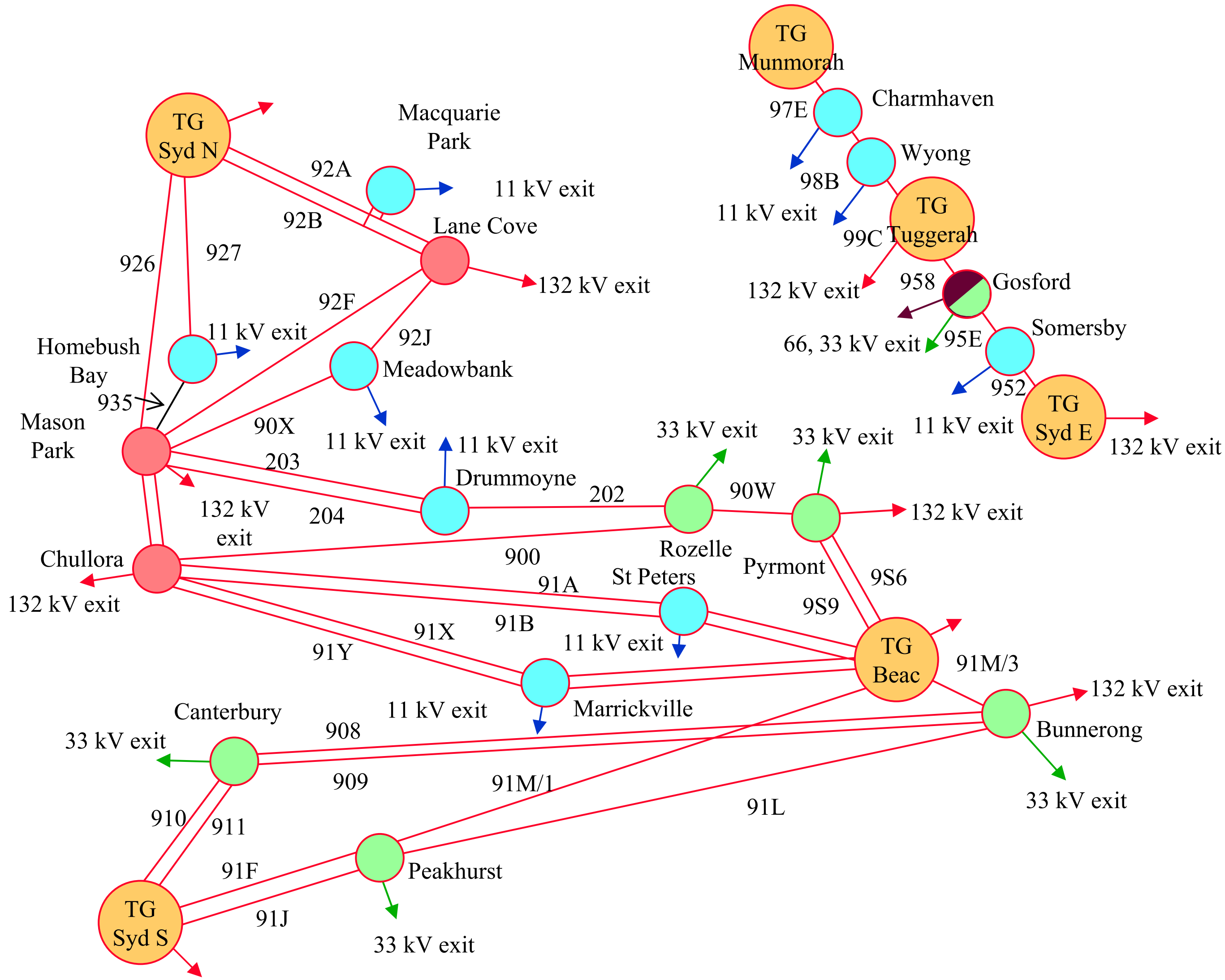
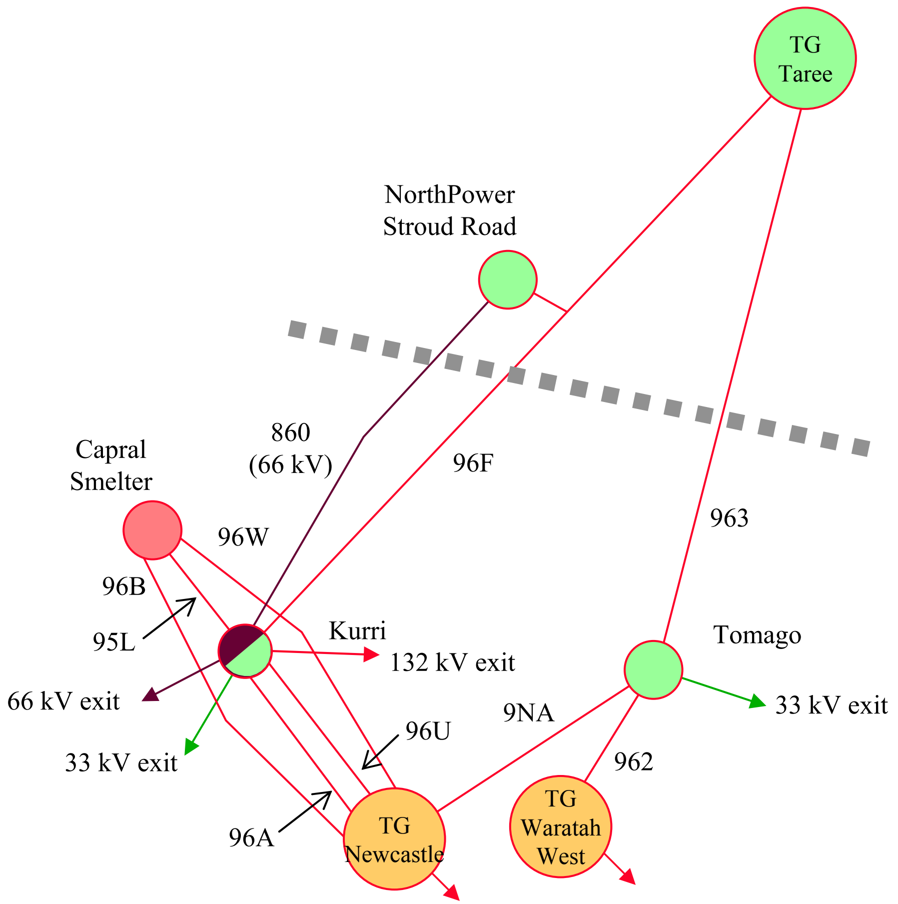
Schematic representation of EnergyAustralia's Transmission Assets

As at 1 July 2004

Sydney and Central Coast areas



Newcastle area



Changes to the configuration of EnergyAustralia transmission network assets

New Parallel and Supporting Assets at 1 July 2004

August 2003

This information is provided in response to questions pertaining to the changing operation and configuration of EnergyAustralia's transmission network assets. The Code's definition of transmission assets will result in several distribution assets being reclassified as transmission assets during the next regulatory period (2004-2009). This information is provided in good faith to both IPART and ACCC.

Purpose of information

The information contained in this document relates to assets that EnergyAustralia considers will be transmission assets from 1 July 2004. The document identifies the specific network elements whose function will change from a distribution function to a transmission function. It provides justification for the change in function on a similar basis to that provided by Erldunda Associates in their recent report to the ACCC.

This document **does not** contain a list of all of EnergyAustralia's transmission assets. This information is already available to the ACCC in the report written by Erldunda Associates in May 2003 and the information will be provided to ACCC in EnergyAustralia's submission relating to the transmission revenue cap due in September 2003. This document merely provides information to explain changes to the network since the Erldunda report was completed. This report therefore focuses on the assets that will change classification from distribution to transmission prior to the beginning of the regulatory period beginning on 1 July 2004.

As a result of changing functions, these network assets will move from regulation under IPART to regulation by the ACCC. This has ramifications for the regulatory asset base, and the capital and operating expenditure of the transmission and distribution businesses owned by EnergyAustralia. This document **does not** contain a valuation of the distribution assets that will be classified as transmission assets. Asset valuation information will be provided in a separate document to both ACCC and IPART to ensure that there is no double counting of assets in the transmission and distribution asset bases as at 1 July 2004.

This document also identifies assets that are likely to change their function after 1 July 2004 but during the next regulatory period (ie between 1 July 2004 and 30 June 2009). EnergyAustralia proposes that these changes in asset classification be ignored for regulatory purposes during the regulatory period (ie. that assets be treated as distribution or transmission for 2004-09 depending on whether they are distribution or transmission as at 30 June 2004) and moved between the distribution and transmission business at the completion of the regulatory period (ie at the 2009 reset). This removes the complexity of changing the allocation of assets between the distribution and transmission regulatory asset bases.

Changes in Classification of EnergyAustralia's Assets

The national Electricity Code defines a transmission network as

"A network within any participating jurisdiction operating at nominal voltages of 220 kV and above plus:

(a) any part of a network operating at nominal voltages between 66 kV and 220 kV that operates in parallel to and provides support to the higher voltage transmission network;

(b) any part of a network operating at nominal voltages between 66 kV and 220 kV that does not operate in parallel to and provide support to the higher voltage transmission network but is deemed by the Regulator to be part of the transmission network. "

EnergyAustralia's transmission network comprises 132kV and 66kV transmission elements that operate in parallel and provide support to TransGrid's network. Associated with these transmission elements are a number of transmission connection points which provide supply at 66kV, 33kV or 11kV to EnergyAustralia's transmission customers. EnergyAustralia's principal transmission customer is the EnergyAustralia distribution network.

Asset Classifications 2000-2004

EnergyAustralia's Transmission assets in 2000 were comprised of 66kV and 132kV elements in the Hunter valley and 132kV elements in the inner Sydney Metropolitan area.

In the period 2000-2004 work on the NSW Central Coast network provided new transmission assets and changed power flows through the existing system. As a result following completion of a new 132kV connection between Ourimbah and Gosford some assets that were considered to be distribution assets in 2000 will be reclassified in 2004 as transmission.

Hunter Assets

In the Hunter 132kV TransGrid lines run from Energy Australia substations at Kurri and Tomago to Taree and then further north to through Port Macquarie and Kempsey to Armidale. 132kV supply to Tomago and Kurri is provided by a network of EnergyAustralia lines emanating from TransGrid's Newcastle 330/132kV substation. An EnergyAustralia 66kV feeder from Kurri also operates in parallel with the 132kV lines.

The 132kV network including EnergyAustralia's feeders operates in parallel with the 330kV system and loading is partially determined by flows on the QNI. The transmission components of the Hunter system were identified as Transmission assets in 2000.

It is anticipated that construction of a new transmission exit point at Beresfield will be completed in 2004.

There were no assets in the Hunter whose classification changed between Distribution and Transmission during that period.

Inner Sydney Metropolitan Assets

High capacity supply to the Inner Metropolitan area is provided by a network of EnergyAustralia 132kV elements emanating from TransGrid substations at Sydney North (Dural) Sydney South (Picnic Point) and Beaconsfield West. As 330kV supply to Beaconsfield West is provided by only a single 330KV cable, EnergyAustralia's 132kV network must supply load to the inner suburbs when supply from Beaconsfield is unavailable. To achieve this EnergyAustralia operate a high capacity network linking the three TransGrid substations. This network parallels TransGrid's 330kV system and its components were classified as transmission assets in 2000.

In the period since 2000 EnergyAustralia has carried out major work to support the transmission supply to the inner metropolitan area. This work has arisen as the result of Joint Planning with TransGrid and has involved substantial expenditure on EnergyAustralia's transmission and distribution systems.

Work is presently in progress to provide connections to TransGrid's new Haymarket 330/132kV substation which will result in new transmission and distribution assets and a change in the categorisation of some assets. This work involves

- the construction of a substantial cable tunnel containing both transmission and distribution cables
- turning two existing transmission circuits into Haymarket (to form 4 transmission circuits).
- installation of one new transmission circuit and the extension and reforming of one distribution circuit as a transmission circuit.
- establishment of a new transmission connection point at Campbell St
- installation of six new 132kV distribution circuits.

It should be noted that whilst major distribution projects such as the interconnection of Bankstown and Greenacre Park substation were carried out to support the transmission system, such projects are classified as distribution projects and do not form part of this submission.

In the period 2000-2004 the only assets whose classification has changed from distribution to transmission is feeder 9SA. In 2000 this feeder operated radially from Beaconsfield West, supplying load in the Sydney CBD and eastern suburbs. In conjunction with the construction of TransGrid's Haymarket substation this feeder will be extended to the new Campbell St substation and will become one of three interconnectors between TransGrid's Haymarket and Beaconsfield substations.

Feeder 9SA must be regarded as transmission because:

- It operates in parallel with TransGrid's 330kV feeder 42 in conjunction with EnergyAustralia's other metropolitan transmission assets.
- Outages of 330kV feeders 41 and 42 can only be accommodated due to the presence of feeder 9SA and the two other Haymarket-Beaconsfield interconnectors. As there is only a single 330kV supply to Haymarket substation, supply could not be maintained to Haymarket without the presence of 132kV interconnectors such as 9SA. Feeder 9SA also provides transfer capacity to help accommodate an outage of cable 41 which is the only 330kV supply to Beaconsfield.
- Removal of the 132kV Haymarket-Beaconsfield interconnectors (including 9SA) would require the provision of an additional 330kV cable to Haymarket to cater for the loss of 330kV feeder 42.
- There is a need to coordinate the operation of the 330kV cable supplies to Haymarket and Beaconsfield and the 132kV system to maintain acceptable system security.
- The Haymarket project was jointly planned using Transgrid 330kV assets and EnergyAustralia 132kV assets to produce an optimum, least cost arrangement.

Central Coast Assets

In 2000, 132kV supply to the Cental Coast was normally provided from TransGrid's Vales Point and Tuggerah 132kV supply points. TransGrid Tuggerah substation has only a single transformer and 330kV feeder. When 132kV supply from Tuggerah is not available, Gosford and Somersby are supplied from TransGrid's Sydney East substation via a single overhead 132kV line. Whilst the EnergyAustralia's 132kV system runs in parallel with the transmission system to link Tuggerah and Sydney East (Belrose), power flows between Tuggerah and Sydney East in 2000 were negligible. Consequently in 2000, the lines to Gosford and Somersby were not considered to be transmission assets. At that time Ourimbah substation was supplied radially from Vales Point and thus Ourimbah and its associated 132kV lines could not be regarded as a transmission asset.

In 2001 a new 132kV connection was completed between Munmorah and Tuggerah. This connection supplied new zone substations at Charmhaven and Wyong and provided 132kV capacity to Tuggerah when the normal supply from the 330kV system was out of service. Power flows through this connection in Winter 2003 are anticipated to be up to 70MW during normal system conditions, increasing to 140MW if the supply from Tuggerah is out of service. As the Tuggerah-Munmorah connection “operates in parallel to and provides support to” the transmission network, it has always been a transmission asset. The two zone substations supplied from this interconnection are transmission connection points.

In 2001, a 132kV feeder reactor was installed at Ourimbah substation and the 132kV lines supplying Ourimbah were closed. This placed the 132kV feeders 957 and 95C in parallel with the 330kV system, providing additional support to TransGrid’s Tuggerah 330/132kV substation and increasing the security of supply to Ourimbah substation.

EnergyAustralia is presently constructing a new 132kV connection between Ourimbah and Gosford. This work will supply a zone substation at West Gosford and to increase supply capacity to Gosford and Somersby substations. This work was originally considered to be a distribution project since it linked two parts of EnergyAustralia’s distribution network[1].

The three changes detailed above will cause power flows between the Central Coast and Sydney East to increase. When the Ourimbah to Gosford link is commissioned in 2004, power flows to Sydney East are expected to be about 40MW. This can no longer be considered to be negligible.

EnergyAustralia’s 132kV system on the Central Coast “operates in parallel to and provides support to” the TransGrid system. It is proposed to classify the Central Coast 132kV feeders as transmission assets from June 2004. The substations connected to the Central Coast 132kV system will then be classified as transmission connection points. This reclassification will result in the following being reclassified from distribution to transmission assets.

Feeder 957	Vales Point – Ourimbah
Feeder 95C	Ourimbah – Tuggerah
Feeder 951	Ourimbah – West Gosford
Feeder 958	Tuggerah – Gosford
Feeder 956	West Gosford – Gosford
Feeder 95E	Gosford – Somersby
Feeder 95Z	Somersby – Mt Colah

Ourimbah subtransmission substation
Gosford sub transmission substation
West Gosford zone substation
Somersby zone substation
Mt Colah switching station.

The above assets must be regarded as transmission because -

- The 132kV feeders operate in parallel with TransGrid’s 330kV system between the Central Coast and Sydney.

[1] This work could not be regarded as transmission unless the 132kv lines from Gosford to Sydney and from Vales Point and Tuggerah to Gosford were also transmission.

- Outages of 330kV feeders 21 or Tuggerah 330/132kV substation can only be accommodated because of the presence of the above EnergyAustralia feeders. As there is only a single 330kV supply to Tuggerah substation, supply could not be maintained to the southern Central Coast without the presence of the above 132kV feeders.
- Removal of the 132kV feeders would require the provision of an additional 330kV feeder and transformer at Tuggerah to cater for an outage of TransGrid's feeder 21 or the single Tuggerah transformer. Alternate 132kV feeders would also be required.
- There is a need to coordinate the operation of the 330kV cable supplies to Tuggerah and the 132kV system to maintain acceptable system security.
- The Central Coast supply system was originally planned by TransGrid. The system has been jointly planned since 1990 to produce an optimum, least cost arrangement.

Asset Reclassification 2004-2009

The proposed transmission works program for the period 2004-09 will be summarised in our submission to ACCC relating to EnergyAustralia's transmission revenue reset.

The works program will result in the construction of new transmission assets during the period. It is also anticipated that some assets will change classification during the period. EnergyAustralia proposes that these assets be treated as either distribution or transmission throughout the 2004-09 regulatory period depending on whether they are classified as distribution or transmission at 30 June 2004. Changes during the period would be reconciled at the start of the subsequent (ie 2009) reset.

Hunter Assets

Whilst new transmission assets will be added between 2004-9 no change in the classification of assets is anticipated

Inner Sydney Metropolitan Assets

It is envisaged that in addition to new work, changes to the classification of a number of assets will be required

A change in the operating arrangements a Rozelle in early 2005 will result in feeder 900 operating radially. When this occurs feeder 900 should be re-classified as a distribution asset.

The replacement of feeders 908 & 909 with new feeder linking Kurnell to Bunnerong will change the operating mode of several elements in the Inner Metropolitan system. The new feeders to Bunnerong will be linked to TransGrid's, Sydney South substation by a double circuit tower line (feeders 916 & 917). When the replacement cables are complete these feeders will operate in parallel with the 330kV system and will be reclassified as transmission assets. Kurnell 132/33kV substation will become a transmission connection point and will also be reclassified.

The 132kV feeders from Sydney South to Canterbury, tee Chullora will remain as transmission assets as they will continue to operate in parallel with the transmission system between Sydney South and Chullora. Canterbury Substation will continue to be a transmission connection point.

When TransGrid's new 330/132kV supply point is established in the Chullora area it is likely that the existing Distribution feeders 240 & 240 will be used to connect the new supply point to the rest of the Inner Metropolitan system. When this occurs these feeders will be reclassified as transmission assets.

Central Coast

Whilst new transmission assets will be added during the period no change in the classification of existing assets is anticipated.

Attachment 3

EnergyAustralia™

EnergyAustralia Network Region Global Electricity and Customer Number Forecasts

2002-2009

April 2003

Attachment 3

Document Change Control

Version	Date	By	Change Description
1.0	9 October 2002	P Gannon	Original Draft – to GM/Network. Source load data does not include embedded generation.
2.0	31 January 2003	P Gannon	Source load data amended to include embedded generation. (Trends and forecast growth rates not materially affected by change in source load data). Editing changes.
3.0	1 April 2003	P Gannon	March review of economic and demographic assumptions.

Contents

1 EXECUTIVE SUMMARY

1.1 Background and Objectives

This report sets out forecasts of electricity usage and customer numbers for the period 2001/02 – 2008/09. The forecasts are "global", focusing on the overall demand for electricity and associated customer numbers within the EnergyAustralia Network region. It should be noted that loads associated with the VAW aluminium smelter and BHP Billiton are excluded from the forecasting analysis.

Objectives of Forecasts

Medium-term forecasts of the following indicators are necessary for key aspects of strategic planning:

- Energy consumption forecasts (in GWh) form the volume basis for projecting network revenue and for assisting in the setting of appropriate network tariffs.
- Peak demand forecasts (summer and winter, in MW) are used to validate and establish the upper bound to the load forecasts that are derived at the sub-transmission and zone substation levels. These spatial/zonal forecasts, prepared independently by Network Capital Planning, are one of a number of key inputs to Network capital expenditure projections. Linking the global peak and spatial demand forecasts in this way ensures consistency in the parameters used in both the revenue and capital expenditure planning functions.
- Customer number forecasts form the basis for estimating future customer connection levels, which are another input to capital expenditure projections.

Overview of Forecasting Process

The global forecasts presented in this report are based on modelling and analysis of historical and expected trends in energy market, economic and demographic conditions in the EnergyAustralia Network region. The impacts of the following drivers are considered in developing the forecasts:

- Economic activity;
- Residential customer numbers and customer characteristics, including appliance holdings;
- Electricity and gas prices;
- Fuel substitution and energy market share trends, including competition from natural gas and solar fuel sources;
- Energy efficiency improvements and environmental impacts;
- Short-term abnormal weather and daytype impacts; and
- The political, economic and market uncertainties associated with future trends in the above issues.

The analysis features a disaggregated approach. The prospects for the Residential and Non-Residential sectors are assessed and forecasted independently using robust statistical models.

In recognition of the inherent uncertainty in predicting future trends in the drivers of electricity consumption, a range of projections corresponding to three plausible economic and energy market scenarios (high, expected and low growth) has been analysed. The detailed economic and demographic projections in each scenario have been provided by the National Institute of Economic and Industry Research (NIEIR), the organisation that develops the scenarios used by Transgrid for inclusion in NEMMCO's annual Statement of Opportunities. The scenarios that underpin the global forecasts are consistent with those used in the Statement of Opportunities.

Future Forecast Reviews

A feature of the forecasting process is routine review of the forecasts. Variances between forecast and actual consumption are analysed for the impacts of abnormal weather and erroneous input assumptions. This routine review process suggests whether forecast consumption levels are on target or are tracking closer to the high or low growth scenario outcomes.

Energy consumption (in GWh) is monitored on a monthly basis with the view to isolating the impacts of abnormal weather and daytypes, thus enabling the underlying trend in consumption to be identified.

Formal review and revision of the forecasts takes place in September and March of each year, at which time the seasonal winter and summer peak demand forecasts are also reassessed.

1.2 Electricity and Customer Number Forecasts 2003/04 – 2008/09

The forecast growth rates for the upcoming IPART regulatory period are summarised in Table 1.1.

Table 1.1: EnergyAustralia Network – Summary Forecast Growth (% p.a, 2003/04 – 2008/09)

	High Growth Scenario	EXPECTED GROWTH	Low Growth Scenario
Energy Consumption	**2.5%**	**1.8%**	**1.0%**
Summer Peak Demand	**3.8%**	**2.9%**	**1.6%**
Winter Peak Demand	**1.9%**	**1.4%**	**0.8%**
Residential Customer Numbers	**1.2%**	**1.0%**	**0.7%**
Non-Residential Customer Numbers	**1.5%**	**1.1%**	**0.7%**
Total Customer Numbers	**1.2%**	**1.0%**	**0.7%**

Annual Energy Consumption (and Customer Number) Forecasts

Over the 2004-09 IPART determination period, annual energy consumption is projected to grow at an average 1.8% p.a. with a possible growth range of between 2.5% and 1.0% p.a. This projected growth is below the average growth expected for the current regulatory period. The expected lower growth outlook is due to a combination of the following factors:

- Lower Economic Growth in EnergyAustralia region: A weak global economic outlook, the impact of the drought, uncertainty surrounding the Middle East and increasing household debt levels are expected to combine to dampen overall economic activity. Compounding this, EnergyAustralia's share in NSW growth is expected to decline as western Sydney attracts increasingly more activity when transport and infrastructure improvements take effect.
- Lower Growth in Residential Customer Numbers: Customer number growth is expected to return to near long-term average rates after experiencing above-average growth over the past five years. Recent growth has been fuelled by a combination of rapid growth in inner-Sydney apartments, an upturn in urban consolidation, and generally strong dwelling building activity associated with low interest rates and the first home owner's grant.
- Stabilisation of Average Consumption per Residential Customer: The recent rapid growth rate in air conditioning stocks is expected to slow as penetration nears saturation levels and weaker economic conditions impact on household income. As well, the penetration of natural gas, both in terms of number of customers and end-use applications, will accelerate as a result of Gas Industry deregulation. The utilisation of solar energy is also expected to increase in response to efficiency and technological improvements.
- Energy Efficiency Improvement: Ongoing end-use efficiency improvements will continue, as will public awareness of energy efficiency and demand side management issues.

Peak Demand (MW) Forecasts

The recent experience whereby summer peak demand has significantly outgrown winter peak demand is expected to continue. On a weather corrected basis:

- Summer peak demand is forecast to grow at an average 2.9% p.a. (possible range 3.8% to 1.6% p.a.).
- Winter peak demand is forecast to grow at an average 1.4% p.a. (possible range 1.9% to 0.8% p.a.).
- The forecast differential in growth is such that given average weather conditions in the future, the network is expected to become consistently summer peaking in the summer of 2004/05. However due to the sensitivity of peak demands to deviations from average weather, it is possible that the summer peak demand could exceed winter peak demand as early as 2002/03.

The impact of ongoing penetration of air conditioning has key implications for EnergyAustralia's Network business. The results of load research suggest that air conditioning loads have a disproportionately high impact on summer peak demand (which is an important driver of capital expenditure) as compared to annual energy consumption (and therefore revenue).

Detailed Forecasts

Table 1.2 sets out the detailed year-to-year electricity forecasts under the Expected, High and Low growth scenarios.

Table 1.3 sets out the customer number forecasts.

Table 1.2: EnergyAustralia Network - Global Energy and Peak Demand Forecasts

YEAR and SCENARIO		ENERGY PURCHASES (Financial Year)		PEAK DEMAND							
				WINTER (Winter of Year)				SUMMER (Financial Year)			
				Actual		WEATHER CORRECTED		Actual		WEATHER CORRECTED	
EXPECTED		**GWh**	*Growth*	**MW**	*Growth*	**MW**	*Growth*	**MW**	*Growth*	**MW**	*Growth*
2002	Actual	**26,648**	*0.9%*	4,985	*1.0%*	**5,003**	*2.0%*	4,460	*-5.0%*	**4,824**	*1.5%*
2003	Forecast	**27,000**	*1.3%*			**5,060**	*1.1%*	5,051	*13.3%*	**4,950**	*2.6%*
2004	Forecast	**27,490**	*1.8%*			**5,110**	*1.0%*			**5,070**	*2.4%*
2005	Forecast	**27,970**	*1.7%*			**5,190**	*1.6%*			**5,240**	*3.4%*
2006	Forecast	**28,450**	*1.7%*			**5,260**	*1.3%*			**5,400**	*3.1%*
2007	Forecast	**28,880**	*1.5%*			**5,320**	*1.1%*			**5,540**	*2.6%*
2008	Forecast	**29,430**	*1.9%*			**5,380**	*1.1%*			**5,670**	*2.3%*
2009	Forecast	**30,000**	*1.9%*			**5,470**	*1.7%*			**5,850**	*3.2%*
Average Growth 2004 - 2009	Forecast	***1.8%***				***1.4%***				***2.9%***	
HIGH CASE		**GWh**	*Growth*			**MW**	*Growth*			**MW**	*Growth*
2003	Forecast	**27,290**	*2.4%*			**5,080**	*1.5%*			**4,950**	*2.6%*
2004	Forecast	**28,190**	*3.3%*			**5,190**	*2.2%*			**5,170**	*4.4%*
2005	Forecast	**28,940**	*2.7%*			**5,310**	*2.3%*			**5,400**	*4.4%*
2006	Forecast	**29,600**	*2.3%*			**5,400**	*1.7%*			**5,600**	*3.7%*
2007	Forecast	**30,240**	*2.2%*			**5,500**	*1.9%*			**5,800**	*3.6%*
2008	Forecast	**31,040**	*2.6%*			**5,590**	*1.6%*			**5,990**	*3.3%*
2009	Forecast	**31,850**	*2.6%*			**5,710**	*2.1%*			**6,220**	*3.8%*
Average Growth 2004 - 2009	Forecast	***2.5%***				***1.9%***				***3.8%***	
LOW CASE		**GWh**	*Growth*			**MW**	*Growth*			**MW**	*Growth*
2003	Forecast	**26,730**	*0.3%*			**5,040**	*0.7%*			**4,950**	*2.6%*
2004	Forecast	**27,050**	*1.2%*			**5,070**	*0.6%*			**5,020**	*1.4%*
2005	Forecast	**27,330**	*1.0%*			**5,110**	*0.8%*			**5,120**	*2.0%*
2006	Forecast	**27,560**	*0.8%*			**5,150**	*0.8%*			**5,210**	*1.8%*
2007	Forecast	**27,850**	*1.1%*			**5,200**	*1.0%*			**5,300**	*1.7%*
2008	Forecast	**28,090**	*0.9%*			**5,220**	*0.4%*			**5,340**	*0.8%*
2009	Forecast	**28,390**	*1.1%*			**5,270**	*1.0%*			**5,440**	*1.9%*
Average Growth 2004 - 2009	Forecast	***1.0%***				***0.8%***				***1.6%***	

Table 1.3: EnergyAustralia Network – Customer Number Forecasts

YEAR and SCENARIO		Residential Customers (as at 30 June)		Non-Residential Customers (as at 30 June)		TOTAL Customers (as at 30 June)	
EXPECTED		**Number**	*Growth*	**Number**	*Growth*	**Number**	*Growth*
2002	Actual	**1,314,973**	*1.1%*	**149,397**	*3.0%*	**1,464,370**	*1.3%*
2003	Forecast	**1,328,100**	*1.0%*	**150,500**	*0.7%*	**1,478,600**	*1.0%*
2004	Forecast	**1,344,200**	*1.2%*	**151,700**	*0.8%*	**1,495,900**	*1.2%*
2005	Forecast	**1,356,800**	*0.9%*	**153,500**	*1.2%*	**1,510,300**	*1.0%*
2006	Forecast	**1,372,300**	*1.1%*	**155,100**	*1.0%*	**1,527,400**	*1.1%*
2007	Forecast	**1,382,900**	*0.8%*	**156,700**	*1.0%*	**1,539,600**	*0.8%*
2008	Forecast	**1,397,200**	*1.0%*	**158,100**	*0.9%*	**1,555,300**	*1.0%*
2009	Forecast	**1,410,900**	*1.0%*	**160,300**	*1.4%*	**1,571,200**	*1.0%*
Average Growth 2004 - 2009	Forecast	***1.0%***		***1.1%***		***1.0%***	
HIGH CASE		**Number**	*Growth*	**Number**	*Growth*	**Number**	*Growth*
2003	Forecast	**1,330,800**	*1.2%*	**150,700**	*0.9%*	**1,481,500**	*1.2%*
2004	Forecast	**1,358,200**	*2.1%*	**152,900**	*1.5%*	**1,511,100**	*2.0%*
2005	Forecast	**1,377,900**	*1.5%*	**155,400**	*1.6%*	**1,533,300**	*1.5%*
2006	Forecast	**1,392,900**	*1.1%*	**157,500**	*1.4%*	**1,550,400**	*1.1%*
2007	Forecast	**1,409,600**	*1.2%*	**159,600**	*1.3%*	**1,569,200**	*1.2%*
2008	Forecast	**1,424,400**	*1.0%*	**161,700**	*1.3%*	**1,586,100**	*1.1%*
2009	Forecast	**1,441,600**	*1.2%*	**164,500**	*1.7%*	**1,606,100**	*1.3%*
Average Growth 2004 - 2009	Forecast	***1.2%***		***1.5%***		***1.2%***	
LOW CASE		**Number**	*Growth*	**Number**	*Growth*	**Number**	*Growth*
2003	Forecast	**1,326,800**	*0.9%*	**150,000**	*0.4%*	**1,476,800**	*0.8%*
2004	Forecast	**1,338,400**	*0.9%*	**150,700**	*0.5%*	**1,489,100**	*0.8%*
2005	Forecast	**1,348,400**	*0.7%*	**151,900**	*0.8%*	**1,500,300**	*0.8%*
2006	Forecast	**1,360,000**	*0.9%*	**152,800**	*0.6%*	**1,512,800**	*0.8%*
2007	Forecast	**1,370,200**	*0.8%*	**154,100**	*0.9%*	**1,524,300**	*0.8%*
2008	Forecast	**1,377,300**	*0.5%*	**154,700**	*0.4%*	**1,532,000**	*0.5%*
2009	Forecast	**1,386,800**	*0.7%*	**156,000**	*0.8%*	**1,542,800**	*0.7%*
Average Growth 2004 - 2009	Forecast	***0.7%***		***0.7%***		***0.7%***	

2 INTRODUCTION

2.1 Background

The energy market in which electricity competes for market share has undergone significant change over the past two decades. At the same time the economic and demographic environments, which largely determine the size of the energy market, have experienced structural changes and fluctuating outcomes from year to year. These key factors which influence Network business performance will continue to undergo further and different forces of change in the future.

This ongoing change presents Network operators with the challenge to prepare reliable and timely forecasts on which to base effective strategic plans.

Reliable forecasts must capture the dynamics of both the energy market and the factors that influence the size of that market, in particular the level of economic activity and associated demographics, and customer behaviour characteristics. The issues that need to be considered in preparing reliable and defensible forecasts include:

- Fuel substitution and energy market share trends (competition from natural gas and solar fuel sources);
- Electricity and gas prices;
- Environmental issues and energy efficiency improvement trends;
- Economic activity;
- Residential customer numbers and customer characteristics, including appliance holdings;
- Short-term abnormal weather and daytype impacts; and
- The political, economic and market uncertainties associated with predicting future trends in each of the above issues.

This report sets out medium-term forecasts of EnergyAustralia Network region load which satisfy these criteria.

2.2 Report Layout

- Section 3	Forecast Methodology
- Section 4	Residential sector annual energy consumption and customer number forecast.
- Section 5	Non-Residential sector annual energy consumption and customer number forecast.
- Section 6	Winter and summer peak demand forecasts, including results from EA's load research programme.
- Section 7	Consolidation of energy and peak demand forecasts.
- Section 8	Customer number forecasts
- Appendix A	Economic and Demographic Projections
- Appendix B	Load Research – Pertinent Results
- Appendix C	Sensitivity Analysis

3 FORECAST METHODOLOGY

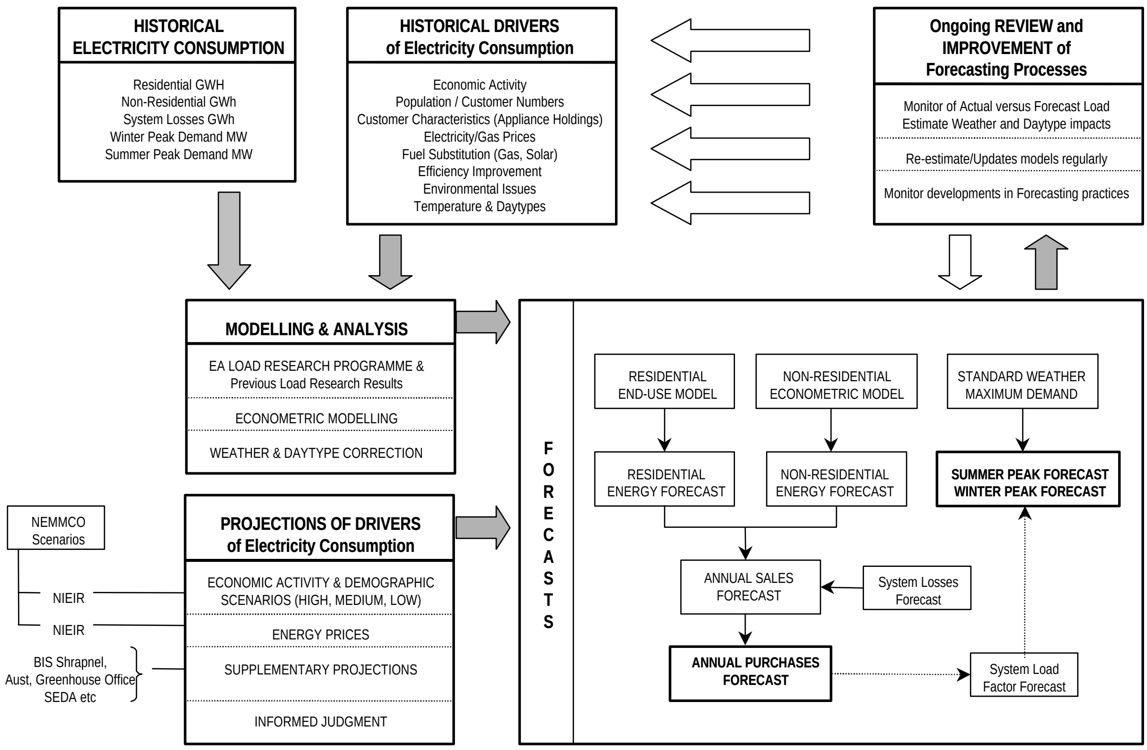
3.1 Overview of Forecasting Approach

The broad principles on which the global forecasts are based are:

- Consideration of electricity consumption in the context of the overall energy market;
- Segmentation of electricity consumption into homogeneous customer sectors, so as to capture the diversity among sectors with regard to electricity intensity and future growth prospects;
- Application of sophisticated forecasting and analytical techniques, including the estimation of weather impacts on loads to identify the true underlying trends in load growth;
- Modelling and analysis of the linkage between electricity consumption and the exogenous drivers of electricity consumption (economic, demographic and energy market issues);
- Adoption of a scenario approach in recognition of the uncertainty in predicting future trends in the drivers of electricity consumption, and to allow contingency planning around a range of plausible outcomes; and
- Ongoing evaluation, review and improvement of the forecasting approach and resultant forecasts. The forecasts are updated on a six-monthly basis, following winter and summer of each year, at which time any enhanced techniques, methodologies and assumptions are incorporated into the forecast processes.

Figure 3.1 illustrates the forecasting methodology.

Figure 3.1: EnergyAustralia Network Region Global Electricity Forecasts: Overview of Processes



Details of the processes employed in developing the forecasts are contained in the separate report “Global Energy Consumption and Peak Demand Forecast Processes”.

3.2 Details of Forecasting Approach – Drivers of Electricity Consumption

Table 3.1 sets out the medium-term global forecasting approach, focussing on the treatment for forecasting purposes of the key drivers of electricity consumption.

Table 3.1: Summary of Forecasting Methodology – Treatment of Key Consumption Drivers

Consumption Driver	Impact	Treatment	Outcome/Forecast Improvement
Daytpye	▪ Electricity consumption is considerably higher on workdays compared with non-workdays. ▪ Leap years – extra day of consumption ▪ Easter – March or April ▪ Loads around the Christmas Eve – early January period are significantly low due to industry/commerce vacation periods.	▪ Historical monthly loads are corrected to standard workday/non-workday month types.	▪ Standardisation process enables the underlying trend in load growth to be identified. ▪ Short-term forecasts allow for future known abnormal daytypes ▪ Longer-term forecasts allow for leap year impacts.
Weather	▪ Daily electricity consumption levels are clearly seasonal, being higher and more volatile from day-to-day in winter and summer.	▪ Historical monthly energy consumption is corrected to standard temperature conditions ▪ Seasonal peak demands are corrected to standard temperature conditions	▪ Standardisation process enables the underlying trend in load growth to be identified. ▪ Short-term forecasts allow for an assumed return to long-term average temperature. ▪ Derivation of "Standard Weather Peak Demand" enables the underlying trend in peak demand to be identified, and ensures that the starting point for the forecasts is not artificially inflated/deflated by abnormal weather.
Economic Activity	▪ Energy, including electricity, is a "factor of production" in economic growth. Economic growth occurs when either: - Companies use existing productive resources for longer periods (trading hours, multiple shifts). - Companies expand their productive resources through investment. - New companies enter industries. ▪ As a result, other things being equal, economic growth induces electricity consumption growth. ▪ Economic growth also has significant multiplier effects on residential sector electricity consumption: a proportion of households invest additional income in comfort and convenience appliances, or use existing appliances more extensively.	▪ Scenarios of future economic activity levels form a key input to long-term electricity forecasts ▪ Non-Residential energy forecasts are based on an econometric approach with drivers including economic activity included among the explanatory variables.	▪ Scenario approach allows contingency planning around a range of plausible future outcomes. This is appropriate given the uncertainty in the future economic outlook.

Consumption Driver	Impact	Treatment	Outcome/Forecast Improvement
Demographics/ Residential Customer Characteristics	▪ Population growth and associated dwelling construction is the key driver of residential customer numbers. More complex demographics, such as trends in household size (people per house) and type (house/unit), are also important determinants of holdings of particular appliances. ▪ Rapid penetration of Residential air conditioning is impacting on Summer peak demand growth	▪ Scenarios of future demographic trends form a key input to long-term electricity forecasts. ▪ Residential energy forecasts are based on an appliance/end-use modelling approach. ▪ EA has undertaken a detailed load research programme into Residential customer load profiling, concentrating on air conditioning usage. ▪ EA has invested in research which identifies trends in air conditioning penetration.	▪ Scenario approach allows contingency planning around a range of plausible future outcomes. This is appropriate given the uncertainty in the future economic outlook. ▪ Market intelligence in customer behaviour and characteristics is a key input to effective energy and peak demand forecasting. ▪ End-use approach allows complex sensitivity analysis to be undertaken. ▪ End-use approach allows impact of input assumptions on peak demand forecasts to be analysed.
Energy Market and Efficiency Issues	▪ Fuel Substitution: approximately 50% of residential electricity consumption (water heating, space heating and cooking) is potentially substitutable by other fuels. The availability and relative attractiveness of gas and solar will be a key determinant of future electricity consumption growth. ▪ Energy Efficiency: is an ongoing and growing phenomenon, as is customer awareness of associated environmental issues. ▪ Price Impacts: Price relativities between electricity and gas are important determinants of the degree of fuel substitution that takes place, while the own-price elasticity of electricity could be significant in an environment of increasing prices.	▪ Energy market analysis and projections form a key input to long-term electricity forecasts.	▪ End-use approach allows complex sensitivity analysis to be undertaken. ▪ End-use approach allows impact of input assumptions on peak demand forecasts to be analysed.

3.3 Scenarios of Future Movements in Drivers of Electricity Consumption

Detailed economic and demographic projections for each of three growth scenarios (Expected, High and Low growth) have been provided by the National Institute of Economic and Industry Research (NIEIR), the organisation that develops the scenarios used by Transgrid for inclusion in NEMMCO's annual Statement of Opportunities. The scenarios that underpin the global forecasts will be consistent with those used in the 2003 Statement of Opportunities.

Appendix A sets out the scenario projections and the key assumptions which underpin the forecasts set out in this report.

4 RESIDENTIAL SECTOR ENERGY CONSUMPTION FORECAST

4.1 Summary and Section Overview

Consumption by the 1.3 million Residential customers in 2001/02 was 9,567 GWh, which represented 38% of total Network region consumption. Residential consumption has grown rapidly in recent years, averaging 3.4% p.a. growth since 1996/97. The main drivers of this growth over the past 5 years have been:

- Relatively strong growth in customer numbers of 1.7% p.a., compared with growth of 1.3% p.a. in the early 1990's. The strong recent growth is an outcome of population and housing growth on the Central Coast, consolidation of urban building blocks, rapid growth in inner-Sydney apartments, and generally high levels of dwelling building activity.
- Strong growth in average consumption per customer of 1.7% p.a., compared with growth of 0.9% p.a. in the early 1990's. The strong recent growth largely reflects rapid penetration of lifestyle/comfort appliances, most notably air conditioning. This has been sufficient to offset the effects of declining penetration of off-peak water heating and electrical space heating in recent years.

Residential sector consumption growth is expected to slow markedly to an average 0.8% p.a. over the period 2003/04 – 2008/09. Factors contributing to the expected slowdown in growth include:

- Customer number growth is forecast to fall back to an average 1.0% p.a. due to a reduction in building activity.
- Average consumption per customer is forecast to decline marginally from 7,276 kWh in 2001/02 to 7,226 kWh in 2008/09. The positive growth impact of ongoing air conditioning penetration will be offset by declining penetration in electrical water heating, space heating and cooking, due to market share competition from natural gas and solar.

Residential consumption growth in the high and low growth scenarios is forecast to be 1.5% and 0.1% p.a. respectively.

4.2 Residential End-use Model Approach

Since the mid-1980's the NSW residential sector has been subject to considerable analysis and research at the end-use/appliance level. In particular the following research has provided insight into the energy consumption patterns of households:

- Household energy usage surveys conducted by the Australian Bureau of Statistics in 1984, 1985/86 and 1989;
- Time-of-use surveys conducted by the Electricity Supply Industry in 1986 and 1993/94. In particular, the 1993/94 Residential End-Use Study produced detailed consumption information down to the individual appliance level; and
- EnergyAustralia's current Load Research programme, commenced in 2000, is examining the electricity consumption patterns of a sample of some 230 households, including the collection of appliance consumption information in 90 of the sample households.

The availability of such information is sufficient to facilitate a detailed forecasting approach, down to appliance level. The end-use forecasting approach disaggregates total residential electricity usage into individual appliances or appliance groupings. The overall residential forecast is given by:

$$\text{GWh (year t)} = \Sigma\,(N^{i} * kWh^{i})$$

where	GWh (year t)	=	Residential Sector electricity consumption in year t
	N^{i}	=	Number of appliance ^{i} in residential sector in year t (*i = 18 appliances)*
	kWh^{i}	=	Average annual consumption by appliance ^{i} in residential sector in year t

The model is calibrated so that modelled historical consumption equates to actual known historical Residential energy consumption levels. The estimates for each year of the average consumptions of the weather-dependent appliances (air conditioning, space heaters, water heaters and refrigerators) are made having regard to the weather effects on overall energy consumption.

4.3 Residential End-use Model – Historical Estimates

Annual Consumption by Appliance

Figure 4.1 defines the 17 appliances in the model and depicts the estimated average consumption of each appliance in 2001/02. Table 4.1 sets out the source/sources of the appliance consumption estimates.

Figure 4.1

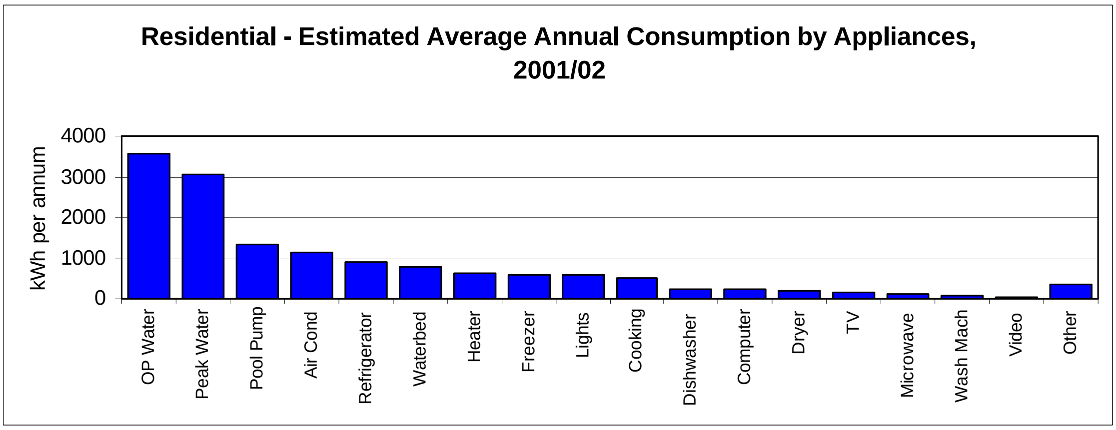


Table 4.1: Residential End-Use Model Inputs – Base Year (2001/02) Annual kWh Consumption by Appliance

Appliance	kWh p.a.	Source/Comments
Off-Peak Water	3581	Known from billing records
Peak Water	3050	Based on RES (2918 kWh pa)
Pool Pump	1350	RES (1353 kWh pa). Comparison: AGO (1000 – 3000 kWh pa)
Air Conditioning	1150	Based on EA Load Research 2000/01/02. Comparison: RES (Ducted 1026 kWh pa, Rev Cycle 698 kWh pa, Cool Only 216 kWh pa)
Refrigerator	900	Based on RES (944 kWh pa, 2nd fridge 828 kWh pa)
Waterbed	780	RES (773 kWh pa). Comparison: AGO (> 1000 kWh pa)
Space Heater	610	Based on RES (Room Heater 427 kWh pa, Ducted Heater 996 kWh pa)
Freezer	600	RES (648 kWh pa)
Lights	570	RES (566 kWh pa). Comparison: AGO (400 – 700 kWh pa)
Cooking	500	Based on RES (Stove 363 kWh pa, Oven 233 kWh pa, Cooktop 187 kWh pa) and AGO (600-700 kWh pa). Estimate allows for non-stove cooking appliances.
Dishwasher	250	Based on RES (227 kWh pa) and AGO (388 kWh pa)
Computer	242	AGO 242 kWh pa
Clothes Dryer	200	Based on RES (123 kWh pa) and AGO (240 kWh pa)
TV	174	Based on RES (157 kWh pa) and AGO (108 kWh pa for 3 hours TV per day). Allows for minor impact of cable TV penetration.
Microwave	130	Based on RES (67 kWh pa). Allows for increased microwave usage
Washing Machine	55	RES (55 kWh pa)
Video	22	AGO (22 kWh pa)
Other	340	Estimate to allow for iron, vacuum cleaner, portable tools, lamps, stereo, fish tanks etc.

Abbreviations: RES = 1993/94 Residential End-use Study; AGO = Australian Greenhouse Office.

In terms of average per customer electricity consumption the major end-uses are water heating, pool pumps, air conditioning and refrigerators. At the other end of the scale, video recorders, washing machines, microwaves, TVs, clothes dryers and computers use relatively little electricity over a year.

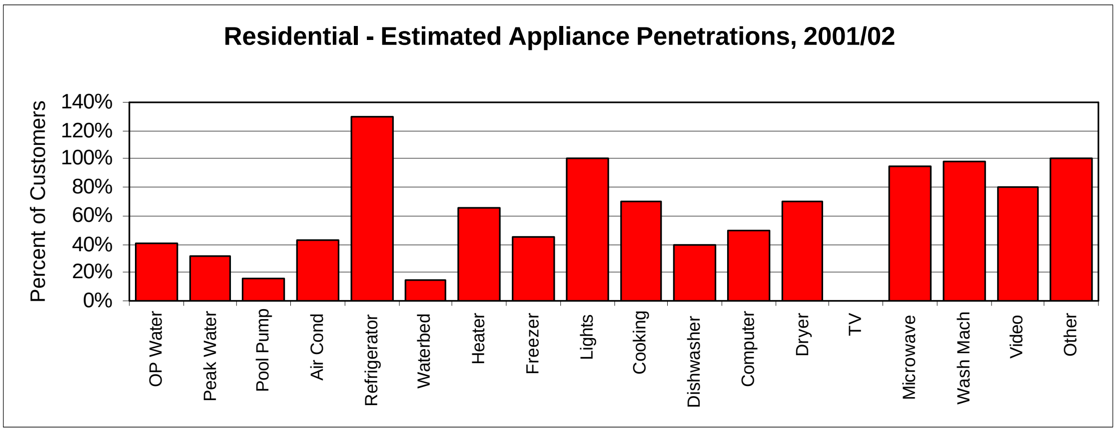
Number of Appliances

The procedure for estimating the total number of appliances in the Network region involves the application of estimated appliance penetration rates (that is, the percentage of customers holding each appliance) to total residential customer numbers.

Appliance Penetration Rates

Figure 4.2 illustrates the estimated penetration rate of each appliance in 2001/02. Table 4.2 sets out the sources of the appliance penetration estimates.

Figure 4.2



Note: TV not shown, estimated at 200%

Table 4.2: Residential End-Use Model Inputs – Base Year (2001/02) Penetration Rate by Appliance

Appliance	Percent of Households	Source/Comments
Off-Peak Water	40%	Known from billing records
Peak Water	32%	Extrapolated from ABS 85/86 (Sydney 40%, NSW 34%) & ABS 89 (Sydney 35%, NSW 30%). Allows for high proportion of home units in Sydney region
Pool Pump	16%	Extrapolated from ABS 85/86 (Sydney 10%) & ABS 89 (Sydney 14%)
Air Conditioning	43%	Based on EA market research 2000 (39% penetration) & confidential NIEIR air conditioning unit sales data
Refrigerator	130%	ABS 1997: 30% of households have additional fridges
Waterbed	15%	Extrapolated from RES (Sydney 13%, Other Metro 28%)
Space Heater	65%	Extrapolated from RES (Sydney 75%, Other Metro 60%)
Freezer	45%	Extrapolated from RES (Sydney 36%, Metro 64%) & ABS 1997: 44%
Lights	100%	
Cooking	70%	Extrapolated from ABS 89 (75%) & RES
Dishwasher	40%	Extrapolated from ABS 85/86 (19%), ABS 89 (24%) & RES (37%)
Computer	50%	Estimate
Clothes Dryer	70%	Extrapolated from ABS 85/86 (50%), ABS 89 (57%) & RES (66%)

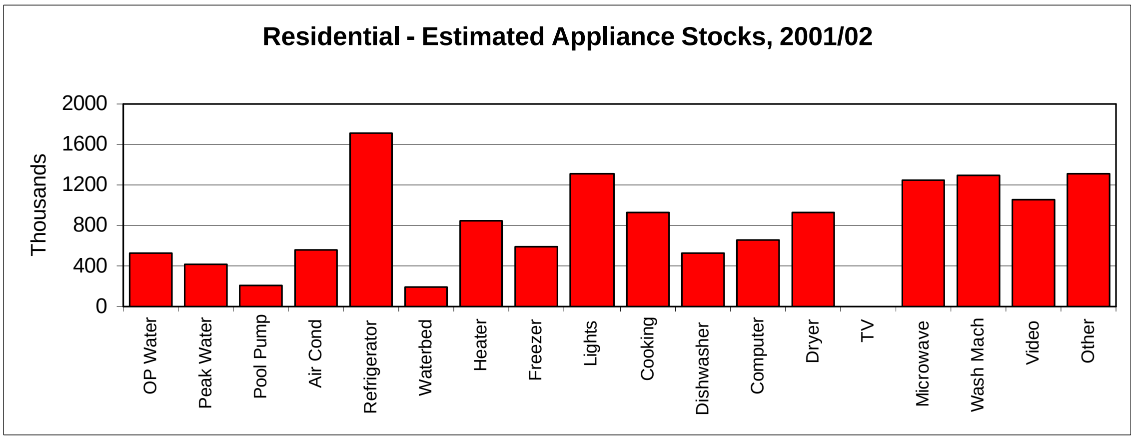
Appliance	Percent of Households	Source/Comments
TV	200%	Estimate (average 2 TVs per house)
Microwave	95%	Extrapolated from ABS 85/86 (34%), ABS 89 (56%) & RES (77%)
Washing Machine	95%	Based on ABS 85/86 (92%) & RES (96%)
Video	80%	Estimate
Other	100%	

Abbreviations: RES = 1993/94 Residential End-use Study; ABS = Australian Bureau of Statistics.

Appliance Numbers

Figure 4.3 illustrates the estimated stock of each appliance in 2001/02. Appliance stocks are derived by multiplying the estimated appliance penetration rates, as set out in Figure 4.2 above, by the number of residential customers.

Figure 4.3



Note: TV not shown, estimated at 2630 thousand based on 200% penetration

In terms of number of appliances, TVs, refrigerators, "lights", "other", microwaves and washing machines dominate. Nearly all households hold these appliances and multiple video/TVs and refrigerators in the one house are common.

Historical Model Calibration

The model has been calibrated so that for each of the years 1992/93 – 2001/02 the modelled consumption equates to known annual Residential sector sales.

4.4 Residential Sector Forecast Assumptions

The inputs required to produce the Residential sector end-use forecasts are:

- Forecasts of Residential sector customer numbers;
- Projections of future penetration rates for each of the 17 appliances; and
- Projections of future average annual electricity consumption rates for each of the 17 appliances.

These inputs are considered below.

Residential Customer Number Forecasts

Residential customer number forecasts are provided by NIEIR, using their "PopInfo" sociodemographic model and judgment as to future population and housing trends in the EnergyAustralia Network region.

Table 4.3 sets out the projected growth rates for number of households in the EA Network region.

Table 4.3: EnergyAustralia Network Region Household Number Projections

Year	Low Case	Historical and EXPECTED	High Case
2001/02		1.1%	
2002/03	0.9%	1.0%	1.2%
2003/04	0.9%	1.2%	2.1%
2004/05	0.7%	0.9%	1.5%
2005/06	0.9%	1.1%	1.1%
2006/07	0.8%	0.8%	1.2%
2007/08	0.5%	1.0%	1.0%
2008/09	0.7%	1.0%	1.2%
Average Growth, 2004 - 2009	0.7%	1.0%	1.2%

The expected case growth of 1.0% p.a. is below the growth experienced over the past five years. Recent household number growth has been influenced by a combination of rapid growth in inner-Sydney apartments, an upturn in multi-dwelling developments on what were previously single dwelling blocks of land, and generally strong dwelling building associated with low interest rates and the first home owner's grant. The projections reflect an expectation that household number growth will return to longer-term averages as recent building activity levels will not be sustained.

Appliance Penetration Forecasts

Appliance penetration forecasts rely on judgment based on in-house experience and historical trends in penetration rates. Table 4.4 sets out the projections assumed for forecasting purposes.

With the exception of air conditioning, any change in penetration rates between 2002 and 2009 is assumed to occur linearly. Air conditioning penetration growth is expected to be stronger in the first four years of the forecast period before tapering off, reflecting a degree of saturation of penetration.

In the Expected Case only air conditioning and computers are expected to increase penetration rates over the forecast period. An expectation that natural gas penetration will continue to erode electricity's share of the market is evident in the declining penetration rates for water heating, space heating and cooking.

Table 4.4: EnergyAustralia Network Region Appliance Penetration Estimates

End-Use	2002 Estimate	2009 Low Case		2009 EXPECTED		2009 High Case	
		Pen. Rate	*Change on 2002*	Pen. Rate	*Change on 2002*	Pen. Rate	*Change on 2002*
Off-Peak Water	40%	39%	*-2%*	40%	*-1%*	41%	*1%*
Peak Water	32%	31%	*-2%*	32%	*-1%*	33%	*1%*
Pool Pump	16%	15%	*0%*	16%	*0%*	16%	*1%*
Air Conditioning	43%	49%	*6%*	57%	*14%*	61%	*18%*
Refrigerator	130%	130%	*0%*	130%	*0%*	136%	*6%*
Waterbed	15%	15%	*0%*	15%	*0%*	16%	*2%*
Heater	65%	61%	*-4%*	62%	*-3%*	65%	*0%*
Freezer	45%	45%	*0%*	45%	*0%*	47%	*2%*
Lights	100%	100%	*0%*	100%	*0%*	100%	*0%*
Cooking	70%	66%	*-4%*	67%	*-3%*	70%	*0%*
Dishwasher	40%	40%	*0%*	40%	*0%*	42%	*2%*
Computer	50%	53%	*3%*	62%	*12%*	68%	*18%*
Dryer	70%	70%	*0%*	73%	*3%*	76%	*6%*
TV	200%	200%	*0%*	200%	*0%*	206%	*6%*
Microwave	95%	95%	*0%*	95%	*0%*	95%	*0%*
Washing Machine	98%	98%	*0%*	98%	*0%*	98%	*0%*
Video	80%	80%	*0%*	80%	*0%*	86%	*6%*
Other	100%	100%	*0%*	100%	*0%*	100%	*0%*

Average Annual Consumption Forecasts – Energy Efficiency Improvements

In general it is expected that the annual energy consumption estimates set out previously in Table 4.1 will hold for the forecast period. Exceptions to this rule are the end-uses set out in Table 4.5, where energy efficiency improvement factors have been built in to the forecasts.

Table 4.5: Residential End-Use Model Inputs – Annual Efficiency Improvement by Appliance

Appliance	Annual Efficiency Improvement	Source/Comments
Off-Peak Water	-9 kWh	AGO 1980-92 efficiency improvement – assumed to continue
Peak Water	-9 kWh	AGO 1980-92 efficiency improvement – assumed to continue
Air Conditioning	-1.0%	AGO 1980-92 efficiency improvement – assumed to continue
Refrigerator	-1.4%	AGO 1980-92 efficiency improvement – assumed to continue
Freezer	-0.2%	AGO 1980-92 efficiency improvement – assumed to continue
Lights	-0.3%	Assumed, impact of compact fluorescent lamps etc.
Dishwasher	-1.2%	AGO 1980-92 efficiency improvement – assumed to continue
Washing Machine	-0.5%	AGO 1980-92 efficiency improvement – assumed to continue

4.5 Residential Sector Forecast

The residential sector electricity consumption forecast is the product of:

- Projected customer numbers (see Section 4.4 above) and
- Projected annual average consumption, in kWh per customer. This is in turn is a function of the projected appliance penetration rates and the projected average annual consumption by appliance (see Section 4.4 above)

Table 4.6 sets out the Residential sector energy consumption forecast growth rates.

Table 4.6: EnergyAustralia Network Region Residential Energy Forecast

Year	Low Case	Historical and EXPECTED	High Case
2001/02		1.8%	
2002/03	-0.5%	1.1%	3.4%
2003/04	0.8%	1.4%	3.2%
2004/05	0.0%	0.6%	1.6%
2005/06	0.2%	1.0%	1.5%
2006/07	0.1%	0.6%	1.6%
2007/08	0.2%	1.2%	1.7%
2008/09	-0.2%	0.4%	1.2%
Average Growth, 2004 - 2009	0.1%	0.8%	1.5%

5 NON-RESIDENTIAL ENERGY CONSUMPTION FORECAST

5.1 Summary and Section overview

Consumption by the 0.15 million Non-Residential customers in 2001/02 was 15,835 GWh, which represented 62% of total Network region consumption.

Non-Residential electricity consumption is clearly driven by economic activity levels. Growth in consumption averaged 3.5% over the five-year period to 1999/2000, but slowed substantially in 2000/01 (1.8% growth) and 2001/02 (0.3% growth). This growth pattern followed that of NSW economic growth, which has been subdued recently following a period of sustained strong growth in the lead up to the Olympics.

Economic activity in the EnergyAustralia Network region is expected to be subject to cyclical swings and to grow at an average 2.8% p.a. over the forecast period (see Appendix A). As a result, Non-Residential electricity consumption growth is expected to recover from recent low levels to an average 2.3% p.a. over the period 2003/04 – 2008/09. Growth in the high and low growth scenarios is forecast to be 3.0% and 1.5% respectively.

5.2 Non-Residential Econometric Model Approach

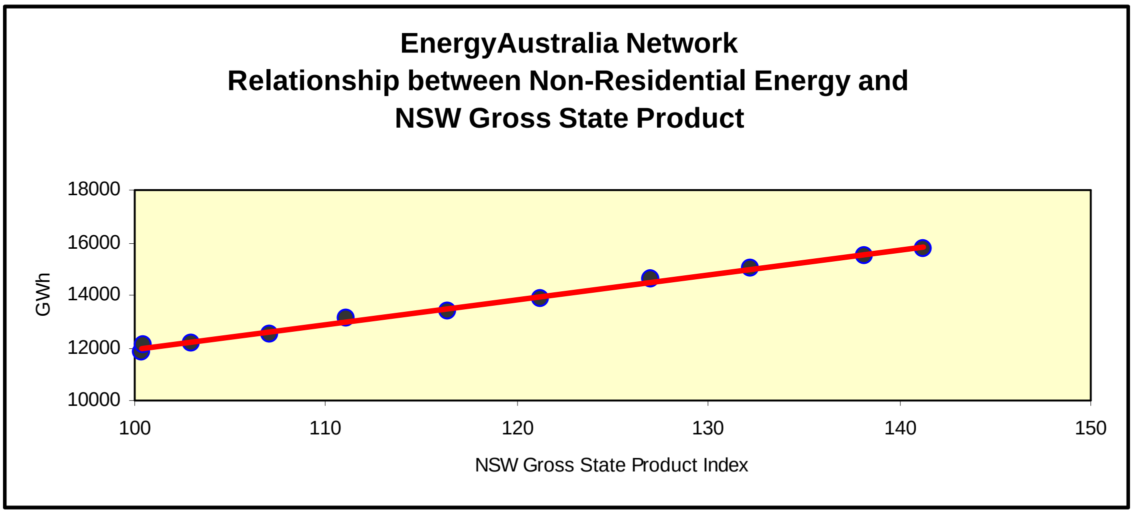
The Non-Residential energy forecast is based on an econometric modelling approach. The statistical relationship between historical electricity consumption levels and economic activity levels (as measured by Gross State Product - GSP), and average electricity and gas prices, was tested. On the basis of the statistical and diagnostic results, the following econometric model was adopted for forecasting purposes:

ln Non-Residential Energy = 5.70 +	0.80 *ln* GSP		r-squared = 0.9947
(64)	(43)		t-values = (brackets)

The model suggests that the long-term elasticity of Non-Residential energy consumption to economic activity is around 0.8. In other words, in the long-term, a 1% per annum increase in GSP could be expected to induce growth of 0.8% per annum in Non-Residential electricity consumption.

Figure 5.1 illustrates the strength of the relationship between Non-Residential electricity consumption and economic activity as measured by GSP.

Figure 5.1



5.3 Non-Residential Sector Forecast Assumptions

Table 5.1 sets out the projected GSP projections under each of the Expected, High and Low growth scenarios.

Table 5.1: EnergyAustralia Network Region GSP Projections

Year	Low Case	Historical and EXPECTED	High Case
2001/02		1.2%	
2002/03	1.6%	1.9%	2.7%
2003/04	1.2%	2.3%	3.6%
2004/05	1.8%	3.0%	4.1%
2005/06	1.4%	2.7%	3.4%
2006/07	1.7%	2.5%	3.2%
2007/08	0.9%	2.3%	3.4%
2008/09	1.9%	3.5%	4.3%
Average Growth 2004 – 2009	1.5%	2.8%	3.7%

The key feature of the projections is the expectation that economic growth in the EnergyAustralia region will be below that experienced in the latter portion of the 1990's, even under the assumptions of the High Growth scenario. Appendix A provides details of the assumptions behind this expectation.

For forecasting purposes, NIEIR's projections of economic growth in the EnergyAustralia region have been adjusted upwards by a factor of 0.7% p.a. NIEIR's projection of expected growth of 2.2% p.a. is based on an assumed significant "drift" in investment to the western part of Sydney, in response to major infrastructure and transport improvements in that region. However, EnergyAustralia believes that NIEIR's assumptions as to the extent of this drift are overstated for the period covered by the forecasts. Accordingly the economic growth assumptions have been adjusted upwards.

5.4 Non-Residential Sector Forecast

The Non-Residential sector electricity consumption forecast is the product of inputting the projected GSP growth rates into the adopted econometric model. Table 5.2 sets out the Non-Residential sector energy consumption forecast growth rates. The 2004 forecast in the High Growth scenario contains an allowance for the effects of a hotter than average summer season.

Table 5.2: EnergyAustralia Network Region Non-Residential Energy Forecast

Year	Low Case	Historical and EXPECTED	High Case
2001/02		0.3%	
2002/03	0.8%	1.5%	1.8%
2003/04	1.5%	2.1%	3.4%
2004/05	1.6%	2.4%	3.3%
2005/06	1.2%	2.2%	2.7%
2006/07	1.6%	2.0%	2.6%
2007/08	1.3%	2.3%	3.2%
2008/09	1.8%	2.8%	3.4%
Average Growth 2004 – 2009	1.5%	2.3%	3.0%

6 GLOBAL PEAK DEMAND FORECASTS

6.1 Summary and Section Overview

Aggregate seasonal forecasts set the upper bounds for independently prepared spatial forecasts at the subtransmission and zone substation levels, which in turn are one of a number of key inputs to Network Capital Expenditure projections. The spatial peak demand forecasts are prepared separately by Network Capital Works Planning.

The coincident peak demand on the EA Network system (excluding the VAW smelter and BHP-Billiton) during 2001/02 was 4,985 MW at 6pm on Tuesday 18 June 2002. The daily average temperature across the region on that day was 11.2 degrees. The winter 2002 peak demand was 1.0% higher than the winter 2001 peak, which was recorded in late August 2001 when the daily average temperature was 10.1 degrees.

The 2002/03 summer peak demand was 5,051 MW at 3:30pm (Eastern Standard Time) on Thursday 30 January 2003. The daily average temperature across the region on that day was 30.9 degrees. The summer 2003 peak demand was 13.2% higher than the previous summer peak, which was recorded on a day when the daily average temperature was a mild 25.8 degrees.

Winter and summer peak demands from year to year are highly dependent on prevailing temperature conditions. Abnormal weather, such as the mild summer experienced in 2001/02, can distort the true underlying trend in peak demand. Accordingly, for forecasting purposes it is necessary to derive “standard weather” measures of winter and summer peak demands.

In recent years, summer peak demand has outgrown annual energy consumption, which has in turn outgrown winter peak demand. This trend is largely attributable to the rapid penetration in residential air conditioning since 1996. Results from EnergyAustralia’s load research programme highlight the disproportionate impact of residential air conditioning on summer peak demand, compared with annual energy consumption. The load factor of the average air conditioner, based on sample survey data, is less than 10%.

The recent trends in relativity between winter and summer peak demand growths are expected to continue. On a weather corrected basis:

- Summer peak demand is forecast to grow at an average 2.9% p.a. (possible range 3.8% to 1.6% p.a.).
- Winter peak demand is forecast to grow at an average 1.4% p.a. (possible range 1.9% to 0.8% p.a.).

The forecast differential in growth is such that, given average weather conditions in the future, the network is expected to become consistently summer peaking in the summer of 2004/05. However given the sensitivity of peak demands to deviations from average weather, it is possible that the summer peak demand could already have exceeded winter peak in 2002/03.

The peak demand forecasting analysis draws heavily on analysis of time-of-use load research information. Appendix B presents an overview of salient outcomes from the load research analysis, with particular focus given to residential air conditioning loads.

6.2 Standard Weather Maximum Demand (SWMD) Derivation

Winter SWMD

The methodology adopted to derive annual winter SWMD involves the regression of a sample of daily maximum demands against a suitable measure of temperature. The sample days are working Mondays to Thursdays in May, June, July and August. The explanatory temperature variable used is a weighting of the daily average temperatures of the day under consideration (80% weight), the previous day (15% weight) and the day two days previous (5% weight).

The winter SWMD is the predicted peak demand that would have occurred at a weighted average daily temperature of 9.5 degrees during the sample period. The standard temperature, 9.5 degrees, represents the long-term 50% probability of exceedance (PoE) temperature within the Network region; that is, based on long-term temperature records there is a one year in two probability that the weighted average temperature will be below 9.5 degrees in any given year.

Figure 6.1

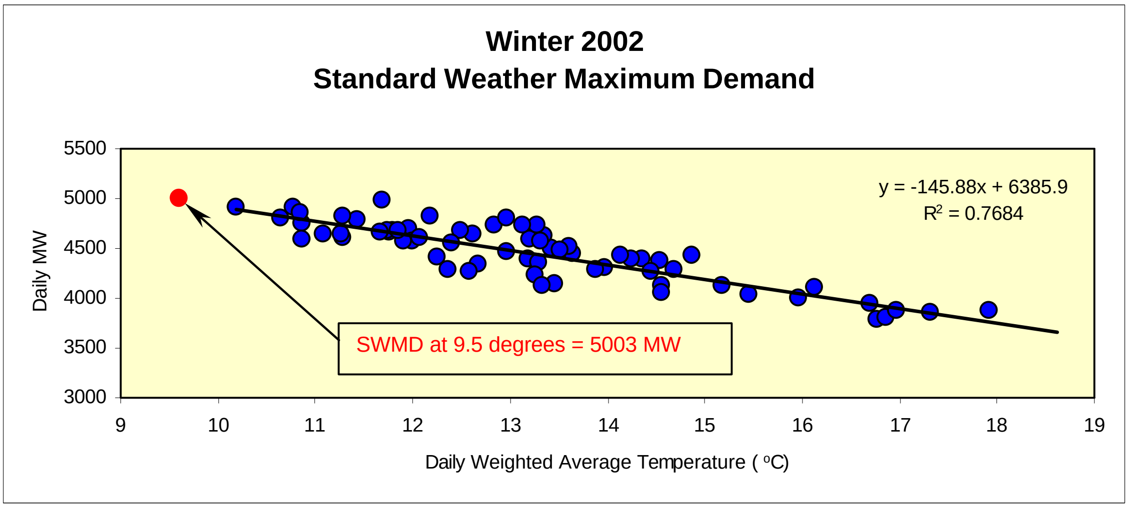


Figure 6.1 illustrates the derivation of the 2002 Winter SWMD of 5003 MW. The procedure of deriving winter SWMD is repeated following winter of each year, thus ensuring that a consistent series of peak demand measures forms the basis of the forecasting analysis.

Summer SWMD

Like winter SWMD, the methodology adopted to derive annual summer SWMD involves the regression of a sample of daily maximum demands against a suitable measure of temperature. The sample days are working Mondays to Thursdays in December, January and February, with the exception of the two to three week period around Christmas and early New Year. The explanatory temperature variable used is the daily average temperature of the day under consideration.

The summer SWMD is the predicted peak demand that would have occurred at a daily average temperature of 29.6 degrees during the sample period. The standard temperature, 29.6 degrees, represents the long-term 50% probability of exceedance (PoE) temperature within the Network region.

Figure 6.2

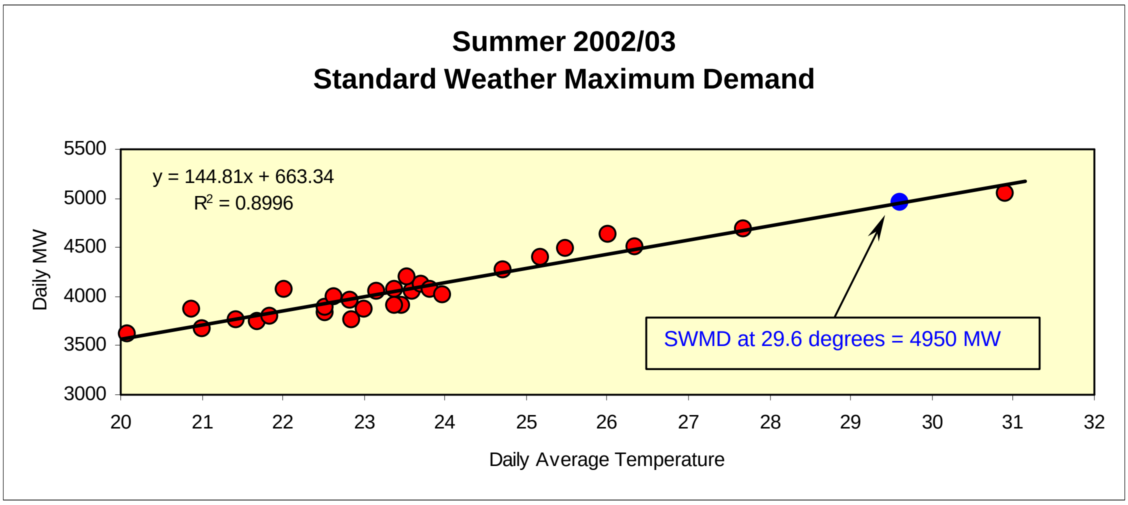


Figure 6.2 illustrates the derivation of the 2002/03 summer SWMD of 4950 MW. The procedure of deriving summer SWMD is repeated following summer of each year, thus ensuring that a consistent series of peak demand measures forms the basis of the forecasting analysis.

6.3 Peak Demand Forecast Methodology

From the energy consumption analysis set out previously in Sections 4 and 5 it is clear that the Residential and Non-Residential components of load are subject to different sets of drivers. Unlike annual energy consumption, which can be disaggregated into homogeneous sectors, peak demand can only be analysed in aggregate.

The peak demand forecasting methodology entails the following steps:

- Derive winter and summer SWMD for the current and previous years.
- Estimate the relative contributions of the Residential and Non-Residential sectors to total load at the time of global system winter and summer peak demands. This step relies on estimates obtained from load research analysis.
- Again using load research results, estimate the relative contributions of Residential sector sub-classes of customers to total load at the time of global system winter and summer peak demands. In summer the relevant sub-classes are customers with and without air conditioning, while in winter the distinction is between customers with and without electric space heating.
- Project the future peak demand contributions of the Non-Residential and Residential sectors, using the same growth assumptions that were applied to forecast energy consumption.

This methodology ensures that:

- The disaggregated forecasting rigour employed in developing the energy consumption forecasts is transferred through to the peak demand forecasts; and that
- The assumptions underlying both the energy and peak demand forecasts are consistent.

6.4 Peak Demand Forecast Assumptions

Winter SWMD Assumptions

Based on load research results:

- The Residential sector contributed an estimated 58% to the winter 2002 system peak demand.
- The estimated 855,000 Residential customers (or 65% of the customer base) with electric space heating accounted for 75% of this contribution.
- The number of customers with electric space heating is expected to grow only moderately to 868,000 by 2009, reflecting increased use of gas and wood heating.
- The Non-Residential sector component of winter peak demand is expected to grow in line with the energy consumption rates set out previously in Section 5.

Summer SWMD Assumptions

Based on load research results:

- The Residential sector contributed an estimated 34% to the summer 2003 system peak demand.
- The estimated 588,000 Residential customers (or 43% of the customer base) with air conditioning accounted for 75% of this contribution.
- The number of customers with air conditioning is expected to grow significantly to 814,000 by 2009.
- The Non-Residential sector component of summer peak demand is expected to grow at rates above the energy consumption rates set out previously in Section 5. This is because of the sensitivity of Non-Residential loads to summer temperatures, and accordingly a premium of 20% has been added to the energy growth rate.

6.5 Peak Demand Forecasts

The peak demand growth rate forecasts which result from applying the growth rate assumptions to the latest actual winter SWMD and summer SWMD are set out in Tables 6.1 and 6.2.

Over the period 2004 – 2009 summer SWMD growth is expected to exceed winter SWMD growth by around 1.5% p.a.

Table 6.1: EnergyAustralia Network Region Global Winter Peak Demand Forecast

Winter of Year	Low Case	Historical and EXPECTED	High Case
2002		1.0%	
2003	0.7%	1.1%	1.5%
2004	0.6%	1.0%	2.2%
2005	0.8%	1.6%	2.3%
2006	0.8%	1.3%	1.7%
2007	1.0%	1.1%	1.9%
2008	0.4%	1.1%	1.6%
2009	1.0%	1.7%	2.1%
Average Growth 2004 – 2009	0.8%	1.4%	1.9%

Table 6.2: EnergyAustralia Network Region Global Summer Peak Demand Forecast

Year	Low Case	Historical and EXPECTED	High Case
2001/02		-5.0%	
2002/03	13.3%	13.3%	13.3%
2003/04	1.4%	2.4%	4.5%
2004/05	2.0%	3.4%	4.4%
2005/06	1.8%	3.1%	3.7%
2006/07	1.7%	2.6%	3.6%
2007/08	0.8%	2.3%	3.3%
2008/09	1.9%	3.2%	3.8%
Average Growth 2004 – 2009	1.6%	2.9%	3.8%

7 NETWORK ENERGY AND PEAK DEMAND FORECASTS

7.1 Summary and Section Overview

This section consolidates the outcomes of Sections 4, 5 and 6 into overall forecasts of annual electricity consumption within the EnergyAustralia Network region. Results of analysis of the sensitivity of the forecasts to the various input assumptions are set out in Appendix C.

7.2 Annual Energy Consumption Forecasts

Table 7.1 combines the forecasts of Residential and Non-Residential energy consumption with projected losses, to give the annual energy purchases forecast.

Table 7.1: EnergyAustralia Network Region Energy Purchases Forecast

EXPECTED Growth		Actual 2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	*Average Growth*	
										2002-09	*2004-09*
Domestic	GWh	7663	7761	7886	7938	8024	8083	8190	8224		
	% growth	*1.2%*	*1.3%*	*1.6%*	*0.7%*	*1.1%*	*0.7%*	*1.3%*	*0.4%*	*1.0%*	*0.8%*
Controlled Load	GWh	1904	1914	1927	1935	1948	1953	1963	1972		
	% growth	*4.3%*	*0.5%*	*0.7%*	*0.4%*	*0.6%*	*0.3%*	*0.5%*	*0.5%*	*0.5%*	*0.5%*
Total Residential	GWh	9567	9675	9813	9873	9972	10035	10153	10196		
	% growth	*1.8%*	*1.1%*	*1.4%*	*0.6%*	*1.0%*	*0.6%*	*1.2%*	*0.4%*	*0.9%*	*0.8%*
Non-Residential	GWh	15835	16063	16396	16789	17152	17495	17897	18398		
	% growth	*0.3%*	*1.4%*	*2.1%*	*2.4%*	*2.2%*	*2.0%*	*2.3%*	*2.8%*	*2.2%*	*2.3%*
Total Sales	GWh	25402	25738	26209	26662	27124	27530	28050	28594		
	% growth	*0.9%*	*1.3%*	*1.8%*	*1.7%*	*1.7%*	*1.5%*	*1.9%*	*1.9%*	*1.7%*	*1.8%*
Estimated Losses	GWh	1246	1262	1286	1308	1330	1350	1376	1403		
	% growth	*0.9%*	*1.3%*	*1.8%*	*1.7%*	*1.7%*	*1.5%*	*1.9%*	*1.9%*	*1.7%*	*1.8%*
Total Load	GWh	**26648**	**27001**	**27494**	**27970**	**28454**	**28880**	**29426**	**29996**		
	% growth	**0.9%**	**1.3%**	**1.8%**	**1.7%**	**1.7%**	**1.5%**	**1.9%**	**1.9%**	***1.7%***	***1.8%***

HIGH Growth		Actual 2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	*Average Growth*	
										2002-09	*2004-09*
Domestic	GWh	7663	7968	8248	8389	8529	8672	8830	8942		
	% growth	*1.2%*	*4.0%*	*3.5%*	*1.7%*	*1.7%*	*1.7%*	*1.8%*	*1.3%*	*2.2%*	*1.6%*
Controlled Load	GWh	1904	1920	1958	1985	2005	2027	2046	2069		
	% growth	*4.3%*	*0.9%*	*2.0%*	*1.4%*	*1.0%*	*1.1%*	*1.0%*	*1.1%*	*1.2%*	*1.1%*
Total Residential	GWh	9567	9889	10207	10374	10534	10699	10876	11010		
	% growth	*1.8%*	*3.4%*	*3.2%*	*1.6%*	*1.5%*	*1.6%*	*1.7%*	*1.2%*	*2.0%*	*1.5%*
Non-Residential	GWh	15835	16120	16665	17211	17679	18132	18710	19354		
	% growth	*0.3%*	*1.8%*	*3.4%*	*3.3%*	*2.7%*	*2.6%*	*3.2%*	*3.4%*	*2.9%*	*3.0%*
Total Sales	GWh	25402	26009	26871	27585	28213	28831	29586	30364		
	% growth	*0.9%*	*2.4%*	*3.3%*	*2.7%*	*2.3%*	*2.2%*	*2.6%*	*2.6%*	*2.6%*	*2.5%*
Estimated Losses	GWh	1246	1276	1318	1353	1384	1414	1451	1489		
	% growth	*0.9%*	*2.4%*	*3.3%*	*2.7%*	*2.3%*	*2.2%*	*2.6%*	*2.6%*	*2.6%*	*2.5%*
Total Load	GWh	**26648**	**27285**	**28189**	**28938**	**29597**	**30245**	**31038**	**31853**		
	% growth	**0.9%**	**2.4%**	**3.3%**	**2.7%**	**2.3%**	**2.2%**	**2.6%**	**2.6%**	***2.6%***	***2.5%***

LOW Growth		Actual 2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	*Average Growth*	
										2002-09	*2004-09*
Domestic	GWh	7663	7620	7691	7694	7717	7731	7754	7738		
	% growth	*1.2%*	*-0.6%*	*0.9%*	*0.0%*	*0.3%*	*0.2%*	*0.3%*	*-0.2%*	*0.1%*	*0.1%*
Controlled Load	GWh	1904	1905	1904	1902	1901	1899	1891	1887		
	% growth	*4.3%*	*0.0%*	*0.0%*	*-0.1%*	*0.0%*	*-0.1%*	*-0.4%*	*-0.2%*	*-0.1%*	*-0.2%*
Total Residential	GWh	9567	9524	9596	9596	9618	9629	9646	9625		
	% growth	*1.8%*	*-0.5%*	*0.7%*	*0.0%*	*0.2%*	*0.1%*	*0.2%*	*-0.2%*	*0.1%*	*0.1%*
Non-Residential	GWh	15835	15953	16194	16454	16651	16917	17133	17434		
	% growth	*0.3%*	*0.8%*	*1.5%*	*1.6%*	*1.2%*	*1.6%*	*1.3%*	*1.8%*	*1.4%*	*1.5%*
Total Sales	GWh	25402	25478	25790	26049	26269	26547	26778	27059		
	% growth	*0.9%*	*0.3%*	*1.2%*	*1.0%*	*0.8%*	*1.1%*	*0.9%*	*1.0%*	*0.9%*	*1.0%*
Estimated Losses	GWh	1246	1250	1265	1278	1289	1302	1314	1327		
	% growth	*0.9%*	*0.3%*	*1.2%*	*1.0%*	*0.8%*	*1.1%*	*0.9%*	*1.0%*	*0.9%*	*1.0%*
Total Load	GWh	**26648**	**26727**	**27055**	**27327**	**27557**	**27849**	**28092**	**28387**		
	% growth	**0.9%**	**0.3%**	**1.2%**	**1.0%**	**0.8%**	**1.1%**	**0.9%**	**1.0%**	***0.9%***	***1.0%***

7.3 Global Peak Demand Forecast

Table 7.2 sets out the annual winter and summer peak demand forecasts.

Table 7.2: EnergyAustralia Network Region Peak Demand Forecast

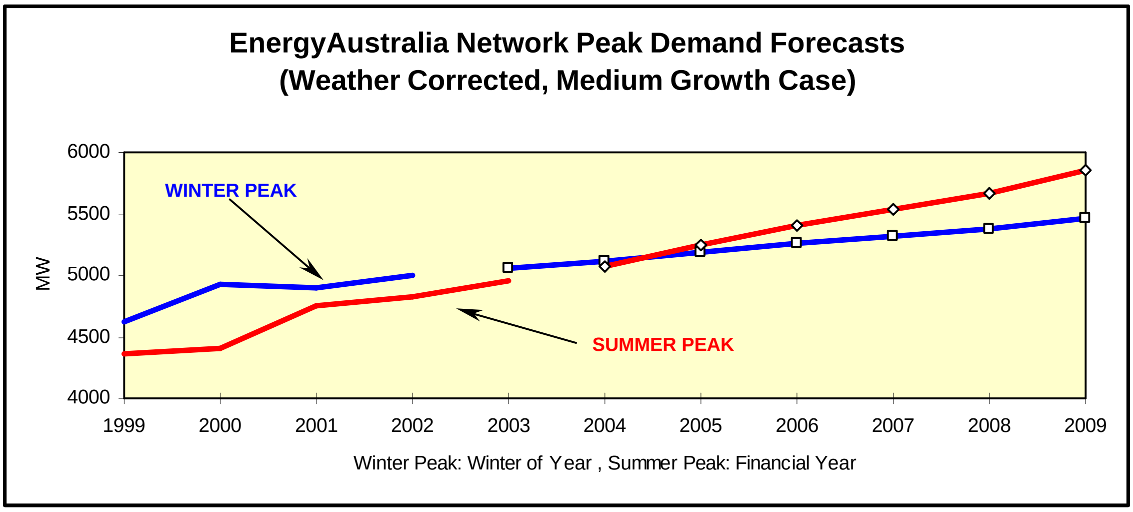
EXPECTED Growth		Actual 2002	2003	2004	2005	2006	2007	2008	2009	Average Growth 2002-09	Average Growth 2004-09
WINTER Peak - Actual	MW	4985									
(July of Year)	*% growth*	*1.0%*									
Weather Corrected	MW	5003	5060	5110	5190	5260	5320	5380	5470		
(July of Year)	*% growth*	*2.0%*	*1.1%*	*1.0%*	*1.6%*	*1.3%*	*1.1%*	*1.1%*	*1.7%*	***1.3%***	***1.4%***
SUMMER Peak - Actual	MW	4460	5051								
(Year Ended 30 June)	*% growth*	*-5.0%*	*13.3%*								
Weather Corrected	MW	4824	4950	5070	5240	5400	5540	5670	5850		
(Year Ended 30 June)	*% growth*	*1.5%*	*2.6%*	*2.4%*	*3.4%*	*3.1%*	*2.6%*	*2.3%*	*3.2%*	***2.8%***	***2.9%***

HIGH Growth		Actual 2002	2003	2004	2005	2006	2007	2008	2009	Average Growth 2002-09	Average Growth 2004-09
WINTER Peak	MW	5003	5080	5190	5310	5400	5500	5590	5710		
(July of Year)	*% growth*	*2.0%*	*1.5%*	*2.2%*	*2.3%*	*1.7%*	*1.9%*	*1.6%*	*2.1%*	***1.9%***	***1.9%***
SUMMER Peak	MW	4824	4950	5170	5400	5600	5800	5990	6220		
(Year Ended 30 June)	*% growth*	*1.5%*	*2.6%*	*4.5%*	*4.4%*	*3.7%*	*3.6%*	*3.3%*	*3.8%*	***3.7%***	***3.8%***

LOW Growth		Actual 2002	2003	2004	2005	2006	2007	2008	2009	Average Growth 2002-09	Average Growth 2004-09
WINTER Peak	MW	5003	5040	5070	5110	5150	5200	5220	5270		
(July of Year)	*% growth*	*2.0%*	*0.7%*	*0.6%*	*0.8%*	*0.8%*	*1.0%*	*0.4%*	*1.0%*	***0.7%***	***0.8%***
SUMMER Peak	MW	4824	4950	5020	5120	5210	5300	5340	5440		
(Year Ended 30 June)	*% growth*	*1.5%*	*2.6%*	*1.4%*	*2.0%*	*1.8%*	*1.7%*	*0.8%*	*1.9%*	***1.7%***	***1.6%***

Figure 7.1 compares the expected growth in winter and summer peak demand.

Figure 7.1



8 NETWORK CUSTOMER NUMBER FORECASTS

Customer number forecasts are a by-product of the global forecasting process. The forecasts are set out in Table 8.1

The Residential customer number forecast growth rates have been obtained from NIEIR as an outcome of the scenario development process.

The Non-Residential customer number forecasts are based on the following assumption: that the yearly growth rate in customer numbers = 50% of the forecast growth in Non-Residential energy consumption. (The remaining 50% growth in energy consumption is assumed to be attributable to existing customers).

Table 8.1: EnergyAustralia Network Region Customer Number Forecasts

YEAR and SCENARIO		Residential Customers (as at 30 June)		Non-Residential Customers (as at 30 June)		TOTAL Customers (as at 30 June)	
EXPECTED		Number	Growth	Number	Growth	Number	Growth
2002	Actual	1,314,973	1.1%	149,397	3.0%	1,464,370	1.3%
2003	Forecast	1,328,100	1.0%	150,500	0.7%	1,478,600	1.0%
2004	Forecast	1,344,200	1.2%	151,700	0.8%	1,495,900	1.2%
2005	Forecast	1,356,800	0.9%	153,500	1.2%	1,510,300	1.0%
2006	Forecast	1,372,300	1.1%	155,100	1.0%	1,527,400	1.1%
2007	Forecast	1,382,900	0.8%	156,700	1.0%	1,539,600	0.8%
2008	Forecast	1,397,200	1.0%	158,100	0.9%	1,555,300	1.0%
2009	Forecast	1,410,900	1.0%	160,300	1.4%	1,571,200	1.0%
Average Growth 2004 - 2009	Forecast	1.0%		1.1%		1.0%	
HIGH CASE		Number	Growth	Number	Growth	Number	Growth
2003	Forecast	1,330,800	1.2%	150,700	0.9%	1,481,500	1.2%
2004	Forecast	1,358,200	2.1%	152,900	1.5%	1,511,100	2.0%
2005	Forecast	1,377,900	1.5%	155,400	1.6%	1,533,300	1.5%
2006	Forecast	1,392,900	1.1%	157,500	1.4%	1,550,400	1.1%
2007	Forecast	1,409,600	1.2%	159,600	1.3%	1,569,200	1.2%
2008	Forecast	1,424,400	1.0%	161,700	1.3%	1,586,100	1.1%
2009	Forecast	1,441,600	1.2%	164,500	1.7%	1,606,100	1.3%
Average Growth 2004 - 2009	Forecast	1.2%		1.5%		1.2%	
LOW CASE		Number	Growth	Number	Growth	Number	Growth
2003	Forecast	1,326,800	0.9%	150,000	0.4%	1,476,800	0.8%
2004	Forecast	1,338,400	0.9%	150,700	0.5%	1,489,100	0.8%
2005	Forecast	1,348,400	0.7%	151,900	0.8%	1,500,300	0.8%
2006	Forecast	1,360,000	0.9%	152,800	0.6%	1,512,800	0.8%
2007	Forecast	1,370,200	0.8%	154,100	0.9%	1,524,300	0.8%
2008	Forecast	1,377,300	0.5%	154,700	0.4%	1,532,000	0.5%
2009	Forecast	1,386,800	0.7%	156,000	0.8%	1,542,800	0.7%
Average Growth 2004 - 2009	Forecast	0.7%		0.7%		0.7%	

APPENDIX A – ECONOMIC AND DEMOGRAPHIC PROJECTIONS

This appendix sets out assumptions and detailed economic and demographic projections behind the Expected, High and Low growth scenarios. The projections and scenario development have been prepared by NIEIR. It should be noted that EnergyAustralia have revised upward NIEIR's forecasts of economic activity, for reasons outlined in Section 5.3.

Introduction

This study represents the primary 2003 economic outlook for the Energy Australia region. There will be an update later in the year.

The Australian economy is currently highly vulnerable to recession, due to the build up in household debt. Household savings ratios have to rise and if the adjustment process occurred over one to two years, then Australia and New South Wales would be plunged into a recession, at least as severe as the 1991 recession. The alternative possibility is that the adjustment will be more gradual over a decade. This has been the assumption of the previous forecasts. Because we do not know when a recession will occur, there is no point at this stage in arbitrarily projecting one. However, given the uncertainty and the severity of the structural imbalances, a responsible approach demands focussing more of the adjustment over the 2004-2008 period. Hence growth over this period has been reduced.

Over the past year or two major infrastructure decisions have been made which are going to alter the pattern of Sydney's growth. Such decisions as the Sydney Orbital, and the Lane Cove Tunnel will encourage investment in Western Sydney relative to East Sydney. This aspect is now being built into the projections.

The national economic outlook

Despite poor world growth and the rapid decline in the tourism industry since 11 September, the Australian economy continues to generate rates of gross domestic product (GDP) growth near its trend rate of growth over recent years. The worsening world growth outlook through 2002 forced monetary institutions around the world to reduce nominal interest rates to levels that had not been seen since the 1960s and early 1970s. This allowed Australia's monetary authorities to also reduce interest rates despite the strong domestic economy.

The obvious question is why did the Australian economy respond so quickly to interest rate reduction, while the North American and European economies did not. The major difference between Australia's economic growth and that of North America and Western Europe over the second half of the 1990s was that Australia's boom was driven more by a household borrow and spend mechanism, while outside Australia high technology driven growth was more important. The 2001 world economic downturn was largely the result of over-capacity being installed in these industries over the late 1990s. When it became obvious that growth expectations for these industries, formed over the second half of the 1990 decade, were not going to be realised, then investment and employment was dramatically cut back. This was the most important explanation of the current world economic slowdown. World recovery will be slow because of:

- the degree of excess capacity created;
- the large debt overhang, debt written off and wealth lost; and
- other general institutional problems such as the United States' low savings ratio.

In Australia everything has gone on as normal. House prices in general kept on rising and even lower interest rates allowed households to keep borrowing and spending.

The stimulus to the economy from debt is the change in the level of new borrowings from year to year. In 2001-02 debt injection into the economy increased by $2 to $3 billion a quarter over and above the level compared to previous years. Little wonder then that quarterly GDP growth averaged 1 per cent a quarter.

The borrowing spending upswing is unsustainable and ultimately will end triggering a decline in Australia's trend growth rate. Part of the incentive and capacity to borrow and spend has been due to Australia's rapid house price inflation of recent years. There are now indications that Australia's housing stock is over-valued. Currently, that is in the September quarter 2002, the ratio of established house prices to the cost of new construction is 1.18 times, the highest since the data has been available.

This high ratio is in part driving the current housing construction boom as it gives builders and construction companies the incentive to build and sell. However, with rising rental vacancy rates and falling capital value for apartment type dwellings, the maintenance of this high rate is unsustainable. It is likely that this ratio will progressively revert to a more sustainable 1.06 times by mid 2004; with dwelling construction over 2003-04 falling by 20 per cent compared to 2002-03. The sharp decline in dwelling construction forecast reflects the overbuild encouraged by low interest rates and the enhanced First Home Owners Grant. Over the last 2 years considerable consumer spending has been leveraged to the housing construction cycle. As housing construction slows a significant portion of consumer spending (i.e. related to housing or household durables) will also slow.

However, this fall in housing prices will reduce the incentive and capacity (that is equity to support booms) of households to borrow and spend. Similarly, by 2004 household debt to income ratios will be around 140 per cent, or near the highest of any economy. At that stage it is likely that households take action to restore household savings and consequent slower growth in consumption expenditure is highly likely.

The growth rates in the current projection, although slower than the past, are not as severe as would be expected given the above discussion. The reasons for this are:

- the capacity for the RBA to reduce interest rates further;
- the ability of the government to take over as a driver of growth;
- the recovery in the world economy;
- the resource development profile;
- a conservative bias of the projection.

Each of these issues will be examined in turn.

Interest rate reductions
The current projection allows for interest rates to decrease over 2003 despite the RBA's current tightening bias. Given the current low level of world interest rates and the probability that they will not increase significantly over 2003, gives the Australian monetary authorities a wide capacity to reduce interest rates once the economy starts to slow. Especially when the dwelling construction cycle takes a sharp downturn, as will be readily apparent by the second half of 2003. This lower interest rate environment will allow the household sector to borrow and support consumption for another year or two and allow the maintenance of low household savings ratios.

Government spending capacity
The improvement in public sector finances over the past decade has been significant with the budget moving from annual (cash) deficits of over $10 billion in the early-1990's to consistent (cash) surpluses over the last 5 fiscal years. The public sector in Australia is therefore now in a position to partially replace the household sector as a growth driver. Prudent fiscal management requires that this be in the area of investment expenditures. However, in the era of public-private sector partnerships a good deal of this additional government effort will take the form of direct support for private investment expenditure on a boost basis.

The world recovery
The world recovery will not now begin to build momentum until 2004 at the earliest. However, it will occur albeit perhaps not with the same vigour of previous world recoveries. The other upside is that Australian tourism exports have fallen back to the levels of 1997 over the past year. Providing the terrorism threat can be contained, world tourism growth will sharply accelerate some time over the next three years.

The resource development profile
Over 2002-03 investment will accelerate in Australian mining and manufacturing resource projects. This will produce a production effect over 2004-05. However, there are likely to be a number of as yet uncommitted projects which will continue as a strong resource development factor in driving Australia's overall growth rate.

The projection dynamics
The attached tables and figures indicate the following core dynamics in the projection. For 2002-03 growth is held back by the approximate 20 per cent contraction in agricultural output because of the drought. The assumption is that the drought breaks early in 2003 and agricultural production resumes normal levels by September quarter 2003.
Growth does not bounce back to 4 per cent for 2003-04. There are a number of reasons for this.

- In 2003-04 a sharp contraction in dwelling construction appears inevitable. With the effect of induced expenditures (i.e. housing related consumer spending) taken into account, this will take between 1.0 and 1.5 percentage points off GDP growth,
- Business investment will reach a high level of activity in 2002-03 which has softened the impact of the drought. Forward indicators suggest it will be hard to sustain such a large contribution to growth in 2003-04.

The most important and pleasing feature of the projection is that it has consumption being "squeezed" by debt with trade growth falling to around 2.2 per cent. The resource development boom and the relatively low dollar engineering growth is being driven by trade expansion over the last three years of the projection. This allows Australia to reduce its current account deficit to more manageable levels. If the projection is realised, it makes it possible that Australia may yet avoid a meltdown.

A severe recessions sometime over the next four years cannot be ruled out

The main reason for this lies in the role that consumer debt has played in driving Australia's recent high economic growth rates. This has taken the structural imbalances in the economy to extreme levels. This is illustrated in the attached table.

Debt and household consumption

Fiscal years	Household consumption borrowing gap as a % of consumption expenditure	Annual direct consumer debt stimulus to GDP (% of GDP)
1990	2.1	–
1991	-1.2	-2.7
Average 1992-1996	1.3	0.8
Average 1997-2001	5.4	0.6
2002	8.0	2.0

Source: NIEIR.

The household borrowing gap for consumption is the difference between household consumption expenditure and cash available from current income to finance consumption. The table data indicates that in the early 1990 decade the household borrowing gap for consumption was near zero. However, over the 1990s the borrowing gap has steadily widened to reach 8 per cent of consumption expenditure in 2001-02.

The immediate question is, how could this be? Didn't the latest National Accounts have household net savings as zero and doesn't this imply that the household sector is in a zero net borrowing position for the finance of consumption expenditure?

The answer is no. Firstly, part of household income includes items which do not represent cash available to households to finance current consumption. These items include superannuation premium payments, interest on accumulated superannuation savings and inputted rent on owner occupied dwellings.

Secondly, a zero aggregate savings rate would only be consistent with a zero household borrowing gap for consumption if all households had a zero savings ratio. In reality many households, especially high income households, will have a significantly positive savings ratio. The current aggregate household savings ratio, which would be consistent with a zero borrowing gap, is estimated by NIEIR at around 6 to 7 per cent. This is roughly consistent with the early 1990 decade outcome of a zero borrowing gap.

The level of the borrowing gap indicates the vulnerability of the economy to shocks. However, for any year the direct stimulus to GDP growth for consumer credit is not the level of the borrowing gap but its change. Thus, in 1990 the borrowing gap was relatively low compared to 2002. In 1991, however, the household sector, under the impact of high interest rates, rising unemployment and the financial shocks from the collapse of financial institutions, spent less on consumption than current cash income. This had the effect of subtracting a direct 2.7 per cent from GDP growth.

This is the reason why forecasters did not anticipate the 1991 recession. In the middle of 1990 the consensus forecast was for a 1991 GDP growth of around 2.6 per cent with most of the growth coming from exports and zero from domestic demand. The export contribution was realised, but the household sector, by reducing its consumption borrowing gap, produced a negative GDP growth outcome for 1991.

At the other extreme, in 2002 the role of household debt in driving GDP growth reached its zenith.
In 2002 consumer credit added 2 per cent to the GDP growth with the remainder of 4 per cent GDP growth was largely explained by the debt driven housing boom.

The current situation is considerably more alarming than in 1990 in that the borrowing gap is much higher. Just to have a zero impact on growth the borrowing gap has to stay where it is, that is, around 8 per cent of household consumption. This represents net additional household debt of $40 billion per annum.

This will be impossible to maintain for long because total household debt to income ratios are already at around the 130 per cent mark with international experience suggesting an upper limit of 140 to 150 per cent of income. Sooner rather than later the household sector is going to have to reduce the borrowing gap which, if done steadily over a decade, will reduce growth by approximately 0.5 per cent per annum below trend.

This is the optimistic scenario and is built into these projections. The pessimistic and increasingly more likely scenario is one where a catalyst, similar to the 1990 financial shocks, triggers a rapid closure of the borrowing gap. There are a variety of plausible candidates. A major terrorism incident, prolonged high oil prices due to failure to resolve the current Middle East tension, a rapid decline in domestic house prices, the continuation of the drought, a re-run of 1990 with one or two major financial institutions collapses or some combination of these.

A borrowing gap closure over two years would produce a domestic recession with an intensity of twice that of the early 1990s recession.

In this context it would be wise for every government when forecasting to assume a recession equal to the 1991 case at some point over the next four years as a contingency alternative to baseline projections of the type of this report. The odds are shortening that such an event will be closer to 2003 than 2007.

National GDP growth

	Base	High	Low
1997	3.8	3.8	3.8
1998	4.5	4.5	4.5
1999	5.3	5.3	5.3
2000	4.0	4.0	4.0
2001	1.8	1.8	1.8
2002	4.0	4.0	4.0
2003	2.9	3.2	2.7
2004	2.7	4.0	2.0
2005	2.9	4.0	1.9
2006	3.0	3.7	1.8
2007	2.6	3.3	2.1
2008	2.5	3.6	1.2
2009	2.8	3.6	1.5
2010	2.7	3.5	2.1
2011	3.4	3.9	2.3
2012	3.9	4.4	2.7
2013	3.3	4.2	2.7

National economic aggregates
(year average per cent change unless otherwise specified)

	1999-00	2000-01	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07
GDP & Components								
Consumer spending	4.1	3.0	3.5	3.6	2.5	2.0	2.0	2.4
Non-dwelling construction	-8.7	-16.5	10.3	13.6	-5.5	-1.1	5.5	-0.8
Equipment	11.3	3.1	2.1	7.0	4.3	4.8	-1.2	3.8
Housing	14.3	-20.9	19.5	12.9	-21.3	0.2	12.4	-1.6
Public expenditure	3.8	1.8	4.5	2.9	3.6	3.0	2.6	2.2
Stocks (% points)	-0.4	-0.4	0.0	0.4	0.1	-1.2	0.3	0.2
Exports	9.4	7.2	-1.5	1.4	5.4	7.4	7.2	4.4
Imports	12.5	-1.3	2.3	6.7	0.9	-2.4	2.6	3.1
GDP	4.0	1.8	3.9	2.9	2.7	3.0	3.0	2.6
Non-farm GDP	3.7	1.7	3.9	3.7	2.2	3.3	3.3	2.6
Farm GDP	12.6	3.2	5.3	-17.2	25.2	8.2	5.5	3.2
Dwelling Sector								
Commencements	16.8	-34.0	45.6	-4.6	-33.7	17.6	26.7	-31.7
Labour Market								
Employment	2.7	2.1	1.1	2.0	0.1	-0.3	0.9	1.7
Unemployment rate	6.6	6.4	6.7	6.1	6.4	6.9	6.8	6.7
Labour force	1.9	1.9	1.4	1.5	0.4	0.2	0.8	1.5
Wages & Prices								
Average weekly earnings	3.3	5.3	5.5	4.6	4.3	4.9	5.4	5.5
CPI	2.4	6.0	2.9	2.7	2.7	3.1	2.8	2.3
Real Household disposable income	4.2	4.5	1.2	2.0	1.5	2.7	2.7	2.2
Finance (year average)								
90 day bank bill rate (%)	5.6	5.8	4.6	4.9	4.4	4.3	4.9	5.0
10-year bond yields (%)	6.5	5.8	5.9	5.6	5.3	5.1	5.6	5.7
$US/$A	62.9	53.8	53.3	54.8	54.6	56.5	58.3	59.0
$A TWI	54.9	50.0	50.6	51.1	49.9	51.9	54.9	56.1
External Sector								
Current account deficit ($bn)	-32.1	-18.1	-21.8	-37.1	-30.2	-17.6	-10.6	-11.0
CAD as a % of GDP	-5.1	-2.7	-3.0	-4.4	-3.8	-2.1	-1.2	-1.2

The New South Wales economic outlook

The New South Wales economic outlook is shown in the tables below. The impact of the drought will hold the New South Wales GSP growth rate to around 2 per cent for 2002-03. At this stage it is assumed that the drought will end in the next two months. This will add 1.0-1.5 per cent to New South Wales GSP growth in 2003-04. However, New South Wales GSP growth for 2003-04 is only marginally above the 2002-03 projected outcome. This is because of the downturn in the housing cycle and weakening in consumption expenditure. Post 2004 the growth is more subdued than previously for reasons outlined above.

New South Wales gross State product by scenario

	Base	High	Low
1997	4.1	4.1	4.1
1998	4.8	4.8	4.8
1999	4.1	4.1	4.1
2000	4.5	4.5	4.5
2001	2.2	2.2	2.2
2002	2.4	2.4	2.4
2003	2.0	2.6	1.6
2004	2.4	3.7	1.7
2005	3.1	4.2	2.1
2006	2.8	3.5	1.6
2007	2.6	3.3	2.1
2008	2.4	3.5	1.1
2009	3.6	4.4	2.3
2010	2.5	3.3	1.9
2011	3.2	3.7	2.1
2012	3.6	4.1	2.4
2013	2.8	3.6	1.9

Macro expenditure aggregates – New South Wales (percentage changes)

	Private consump-tion expenditure	Private business investment	Private housing expenditure	Private sector demand (incl. rete.)	Public current expenditure	Public capital expenditure	Public sector demand	Gross State expenditure	Net exports and stats. Discrep.	State product
1992	1.5	-11.0	1.3	0.1	0.5	0.7	0.6	0.2		0.2
1993	0.6	-0.3	10.7	1.1	3.0	2.3	2.8	1.5		2.4
1994	1.4	9.1	8.1	2.6	1.6	-2.0	0.8	2.2		3.9
1995	4.9	17.5	9.0	6.5	4.0	10.4	5.3	6.2		3.8
1996	4.0	7.8	-6.9	3.6	2.4	-8.0	0.2	2.9		4.8
1997	3.0	4.0	-2.5	2.8	0.5	-5.0	-0.6	2.0		4.1
1998	4.2	14.8	18.7	6.4	3.4	1.2	2.9	5.7		4.8
1999	5.2	4.6	11.5	5.6	4.3	2.1	3.9	5.2		4.1
2000	4.3	16.9	7.0	6.2	2.7	19.0	5.7	6.1		4.5
2001	2.7	-2.1	-28.7	-0.4	2.6	-6.8	0.7	-0.2		2.2
2002	2.2	-5.6	17.8	2.0	2.8	3.7	2.9	2.2		2.4
2003	2.6	0.5	13.9	3.1	3.0	0.2	2.5	3.0		2.0
2004	2.3	1.3	-15.7	0.9	3.8	4.4	3.9	1.5		2.4
2005	1.9	5.3	-0.9	2.2	3.2	2.5	3.1	2.4		3.1
2006	1.9	5.9	11.6	3.0	2.3	4.2	2.6	2.9		2.8
2007	3.1	5.5	-9.0	2.7	3.4	3.0	3.3	2.8		2.6
Compound growth rate										
2001-2007	2.34	2.08	2.19	2.29	3.07	3.00	3.06	2.45		2.55

New South Wales industry employment projections – survey basis (percentage change)

	Agri-culture, forestry, fishing, hunting Div A	Mining Div B	Manu-facturing Div C	Electricity, gas, water Div D	Const-ruction Div E	Commerce wholesale, retail trade Div F&G	Transport, storage, commun-ication Div I&J	Finance, property, business services Div K&L	Public admin., defence, commercial services Div M, N&O	Recreational personal and other services Div H, P&Q	Total Employment Labour Force Survey basis (4 qtr average)
1992	-5.4	-6.9	-5.3	5.5	-14.9	-0.5	-4.7	0.2	1.5	7.9	-1.6
1993	0.2	-0.1	1.0	-5.2	-0.5	0.7	-8.3	-4.3	0.2	-3.9	-1.4
1994	0.5	16.9	1.3	-5.1	4.8	1.4	0.7	1.8	3.5	0.1	1.9
1995	-1.2	-14.2	-1.2	-5.4	2.4	6.5	5.9	8.7	0.9	9.8	3.8
1996	4.3	5.0	-3.5	-14.6	10.3	3.9	2.5	5.9	5.2	1.1	3.3
1997	-7.5	-10.2	6.9	-21.8	-6.3	-2.3	4.8	4.4	0.3	2.7	0.6
1998	16.4	-6.4	-0.5	1.7	3.3	-1.1	-6.0	3.4	-0.9	2.0	0.7
1999	-4.5	-15.2	-8.9	-2.2	8.7	4.7	10.3	5.8	4.5	-0.7	2.4
2000	0.9	-6.7	3.0	-0.7	12.8	0.9	-1.1	6.7	-0.6	7.4	3.2
2001	-0.6	-15.4	0.7	-0.9	-5.3	-2.5	5.1	10.1	2.4	3.7	1.9
2002	-2.1	23.6	-4.1	-2.3	0.8	1.4	2.4	-1.8	4.8	1.4	0.8
2003	-10.2	-1.7	-3.3	-4.5	10.0	1.5	1.1	1.9	4.7	5.6	2.2
2004	3.2	-2.6	-10.7	-6.8	-9.3	1.3	3.6	4.1	4.3	6.3	1.0
2005	-11.6	2.4	-7.2	-7.4	2.5	-0.5	2.2	4.9	3.1	5.7	1.4
2006	-7.3	-4.5	-4.6	-4.3	8.1	-1.5	0.1	3.6	1.3	5.8	1.4
2007	2.8	-5.9	-1.3	-4.0	-1.2	-1.5	-0.6	2.6	1.9	5.9	1.2
Compound growth rate (per cent)											
2001-2007	-4.38	1.44	-5.24	-4.93	1.62	0.10	1.45	2.54	3.34	5.10	1.32

Key features of national scenarios – base, high and low

Low – major points	Base – major points	High – major points
• Base or high international scenarios lead to rapid recovery in world interest rates. This translates into interest rates in Australia returning to 5-6 per cent by end of 2004. Very high debt service costs lead to very slow growth in private consumption expenditure and big wealth losses from falls in house and equity prices. • Positive economic growth outcomes due to mining and manufacturing expansion. However, benefits from mining expansion limited by low exchange rate, and governments using tax revenues to maintain budget surplus. No large scale infrastructure program to kick-start economy. • Australia falls further behind in competitiveness in the new industries of information technology, biotechnologies and multi-media. Increasing import penetration in traditional industries keeps manufacturing output growth at 1 per cent per annum over 2000 to 2012. • Best home grown skills leave Australia for higher income jobs in US and Europe.	• Slow world economic recovery allows Australia to maintain interest rates at near current levels to end of 2004. • The build up of debt grinds down the rate of growth of private consumption expenditure to the 1.5 to 2.0 per cent range over 2003 to 2006. However, 2.0-2.5 per cent plus growth rates maintained to 2006 by resource expansion and government expenditure expansion. • House prices stabilise at near current levels to 2008 while equity prices also stabilise at current levels to 2006. That is, there is no major negative wealth effects although positive wealth effects do not drive growth again until late in the projection period. • The period 2007 to 2010 is for weak economic demand growth as households reduce debts relative to income and increase savings rates to 6 per cent plus. Supply side, the economy consolidates as high technology industries expand rapidly, albeit from a low base.	• Aggressive public sector policies to expand core physical, skills and knowledge infrastructure. • Exchange rate strengths to encourage the development of new emerging industries. • Domestic savings (via managed funds) does not flow to any large extent offshore as is the case for the low and base scenarios, but is allocated to building domestic infrastructure and as venture capital for the establishment and growth of new emerging industries. • Moderate to high income full time employment growth strong as distinct from the rapid growth in part time and low income full time employment under the low and base scenarios. • Strong constraints on growth in household expenditures as per base and low scenarios. However, strong supply side expansion and investment neutralises this aspect by delivering high overall growth rates.

• High debt in household and corporate sector hold back US recovery. Growth not back to historical trend levels until 2006 when household savings ratios are restored to at least 6 per cent. • Japan fails to rapidly correct its banking and other financial sector bad debts. Fails to open up economy. High government deficits remain over the longer term. Little Japanese growth for a decade. Japanese economic implosion beyond 2012. • China captures direct capital inflows and world trade growth opportunities largely at the expense of other East Asian economies. • Political instability and tight political control maintains high and increasing real oil prices.	• US recovery relatively rapid, driven by fiscal stimulus, low inflationary growth maintaining low interest rates and rapid recovery of high technology sector. However, debt and savings constraint begin to bite by 2006 forcing low growth (compared to low scenario) over the 2007 to 2010 period. • Relatively high US growth stimulus, rapid world economic recovery. However, by 2006 Europe takes over from the US to drive reasonable world economic growth rates to 2012. • Rapid diversification of energy sources and rapid gains in energy efficiency (especially in transport) will neutralise the potential for oil prices to retard economic growth. • Japanese restructuring slow but steady. Japan averages 1 per cent per annum to GDP growth to 2010. • China's growth prospects more limited by diversification of world capital flows to rest of Asia.	• Further EU intention stimulates high economic growth in Central and Eastern Europe 2004-2012. • High growth in Western Europe 2004 to 2012 as the benefits of past structural reform is translated into higher growth, especially in Germany, France and Italy. • Slow growth in US until 2004 as corporate and household balance sheets are restructured. The potential of the information and biotechnology revolutions drive high US growth post 2004. • Chinese integration into world economy is seamless with both the rest of the world and China benefiting in terms of higher growth potential. • Japan opens up economy and allows unrestricted capital inflows. This eases Japanese restructuring and unlocks 2 per cent plus growth post 2006.

Constraints on Sydney's growth

To sustain and manage these high rates of economic growth, the emerging constraints on Sydney's economic growth need to be identified and addressed. Three constraints that could potentially undermine Sydney's growth are emphasised.

Firstly, infrastructure constraints on Sydney's growth are becoming more pressing. Lack of world class airport infrastructure is adding increasing costs on Sydney now due to the on-site and offsite inefficiencies associated with Kingsford Smith Airport. Capacity constraints and the poor location of KSA are a major challenge for global Sydney. Sydney will not remain a global city if it does not shift to a two-airport system quickly. Congestion costs, multiple freight handling and insufficient landing slots for international carriers are threatening to undermine Sydney's competitiveness.

Secondly, environmental constraints will become paramount unless Sydney is successful in improving transport infrastructure and the quality of urban development, and protecting the city's natural environment. The overriding planning priority over the past 20 years has been to increase residential densities in established areas of Sydney in order to improve utilisation of existing infrastructure. Whilst resulting in some positive outcomes, urban consolidation around the centre of Sydney will not be sufficient as Sydney seeks to accommodate an additional 1 million people by 2020. Around 80 per cent of the population growth of the Greater Metropolitan Region will need to be accommodated in Western Sydney, Central Coast, Wollongong SD and the Lower Hunter. This entails a major commitment to upgrade water and sewerage treatment facilities to protect the Hawkesbury-Nepean Rivers, reduce car dependence, upgrade public transport and dramatically increase the number of knowledge based jobs away from global Sydney, particularly in regional centres – Parramatta, Liverpool, Penrith, Gosford-Wyong, Wollongong and Newcastle.

Thirdly, skills constraints are becoming more apparent. Conservative forecasts suggest that NSW will experience a growing shortage of high skilled knowledge workers particularly in the high growth IT&T and bio-medical occupations. Sydney is experiencing a "minor" brain drain of high skilled IT&T professionals to globally competitive regions such as west coast USA partly due to high incomes available overseas and partly due to the relatively small number of high technology knowledge creators in Sydney.

Future development plans
The current development path for Sydney and NSW is not sustainable. The productivity of Sydney is expected to decline for a number of reasons.

Firstly, the area is confronted with increased costs of doing business, living and travelling. Census figures clearly demonstrate that lower income earners are getting pushed out of Global or inner Sydney towards the periphery. Secondly, the re-concentration of knowledge based jobs in global Sydney is skewing the Sydney labour market. A concerted effort is required to increase the number of knowledge based jobs in Western Sydney, Central Coast, and non-metropolitan NSW to provide better access and to stimulate employment growth outside of the city centre. Thirdly, Sydney's infrastructure is not adequate to meet the challenges ahead. Airport infrastructure, including passenger and airfreight facilities, is not commensurate with the demands of a global Sydney; significant public transport investments are required, and a major shift towards knowledge infrastructure is required. Fourthly, environmental externalities are increasing. Hot spots include congestion around Sydney's transport gateways and some freeways, deteriorating air and noise quality, and the sensitivity of the Nepean-Hawkesbury Rivers to urban development.

If these constraints on Sydney's developments are not addressed, the economic opportunities associated with globalisation are likely to increase in Melbourne and Brisbane, in the first instance, but are more likely in the longer term to enhance global opportunities in other Asia-Pacific cities such as Singapore and Hong Kong. In the event that Sydney performs below optimal there will be a negative impact on national growth rates. It is unlikely to have a major impact on population growth, however, as Sydney will remain a preferred destination for workers from other parts of Australia and migrants.

The New South Wales Government's Sydney development strategy featured Western Sydney. For Sydney the strategy is based on:
- shifting to grid pattern transport system (connecting the nodes) and away from radial system. The Western Sydney Orbital (WSO) is an important component of this new grid;
- multi-centred urban development pattern/strategy and shifting 2,000 NSW public sector jobs to innovative regional centres of Sydney;
- support creation of high value industry clusters (IT, biotechnology, medical technology) in Western Sydney including Moorebank Technology Park, Westmead Biomedical Precinct, Central West Economic Development Zone, and strong links to North Ryde through Parramatta-Chatswood rail link;
- compact city around all nodes not just established Sydney;
- conserve public resources for high quality infrastructure, technology parks, offices, community infrastructure in Western Sydney. Market (with sound planning and environmental regulatory framework) will look after global Sydney but not Western Sydney;
- target Western Sydney to become equal partner with Eastern Sydney to strengthen Global Sydney; and
- integrate planning for local use development, transport infrastructure and economic development. Create low risk environment for private sector leverage.

The transport infrastructure currently being installed will result in market forces reinforcing government policy objectives. The net outcome of this will be to shift energy intensive activities to Western Sydney at a greater rate than what would have been envisaged a few years ago.

Tables A1 to A6 set out the projections of the key economic and demographic variables which form inputs to the EnergyAustralia electricity forecasts.

Table A.1: NIEIR Gross State Product Projections ($1998/99 billions)

Year Ended	NSW			EnergyAustralia			EA Share (ratio)		
June	Expected	High	Low	Expected	High	Low	Expected	High	Low
1999	222.4	222.4	222.4	145.8	145.8	145.8	65.6%	65.6%	65.6%
2000	232.4	232.4	232.4	151.2	151.2	151.2	65.1%	65.1%	65.1%
2001	237.6	237.6	237.6	156.6	156.6	156.6	65.9%	65.9%	65.9%
2002	243.2	243.2	243.2	158.4	158.4	158.4	65.1%	65.1%	65.1%
2003	248.0	249.5	247.1	161.3	163.0	160.8	65.0%	65.3%	65.1%
2004	254.1	258.8	251.3	163.5	167.2	162.0	64.4%	64.6%	64.5%
2005	261.9	269.7	256.6	167.5	173.3	164.4	63.9%	64.3%	64.1%
2006	269.3	279.1	260.7	171.5	179.4	166.4	63.7%	64.3%	63.8%
2007	276.3	288.3	266.2	174.8	184.4	168.7	63.3%	64.0%	63.4%
2008	282.9	298.4	269.1	177.9	189.8	169.9	62.9%	63.6%	63.1%
2009	293.1	311.5	275.3	182.5	196.4	172.5	62.3%	63.0%	62.7%
Growth									
2000	4.5%	4.5%	4.5%	3.7%	3.7%	3.7%	-0.5%	-0.5%	-0.5%
2001	2.2%	2.2%	2.2%	3.6%	3.6%	3.6%	0.8%	0.8%	0.8%
2002	2.4%	2.4%	2.4%	1.2%	1.2%	1.2%	-0.8%	-0.8%	-0.8%
2003	2.0%	2.6%	1.6%	1.9%	2.9%	1.5%	-0.1%	0.2%	0.0%
2004	2.4%	3.7%	1.7%	1.4%	2.6%	0.8%	-0.6%	-0.7%	-0.6%
2005	3.1%	4.2%	2.1%	2.4%	3.6%	1.4%	-0.5%	-0.3%	-0.4%
2006	2.8%	3.5%	1.6%	2.4%	3.5%	1.2%	-0.2%	0.0%	-0.3%
2007	2.6%	3.3%	2.1%	1.9%	2.8%	1.4%	-0.4%	-0.3%	-0.4%
2008	2.4%	3.5%	1.1%	1.8%	2.9%	0.8%	-0.4%	-0.4%	-0.3%
2009	3.6%	4.4%	2.3%	2.6%	3.5%	1.5%	-0.6%	-0.6%	-0.4%
Av Growth									
1999-2004	2.7%	3.1%	2.5%	2.3%	2.8%	2.1%			
2004-2009	2.9%	3.8%	1.8%	2.2%	3.3%	1.3%			

Table A.2: EnergyAustralia Gross State Product Projections ($1998/99 billions) – Assumed for Forecasts

Year Ended	NIEIR Projections			EnergyAustralia Projections (used in Forecasts)			Difference		
June	Expected	High	Low	Expected	High	Low	Expected	High	Low
1999	145.8	145.8	145.8	145.8	145.8	145.8			
2000	151.2	151.2	151.2	151.2	151.2	151.2			
2001	156.6	156.6	156.6	156.6	156.6	156.6			
2002	158.4	158.4	158.4	158.4	158.4	158.4			
2003	161.3	163.0	160.8	161.5	162.8	160.9			
2004	163.5	167.2	162.0	164.5	167.9	162.9			
2005	167.5	173.3	164.4	169.0	174.5	165.8			
2006	171.5	179.4	166.4	173.4	180.6	168.1			
2007	174.8	184.4	168.7	177.4	186.1	171.0			
2008	177.9	189.8	169.9	181.1	192.1	172.6			
2009	182.5	196.4	172.5	186.7	199.6	175.9			
Growth									
2000	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	0.0%	0.0%	0.0%
2001	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%	0.0%	0.0%	0.0%
2002	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	0.0%	0.0%	0.0%
2003	1.9%	2.9%	1.5%	1.9%	2.7%	1.6%	0.1%	-0.1%	0.0%
2004	1.4%	2.6%	0.8%	1.9%	3.2%	1.2%	0.5%	0.6%	0.5%
2005	2.4%	3.6%	1.4%	2.8%	3.9%	1.8%	0.3%	0.3%	0.3%
2006	2.4%	3.5%	1.2%	2.6%	3.5%	1.4%	0.2%	0.0%	0.2%
2007	1.9%	2.8%	1.4%	2.3%	3.0%	1.7%	0.3%	0.3%	0.4%
2008	1.8%	2.9%	0.8%	2.1%	3.2%	0.9%	0.3%	0.3%	0.2%
2009	2.6%	3.5%	1.5%	3.1%	3.9%	1.9%	0.5%	0.5%	0.4%
Av Growth									
1999-2004	2.3%	2.8%	2.1%	2.4%	2.9%	2.2%			
2004-2009	2.2%	3.3%	1.3%	2.6%	3.5%	1.5%			

Table A.3: NIEIR Employment Projections ($1998/99 billions)

Year Ended	NSW			EnergyAustralia			EA Share (ratio)		
June	Expected	High	Low	Expected	High	Low	Expected	High	Low
1999	2.902	2.902	2.902	1.453	1.453	1.453	50.1%	50.1%	50.1%
2000	2.994	2.994	2.994	1.501	1.501	1.501	50.1%	50.1%	50.1%
2001	3.051	3.051	3.051	1.546	1.546	1.546	50.7%	50.7%	50.7%
2002	3.075	3.075	3.075	1.545	1.545	1.545	50.2%	50.2%	50.2%
2003	3.143	3.159	3.131	1.587	1.599	1.578	50.5%	50.6%	50.4%
2004	3.174	3.209	3.152	1.591	1.612	1.578	50.1%	50.2%	50.0%
2005	3.217	3.273	3.180	1.604	1.637	1.583	49.8%	50.0%	49.8%
2006	3.261	3.331	3.203	1.619	1.662	1.588	49.6%	49.9%	49.6%
2007	3.301	3.383	3.231	1.628	1.678	1.591	49.3%	49.6%	49.2%
2008	3.337	3.438	3.247	1.637	1.696	1.592	49.1%	49.3%	49.0%
2009	3.389	3.508	3.275	1.649	1.717	1.595	48.7%	48.9%	48.7%
Growth									
2000	3.2%	3.2%	3.2%	3.3%	3.3%	3.3%	0.0%	0.0%	0.0%
2001	1.9%	1.9%	1.9%	3.0%	3.0%	3.0%	0.6%	0.6%	0.6%
2002	0.8%	0.8%	0.8%	-0.1%	-0.1%	-0.1%	-0.5%	-0.5%	-0.5%
2003	2.2%	2.8%	1.8%	2.8%	3.5%	2.2%	0.3%	0.4%	0.2%
2004	1.0%	1.6%	0.7%	0.2%	0.8%	0.0%	-0.4%	-0.4%	-0.4%
2005	1.4%	2.0%	0.9%	0.8%	1.5%	0.3%	-0.3%	-0.2%	-0.2%
2006	1.4%	1.8%	0.7%	1.0%	1.5%	0.3%	-0.2%	-0.1%	-0.2%
2007	1.2%	1.6%	0.9%	0.6%	1.0%	0.2%	-0.3%	-0.3%	-0.4%
2008	1.1%	1.6%	0.5%	0.5%	1.0%	0.1%	-0.2%	-0.3%	-0.2%
2009	1.6%	2.0%	0.8%	0.8%	1.2%	0.2%	-0.4%	-0.4%	-0.3%
Av Growth									
1999-2004	1.8%	2.0%	1.7%	1.8%	2.1%	1.7%			
2004-2009	1.3%	1.8%	0.8%	0.7%	1.3%	0.2%			

Table A.4: NIEIR Inflation and Wages Growth Projections

Year Ended	CPI			Average Annual Earnings ($'000)		
June	Expected	High	Low	Expected	High	Low
1999	122.5	122.5	122.5	42.1	42.1	42.1
2000	125.4	125.4	125.4	45.5	45.5	45.5
2001	133.2	133.2	133.2	48.3	48.3	48.3
2002	137.2	137.2	137.2	50.6	50.6	50.6
2003	140.8	140.7	141.0	51.9	51.8	51.9
2004	144.8	143.9	145.9	53.6	53.3	54.0
2005	149.0	147.5	151.9	56.0	55.9	56.6
2006	153.5	149.8	155.8	58.5	58.1	58.8
2007	157.8	153.2	160.9	61.0	60.4	61.1
2008	162.0	156.7	165.9	63.4	63.1	63.5
2009	166.5	160.1	171.1	66.2	65.9	66.1
Growth						
2000	2.4%	2.4%	2.4%	7.9%	7.9%	7.9%
2001	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%
2002	3.0%	3.0%	3.0%	4.8%	4.8%	4.8%
2003	2.7%	2.6%	2.8%	2.6%	2.5%	2.7%
2004	2.8%	2.3%	3.5%	3.4%	2.8%	4.0%
2005	2.9%	2.5%	4.1%	4.4%	4.8%	4.8%
2006	3.0%	1.6%	2.6%	4.5%	4.0%	3.9%
2007	2.8%	2.2%	3.2%	4.2%	4.0%	3.9%
2008	2.7%	2.3%	3.1%	4.0%	4.4%	3.9%
2009	2.8%	2.1%	3.2%	4.4%	4.5%	4.0%
Av Growth						
1999-2004	3.4%	3.3%	3.6%	4.9%	4.8%	5.1%
2004-2009	2.8%	2.1%	3.2%	4.3%	4.3%	4.1%

Table A.5: NIEIR Population Projections (millions)

Year Ended June	NSW			EnergyAustralia			EA Share (ratio)		
	Expected	High	Low	Expected	High	Low	Expected	High	Low
1999	6.412	6.412	6.412	3.089	3.089	3.089	48.2%	48.2%	48.2%
2000	6.491	6.491	6.491	3.129	3.129	3.129	48.2%	48.2%	48.2%
2001	6.578	6.578	6.578	3.174	3.174	3.174	48.2%	48.2%	48.2%
2002	6.647	6.647	6.647	3.196	3.196	3.196	48.1%	48.1%	48.1%
2003	6.716	6.717	6.715	3.228	3.231	3.226	48.1%	48.1%	48.0%
2004	6.784	6.795	6.774	3.259	3.269	3.250	48.0%	48.1%	48.0%
2005	6.852	6.874	6.835	3.284	3.303	3.272	47.9%	48.0%	47.9%
2006	6.921	6.956	6.893	3.309	3.326	3.292	47.8%	47.8%	47.8%
2007	6.991	7.040	6.950	3.330	3.353	3.308	47.6%	47.6%	47.6%
2008	7.061	7.126	7.008	3.352	3.380	3.324	47.5%	47.4%	47.4%
2009	7.132	7.214	7.066	3.374	3.408	3.340	47.3%	47.2%	47.3%
Growth									
2000	1.2%	1.2%	1.2%	1.3%	1.3%	1.3%	0.0%	0.0%	0.0%
2001	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	0.0%	0.0%	0.0%
2002	1.1%	1.1%	1.1%	0.7%	0.7%	0.7%	-0.1%	-0.1%	-0.1%
2003	1.0%	1.1%	1.0%	1.0%	1.1%	0.9%	0.0%	0.0%	-0.1%
2004	1.0%	1.2%	0.9%	1.0%	1.2%	0.8%	-0.1%	0.0%	0.0%
2005	1.0%	1.2%	0.9%	0.8%	1.0%	0.7%	-0.1%	-0.1%	-0.1%
2006	1.0%	1.2%	0.9%	0.8%	0.7%	0.6%	-0.1%	-0.2%	-0.1%
2007	1.0%	1.2%	0.8%	0.7%	0.8%	0.5%	-0.2%	-0.2%	-0.2%
2008	1.0%	1.2%	0.8%	0.7%	0.8%	0.5%	-0.1%	-0.2%	-0.2%
2009	1.0%	1.2%	0.8%	0.7%	0.8%	0.5%	-0.2%	-0.2%	-0.1%
Av Growth									
1999-2004	1.1%	1.2%	1.1%	1.1%	1.1%	1.0%			
2004-2009	1.0%	1.2%	0.8%	0.7%	0.8%	0.5%			

Table A.6: NIEIR Number of Households Projections (millions)

Year Ended June	NSW			EnergyAustralia			EA Share (ratio)		
	Expected	High	Low	Expected	High	Low	Expected	High	Low
1999	2.377	2.377	2.377	1.209	1.209	1.209	50.9%	50.9%	50.9%
2000	2.419	2.419	2.419	1.228	1.228	1.228	50.8%	50.8%	50.8%
2001	2.452	2.452	2.452	1.243	1.243	1.243	50.7%	50.7%	50.7%
2002	2.479	2.479	2.479	1.256	1.256	1.256	50.7%	50.7%	50.7%
2003	2.521	2.521	2.521	1.275	1.277	1.275	50.6%	50.7%	50.6%
2004	2.554	2.571	2.547	1.291	1.303	1.286	50.5%	50.7%	50.5%
2005	2.587	2.617	2.575	1.303	1.322	1.296	50.4%	50.5%	50.3%
2006	2.628	2.667	2.607	1.318	1.336	1.307	50.1%	50.1%	50.1%
2007	2.660	2.717	2.642	1.328	1.352	1.317	49.9%	49.8%	49.8%
2008	2.703	2.762	2.667	1.341	1.367	1.323	49.6%	49.5%	49.6%
2009	2.745	2.814	2.701	1.355	1.383	1.333	49.3%	49.2%	49.3%
Growth									
2000	1.8%	1.8%	1.8%	1.6%	1.6%	1.6%	-0.1%	-0.1%	-0.1%
2001	1.3%	1.3%	1.3%	1.2%	1.2%	1.2%	-0.1%	-0.1%	-0.1%
2002	1.1%	1.1%	1.1%	1.0%	1.0%	1.0%	0.0%	0.0%	0.0%
2003	1.7%	1.7%	1.7%	1.5%	1.7%	1.5%	-0.1%	0.0%	-0.1%
2004	1.3%	2.0%	1.1%	1.2%	2.1%	0.9%	-0.1%	0.0%	-0.1%
2005	1.3%	1.8%	1.1%	0.9%	1.5%	0.8%	-0.1%	-0.2%	-0.2%
2006	1.6%	1.9%	1.2%	1.1%	1.1%	0.9%	-0.3%	-0.4%	-0.2%
2007	1.2%	1.9%	1.4%	0.8%	1.2%	0.8%	-0.2%	-0.3%	-0.3%
2008	1.6%	1.6%	0.9%	1.0%	1.1%	0.5%	-0.3%	-0.3%	-0.2%
2009	1.6%	1.9%	1.3%	1.0%	1.2%	0.7%	-0.3%	-0.3%	-0.3%
Av Growth									
1999-2004	1.5%	1.6%	1.4%	1.3%	1.5%	1.2%			
2004-2009	1.5%	1.8%	1.2%	1.0%	1.2%	0.7%			

APPENDIX B – LOAD RESEARCH RESULTS

Load Research Programme Overview

In 1999 EnergyAustralia embarked on a comprehensive Load Research programme in order to provide an insight into the following aspects of customer behaviour:

- Time-of-day electricity usage patterns;
- Day-of-week electricity usage patterns (workdays, weekends);
- Seasonal usage patterns (especially in summer and winter);
- Intra-seasonal usage patterns (day-to-day temperature effects); and
- Diversity in usage patterns among customer classes and sub-classes.

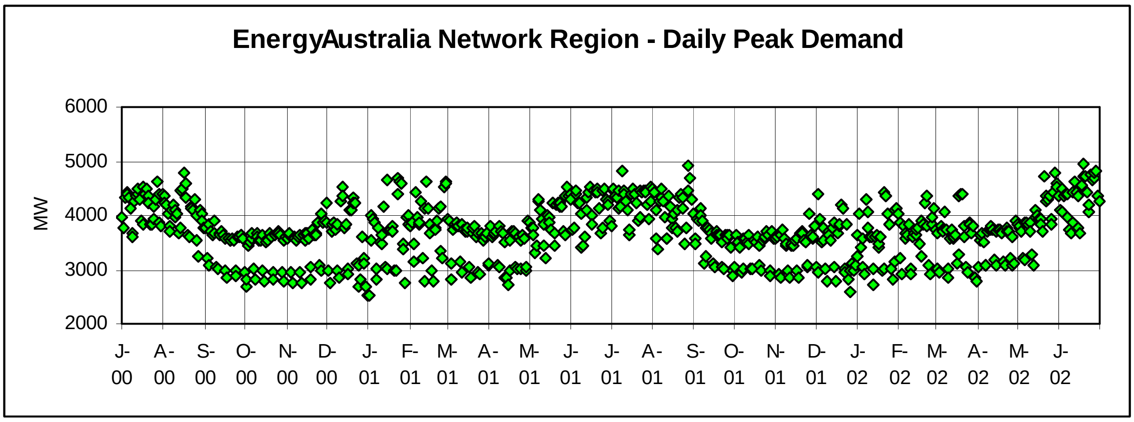
The programme involved the analysis of half-hourly load profile data and the associated characteristics from a sample of some 230 households and 110 Small/Medium Enterprises. The load profiles of individual appliances in a subsample of 95 of the sample households were also analysed.

The programme is ongoing, and to date almost 3 years of load data has been collected and analysed. The key insights gained from the analysis from a forecasting point of view are set out below.

Variability of Load Levels

Overall EA Network

The daytype and seasonal characteristics of overall Network daily peak demands are summarised below.



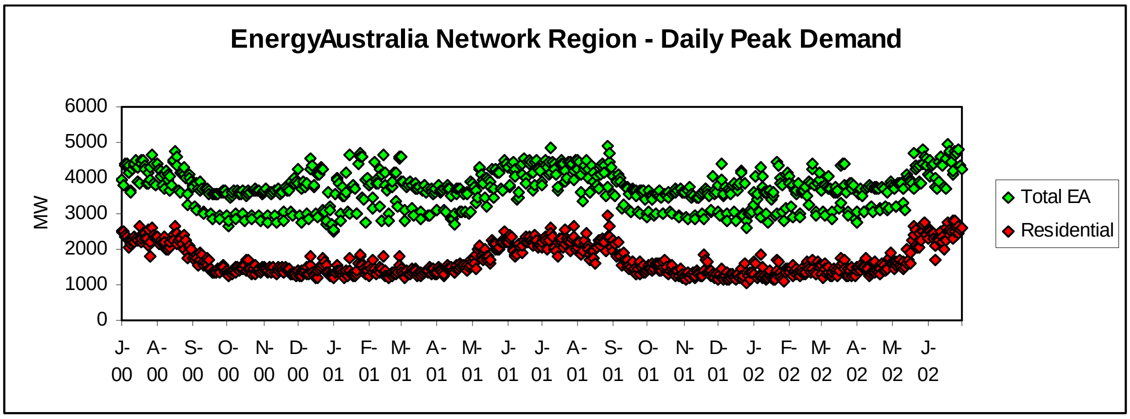
Daily loads are clearly seasonal, being higher, and more volatile from day-to-day, in winter and summer than in spring and autumn. Loads are also sensitive to day-types, being higher on workdays than non-workdays.

Contribution of Residential sector to overall EA Network load variability

The day-type and seasonal characteristics of the overall Network load are compared with those of the Residential sector component in the Figure below.

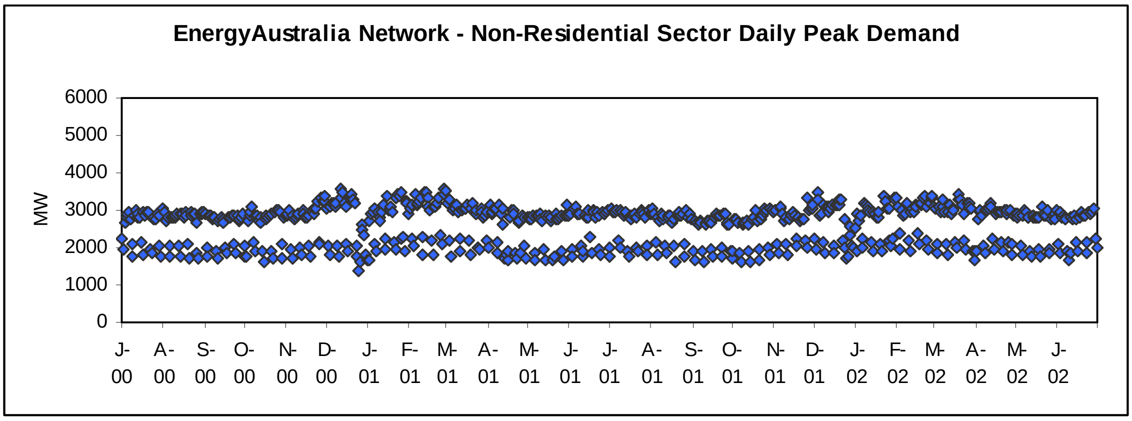
Compared with the total load, Residential loads are less sensitive to day-types. The lower points on the Total EA load trace generally represent weekend and public holiday loads. The distinction between workdays and non-workdays in the Residential load trace is less obvious.

Residential daily load levels exhibit a high degree of seasonality being highest in winter, followed by summer and then the other seasons. In both winter and summer the day-to-day volatility of the Residential Sector largely explains the corresponding volatility in overall daily peak demands. Residential peak loads tend to coincide with system peak loads in the winter months, but are somewhat diverse from summer system peaks.



Contribution of Non-Residential sector to overall EA Network load variability

The day-type and seasonal characteristics of Non-Residential Sector loads are summarised below.



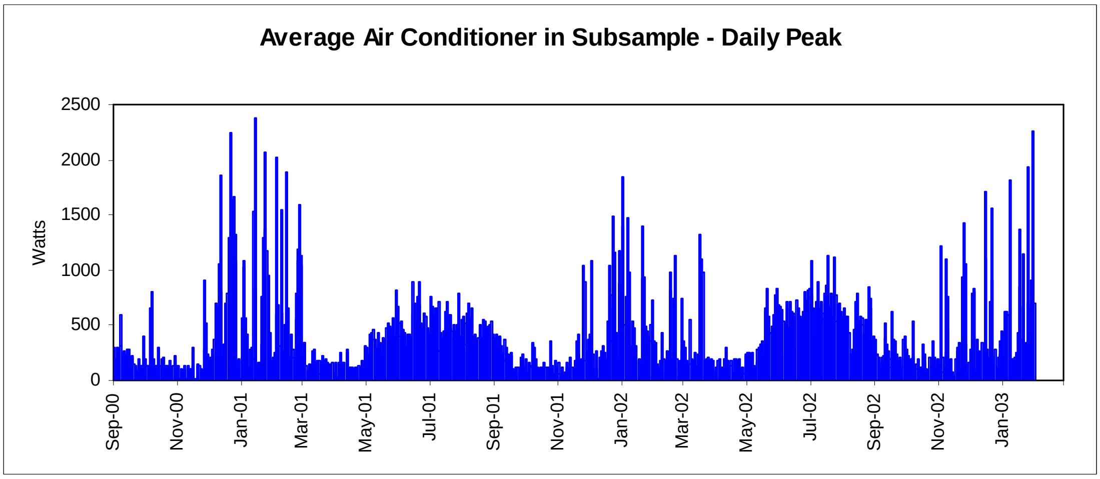
Non-Residential loads are extremely sensitive to day-types. The lower points on the graphs represent weekend and public holiday loads. Summer Non-Residential load levels also exhibit a significant downturn from Christmas to late January.

Non-Residential load levels are seasonal, being higher, and more volatile from day-to-day, in summer than in the other seasons. There is little difference in winter, spring and autumn load levels.

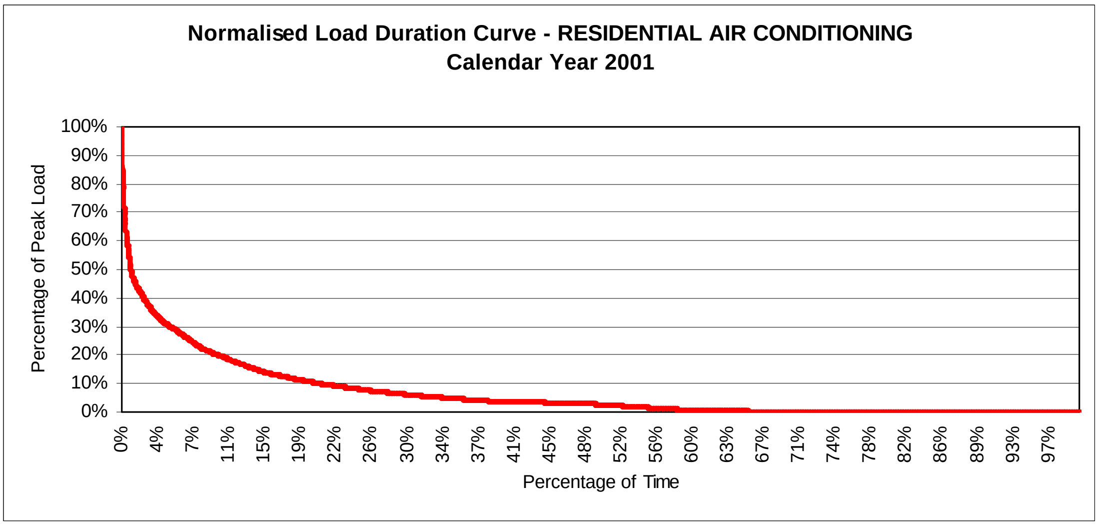
Residential Air Conditioning

As noted previously, one of the key drivers of recent load growth has been the rapid penetration of residential air conditioning which has increased from an estimated 350,000 customers in 1996/97 to 570,000 customers in 2001/02. Growth in penetration is expected to continue over the forecast period and reach 820,000 by 2008/09. This expected growth has important implications from a Network Planning perspective, as load research results suggest that air conditioning has a disproportionately severe impact on summer peak demand levels as compared to annual energy consumption. Air Conditioners are used very intermittently, but typical time of use is a key driver of network peak demand.

The intermittent nature of the operation of air conditioners is shown in the figure below which illustrates the daily peak load level of the average air conditioning unit.



The load duration curve (LDC) of the average air conditioner, as estimated from sample metered data, is shown below.



The LDC illustrates the extreme "peakiness" of Residential air conditioning. Air conditioners are virtually idle for 40% of the year, and for 95% of the hours in the year they operate at less than 36% of capacity.

In financial year 2000/01, Residential air conditioners are estimated to have contributed just 2.5% to total energy consumption, compared with a 19.5% contribution to Network load at the time of summer peak demand. The implications for future EnergyAustralia revenue associated with ongoing penetration of air conditioning are very small compared to the need for expansion of capacity.

APPENDIX C - SENSITIVITY ANALYSIS

The range of forecast growth rates associated with the expected, high and low growth scenarios gives an indication of the sensitivity of future electricity consumption levels to assumed trends in the drivers of consumption.

This section highlights the sensitivity of the forecasts through explicit examples over the forecast period.

Residential Sector

As noted in Section 4 the key drivers of Residential sector electricity consumption are customer numbers and average consumption per customer, which is in turn a function of appliance holdings.

Customer Numbers

Expected:	Additional 96,000 customers by 2008/09 (average growth of 13,700 p.a.)
Sensitivity:	If actual growth is +/- 5,000 p.a. compared with forecast:
Impact on Forecast:	Annual consumption forecast in 2008/09 is out by +/- 0.9% or 250 GWh Summer peak forecast in 2008/09 is out by +/- 0.8% or 45 MW.

Customers with Air Conditioning

Expected:	Additional 246,000 customers have air conditioning by 2008/09 (average growth of 35,100 p.a.)
Sensitivity:	If actual growth is +/- 5,000 p.a. compared with forecast:
Impact on Forecast:	Annual consumption forecast in 2008/09 is out by +/- 0.1% or 40 GWh. Summer peak forecast in 2008/09 is out by +/- 0.9% or 50 MW.

Customers with Off-Peak Water Heating

Expected:	Additional 29,000 customers have off-peak water by 2008/09 (average growth of 4,100 p.a.)
Sensitivity:	If actual growth is +/- 5,000 p.a. compared with forecast:
Impact on Forecast:	Annual consumption forecast in 2008/09 is out by +/- 0.4% or 125 GWh. Summer peak forecast impact is negligible.

Non-Residential Sector

As noted in Section 5 the key driver of Non-Residential sector electricity consumption is economic activity.

Economic Activity

Expected:	Average growth of 2.6% p.a. over the 2004-09 period.
Sensitivity:	If actual economic growth is +/- 0.5% p.a. compared with forecast:
Impact on Forecast:	Annual consumption forecast in 2008/09 is out by +/- 1.5% or 425 GWh. Summer peak forecast in 2008/09 is out by +/- 1.6% or 90 MW.

Large (20 MW, 90% capacity factor) customer ceases business or relocates outside EA region

Expected:	n.a.
Impact on Forecast:	Annual consumption forecast in 2008/09 is out by –0.5% or 160 GWh. Summer peak forecast in 2008/09 is out by –0.3% or 20 MW.

Weather Related Sensitivity – Impact on Annual Energy Consumption

Above Average Summer Temperatures – Summer of 2000/01
Expected: Average weather conditions (weather index = 252 cooling degree days)
Sensitivity: Summer 2000/01 weather index was 345

Impact on Forecast: Weather-related consumption added 161 GWh to annual consumption

Above Average Summer Temperatures – Summer of 1997/98
Expected: Average weather conditions (weather index = 252).
Sensitivity: Summer 1997/98 weather index was 404

Impact on Forecast: Weather-related consumption added 155 GWh to annual consumption

Below Average Summer Temperatures – Summer of 2001/02
Expected: Average weather conditions (weather index = 252).
Sensitivity: Summer 2001/02 weather index was 235

Impact on Forecast: Consumption was reduced by 27 GWh

Above Average Winter Temperatures – Winter of 2000
Expected: Average weather conditions (weather index = 502).
Sensitivity: Winter 2000 weather index was 526

Impact on Forecast: Weather-related consumption added 43 GWh to annual consumption

Below Average Winter Temperatures – Winter of 2001
Expected: Average weather conditions (weather index = 502 heating degree days).
Sensitivity: Winter 2001 weather index was 459

Impact on Forecast: Consumption was reduced by 77 GWh

Zone Substation Spatial Demand Forecasts

April 2003

SUBSTATION NAME	2002 Substation Firm Capacity (MVA)		2002 Peak Demand (MVA)		2002 Historical Utilisation (%)			2009 "Do Nothing" Forecast Utilisation (%)		
	Summer	Winter	Summer	Winter	Summer	Winter	Max	Summer	Winter	Max
Aberdeen	7.00	7.00	6.37	5.79	91%	83%	91%	98%	86%	98%
Adamstown	22.90	22.90	15.20	26.19	66%	114%	114%	77%	125%	125%
Alexandria 5kV	14.77	15.68	7.86	6.70	53%	43%	53%	53%	43%	53%
Arncliffe	26.77	28.39	18.04	22.67	67%	80%	80%	132%	159%	159%
Auburn	45.92	48.58	41.21	35.13	90%	72%	90%	106%	84%	106%
Avoca	30.48	30.48	29.97	39.78	98%	130%	130%	143%	184%	184%
Avondale	22.90	22.90	22.63	26.66	99%	116%	116%	135%	144%	144%
Baerami	1.10	1.10	1.03	1.15	94%	105%	105%	101%	138%	138%
Balgowlah	28.86	28.86	23.85	34.79	83%	121%	121%	118%	140%	140%
Bass Hill	27.72	29.44	24.69	26.01	89%	88%	89%	97%	93%	97%
Beacon Hill	27.44	27.44	22.73	21.19	83%	77%	83%	105%	77%	105%
Belrose	24.39	25.72	14.16	22.18	58%	86%	86%	77%	101%	101%
Berkeley Vale	31.63	32.01	33.28	32.87	105%	103%	105%	170%	159%	170%
Berowra	22.67	24.10	15.68	23.74	69%	98%	98%	102%	127%	127%
Blackwattle Bay 5kV	42.74	43.82	32.67	28.91	76%	66%	76%	86%	77%	86%
Blakehurst	23.91	24.39	19.49	25.82	82%	106%	106%	96%	125%	125%
Boolaroo	27.90	27.90	30.78	32.19	110%	115%	115%	67%	59%	67%
Botany	41.44	46.20	34.20	32.29	83%	70%	83%	83%	73%	83%
Bradford	5.50	5.50	7.67	7.08	139%	129%	139%	172%	146%	172%
Branxton	10.00	10.00	10.66	8.87	107%	89%	107%	179%	108%	179%
Broadmeadow	22.90	22.90	28.47	21.86	124%	95%	124%	155%	103%	155%
Brookvale	53.82	58.30	47.04	41.55	87%	71%	87%	104%	83%	104%
Burwood	92.88	97.64	66.32	65.83	71%	67%	71%	99%	87%	99%
Camperdown 5kV	54.17	55.43	42.95	41.72	79%	75%	79%	82%	81%	82%
Campsie	61.25	66.21	46.98	55.67	77%	84%	84%	80%	87%	87%
Cardiff	22.90	22.90	30.07	22.97	131%	100%	131%	188%	115%	188%
Careel Bay	12.86	14.29	11.22	15.24	87%	107%	107%	137%	121%	137%
Caringbah	30.29	34.39	25.17	33.04	83%	96%	96%	104%	121%	121%
Carlton	47.25	50.87	45.57	50.37	96%	99%	99%	104%	117%	117%
Carrington	26.20	26.20	21.34	23.21	81%	89%	89%	94%	100%	100%
Castle Cove	76.11	76.69	65.88	60.42	87%	79%	87%	109%	107%	109%
Cessnock	22.90	22.90	32.71	27.85	143%	122%	143%	187%	153%	187%
Charlestown	27.40	27.40	25.21	23.16	92%	85%	92%	119%	89%	119%
Charmhaven	67.16	74.97	22.98	28.39	34%	38%	38%	62%	64%	64%
Chatswood	61.64	66.59	50.51	55.88	82%	84%	84%	106%	101%	106%
City Central 33_11kV	64.02	69.35	68.70	54.97	107%	79%	107%	107%	79%	107%
City East	53.92	53.92	55.12	44.09	102%	82%	102%	102%	82%	102%
City Main	35.50	37.00	58.79	43.88	166%	119%	166%	217%	137%	217%
City North	63.73	63.73	55.61	44.49	87%	70%	87%	87%	70%	87%
City South	185.19	185.19	185.19	148.15	100%	80%	100%	100%	80%	100%
Clovelly	100.60	111.55	63.14	90.19	63%	81%	81%	91%	106%	106%
Concord	33.34	36.77	28.77	26.96	86%	73%	86%	124%	123%	124%
Cronulla	55.92	64.02	26.94	42.83	48%	67%	67%	69%	85%	85%
Crows Nest	58.11	59.83	49.52	47.56	85%	79%	85%	95%	88%	95%
Dalley Street	164.42	164.42	159.60	127.69	97%	78%	97%	97%	78%	97%
Darling Harbour	76.21	76.21	34.75	28.56	46%	37%	46%	72%	60%	72%
Darlinghurst	79.45	86.59	75.43	62.09	95%	72%	95%	115%	81%	115%
Dee Why West	47.54	50.87	31.15	45.42	66%	89%	89%	80%	100%	100%
Denman	15.40	15.40	9.10	6.37	59%	41%	59%	86%	53%	86%
Double Bay	53.06	85.07	40.32	50.24	76%	59%	76%	100%	75%	100%
Drummoyne	56.11	61.73	41.63	61.64	74%	100%	100%	109%	135%	135%
Dudley	8.50	8.50	9.24	11.60	109%	136%	136%	109%	141%	141%
Dulwich Hill	52.59	54.68	36.35	48.72	69%	89%	89%	73%	101%	101%
East Maitland	27.40	27.40	32.21	29.93	118%	109%	118%	183%	140%	183%
Edgeworth	22.90	22.90	25.67	24.72	112%	108%	112%	191%	158%	191%
Enfield	42.49	43.63	26.83	33.11	63%	76%	76%	82%	87%	87%
Engadine	28.96	34.01	22.90	31.47	79%	93%	93%	108%	119%	119%
Epping	75.07	79.45	58.57	60.02	78%	76%	78%	115%	90%	115%
Erina	38.87	50.78	37.15	42.35	96%	83%	96%	157%	113%	157%
Five Dock	58.40	63.25	30.39	42.07	52%	67%	67%	74%	92%	92%
Flemington	106.31	108.03	60.32	52.24	57%	48%	57%	68%	58%	68%
Gateshead	13.40	13.40	13.70	11.54	102%	86%	102%	73%	60%	73%
Gore Hill	97.64	97.64	64.80	57.12	66%	58%	66%	77%	67%	77%
Graving Dock	16.00	16.39	12.35	8.63	77%	53%	77%	77%	53%	77%
Greenacre Park	94.98	99.84	80.44	70.86	85%	71%	85%	100%	84%	100%
Gwawley Bay	34.87	36.96	29.84	30.85	86%	83%	86%	107%	93%	107%
Harbord	27.72	30.58	16.39	25.78	59%	84%	84%	73%	98%	98%

SUBSTATION NAME	2002 Substation Firm Capacity (MVA)		2002 Peak Demand (MVA)		2002 Historical Utilisation (%)			2009 "Do Nothing" Forecast Utilisation (%)		
	Summer	Winter	Summer	Winter	Summer	Winter	Max	Summer	Winter	Max
Homebush Bay	60.97	60.97	24.63	24.29	40%	40%	40%	52%	48%	52%
Hornsby	64.40	67.64	63.25	69.35	98%	103%	103%	147%	129%	147%
Hunters Hill	64.02	70.02	52.57	59.37	82%	85%	85%	109%	99%	109%
Hurstville North	25.24	26.29	26.43	27.36	105%	104%	105%	118%	135%	135%
Jannali	28.96	36.87	24.90	33.97	86%	92%	92%	107%	98%	107%
Jewells	15.60	15.60	12.91	15.44	83%	99%	99%	116%	105%	116%
Killarney	19.91	19.91	11.58	16.96	58%	85%	85%	72%	101%	101%
Kirrawee	33.44	35.53	27.11	35.32	81%	99%	99%	91%	118%	118%
Kotara	16.10	16.10	16.88	15.59	105%	97%	105%	158%	119%	158%
Kurnell 11kV	28.67	29.25	25.38	24.44	89%	84%	89%	129%	120%	129%
Kurnell 6.3kV	9.71	9.71	8.48	5.82	87%	60%	87%	87%	60%	87%
Kurri	27.40	27.40	22.01	19.29	80%	70%	80%	115%	89%	115%
Lake Munmorah	15.24	17.24	11.97	12.99	79%	75%	79%	144%	107%	144%
Leichhardt	31.44	34.58	27.49	32.83	87%	95%	95%	108%	114%	114%
Leightonfield	32.96	32.96	24.33	23.00	74%	70%	74%	76%	74%	76%
Lemington	4.70	4.70	3.23	2.40	69%	51%	69%	82%	71%	82%
Lidcombe	31.91	33.53	25.57	22.06	80%	66%	80%	103%	79%	103%
Lindfield	39.44	42.01	28.67	39.32	73%	94%	94%	87%	97%	97%
Lisarow	24.96	27.25	20.92	26.46	84%	97%	97%	96%	112%	112%
Long Jetty	39.06	45.73	36.37	42.70	93%	93%	93%	134%	98%	134%
Lucas Heights	5.72	5.72	5.30	4.73	93%	83%	93%	205%	180%	205%
Macquarie Park	65.73	68.40	38.94	38.62	59%	56%	59%	104%	74%	104%
Maitland Central	22.50	22.50	20.06	15.24	89%	68%	89%	113%	78%	113%
Manly	23.24	26.20	18.84	26.08	81%	100%	100%	91%	124%	124%
Maroubra	45.82	45.82	48.53	50.97	106%	111%	111%	142%	152%	152%
Marrickville	78.12	78.69	60.23	60.80	77%	77%	77%	78%	79%	79%
Mascot	62.02	63.06	43.54	35.74	70%	57%	70%	83%	67%	83%
Matraville	62.49	69.26	39.99	48.47	64%	70%	70%	67%	71%	71%
Mayfield	22.10	22.10	24.44	23.28	111%	105%	111%	123%	106%	123%
Meadowbank	102.88	102.88	60.42	66.53	59%	65%	65%	91%	100%	100%
Menai	64.97	74.50	32.18	42.32	50%	57%	57%	75%	84%	84%
Merriwa	3.30	3.30	3.04	3.22	92%	98%	98%	114%	103%	114%
Milperra	47.16	47.16	43.17	42.35	92%	90%	92%	96%	91%	96%
Miranda	36.87	37.44	32.26	38.52	87%	103%	103%	116%	134%	134%
Mitchell Line	27.50	27.50	5.09	4.04	19%	15%	19%	26%	18%	26%
Mitchells Flat	5.50	5.50	0.64	0.58	12%	11%	12%	12%	11%	12%
Mona Vale	26.01	29.82	23.28	29.89	90%	100%	100%	107%	124%	124%
Moonan	3.30	3.30	1.19	1.29	36%	39%	39%	43%	46%	46%
Mortdale	47.82	51.44	34.94	46.89	73%	91%	91%	87%	108%	108%
Mosman	73.54	82.50	52.18	79.70	71%	97%	97%	81%	100%	100%
Mt.Hutton	27.30	27.30	30.84	32.57	113%	119%	119%	154%	128%	154%
Mt.Thorley	12.00	12.00	8.81	7.07	73%	59%	73%	99%	91%	99%
Muswellbrook	22.90	22.90	19.85	18.91	87%	83%	87%	113%	99%	113%
Narrabeen	19.72	21.24	11.22	16.86	57%	79%	79%	74%	94%	94%
Nelson Bay	45.00	45.00	31.29	34.25	70%	76%	76%	94%	95%	95%
New Lambton	16.00	16.00	17.66	17.53	110%	110%	110%	168%	144%	168%
Newdell	25.00	25.00	6.81	7.02	27%	28%	28%	27%	28%	28%
Newport	22.58	22.67	11.30	16.52	50%	73%	73%	59%	75%	75%
Noraville	22.58	24.29	15.78	22.81	70%	94%	94%	110%	130%	130%
North Head	22.86	25.44	19.40	12.14	85%	48%	85%	85%	48%	85%
North Ryde	41.73	41.73	27.42	29.11	66%	70%	70%	95%	85%	95%
North Sydney	111.65	112.22	91.51	75.47	82%	67%	82%	82%	67%	82%
Paddington	53.63	56.30	43.08	49.96	80%	89%	89%	86%	92%	92%
Padstow	46.58	48.01	41.95	40.09	90%	83%	90%	96%	87%	96%
Paxton	5.00	5.00	3.62	4.20	72%	84%	84%	90%	114%	114%
Peats Ridge	12.96	13.15	12.59	12.52	97%	95%	97%	124%	116%	124%
Pelican	12.00	12.00	12.35	10.79	103%	90%	103%	131%	103%	131%
Pennant Hills	100.22	112.79	64.04	79.43	64%	70%	70%	86%	80%	86%
Punchbowl	72.78	77.73	38.79	45.88	53%	59%	59%	59%	64%	64%
Pymble	38.96	41.53	36.39	44.60	93%	107%	107%	118%	116%	118%
Randwick	63.64	67.35	34.10	46.30	54%	69%	69%	68%	78%	78%
Raymond Terrace	22.90	22.90	25.54	23.00	112%	100%	112%	154%	116%	154%
Revesby	45.82	51.16	37.50	48.41	82%	95%	95%	100%	115%	115%
Riverwood	27.44	27.44	20.27	25.28	74%	92%	92%	87%	108%	108%
Rockdale	22.29	25.15	17.66	18.46	79%	73%	79%	99%	85%	99%
Rose Bay	48.39	49.92	26.98	39.23	56%	79%	79%	76%	91%	91%
Rothbury	15.00	15.00	7.78	5.08	52%	34%	52%	78%	42%	78%

SUBSTATION NAME	2002 Substation Firm Capacity (MVA)		2002 Peak Demand (MVA)		2002 Historical Utilisation (%)			2009 "Do Nothing" Forecast Utilisation (%)		
	Summer	Winter	Summer	Winter	Summer	Winter	Max	Summer	Winter	Max
Rouchel	2.70	2.70	1.82	1.52	67%	56%	67%	101%	104%	104%
Salt Ash	6.00	6.00	7.99	9.59	133%	160%	160%	138%	168%	168%
Sans Souci	22.58	22.86	15.38	23.30	68%	102%	102%	75%	122%	122%
Scone	13.70	13.70	12.74	11.71	93%	85%	93%	126%	106%	126%
Sefton	46.96	47.16	41.88	46.53	89%	99%	99%	105%	113%	113%
Shortland	27.60	27.60	24.33	21.71	88%	79%	88%	113%	91%	113%
Singleton	22.90	22.90	26.73	24.30	117%	106%	117%	153%	120%	153%
Somersby	56.21	56.21	12.71	13.41	23%	24%	24%	56%	57%	57%
St. Ives	27.72	29.91	27.23	36.14	98%	121%	121%	136%	155%	155%
St. Peters	94.02	98.79	67.66	63.31	72%	64%	72%	81%	69%	81%
Stockton	9.80	9.80	4.76	5.43	49%	55%	55%	56%	59%	59%
Surry Hills	80.21	82.12	63.81	53.82	80%	66%	80%	84%	66%	84%
Swansea	15.60	15.60	10.45	11.89	67%	76%	76%	82%	77%	82%
Tarro	22.90	22.90	32.10	25.67	140%	112%	140%	202%	129%	202%
Telarah	13.70	13.70	15.80	14.22	115%	104%	115%	151%	115%	151%
Terrey Hills	10.29	10.29	11.70	12.80	114%	124%	124%	160%	178%	178%
Toronto	26.90	26.90	27.62	33.67	103%	125%	125%	133%	145%	145%
Turramurra	42.01	43.44	31.61	47.04	75%	108%	108%	89%	116%	116%
Umina	30.48	30.48	24.46	27.99	80%	92%	92%	123%	117%	123%
Vales Point	11.72	11.72	8.25	8.35	70%	71%	71%	70%	71%	71%
Wallalong	5.50	5.50	1.74	1.81	32%	33%	33%	41%	45%	45%
Wallsend	27.10	27.10	29.48	27.19	109%	100%	109%	166%	120%	166%
Waverley	41.15	46.87	24.71	33.17	60%	71%	71%	63%	76%	76%
West Gosford	38.87	38.87	38.18	32.85	98%	85%	98%	153%	107%	153%
Williamtown	13.40	13.40	17.20	15.73	128%	117%	128%	216%	173%	216%
Woy Woy	38.11	38.11	22.37	29.34	59%	77%	77%	106%	117%	117%
Wyong	54.01	58.68	25.21	24.75	47%	42%	47%	70%	60%	70%
Zetland	100.22	105.27	81.01	67.79	81%	64%	81%	109%	93%	109%

SKM Report on EnergyAustralia's Operating Cost Program

April 2003

EnergyAustralia operates a network that includes both distribution and transmission elements. The elements of the network that are defined to be transmission assets are captured because they operate in parallel and provide support to other transmission assets (ie TransGrid). Often EnergyAustralia's transmission assets are different from distribution assets in name only. In other words, they are the same assets, but are used in a part of the network that is configured to be parallel This report written by SKM provides analysis of operating and maintenance expenditure for the entire network.

Most of the sections of this report will be of some interest to the ACCC in terms of its transmission network review. However, the sections that relate specifically to EnergyAustralia's transmission assets are highlighted below:

Sections 1-7 provide general information about EnergyAustralia's network assets including age profiles. Section 4 provides a comparative analysis of operating costs between EnergyAustralia and other distribution company's performance on opex. SKM has not provides a comparison of costs with other transmission companies.

Sections 8 and 9 specifically discuss higher voltage assets, a high proportion of which are transmission assets (see 8.2.2 and section 9). Also, Section 13 provides specific assessment of the condition of these higher voltage assets.

EnergyAustralia

Operational and Maintenance (O&M) Expenditure Review and Projection for the 2004/05-2008/09 Regulatory Period

April 2003: Final Report (Commercially Sensitive)

ATTACHMENT 5

EnergyAustralia

Operational and Maintenance (O&M) Expenditure Review and Projection for the 2004/05-2008/09 Regulatory Period

April 2003 Final Report (Commercially Sensitive)

Sinclair Knight Merz Pty Limited
ACN 001 024 095
ABN 37 001 024 095
PO Box 246
Spring Hill QLD 4004
369 Ann Street
Brisbane QLD 4000
Australia
Telephone: +61 7 3244 7100
Facsimile: +61 7 3244 7301

Contents

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1. Executive Summary

1.1 Forecast O&M Expenditure

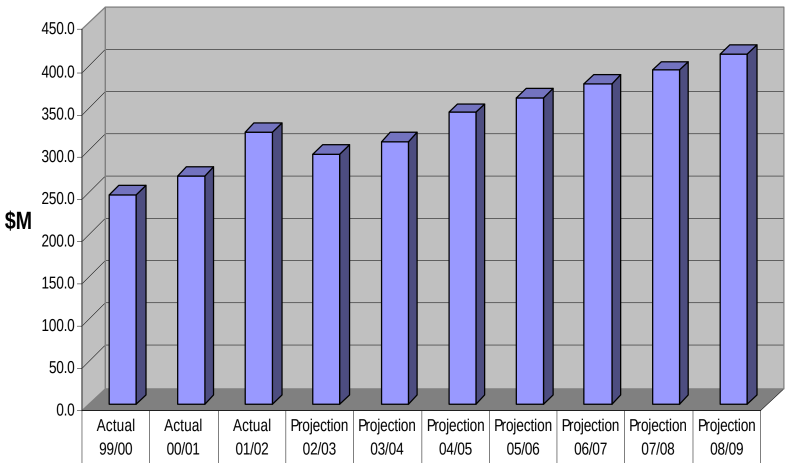
EnergyAustralia has engaged Sinclair Knight Merz to review its historical operating and maintenance expenditure (O&M), and to develop a "baseline" O&M forecast for its Networks Line of Business (NLOB) for the next five year regulatory period (2004/05 to 2008/09).

Having analysed EA Network LOB operations, interviewed key management and incorporated other relevant factors, SKM is of the view that the appropriate level of O&M expenditure for the Networks Line of Business is as shown in Figure 1-1 (Nominal Values) and Figure 1-2 (Real Values).

Figure 1-3 provides actual and forecast O&M expenditure (Nominal Values) for the period 1999/00 to 2008/09, broken down by subsidiary (Enerserve, Customer Service, Network) and including corporate overheads.

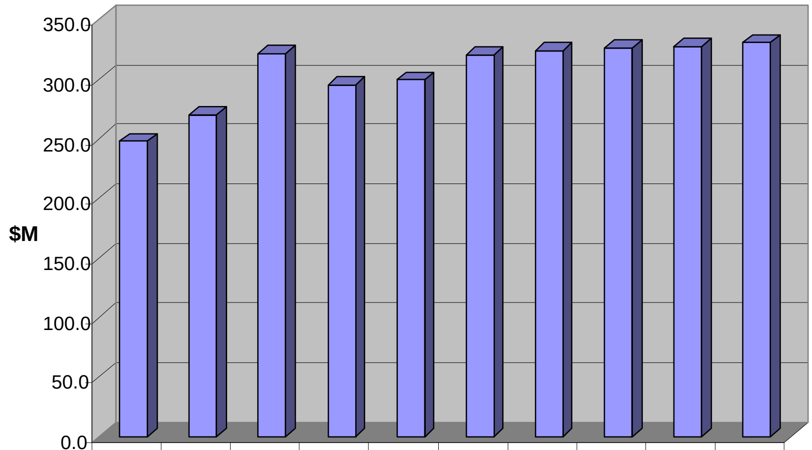
Figure 1-4 provides the same break-down of costs using real values.

■ **Figure 1-1 Network LOB Total O&M Expenditure – Nominal Values**



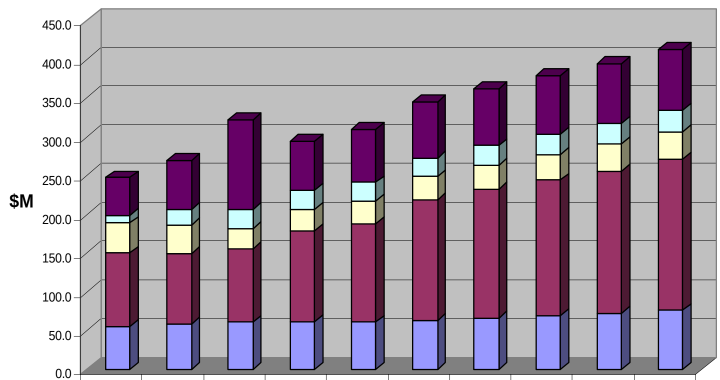
	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Total Adjusted O&M Expenditure	247.3	270.0	321.4	294.8	310.1	344.4	362.0	378.4	394.2	413.2

- **Figure 1-2 Network LOB Total O&M Expenditure – Real Values**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Total Adjusted O&M	247.3	270.0	321.4	294.8	299.2	319.8	323.7	326.0	327.1	330.2

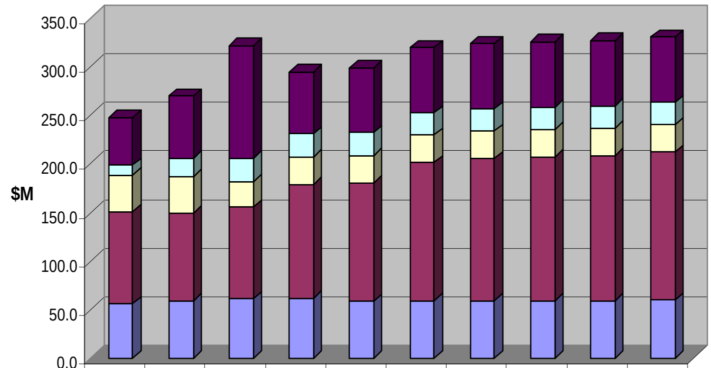
- **Figure 1-3 EnergyAustralia O&M Expenditure – Contributors (Nominal Values)**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Corporate Overheads	48.9	63.9	115.1	64.0	69.0	71.1	73.2	75.2	77.3	79.5
External Contracts	9.6	19.1	24.9	23.7	24.1	24.4	24.9	25.8	26.2	26.7
Netw ork internal	38.3	37.9	26.1	28.0	29.2	30.5	31.8	33.3	34.7	36.3
Enerserve adjusted total	94.7	89.8	94.3	117.7	126.6	154.4	165.3	174.4	183.0	194.4
Customer Services	55.8	59.3	61.0	61.5	61.2	64.0	66.8	69.7	73.0	76.4

Note: All figures are nominal costs escalated to the year in which expenditure is expected.

■ Figure 1-4 Breakdown (Real Values)



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Corporate Overheads	48.9	63.9	115.1	64.0	67.2	67.2	67.2	67.2	67.2	67.2
External Contracts	9.6	19.1	24.9	23.7	23.5	23.1	22.9	23.1	22.8	22.6
Netw ork internal	38.3	37.9	26.1	28.0	28.0	28.1	28.2	28.3	28.3	28.4
Enerserve adjusted total	94.7	89.8	94.3	117.7	121.6	142.4	146.3	148.2	149.3	152.2
Customer Services	55.8	59.3	61.0	61.5	58.8	59.0	59.1	59.3	59.5	59.8

1.2 Key Findings and Conclusions

- EnergyAustralia will require a total Network line of business O&M expenditure of $1 892.2 over the next 5 year regulatory period (nominal values incl. CPI and labour adjustments). Refer to Figure 1.1.
- O&M expenditure will be impacted unfavourably by operational requirements such as Regulation 2001 (OH&S) ($8M), bushfire mitigation legislation, and bushfire mitigation strategies (disabling of auto-reclose) ($480k pa).
- A number of external factors have materialised within the current regulatory period and have impacted O&M expenditure in this period. They will continue to impact expenditure in the next period. The net difference in cost impact between the two periods is calculated as $30.5M and represents the additional costs that EnergyAustralia will incur as a result of changed external parameters over which they have little or no control. Refer to Section 15.
- Growth in customer connections, and additional network assets will increase O&M expenditure by $22.8M over the next five year regulatory period. Refer to Table 1, Appendix A.
- Increasing capital expenditure on asset refurbishment, as recommended in SKM report “Capex Assessment – Stage 2” will result in a reduction of total O&M costs over the next 5 year regulatory period of $27.3M. Refer to Table 1, Appendix A.
- The ratio of planned maintenance to corrective and storm/emergency repairs indicates a balanced approach close to optimum, ie. planned maintenance is at an adequate level, while not being excessive.
- SKM’s review of EA’s maintenance policies and practices indicates that the network is in a generally sound state, subject to the obvious qualifications about the aging nature of the assets, particularly zone/subtransmission substations and transmission/subtransmission cables.
- There is evidence of an increasing backlog of corrective maintenance items, as reported in the TIS database. The backlog of corrective maintenance is not at an unmanageable level however, provided sufficient funds are provided to address the current backlog. The SKM forecast O&M expenditure caters for the appropriate reduction in this backlog.
- The current level of pole inspections and vegetation management is consistent with good industry practice.
- The overall level of reliability of the EA network, as measured by SAIDI and SAIFI is stable, and is consistent, if not superior to the performance of equivalent networks. Refer to Figures 13.1, 13.2 and 13.4.
- There is some evidence that total customer interruptions has increased over the period 1997 to 2002. Refer to Figure 13.3.
- EnergyAustralia has one of the oldest network age profiles of any electricity distributor in Australia, with a weighted average network age of 29.6 years (weighted by $ value at 30/6/02). It is further noted that the average age of the network will continue to worsen by about 1.95 years over the next regulatory period. Refer to Section 3.

- SKM modelling has revealed that for every additional year that is added to the average network age, an additional $20M approx. is required in O&M expenditure. Refer Table 3.4.
- SKM has made provision, for the introduction of EA's transition to an "asset specific, condition based, maintenance regime" (the FMECA project). There remain some differences however between the respective O&M forecasts.
- SKM supports EA's strategy of adopting "asset specific condition based maintenance" and notes that it will result in a more targeted approach to planned maintenance, and should result in due course to a reduction in corrective and breakdown maintenance.
- Based on an independent analysis of Market Prices for distribution activities, Enerserve provides such services to EnergyAustralia Networks on average at a level very close to the Deemed Market Price for such services. The overall variance is on average less the 0.5% from the Deemed Market Price.
- Based on cross-jurisdictional studies, EnergyAustralia's previous determination (1998) for operational expenditure was substantially below the industry average.
- Based on these same cross-jurisdictional studies, we consider that the SKM projected O&M expenditure for EnergyAustralia represents an appropriate and efficient level of expenditure, given the age profile of the EnergyAustralia system.

1.3 Context

In preparing this "baseline" O&M forecast for the next regulatory period, SKM has given particular attention to the following issues:

- The underlying level of appraisal, planned and corrective maintenance required to maintain the network in a safe, reliable and serviceable state.
- The planned transition from "time-based" to "asset specific, condition-based maintenance" (the FMECA project).
- The CAPEX/OPEX trade-off associated with the proposed increase in refurbishment capital expenditure.

The SKM forecasts are based upon:

- Interviews with EnergyAustralia staff across Networks, Enerserve and Customer Service Divisions,
- Historic O&M expenditure especially 2001/02 actuals, provided by EnergyAustralia,
- Our analysis and determination of efficient O&M expenditure based upon our experience with other electricity companies, and EnergyAustralia specific modelling which we have developed for the purpose.

2. Introduction

2.1 Scope

Sinclair Knight Merz has been engaged by EnergyAustralia to research and report on the historical levels of O&M expenditure for the regulated network business, and to develop a sustainable and justifiable forecast of O&M expenditure for the next 5 year regulatory period (1994/95 to 1998/99). The projected O&M expenditure is to be for the regulated "Network Line of Business" only, as it is to exclude any operating costs and overheads associated with retail activities, and external competitive business activities.

The forecast O&M expenditure is to represent a credible "baseline" estimate of the required O&M expenditure to continue to maintain the network assets in a safe, reliable and satisfactory condition into the future. The forecast is to make appropriate provision for:

- The underlying level of appraisal, planned and corrective maintenance required to maintain the network in a safe, reliable and serviceable state.
- The expected level of emergency and repair costs appropriate to the ageing nature and general condition of the assets, and the environment in which they are expected to operate.
- Any identified backlog of critical maintenance works that may be outstanding at the end of the current regulatory period.
- The transition from "time-based" to "asset specific, condition based "maintenance as proposed by EnergyAustralia (the FMECA project), taking cost figures developed by Enerserve.
- Any increased costs flowing from recent statutory, safety, regulatory, environmental, and community expectations.
- Any potential reduction in costs resulting from reduced work volumes and/or identification of "one-offs" and abnormals.
- Reasonable allowance for customer and network growth.
- Expected reduction in O&M costs resulting from the recommended increase in refurbishment capex expenditure (increasing from $40M pa to an average of $100M pa over the next regulatory period).

In preparing this "baseline" O&M projection for EnergyAustralia, SKM wishes to emphasise that it is predicated on the underlying assumption that EnergyAustralia escalates its capital expenditure on refurbishment/replacement works from the current level of approximately $40M pa at least to the levels recommends in the SKM report "Capex Assessment – Stage 2" dated November 2002.

This baseline O&M projection has been constructed on a "bottom-up" basis, being aggregated from the necessary spend at an activity level (eg. vegetation management, meter reading, system operations, etc). Information has been obtained from Networks LOB accounts and meetings with a wide range of EnergyAustralia staff.

We have attempted to incorporate into the forecast all known changes in corporate accounting practices, overhead allocations, capital/operating apportionments, regulatory/statutory obligations, work practice, maintenance policies, operating procedures, etc.

Before completing the baseline O&M forecast, we have made a high level assessment of the status of the EnergyAustralia network. This assessment has been based on:

- A review of records of maintenance undertaken, deferred and outstanding.
- Discussion with specialist line managers and staff with a knowledge of maintenance and current network condition.
- A review of maintenance summary reports.
- An assessment of vegetation management and line/pole inspection practices.
- A review of substation and underground monitoring and maintenance practices.

The "status assessment" of the EA network did not involve extensive field checks and asset condition monitoring (although a number of site visits were made), but was more a validation of the policies, procedures and practices of the company. A number of "sanity checks" were undertaken to ensure that stated policies, procedures and practices were actually implemented.

2.2 Out of Scope Areas

This study is not a comprehensive analysis of EnergyAustralia business units. Our projections, conclusions and recommendations are drawn largely from single meetings with senior business managers with occasional follow-ups to enhance clarity. The information obtained has been assessed against our network business experience but has been taken largely at face value. We have applied our knowledge and experience to the information provided to predict future O&M costs.

This report does not focus on the composition of, analysis of, or allocations associated with Corporate overheads. Overheads are included only in so far as they complete the total cost picture for the future O&M projections.

The study did not undertake a detailed analysis of the appropriateness and benefits of the proposed new asset specific condition based monitoring maintenance regime, although it was necessary to have a clear understanding of its objectives and manner of operation. The SKM O&M projection makes some provision for the new maintenance regime, although insufficient to see it fully implemented in the next regulatory period.

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.

3. EnergyAustralia System Age Profile

3.1 General

An important consideration in determining the appropriate level of O&M expenditure for any distribution company is consideration of the impact that “average system age”, or “expired asset life” has on the costs to maintain the system in a safe and reliable state. SKM has determined the “expired asset life” of a range of Australian distributors, and has modelled the relationship between “average system age” and O&M requirements. The impact of these issues on EnergyAustralia’s O&M requirements for the next regulatory period are outlined below.

3.2 Average System Age

Distribution utilities have a wide range of diverse assets and equipment installed over a long period of time (typically 70 years or more). In recent times, some of the larger utilities have developed and populated computer based asset databases which provide more complete information about the number and age of installed assets. As best however, these systems can be described as providing approximate information (±5%) about the quantity and age of installed assets.

The valuation of distribution assets using a consistent methodology has been undertaken in the Australian Electricity Supply Industry only since the early 1990’s. These valuations probably represent the most accurate representation of “average system age” available to the utility industry.

The ratio of Depreciated Replacement Cost (DRC) to Replacement Cost (RC) is a reasonable, although not perfect surrogate of comparative system age. This ratio effectively represents the “remaining life” of a distribution system. It is an imperfect surrogate due to the fact that an individual asset that happens to remain in service ceases to be depreciated 5 years prior to the assigned regulatory life of the asset class to which it belongs. Most utilities may have up to 20% of assets in a particular asset class that have ceased to be depreciated, and may be older than the assigned regulatory life for that asset class. For these assets, depreciation has ceased, even though they continue to age.

Nevertheless, the ratio of DRC/RC is a reasonable, if imperfect, measure of “remaining asset life”. Based on the most recent asset valuations carried out in Australia, the “remaining asset lives” of distribution companies as represented by the ratio of DRC/RC, is as shown in Table 3-1.

- **Table 3-1 Remaining Asset Lives – Australian Distributors**

Distrib tor	Valuati n Date	Remaining As et Lives (DRC/R C)	Equivalent Diff rence in Average Syst m Age
EnergyAu stralia	20 2	39.3	-
Integral E nergy	20 2	55.0	-7.7 yr
Country E nergy	20 2	46.7	-3.6 yr
Aust In and	20 2	64.5	-12.35 y
Energ ex	20 0	59.7	-8.3 yr
Ergon E ergy	20 0	49.7	-3.3 yr

Note: DRC/RC ratios exclude non system assets (eg. land, spares, SCADA, comms, etc)

The remaining asset life percentage for EnergyAustralia (39.3%) is equivalent to an average weighted expired life of 29.6 years. SKM has calculated the amount of overaged assets on the EA system to be 5.67% (weighted by value) which extends the 29.6 years to 32.64 years (compared with EA's own estimates of 31.21 years)

It can be clearly seen that EnergyAustralia has one of, if not the oldest electrical system of any distributor in Australia, for which consistent asset valuation data is available. To the best of our knowledge, no similar and comparable information is available for the Victorian distributors.

3.3 Specific Asset Class Age Profiles

EnergyAustralia has researched the specific age profiles used in their 2002 asset valuation, and projected them forward, based on the assessed growth of new assets, and the planned refurbishment through their capital works programme. The projections obtained of the movement over time, of the average age by asset class is as shown in Table 3-2.

- **Table 3-2 Projected Trend in Age Profile by Asset Class**

Asset Category	19 9/00	20 3/04	20 8/09
Transmission Subs	3 .55	3 .74	3 .31
Zone subs	3 .63	3 .18	3 .13
O/H Transmission Lines	3 .01	3 .34	4 .65
U/G Transmission Cables	3 .16	3 .95	4 .57
Dist'n Transf and S/S	2 .16	2 .57	2 .20
Dist'n O/H and U/G (incl S/L and p es)	2 .53	2 .05	3 .55
Weighted average age (weighted b value)	2 .38	3 .21	3 .16

Table 3-2 shows that over the period 1999/00 to 2003/04, average system asset age increased from 28.38 years to 31.21 years (ie. 2.83 years in a 5 year period), and is projected to worsen from 31.21 years to 33.16 years (1.95 years) in the next 5 year period, despite a significant increase in capex refurbishment spend from $40M pa to approximately $100M pa.

This trend highlights the impact that a sustained underspend in refurbishment over a lengthy period of time has had on the financial drain (both capex and opex) required to maintain and refurbish the EnergyAustralia system. Significant increased spending is required in both capex and opex simultaneously, and yet average system age will continue to decline (by 1.95 years over the next 5 years).

3.4 SKM Modelling of Average Age and Future Trend

SKM has separately modelled (refer Appendix L), from the 2002 asset valuation data, the impact of the following factors on average system age:

- % remaining life (from the DRC/RC ratio).
- The projected level of capex refurbishment spend (increasing from $40M in 03/04 and over $100M by 2007).
- The growth in new system assets, as indicated by the demand driven capex.
- The incremental increase in weighted average network age.

The trend in the weighted average network age for both the SKM modelling, and the more asset class specific EA calculation is shown in Table 3-3.

- **Table 3-3 Projected Trend in Weighted Average Network Age**

	SKM Projection (years)	EA Projection (years)
1999/00	N/A	28.38
2003/04	32.64	31.21
2008/09	33.73	33.16
2013/14	34.47	35.07

As can be seen there is a close correlation between the SKM age projection and the EA age projection even though they are based on very different techniques. Both techniques demonstrate that the system will continue to age (by 1.1 years and 1.95 years respectively) during the next regulatory period.

3.5 The O&M/System Age Relationship

SKM has been able to successfully model the O&M expenditure to asset age profile for all of the major asset categories (refer to Appendix D). By aggregating these profiles to a "total system" level, weighted by the respective asset values of each asset class, we have been able to model the relationship between O&M requirements, and the average age of the EnergyAustralia network. This O&M/network average age relationship is shown in Appendix C.

The profile defining the relationship between total system O&M spend relative to average system age indicates that for every year that the system ages (on average), the following additional O&M expenditure is required to maintain the network.

- **Table 3-4 Incremental Increase in O&M with System Age**

Weighted Average System Age (years)	Incremental Annual O&M Requiremen for each yearly increase in average ag
30	$19.48M
31	$21.05M
32	$22.75M
33	$24.59M
34	$26.57M
35	$28.71M

These incremental increases in O&M requirements have been factored into SKM's forecast O&M for the period 2004/05 to 2008/09.

4. Comparative Analysis

4.1 Market Price Surveys

EnergyAustralia has been benchmarking the unit prices for work activities being charged by Enerserve to EA Networks, for a range of capital and O&M activities.

This market price survey work has been conducted by SKM on a confidential basis such that only SKM knows what prices have been submitted by the participants to the survey. There have been two surveys conducted, one reported on in November 2001, and one in September 2002. A third survey is currently being undertaken.

Participants to the surveys have been:

- Enerserve (EA)
- ActewAGL
- NPS
- Powercor
- ETSA Utilities
- Ergon Energy
- Aurora Energy
- Integral Energy
- Agility
- Energex
- TXU
- Western Power
- Alstom Australia

The Market Price Surveys are structured to determine the price that EnergyAustralia would be expected to be charged for a service if that service was procured under a competitive tendering process. Sinclair Knight Merz secured the participation of a total of thirteen electricity utilities (government owned and private), plus contacting companies to submit data on the basis that all information is confidential, and that all participants receive the results of the survey.

Key features of the results of the surveys are:

- Prices valid for 12 months from date of survey.
- Prices generally exclude material costs.
- Prices accurate to ±10%.
- Prices include all necessary costs (direct, on-costs, overheads, profit, etc).
- Prices submitted to standard work specifications.
- Data validation undertaken, non-credible prices eliminated.

- Prices are normalised for EBA and hourly rate differences.
- Market price to be industrially and commercially sustainable in NSW.

An example of the results of the two surveys conducted to date are displayed graphically in Figure 4-1. No individual prices are displayed.

- **Figure 4-1 Typical Market Price Survey Result**

COMMERCIALLY SENSITIVE

The comparison of Enerserve's submitted price against the deemed market price (DMP) for all work activities surveyed to date are shown in Table 4-1.

- **Table 4-1 Comparison of DMP with Enerserve Submitted Price**

Survey 1

COMMERCIALLY SENSITIVE

Survey 2

COMMERCIALLY SENSITIVE

The key findings to emerge from the market price surveys were:

- On a weighted average basis (weighted by quantities), the total Enerserve pricing is marginally higher (+ 0.36%) than the Deemed Market Prices.
- The total annual value of work activities surveyed is $23M, or approximately 19% of the annual O&M budget for Enerserve.
- Enerserve has the second highest direct labour costs of all companies in the survey.
- Enerserve have the highest labour on-costs of all companies in the survey (annual and long service leave, superannuation, sick leave, workers compensation, payroll tax).

4.2 Cross-Jurisdictional Comparisons

4.2.1 General

A comparison has been undertaken of various ratios and performance indicators of operational expenditure from previous determinations in NSW and other Australian jurisdictions. These include:

- Office of Regulator General (Vic) Determination,
- Queensland Competition Authority Determination,
- IPART Determination, 1998.

The purpose of this section of the report is to establish some comparative "norms" of operational expenditure by distribution utilities throughout Australia.

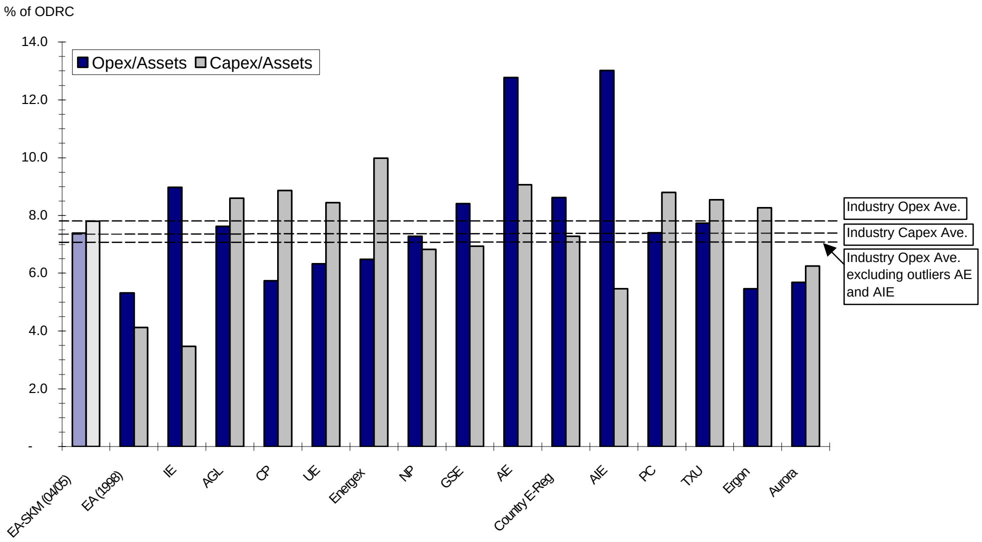
It should be emphasised that the following charts and commentary relate to operating and capital expenditures approved by the appropriate regulatory authority, not the actual expenditures incurred by the utilities during the period.

It will be noted that some of the graphs and figures make reference to capital expenditure, as distinct from operating expenditure. This is deliberate, as it is essential to understand the "total cost" of utilities in some performance measures. Different accounting practices may also result in some costs being considered "capital" by some companies, and "operating" by other companies.

4.2.2 Opex/Assets and Capex/Assets Ratios

Figure 4-2 displays the ratios of Opex/Assets and Capex/Assets for the most recent determinations, and a selected range of other known utilities.

- **Figure 4-2 Ratios of Opex/Assets (Valid for 2003)**



Note to Figure 4.2: All capex and opex ratios are based on the approved regulatory projections for year 2003. The EA – SKM (04/05) projection is SKM's recommended Opex (nominal for 04/05).

The ratio Opex/Assets is a general measure of the operating expense incurred by a networks business in inspecting, maintaining and repairing the assets in the regulated asset base. In EnergyAustralia's case, approximately 48% of its operating expenditure are devoted to these activities. The remaining 52% are made up of customer service activities (approx. 20%), and Network Division/Corporate costs (32%).

The ratio Capex/Assets is a general measure which reflects the capital required to cater for growth, refurbishment and enhancement of the network and related assets.

The two ratios are considered in concert, to ensure that total distribution costs are taken into account. Some variations may occur in the time that the determinations were made, and the methodology used to determine the asset valuations, but Figure 4-2 clearly shows that the capital and operating costs allowed for EnergyAustralia in the 1998 determination was significantly below the industry average.

The proposed SKM projections of capex and opex for 2004/05 for EnergyAustralia are represented by the hatched pair of bars in Figure 4-2, and as can be seen they virtually match the "industry average" opex and capex determinations for 2003. This is despite the increased capex provision for refurbishment works and the opex provisions for system ageing and the curtailment of the backlog of corrective maintenance.

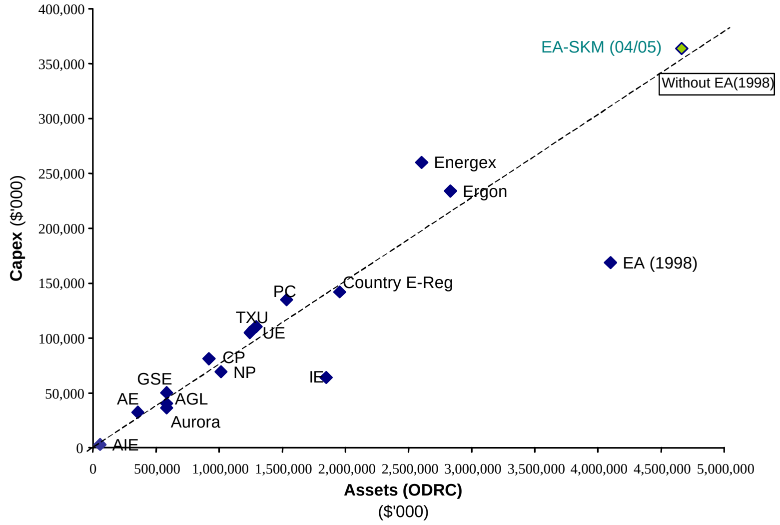
The comparison demonstrates that the total spend (combined capex and opex) recommended by SKM is not unreasonable, when compared with other regulatory determinations.

4.2.3 Capex to Asset Valuation

Figure 4-3 shows the Capex to Asset Valuation relationship for recent regulatory determinations, and selected other utilities.

All the capex expenditures shown are for the 2003 year (except the SKM projection for 04/05), and the trend lines shown represents a “least squares” average. This figure again demonstrates that EnergyAustralia’s capex allocation at the 1998 determination was well below the industry trend lines.

- **Figure 4-3 Capex to Asset Valuation (Valid for 2003)**

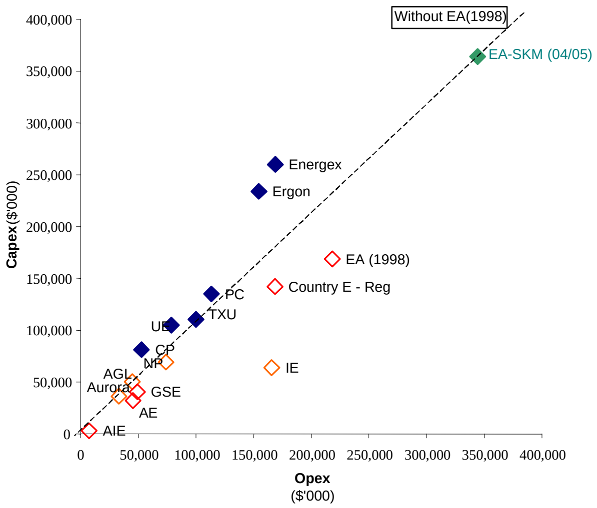


The SKM recommended level of capital expenditure for 04/05 is very close to the line (excluding EA (1998) data point) even though there is provision for increased refurbishment spending.

4.2.4 Capex to Opex Ratio

Figure 4-4 demonstrates the relationship between Capex and Opex for recent determinations and other selected utilities. The clear conclusion to be drawn from this graph is that the ratio of Capex to Opex for other jurisdictions and utilities is higher than for NSW distributors. This highlights the need to consider both Capex and Opex simultaneously rather than "benchmarking" them individually.

- **Figure 4-4 Capex to Opex Ratio (Valid for 2003)**



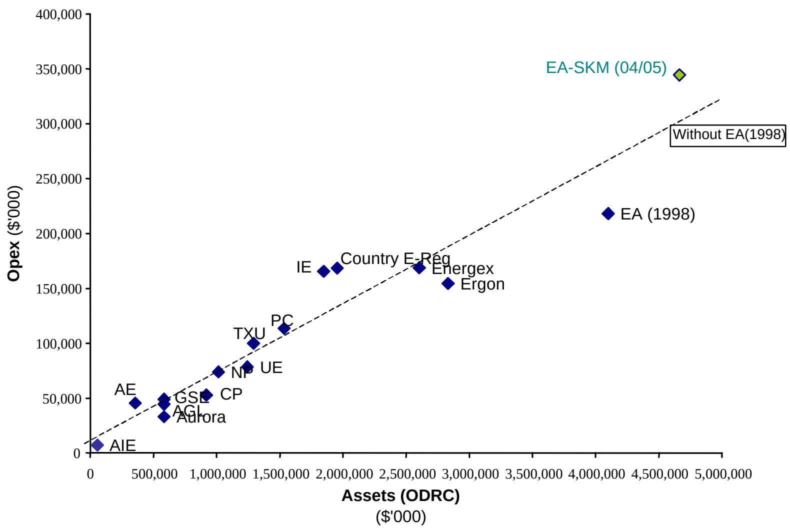
It will be noted that the SKM projections for capex and opex for 2004/05 are for virtually identical amounts, more in line with general industry trends.

4.2.5 Opex to Asset Valuation

Operating expenditure is directly linked to the need to inspect maintain and operate the network assets. Figure 4.5 shows the range of recent determinations and other selected utilities, relative to EnergyAustralia. Based on the "least squares" trend line, it is evident that EnergyAustralia's 1998 determination made below average Opex provision (in addition to inadequate Capex provision).

Given the much younger age profiles of other Australian utilities, one would have expected EA to be somewhat above the trend line, not below it. As can be seen, the SKM Opex forecast for 04/05 is close to the trend line (with EA (1998) data point removed).

- **Figure 4-5 Opex to Asset Valuation**



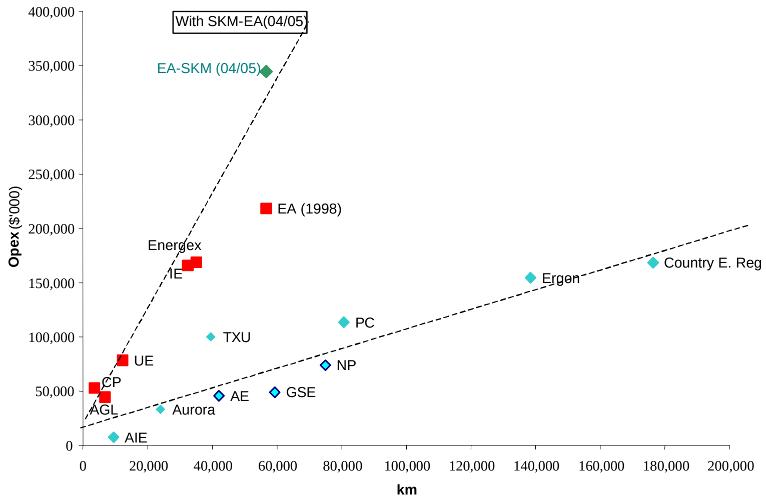
As can be seen, three trend lines are shown. The lower two trend lines depict the average O&M spend from previous determinations (including and excluding EA-1998 which was demonstrably low and distorts the real trend due to its position on the graph).

The upper trend line is the same previous determinations, plus the SKM recommended opex for 2004/05. As can be seen the SKM 2004/05 forecast is marginally above the trend line which is not inconsistent with the likely impact on O&M expenditure of the ageing nature of the EA system relative to the other utilities, and the marginal effect of 2 years additional CPI.

4.2.6 Opex per Kilometre of Line

Figure 4-6 compares the Opex cost per kilometre of line for recent determinations and other selected distributors. Two clear trends are evident, with the predominantly urban distributors AGL, Citipower, United Energy, Integral, Energex and EnergyAustralia displaying higher costs than their lower density regional/rural counterparts. It is notable that EA (1998 determination) is again below the trend line. EnergyAustralia's network related O&M costs represent 48% of total operating costs (04/05, including overheads).

■ **Figure 4-6 Opex Cost per Kilometre of Line**

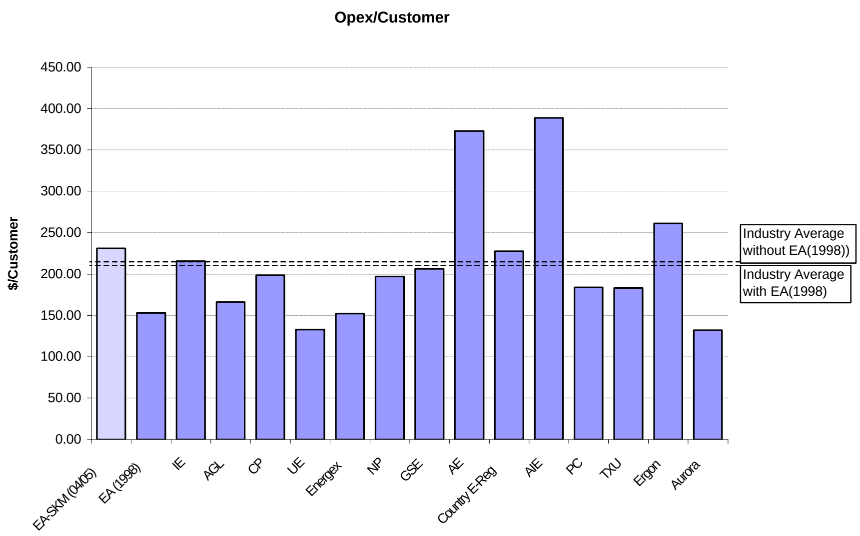


The effect that EA has on the industry trend is notable. The SKM 2004/05 projection places EA above the "opex per km" industry trend which is once again not unexpected considering the size and age of the network compared to other predominantly urban distributors.

4.2.7 Opex per Customer

Figure 4-7 demonstrates the Operating Expenditure per customer for recent determinations, and other selected distributors. Customer driven costs represent approximately 20% of EnergyAustralia's operating costs (04/05, including overheads). As can be seen the EA(1998) opex allocation was substantially below the industry average and when the SKM 2004/05 projection is used the EA "cost per customer" becomes $231.25/customer which is slightly above the industry average. The figure is still comparable with other similar utilities such as Integral Energy, Citipower, Powercor and TXU.

- **Figure 4-7 Operating Expenditure per Customer**



4.3 Benchmarking Summary

In summary, the comparison of a number of financial ratios and performance indicators shows that the SKM recommended level of O&M expenditure for EnergyAustralia is comparable with other previous regulatory determinations and selected utilities. It should be noted that up to this date, no previous regulatory determinations appear to have made appropriate provision in O&M forecasts to cater for differences in the impact of average network age on O&M requirements. SKM is strongly of the view that regulatory determinations should take the O&M/average age relationship into account.

As demonstrated in Figure 4.2 any performance comparisons between jurisdictions or utilities must take account of both capex and opex in tandem. To consider one in isolation of the other will most likely lead to incorrect conclusions about the relative efficiency of organisations.

5. Key Assumptions and Inputs

5.1 Key Assumptions

1) Labour costs have been escalated at the following rates:

Year	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
Labour rate escalator %	4.2[1]	4.2	4.7	4.6	4.3	4.0	4.0[2]

2) The percentage labour component of costs was based on the spreadsheet containing Networks LOB costs for the 3 years 1999/00 to 2001/02.

3) Non labour costs were escalated at CPI rates as follows:

Year	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
CPI escalator %	2.7[1]	2.7	3.0	2.9	2.8	2.8	2.8[1]

The above figures were provided by EnergyAustralia Network Finance.

4) Discussions with various EnergyAustralia personnel have led us to the opinion that 2001/02 historical data is probably more reliable than data for previous years. In developing our zero based budget, we have therefore placed greater reliance on 2001/02 figures than previous years' actuals. The 2001/02 figures were generally better supported by cost breakdowns. There were conflicting views on this issue however, with the actual expenditure by Enerserve on planned maintenance in 2001/02 having been constrained due to budgetary restraints in that year. This view appears to be supported by the trend in expenditure shown in figure 8.4.

5) Where available, we have used the 2002/03 budget figures as a further source of information and they are reproduced in our spreadsheets and graphs. In some areas, such as Customer Service, we have had no reason to move away from these figures as they represent the latest knowledge regarding the O&M costs expected to be incurred. In other areas, such as substation maintenance, we have independently developed an O&M forecast based upon an engineering/financial assessment of the system status and our view of the impact of the new asset specific condition based monitoring maintenance program.

   In some cases we have been provided with 2003/04 budget bids for various business units. We have taken the same approach with these figures as with the 2002/03 budget figures.

6) The "baseline" O&M projection is predicated on the underlying assumption that EnergyAustralia escalates its capital expenditure on refurbishment/replacement works from the current level of approximately $40M pa at least to the levels recommended in the SKM report "Capex Assessment – Stage 2" dated November 2002.

[1] Not provided by EnergyAustralia. Following year's figure has been used.
[2] Not provided by EnergyAustralia. Previous year's figure has been used.

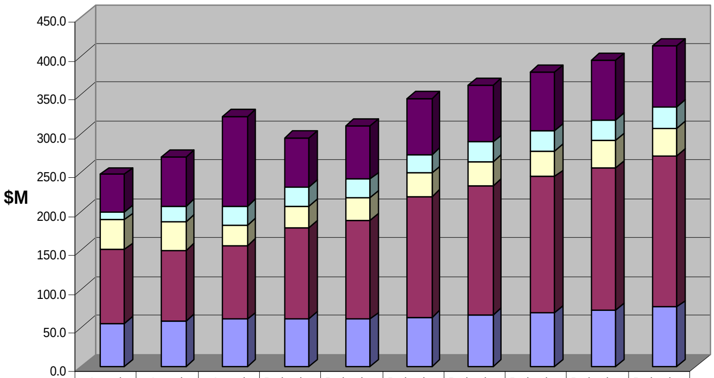
7) No account has been taken of possible or announced future organisational changes in determining projected O&M expenditure within the subsidiary businesses.

6. Main Sources of Networks LOB O&M Expenditure

Figure 6-1 provides actual and forecast O&M expenditure for the period 1999/00 to 2008/09, broken down by subsidiary (Enerserve, Customer Service, Network) and including corporate overheads.

Figure 6-5 provides the O&M forecast for corporate overheads. The overhead allocations by subsidiary were not available. The forecast is based upon figures supplied by EA.

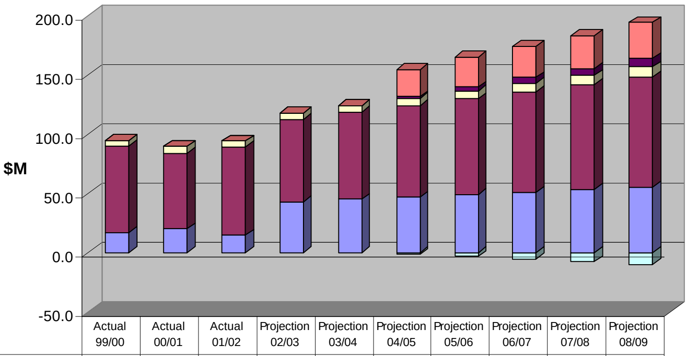
■ **Figure 6-1 EA O&M Expenditure Contributors**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Corporate Overheads	48.9	63.9	115.1	64.0	69.0	71.1	73.2	75.2	77.3	79.5
External Contracts	9.6	19.1	24.9	23.7	24.1	24.4	24.9	25.8	26.2	26.7
Netw ork internal	38.3	37.9	26.1	28.0	29.2	30.5	31.8	33.3	34.7	36.3
Enerserve adjusted total	94.7	89.8	94.3	117.7	126.6	154.4	165.3	174.4	183.0	194.4
Customer Services	55.8	59.3	61.0	61.5	61.2	64.0	66.8	69.7	73.0	76.4

The chief Enerserve contributors to the N/W O&M Expenditure are detailed in Figure 6-2.

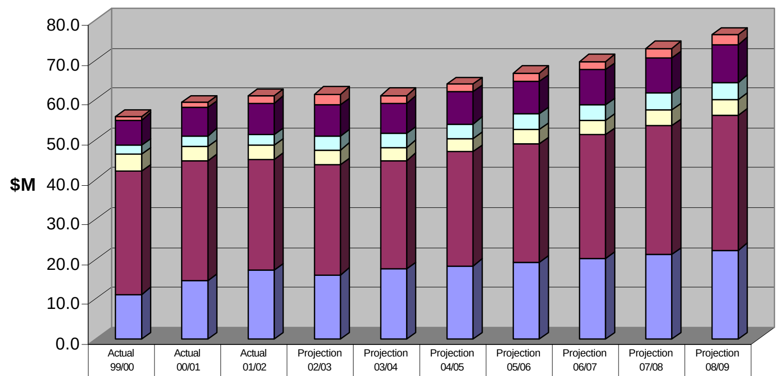
■ Figure 6-2 Enerserve O&M Expenditure Contributors



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
O&M adjustment for increasing asset age	0.0	0.0	0.0	0.0	0.0	22.7	25.5	26.5	27.4	30.6
O&M increases due new Capex	0.0	0.0	0.0	0.0	0.0	1.5	3.3	4.9	5.9	7.2
O&M savings due Refurb Capex	0.0	0.0	0.0	0.0	0.0	-1.4	-3.1	-5.5	-7.5	-9.8
Cables	4.4	6.0	4.8	5.1	5.4	6.1	6.7	7.2	7.9	8.6
Distribution	73.1	63.6	74.7	69.4	73.8	77.2	80.8	84.6	88.6	92.7
Substations	17.1	20.1	14.7	43.1	45.1	46.9	49.0	51.1	53.3	55.4

The chief Customer Service contributors to the N/W LOB are detailed in Figure 6-3.

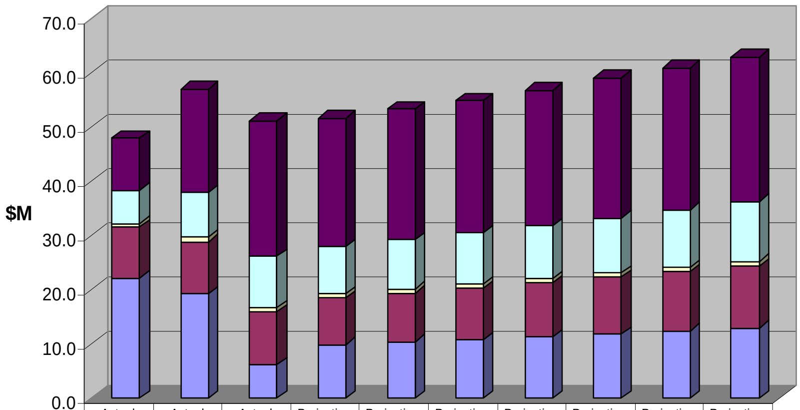
■ Figure 6-3 Customer Service O&M Expenditure Contributors



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Other	0.8	1.1	1.7	2.8	2.0	2.0	2.1	2.2	2.3	2.4
Contact Centre	6.4	7.0	7.9	7.9	7.5	7.9	8.3	8.6	9.0	9.5
Customer Operations	2.3	2.9	2.7	3.3	3.6	3.8	3.9	4.1	4.2	4.4
Customer Billing	4.1	3.5	3.5	3.7	3.2	3.4	3.5	3.6	3.8	4.0
Customer Supply	31.0	30.1	27.7	27.8	27.3	28.5	29.6	30.9	32.3	33.8
Utility Services	11.2	14.7	17.4	16.1	17.6	18.5	19.4	20.3	21.3	22.3

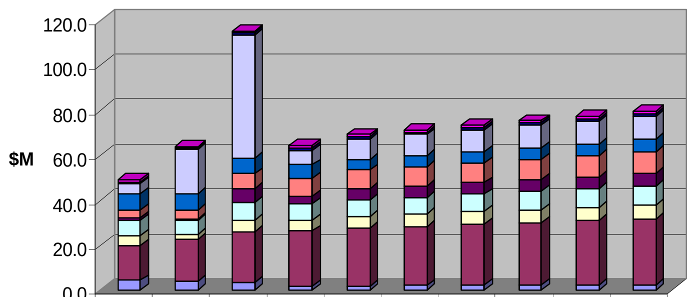
The chief Network contributors to the N/W LOB are detailed in Figure 6-4.

■ Figure 6-4 Network O&M Expenditure Contributors



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
External Contracts	9.6	19.1	24.9	23.7	24.1	24.4	24.9	25.8	26.2	26.7
Asset and Service Provider Management	6.2	8.2	9.4	8.8	9.1	9.5	9.8	10.2	10.6	11.0
Capital Works Planning	0.6	0.8	0.8	0.7	0.7	0.7	0.8	0.8	0.8	0.9
Network Control	9.3	9.7	9.7	8.6	9.0	9.5	9.9	10.4	10.9	11.4
Management and Support	22.2	19.2	6.2	9.9	10.4	10.9	11.4	11.9	12.4	13.0

■ Figure 6-5 Corporate Overheads O&M Expenditure Contributors

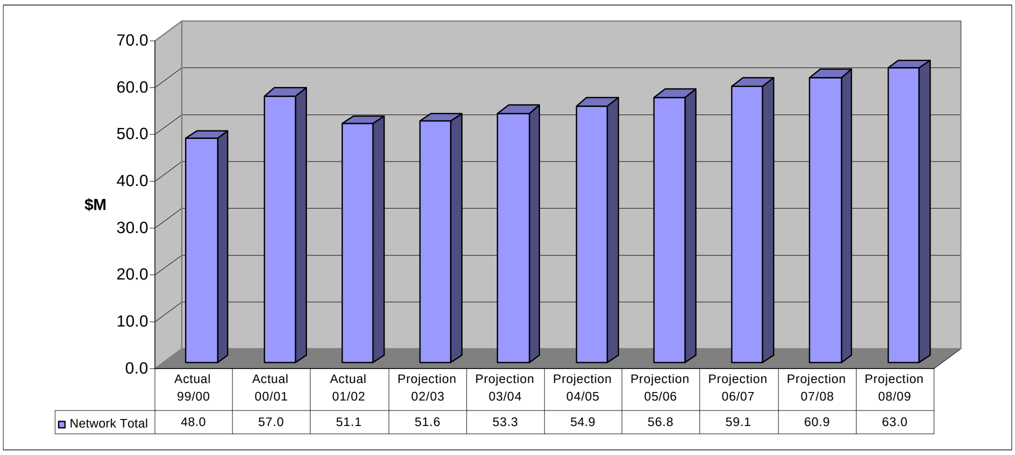


	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Executive Management	0.8	0.7	0.8	0.9	1.0	1.0	1.0	1.0	1.1	1.1
Internal Audit	0.6	0.7	0.8	1.1	1.1	1.1	1.1	1.1	1.2	1.2
Finance & Corporate Secretary	4.5	19.6	54.9	6.5	9.0	9.2	9.5	9.8	10.0	10.3
Corporate Strategy & Business Development	7.6	7.2	7.0	6.1	4.9	5.0	5.1	5.3	5.4	5.6
Property	3.3	4.1	6.3	7.8	8.3	8.5	8.8	9.0	9.3	9.5
Insurance	0.9	0.7	6.4	3.1	4.8	4.9	5.1	5.2	5.4	5.5
Rent & Rates	7.0	6.0	8.0	7.3	7.4	7.7	7.9	8.1	8.3	8.6
Land Tax	4.7	2.2	5.0	5.0	5.2	5.3	5.5	5.6	5.8	5.9
IT&T (incl IT Group + Other IT & Comm's Exp)	15.4	18.7	22.4	24.3	25.7	26.5	27.2	28.0	28.8	29.6
Corporate Branding, Advertising, Safety Campaigns	4.2	3.9	3.5	1.8	1.8	1.9	2.0	2.0	2.1	2.1

7. Networks OPEX Analysis

Figure 7-1 provides the 1999/00 to 2001/02 operating expenditures for the Network Division and the 2002/03 budget figures, together with forecasts for the period 2003/04 to 2008/09. The Network Operating expenditure is inclusive of external contracts.

- **Figure 7-1 Network Division Total O&M Expenditure**



The total Operational expenditure for Networks in 2001/02 was $51.08m which is 17% of the total EnergyAustralia Opex for 2001/02 (23% in 1999/00). The expenditure over the last three years shows an average growth of 3% per annum with an increase in 2000/01 which pushed the Operating expenditure to 27% of the total. Discussions with Energy Australia staff and an analysis of the expenditure breakdown provided indicates that the increased expenditure in 2000/01 is as a result of an increase in external contract expenditure in the Service Provider Management section.

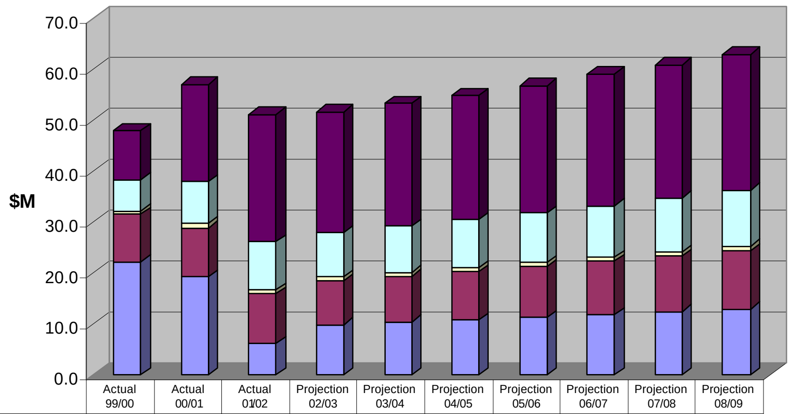
The 2002/03 budget figures were used as the base for the projections.

CPI and labour growth factors form the basis of the projected Operating and Maintenance Expenditure in the Network division with adjustments made to cater for any known factors that will impact on the budget.

7.1 Primary Business Activities and Operating Expenditure

There are four Business Units within the Networks Division. Figure 7-2 provides the O&M expenditure projection at the business unit level.

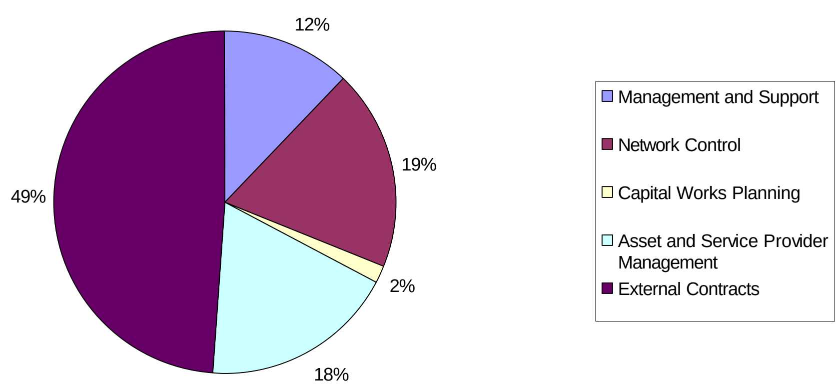
- **Figure 7-2 Network Division - O&M Expenditure Projection by Business Unit**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
External Contracts	9.6	19.1	24.9	23.7	24.1	24.4	24.9	25.8	26.2	26.7
Asset and Service Provider Management	6.2	8.2	9.4	8.8	9.1	9.5	9.8	10.2	10.6	11.0
Capital Works Planning	0.6	0.8	0.8	0.7	0.7	0.7	0.8	0.8	0.8	0.9
Network Control	9.3	9.7	9.7	8.6	9.0	9.5	9.9	10.4	10.9	11.4
Management and Support	22.2	19.2	6.2	9.9	10.4	10.9	11.4	11.9	12.4	13.0

Figure 7-3 provides the percent breakdown by business unit for 2001/02.

- **Figure 7-3 Networks O&M Expenditure Contribution - % by Business Unit 2001/02**

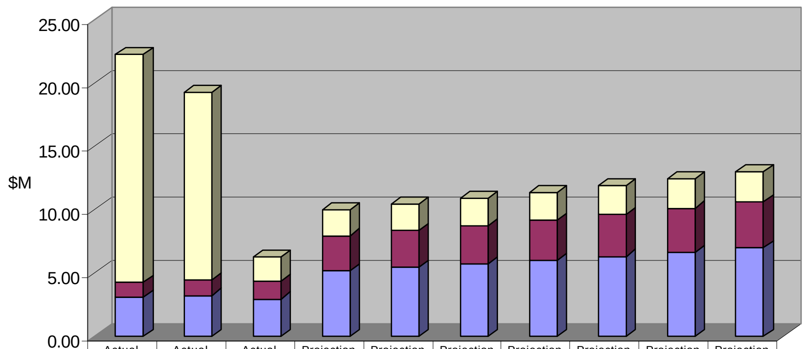


The projections provided in Figure 7-2 are a summary of a lower level projection that was undertaken in the categories Labour, Contract Services, Material and Other. CPI and labour growth factors were applied. The summary projection figures show that Asset and Service Provider Management has the largest average percentage growth per annum in the Network Division of 6%. CPI growth was applied to the contract expenses after each three year contract period assuming that new contracts were put in place in 2001/02. The competitive market damps the growth rate, thus CPI escalation was used instead of labour rate. Network Control, Management and Support, and Capital Works Planning has a projected growth rate of 5.2%, 4% and 3.6% respectively per annum, this is largely as a result of labour escalation factors as the greater part of the expenditures in these groups are labour costs.

7.1.1 Management and Support (Fig 7.4)

This Business Unit consists of the Network Management, Network Business, Businesses Processes & Development and Network Finance & Support groups. The information received did not allow a low level projection for each of the separate sections, thus the projection was done for the Business unit as a whole.

- **Figure 7-4 Management and Support O&M Expenditure by Contribution**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Other	17.97	14.79	1.87	2.02	2.07	2.13	2.20	2.26	2.32	2.39
Contract Services	1.18	1.20	1.40	2.74	2.88	3.02	3.17	3.33	3.50	3.67
Labour	3.08	3.20	2.93	5.17	5.43	5.70	5.99	6.29	6.60	6.93

The 1999/00 and 2000/01 exceptionally high expenditures shown in the category "other" was due to cost recovery capitalisation associated with transfers from Customer Services to Network. For 2001/02 the costs seem to be more in line with actual trends.

Expenditure under the category "other" is cost incurred for Training, Vehicles, Entertainment, Printing & Stationary, Telephone costs, Travel and IT (PC's). No significant changes are foreseen for this category and thus a CPI growth was applied. The EA 2002/03 budget figure shows a 76% increase in labour expenditure. We note, however, that the overall increase in the category "labour" for the Network Division is 15% with a corresponding decrease in the categories "contract services" and "other" suggesting the labour increase could be the result of a change in accounting policy. Having this increase in the budget suggests reasonable certainty, thus the budget figure was used as the base for the projection and a labour growth rate was applied.

Contract services in this section mainly concerns casual or temporary staff allocations where hourly rates are competitively negotiated and thus a CPI growth rate was used.

7.1.2 Network Control (Fig 7.5)

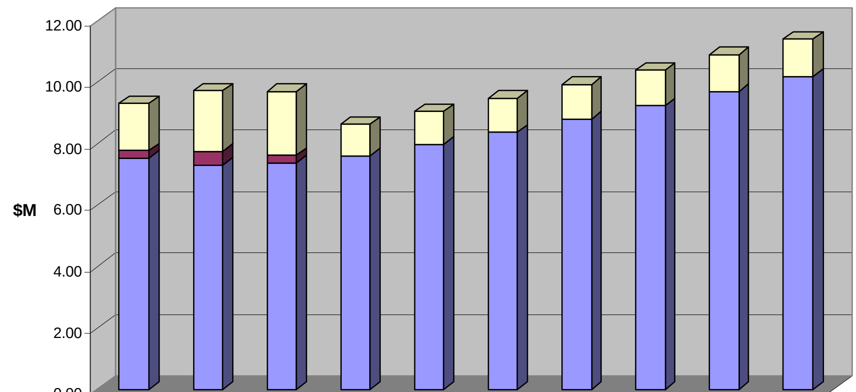
The operational costs in Network Control are associated with the staffing of the Sydney control centre. The actual, budget and projected expenditures are provided in Figure 7-5.

The reduction in labour costs in 2000/01 was as a result of staff transfers and staff training. Telecomms and Corporate IT&T, SCADA and DNMS were transferred out of the Network Control section and contract services were obtained to stand in for staff training that was done in that year, thus the increase in contract services for that year.

The 2002/03 budget figures indicates that all contracting labour will be stopped or transferred to internal. A 50% reduction in the category “other” is budgeted for, which will impact on training, vehicles, entertainment, printing & stationary, telephone costs, travel and IT expenditures. The budget figures were used for the projection. CPI and labour escalators were used in 2002/03 projections.

It is notable that all Network control expenditure is allocated to Operating costs whereas an evaluation done by the network section indicated that approximately 8-10% of the switching work is done for capital work and around 10–15% for Transmission work. Introducing measures to allocate operating expenditures to specific expenditure categories will realise reductions in operating expenditure in this Business Unit.

■ **Figure 7-5 Network Control – O&M Expenditure by Contribution**

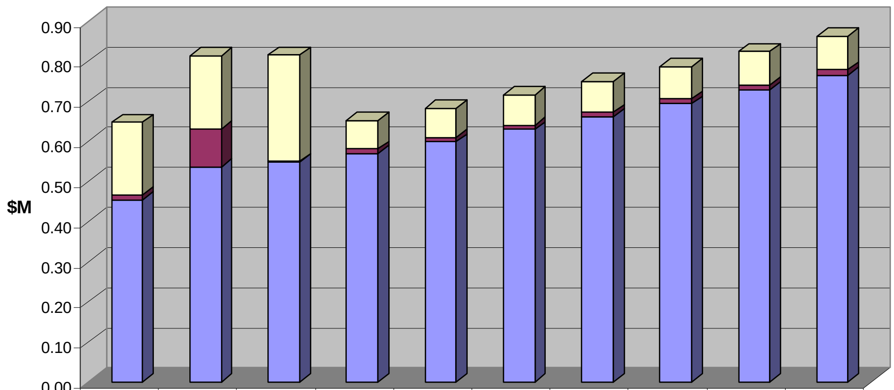


	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Other	1.54	1.97	2.08	1.04	1.07	1.10	1.13	1.16	1.20	1.23
Contract Services	0.25	0.45	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Labour	7.52	7.29	7.36	7.59	7.96	8.36	8.78	9.22	9.68	10.16

7.1.3 Capital Works Planning (Fig 7.6)

Operating and Maintenance expenditure work in this area involves network voltage and system investigations resulting from customer and system operations requests. The expenditure in this area is predominantly labour related and no change in the level of expenditure is anticipated. The 2002/03 budget figures show a reduction in the category "other". CPI and labour growth rates were used for the projections and the 2002/03 budget figures were used as base for the projections.

- **Figure 7-6 Capital Works Planning - O&M Expenditure by Contribution**



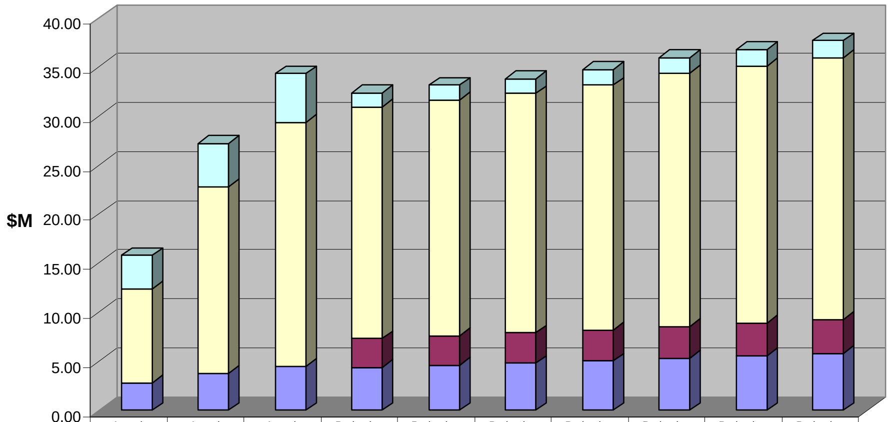
	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Other	0.18	0.18	0.27	0.07	0.07	0.08	0.08	0.08	0.08	0.09
Contract Services	0.01	0.10	0.0010	0.01	0.0105	0.0110	0.0116	0.0122	0.0128	0.0134
Labour	0.46	0.54	0.55	0.57	0.60	0.63	0.66	0.69	0.73	0.77

7.1.4 Asset & Service Provider Management (Fig 7.7)

Note that the forecast expenditure shown in Figure 7-7 includes significant expenditure on external contract works, the price of which is market tested, and should be seen as separate and distinguishable from other costs incurred in this area.

This business activity involves the management and facilitation of internal and external contracts. The internal contracts are with Enerserve and Customer Services, while external contracts are with accredited contractors in the competitive market of pole inspections, pole reinforcement, vegetation management and street lighting (Servicing of Luminaries). The level of operating expenditure in this business area has shown a $18.58m increase from 1999/00 to 2001/02. This increase is as a result of a $15.3m increase in external contract expenditure for vegetation management, pole inspections and pole reinforcements of which vegetation management dominated, contributing to 74% of the expenditure.

■ **Figure 7-7 Asset & Service Provider Management – O&M Expenditure by Contribution**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Other	3.38	4.47	4.97	146	149	154	158	163	167	172
Contract Services	9.63	19.07	24.94	23.69	24.09	24.42	24.92	25.82	26.18	26.69
Material				2.94	3.02	3.11	3.20	3.29	3.38	3.48
Labour	2.79	3.75	4.47	4.35	4.57	4.80	5.04	5.29	5.56	5.83

The increase in contract expenditure was dictated by a change in the scope of work and also the award of new contract agreements. In vegetation management the scope of work was changed to include the trimming of trees previously maintained by local government, and to account for increased safety clearances that were introduced. The scope of work for Pole inspections were increased to include the Hunter area. The award of new external contracts also caused an initial increase in expenditure to allow for the normalisation of the contract areas by the contractors in the first year of their contract. This policy is under review and it is expected that the initial peak in expenditure at the onset of new contracts will be reduced significantly. A more scientific approach to tree trimming is also expected to realise some reductions in contract expenditures over the next 5 years. The approach includes the trimming of trees according to species, where slow growing species are not trimmed and problem trees are replaced with less aggressive growers. The use of Aerial Bundled Conductor (ABC) is another item that will reduce the level of tree trimming required.

The 2002/03 budget figures were used as the base for the projections and a reduction in contract expenditures over the period to 2008/09 were implemented. This reduction however is offset by the inclusion of a scope change anticipated this year (03/04) to include the Cessnock area.

8. Enerserve: Substations Analysis

8.1 Maintenance Policies and Practices

Most Australian utilities have one of the following two maintenance philosophies:

1. Time based maintenance, or
2. Condition based maintenance

With the reduction of capital investment in new projects, maintenance costs are of greater importance in the overall utility budget. This is supported by the fact that many substation assets are near or beyond their useful lives. In the case of EA's zone and sub-transmission substation assets, the data shows that 77.5% of zone substations are older than 30 years (refer figure 8.2), and 81.5% of sub-transmission substations are older than 30 years (refer figure 8.3). This age profile indicates that the cost of maintaining substations is high and will continue to increase unless curtailed by an increase in refurbishment capital expenditure.

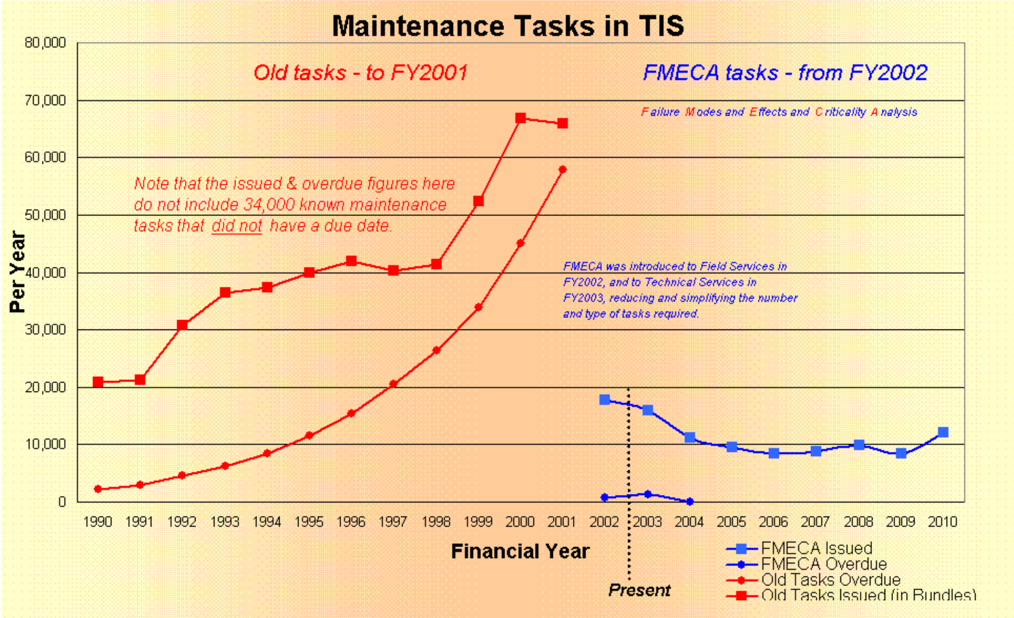
Time based maintenance at fixed intervals and the replacement of components after planned lifetime normally achieves acceptable availability of the assets. It is now widely accepted that this approach is not the most economical. The fixed maintenance intervals are determined mainly on past utility maintenance experience with that asset, or the manufacturers recommended maintenance regime. Very often, time based maintenance is supplemented by corrective maintenance.

It is globally accepted that in the areas of substation maintenance, condition based maintenance is superior to a time-based philosophy. Having said this, one must recognise that for condition based maintenance to be efficient, the condition of the assets must be known with a reasonable degree of precision. Hence, monitoring the condition of the assets becomes of paramount importance and a range of new techniques and devices are now available for monitoring asset condition.

The aim of the condition based maintenance policy is to reduce O&M costs, diagnose and fix problems before they cause outages, and improve substation power quality and reliability. It is based on the development of a unique maintenance program for a specific item of plant based on its operating conditions.

EnergyAustralia commenced implementing the condition based maintenance policy during 2001/02. Prior to that EA had a time based maintenance policy. The EA "asset specific condition based maintenance regime" (FMECA) has, and will continue to entail additional costs in asset inspection and appraisal, but should in due course result in significant reduced corrective and breakdown maintenance costs.

- **Figure 8-1 Maintenance Tasks in TIS**



Infigure 8.1 above, the red graph indicates the number of maintenance tasks under the old time-based regime. The implementation of the condition based regime has not been implemented for all asset classes as yet, so the above graph is a calculated prediction based on the internal and external experiences with similar policies. As indicated the number of maintenance tasks is to drop to below 20000 in 2002/2003 and stabilise around 10000 tasks in the next few financial years.

The experience from other utilities who introduced condition based maintenance policies, indicate that in the first few years of implementation, the actual O&M budget goes up, due to the establishment cost of various monitoring devices. The main principle of condition based policy is to know and monitor the condition of the asset before any maintenance is performed. In the case of very old assets, it may be difficult to properly establish their condition, since techniques and devices for monitoring may not be suitable.

Managing the maintenance process in order to meet the demanding targets for cost/reliability ratios which are based on a policy of condition based maintenance, requires for more engineering effort. It is obvious that diagnostic techniques offer improved possibilities for better understanding and handling of the equipment.

The cost of diagnostic systems and their reliability will play an important role when introduced on a large scale. Diagnostic techniques offer excellent information, however, it is only equipment related. Even when data is correct, the experienced power system maintenance or planning engineer will have to consider other relevant factors to take correct decisions on maintenance or refurbishment. To fully take advantage of the knowledge of the equipment condition will require co-operation between maintenance, operation and planning engineering personnel in order to reduce cost and satisfy customer expectations for reliability and quality.

8.2 Substation Operations and Maintenance Cost

8.2.1 Typical O&M Costs

The annual cost for maintaining and operating a substation asset can vary between utilities and also will depend on a number of factors including:

- Age of the asset
- Utilisation of the asset
- Initial cost of the asset
- Operation practices
- Maintenance practice
- Internal utility policies and practices
- Location of the asset

The annual cost of operating and maintaining a substation asset can be expressed as a percentage of its replacement value. The annual O&M cost are established based on company policies, past actual data, current maintenance practices, experience of the involved individuals etc.

It is established that the annual cost for operating and maintaining a substation asset is of the order of 2 to 3% of its replacement value although we note that EnergyAustralia’s 2001/02 O&M expenditure was around 1% of Replacement Cost (indicating a reduction in planned maintenance that we understand was imposed in 2001/02 financial year). For example, a one million dollar substation asset will cost about $25,000 to operate and maintain per annum. This is an average figure, and the actual cost is determined mainly by the age of the asset and utilities operation and maintenance policies. The older the asset, the more rigorous the maintenance regime required becomes, thus the maintenance costs are higher. Conversely, new assets usually do not require major maintenance in the first 5-10 years, unless they operate under special circumstances.

8.2.2 EnergyAustralia Sub-Transmission and Zone Substations

EnergyAustralia has an extensive network of Sub-transmission and Zone Substations. The total number of Sub-Transmission and Zone Substation is given in Table 8-1.

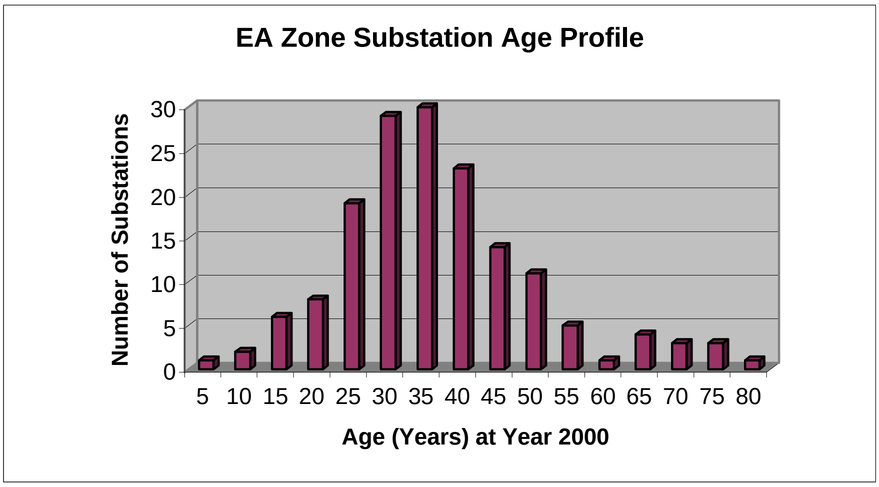
■ **Table 8-1 Number of Substations by Voltage Level**

Zone Substation – Voltage levels	Number Of
33/11kV Substations	116
66/22kV Substations	17
132/110/11kV Substations	32
33/5.5kV Substations	3
Total Number Of Zone Substation	**168**

Sub-Transmission Substation – Voltage levels	Number Of
132/33kV Substations	24
132/66kV Substations	2
132kV and 33kV ST Substations	12
Total Number Of Sub-Transmission Substations[3]	**38**

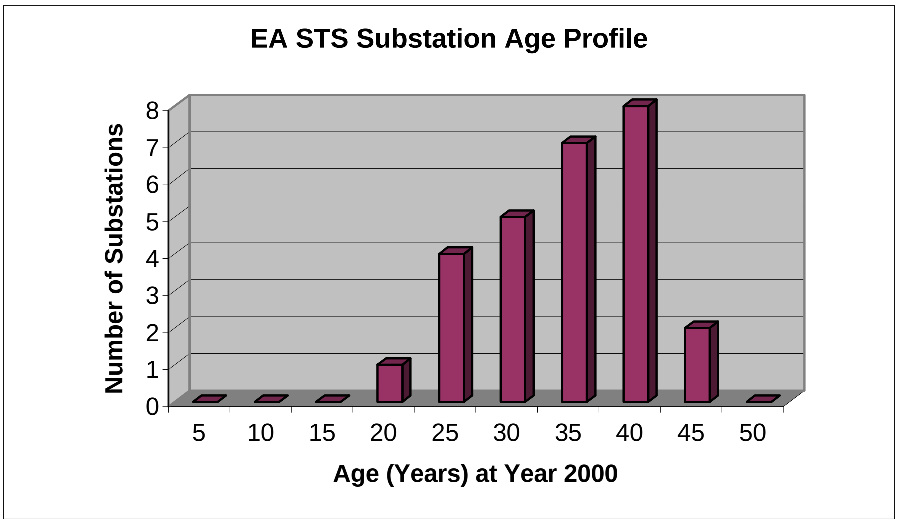
The age profiles of zone and subtransmission substations is provided in Figure 8-2 and Figure 8-3.

■ **Figure 8-2 EA Zone Substation Age Profile**



[3] Source: NSW Treasury Asset Valuation

■ **Figure 8-3 EA STS Substation Age Profile**



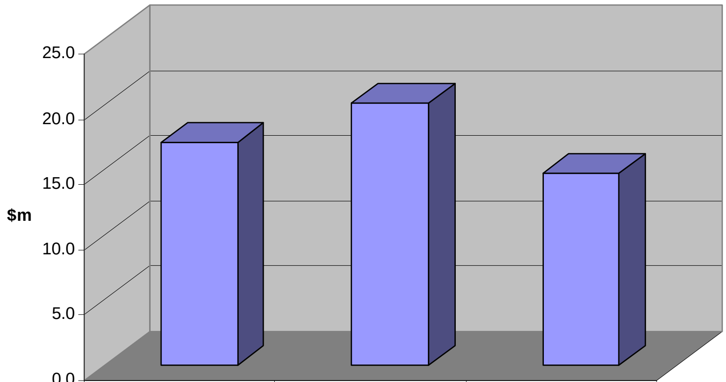
This indicates EnergyAustralia's substation assets are quite aged. In fact, analysis indicates that:

- 76% of EnergyAustralia's zone substations are older than 30 years
- 81% of EnergyAustralia's sub-transmission substations older than 30 years

8.3 Historical Substation O&M Expenditure

Figure 8-4 provides the historic substation O&M expenditure. The quality of historic financial data has prevented any further breakdown of this O&M expenditure.

■ **Figure 8-4 Historic Substation O&M Expenditure**



	actual 1999/2000	actual 2000/2001	actual 2001/2002
Substations TOTAL	17.1	20.1	14.7

The ratio between planned and corrective/storm related maintenance varies from year to year and from asset to asset. Analysis of EA financial records demonstrate the following ratios of planned to corrective/breakdown maintenance.

■ **Table 8-2 Planned vs Corrective/Breakdown Maintenance**

Asset Category	Ratio
Sub-transmission Subs – Switchgear	1.02
Zone Substations – Switchgear	0.83
Sub-transmission Subs – Transformers	0.38
Zone Substations – Transformers	0.8
Sub-transmission Subs – Protn & Contro	1.94
Zone Substations – Protn & Control	1.37
Substation Buildings and Grounds	0.34

It should be noted that limited data is available to provide the breakdown of expenditure on planned to corrective/breakdown. The figures shown are for 2001/02 financial year. Economic theory suggests that minimisation of total maintenance costs occurs at the point where planned maintenance approximates corrective/breakdown maintenance. The limited range of data shown in the Table 8-2 suggests that EnergyAustralia has a reasonable balance in this ratio.

8.4 O&M Budget Forecast for Years 2002/03 to 2008/09

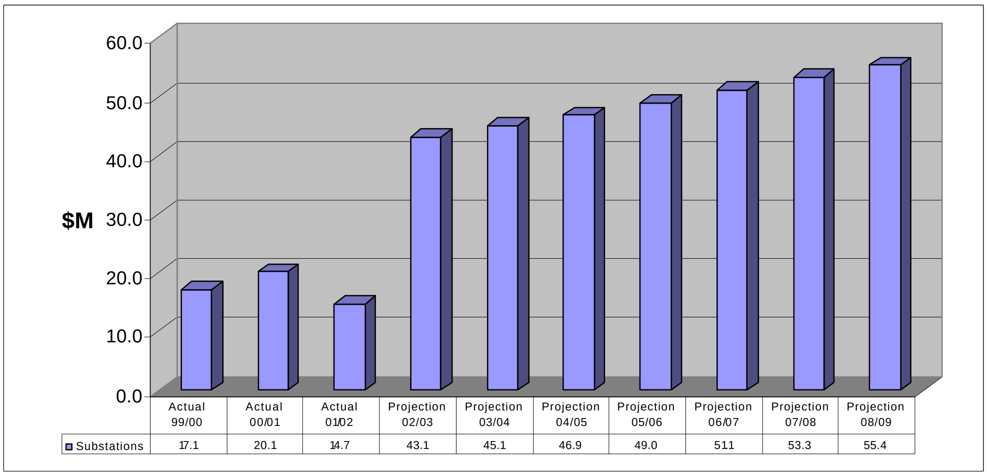
In establishing the O & M Budget for the financial years 2004/05 – 2008/09 we have taken into account the following variables:

- Asset age
- Asset voltage levels (Zone Substations and Sub-transmission Substations)
- Materials and Labour Costs
- Material and labour cost escalation

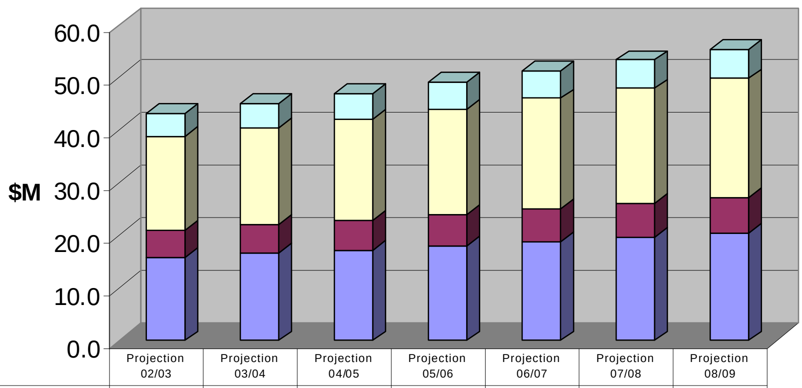
Figure 8-5 shows actual and projected substation O&M expenditure. This data is displayed by substation type (zone vs STS) and category (planned and corrective/breakdown) in

Figure 8-6.

- **Figure 8-5 Total Substation O&M Expenditure**



- **Figure 8-6 Substation O&M Expenditure by Category**



	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Sub transmission substations - corrective	4.4	4.6	4.8	5.0	5.2	5.4	5.6
Zone substations - corrective	17.7	18.4	19.2	20.0	20.9	21.8	22.7
Sub transmission substations - planned	5.2	5.5	5.7	6.0	6.2	6.5	6.7
Zone substations - planned	15.7	16.5	17.2	18.0	18.8	19.6	20.3

The step function increase in O&M expenditure in 2002/03 is as a result of the transition from a period where more appraisal and assessment was being undertaken, to a period where the implementation of the new assets specific condition based maintenance protocols has commenced.

9. Enerserve: Underground Cables (132kV and 33kV) Analysis

9.1 Background

EnergyAustralia has an extensive HV cable network comprising 509km of 132kV cables and 838km of 33kV cables. (There are a few km of 66kV cables however these are typically only short sections in 66kV overhead circuits). The replacement cost of these assets is approximately $991M.

Enerserve has responsibility for maintaining the cable network. As such, Enerserve is responsible for arranging cable testing, day-to-day maintenance activities, responding to cable incidents, keeping maintenance records and generally ensuring the availability of the cable network to meet the needs of EnergyAustralia's customers.

Key data relating to Energy Australia's HV cable network is shown below.

■ **Table 9-1 EnergyAustralia HV Cable Network Data**

Item	132kV	33kV
Circuit Length	509km	838km
Total Length	1527km	838km
Replacement Cost ($M)	$512.8M	$478.6M
Average Age (30/6/01)	31.0 years	47.9 years
Engineering Life	45 years	45 years
Type	Single Phase Oil-filled	Three phase gas-filled and XLPE

9.2 Maintenance Practices

Discussions were held with Enerserve staff regarding Enerserve's maintenance practices. Significant points arising from the discussions were:

- 132kV cables are subjected to a 5-year testing cycle. This included sheath testing and oil sampling;
- 33kV cables are also subjected to a 5-year testing cycle. Sheath testing (partial discharge method) of the 33kV cables is not performed;
- Main maintenance issues pertain to the cable link boxes, repair of oil and gas leaks.
- Gas leaks are the biggest problem for 33kV cables;
- No planned maintenance carried out on the actual cables;
- Routine maintenance is confined to end boxes and signalling equipment.

Records were provided for various aspects of cable maintenance for the last 18-22 months. These records provide a detailed account of the maintenance practices, cable failures, cable damage incidents, gas leakages and oil leakages for the period.

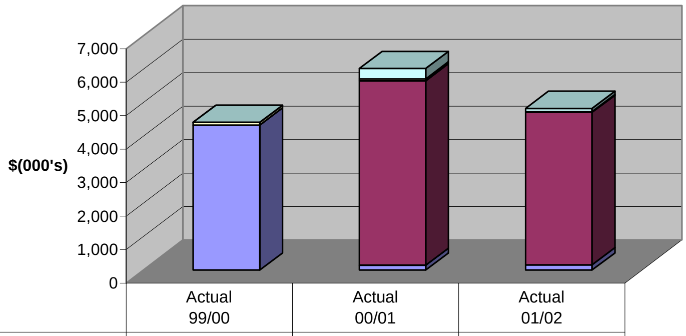
Routine monitoring of oil and gas levels is carried out. This identifies any cables that are deteriorating and allows for assessment of the effort required to keep the cables in service. Enerserve have provided evidence that they monitor and respond to the oil and gas leakages in an appropriate manner.

9.3 Maintenance Costs

Maintenance costs were obtained from the NW LOB Operating Costs spreadsheet. Information relating to the 1999/2000 period has been ignored, due to the abnormal effect of the preparations for the Olympic Games.

Recent maintenance costs are displayed in Figure 9-1.

- **Figure 9-1 Transmission Cables - Historic O&M Expenditure**



	Actual 99/00	Actual 00/01	Actual 01/02
66kV/33kV_Correct_Storms_B/D	0	315	94
66kV/33kV_Planned	82	58	24
132kV_Correct_Storms_B/D	0	5,505	4,555
132kV_Planned	4,334	147	155

Key points regarding the reported operating expenditures are:

- The majority of operating expenditure in 2001/02 is unplanned and caused by damage to the cables by external events;
- Planned maintenance costs are very low and as a consequence there is little or no scope for efficiency savings or cost reductions over the next 5 years;
- In 99/00, all cable maintenance was booked to “planned”, irrespective of where it occurred.

The low level of planned maintenance costs is surprising. For example, the maintenance costs allocated for 33kV cables in 2001/02 represent less than 0.01% of the asset replacement cost. Even in the 1999/2000 period, when preparations for the Olympics resulted in an abnormally high focus on network reliability, expenditure on cable maintenance was $4.33M or less than 1% of asset replacement cost.

The low maintenance expenditure can be partially attributed to the fact that in practice there is little or no maintenance that can be carried out on a cable. In addition, the recent reported costs may be historically low as a consequence of the widespread maintenance activities carried out in preparation for the Olympic games.

Given the average age of cable assets, Sinclair Knight Merz consider that it would be prudent to increase expenditure on cable condition monitoring and to increase the frequency of the cable testing cycles. Based on SKM experience with other utilities which have large CBD and cable networks, an appropriate amount may be around $250K per year, with $150K being for 132kV cables and $100K for 33kV (and 66kV) cables.

Due to the distortion in maintenance costs resulting from the pre-Olympic activities, it is difficult to obtain a reliable estimate of the base-line maintenance costs. However, the costs for 2000/01 and 2001/02 have been used for this purpose.

9.4 Backlog

There does not appear to be any evidence of a major backlog in maintenance activities. Records have been provided which show the maintenance history and activities associated with every HV cable. The cable maintenance is prioritised and there is no evidence of increasing failure rates. It is clear that the monitoring and on-going control of leaks is thoroughly undertaken.

Anecdotal evidence is that Enerserve is just keeping the maintenance of the HV cables under control, however the situation may not be sustainable into the future. Given the cable ages, loss of technical capability and increased cable loading, Sinclair Knight Merz concurs with this view.

9.5 Future Trends in Maintenance Costs

The cost of providing maintenance services for cables is expected to increase above the inflation rate over time. There are a number of reasons for this:

- Increased network loading means that there is less time available to allow access to cables for planned maintenance activities. It has been reported that at present the window of opportunity for planned access is often only at night or on weekends. Such out-of-hours maintenance attracts higher labour costs;
- Increased network loading with consequential higher average cable temperatures can be expected to lead to increased problems with joints and end boxes;
- Reduced staff numbers with the appropriate technical skills for HV cable installations;
- Increasing age of the cable assets leading to higher failure rates (although there is no evidence that this is occurring at present).

Cable refurbishment will eliminate the older, less reliable cables and lead to a reduction in maintenance costs. However this effect is expected to be very small because:

a) the maintenance costs, in total, are very small to start with;

b) the major maintenance costs are associated with mechanical damage caused by third parties;

c) the average age of the cable population will be increasing (or at best stationary) even with the cable refurbishment program.

There would appear to be little scope for productivity and efficiency gains to be made in the cable maintenance area. Improvements in condition monitoring of the cables can be expected to impact on the cable refurbishment program but not in the area of actual cable maintenance. This is because the cable repair and jointing techniques must be consistent with the technology of the existing cables – the majority of which are over 40 years old.

9.5.1 Transmission Cables OPEX Projection

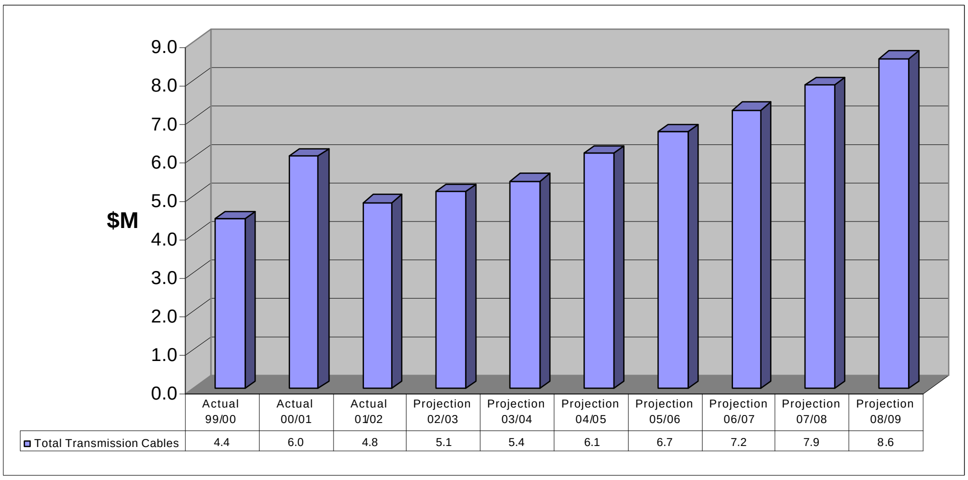
Assumptions:

- For the reasons listed above, SKM has included a maintenance cost escalation at 5% above the labour and CPI escalation rates.
- The maintenance costs recorded for 2000/01 and 2001/02 are reflective of the base-line maintenance costs. The SAIDI data indicates no major change in the trend for Customer Minutes off Supply for the period 1996/97 to 2001/02. This can be taken as support for this assumption.
- Cable condition monitoring costs will increase at approximately 9%, being the sum of the labour escalation rate and the 5% increase discussed above. It is expected that improvements in technology and productivity gains will be matched by an increase in monitoring rates. The costs for cable condition monitoring are based on SKM data from Utilities with CBD/Cable networks and corrected for circuit length.
- Costs for repair of cable damage caused by 3rd parties have been separated from the other maintenance categories as they are quite variable from year to year.
- Costs for 1999/2000 have been excluded from consideration due to the impact of the 2000 Olympic Games.

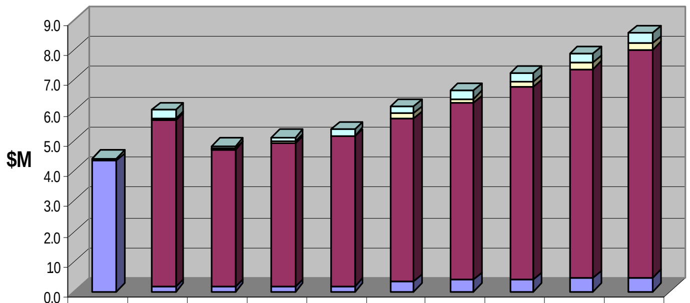
The following figures provides forecasts of the required maintenance expenditure, beginning with current actuals and finishing at the end of the next regulatory period in 2008/09.

Figure 7.2 provides the headline O&M forecast for all cable expenditure. Figure 7.3 provides the expenditure by cable type and split by planned vs corrective/storms/breakdowns.

- **Figure 9-2 Transmission Cable O&M Expenditure Projection**



- **Figure 9-3 Transmission Cable O&M Expenditure Projection by Contribution**

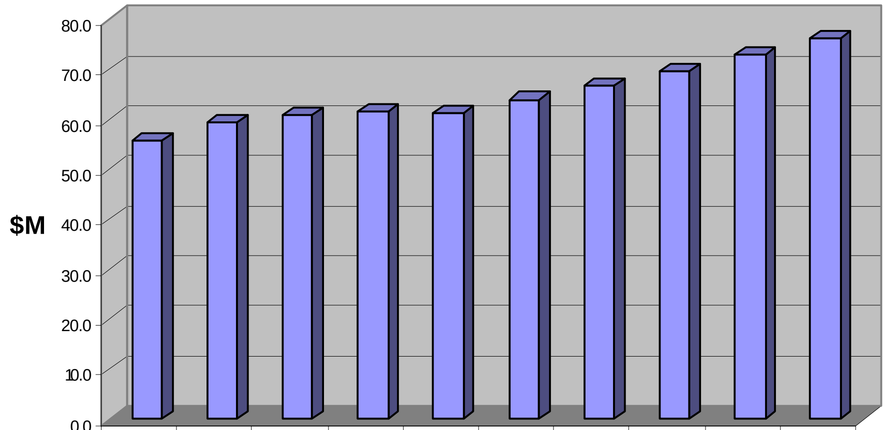


	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
66kV/33kV_Correct_Storms_B/D	0.0	0.3	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3
66kV/33kV_Planned	0.1	0.1	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.2
132kV_Correct_Storms_B/D	0.0	5.5	4.6	4.8	5.0	5.4	5.9	6.4	6.9	7.6
132kV_Planned	4.3	0.1	0.2	0.2	0.2	0.3	0.4	0.4	0.4	0.5

10. Customer Service

Customer Service actual and projected costs are provided in Figure 8.1. All figures are based on discussions with EA staff and the forecasts and actuals provided by them.

- **Figure 10-1 Customer Service OPEX Actual and Forecast**

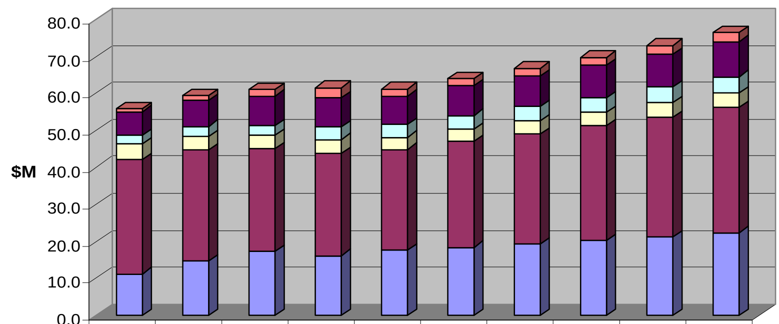


	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Customer Services	55.8	59.3	61.0	61.5	61.2	64.0	66.8	69.7	73.0	76.4

Actual costs used for 99/00 to 01/02 were those provided by Customer Service in December 2002. Customer Service costs went through a number of iterations since then but at the time of writing of this version of the report, the 01/02 figures upon which the projection is based were virtually unchanged.

The customer service O&M forecast, broken down by contribution is provided in Figure 10-2.

- **Figure 10-2 Customer Service O&M Expenditure Projection by Contribution**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Other	0.8	1.1	1.7	2.8	2.0	2.0	2.1	2.2	2.3	2.4
Contact Centre	6.4	7.0	7.9	7.9	7.5	7.9	8.3	8.6	9.0	9.5
Customer Operations	2.3	2.9	2.7	3.3	3.6	3.8	3.9	4.1	4.2	4.4
Customer Billing	4.1	3.5	3.5	3.7	3.2	3.4	3.5	3.6	3.8	4.0
Customer Supply	31.0	30.1	27.7	27.8	27.3	28.5	29.6	30.9	32.3	33.8
Utility Services	11.2	14.7	17.4	16.1	17.6	18.5	19.4	20.3	21.3	22.3

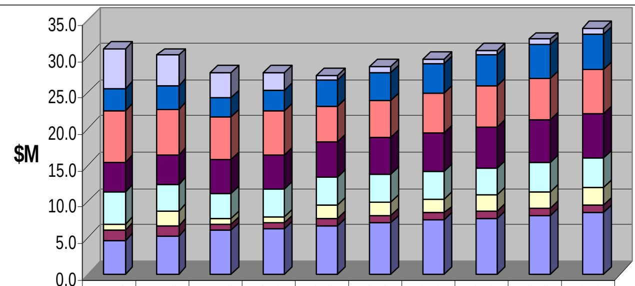
10.1 Customer Supply

Customer Supply had 373 FTEs as at end November 2002, up marginally from the 30 June 2002 figure of 368. Figure 10-3 provides actual and projected costs from 1999/00 to the end of the next regulatory period, broken down by contribution. Total actual O&M costs for Customer Supply in 2001/02 was $27.7M.

The work undertaken by Customer Supply for Networks is covered by a Service Level Agreement. The SLA contains functions with associated activities. It doesn't contain information that would enable monitoring or control of costs by Network, such as activity costings and estimated quantities. Customer Service advise activity costings and quantities will be introduced in 2003/04.

Customer Service advise that all services provided by Customer Supply are transfer priced according to economic cost.

- **Figure 10-3 Customer Supply O&M by Contribution**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Other	5.5	4.1	3.3	2.4	0.6	0.7	0.7	0.7	0.8	0.8
Cust.Claims Mgmt & EWON	2.9	3.4	2.7	2.8	3.6	3.8	4.1	4.3	4.6	4.8
Cust.Supply Operations	7.2	6.1	5.9	6.1	4.9	5.1	5.4	5.6	5.8	6.1
Installation Inspections	4.0	4.2	4.5	4.7	4.9	5.1	5.4	5.6	5.9	6.1
Ntk.Design & Planning	4.5	3.6	3.6	3.8	3.8	3.8	3.8	3.8	3.9	4.1
Ntk.Volt./ System Investgns	0.8	2.1	0.8	0.8	1.8	1.9	2.0	2.1	2.2	2.3
Ntk. Mtce & Repair (tot)	1.5	1.3	0.8	0.9	0.9	0.9	1.0	1.0	1.1	1.1
Emerg. Response	4.6	5.3	6.0	6.2	6.7	7.1	7.4	7.7	8.1	8.5

10.1.1 Emergency Response

The increase in actuals from 2000/01 to 2001/02 was due in part to an increase in staff numbers (rosters were running short in 2000/01) and to tariff change costs now being regulated (Change of off-peak tariff by changing channels on frequency injection relays – SLA p13).

Customer Supply advise their costs are increasing in this area as a result of a change in work practices to address asbestos issues (meter panels have been identified as having a (low) level of asbestos). New work practices to address this include special equipment, clothing and labour practices. They have requested an additional $500k for 2003/04 year and anticipate this additional level going forward. They are trying to modify the work practices that would reduce this cost.

The EnergyFix service, introduced as a means of better meeting customer needs and reducing Network costs, resides within this operational area. EnergyFix undertake work for customers beyond the meter. Whereas previously, when the fault lay behind the customer's meter no action was taken, Customer Supply now offer to assist the customer under the EnergyFix banner. Should the customer accept, all costs are booked to EnergyFix. Customer Supply advises that Network costs are reduced by around 30% using this approach. The call centre does not try to determine from the customer call the nature of the problem.

10.1.2 Network Maintenance and Repair

This group deals with maintenance and repair of substation equipment, mains equipment, control equipment and plant and tools. Network Maintenance and Repair O&M costs have been falling over the last few years due in part to better and more rigorous booking procedures. Customer Supply indicated that the 2001/02 actuals level of O&M expenditure represented the correct level of spending in this area going forward.

10.1.3 Network Voltage/System Investigations

These investigations are driven by the gradual increase in load on the Network at the LV level, and are requested by Networks. There is currently no monitoring of the LV Network in respect of quality of supply apart from these investigations. A pilot in the eastern suburbs 2 years ago did however indicate a growing problem. Customer Supply wants to move from a reactive response to a proactive approach involving monitoring, problem identification and augmentation design followed by a handover to Enerserve. They have asked for an additional $1.0M for the 2003/04 FY to enable this. Outlay for 2003/04 is planned to be the 2001/02 level of $797k plus labour/CPI plus $1.0M.

10.1.4 Network Design and Planning

Work in this area involves significant community consultation activity especially in the Hunter and Central Coast areas. (SLA p14). Cost drivers are economic, and particularly housing, activity therefore workload could drop off as housing market cools. Customer Supply indicate that it is difficult to realise cost savings due to the inability to shed staff easily along with the significant timescales involved in training staff. They believe the current spend level will run through the next regulatory period (CPI/EBA adjusted) although some costs savings may be available through natural attrition in the event the housing market cools. Cost savings may be balanced by new 11kV planning responsibilities taken over from Capital Works Planning. We have allowed for labour and CPI increases to 2003/04 and then proceeded with no increases for the next three years. Labour/CPI is reapplied in 07/08 and 08/09.

10.1.5 Installation Inspections

Customer Supply undertakes around 11000 installation inspections per year. Under this regime, for installations under 100A, the Contractor's first 3 jobs are inspected and if no serious defect is found he is moved to a 1/10 regime. If however a defect is found then the contractor is moved back to the 3 in a row approach. All installation works above 100A are inspected.

Recent additional costs have been driven by the need to comply with the Customer Installation Safety Plan. Customer Supply is also concerned that ongoing NMI problems in the National Electricity Market could result in an increased call on installation inspectors for support in this area. Similarly, billing issues and problems driven by the new market could translate into a need for site inspections. Nevertheless customer supply expects costs on this area to maintain their current level into and through the next regulatory period.

Note: SKM were advised in March 2003 that a revised capitalisation policy being issued by Corporate Finance enables approximately $2.2M of expenditure relating to the inspection of new installations to be capitalised. We have not factored in this new policy so as to ensure consistency of approach to the December 2002 figures and information received at that time. We also note that outcomes are not always reflective of policy decisions.

10.1.6 Customer Supply Operations

This group contains 60 to 70 people who mainly deal with administrative functions associated with requests for connection, quotes for supply and connection etc. Staff enter data, schedule work, organise initial meter readings, manage the auditing process for the installation inspections etc. Following a business restructure, a number of staff involved in this function will be transferred to Enerserve. The resulting cost reduction in Customer Supply of around 20% has not yet been reflected in their forecasts although Enerserve have included additional O&M expenditure to pick up this extra workload. We have therefore adjusted the Customer Service forecast down 20% from their forecast figure for 2003/04.

10.1.7 Customer Claims Management and EWON

Customer Claims Management deals with claims arising from consequential damage as a result of loss of supply. It also therefore deals with the Energy & Water Ombudsman NSW (EWON).

This area carries not only the administrative costs of customer claims management but also carries the cost of any lost claims. Costs are increasing because the excess on claims has now risen to $20,000 and so EnergyAustralia are likely to pay out more claims. The 2002/03 budget requested more funds to address the impact of the increased excess and Customer Supply has requested an additional $700k for the 2003/04 F/Y. Therefore 2003/04 budget = 2002/03 + $700k + CPI/labour.

10.1.8 Other

This category comprises;

Franchise Metering Maintenance:

Utility Services undertake most of the franchise metering maintenance work however Customer Supply operatives are called upon to undertake a certain amount of this work which is expected to continue. It is assumed that Utility Services will take on the work associated with additional site testing of meters resulting from the removal of the National Measurements Act exemption on meters. Operating costs are 100% allocated to Network. Forecasts have been baselined at the 2001/02 actuals but with labour and CPI escalators applied thereafter.

Customer Supply Systems and Processes:

No longer within Customer Supply and baseline costs set to zero.

Special Meter Reads/Disconnects and Reconnects:

This area has been taken over by Utility Services although Customer Supply anticipates the current trickle of work in this area to continue due to minor work undertaken by EMSOs (see SLA p 13).

Network Mapping:

This area, associated with the GIS "Smallworld" project was transferred to Customer Operations about 8 months ago. Future expenditure will be incurred by Customer Operations.

FRC Related Costs (CS Regions):

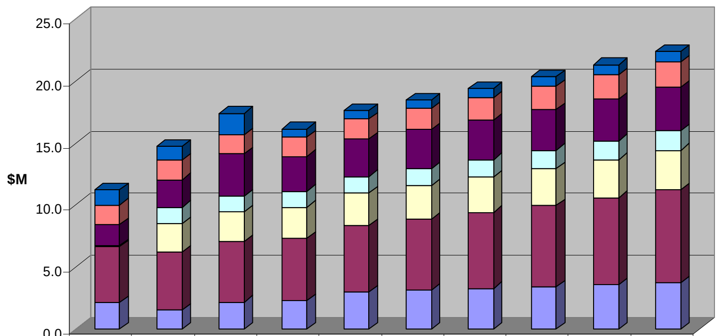
This was a special category introduced to track FRC costs and has reduced to zero for the 2002/03 budget.

10.2 Utility Services (ex TCA)

Utility Services had 228 FTEs as at end November 2002, up marginally from the 30 June 2002 figure of 223. Figure 10-4 provides actual and projected costs from 1999/00 to the end of the next regulatory period. Total actual O&M costs for Utility Services in 2001/02 was $17.4M.

The work undertaken by Utility Services for Networks is covered by a Service Level Agreement. Generally, the SLA quotes estimated quantities and prices where this is possible. Networks receive a monthly bill supported by a line by line quantity statement against the SLA. The basis elements necessary for tighter cost control by Networks of Utility Services activities are therefore in place.

- **Figure 10-4 Utility Services O&M by Contribution**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Other	12	11	18	0.6	0.7	0.7	0.7	0.8	0.8	0.8
Instrument Calibration	16	16	15	16	16	17	18	19	19	2.0
Metering Business Systems Operations	17	2.2	3.4	2.8	3.0	3.1	3.2	3.3	3.4	3.5
Contestable Metering Operations	0.0	13	12	13	13	14	14	15	15	16
Special Meter Reading Dis/Reconnects	0.1	2.3	2.4	2.5	2.6	2.7	2.8	3.0	3.1	3.2
Meter Reading and Support	4.5	4.7	4.9	5.0	5.4	5.7	6.1	6.5	7.0	7.5
Franchise Metering Maintenance	2.1	15	2.2	2.3	3.0	3.1	3.3	3.4	3.6	3.8

It would appear that Utility Services allocation of depreciation costs is more heavily weighted towards revenue earned from Networks than external business.

The chief business activities within Utility Services are described below.

10.2.1 Franchise Metering Maintenance

This activity includes re-calibration of meters returned to service, responding to problems raised by customers or meter readers, inbound acceptance testing, and recertification of meters. Around 50% of meters are over 25 years of age which raises concerns in respect of accuracy, particularly in light of the newly imposed National Measurements Act requirements. Meters less than 25 years old which come back into stores are inspected and despatched to a contractor for refurbishment at $12 to $13 per meter. EnergyAustralia refurbishes the top end meters. Note the new accumulation meter costs $40. New Type 6 probe read meters which store interval data for downloading by probe as well as displaying an accumulation register cost $80 and are becoming more prevalent each year.

Metering has been exempt from the National Measurements Act and therefore meters have not had to be maintained and tested to the same extent as other commercial measuring devices. This exemption has now been lifted and there is therefore a legal obligation to maintain and test meters in accordance with various State Metrology Procedures which all require adherence to AS1284. Part 13 of this standard stipulates sampling methodologies. The impact on EnergyAustralia, with a meter population of 3 million is an increase in the amount of in service testing undertaken of about 3500 meters per annum at an average cost of $200/meter, thereby imposing a cost increase for 2003/04 of around $700k.

10.2.2 Meter Reading and Support

The cost of meter reading and support is increasing due to growth in customer numbers of 3 to 4% pa.

All meter reading costs are allocated to Network who have the responsibility under the current NEM metering derogation. The current meter reading contract expires September 2003 and Utility Services are going out to tender with the intention of replacing a single contract covering all meter reading activities with a number of targeted contracts. Note the new contract will incorporate probe readings of new domestic meters which will take longer and therefore cost more. Within the next 12 months Utility Services are expecting 20-30,000 probe meters. (EnergyAustralia have 3m meters in total). Therefore O&M costs are expected to continue to grow.

10.2.3 Special Meter Readings – Disconnects/Reconnects

No change to current levels of O&M expenditure is anticipated in this area. There is industry discussion around allowing customer transfers to occur on estimated meter reads rather than actuals. If this happened, meter reading costs would reduce as the number of special reads reduced. This possibility has not been factored into our forecasts.

10.2.4 Contestable Metering Operations

This business activity involves acting as Metering Provider and Meter Data Agent for all meters within EnergyAustralia's network area associated with customers on contracts (EnergyAustralia contracts and other Retailers), both above and below 160kWh. Utility Services allocates 24.2% of the costs in this area to Networks. This business activity will grow if the number of customers on contracts within the EnergyAustralia Networks area grows. However growth is likely to be slow for the near future if domestic customer churn in the new market remains low and wins and losses in the C&I market are balanced. Therefore a growth rate based upon Labour & CPI escalators has been assumed.

Transfer prices for Contestable Metering Services are based upon market prices rather than economic cost.

10.2.5 Metering Business Systems Operations

This group runs the MBS system that offers meter registration database services to TXU, CitiPower and ETSA as well as EnergyAustralia networks. The group has had quite high costs over the last few years due to Y2K, SAP/CCS implementation and then FRC. Going forward the IT staff will move to the Corporate IT&T and this will tend to reduce costs. Progressive actuals for 2002/03 is $1.2M for first 5 months (July to November) with a 2002/03 budget of $2.8M. The 2003/04 budget bid is $3.0M which includes an additional $100k for data input activities associated with MBS due to increased usage as a result of the introduction of FRC. Labour and CPI escalators have been applied from 2004/05.

10.2.6 Instrument Calibration

This activity is undertaken on Enerserve staff working instruments by the Instrument Calibration Group within Utility Services. Costs in this area are expected to remain fairly static.

10.2.7 Other

This category comprises;

Network Voltage/System Investigations:

These investigations tend to be Network driven (rather than Customer driven) and involve special investigations in particular network areas as requested by Networks. These are covered by unit rates within the SLA. It amounted to $289k in 2001/02.

MBS – FRC Costs:

This accounting category was used for FRC recovery purposes but will not appear going forward.

Metering FRC Costs:

This accounting category was used for FRC recovery purposes but will not appear going forward.

Metering Other Operations:

This is a minor expenditure item ($175k in 2001/02) which we have carried forward at the same level.

Testing and Consulting Services:

This is a minor expenditure item. ($151k in 2001/02) which we have carried forward at the same level.

10.3 Customer Billing

Customer billing had 101 FTE staff as of end November 2002, up from 89 staff at end June 2002. Labour accounts for around 85% of customer billing costs. Customer billing actual and projected costs are displayed in Figure 10-5.

Customer Billing has recently restructured. Under the previous business structure Customer billing activity consisted of 2 parts: contestable billing which billed those commercial and industrial customers who moved to contracts (be they EnergyAustralia customers or other Retailers' customers), and customer billing which billed those customers who remained on the ETEF regulated tariff plus the currently small number of domestic customers who either changed Retailer or moved from the ETEF tariff.

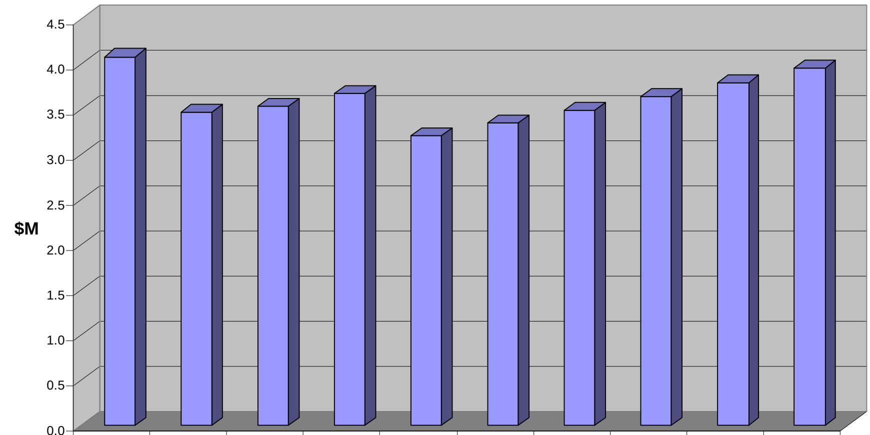
Contestable billing had a 0% allocation to Networks on the basis that commercial and industrial contract customers are moved from CCS (where the Network bill is also calculated) on to the Contestable Billing System.

The remaining customer billing had a 35.3% allocation to Networks which addressed the service provided to Networks to enable the subsequent calculation of the Networks bill but excludes those domestic customers (<160kWh) who had moved to a Retail contract.

Customer Service advise that the new business structure amalgamates the two billing activities and Networks are allocated 46.8% of the total billing costs. This allocation is up from 35.3% and SKM believe it could increase further in the event that a large number of customers were lost by EnergyAustralia or moved to contracts in which case more of the costs of CCS may be allocated to Network. The marketing strategies of EnergyAustralia and other Retailers could therefore impact Network's share of the costs of CCS. Note that a large loss of customers would also impact Network billing which would have to bill an increased number of Network only customers with what is a largely manual process.

SKM have not included the cost impact of the reallocation in our forecasts is which are based on the December 2002 figures and information provided by EA staff. This avoids a forecast based upon two competing sets of figures.

■ **Figure 10-5 Customer Billing**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Customer Billing	4.1	3.5	3.5	3.7	3.2	3.4	3.5	3.6	3.8	4.0

There have been discussions of a possible Retail billing engine. This is not expected to become reality within the next Regulatory period. When or if a Retail billing engine was implemented, again more of the costs of CCS would be borne by Network.

10 to 15% of all billing interactions require manual intervention. This is often due to B2B problems plus the objection process in the "Win a Customer" process. Thus an increase in the churn rate could impact the billing OPEX. This could be effected by increased marketing by either EnergyAustralia or its competitors.

10.4 Sustainable Energy

In 2001/02, 96.8% of Sustainable Energy costs were allocated to Networks. This amounted to $954k in 2001/02. We have been advised that recently some costs have been allocated to Corporate associated with energy efficiency consultancy. It is assumed that the majority of Corporate costs will be reallocated to Networks.

10.5 Call Centre

EnergyAustralia's call centre is divided between two locations.. One in Sydney (70 seats and 85 staff) and one in Wallsend (142 seats and 179 staff) Total FTEs at end November 2002 are 209 down from 224 at the end of June 2002. The argument for retaining 2 call centre locations is redundancy/business continuity.

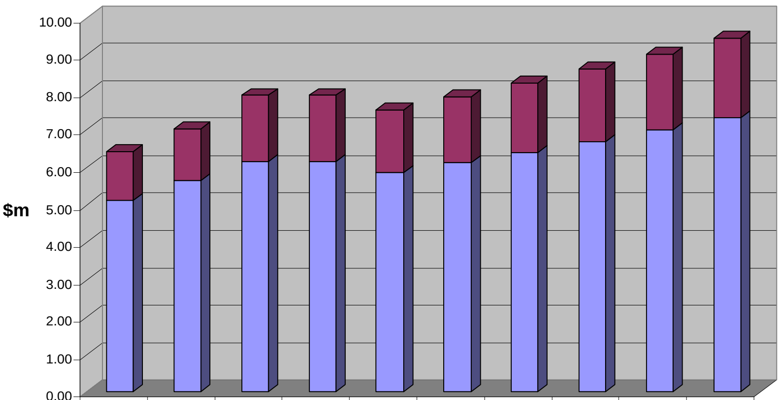
Contact centre actual and projected costs are displayed in Figure 10-6, broken down by contributions.

100% of the costs of storm and breakdown related calls are allocated to Networks. 33% of remaining call centre costs are allocated to Networks. 15% of calls are Network related. The discrepancy between the allocation and the number of Networks related calls is justified by Customer Service on the basis of staff and infrastructure availability for large Network outages. Presumably Networks allocation of costs would increase in the event that EnergyAustralia Retail started losing significant numbers of customers.

Costs are dictated by call centre load that is a combination of volume and handling time. The introduction of new business processes could impact handling time; any customer facing errors will impact volumes and handling times (e.g. billing errors or changes to customer bills).

O&M increases over the last few years are a result of staff increases needed to address the changing market. Staff numbers are now decreasing. Staffing costs amount to around 83% of total costs allocated.

- **Figure 10-6 Contact Centre**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Emergency Despatch & Storms	1.31	1.39	1.77	1.77	1.68	1.76	1.85	1.94	2.03	2.13
Contact Centre (excl despatch & Storms)	5.11	5.65	6.16	6.16	5.86	6.13	6.41	6.70	7.01	7.33

The 2002/03 outturn is looking close to the total (before Networks allocation) budgeted figures of $19.812M. The 2003/04 budget bid is slightly lower reflecting lower staffing levels.

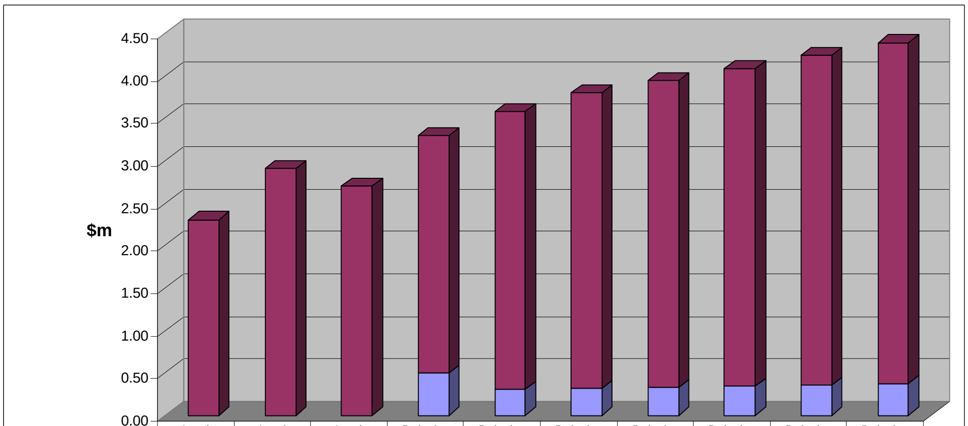
10.6 Customer Operations

Customer Operations is comprised of 2 main functions, the GIS data capture/maintenance group which was formed in July 2002, and the National Electricity Market Support Group, which includes Network Billing (the billing of Retailers for the use of the EnergyAustralia network.

Customer operations actual and projected costs are displayed in Figure 10-7, broken down by contributions.

The main work area facing Customer Operations in the GIS "Smallworld" environment is the completion of data capture for the EnergyAustralia network. Customer Operations requested $2.7M in the 2002/03 budget comprising $2.2M capex and $0.5M O&M. Going forward, $3.0M has been requested for 2003/04 with $0.3M being O&M. The O&M component is largely associated with administration costs and “call before you dig” telephone systems and is allocated 100% to Networks.

- **Figure 10-7 Customer Operations**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Nat.Mkt Support/Ntwk Billing	2.30	2.90	2.70	2.79	3.28	3.49	3.61	3.74	3.87	4.01
GIS System	0.00	0.00	0.00	0.50	0.30	0.31	0.33	0.34	0.36	0.37

The National electricity market support group provides the following functions for Networks:

- Fulfilment back office activities for disconnections, NMI discovery, special reads, re-energisations and Network transfers, dealing with other Retailers and Networks businesses.
- Networks billing covering the billing of Retailers for their use of the EnergyAustralia network and councils for streetlight billing which is now contestable.
- Account reconciliation that deals with disputes.

The total costs for this group in 2001/02 was $2.7M. Customer Operations have requested $3.2M for the 2003/04 budget of which nearly $2.0M is associated with Customer Transfers. The current transaction cost is $35 per new transfer that Customer Operations are attempting to drive down to $26 and the 2003/04 budget is based upon this figure. The individual transaction cost is high due to the need for the operator to access in excess of 50 screens per transfer. Was churn to increase or Customer operations not be able to meet the target transaction cost, this cost could exceed budget significantly.

The Network billing budget has decreased from $1.23M in 2002/03 to $0.54M for 2003/04. Again it is possible this figure could be exceeded particularly should EnergyAustralia Retail lose customers which would then have to be billed through Network billing.

Other factors which could cause costs increases include NMI exceptions which require investigation and transfer exceptions.

10.7 Debtor Management

Debtor Management is managed within Customer Services Finance and HR department and consists of 3 separate areas; Field Force (33.5% allocated to Networks), Revenue Protection (100.0% allocated to Networks) and Recovery and Revenue Collection (0.0% allocation to Networks).

Field force cost allocation to Networks in 2001/02 were $358k while Revenue Protection costs were $370k.

11. Distribution OPEX Expenditure

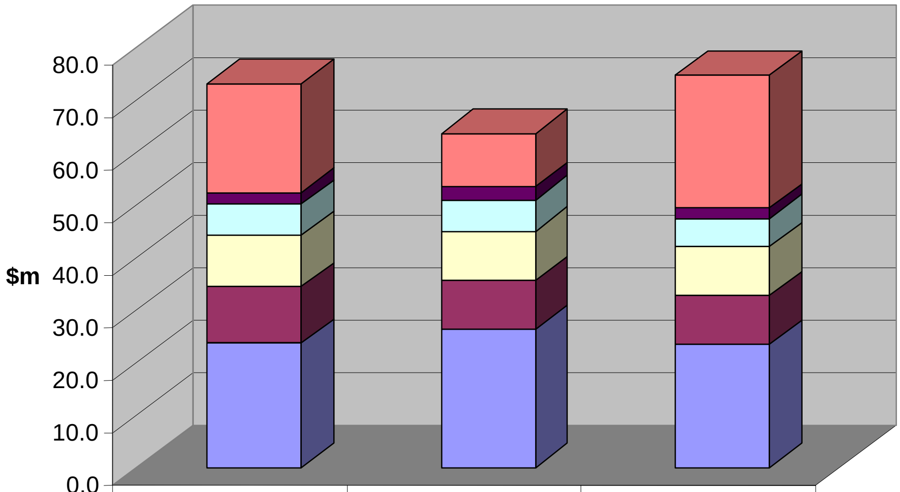
11.1 Introduction

This section addresses Enerserve's operating expenditure on distribution assets – overhead lines, HV and LV underground cables, distribution transformers, vegetation management, streetlight maintenance and miscellaneous activities such as fleet, logistics, general administration etc not covered elsewhere.

11.2 Historical Cost Data

Figure 11-1 below summarises the actual expenditure on the items covered in this section as provided to SKM by Energy Australia.

■ **Figure 11-1 Enerserve Distribution Historic O&M Expenditure by Contribution**



	Actual 99/00	Actual 00/01	Actual 01/02
Miscellaneous	20.7	10.2	25.4
Vegetation	2.2	2.5	2.0
Streetlights	6.0	6.0	5.4
HV&LV Underground	9.7	9.4	9.3
Distribution transformers	10.7	9.3	9.3
Overhead lines	23.7	26.2	23.4

11.3 Findings/Observations

11.3.1 Field Operation Expenditure

When "miscellaneous", non-field operation items, are extracted from Enerserve's actual expenditure, over the three year period, actual expenditure in the field operations area has declined. A break-up of costs into planned, corrective and emergency was not available for the initial year 1999/00, however, it can be seen in the table below that the reduced expenditure has been predominantly due to lower bookings to planned maintenance items. There are smaller reductions in corrective and emergency works.

■ **Table 11-1 Breakdown of Total Field Operations Distribution Expenditure**

Total Expen[illegible]iture on Field Operat[illegible]on items	**99/0[illegible] $(000[illegible])**	**00/0[illegible] $(000[illegible])**	**01/0[illegible] $(000[illegible])**
total pla[illegible]ned	52,38[illegible]	13,51[illegible]	10,04[illegible]
Total corr[illegible]ctive	N/A	16,97[illegible]	16,65[illegible]
Total st[illegible]ms	N/A	22,95[illegible]	22,67[illegible]
TOT[illegible]	52,38[illegible]	53,44[illegible]	49,36[illegible]

The reduction in Enerserve's planned maintenance expenditure is more than off-set by increases in planned maintenance under external contracts administered by the Networks group. The bulk of this increase in external contracted planned maintenance has been in vegetation management and this is discussed in Section 5. When Network's planned maintenance budget is included, the total expenditure on distribution assets as defined above shows an increase of $11.5 million over the three year period.

It is believed that there was an increase in planned and corrective maintenance in the lead up to the 2000 Olympics that will have impacted on maintenance expenditure in the first two years.

More specific comments are included in subsequent sections of this report.

11.3.2 Ratio of Emergency and Corrective Work to Planned

The ratio of Emergency and Corrective work to Planned provides a qualitative assessment of the mix of work undertaken. It has been suggested that an optimal mix of work providing minimum total maintenance expenditure is reached as this ratio approaches unity.

Considering only Enerserve's expenditure, the ratio of Emergency and Corrective to Planned varies between three and four. However, when Network's planned maintenance expenditure is also included (eg. vegetation management, pole inspection, etc.) this ratio approaches unity. This provides a positive signal that the mix of work overall is correct, although some concerns remain about the backlog of corrective work reported.

The strong reliability figures reported also support this impression. An overall SAIDI of approximately 100 minutes is considered to be a very good result for a mixed CBD, urban and rural network. Even in the most rural area (Upper Hunter), a predominantly radial system, network performance has been satisfactory with a total SAIDI of approx 480 minutes.

11.3.3 Increases in the Quantum of Work

As the assets in service grow, the quantum of maintenance work required is expected to increase. This has modelled in the forecast by increasing material and other costs at half the expected rate of growth in summer peak demand (4.1%) ie: 2.05% pa.

11.3.4 Impact of Regulation 2001

Regulation 2001 is a state government (Workcover) document that governs the workplace health and safety requirements for the fieldwork undertaken by Enerserve.

The direct costs of meeting EA's obligations under this Regulation in terms of additional people, training, protective clothing and equipment etc, have been calculated by Enerserve's finance team at approximately $8 million pa and included in the forecast for Miscellaneous items (see below).

However, the greatest impact of the new Regulations will be in extending the time spent on each maintenance activity. This effect is likely to reduce the quantum of work performed rather than increase the costs in total (unless staff increases are allowed to compensate for increased time per activity). This has the potential to add further to the backlog of work that currently exists and will require further review and prioritising of the corrective work actually done.

11.3.5 Revised Maintenance Strategies

Energy Australia has recently reviewed its asset maintenance strategies aiming to produce a more condition-based maintenance approach. An internal team is reviewing the impact that this is likely to have on O&M.

11.3.6 Bush Fire Mitigation

The extreme bush fire threat in NSW over recent years has prompted a further review of Energy Australia's operation practices in "at risk" areas throughout the bush fire season. A number of changes to practices and constraints on field operations have been introduced or proposed. For example, disabling auto-reclose facilities in zone substations and line reclosers plus requiring a feeder patrol before any manual reclose operation is attempted. Such changes will impact on emergency expenditures, labour available for planned and corrective works, and on the system reliability indices.

The impact of these changes has not been included in the baseline forecast. SKM has quantified the likely input of the Bushfire Mitigation policy as around $480k pa. See Appendix H for details.

11.3.7 Opex/Capex Relationship

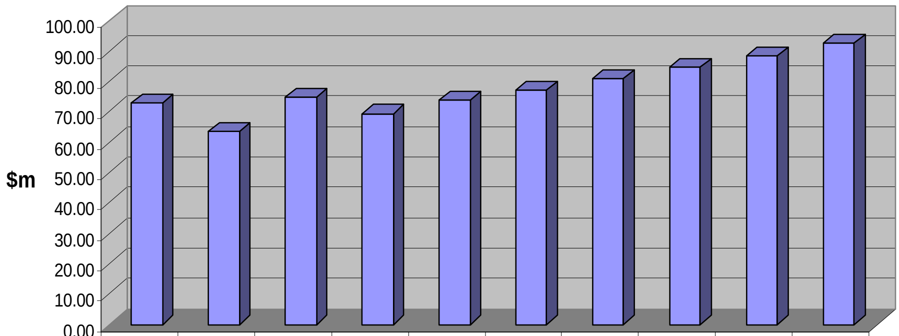
Generally Enerserve crews will work on both Capex and Opex projects. Workforce numbers are controlled, therefore an increase in capex expenditure has the potential to divert scarce labour resources from operating functions to capital functions. Current forecasts are predicting an increase of 40% in total capital expenditure per year of the next regulatory period compared to current expenditure.

Substantial increases in Refurbishment capex have been projected. It is expected that this targeted additional capital expenditure will have some impact on maintenance spend. This impact has been modelled globally and is incorporated in the final forecast.

11.4 Baseline Projection

The baseline projection of expenditure in the Distribution area of Enerserve's responsibilities is shown in Figure 11-2.

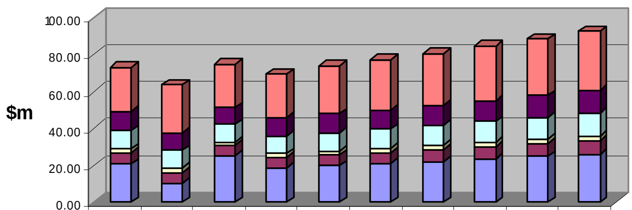
- **Figure 11-2 Enerserve Distribution O&M Expenditure**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Enerserve Distribution Opex	73.12	63.63	74.73	69.43	73.78	77.24	80.84	84.61	88.56	92.70

The breakdown of the actual and forecast O&M expenditure by contribution is provided in Figure 11-3.

- **Figure 11-3 Distribution O&M Expenditure by Contribution**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Overhead Lines	23.68	26.24	23.36	23.71	25.85	26.98	28.15	29.37	30.64	31.97
Distribution Transformers	10.74	9.33	9.30	9.71	10.12	10.57	11.04	11.52	12.02	12.55
HV&LV Underground	9.73	9.41	9.35	9.71	10.08	10.48	10.89	11.32	11.76	12.23
Vegetation	2.25	2.47	1.96	2.05	2.13	2.22	2.32	2.42	2.52	2.63
Street Lights	5.99	6.00	5.39	5.61	5.83	6.08	6.33	6.60	6.87	7.16
Other Miscellaneous expenditure items	20.73	10.18	25.36	18.66	19.76	20.90	22.11	23.39	24.74	26.17

11.5 Analysis By Asset Categories

11.5.1 Overhead Lines

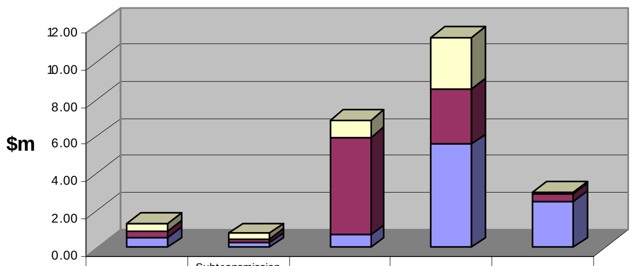
11.5.1.1 General

Planned (preventive) maintenance for overhead line assets is controlled by the Network Group. Corrective maintenance is identified by field inspections carried out by two separate groups - ground line pole inspection is undertaken (generally) by external contractors on a four year cycle followed by a pole top inspection undertaken by Enerserve approximately two years later. Enerserve does have responsibility for ground line inspections in the Newcastle and Southern regions. Defects are prioritised and entered directly into Energy Australia's NAMs system.

11.5.1.2 Historical Cost Data

Figure 11-4 details the O&M expenditure for overhead lines by contribution for 2001/02.

■ **Figure 11-4 Overhead Lines O&M Expenditure 2001/02**



	Transmission Overhead - 132kV	Subtransmission Overhead- 66kv/33kv	Poles	Oh mains/ switchgear & equip	Services
Planned	0.45	0.32	0.92	2.81	0.06
Corrective	0.33	0.18	5.30	2.98	0.43
Emergency	0.56	0.27	0.68	5.58	2.51

11.5.1.3 Findings/Observations

Inspection is carried out on timber poles and was recently reduced from a 4.5 year to a four year cycle with a resulting increase in inspection costs. Energy Australia has a high population of timber poles for both LV and HV distribution. Subtransmission poles are also predominantly timber and approximately 50% of 132kV lines are also on timber pole structures.

Inspection requires digging around the pole to a depth of 350mm to determine ground line pole decay followed by sounding of the pole and a drill sample to determine pole residual strength.

Should the pole have less than 50% residual strength, an assessment as to replacement or nailing of the pole is made by Network contract supervision staff. Recent history would suggest that the pole defect rate is approximately 1.6% of inspected poles. The percentage of poles assessed to be nailed has increased over the last three years from less than 20% in 99/00 to approximately 43% for the first five months of this financial year. The expectation within Networks is that this percentage will continue to grow, though there is some opposition from within Enerserve. There is a potential problem with union refusal to climb nailed poles.

This increase in re-instatement through nailing has the potential to reduce pole maintenance costs. The projected expenditure in this area reflects the current mix of works thus a small reduction over recent historical spend.

The close off of service orders indicates that although a slight majority of defective poles are still being assessed for replacement, the rate of pole nailing exceeds the rate of pole changes. There is accordingly an increasing backlog of poles awaiting change-out. At the end of November 2002, the backlog of poles to be changed stood at 1686. In the Sydney area, a number of these poles are lashed to newly installed poles and are considered to be of lower risk.

One measure of the effectiveness of the pole management process is the recorded pole failure rate. Energy Australia appears to target a failure rate of less than one in ten thousand. Recently performance has averaged approximately 8 in 100,000 pa – within the target performance.

Other outstanding work includes 12,323 work orders for overhead maintenance and 376 poles to be nailed. Anecdotal evidence suggests that conscious decisions have been made by Enerserve management to focus on higher priority defects only, to meet budgetary constraints. No budget allocation has been provided to reduce this existing backlog.

Enerserve is to take additional responsibility for services from Customer Services. Though most of the work being transferred will be capital expenditure, this transfer is expected to increase Enerserve operating costs by approx $1,138,000 pa. Most of this expenditure will be labour related. In the forecast expenditure, this additional expense has been included under planned maintenance only to keep it under the “services” item. In reality, it is likely to be recorded as part of general administration costs in the “miscellaneous” area.

11.5.1.4 Work Practices Issues

To an external reviewer, the practice of using a specialist pole gang and specialist line crew in some regions for pole changes, contributes to the backlog of poles replacements, requires several visits to the same work site and must increase overall costs. Staff in those areas of EA where multi-skilled crews are the norm, seem to share this view. This practice results in the large number of lashed poles in the system still requiring recovery after the mains have been relocated onto the replacement pole.

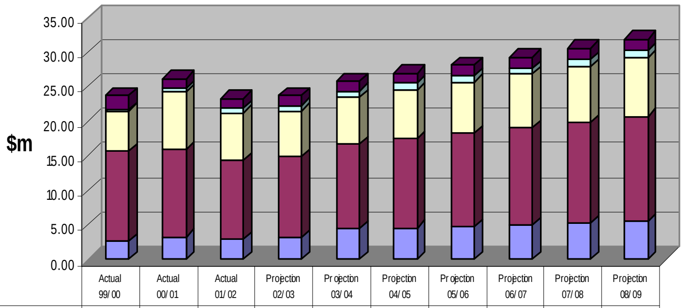
The use of poles to carry cable TV presents a similar problem. As poles are replaced the cable TV connection must be undertaken by OPTUS. This often results in new poles being lashed to failed poles in order to permit the cable TV to be maintained until transfer is arranged by OPTUS.

SKM also received anecdotal reports that some decayed poles are being nailed prior to change-out because of delays in Enerserve’s response to a pole change works order.

11.5.1.5 Base Line Projections

The projected expenditure for overhead lines is presented in Figure 11-5.

- **Figure 11-5 Overhead Lines O&M Expenditure Projection by Contribution**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Transmission Overhead - 132kV	2.02	1.35	1.34	1.39	1.45	1.51	1.57	1.63	1.70	1.77
Subtransmission Overhead-66kv/33kv	0.11	0.63	0.76	0.80	0.83	0.86	0.90	0.94	0.98	1.02
Poles	5.82	8.24	6.90	6.56	6.83	7.13	7.43	7.75	8.08	8.43
Oh mains/ switchgear & equip	13.13	12.69	11.37	11.85	12.35	12.88	13.44	14.02	14.62	15.25
Services	2.58	3.33	2.99	3.12	4.40	4.60	4.81	5.03	5.26	5.50

This forecast generally represents a "business as usual" approach accepting the current work practices, maintenance strategies and operational responses. The forecast does reflect the change in the pole inspection frequency and the corresponding increase in pole defects expected. It also reflects the reduced number of pole changes because of the increased rate of pole re-instatement using pole nails.

The forecast also includes the effect of transferring certain service (wire) responsibilities from Customer Service to Enerserve.

As discussed earlier, this forecast does not include the impact of the changes to operations being introduced by bush fire mitigation obligations.

11.5.2 HV and LV Underground Distribution

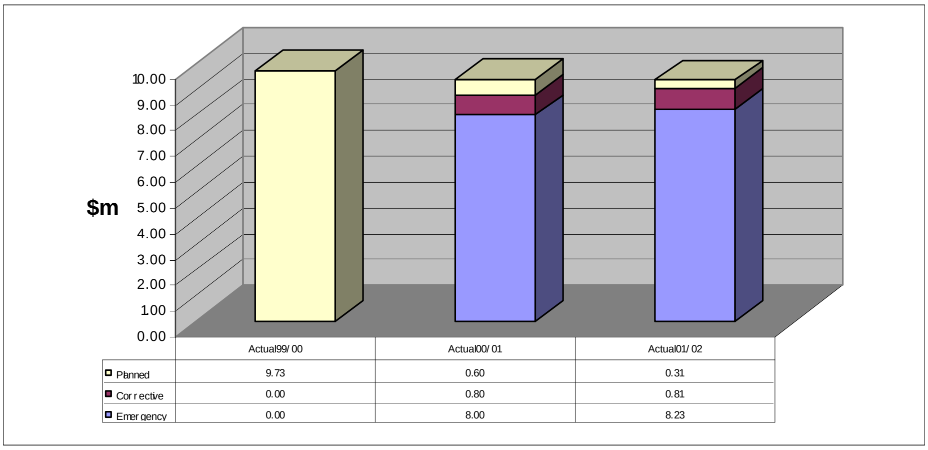
11.5.2.1 General

This section covers expenditure on high voltage and low voltage underground mains and URD assets.

11.5.2.2 Historical Cost Data

The historical spend in this area is shown in Figure 11-6 below.

- **Figure 11-6 U/G Mains and URD Historic O&M Expenditure by Contribution**



Note: No break-up of expenditure available for 99/00.

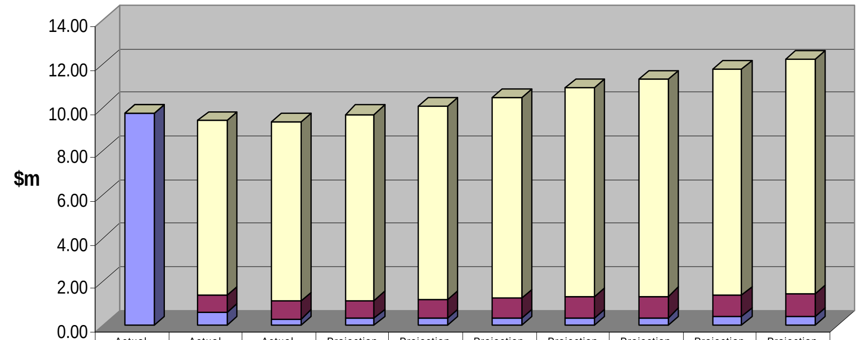
11.5.2.3 Findings/Observations

There has been a small decrease in expenditure in this area over the three years possibly reflecting a small surge in planned works leading up to the Olympics. Generally there is limited planned and preventative work that can be done on an underground network. Hence the emergency maintenance expenditure swamps planned and corrective indicating that most work is performed in response to failures. This would be typical industry practice.

11.5.2.4 Baseline Projections

The base case projection of future expenditure is based on the 2001/02 expenditure and is displayed in Figure 11-7.

- **Figure 11-7 U/G Mains & URD O&M Expenditure Projection by Contribution**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Total storms	0.00	8.00	8.23	8.54	8.87	9.22	9.59	9.96	10.35	10.76
Total corrective	0.00	0.80	0.81	0.84	0.88	0.91	0.95	0.98	102	106
Total planned	9.73	0.60	0.31	0.32	0.33	0.35	0.36	0.37	0.39	0.40

11.5.3 Distribution Transformers

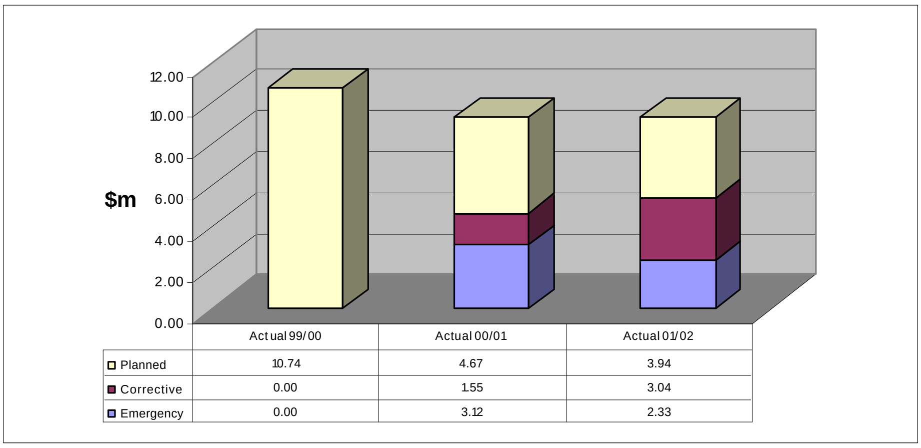
11.5.3.1 General

The routine overhead line inspections (approximately every four years) include at least a visual inspection of pole mounted transformers. There is a separate programme of transformer planned maintenance and inspection. This programme is being reviewed as part of the introduction of reliability centred maintenance strategies. There is a general expectation that at least the planned maintenance expenditure will decrease as the inspection programme is tailored for the specific transformer make, location, age etc. There is some indication that the benefits of this review are already being seen in the 2001/2002 expenditures (see below).

11.5.3.2 Historical Cost Data

The historical cost data is shown in Figure 11-8 below.

- **Figure 11-8 Distn Transformers Historic O&M Expenditure by Contribution**



Note: No breakup of expenditure provided for 99/00.

11.5.3.3 Findings/Observations

Overall expenditure in this area has declined over the last three years. From 2000/01 to 2001/02, there was a reduction in planned maintenance expenditure of approximately $700,000. It has been assumed that this reflects alterations to the frequency of routine inspections and that this level of expenditure will continue into the future.

Over the same time period, corrective expenditure has increased significantly. Recorded transformer defects are listed as "non-negotiable" and "negotiable", indicating the assessed priority of each defect. Anecdotal evidence indicates that Enerserve staff have increased the amount of corrective work done, focussing almost completely on the "non-negotiable" work orders. Very little negotiable maintenance is actually completed.

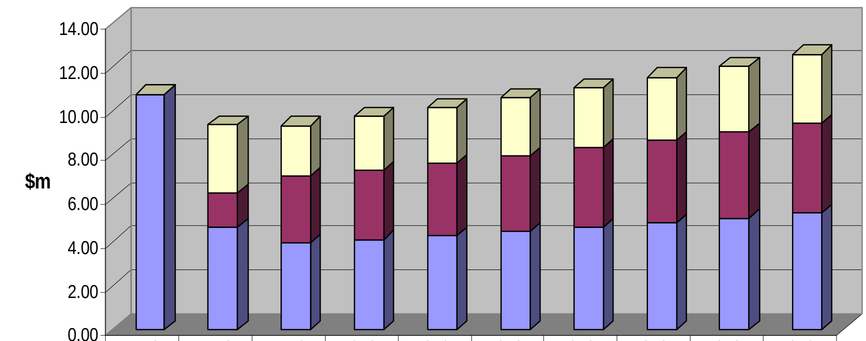
It is believed that the level of expenditure on corrective work in 2001/02 is a reasonable indication of the expenditure required to remain in control of these priority works. "Negotiable" work will continue to build as a backlog. At the end of September 2002, the backlog of "non-negotiable" maintenance stood at approximately 818 works orders, while the backlog of "negotiable" maintenance stood at 8,674.

Transformers that are replaced under emergency (storm or break down) conditions should be capitalised. There may be some small opex savings available if this requirement is vigorously enforced.

11.5.3.4 Baseline Projections

The projected expenditure for Distribution Transformers is presented in Figure 11-9.

- **Figure 11-9 Distn Transformers O&M Expenditure Projection by Contribution**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Total storms	0.00	3.12	2.33	2.43	2.53	2.64	2.76	2.88	3.01	3.14
Total corrective	0.00	1.55	3.04	3.17	3.31	3.46	3.61	3.77	3.93	4.10
Total planned	10.74	4.67	3.94	4.11	4.28	4.47	4.67	4.87	5.09	5.31

11.5.4 Vegetation Management

11.5.4.1 General

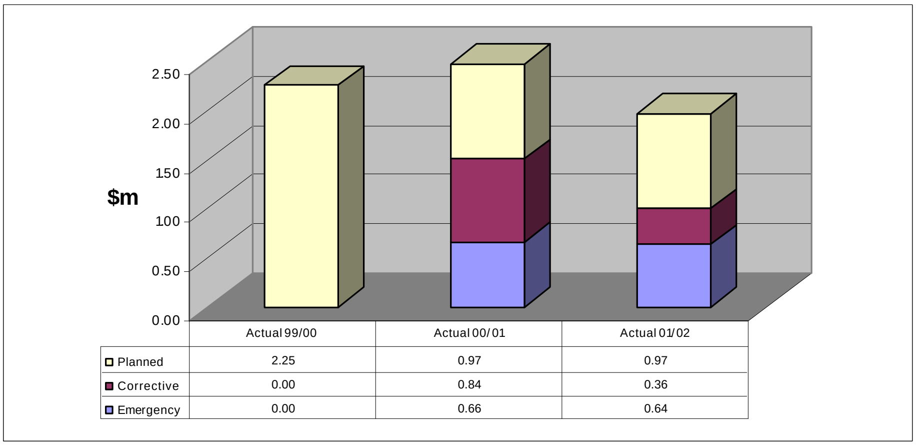
The majority of Energy Australia's distribution area overhead lines have vegetation control contracts with outsourced contract providers to ensure that the statutory clearances of trees under or adjacent to power lines is maintained. The exception areas are Central Coast and Cessnock, which are maintained by Enerserve.

It is noted that Energy Australia has performance based contracts in place for tree trimming, which ensures that ongoing vegetation management is maintained. Some concerns about the effectiveness of vegetation management in the Central Coast and Cessnock regions have been expressed by network staff since labour allocated for vegetation management here is also used for other tasks. The Service Level agreement between Enerserve and Network has not been sighted, however, there may be some scope for including performance clauses in the SLA similar to the external contracts.

11.5.4.2 Historical Cost Data

The historical expenditure by Enerserve in the vegetation management area is shown in Figure 11-10.

- **Figure 11-10 Veg. Management Historic O&M Expenditure by Contribution**



	Actual 99/00	Actual 00/01	Actual 01/02
Planned	2.25	0.97	0.97
Corrective	0.00	0.84	0.36
Emergency	0.00	0.66	0.64

Note: No breakup of expenditure provided for 99/00.

11.5.4.3 Findings/Observations

Over the last three years more of this work has been transferred from Enerserve to external contractors.

The maintenance of access tracks remains an Enerserve responsibility. Some concern has been expressed in rural areas regarding the state of some access tracks and the build up of thick low growth beneath powerlines. These are issues that need to be discussed between Network and Enerserve and have the potential to increase future expenditure in this area.

In order to improve reliability performance under high wind conditions and to meet local community expectations in respect of visual aspects of tree trimming, local councils have requested and are contributing towards the installation of ABC and CCT conductors. The problem with this program is that there is a backlog of work of up to three years due to internal fund limitations and inability of Enerserve to undertake the work. It is noted that approximately 500 spans of ABC is installed per year. Although this is a capital project, it competes with maintenance projects for scarce line resources.

It is noted that Energy Australia now completely funds tree management within its distribution area. This is contrary to other Distribution areas within the State where tree trimming is jointly undertaken by both the Distributor and the Local Councils.

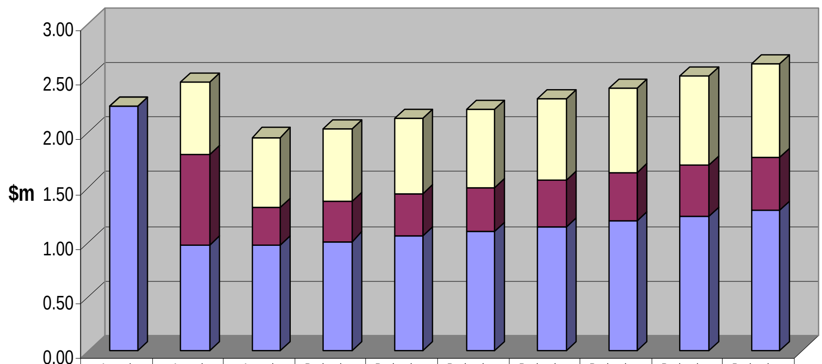
11.5.4.4 Work Practice Issues

External contractors are not permitted to undertake any electrical work. This includes switching and earthing of electrical assets. It also restricts the contractors from utilising trained live line workers to cut vegetation within normal approach distances while maintaining supply. These factors limit the efficiency of the contractors used, increase the number and duration of outages seen by customers and increase the overall cost to the business.

11.5.4.5 Baseline Projections

The projected expenditure for vegetation management is presented in Figure 11-11.

■ **Figure 11-11 Veg. Management O&M Expenditure Projection by Contribution**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Total storms	0.00	0.66	0.64	0.66	0.69	0.72	0.75	0.79	0.82	0.85
Total corrective	0.00	0.84	0.36	0.37	0.39	0.40	0.42	0.44	0.46	0.48
Total planned	2.25	0.97	0.97	1.01	1.05	1.10	1.14	1.19	1.24	1.30

11.5.5 Street Lighting

11.5.5.1 General

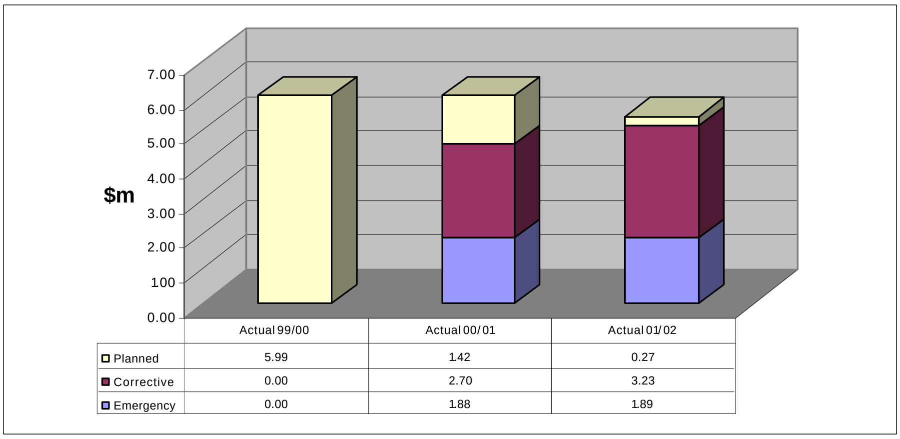
Street lighting bulk replacement is undertaken by external contractors on behalf of Energy Australia. The system used throughout most of Energy Australia is based on bulk lamp replacement rather than replacement as lamps fail. Fittings that are detected as faulty during the bulk change are reported to Enerserve for attention and repair. All spot replacements are carried out by Enerserve.

In Newcastle and the Hunter area, bulk lamp replacement is not the normal maintenance strategy. Streetlighting in this area is maintained by Enerserve through spot replacements.

11.5.5.2 Historical Cost Data

The historical expenditure by Enerserve on streetlight maintenance is shown in Figure 11-12.

- **Figure 11-12 Streetlighting Historic O&M Expenditure by Contribution**



	Actual 99/00	Actual 00/01	Actual 01/02
Planned	5.99	1.42	0.27
Corrective	0.00	2.70	3.23
Emergency	0.00	1.88	1.89

Note: No breakup of expenditure provided for 99/00.

11.5.5.3 Findings/Observations

The expenditure in this area has shown a small decline over the last three years. Enerserve do very little planned maintenance work on streetlights and the high expenditure in 2000/01 is difficult to explain. It may include a surge in maintenance prior to the Sydney Olympics and a trial bulk replacement programme in the Hunter. The planned expenditure seen in 2001/02 is considered to be a more realistic level.

EA’s population of non-traffic streetlights is predominantly fluorescent and these are relatively low life/high maintenance. At present, the bulk change frequency is 18 months for non-traffic (fluorescent), 30 month for traffic lighting.

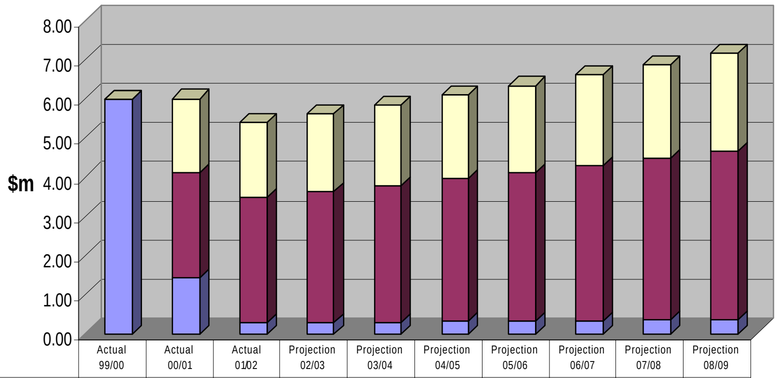
A previous SKM survey of a selection of Australian distribution businesses indicates that EA’s streetlight maintenance costs are relatively high by industry comparison. Savings may be available by replacing fluorescent lighting with mercury vapour or sodium, wider use of night patrols and spot replacement, lower levels of bulk replacement and wider use of contract labour for electrical works associated with bulk replacement and for spot replacement.

11.5.5.4 Work Practice Issues

External contracts are limited to “non-electrical” work that limits the general lamp maintenance that can be done during bulk change programmes. Enerserve staff address any “electrical” defects – requiring a second visit. Anecdotal evidence suggests that even replacement of fuses is classed as electrical work outside the scope of the external contracts.

11.5.5.5 Baseline Projections

The projected expenditure for streetlight maintenance is presented in Figure 11-13.



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Total storms	0.00	1.88	1.89	1.96	2.04	2.13	2.22	2.31	2.40	2.50
Total corrective	0.00	2.70	3.23	3.36	3.49	3.64	3.79	3.95	4.12	4.29
Total planned	5.99	1.42	0.27	0.29	0.30	0.31	0.32	0.34	0.35	0.36

■ **Figure 11-13 Streetlighting O&M Expenditure Projection by Contribution**

11.5.6 Miscellaneous Expenditure

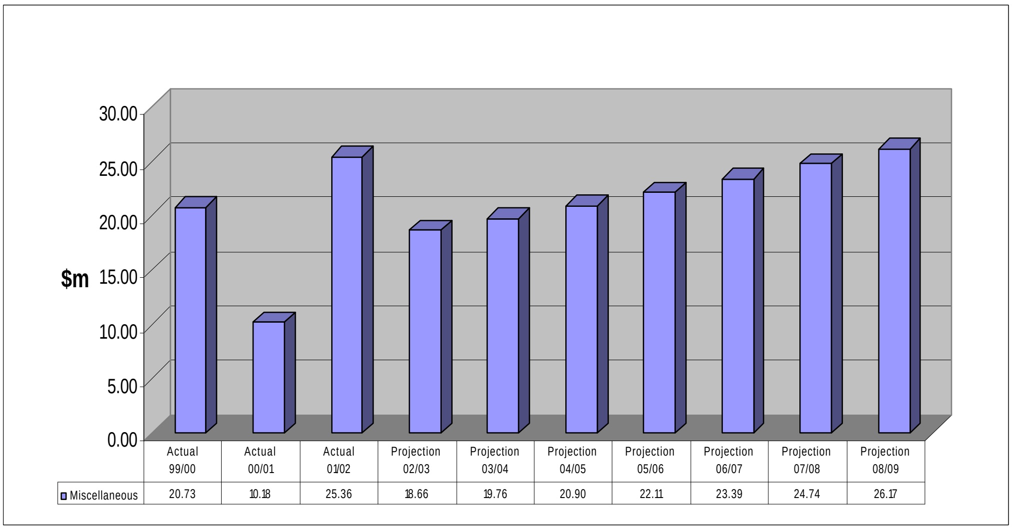
11.5.6.1 General

This area covers a broad range of functions including fleet, logistics, branch administration, non-productive time, apprentice charges, training, engineering consulting, plant and equipment testing plus it incorporates internal income.

11.5.6.2 Historical Cost Data and Projections

The historical and projected expenditure under miscellaneous is shown in Figure 11-14.

- **Figure 11-14 Miscellaneous O&M Actuals and Forecast**



11.5.6.3 Findings/Observations

The historical figures show large fluctuations in costs from year to year which don't appear to be well explained.

Fleet and Logistic costs can be isolated. The remaining figures show a large variation in labour costs from year to year which is unlikely given a fairly constant work force. We are of the opinion that these fluctuations are associated with cost centre residuals. The apparent increase in labour component from 2000/01 to 2001/02 was approximately $12 million. In the forecast, this increase has been backed out.

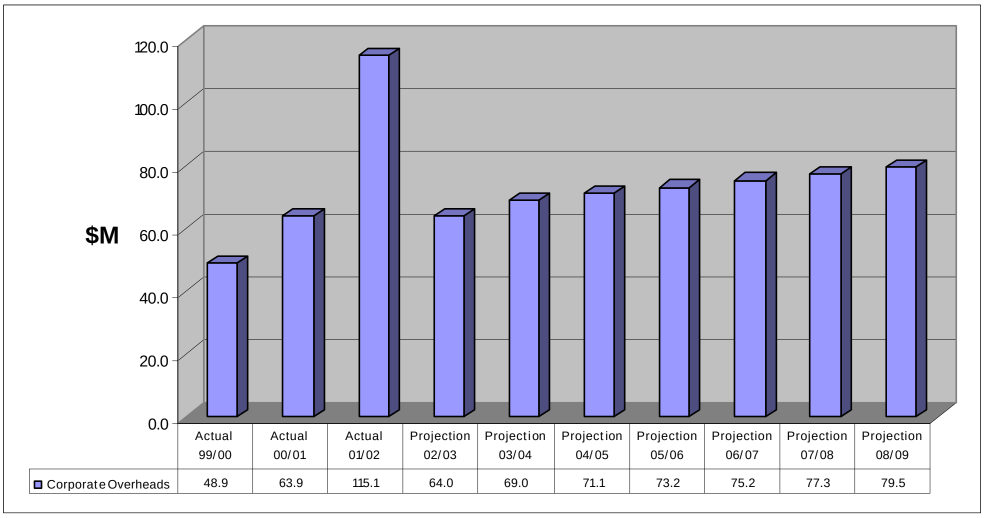
Additional costs associated with asbestos and other safety issues precipitated by Regulation 2001 are included in this area. Expenditure to date in these areas has been recorded under Engineering Consulting and this allocation has been increased to meet the Enerserve calculation.

The Fleet and Logistic figures provided appear to show an imbalance between internal income and costs resulting in an apparent over-recovery of costs amounting to approximately $10 million in 2001/2002.

12. Corporate Overheads

Historic and forecast corporate overheads O&M expenditure is provided in Figure 12-1. The figure for 2002/03 was provided by EnergyAustralia.

- **Figure 12-1 Corporate Overheads Expenditure Projection**

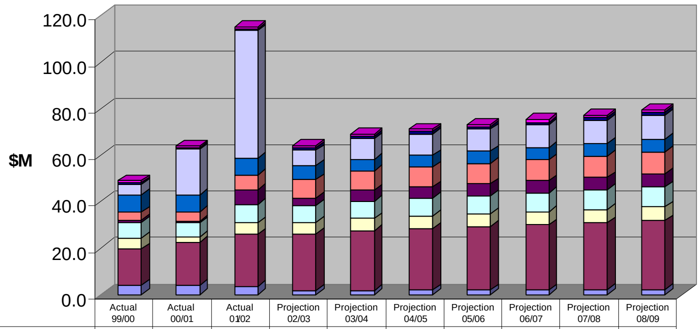


	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Corporate Overheads	48.9	63.9	115.1	64.0	69.0	71.1	73.2	75.2	77.3	79.5

The forecast corporate overhead allocation to networks LOB is escalated from the 2001/02 figure at CPI.

Figure 12-2 provides Corporate Overheads by Contribution.

- **Figure 12-2 Corporate Overheads - O&M Expenditure Contributors**



	Actual 99/00	Actual 00/01	Actual 01/02	Projection 02/03	Projection 03/04	Projection 04/05	Projection 05/06	Projection 06/07	Projection 07/08	Projection 08/09
Executive Management	0.8	0.7	0.8	0.9	10	10	10	10	11	11
Internal Audit	0.6	0.7	0.8	11	11	11	11	11	12	12
Finance & Corporate Secretary	4.5	19.6	54.9	6.5	9.0	9.2	9.5	9.8	10.0	10.3
Corporate Strategy & Business Development	7.6	7.2	7.0	6.1	4.9	5.0	5.1	5.3	5.4	5.6
Property	3.3	4.1	6.3	7.8	8.3	8.5	8.8	9.0	9.3	9.5
Insurance	0.9	0.7	6.4	3.1	4.8	4.9	5.1	5.2	5.4	5.5
Rent & Rates	7.0	6.0	8.0	7.3	7.4	7.7	7.9	8.1	8.3	8.6
Land Tax	4.7	2.2	5.0	5.0	5.2	5.3	5.5	5.6	5.8	5.9
IT&T (incl IT Group + Other IT & Comm's Exp)	15.4	18.7	22.4	24.3	25.7	26.5	27.2	28.0	28.8	29.6
Corporate Branding, Advertising, Safety Campaigns	4.2	3.9	3.5	18	18	19	2.0	2.0	2.1	2.1

13. EA Network Status Assessment

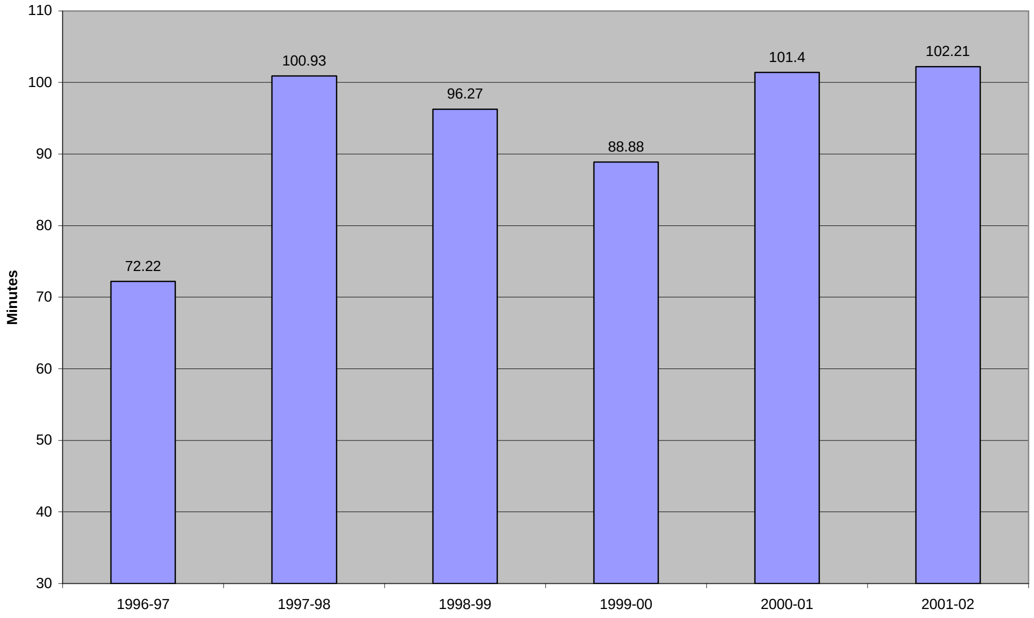
13.1 General

Before undertaking a forecast of O&M expenditure requirements for the next regulatory period, SKM considered that it would be most prudent to make a high level assessment of the status of the EnergyAustralia system, both in a general sense, and in respect of individual system components (eg. cables, substations, poles, etc).

13.2 Reliability Statistics

The overall performance of the EnergyAustralia transmission, subtransmission and distribution system, as measured by the traditional SAIDI and SAIFI indicators, is excellent by comparison with other Australian utilities.

■ **Figure 13-1 EnergyAustralia Trend in SAIDI**



■ **Figure 13-2 EnergyAustralia Trend in SAIFI**

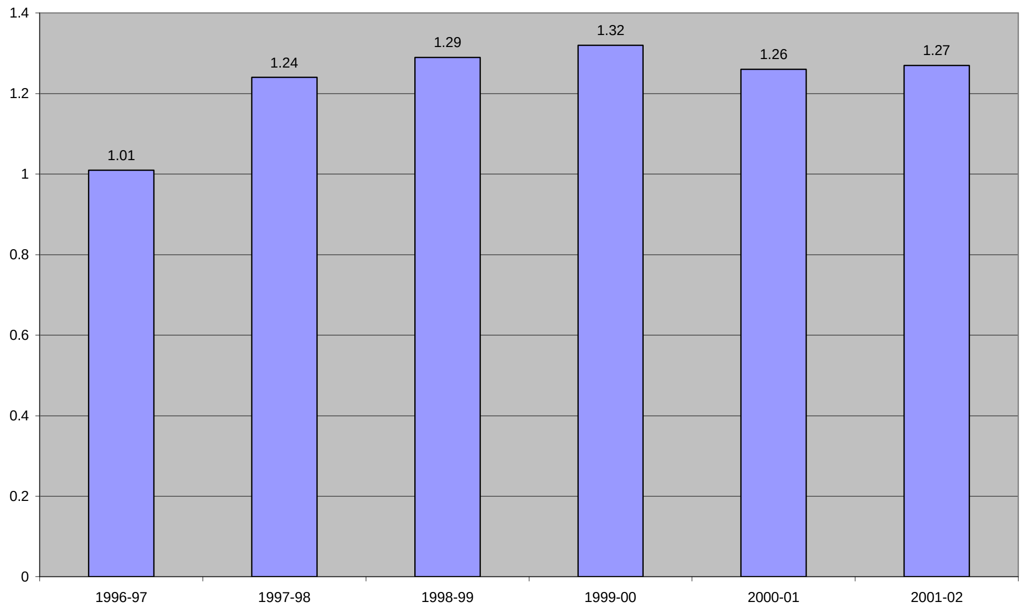
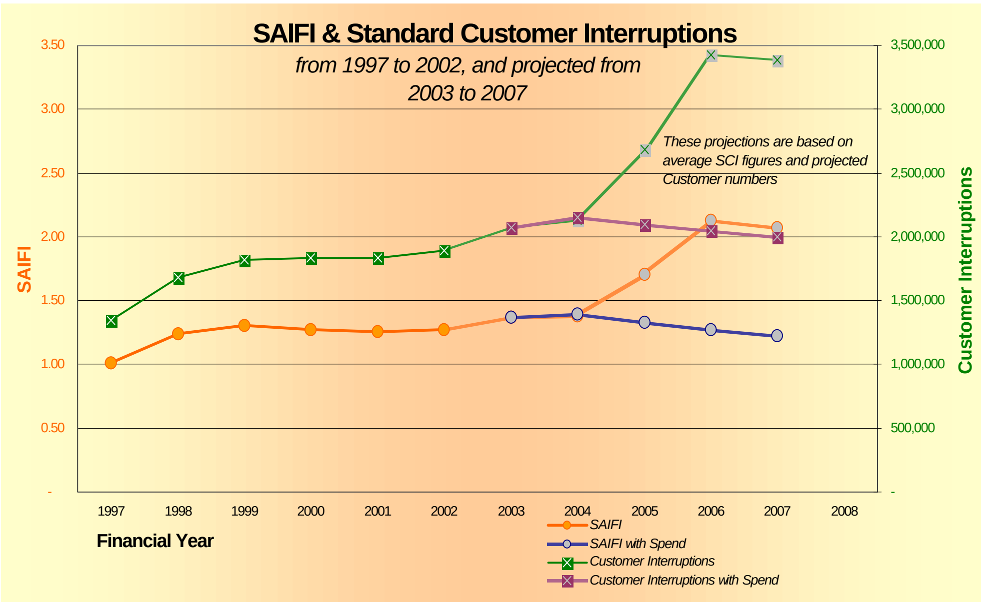
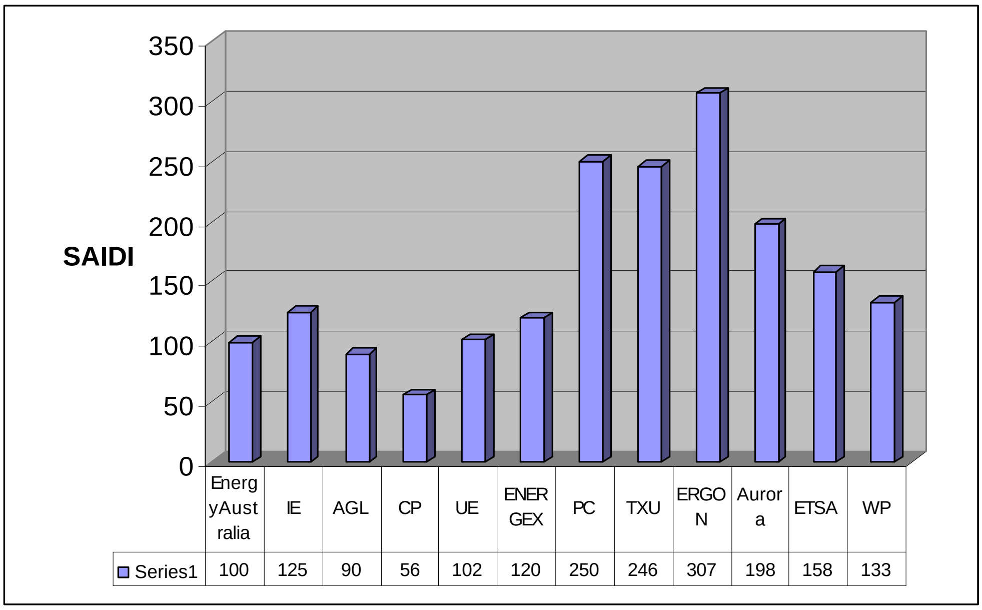


Figure 13.3 below shows the historical trend in Standard Customer Interruptions over the period 1997 to 2002. There is an increasing level of customer interruptions evident, and the forward projections for 2003 to 2007 are possible scenarios related to the introduction of the asset specific condition based maintenance project (FMECA).

■ **Figure 13-3 EnergyAustralia Trend in Standard Customer Interruptions**



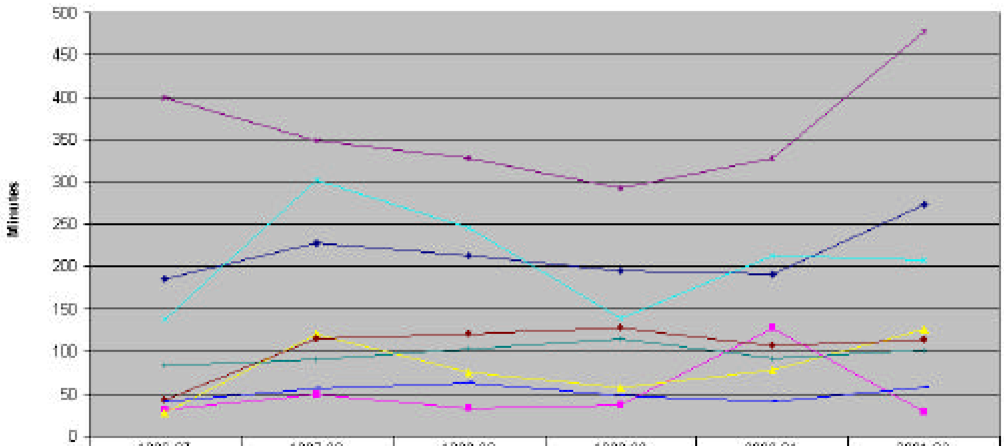
■ **Figure 13-4 Comparison of SAIDI for Various Australian Utilities**



Comparison of system wide SAIDI and SAIFI statistics can however be misleading, as reliability in particular geographic regions, particularly rural and remote areas, can be substantially worse than the average, and may be generally unacceptable to the communities and customers serviced from those networks.

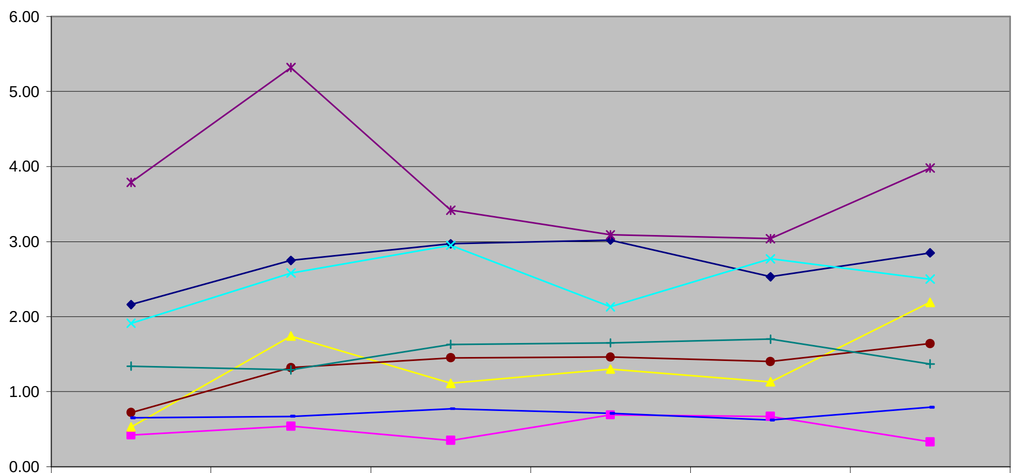
In EnergyAustralia's case, the regions of Muswellbrook, Central Coast and Maitland are generally speaking the worst performing parts of the system, as shown in Figure 11.5 and 11.6 but even these regions (with the possible exception of Muswellbrook) are comparable with regional and rural systems in other states (refer Figure 11.7)

■ Figure 13-5 EnergyAustralia – SAIDI by Region



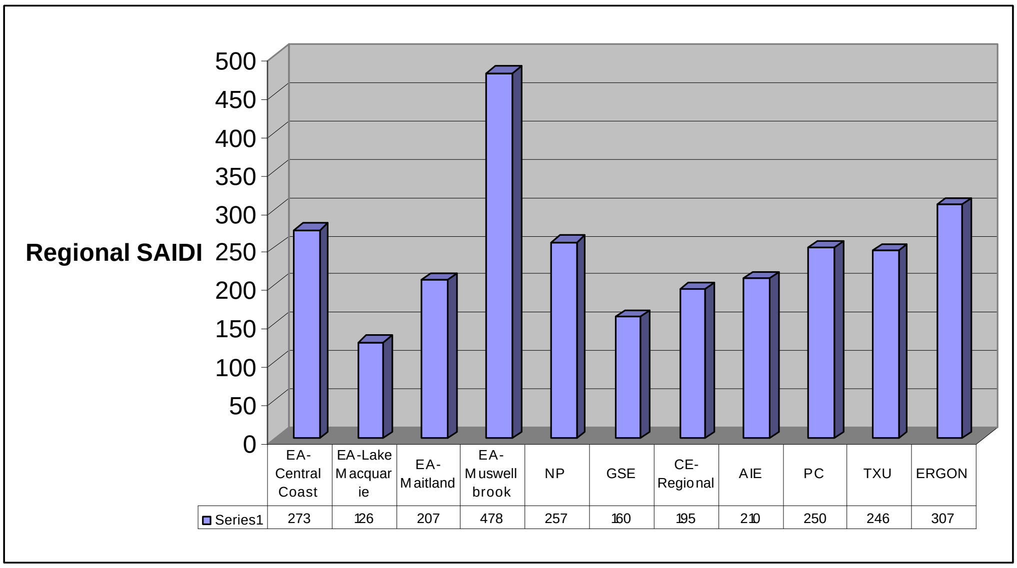
	1996-97	1997-98	1998-99	1999-00	2000-01	2001-02
Central Coast	185.73	228.28	212.39	195.68	190.83	273.16
Eastern Region	31.35	50.03	33.41	36.63	127.73	29.16
Lake Macquarie	27.65	120.47	76.21	58.17	77.97	126.22
Maitland	137.15	302.73	245.87	139.02	213.36	207.15
Muswellbrook	399.66	349.21	328.12	291.94	328.25	478.46
Newcastle	42.51	116.37	120.35	127.33	107.32	114.25
Northern Region	84.41	90.38	103.37	115.04	91.81	102.02
Southern Region	41.65	56.83	63.47	48.61	41.83	57.21

■ Figure 13-6 EnergyAustralia – SAIFI by Region



	1996-97	1997-98	1998-99	1999-00	2000-01	2001-02
Central Coast	2.16	2.75	2.97	3.02	2.53	2.85
Eastern Region	0.42	0.54	0.35	0.69	0.67	0.33
Lake Macquarie	0.53	1.74	1.11	1.30	1.13	2.19
Maitland	1.91	2.58	2.95	2.13	2.77	2.50
Muswellbrook	3.79	5.32	3.42	3.09	3.04	3.98
Newcastle	0.72	1.32	1.45	1.46	1.40	1.64
Northern Region	1.34	1.29	1.63	1.65	1.70	1.37
Southern Region	0.65	0.67	0.77	0.71	0.62	0.79

■ **Figure 13-7 Comparison of Regional/Rural SAIDI Performance from State to State**



13.3 Distribution System

EnergyAustralia's distribution system consists of some 34,800km of overhead (all voltages), 508,000 poles, 27,500 distribution substations, and 13,900km of underground cables (all voltages), as well as the usual configuration of miscellaneous items of equipment, terminations, protection and control, etc.

While there are some individual items of concern about maintenance practices on the distribution system, overall we would assess that the status of the system is generally good, reflecting sound industry practice at managing a diverse and complex range of assets.

Specific details and comments are as follows:

13.3.1 NAMS Defect Database

The Network Asset Management System (NAMS) database contains asset data for all non-plant assets. This includes defect data as recorded by the various inspection programmes. Inspectors record all defects observed directly into the NAMS database. At the time of recording, defects are given an assessed priority that also provides a required response time. Various reports can be generated from NAMS to provide an indication of how defects are being addressed.

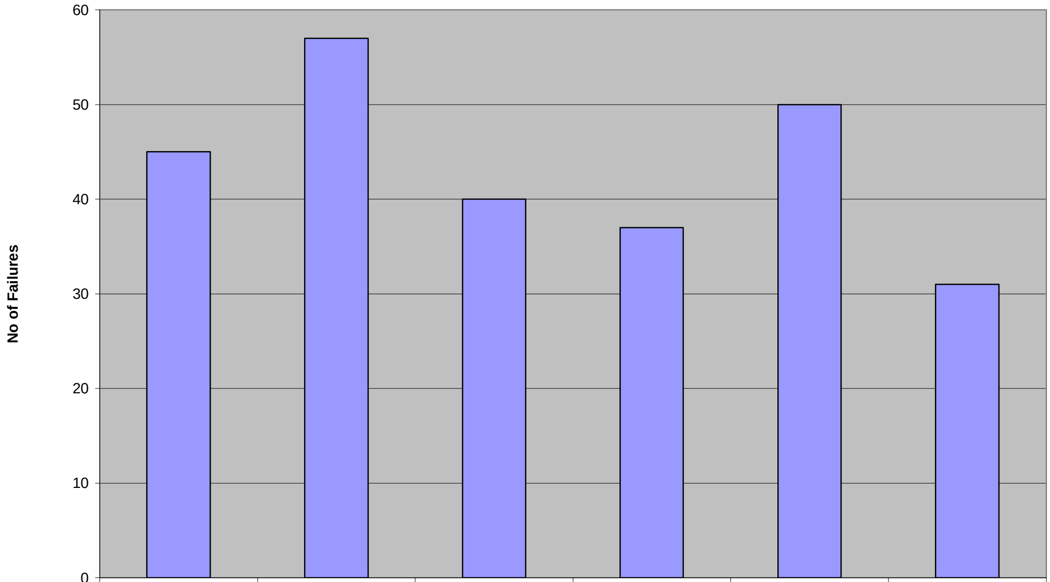
13.3.2 Pole Inspection, Staking and Replacement

The frequency of below ground pole inspections has recently been increased from a 4.5 year cycle to a 4 year cycle with a corresponding increase in the number of poles to be inspected each year. At the end of November 2002 the pole inspection contract was running 90% to programme.

The percentage of defective poles re-instated (staked or nailed) has increased over the last few years to approximately 43%. The backlog of poles awaiting re-instatement is equivalent to 1.5 months at present work rates which is considered quite reasonable. However, the backlog of poles to be replaced is equivalent to 13 months work. This is an area for concern.

Despite this concern, the effectiveness of the pole management programme can be measured by the number of reported pole failures per annum (see figure below).

- **Figure 13-8 Pole Failure Trend**



	96-97	97-98	98-99	99-00	00-01	01-02
Series1	45	57	40	37	50	31

The average failure rate over the last three years has been 39 pa. This represents a rate of 8 per 100,000 and is considered acceptable. Another positive indication is that the trend appears to be reducing.

13.3.3 Vegetation Management

There have been very large increases in expenditure on vegetation management over the last three years. This increase has been mainly due to increased scope of contracts to include all trees in the contract area (previously local government took some responsibility). It is very early in the process since the contracts were expanded. However, anecdotal evidence suggests that vegetation initiated outages for 2002/03 (year to date) are already showing a marked reduction – “Trees growing into Mains” and “Trees bring mains down” are approximately 50% down on recent history.

13.3.4 Distribution Substations

The preventive maintenance programme for distribution substations has recently been reviewed. The full impact of any changes has yet to be seen, however, on the limited figures available, there appears to be a shift in expenditure in this area from “emergency” to “corrective” which suggests an improvement in the degree of control over this maintenance. Anecdotal evidence suggests that “non-negotiable” works are generally under control with smaller backlogs, while “negotiable” works are in most instances, simply not addressed.

13.3.5 Underground Distribution Cables

There does not appear to be a planned maintenance programme for underground distribution cables. This would reflect practice throughout the electricity supply industry. From the limited figures available, there is nothing to indicate that performance in this asset category is declining. Total expenditure on this category over the last three years has shown a small decrease.

13.3.6 Streetlighting

The maintenance strategy adopted by Energy Australia for streetlights in most of its supply area would be described as effective but perhaps costly. This would be characteristic of the bulk change strategy. SKM’s report for Energy Australia on the Streetlight Benchmarking Study done for the South Australian Independent Industry Regulator (August 2000) suggested that performance in this area could be improved. This could be achieved by reducing the proportion of fluorescent lamps in the system, and by using contractors to do spot changes to allow the bulk change period to be increased.

13.3.7 Bushfire Mitigation and Preparedness

As discussed elsewhere in this report, some changes introduced to mitigate bush fire risk have the potential to degrade the network reliability as measured by the traditional utility measures. For example, disabling auto-reclose facilities in zone substations and line reclosers will increase the frequency of sustained outages thus increasing SAIFI. Requiring a feeder patrol before any manual reclose operation is tried will increase the duration of outages thus increasing CAIDI. SAIDI is the combination of these measures.

13.4 Subtransmission and Zone Substations

13.4.1 General Substation Asset Condition

13.4.1.1 Substation Assets Age

As indicated previously, one of the main drivers of substation O&M budgets is the age of the assets. EnergyAustralia have many ageing substation assets, some of them well beyond their design useful life. The following tables list the substations, both zone and sub-transmission which are older than 40 years.

■ Table 13-1 Sub-Transmission Substations Older than 40 Years

It m	Su ɔ – Trans iission Subs ation	Ins lled Capaci y (MVA)	D te Comm sioned	A je
.	Wa atah	2 .0	1 52	1
	Ro elle	ɔ	1 54	ɔ
	War ngah	3 0	1 55	3
.	Banl stown	2 .0	1 57	5
	Ku nell	1 0	1 58	5
	Musw llbrook	1 0	1 59	4
	Our nbah	1 5	1 59	4
	Av aba	1 0	1 60	3
	Port H acking	1 0	1 60	3
ɔ	Cant rbury	2 .0	1 61	2
1	Ku ngai	3 0	1 62	1
2	K rri	2 .0	1 63	ɔ
3	To ago	1 0	1 63	ɔ
Total Installed Capac y		254 MVA		

■ Table 13-2 Zone Substations Older than 45 Years

It m	Zone S bstation	Ins lled Capaci y (MVA)	D te Comm sioned	A je
.	Crow Nest	5	1 30	3
	Rar wick	5	1 30	3
	Bo any	5 .5	1 31	2
.	City entral	1	1 35	3
	Wa send	5	1 36	7
	Camp rdown	6 .5	1 37	5
	Padd ngton	5	1 40	3
	Gravi g Dock	7	1 46	7
	Ma cot	ɔ	1 46	7
ɔ	Au urn	5	1 49	4
1	Blackw ttle Bay	5 .5	1 51	2
2	Wa erly	5 .5	1 51	2
3	Sto kton	5	1 52	1
4	Adar stown	ɔ	1 53	ɔ
5	City North	1	1 53	ɔ
5	Lidc mbe	2	1 53	ɔ
7	Ma field	ɔ	1 53	ɔ
3	Pe can	ɔ	1 53	ɔ
ɔ	Boo aroo	5	1 54	ɔ
ɔ	Five Dock	ɔ	1 54	ɔ
1	Raymor l Terrace	ɔ	1 54	ɔ
2	T ro	ɔ	1 54	ɔ
3	Alex ndria	3	1 55	3
4	Co cord	3	1 55	3
5	R de		1 55	3
5	Broad ieadow	ɔ	1 57	5
7	Chat wood	7 .5	1 57	5
3	Mir nda	7	1 57	5
ɔ	Balg wlah	3	1 58	5
ɔ	Surr Hills	1 4	1 58	5
1	West osford	ɔ	1 58	5
2	W ong		1 58	5
Total Installed Capac y		1641 MVA		

There are another 20 zone substations throughout the network which are older than 40 years with total installed capacity of 810.3 MVA. So the total installed capacity of the zone substations older than 40 years is 2451.8 MVA.

13.4.1.2 Site Visits and Inspections

As part of this exercise a number of sub-transmission and zone substations were visited and inspected to check their condition. The substations that were visited were:

- Castle Cove Zone Substation
- S333 Distribution Substation
- Willoughby Sub-transmission Substation
- Gore Hill Zone Substation
- Crows Nest Zone Substation

Castle Cove Zone Substation

Castle Cove zone substation is 132/11kV substation located in Sydney's northern suburbs. The main features of the substation are:

- Four 132/11kV transformers (three in service and one spare)
- 11kV switchboards with oil circuit breakers
- Very old communications cable monitoring systems, for which neither components nor human skills are available any longer
- Very limited optical fibre network for communications and protection systems
- Three types of DC supply, 110V DC, 240V DC and 50V DC
- Very old station service transformers
- Very old motor-generator sets for audio frequency load control
- One power transformer is 9 years old, two are more than 30 years old and one is new and not in service yet

The substation appears to be in good condition, but a number of critical components show their age. This substation is one of the typical zone substations in the inner Sydney area.

S333 Distribution Substation

This distribution substation is typical of many in the inner Sydney area. Most can be categorised in the following way:

- They are built in the 1930's
- Have live exposed LV buses which present safety hazards for personnel entering the substation building
- Have LV oil circuit breakers
- Require a rigorous maintenance regime of the CB's (every year)
- There are about 100 of these substations in the area
- Occupy large blocks of land, most of them suitable for a larger capacity modular type of zone substation

Willoughby 132/33 Sub-Transmission Substation

This is a large multi transformer sub-transmission 132/33kV substation. The substation is very old and although it has gone through staged refurbishment, most of the equipment is 40-50yrs old. The main features are:

- Four large 120MVA 132/33kV transformers
- The system is configured to operate as transformer ended feeders
- The transformers have Canadian GE tap-changers which were manufactured in 1963
- Tap changer mechanicals are labour intensive and require monthly check up, inspection and maintenance
- The transformers have fire protection installed in the form of water deluge system, which according to the EA representatives is never tested
- There is a large array of 33kV capacitor banks which are the same vintage as transformers (about 40 years old)
- The substation has a large number of bulk oil circuit breakers located in separate compounds. The CB's are about 40 years old and require regular maintenance. They also occupy a large area.
- The 33kV control and protection panels occupy a very large area
- The communications system is very old, maintenance of the control and protection systems is very labour intensive, spare parts are increasingly harder to find and also the expertise is becoming harder to find
- Some protection panels contain asbestos
- There is visible termite damage to some areas of the control building
- Control cables are lying on the ground, unprotected
- Pilot isolation cubicles are termite damaged

Based on the equipment installed in the substation it is obvious that the substation is entering a period of more intensive and costly maintenance.

Gore Hill Zone Substation

Gore Hill substation is in near vicinity of the Willoughby substation. It is a newer substation, build in the 80's and has four 33/11kV transformers built in the 80's and one transformer which is built in 1970.

Crows Nest 33/11kV Zone Substation

The substation is located in the inner Sydney area and has four 33/11kV transformers, all manufactured between 1964 and 1967. The main features of the substation are:

- Transformers are fitted with cable link boxes on the 33kV side. This is considered to be a major fire risk.

- The transformers are fitted with oil containment tanks which may not have fire traps fitted
- The substation feeds a very important area of Sydney
- The CB's are indoor bulk oil type and all are manufactured in 1920's
- Part of the interior of the substation is used as a storage space for old redundant equipment which is kept for spares

13.5 Subtransmission Cables

13.5.1 Background

Discussions were held with Enerserve engineering staff on 18 December 2002 at the Homebush offices. The discussions were aimed at establishing the background of maintenance practices carried out by Enerserve on behalf of Energy Australia and to obtain information that would assist in assessing the present state of Energy Australia's HV cable network.

- **Table 13-3 Key Data Relating to EnergyAustralia's HV Cable Network**

Item	132kV	33kV
Circuit Length	509km	838km
Total Length	1527km	838km
Replacement Cost ($M)	$512.8M	$478.6M
Average Age (30/6/01)	31.0 years	47.9 years
Engineering Life	45 years	45 years
Type	Single Phase Oil filled	Three phase gas-filled and XLPE

13.5.2 Asset Condition

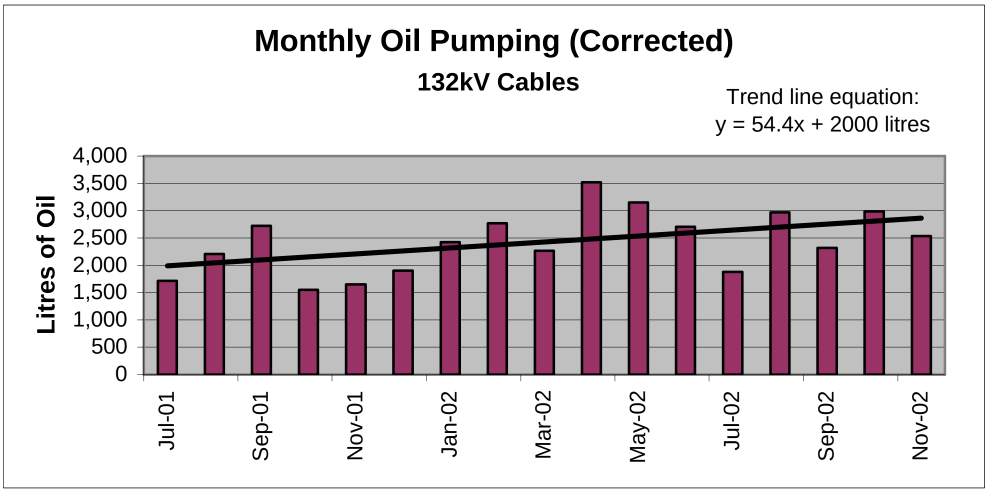
It is inherently difficult to make an assessment of the condition of underground cables. However, Enerserve provided SKM with copies of their weekly maintenance records for Transmission and Subtransmission cables. These records provide a detailed account of the maintenance practices, cable failures, cable damage incidents, gas leakages and oil leakages for the period. The records include leakage-monitoring data for both oil and gas. Using this data, it is possible to get an indication of the change in condition of the underground cable network, as a whole, over time.

Routine monitoring of oil and gas levels is carried out. This identifies any cables that are deteriorating and allows for assessment of the effort required to keep the cables in service. Enerserve have provided evidence that they monitor and respond to the oil and gas leakages in an appropriate manner.

13.5.3 132kV Oil-Filled Cables

The trend for oil leakages (for the period July 2001 to November 2002) has been plotted in Figure 1 below. The oil leakage data has been corrected to remove the effects of oil leakages associated with two cables scheduled for refurbishment (Cables 91L and 92M).

- **Figure 13-9 Oil Pumping since July 2001**

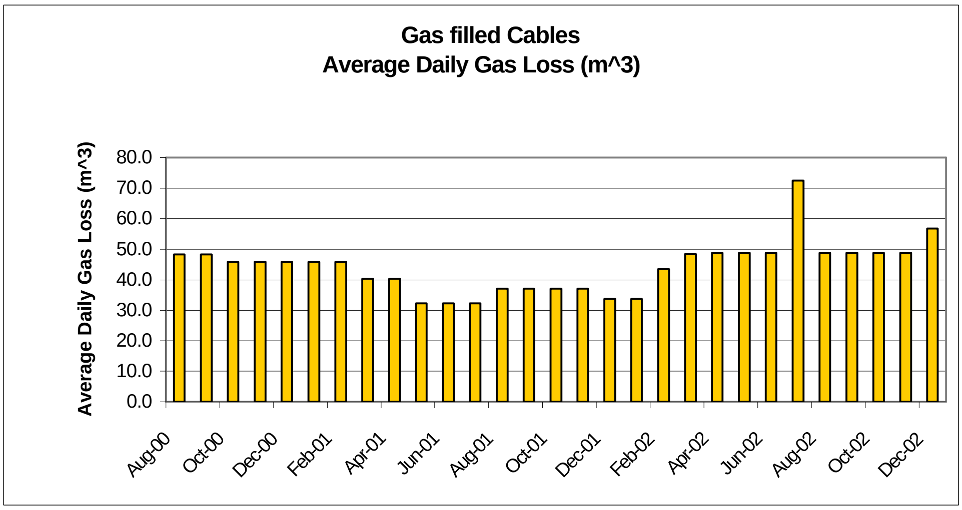


Short-term trend lines are sensitive to the end points selected. However, inspection of the minimum monthly levels of oil pumping shown Figure 9.1 suggests a high likelihood of a rising trend.

13.5.4 33kV Gas-Filled Cables

Replacement gas volumes (as a consequence of gas leakages) for the period August 2000 to December 2002 have been plotted in Figure 2 below. The data excludes gas usage arising from emergency repairs and reflects the routine use of gas filling to keep cables in a serviceable condition.

- **Figure 13-10 Average Daily Gas Loss (m^3)**



13.5.5 Assessment of Asset Condition

The oil leakage data for 132kV cables (figure 1 above) shows an approximate 50% increase in oil filling over the 17-month period from July 2001 to November 2002. This increase is cause for some concern as the increase is due to cable leakages across the entire 132kV network and could be symptomatic of a cable network in slow decline. It is clear that the trend for increased oil usage cannot be sustained in the long run and that positive action will be required to reverse the trend.

It is important to stress that the increased oil leakage is not causing a corresponding increase in cable failure at this stage. The cable failure data shows that there have only been several cable failures in the last two years. However, the oil-leakage trend does lend support to the case for increased expenditure on cable condition monitoring and the need to consider a cable refurbishment program.

The gas-loss data for 33kV cables (figure 2 above) shows that there is no significant increase in gas replacement over the period August 2000 to December 2002. This demonstrates that the asset management approach for these cables is appropriate.

This view is supported by the SAIDI data that shows no indication of reduced reliability over the period 1996-2002.

13.5.6 Asset Age Profile and Refurbishment Issues

The average age of the cables is cause for some concern. The 33kV cables have an average age in excess of the stated engineering life of the cables. While the average age of the 132kV cables is well below the stated engineering life, the increased oil replacement may indicate a problem waiting to surface.

Given the low failure rate observed in the 132kV and 33kV cables it is possible that the assumed cable lives are too conservative. Consideration should therefore be given to reviewing the stated engineering lives and the allowable percentage of over-age cables. Even with revision to the engineering lives and percentages allowed for over-age cables, there will still be many over-age cables. As a consequence, a capital refurbishment program must be put in place to commence refurbishment of the cable population in an orderly and cost-effective manner. It is recommended that such refurbishment be performed on the basis of condition rather than on age.

14. The Capex/Opex Trade-off

14.1 Introduction

Energy Australia has an asset base to the value of $10.9b (2002). This includes substations, transformers, overhead lines, cables, and other equipment, from LV to Sub-Transmission voltages. All these assets require some level of maintenance throughout their life and the total O&M expenditure on assets in 2001/02 was $120.4m (Enerserve and external contracts). The level of maintenance of an asset varies with the age of the asset. The longer an asset is in service the more maintenance it requires, thus any capital expenditure which reduces the age of assets will also reduce the maintenance requirements.

The projected level of ongoing refurbishment expenditure in Energy Australia is $90m to $125m over the next 15 years, which increased from around $40m previously. This increased capital investment in the refurbishment and replacement of assets will realise savings in maintenance expenditure. These savings are however offset by the addition of new assets to the asset base requiring additional maintenance expenditure, albeit less than that for the assets replaced.

There exists therefore a relationship between capital investment and maintenance expenditures. SKM have investigated this relationship by modelling the Operating and Maintenance expenditure over the life of an asset. The key parameters of the model are the average and the initial expected Operating and Maintenance expenditure for an asset category related to the replacement value of that asset category, and the life of the asset category. We have assumed that O&M expenditure increases exponentially over the life of an asset.

14.2 The Operating and Maintenance Model

14.2.1 Key Inputs to the Model

The Energy Australia asset base was divided into the following 10 asset categories:

1) Distribution substations
2) Sub-transmission Substation Circuit Breakers
3) Zone Substation Circuit Breakers
4) Sub-Transmission Substation Transformers & Tap Changers
5) Zone Substation Transformers & Tap Changers
6) Sub-transmission & Zone Substation Protection & Control
7) Transmission Lines – Overhead
8) Transmission Lines – Underground
9) Distribution Lines – Overhead
10) Distribution Line - Underground

For each of these categories an average O&M spend as a percentage of the Replacement Cost of the assets was calculated as well as an initial expected O&M

cost. The expenditure in each category is due to planned, corrective, and emergency (storm) maintenance, the initial expected O&M expenditure was taken to be planned maintenance cost only and as emergency (storm) maintenance is not affected by refurbishment investments it was excluded from all calculations.

14.2.2 The Model Explained

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■ **Figure 14-1 Generic Capex/Opex Trade Off Model**

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14.3 Energy Australia O&M Expenditure/Savings

The major projects and programs capital expenditure for new assets and refurbishment were evaluated with regard to the expected Operating Expenditure/Savings. For the programs an average asset age was determined and used in the model as the age at the time of replacement of the assets. For major projects an average age was determined based on specific age information available for the projects. The result of the analysis is tabulated below.

Total expected O&M expenditure on new assets: This is the cost of O&M on the new assets added through the major projects and programmes. The costs for each asset category are ascribed the initial O&M cost ("k" in the model).

Total expected O&M savings on refurbished/replaced assets (Projects and Programmes): This is the O&M savings obtained by replacing an old asset with a new asset. The saving represents the difference in O&M costs between a point high on the curve (an older asset) compared to O&M costs at point "k" – a new asset.

The total capital expenditure projected for the next regulatory period is $1 306m. The expected net operating and maintenance expenditure based on these major projects and programs is a saving of $17.30m over the 5 years. This savings represents 1.3% of the capital investment in the next regulatory period.

	2004/05	2005/06	2006/07	2007/08	2008/09
Total expected O&M expenditure on new Assets	1.5	3.3	4.9	5.9	7.2
Total expected O&M savings on refurbished/repl: ced Assets (Projects and Programmes)	-1.4	-3.1	-5.5	-7.5	-9.8
Net savings	0.1	0.2	-0.6	-1.6	-2.6

15. New External Factors Costs Impacts

A number of external factors have materialised within the current regulatory period and have impacted O&M expenditure in this period. They will continue to impact expenditure in the next period. The net difference in cost impact between the two periods is calculated below.

15.1 Regulation 2001

Regulation 2001 is part of NSW state legislation covering workplace health and safety requirements. SKM has not reviewed the document but based on advice from Enerserve staff, this regulation covers such areas as safety supervision, risk analysis (and the requirement for task specific safe working method statements), training, work methodology and equipment requirements for defined work situations such as working with asbestos, working in confined spaces and working at heights. It also places some limits on live work and the requirement for competent off-siders.

Some additional costs associated with this regulation have already been seen in 2001/02 expenditure. We understand that this is reflected in NW LOB item 30, Engineering Consulting (part of miscellaneous expenditure in the forecast) – where costs associated with asbestos consultants, training and general compliance expenditure have been trapped. Over the three years actual data available, expenditure in this area has increased from approximately $4.4m to $6.4m. These costs will therefore impact in expenditure for the remainder of the current regulatory period but would not have been apparent at the time regulatory approvals were sought.

Based on forecasts provided to SKM by Enerserve staff, expenditure in this area is expected to grow to approximately $9.3 in 2002/03 and then fall and stabilise at around $8 million by 2004/05. This cost incorporates training costs including staff time, allowances, equipment, additional manning levels and increased task times.

If staff levels are constrained and overtime restricted, the increased manning levels and task times may have a limited impact on labour expenditure and rather reduce the quantum of work performed by existing staff levels. This has the potential to further increase the backlog of identified defects yet to be addressed. EA should be developing a strategy to cope with this influence. The capacity of the organisation to make up some of the lost efficiency by the wider use of contractors is limited by the industrial relations climate and the restriction of contracts to "non-electrical" work.

If we assume unconstrained staffing levels as per the figures provided by EnergyAustralia, we estimate the total cost impact in the next regulatory period above and beyond the cost impact in this current regulatory period to be around $8.2m (calculation includes labour rate/CPI adjustments).

Total additional O&M Expenditure incurred: $8.2m

15.2 Bushfire Mitigation strategy

Bushfires have been recognised as a severe threat in some of EA's supply area. As a good corporate citizen, EA has introduced a range of strategies to limit the contribution of EA's network to the bushfire hazard. Some of these strategies include disabling auto reclose functions, requiring a feeder patrol before manual reclose attempts, inspection of customer owned lines (and poles) and the installation of low voltage spacers in bushfire areas.

These strategies are expected to increase the "emergency" workload (with resulting reduction in availability for non-emergency work) and result in a deterioration of reliability performance during the bushfire season. There will be additional costs associated with the "emergency" work.

We have calculated that the cost of the additional patrols will be of the order of $400000pa. If we assume an additional 20% for materials etc described above, the total cost impact of the Bushfire mitigation strategy will be of the order of $480000 pa. Assuming it was introduced in 2001/02, 3 years of this regulatory period and all of the next regulatory period will bear the this additional cost. The net difference between the 2 periods will therefore by (5 – 3) x 480000 = $1.0m

Total additional O&M Expenditure incurred: $1.0m

15.3 Vegetation Management

Occupational Health and Safety requirements to increase safety clearances on overhead lines saw a once off increase in contract expenditures in 2000/01 to normalise the system. The specific expenditure for this is not available but is the major contributor to the hike in expenses in 2000/01 and is assumed to make up the majority of the increase in that year of $8m. Maintaining the new clearances should not have an influence on the expenditure in the following years.

In 2001/02 the scope was increased to include parts of the Hunter area at an additional expenditure of $7m pa. The same year tree trimming work was taken over from the Council contributing approximately another $2m pa. These are all costs that will run into the new regulatory period, amounting to $9m pa.

In 2003/04 the scope will be increased to include the Cessnock area at an additional $0.4m pa.

Thus,
Cost impacts current Regulatory period: $8.0 + ($7.0 x 3yrs) + ($2.0 x 3yrs) + ($0.4 x 2yrs) = $35.8m

Cost impacts next Regulatory period: ($7.0 x 5yrs) + ($2.0 x 5yrs) + ($0.4 x 5yrs) = $47.0m plus say an average 8% labour/CPI escalation over the period = $50.1m

Regulatory period differential = 50.1 – 35.8 = $14.3m

Total additional O&M Expenditure incurred: $14.3m

15.4 Pole Inspections

An increase occurred in 2001/02 to include the Hunter and Cessnock areas, amounting to $0.9m pa.

Total Regulatory period differential for Pole Inspections = $$0.9 x 5 yrs - $0.9 x 3yrs = $1.8m

Total additional O&M Expenditure incurred: $1.8m

15.5 Full Retail Competition

The cost impact of FRC has been contained as a result of the low level of churn in the market. As stated in the Customer Service section, an increase in churn, which could be brought about by generation costs falling or strategies enacted by either EnergyAustralia Retail or their competitors may increase Network costs across a number of areas.

FRC cost impacts at current churn levels:

New metrology maintenance procedures:	$0.7m in 2003/04 going forward
Increased usage of MBS:	$0.1m in 2003/04 going forward
Meter Reading & Support:	$0.2m in 2003/04 going forward
Customer Operations:	$0.2m in 2003/04 going forward

Total Regulatory period differential for FRC = $1.2 x 5 yrs - $1.2 x 1yrs = $4.8m plus an average 8% labour rate/CPI escalation = $5.2

Total additional O&M Expenditure incurred: $5.2m

Please note that these additional costs only relate to increased activity in the Customer Service section and do not include additional IT&T costs.

15.6 Total Cost Impact of External Factors

Therefore the total additional O&M expenditure due to external factors which will be incurred in the next regulatory period above that which was incurred in the current regulatory period amounts to $30.5m.

Appendix A Summary Spreadsheets – EA and SKM OPEX Forecasts

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Appendix B Detailed Spreadsheets

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Appendix C EnergyAustralia System OPEX/Age Profile Relationship

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Appendix D Asset Categories OPEX/Age Profile Relationship

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Appendix E Staff Interviewed

The following staff were interviewed and provided the information which forms the basis of this report. The high level of co-operation and assistance received is noted and appreciated.

Enerserve

John Eisenhuith
Peter Mervin
Steve McHardy
Greg Olle
Alf Briscoe
Trevor Ashton
David Barr
John Hardwick
Rod Smith
Wade Cooke
Bob Parkinson

Networks

Colin Peacock
Mark Muirhead
Gordon McMurray
Mike Winspear
Ron Miller
Peter Mervin
Pauline Sammut
Rob Bareham
Matt Cooper
Trevor Armstrong
Mike Martinson
Denis Shanahan

Corporate

Kristen Watts
Jason Prince
Son Vu
Jon Hocking

Customer Service

Geoff Lillis
Chris Mahony
Richard Newell
Brad Newell
Keith Yates
Timothy Szakacs
Elaine MacDonald

Appendix F List of Source Documentation

The following documentation and files were provided by EnergyAustralia staff.

	Document/file	Received from
1	Customer Service OPEX 1999/00 to 2001/02 spreadsheets	D Williams
2	NW LOB costs for 3 yrs by c_elem & appr-prev-stms split for SKM.xls	P Sammut
3	Opex by Business Area_PS.xls	P Sammut
4	NW LOB costs for 4 yrs by c_elem & appr-prev-stms split for SKM.xls	P Sammut
5	EA Network Business Performance	
6	Energy Australia Distribution Revenue Path Forecast	
7	Network Organisational Structure Chart	V Popov

Appendix G High Level SKM CAPEX Forecast

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Appendix H Scoping Document

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Appendix I Capex/Opex Trade-off by Project Category

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Appendix JCAPEX/OPEX Relationship Model

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Appendix K Cost Impact of Bushfire Mitigation Policy

Number of Lockouts

Assume 40 lockouts/storm and 12 storms per year, gives 480 lockouts per year.

If auto reclosers are not in operation, the number of lockouts will increase what would otherwise be transient faults result in lockouts. Since around 70% of trips are successfully reclosed, we can expect around three times as many lockouts.

Therefore expected number of lockouts under the bushfire mitigation plan is say 1400 lockouts per annum.

Feeder Details

The number of zone substations is 168. If we assume 15 feeders per substation of which 10 are overhead we have 1680 o/h feeders. EnergyAustralia has 10088 km of o/h 11kV and 22kV distribution and therefore the average feeder length is 10088/1680 = 6km. More incidents will occur on longer feeders; assume 840 feeder (112) are 9km, 840 feeders are 3km and ¾ of lockouts occur on longer (km) rural feeders.

Patrol Times and Costs

Long feeders:	10km/hr + 30 min travel each way = 2 hours per feeder
Short feeders:	10lm/hr + 20 min travel each way = 1 hour per feeder

Assume \$65/hr x 2 + 25% vehicle on cost

∴ long feeder patrol:	(65 x 2) x 2 x 1.25 = \$325/outage
short feeder patrol:	\$160/outage

Total Cost Impact

Long Feeder:	1400 lockout x ¾ x \$325 = \$340 000
Short Feeder:	1400 lockout x ¼ x \$160 = \$56 000

Add material costs at 20%.

Total cost impact of the bushfire mitigation plan is \$480 000 per annum.

Appendix L Projection of System Assets Remaining Life

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