Test application for distribution projects will be considered equivalent to the least cost test specified in the DM Code
- EA will apply the full NEC process and Regulatory Test for major transmission projects

The evaluation in the DM Code of Practice allows for options to be ranked on the basis of '*total net…costs of system support incurred, plus the cost or benefits of changes to transmission and distribution losses'.* Costs include all capital, fixed and operating costs of securing the specified level of system support (these levels are specified in EA's planning guidelines that are documented in the AESDR). If the market operates efficiently, this basis of evaluation should accord with the ACCC's Regulatory Test.

INDIVIDUAL PROJECT ASSESSMENTS

1. Gosford/Ourimbah 132kV Line and Upgrade of West Gosford Zone Substation

A program to address network capacity issues on the southern Central Coast was included in the 1997 IPART capex submission. This program comprised:

- construction of a 132kV line between Tuggerah and Gosford $7.9m
- conversion of Lisarow zone substation to 132kV operation $10.7m

This project was reviewed in 1998 and the scope was amended to provide for:

- construction of a line between Ourimbah and Gosford; and
- conversion of West Gosford zone substation to 132kV operation .

Following this amendment, $7.9m associated with line construction was included in EnergyAustralia's transmission capex projections. However, the substation work was not included in the ACCC capex projections. Design work and consultation for this project commenced in early 1999.

The estimated final total project cost is $26.7m. Circumstances surrounding an extended community consultation process, traffic control, additional oil containment works and maintenance of supply staging problems increased the cost but are not normally reflected in asset valuations.

Afterwards, it was realised that the new line linked two different parts of EnergyAustralia's 132kV distribution network. However, it was considered that this infrastructure could not be legitimately regarded as a transmission asset unless other parts of EnergyAustralia's 132kV network were reclassified as transmission. The uncertainty associated with the outcome of EnergyAustralia's request that the ACCC alter the classification of some assets from distribution to transmission led to the capital expenditure on this project not being included in ACCC regulatory accounts.

EnergyAustralia subsequently requested that the Central Coast 132kV system including the Ourimbah-Gosford feeder and West Gosford zone substation be reclassified as transmission assets. ACCC has agreed to this request and the Central Coast infrastructure will be reclassified as transmission from June 2004.

Gosford and Ourimbah substations supply electricity to the southern parts of the Central Coast that is the fastest growing region in EnergyAustralia's franchise area. Load forecasts indicate that after 2003 rationing of electricity in the Gosford area would be required during outages of the single feeder which supplies the Gosford area from TransGrid's Tuggerah substation. The West Gosford substation has exceeded its firm capacity since 2001 and there is no practical scope for load reduction of the extent required given the high growth.

Alternative options were investigated and included demand management, transmission developments, different options for subtransmission line development and zone substation development. The construction of an overhead 132kV line from Ourimbah to Gosford required by far the least amount of construction over the shortest route with the least cost, environmental impact and network losses. The uprating of the West Gosford substation was clearly the least cost option to relieve the loading problems on the substation and the lower voltage lines in the area.

Extensive consultation was carried out via a community working group and Sinclair Knight Merz were commissioned to report on the environmental, technical, social and financial issues associated with route options.

Community consultation outcomes increased the cost of the feeder to $8.1m because of changes to the line route and the requirement to replace existing distribution infrastructure to allow line construction. The cost of the substation work also increased due to the need to extend the 11kV switchroom and provide improved oil containment and fire mitigation.

SKM assessed the project as being prudent in terms of timing and cost given the circumstances surrounding the project.

Documentation: Value Management study, Board Report and Economic Evaluation, SKM Prudence Report

2. Uprating of Feeders 910/911 Sydney South to Chullora

An allowance of $11.7m to uprate feeder 910 and 911 between Sydney South and Chullora was included in the ACCC capital expenditure projections for the current regulatory period. This project was completed in October 2001 at a cost of $7m.

Project justification

This project was identified in an early 1998 Value Planning study as an relatively low cost project to optimise the load flows on the interconnected 132kV system and cost effectively defer the expenditure by TransGrid and EnergyAustralia associated with the planned 330kV augmentation (see above). It was listed as one of the associated projects in the NEC report on supply to the Sydney CBD and Inner Suburbs.

The uprating of this double circuit line required reconductoring of about 15km of double circuit transmission line, and included the structural reinforcement of towers. The augmentation provides an additional 100MW of capacity at Chullora during normal system conditions and up to 160MW of additional capacity when the (single) TransGrid 330kV cable to Beaconsfield substation is out of service. It also provided better utilisation of the transformers at TransGrid's Sydney South substation that supplied these feeders as they were only capable of being utilised to about 50% of their capacity because of the feeder limitations. The planning study analysis estimated a cost of $90/MW compared with the $280/MW for the proposed second 330kV supply to the Sydney CBD.

Design work on the project commenced in mid-1998 and formal approval was given by the Board of EnergyAustralia in June 1999. This was prior to the date (July 1999) when the augmentation would be regarded as part of the transmission system.

Documentation: Value Planning Study, Economic Evaluation

3. Macquarie Park132kV Substation

An allowance of $11.3m to construct a new zone substation at Macquarie Park was included in the 1997 IPART capital expenditure review. No allowance for this project was included in the ACCC capital expenditure review as it was not known at the time of the submission that the substation would be a transmission asset.

The combined allocated cost of the substation and 132kV connections is $12.5m for the current regulatory period. A post implementation review in August 2002 confirmed the prudence of this investment.

Project justification

The need for a new zone substation in the Macquarie Park area was identified in the early 1990s to be required in about 2005.based on anticipated load growth. This timing was achievable through a combination of minor augmentations, load transfers, risk management and demand management. This need was confirmed in a 1998 Value Management study. Following the study actions were initiated to procure a substation site and begin conceptual design work.

At the time of the study the full extent of the load growth in the Macquarie Park area was unknown and the subsequent large individual projects were not factored into the forecasts. In fact between 1996 and 2000 there was unprecedented load growth of 18%. As a result the firm capacities of the Epping and North Ryde zone substations were exceeded by 4% and 8% respectively during the summer of 1999/2000 and 10% and 20% in 2000/2001.

Demand Management possibilities were initially identified in a joint EA/SEDA sponsored consultants review (Charles Rivers Associates). A subsequent market approach via an Expression of Interest identified some practical options that could provide a short deferral of the expenditure given the load growth forecasts at the time. However, continuing promotion of the area as a high tech environment with access to appropriate infrastructure led to large, unanticipated projects with high electricity use emerging. This growth far outstripped the practical capability of the identified demand management alternatives. The size of these projects was considerably larger than historical customer developments in the area. Moreover the two substations provided a high degree of mutual support in contingencies, so the overloading of both created operating problems.

The establishment of a new 132/11kV Macquarie Park substation was, by a very large margin, the least cost alternative to meet future demand in the area.

SKM assessed it as a prudently timed investment at a prudent cost given the urgency of the project.

Documentation: Value Management Study, Economic Evaluation, SKM Prudence Report

4. Sydney CBD Project (132kV connections to the new TransGrid Haymarket 330kV substation and EA's new Campbell St substation)

This works program corresponds to three different projects which were included in EnergyAustralia's 1997 IPART submission.

- Establish Broadway zone $13.5m
- Sydney Central 330/132kV substation connections $28.2m
- Taylor Square zone substation $33.8m (2005–09)

Subsequently, $29m associated with the 330/132kV substation connections was included in EnergyAustralia's transmission capex projections. The substation work was not included in the ACCC capex projections as the requirement to connect these substations to the transmission system was not recognised at the time the capex submission was made.

Subsequent planning work resulted in identification of the need to establish a transmission exit point in the Surry Hills area. This substation will take the place of the substations (Broadway & Taylor's Sq) identified in the IPART report.

EnergyAustralia's part in this project comprises

- the establishment of a 132/11kV substation in the Surry Hills area (Campbell St)
- the purchase of land for the Campbell St substation
- the connection of its 132kV system to the Haymarket supply point
- Purchase from TransGrid of 50% of their cable tunnel from Haymarket to Wattle St

Part of the works associated with connection to Haymarket are regarded as distribution assets. Consequently only 50% of the costs associated with providing 132kV connections to Haymarket are Transmission charges. Thus the Transmission expenditure associated with this project will be $67.8m for the current regulatory period.

Reasons for increased expenditure above that included in the previous ACCC capex projections are:

- Campbell St zone substation and associated land was omitted from projections as it was not recognised at the time that it would be a transmission asset.
- Cost of a site for Campbell St substation was greater than anticipated.
- Cost of 132kV connections to Sydney Central (now Haymarket) were under estimated as projections were based on typical unit rates for 132kV installation and it was not realised at the time that construction of cable tunnels would be necessary.

Project justification

This project is definitely the most documented of all EA transmission projects since it was the first evaluated (in conjunction with TransGrid) under the requirements of the amended ACCC Regulatory Test.

The supply of electricity to the Sydney CBD and inner suburbs is provided by EnergyAustralia's interconnected 132kV system that links TransGrid's 330kV substations at Beaconsfield, Sydney South and Sydney North. Joint planning studies undertaken by TransGrid and EA showed that by summer 2003/04 the present supply system would not meet appropriate network performance standards. In 1998 an economic analysis of possible augmentation options (including proposed cogeneration projects) was carried out by National Economic Research Associates (NERA). It was found that the optimum solution, in terms of the market benefits aspect of the ACCC Regulatory Test, was to augment the main supply system by:

- TransGrid installing a 330kV cable from Sydney South to a new 330/132kV supply point at Haymarket; and
- EnergyAustralia establishing a 132kV busbar at Surry Hills as part of the 132kV connections

In addition to the planning studies done by TransGrid and EnergyAustralia and the economic analysis carried out by NERA, independent analysis was carried out by both IPART and ACCC consultants. The ACCC consultants Ewbank Preece Pty Ltd, prepared a report in February 1999 'Review of Proposed Supply to the Sydney CBD' that considered all the relevant items: reliability criteria, capital costs, fuel costs, network support by embedded generation, lead times, demand side options, environment etc.

The process of planning approval for this project *exceeded* the NEC requirements in terms of consultations and treatment of demand side and embedded generation alternatives to network augmentation.

Consultation Opportunities

- A public forum was held to discuss the issues and receive verbal submissions (not an NEC requirement);
- The environmental lobby made formal submissions and attended the public forum; and
- Multiple of opportunities for input: draft cost effectiveness study; public forum; draft final report; 40 day dispute period (on price basis or application of process).

Independent Verification

A wide range of independent analyses was carried out including:

- An economic cost effectiveness analysis by National Economic Research Associates (NERA)
- An ACCC sponsored need/costing/engineering analysis by Ewbank Preece
- Independent review of the need & timing by Worleys International on behalf of IPART
- An independent forecasting analysis by National Institute for Economic and Industrial Research

Genuine response to Consultation

- All submissions were responded to and included in the Final Report
- All reports (including internal reports e.g. NERA paper) were placed on a website and forwarded to interested parties (including Total Environment Centre, Public Interest Advocacy Centre and Sustainable Energy Development Centre - SEDA)
- Supplementary submission data on available Demand Management and average costs received from SEDA was accepted at "face value" and included in sensitivity tests

Consideration of Alternative technology solutions and Greenhouse Gas implications

- Negotiations with large embedded generation/cogeneration proponents for network support were undertaken. (Network support payments on the basis of deferred investment, or avoided TUOS were not sufficient and market energy prices too low. No further approaches from such proponents have been received subsequently)
- A new 330kV cable does not promote energy use and greenhouse gas. In fact such a development reduces peak losses on the system by about 8 MW.
- The NSW DM Code was redrafted to put emphasis on market based approaches to DM

Second phase to include sourcing of DSM and cogeneration opportunities

The project consists of two phases:

- The first phase is the second 330 kV cable, substation and 132 kV works by summer 2003/04
- The second phase will include sourcing of DSM and cogeneration alternatives which may defer the need of the next third 330 kV cable. PlanningNSW included a development approval requirement that TransGrid and EnergyAustralia fund $10M for the primary purpose of providing robust, practical and accurate information about the extent to which demand reductions can be used in the Sydney basin and to identify specific distributed generation options that may defer further developments to the supply infrastructure.

Reliability Criteria

- The reliability criteria is bench marked to world practices adopted in similar type capital cities
- The Final Report (NERA) contains a table of the results of the bench marking survey
- The criteria adopted is less stringent than full (N-2) as it does not allow for 2 simultaneous outages in the 330 kV system (i.e., outage of only one 330 kV cable is assumed.)

It should also be noted that a review in March 2003 by Sinclair Knight Merz (SKM) concluded that this project appeared prudent in terms of need, timing and cost.

Documentation: The final NERA Report, SKM Prudence Report.

- Beresfield 132/33kV Subtransmission Substation

No allowance was made in the previous capex submission for this project as the project requirement was not anticipated at the time of the submission.

The expected expenditures for the current regulatory period is $12.4m with the balance in the next regulatory period.

Project justification

The supply capacity and security for loads fed from the Kurri Kurri subtransmission substation (STS) is inadequate. There is high residential growth in the East Maitland/Tarro area in addition to associated commercial load. This load cannot be supplied by the firm capacity of the existing subtransmission network.

Kurri STS load peaked at 192MVA in January 2003, which is 141% of the existing firm capacity. The load forecast is expected to increase to over 209MVA by the 2004/05 summer, which is above total installed capacity i.e. any equipment failure would necessitate customer load shedding.

The STS is located some distance from adjacent STS and all available low cost load transfers have been completed in December 2002. A transformer outage at Kurri STS could therefore require load shedding of up to 73MVA, for up to 15 hours a day, by the 2004/05 summer unless measures are taken to provide load/capacity relief.

Tomago STS load peaked at 150MVA in January 2003, which is 110% of the existing firm capacity. The STS is forecast to experience loads over 124MVA by the 2004/05 summer, actual peak loads have been above this forecast due to delays in other minor projects.

A planning investigation commenced in 1999 into future supply requirements for the area which progressed to a Value Management Study with endorsement of a preferred strategy in April 2002. The establishment of a new 132/33kV STS at Beresfield is the cornerstone of the preferred strategy. Siting investigations and negotiations have been ongoing since 2001.

The proposed Beresfield 132/33kV STS project will ensure residents and businesses in the Lower Hunter enjoy an acceptable standard of electricity supply reliability and will provide well overdue load relief for Kurri and Tomago substations. A more recent value management study has supported the proposed supply development strategy.

Alternative reinforcement options were considered but this was the least cost option. Studies were also carried out by the Sustainable Energy Unit into the possibility of demand management options. These were not viable because of the large supply capacity shortfall and high growth.

Funding of $24.3M is approved for the Beresfield Sub Transmission Substation and construction has commenced.

SKM assessed the project as a prudent investment required to overcome significant and multiple system constraints under single contingency conditions. They also declared the magnitude of the investment appeared appropriate.

Documentation: Planning Reports, Economic Evaluation, SKM Prudence Report

6. Conversion of Wyong and Charmhaven Zones to 132/11kV and the construction of Tuggerah to Munmorah 132kV feeder

This works program comprised three different projects which were included in EnergyAustralia's 1997 IPART submission:

• Construction of a 132kV Line from Tuggerah-Munmorah	$5.0m
• Construction of a 132/11kV zone substation at Wyong[1]	$9.9m
• Construction of a 132/11kv zone substation at Charmhaven[1]	$10.4m
Total	$25.3m

Initial project work commenced in 1998. Subsequently, $4.5m of expenditure associated with the remaining line construction was included in EnergyAustralia's transmission capex projections for the period 2000-04. None of the expenditure associated with the construction of 132/11kV zone substations at Wyong and Charmhaven was included in the transmission projections. It was subsequently realised that these substations were transmission exit points and should have been regarded as transmission capex.

The total actual cost of the project was very close to the approved budget of $25.3m.

Project justification

The conversion of the Wyong and Charmhaven zone substations and construction of the transmission feeder was undertaken to improve the reliability of the existing network, reduce system losses, replace some aged assets and cater for high demand growth (4%) over the next ten to fifteen years. The peak loading on the existing 33kV network prior to completion of the conversion works was in fact in excess of the network's firm capacity with a real risk of load shedding for any equipment failure.

The project was jointly planned, inter alia, as an interim solution to the growing TransGrid bulk supply deficit for the Central Coast. It was actually identified as an optimum solution in an early 1997 Value Management Study and received Board approval before the Regulatory Test requirements became operable.

The project provided for:

- The deferment of $21.8m (nominal) expenditure by TransGrid ($10.5M until 2004 and a further $11.3M til 2008).
- Elimination of substation overloads and added capacity for growth
- Improvement of network security to within planning guidelines
- Improvement of reliability to an area with nearly three times the customer minutes lost than the organisational average
- Replacement of aged equipment (> 44 years old) with increasing operating costs
- Reduction of system losses

The project was deferred from 1999 to 2000 through the application of risk management principles. However, further deferral had unacceptable risks to end use reliability.

The Value Management Study considered a range of project alternatives including the potential for demand reduction, the application of risk management (adopted in deferring the investment), alternative supply options (small and large scale local generation) and alternative transmission developments. On a 'least cost' basis the proposed option was substantially less than the alternatives.

An extremely involved community consultation process was undertaken for the feeder component of this project. Prior to the preparation of the EIS, EnergyAustralia elected to undertake a Route Options Report that included a consultation phase involving both the community and government authorities. The purpose of the report was to select a route that would form the basis of the EIS. The extensive consultation included newspaper articles, information pamphlets, community information meetings, radio and television interviews, an information toll free telephone number, technical information brochures and site meetings in response to requests from the community.

[1] Construction replaced an existing aged 33/11kV substation.

EnergyAustralia presented route options to the community and interested parties with an open invitation to suggest alternatives. All public concerns were taken into account and assessed along with a comparison of technical and financial impacts of all options.

SKM assessed the project as a prudent investment in terms of cost and scope and stated that on the basis of energy at risk and reliability of supply the investment could not have been deferred any further.

Documentation: Value Management studies, Economic Evaluatio1n, SKM Prudence Report

Comparison of actual and allowed Capital Expenditure for current Determination period 1999-2004 (real 03/04 $)

Pricing inflation rate			1.85%	2.92%	4.40%	3.00%							
Nominal to real 03-04 inflator			1.13	1.11	1.08	1.03	1.00	real 99-00 to real 03-04 inflator:			1.127		
		ACCC Regulatory Accounts						Allowed CAPEX					
Transmission projects real 03-04 $000's	**Proj. ID**	**Total '00 - '04**	**2000**	**2001**	**2002**	**2003**	**Forecast 2004**	**Total '00 - '04**	**2000**	**2001**	**2002**	**2003**	**2004**
Growth													
Total Growth	**A**	**104,290**	**809**	**8,375**	**29,207**	**27,300**	**38,600**	**43,397**	**7,327**	**7,890**	**5,636**	**16,908**	**5,636**
Replacement & Compliance													
Total Replacement & Compliance	**B**	**30,952**	**18,739**	**1,555**	**2,416**	**743**	**7,500**	**37,874**	**4,960**	**9,243**	**10,257**	**8,905**	**4,509**
Other	C	**1,727**	32	957	532	207	-	**7,890**	225	338	5,072	2,254	-
Total	**A+B+C**	**136,970**	**19,580**	**10,886**	**32,155**	**28,250**	**46,100**	**89,161**	**12,512**	**17,472**	**20,966**	**28,067**	**10,145**
Variance in total		**47,809**	**7,068**	**(6,585)**	**11,189**	**183**	**35,955**						