Report
to

THE QUEENSLAND COMPETITION AUTHORITY

CAPITAL AND OPERATING EXPENDITURE STUDY FOR DISTRIBUTION NETWORK SERVICE PROVIDERS IN QUEENSLAND - ENERGEX

Final Report 14th December 2004

Burns and Roe Worley Pty Ltd ("BRW")

Level 15, 300 Flinders Street

Melbourne

Victoria 3000

g:\jobs\1716c - qca opex & capex review\draft report\report energex v3 20041214.doc

Disclaimer, Limitation, Ownership and Confidentiality

The concepts contained in this report are owned by Burns and Roe Worley Pty Ltd.

The report is issued to the Client **COMMERCIAL IN CONFIDENCE.**

Copying this report without the permission of the Client or Burns and Roe Worley Pty Ltd is not permitted.

PROJECT NUMBER: 024/C1716				
DOCUMENT NUMBER: C1716/002				
REV	**DESCRIPTION**	**PREPARED BY**	**REVIEWED BY**	**DATE**
0	Draft	BRW	I. Wright	30th June 2004
1	Draft	BRW	I. Wright	30th July 2004
2	Draft	BRW	I. Wright	24th August 2004
3	Draft	BRW	I. Wright	24th September 2004
4	Draft	BRW	BRW	4th October 2004
5	Draft	BRW	BRW	6th October 2004
6	Final	BRW	BRW	16th November 2004
7	Final	BRW	BRW	14th December 2004

Table of Contents

Tables

Figures

1 EXECUTIVE SUMMARY

1.1 Scope

This report reviews the operating expenditure, capital expenditure and asset management practices of the Electrical Distribution Network Service Provider, Energex. An overall strategic view is provided with regard to whether the proposed levels of capital and operating expenditures, for the period 2004/05 to 2009/10, are reasonable and efficient.

A key input to the review of the requirements for Capital Expenditure ("CAPEX") and Operational Expenditure ("OPEX") was the assessment of Energex's growth forecasts.

Unless stated otherwise, all forecast and historical figures are in June 2004 dollars.

1.2 Business Environment

The Consultant took note of the business environment in which Energex conducts its business. This included the following requirements:

- Regulatory;
- Operational;
- Safety;
- Customer service standards; and
- Environmental.

The Consultant concluded that Energex operates in a similar business environment to electricity distributors in other jurisdictions in Australia.

1.3 Asset Management

Asset management covers the processes for planning, development, operation and maintenance of all components of the electricity network. Clearly, sound asset management processes are a prerequisite for prudent and efficient capital and operating expenditure. Energex does not prepare an integrated Asset Management Plan, but relies instead on a series of plans and strategies. The general planning approach adopted by Energex is similar to that of other electricity distributors in Australia.

1.4 Asset Utilisation

Energex is achieving a greater asset utilisation than comparable distributors. Energex contend that they have increased the utilisation of zone substation transformers beyond economic limits, and plan to install additional transformer capacity to reduce the Plant Utilisation Factor to 65%.

The Consultant considers Energex has, through past underspending allowed the utilisation of its zone substations to increase to the point where (n-1) design standards are no longer achieved for extended periods during summer. This has meant that the capability of the system to provide continuity of supply through major storm incidents has been significantly compromised.

Energex adopted a probabilistic approach to network planning in the early 1990s, which resulted in a significant reduction in capital investment and an increased level of asset utilisation. This has lead to significant numbers of its bulk supply and zone substations exceeding their capacity during the summer peak load period. The higher utilisation of the network has resulted in a reduced capability for the network to cope with extreme weather conditions.

1.5 Service Standards

Energex has a high level of customer complaints and the indications are that Energex has room for improvement in the level of customer service provided, as viewed from a customer complaints perspective. In addition, Energex's supply reliability performance is worse than the average of the comparable distributors, particularly in regard to unplanned interruptions.

In establishing the CAPEX and OPEX building blocks for the next regulatory period, the distributors are required to submit forecasts to the jurisdictional regulator in respect to:

- Maintaining the current service quality level (Tier (a));
- Improving service quality aimed at delivering an agreed average level of service (which may be somewhat higher than current service levels) (Tier (b)); and
- Specific additional commitments aimed at improving service quality in specific parts of the network or addressing identified customer requirements and including clearly identified service quality outcomes (Tier (c)).

Expenditure totals for OPEX and CAPEX contained in this report are for Tier (a), with expenditure for the Tiers (b) and (c) identified separately.

1.6 Cost Differentials

Factors which contribute to cost differentials between Energex and industry best practice include the significant number of assets which are operating beyond their capacity.

1.7 Pass Through Costs

Energex supports the concept of some form of pass-through mechanism to cater for unpredictable projects beyond its control. The issue is, what should be the mechanism for determining which projects should be eligible for pass-through consideration. The Consultant recommends that the Queensland Competition Authority ("QCA") develops a detailed mechanism in conjunction with the two Distribution Network Service Providers ("DNSPs").

1.8 Efficient OPEX Program

The OPEX is made up of the following key components:

- Maintenance activities - Planned and unplanned maintenance work on all network assets; and
- Operating activities:
    - System Control Centre;
    - Network Systems Operations;
    - Fault Call Centre;
    - Executive and Financial Management;
    - Training;
    - Information Technology ("IT") Support;
    - National Electricity Market;
    - Network Planning;
    - Distribution Standards;
    - Customer Complaints; and
    - Work Practices and Safety.

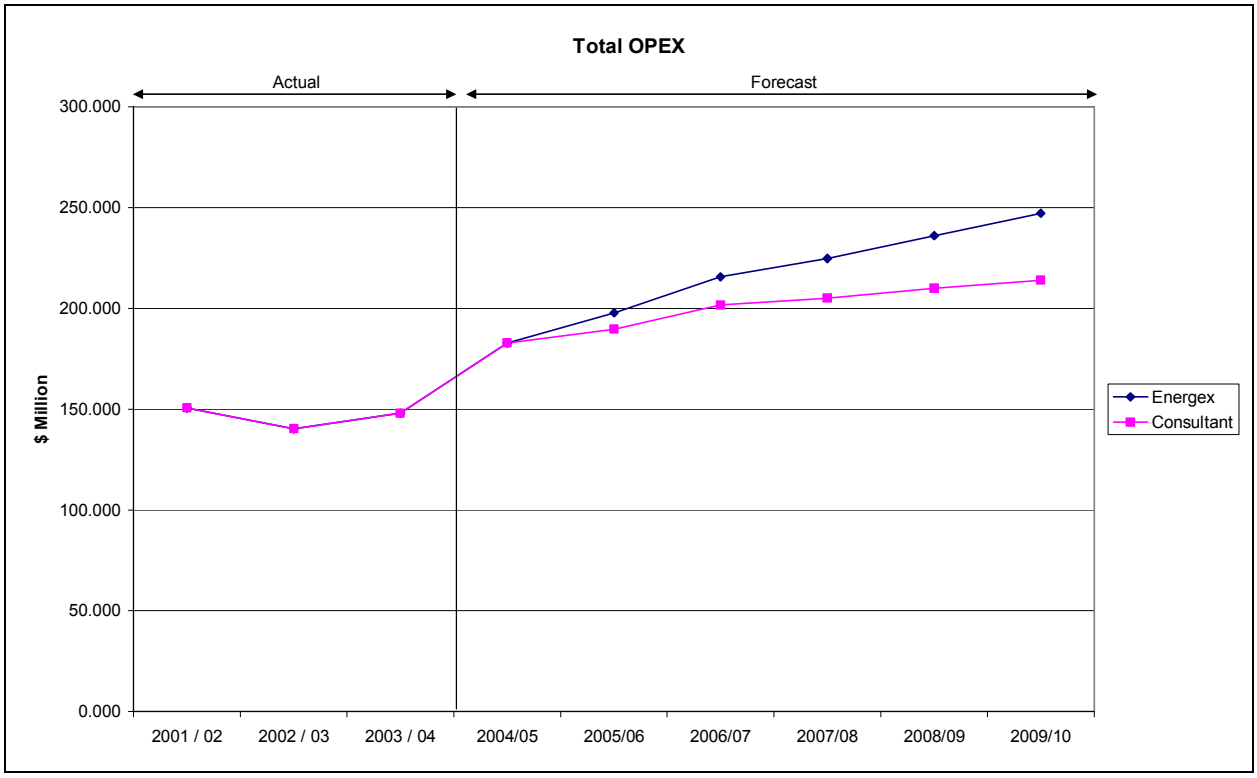
Over the six year period 2004/05 to 2009/10, Energex has estimated that the annual OPEX expenditure will increase from $164.6 million (2004/2005) to $247.2 million (2009/2010). This corresponds to a significant increase (approximately 67%) compared to the current (2003/04) annual OPEX expenditure. The Consultant is of the opinion that this step change in OPEX is dictated by previous underspending, particularly in the areas of service cable, sub-transmission line and pole top inspections, as well as thermo-scanning and vegetation management. The Consultant agrees that more rigorous inspection and maintenance programs in these areas require a significant increase in corrective maintenance expenditure. Nevertheless, by implementing the initiatives outlined in the review, the Consultant considers that a significant reduction in spending of approximately $101 million (8.7% of the sum requested by Energex) can be achieved over the period. Historical spending and Energex's estimates of OPEX are shown in the following table and graph together with the Consultant's estimate. . It should be noted that these figures exclude Service Quality Incentive and Non Distribution Services costs.

Table 1-1: Consultant's OPEX Expenditure

		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06-09/10
Energex	$M	150.6	140.2	147.9	182.8	197.8	215.5	224.7	236.0	247.2	1,121.2
Consultant	$M					189.6	201.7	205.1	209.8	214.0	1,020.2

All forecast and historical figures are in June 2004 dollars

Figure 1-1: OPEX expenditure



All forecast and historical figures are in June 2004 dollars

The Consultant has identified approximately $101M worth of potential OPEX savings. The main contributor to these savings is the use of alternate escalation factors to determine the OPEX forecasts. In particular, the Consultant has introduced a new Network Escalation Factor ("NEF") for network related assets and activities which is significantly less than the Network Unit Escalation ("NUE") factor used by Energex. Furthermore, there are a number of categories (e.g. streetlights) where Energex has applied the NUE where it would be more appropriate to apply the customer growth escalation factor. Overall, using alternate escalation factors contributes approximately $55.3M to the total savings.

Other areas for potential OPEX savings include:

- $2.6M in inspection and maintenance of sub-transmission underground ("UG") Cables;
- $0.8M in inspection and maintenance of low voltage ("LV") Services;
- $0.62M on Zone Substation transformer maintenance;
- $7.2M Customer Service;
- $1.7M on Network Operations;
- $11.4M for efficiency gains in line asset inspections;
- $3.6M for reducing asset inspection and planned maintenance intervals to industry standards;
- $7.7M in corrective repairs;
- $8.2M in general efficiency improvements due to enterprise bargaining agreements ("EBA") e.g. spread of hours, multi-skilling, reduced crew sizes etc.; and
- $1.5M in Levies.

1.9 Review of Capital Projects

A wide range of capital projects was reviewed by the Consultant. The review identified the following issues of concern:

- The process of compiling project files to support capital expenditure is not well defined at Energex and should be improved;
- The process for project approval would be enhanced by the provision of pre-project information, use of quantified risk assessments, documented system planning/network capacity impacts and improved financial assessments; and
- The process for project reconciliations should be tightened up.

Notwithstanding these concerns, the Consultant is of the view that the capital expenditure for the projects reviewed was generally prudent and that the expenditure appeared to be efficient.

1.10 Independent Review of Growth Forecasts

The growth forecasts have been separately reviewed by McLennan Magasanik & Associates ("MMA") who have predicted lower average growth in both customer numbers and maximum demand over the forecast period than Energex. The Consultant has based its expenditure forecasts on the growth forecasts provided by Energex.

Based on MMA's forecasts, the Consultant has estimated that the difference in the forecasts of customer numbers and maximum demand ("MD") equates to changes to the Consultant's OPEX and CAPEX estimates over the period 2005/06 to 2009/10 of approximately:

- $2.0M decrease for MD related OPEX works;
- $2.8M decrease for customer related OPEX works;
- $8.5M decrease for customer initiated capital works; and
- $125M decrease for corporate initiated capital works.

1.11 Planning & Budget Processes

The Consultant considers that Energex's approach to system planning has not been effective in recent times, due to inappropriate planning criteria combined with unexpectedly high growth rates and insufficient resources applied to this task. The Consultant is of the view that Energex accepted a significantly increased level of risk (to contain costs) and has been caught out by several years of higher than expected growth in maximum demand.

The effectiveness of Energex's budgeting process is seriously affected by Energex's inability to process the most recent summer MD information in time to feed into the budget due to lack of time and resources. This resulted in the need to estimate the impact on a macro basis. The Consultant considers that this significantly reduces the confidence in Energex's forecasts of demand related CAPEX, particularly in an environment of wide fluctuations in MD.

Budget requirements for customer and minor works are identified by trending leading indicators (mainly expenditures) and adjusting them to take account of known factors. The Consultant considers that a more rigorous and more appropriate approach is to trend physical quantities and to multiply them by unit rates. The Consultant is concerned that this approach has not been adopted by Energex, and that some of the basic physical quantities are not reliably recorded.

1.12 Efficient CAPEX Program

Over the six year period 2004/05 to 2009/10, Energex has forecast total CAPEX of $3,734 million (based on Tier (a) of the Service Quality Incentive Scheme). The Consultant considers a CAPEX of $3,072 million would be more appropriate. This is a reduction in CAPEX of $663M or 17.8%. However it should be appreciated that the sum of $3,072 million represents a significant increase in the rate of spending compared to the current regulatory period, for the reasons discussed in Section 1.14.

Energex supplied the Consultant with various versions of Energex's historical CAPEX. The regulatory accounts contained insufficient detailed breakdown to allow comparison and analysis. For this reason, the most recent set of historical CAPEX values supplied by Energex that contain a detailed breakdown have been used by the Consultant for the analysis. The regulatory CAPEX and the CAPEX used for analysis are shown in the following table:

Table 1-2: Historical CAPEX Expenditure

		01/02	02/03	03/04
Regulatory CAPEX	**$ M**	287.4	289.9	300.0
Analysed CAPEX	**$ M**	281.0	288.9	296.2

All forecast and historical figures are in June 2004 dollars

Energex's estimates and the Consultant's estimates of Capital expenditure are shown in the following table and graph:

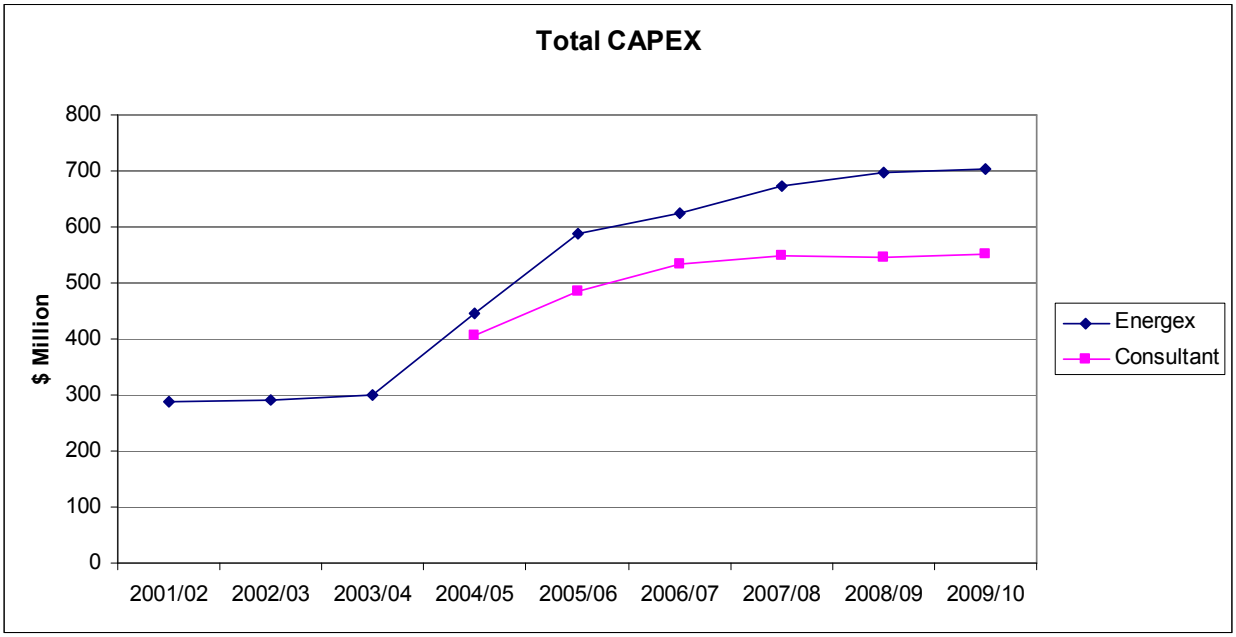
Table 1-3: Consultant's CAPEX Expenditure

		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06-09/10
Energex	**$M**	281.0	288.9	296.2	446.6	588.4	624.8	673.1	697.9	703.7	3,287.8
Consultant	**$M**				405.8	484.3	533.5	549.9	546.2	552.7	2,665.9

All forecast and historical figures are in June 2004 dollars

Note that for ease of comparison, the figures in the above table are in June 2004 dollars, whereas the figures in Table 9-7 are in dollars of the day to enable comparison with QCA determination figures. It should also be noted that expenditure specifically related to improving service quality has been excluded from Table 1-3.

Figure 1-2: Consultant's CAPEX Expenditure



All forecast and historical figures are in June 2004 dollars

The principal reasons for the difference between Energex's CAPEX forecasts and those of the Consultant are:

- $251M for reduced estimates for Demand Driven Primary;
- $123M for reduced estimates for Domestic and Rural;
- $61M for reduced estimates for Service Connections;
- $56M for reduced estimates for Pole Replacement and Nailing; and
- $41M for reduced estimates for Customer Driven Primary

1.13 Resource Capability

Energex developed a resourcing strategy in early 2004 to deliver the increased workload and advised that the key elements of the strategy were:

- Assessing the projects in the program and the risks associated with deferring them;
- Reviewing internal and external resources to deliver the program; and
- Assessing the ramp up rate of these resources.

In the light of previous expenditure history and the absence of a detailed resource plan, the Consultant has grave concerns regarding Energex's capability to deliver the level of work proposed by the Consultant, particularly given proposed increases in forecast expenditure in other jurisdictions and the resulting shortage of skilled resources generally throughout Australia and New Zealand.

The Consultant is confident that Energex could spend around 80% of the expenditure recommended by the Consultant, and considers that Energex may be able to spend more depending on how successful they are in finding the required skilled manpower.

The Consultant recommends the following actions by the QCA:

- Require Energex to submit a detailed and comprehensive resourcing plan for review by the QCA; and
- Consider modifying the pricing mechanism to take account of significant under-spends in expenditure.

1.14 Step Change in CAPEX from Historical Levels

Energex has forecast a significant increase in CAPEX from $296M in 2003/04 to $447M in 2004/05 and to $588M in 2005/06.

The main contributors to the increase in 2004/05 are:

- An increase of $17M in Refurbishment Driven Primary (due mainly to the need to replace gas insulated 33kV cables – this increase is supported by the Consultant);
- An increase of $123M in Demand Driven Primary (required to address load increases and existing overload conditions, due to past inactivity caused in part by poor planning – the Consultant has reduced this increase by $30M); and
- An increase of $23M in Non-System (due mainly to increased expenditure on vehicles to accommodate increased resources and IT systems – the Consultant accepts this estimate).

The main contributors to the increase in 2005/06 are:

- An increase in Demand Driven Primary of $118M (required to address load increases and existing overload conditions, due to past inactivity caused in part by poor planning – the Consultant has reduced this increase by $58M); and
- An increase in Non-System of $25M (due mainly to IT systems and motor vehicles – the Consultant accepts this estimate).

2 SCOPE AND METHODOLOGY

This section covers the review of operating expenditure and capital expenditure and associated asset management practices of Energex for its electricity network. An overall strategic view is provided with regard to whether the proposed levels of capital and operating expenditure, for the periods 2004/05 to 2009/10 are reasonable and efficient.

As requested by the QCA, the Consultant has based its forecasts of OPEX and CAPEX on growth forecasts provided by Energex. As discussed further in Section 9.5, variation in MD or customer numbers will necessitate changes to expenditure requirements.

2.1 Terms of Reference

For OPEX, the Terms of Reference issued by the QCA required the Consultant to:

- Assess the current efficiency of the DNSP's OPEX and determine anticipated future efficiency gains, taking into account comparisons with suitable peers and the efficiency study undertaken in setting the current regulatory arrangements; and
- Determine the rate of growth in OPEX expected to result from growth in demand for the DNSPs' services.

For CAPEX, the Terms of Reference issued by the QCA required the Consultant to:

- Review the procedures in place for assessing CAPEX;
- Assess the reasonableness of the major drivers of each DNSP's CAPEX program;
- Provide an opinion on the efficiency of each DNSP's estimates of CAPEX in the roll-forward period from 1 July 2004 to 30 June 2005;
- Provide an opinion on the efficiency of each DNSP's estimates of CAPEX for each year from 1 July 2005 to 30 June 2010; and
- Provide estimates of the level of aggregate CAPEX for each year that the Consultant considers to be efficient.

The Consultant was also required to consider the relationship between CAPEX and OPEX.

2.2 Methodology

The review was conducted in five stages:

Stage one - Data Collection;

Stage two - "Desk Study" Review;

Stage three - Further Gathering of Information;

Stage four - Review of Significant Issues;

Stage five - Preparation of Draft Report; and

Stage six - Preparation of Final Report (still to be done).

Unless stated otherwise, all figures are in June 2004 dollars. The Consultant has used the Australian Bureau of Statistics all groups CPI for Brisbane as a deflation factor to convert historical expenditure to June 2004 dollars.

The deflation factors are:

Table 2-1: Deflation factors

Period	Percentage change from previous financial year
2000-01	5.9
2001-02	2.9
2002-03	3.2
2003-04	2.9

2.2.1 Data Collection

This stage involved gaining a detailed understanding of the operation of the Energex regulated electricity distribution business and its key processes. A wide range of information was collected, collated, reviewed and cross-referenced as the foundation for detailed analysis. A number of site visits were made and interviews held with key personnel within Energex. Details of the site visits (for this and later stages) are contained in Appendix 14.1 and a list of key documents accessed (during this and later stages) is contained in Appendix 14.2.

2.2.2 "Desk Study" Review

This stage involved the detailed review of the information gained in Stage one. Factors considered included the following:

- Operating, maintenance, augmentation and replacement strategies;
- Asset details - numbers, types, ages, condition;
- Planning processes;
- Network capacity and utilisation;
- Regulatory, safety and environmental compliance issues;
- Organisation and staffing;
- Performance standards;
- Comparisons with other electricity utilities; and
- Assumptions underpinning Energex's forecasts of CAPEX and OPEX.

Outcomes from this stage were the identification of key issues, identification of areas requiring further information and identification of valid causes for significant differences between Energex and other utilities. In making comparisons with other utilities, the Consultant has utilised only information that is available in the public domain, particularly on the Websites of jurisdictional Regulators and utilities. The Consultant recognises that some of the information available may not be directly comparable; however the Consultant is of the opinion that the comparisons are still an indication of relative performance.

2.2.3 Further Gathering of Information

This stage involved meetings with staff to assess processes and design, planning, operating and maintenance standards. It also involved audits of specific assets and systems to verify their condition and operational risks. A detailed review of a range of capital projects was also undertaken to assess the prudency and efficiency of associated capital expenditure.

2.2.4 Review of Significant Issues

Significant issues identified in the earlier stages of the review were discussed with relevant managers within Energex to ensure that the Consultant correctly understood the issues and to gain further insights into the business.

2.2.5 Preparation of Draft Report

The findings, analysis and conclusions arising from the four preceding stages were collated and integrated into the draft report.

2.2.6 Preparation of Final Report

Comments received and issues raised from the Draft Report have been considered and used as input into the preparation of this Final Report.

3 ORGANISATIONAL DESCRIPTION

3.1 Purpose and Scope of Section

The organisation structure and its personnel can have a significant affect on the efficiency of an electricity utility. This section describes the organisation structure of Energex Electricity Distribution and the relationship with Energex at the corporate level.

3.2 Organisation Structure

3.2.1 Corporate

Energex is part of a broader organisation consisting of Energex Ltd and Energex Retail.

The Corporate business has five parts:

- Holding Company; covering legal and corporate affairs (including legal services, regulatory affairs, public affairs, internal audit, secretariat and external investments), planning and investment (including corporate finance, corporate taxation, corporate planning and analysis, and tradeable elements program), and corporate development (including development, growth and strategic relationships);
- Regulated business; covering network asset management and asset services as described in Section 3.2.2;
- Non-regulated business; covering commercial services, Metering Dynamics, energy impact and asset management solutions, and Energex New Zealand;
- Shared services; covering human resources, information technology, telecommunications, procurement, customer contact centre, property services and Services Essentials Pty. Ltd. (a joint venture between Energex and Ergon Energy established in July 2002); and
- Energex Retail; covering trading, sales and marketing.

The organisation structure and key functions performed are shown in Appendix 14.3.

3.2.2 Regulated Business

The regulated business incorporates both electricity and gas distribution systems. The returns of this business are set by the QCA. It is divided into two parts:

- Network Asset Management; covering network investment and performance, network capability and planning, technical standards and safety; and
- Asset Services; covering customer connections, gas services, distribution services, network operations, transmission services, and network program delivery.

3.2.3 Personnel Numbers

Personnel numbers as at January 2004 for both the regulated and non-regulated areas of Energex are detailed in the table below:

Table 3-1: Energex Ltd. personnel numbers

Business Area	Organisation	Gas	Electricity	Total
Regulated	Asset Management	10	124	134
	Asset services	57	1,189	1,246
	Total	**67**	**1,303**	**1,370**
Non- regulated	Holding company		69	69
	Shared Services	3	907	910
	Asset solutions (Aust. Vic. & NZ)		282	282
	Retail		157	157
	Total	**3**	**1,415**	**1,418**
Combined	**Total**	**70**	**2,728**	**2,798**

4 BUSINESS ENVIRONMENT

4.1 Purpose and Scope of Section

In assessing the prudency and efficiency of expenditure, it is necessary to consider the business environment in which the business operates. This section considers such issues that may impact on the prudency and efficiency of capital and operating expenditure.

4.2 Regulatory

The key regulations applicable to the electricity industry in Queensland are:

- The National Electricity Code ("NEC");
- The Electricity Act 1994; and
- The Queensland Competition Authority Act 1997.

The QCA is the Jurisdictional Regulator for electricity distribution network service providers under the NEC in Queensland.

The NEC governs the following:

- The National Electricity Market;
- The terms, conditions and technical requirements of access to the transmission and distribution networks; and
- The methodology for the pricing of network services.

The Electricity Act 1994 regulates:

- The contestability timetable;
- Authorisations and special approvals;
- Pricing and service quality for customers in relation to transmission, distribution and retail functions;
- Customer protection, including standard customer contracts and the resolution of disputes under those contracts; and
- Electricity rationing.

The QCA Act, Electricity Act and the NEC provide the QCA with the following responsibilities:

- Acting as Jurisdictional Regulator under the NEC to regulate pricing for electricity distribution networks and ring fencing between distribution entities and contestable activities;
- Making and enforcing conduct rules;
- Monitoring service quality standards (set by the Minister) of electricity entities; and
- Assessing competitive neutrality.

The Queensland electricity distributors hold an authority, issued by the Office of Energy, to distribute electricity in Queensland. The distributors are required to comply with the conditions of their licences, the Electricity Act, the Electricity Regulation and other applicable laws.

The distributors are also required to adhere to a range of other Acts, Regulations and Codes, including:

- Electricity Safety Act 2002;
- Electrical Safety Regulation 2002;
- Electricity Regulation 1994;
- Code of Practice – Electrical Work;
- Code of Practice – Working Near Exposed Live Parts;
- Code of Practice - Works (Protective Earthing, Underground Cable Systems and Maintenance of Supporting Structures for Powerlines);
- Workplace Health & Safety Act 1995;
- Integrated Planning Act 1997; and
- Environmental Protection Act 1994.

The Consultant considers that the Regulatory environment in which the electricity distributors operate is substantially the same as that which applies elsewhere around Australia, so no special considerations are required in this area.

4.3 Operational Requirements

The parameters for supply quality are governed by the NEC and the Electricity Act. The Electricity Act includes the requirement to operate, maintain and protect the supply network to ensure the adequate, economic, reliable and safe supply of electricity. Standards for frequency and voltage are contained in the Electricity Regulation 1994.

The Electricity Safety Act requires the distributors to ensure that works are operated in a way that is electrically safe, and includes the obligation to inspect, test and maintain.

The Consultant considers that the operational requirements are very similar to those that apply in other Australian jurisdictions, so no special considerations are required in this area.

4.4 Safety Requirements

The distributors are required to adhere to the Workplace Health & Safety Act 1995 and the Electricity Safety Act 2002. Under the Electricity Safety Act, electricity entities are obliged to:

- Ensure their works are electrically safe; and
- Ensure their works are operated in a way that is electrically safe.

This obligation includes ensuring their works are inspected, tested and maintained.

The Electricity Safety Regulations:

- Prescribe matters in support of the electrical licensing arrangements established under the Act;
- Prescribe requirements for working around exposed parts;
- Prescribe requirements for electrical installations;
- Prescribe matters about electrical equipment;
- Prescribe requirements and procedures for the design, building and maintenance of electric lines and the works of electricity entities;
- Prescribe requirements for the performance of electrical work;
- Provide for the preparation, lodging and auditing of safety management plans;
- Prescribe requirements for the operation of cathodic protection systems and requirements for particular systems to be registered; and
- Prescribe notification and reporting requirements for serious electrical incidents and dangerous electrical events.

More detailed electrical safety requirements are contained in the following Codes of Practice:

- Code of Practice - Electrical Work;
- Code of Practice - Working Near Exposed Live Parts; and
- Code of Practice - Works (Protective Earthing, Underground Cable Systems and Maintenance of Supporting Structures for Powerlines).

Within Energex, Safety Management Systems are externally accredited to AS 4801 for the Regulated Line of Business and Procurement and Services Group at Banyo. It is apparent that Energex has a high level of commitment to Health and Safety matters throughout the business and that sound processes are in place to achieve measurable outcomes in this area.

The Consultant considers that the safety requirements applicable to the Electricity Networks business are very similar to those that apply elsewhere around Australia, so no special considerations are required in this area.

4.5 Customer Service Standards

Customer service standards are not prescribed; however, the distributors are required to report to the QCA on a number of reliability and service quality measures, as detailed in the Electricity Distribution: Service Quality Reporting Guidelines issued by the QCA.

Further discussion in regard to customer service standards is contained in Section 5.6.3.

4.6 Environmental Requirements

Energex recognises that activities it conducts have the potential to impact on the environment. An Environmental Management System, compliant with and certified to the international standard ISO 14001 has been developed and implemented within Energex to ensure processes are in place to identify and manage environmental responsibilities in an economically reasonable, environmentally responsible and socially acceptable manner.

Environmental assessments are required for triggered activities, that is, projects with the potential to require specific environmental management plans.

- If a project does not trigger an environmental assessment, general environmental requirements (that is, basic environmental management requirements) are required to be complied with.
- If a project does trigger an environmental assessment but that assessment does not identify any matters of environmental significance, general environmental requirements are required to be complied with.
- If a project does trigger an environmental assessment and that assessment identifies issues of environmental significance, a specific Environmental Management Plan for the works is produced and complied with.

The environmental assessments take into account a range of issues, including the management of vegetation, fauna, waste, noise and social issues.

Current environmental issues faced by Energex include:

- Fire ants – some increase in costs due to restrictions (for example disposal of soil);
- Acid sulphate soils – some increase in costs due to the need to remove soil and replace (as an alternative, may choose another location or route); and
- Vegetation – requirements of Department of Primary Industry (“DPI”) Code of Practice for Work in Mangrove, Marine Plant & Fish Habitat Areas (Energex has permission to cut mangroves for existing lines, but must notify DPI).

Although there are some differences in emphasis, the Consultant considers that the environmental requirements are similar to those that exist elsewhere around Australia, so no special considerations are required in this area.

5 ASSET MANAGEMENT

5.1 Scope of Section

Asset management covers the processes for planning, development, operation and maintenance of all components of the electricity network. Clearly, sound asset management processes are a prerequisite for prudent and efficient capital and operating expenditure.

This section considers the asset management policies and practices of Energex and compares them to best practice.

5.2 Approach to Asset Management

An effective approach to Asset Management should ensure that:

- Assets are developed, operated and maintained in a manner which will permit customer service delivery targets to be achieved and asset economic life to be maximised, whilst minimising environmental impact and costs;
- Appropriate financial records relating to the assets are maintained; and
- Processes and procedures are in place for undertaking sound asset management activities with respect to:
    - Network planning, development and augmentation;
    - Network capacity and performance assessment;
    - Network operation;
    - Asset protection;
    - Network condition assessment, maintenance planning and maintenance execution; and
    - Asset data capture and management.

Given the strategic importance of asset management, the Consultant would have expected that an electricity distributor would have in place a comprehensive Asset Management Plan spanning the current and at least one further Regulatory period. Energex prepared a draft Asset Management Plan in 2001 covering the period 2002-2012, but it appears this was not finalised nor communicated across the business. The Consultant has been informed that Energex is proposing to prepare an updated and more comprehensive Asset Management Plan. The Consultant is concerned that the lack of such a coordinated plan leads to reduced levels of confidence in Energex's proposed OPEX and CAPEX forecasts.

5.3 Policies

5.3.1 Planning & Development

Energex's policies and system planning philosophies are currently under internal review. The preferred loading criteria for the various parts of the network and load categories are contained in Document SP02 – Criteria for Loading of the Electricity Network. It is Energex's policy that network augmentation proposals will be raised, approval be obtained and works be commissioned prior to the time when forecast loading exceeds these criteria. The Consultant considers that this process has not been effective in recent times, due to inappropriate planning criteria combined with unexpectedly high growth rates and lack of skilled planning resources. The Consultant considers Energex has, through past underspending allowed the utilisation of its zone substations to increase to the point where (n-1) design standards are no longer achieved for extended periods during summer. This has meant that the capability of the system to provide continuity of supply through major storm incidents has been significantly compromised. This issue is discussed further in Sections 5.6.2 and 9.2.1.

Energex aims to integrate capital and operating plans to achieve specific performance outcomes on the network.

The Consultant considers that these policies are similar to those adopted by other electricity distributors, but notes that Energex is moving back towards a more deterministic approach as discussed in Section 5.6.2.

5.3.2 Operation & Maintenance

5.3.2.1 Operation

The Energex operational policy centres around an existing control structure with the aim of extending automation of the network and upgrading systems as required to keep abreast with industry practice.

To manage the distribution and sub-transmission network the control centres at Victoria Park and Nambour using a Distribution Management System with supervisory control and data acquisition ("SCADA") based monitors which receive and process information from the field based Remote Terminal Units ("RTUs"). SCADA has been extended to all zone substations and this allows operation and monitoring of substation based equipment. Manually operated white boards are used by operators for planned and emergency switching and outage coordination of the 11 kV network.

Automation and remote monitoring of distribution equipment is being introduced.

Emergency and load shedding procedures are standardised according to national Electricity Supply Association of Australia ("ESAA") practices.

Field operations are performed by field staff who may be dedicated switching operators, multi-skilled tradesman or technicians.

The call centre which manages the customer call and fault response system is closely integrated with the control centre.

5.3.2.2 Maintenance

The policy for maintenance of substations and overhead and underground mains is outlined in two comprehensive documents titled Substation Asset Maintenance Policy ("SAMP") and Mains Asset Maintenance Policy ("MAMP").

The policies use a combination of a number of maintenance philosophies including:

- Operate to failure;
- Time based;
- Opportunity;
- Condition monitoring;
- Reliability Centred Maintenance ("RCM"); and
- Maintenance Free.

Of these philosophies, there is a current trend toward condition monitoring and RCM, i.e.

- All plant, mains and public lighting assets and vegetation are inspected or maintained on a routine basis;
- Some assets are opened and inspected when the opportunity arises, i.e. when outages can be arranged;
- Some assets are tested to record and analyse the condition; and
- Records are examined on specific items to determine causes, trends and costs and to assess optimum strategies.

Asset life plans with appropriate standards are produced, based on manufacturers' recommendations, known experience and history, consultation with other utilities and environmental influences. These life plans are fluid and modified with experience. These standards are expressed in comprehensive maintenance procedures (Standard Work Procedures), plant manuals, work instructions and schedules.

5.4 Support Systems

5.4.1 IT Systems

A comprehensive road map of the functions that occur in the Regulated business has been prepared. This documents the IT systems that are existing and being used throughout the business and those that are planned for implementation. It shows the linkages to other sources of information and links business functions and key staff.

Each business function and IT system is drawn together on a matrix with the linkages between them.

The main information systems include:

- Network Facility Management ("NFM") – master asset database, network planning, load analysis, asset and property management. This system was commissioned in 1995;
- Distribution Management System ("DMS") – SCADA, Load management, customer service, outage management;
- MINCON Ellipse - fully integrated financial, project, works management and maintenance system used for asset management. This single management system replaces a number of separate management systems. It was commissioned in May 2003 and planning for all maintenance and new work is managed via this system. The system interfaces to hand held computers for planning, patrolling, scheduling repairs of identifiable faults, costing of work and close out through the equipment register of all maintainable items;
- Peoplesoft Human Resources – Human Resources Management;
- Peoplesoft Financials – General financial ledger, asset register, customer and billing data;
- AutoCAD applications – managing conceptual designs and planning;
- ENERGISE – Geographic information system, dial before you dig, maintenance maps, asset data, aerial photographs, property information, administrative boundaries;
- Planet – Network outage management system, load curves for assets, protection settings, streets and localities; and
- FACOM – Customer initiated requests and faults created in the customer and retail databases.

Each of the above systems is linked to many minor systems specific to the each part of the business.

5.4.2 Communication Systems

The current forms of communication used by Field staff are:

- Trunk Mobile Radio ("TMR") system, provided by Telstra, which incorporates fixed base stations located in Energex buildings, mobile units fitted to field vehicles and handheld units for field staff. Special console units are located at the two Energex Control Centres. Mobile phones and land lines can call into and receive information from the TMR system;
- Mobile Phones are used for field staff operating predominantly in built up areas. They are also used as a backup to the TMR system;
- Paging System, provided by Orange, is linked to Standby Roster software and the Energex electronic phone book. Messages can be sent from any Energex networked PC. This system allows rapid Storm Response Notification via the use of a common channel on pagers of the relevant personnel; and
- Computer Aided Dispatch ("CAD"). Networks jobs are sent directly to computing facilities in Energex vehicles via the Energex Local Area Network ("LAN"). The TMR system is used as the underlying communications medium.

5.4.3 Quality System

Energex has external certification to ISO 9001 for its Quality Management Systems covering the Regulated Line of Business and the Procurement and Services Group at Banyo.

5.4.4 Performance Management

The use of a diverse range of Key Performance Indicators ("KPIs") and their application at all levels in the organisation, is considered to represent industry best practice. Each employee should be able to see a clear link between what he or she does and the objectives of the business, which should be reflected in the KPIs.

The Consultant requested copies of the Distribution Business Unit Monthly Reports, but these have not been made available. Energex did provide copies of high-level monthly reports for the Regulated Business (electricity and gas), but these were not sufficiently detailed for the Consultant to form a view as to the diversity of the range of KPI's and their application at all levels in the organisation.

5.5 Planning Process

5.5.1 Capital Works

Energex does not prepare an integrated Asset Management Plan, but relies instead on a series of plans and strategies. Planning for capital works is brought together in the Network Program of Work which forms the basis of capital network decisions.

Various aspects of the planning process are detailed in a number of documents within the Quality Management System, including the following:

- SP24 – Provision of Annual Load Forecast for Bulk Supply and Zone Substations;
- 6056-A4 – Reliability Assessment Planning Guidelines;
- SP15 – Production of a Strategic Network Plan (this is currently under review); and
- SP25 – Production of the Annual Network Development Plan.

Energex considers the requirements for investment in three main areas:

- Sub-transmission and 11 kV Backbone – this includes:
    - Customer connections to the sub-transmission and 11 kV backbone;
    - Headworks to meet normal load growth;
    - Work to maintain performance standards due to normal load growth (including voltage regulation and the reduction in losses);
    - Work to improve reliability and performance (including major safety and environmental projects);
    - Works to replace ageing equipment or extend the life of existing equipment;
    - Acquisition of land and easements; and
    - Work for community requirements (for example undergrounding of overhead transmission).

- Distribution Augmentation – this includes:
    - Works to extend the network to connect domestic, rural, industrial and commercial customers;
    - Capital works requiring a capital contribution from customers (for example undergrounding of overhead and relocations);
    - Replacement or refurbishment of ageing equipment; public lighting; company initiated distribution augmentation (for example transformer upgrades, quality of supply and reliability projects); and
    - Service connections.
- Non-System Expenditure – this includes spending on Information Technology and property projects.

The following drivers of CAPEX are implicit in the Capital Program Definitions:

- Normal load growth;
- Connection of new customers;
- Reliability improvement;
- Replacement/refurbishment of ageing equipment;
- Property & easement acquisitions;
- Safety;
- Environment;
- Reduce losses;
- Quality of supply (including voltage regulation);
- Community requirements; and
- Customer requests for relocations/alterations (a capital contribution would be expected).

Missing from the above list is capital expenditure to reduce operating expenditure.

Details regarding the processes for approval and prioritisation of capital expenditure are contained in Section 9.2.

A key consideration in planning the development of the electricity network is the need to ensure that the network has sufficient capacity to meet the maximum demand. This involves the careful consideration of the level of spare capacity on the various elements of the network against the projected increases in demand. Ten year forecasts of summer and winter maximum demands are prepared for each transmission and sub-transmission substation. Sub-transmission line forecasts are not produced – substation forecast loads and proposed network configurations are used in power flow analysis to determine sub-transmission line limits.

Energex caters for the high and low growth scenarios by advancing their forecasts by one year, for the high growth scenario, and retarding them by one year for the low growth scenario. Although some utilities prepare high and low scenarios based on the probability of occurrence, Energex's approach provides a simple and practical method that is likely to provide similar results.

The Consultant considers that the overall approach to and processes for the planning of capital works is broadly in line with that used by other electricity distributors. However, as stated previously, the process has not been effective in recent times, as discussed further in Sections 5.6.2 and 9.2.1.

5.5.2 Maintenance Planning

Maintenance planning is well managed through the Ellipse asset management system.

The life cycle approach is adopted with consideration to life expectancy.

Maintenance plans for each asset type have been prepared which include time based inspections, non-intrusive condition monitoring, condition based maintenance, refurbishment when required and replacement at end of life.

This approach resembles that which is adopted by most utilities in the distribution business.

In addition the RCM principles have been used to analyse issues that have arisen with many asset types.

Examples of this have been:

- Overhead Conductor Wires Down;
- 33 kV Gas Pressure Cable Maintenance; and
- Service Cable Failures.

A system of standardised policies (Business Management System) and work instructions (Standard Work Procedures) has been established for use by work parties for planned maintenance on individual assets. These are supported by documented processes that detail actions for investigation and rectification of abnormalities and defects. This is essential to ensure a high standard and consistent approach to all maintenance.

What is not evident to the Consultant is the extent to which Energex is implementing their policies and planned maintenance activity given the reduced level of OPEX and the observed network reliability performance.

In recent months, severe storms have placed a high degree of importance on all aspects of asset management and considerable work has been undertaken to improve the systems for planning and implementing the maintenance activity.

5.6 Description of Best Practices

5.6.1 Asset Provision

Energex has installed equipment on the network which is consistent with industry standards. It is noted that Energex does not aim to develop or install leading edge technology, but to apply appropriate technology that has been proven by others. Given Energex's comparative network size, the Consultant is supportive of this approach.

The plant and equipment installed on the network conforms to Australian and/or International Standards and is used by other electricity distributors in Australia. The Consultant has seen no evidence to indicate that Energex are using inappropriate plant and equipment.

5.6.2 Asset Utilisation

The Consultant has used a number of measures to benchmark Energex's asset utilisation:

5.6.2.1 Energy Utilisation Factor ("EUF")

The EUF is the percentage ratio of total energy distributed to the capacity of the zone substation transformers times the time period. On an annual basis, the time period is 8,760 hours.

EUF% = (Energy*100)/(Capacity*8,760) %

where: Energy = total annual energy distributed by the network (MWh)

Capacity = total zone substation transformer capacity (MVA)

The EUF provides an indication of how effectively the zone substation transformers are being utilised from an energy perspective. An increasing trend in EUF would mean an increasing income in relation to zone substation transformer capacity. A higher EUF would mean a greater income in relation to zone substation transformer capacity.

5.6.2.2 Network Load Factor ("NLF")

The Network Load Factor is the percentage ratio of the total network average load to the network peak load.

NLF% = ((Energy/8760)*100)/Maximum Demand %

where: Energy = total annual energy distributed by the network (MWh)

Maximum Demand = the network coincident maximum demand (MW).

The NLF gives an indication of how hard the network assets are working on average in relation to the heaviest load conditions. A higher NLF indicates a more effective use of the network assets. An increasing trend in NLF indicates a more effective use of the network assets. Effective demand management activities would result in an increase in the NLF.

5.6.2.3 Plant Utilisation Factor ("PUF")

The PUF is the percentage ratio of the network peak load to the installed zone substation transformer capacity.

PUF% = (Maximum Demand)*100/Capacity %

where: Maximum Demand = the network coincident maximum demand (MVA)

Capacity = total zone substation transformer capacity (MVA).

The PUF gives an indication of how hard the network assets are working in relation to the heaviest loading conditions. A higher PUF indicates a more effective use of the network assets. An increasing trend in PUF indicates a more effective use of the network assets. Effective demand management activities would result in an increase in the PUF.

5.6.2.4 Asset Energy Factor ("AEF")

The AEF is the ratio of the dollar value of the network assets to the energy distributed.

AEF = (Asset/Energy) ($/MWh)

where: Asset = the value of the Regulated Asset Base ($AUD)

Energy = total annual energy distributed by the network (MWh)

The AEF gives an indication of the size of the asset base required to distribute energy around the network. A lower AEF indicates a more efficient use of the assets. A decreasing trend in AEF indicates a more efficient use of the assets.

Table 5-1 shows Energex's performance for each of these measures as well as the performance of other Australian electricity utilities for the 2002/2003 year (the indicators for the Victorian distributors are for the 2002 calendar year).

Table 5-1: Asset Utilisation

	ENERGY UTILISATION FACTOR (%)	NETWORK LOAD FACTOR (%)	PLANT UTILISATION FACTOR (%)	ASSET ENERGY FACTOR ($/MWh)	CUSTOMERS PER km
ENERGEX	36	54	75	177	26.8
INTEGRAL ENERGY		54		156	26.9
ENERGY AUSTRALIA		58		151	33.8
UNITED ENERGY	30	51	65	144	47.7
AGL	32			121	37.7
CITIPOWER	28	46	67	148	67.5
TXU	36			163	19.4
POWERCOR	34			147	4.2
ETSA	29	48	68	248	9.7
ERGON ENERGY	34	75	51	201	3.6
COUNTRY ENERGY	34	60	63	201	4.2

All factors are for the 2002/03 financial year except Victorian utilities which are for the 2002 calendar year

Although a range of Australian distributors are included in Table 5-1, the Consultant considers that a reasonable comparison can be made between Energex and Integral Energy, Energy Australia, United Energy and AGL. It should be noted that Energex's asset base includes some transmission assets, whereas United Energy and AGL do not have responsibility for transmission assets.

It can be seen that Energex has an Energy Utilisation Factor at the high end compared to other Australian distributors for which this information was available, although there is relatively little spread. It can also be seen that Energex's Network Load Factor is in the mid range of the comparable distributors and that Energex's Plant Utilisation factor is significantly higher than any of the other Australian distributors.

Taking these three factors together, the Consultant concludes that Energex is achieving a greater asset utilisation than comparable distributors. Energex contend that they have increased the utilisation of zone substation transformers beyond economic limits, and plan to install additional transformer capacity to reduce the Plant Utilisation Factor to 65%.

It can also be seen that Energex has a significantly higher Asset Energy Factor than comparable distributors, although lower than the larger rural distributors (which is to be expected), indicating that Energex has more assets tied up to distribute the same amount of energy than other comparable distributors. This is not consistent with Energex's higher asset utilisation, and suggests that Energex's assets may be more highly priced than comparable distributors. As Energex has a similar Network Load Factor to that of the comparable distributors, the higher Asset Energy Factor cannot be attributed to a lower load factor.

The level of asset utilisation is driven not only by the growth in load and demand, but also by the network planning and design philosophies which dictate the points at which network augmentation will be carried out.

A deterministic system planning philosophy is based on zero supply interruptions to customers in the event of any single outage of a network element. Any planned or unplanned outage of individual network elements (this is the "n-1" criterion) can be tolerated without affecting customer supply due to redundancy built into the distribution network. The strict application of a deterministic philosophy using the n-1 criteria can result in inefficient network investment, as the risk of customer interruptions is reduced by providing reserve or backup capacity without consideration of the cost of likely interruptions or alternatives.

Under a probabilistic planning philosophy, the strict deterministic n-1 criterion is relaxed, depending on the assessed risk, with investment proceeding only when the expected (probability weighted) total costs of outages exceeds the cost of augmentation. With this approach, there will be some conditions under which all the load cannot be supplied with a network element out of service but the load at risk is very small when considering the probability of an unplanned outage

As detailed in their Distribution Planning Reports, Victorian Electricity distributors have all adopted a probabilistic approach to network planning. Integrating the investment planning and risk management processes will maximise the benefits from network investments. For this approach to be adopted, sound outage data is required. Based on information compiled by the NSW Ministry of Energy and Utilities, the NSW electricity distributors are also moving towards a probabilistic approach but have not progressed as far as those in Victoria.

Energex adopted a probabilistic approach to network planning in the early 1990s, which resulted in a significant reduction in capital investment and an increased level of asset utilisation. This has lead to significant numbers of its bulk supply and zone substations exceeding their Emergency Cyclic Capacity at the time of summer peak load. This higher utilisation of the network resulted in a reduced capacity for the network to cope with extreme weather conditions. The Consultant is of the view that Energex accepted a significantly increased level of risk (to contain costs) and has been caught out by several years of higher than expected growth in maximum demand.

Energex proposes to amend its planning guidelines to a more deterministic approach, with the aim of reducing utilisation from 75% to 65%. The current planning philosophy is generally based on forecast loading on the various elements of the network not exceeding 0.8 of their Normal Cyclic Capacity for the network intact, with loss of load for a single credible contingency restored by switching. The proposed philosophy establishes a series of loading criteria based on the network item and the type of load supplied.

The Consultant concurs that Energex has gone too far in increasing its utilisation – between 60-65% is considered to represent good industry practice (it is noted that United Energy has a utilisation of 65%). The Consultant supports the move in the medium term to a more deterministic approach. It is anticipated that Energex would implement the change to a more deterministic philosophy over an extended period, going beyond the next Regulatory period. The implementation of this changed philosophy will increase the level of capital investment required. The Consultant considers that Energex will need to re-assess its planning guidelines following the reduction in asset utilisation (beyond the next regulatory period).

An alternative to network augmentation may be to install embedded generation or implement demand management programs, and it is noted that Energex is reviewing options in this area (refer to Section 9.6.4). Although several examples of major proposals in conjunction with Powerlink where provided, where alternative solutions were invited from external parties, Energex does not appear to be actively encouraging non-network solutions. The Consultant recommends that Energex explore appropriate means, including the use of incentive payments to customers who implement non-network solutions, which defer or avoid network augmentation. The Essential Services Commission in Victoria has indicated that it favours a more or less equal sharing of savings between the customer and the distributor in such situations.

5.6.3 Service Standards

Technical service standards for electricity supply are largely governed by the NEC and the Electricity Act. Energex has the aim of performing up to the required standards.

Service standards for customer service are not prescribed, although Energex provides quarterly service quality reports to the QCA which include information regarding system reliability, call centre performance, appointments, timeliness of connections, response to faults, streetlight maintenance, Guaranteed Service Levels ("GSLs") and complaints.

The level of service delivered by Energex can be assessed by:

- The number of complaints received (normalised per 100,000 customers);
- The number of GSL payments made (normalised per 100,000 customers); and
- Performance against supply reliability targets.

Energex has developed its own customer service standards which are detailed in Energex Standard 01454. This standard covers a range of service activities, including appointments, response to enquiries, new connections, disconnections, supply interruptions, street lights, trees, quality of supply and complaints. It is noted that there are several discrepancies between this standard and the information contained on Energex's Website.

Energex has introduced a number of GSLs and makes payments to customers on application by the customer when the guaranteed performance standard has not been achieved. GSLs apply to the following (based on the information on Energex's Website):

- New Connections – where electricity mains do not exist outside the premises, Energex will contact the customer within ten business days to advise on what is required to make supply available. A credit of $20 applies for each day Energex is late, up to a maximum of $200. This is a lower standard than other utilities, where the quantum is higher and the service relates to the date supply is connected.
- Interruption Advice – Energex will provide at least two days' notice of planned interruptions (excluding emergency situations), applying a credit of $20. The same guarantee is offered by several other utilities, and Ergon Energy guarantees four days' notice and offers a higher credit for rural customers. The Consultant considers the service standard for this guarantee as being relatively easy for Energex to achieve.
- Appointments – Energex will be on time for appointments, and will apply a credit of $20 if more than 15 minutes late. This is the same quantum and time period applied by most utilities surveyed.
- Quality of Supply – Energex will investigate and respond to quality of supply problems within ten business days, applying a credit of $20. None of the other utilities surveyed offers such a guarantee.
- Wrongful Disconnection – Energex will credit a customer for $100 for wrongful disconnection of supply. The Consultant notes that none of the other utilities surveyed offers such a guarantee, but considers that the incidence of such occurrences should be very low.

Overall, the Consultant considers that the standards of service relating to the GSLs offered by Energex are relatively soft, with the exception of responses to quality of supply problems. The Consultant also notes the requirement for customers to apply for the GSL credit, rather than it being provided as a matter of course when Energex fails to meet its customer service standards, resulting in a lower number of GSL payments. A detailed comparison between Energex's GSLs and those of other utilities is contained in Appendix 14.10.

Table 5-2 shows the number of complaints and GSL payments for Energex and other Australian distributors, for the financial year 2002/03 for SA and NSW and calendar year 2002 for Victoria and Energex.

Table 5-2: Complaints & GSL Payments

	NO. OF COMPLAINTS PER 100,000 CUSTOMERS	NO. OF GSL PAYMENTS MADE PER 100,000 CUSTOMERS
ENERGEX	514	16
INTEGRAL ENERGY	234	
ENERGY AUSTRALIA	37	
UNITED ENERGY	113	142
AGL	97	141
CITIPOWER	45	170
TXU	131	300
POWERCOR	27	11
ETSA	447	402
COUNTRY ENERGY	322	

All values are for 2002/03 financial except Energex which is for 2003 calendar and the Victorian utilities which are for the 2002 calendar year.

It can be seen that Energex has a high level of complaints per 100,000 customers and has a low level of GSL payments per 100,000 customers, in relation to other distributors.

The Consultant considers that the lower number of GSL payments has been influenced by the standards set for which GSL payments apply, as discussed earlier. Another factor could be the level of understanding by customers about GSLs. GSL payment statistics are also heavily influenced by customer expectations - if customers expect a higher level of service, for example, then the same level of complaints might be experienced even though a higher level of service is being provided. In spite of these limitations, indications are that Energex has room for improvement in the level of customer service provided, as viewed from a customer complaints perspective. It is noted that Energex offers GSL payments on a voluntary basis, whereas the GSL schemes form part of the Regulatory arrangements in Victoria and South Australia.

In its Final Determination covering the current Regulatory period, the QCA signaled its intention to consider including some form of service quality incentive mechanism in the next Regulatory period. The QCA issued a Final Decision in April 2004, proposing a scheme that would target specific service quality outcomes to be achieved by the end of the next regulatory period.

In establishing the CAPEX and OPEX building blocks for the next regulatory period, the distributors are required to submit forecasts associated with:

- Maintaining the current service quality level (Tier (a));
- Improving service quality aimed at delivering an agreed average level of service (which may be somewhat higher than current service levels) (Tier (b)); and
- Specific additional commitments aimed at improving service quality in specific parts of the network or addressing identified customer requirements and including clearly identified service quality outcomes (Tier (c)).

The CAPEX and OPEX expenditures associated with these three tiers of service levels are discussed later in this report.

Key measures of supply reliability are:

- System Average Interruption Duration Index ("SAIDI") – this is a measure of how long each customer is without supply for the year when averaged over all customers;
- System Average Interruption Frequency Index ("SAIFI") – this is a measure of the number of sustained supply interruptions each customer experiences for the year averaged over all customers (a sustained interruption is one in excess of a specified duration, usually one minute);
- Customer Average Interruption Duration Index ("CAIDI") – this is a measure of the average duration of each supply interruption per customer who experienced an interruption, and indicates how quickly a distributor restores supply; and
- Momentary Average Interruption Frequency Index ("MAIFI") – this is a measure of the number of momentary interruptions each customer experiences for the year averaged over all customers (a momentary interruption is one less than the specified duration).

It is noted that Energex does not monitor and record momentary interruptions, so a comparison of performance using MAIFI as an indicator could not be made. Based on the Consultant's experience, momentary interruptions are an increasing cause for concern to customers, with the proliferation of electronic and digital equipment. The Consultant recommends that the QCA consider introducing such a performance measure in the regulatory period after the forthcoming period.

Table 5-3 shows key supply reliability indicators for Energex and other Australian electricity distributors for the 2002/03 financial year (the indicators for the Victorian distributors are for the 2002 calendar year).

Table 5-3: Supply Reliability

		ENERGEX	INTEGRAL ENERGY	ENERGY AUSTRALIA	UNITED ENERGY	AGL	CITIPOWER	TXU	POWERCOR	ETSA	COUNTRY ENERGY
SAIDI MINUTES	PLANNED	4	35	5	16	6	9	29	17		48
	UNPLANNED	180	182	113	73	74	33	219	187		239
	TOTAL	184	217	118	89	80	41	248	203	179	287
SAIFI	PLANNED	0.015	0.12	0.03	0.05	0.03	0.03	0.13	0.11		0.21
	UNPLANNED	2.008	2.62	1.25	1.49	1.49	0.69	2.96	2.21		2.18
	TOTAL	2.022	2.78	1.28	1.55	1.52	0.72	3.09	2.32	1.79	2.39
CAIDI MINUTES	PLANNED	246	305	184	305	238	286	234	155		234
	UNPLANNED	90	69	81	49	49	47	74	85		109
	TOTAL	91	78	92	58	53	57	81	88	100	121

All values are for 2002/03 financial except the Victorian utilities which are for the 2002 calendar year.

It can be seen that Energex's planned SAIDI is the best of the comparable distributors, although this is offset by the unplanned SAIDI that is very close to the highest, giving a total SAIDI towards the higher end of the spectrum. This indicates that when averaged across all customers, Energex's customers are off supply for a longer period each year than most of the comparable distributors, some of whom have far lower time periods (less than half). Nearly all of the time off supply is due to unplanned interruptions.

It can also be seen that Energex's planned SAIFI is the best of all the distributors surveyed, but this is offset by unplanned SAIFI that is higher than the average of the comparable distributors. This gives Energex a total SAIFI that is higher than the average of the comparable distributors. This indicates that when averaged across all customers, Energex customers are experiencing more interruptions than most of the comparable distributors. Again, most of the impact is from unplanned interruptions.

Energex's planned CAIDI is in the mid range of the comparable distributors and the unplanned CAIDI is higher than any of the comparable distributors, giving a total CAIDI that is very close to the highest of the comparable distributors. This indicates that for unplanned interruptions, it takes longer for Energex to restore supply than other comparable distributors.

Overall, Energex's supply reliability performance is worse than the average of the comparable distributors, particularly in regard to unplanned interruptions.

6 REVIEW OF ASSETS

6.1 Scope of Section

Key drivers of operating expenditure and replacement capital expenditure include the number, age and condition of the various elements of the electricity network. This section describes the number, age and type of key equipment items of the network.

6.2 Overview of Electricity Network

The Energex electricity network spans more than 25,000 square kilometres throughout south east Queensland. It is supplied by Powerlink at 17 locations:

- 132 kV: Woolooga;
- 132 / 110 kV: Palmwoods;
- 110 kV: Middle Ridge, Mudgeeraba, South Pine, Molendinar, Murarrie, Rocklea, Swanbank;
- 110 / 33 kV: Tennyson, Abermain, Ashgrove West, Belmont, Loganlea;
- 33 kV: Richlands, Run Corn; and
- 11 kV: Redbank Plains.

In addition, bulk supply substations at Coomera and Postman's Ridge are due to be commissioned during the 2003/2004 period.

Electricity is transmitted from the bulk supply substations to zone substations via 132 kV, 110 kV and 33 kV sub-transmission networks. The zone substations, 199 in total, supply three phase 11 kV radial distribution networks. Both the sub-transmission and distribution networks incorporate both overhead and underground conductors. The electricity is transformed to 415 V three phase and 240 V single phase at distribution substations, for customer supply.

6.3 Description of Assets

This section contains a summary of the electricity network assets.

6.3.1 Meters

6.3.1.1 Quantities

Table 6-1 below details the approximate population of Energex's LV and High Voltage ("HV") meter assets.

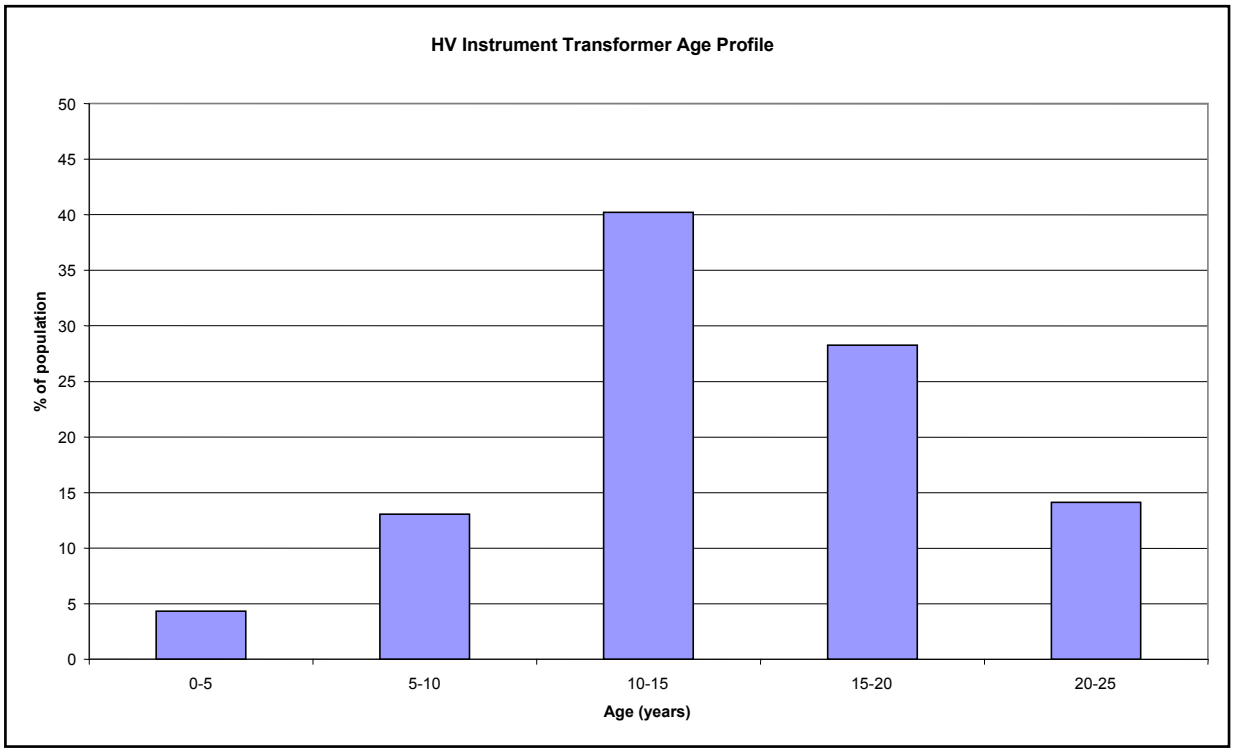
Table 6-1: Meter Type and Quantity

Asset	Qty.
1 ph. LV meters	1,842,854
2 ph. LV meters	51,865
3 ph. LV meters	93,602
3 ph. bi-rate LV meters	4,617
LV Current Transformers ("CT")	12,971
Instrument transformers 33 kV	648
Instrument transformers >33 kV	391

6.3.1.2 Age profile

The age profile of the HV instrument transformers is given in Figure 6-1. Energex has been unable to provide age profile information for LV meters. Given the stability of Energex's network boundaries, it is unusual that Energex does not have this information available. LV meter aging is a problem currently faced by many Australian utilities. Therefore, given the quantity of LV meters and their importance to customer relations, the Consultant recommends that Energex address this problem over the next regulatory period. In cases where records have not been kept, accurate age estimation techniques are available.

Figure 6-1: HV Instrument Transformer Age Profile



6.3.1.3 Condition

No information has been made available regarding the current condition of Energex's meters. Again, given the importance and size of this asset group, it would be expected that Energex would have some knowledge of those instruments which have recurring problems. A review of customer feedback and maintenance records would provide this type of information

6.3.2 Poles

6.3.2.1 Quantities

Energex's pole population is predominately wooden as shown in Table 6-2.

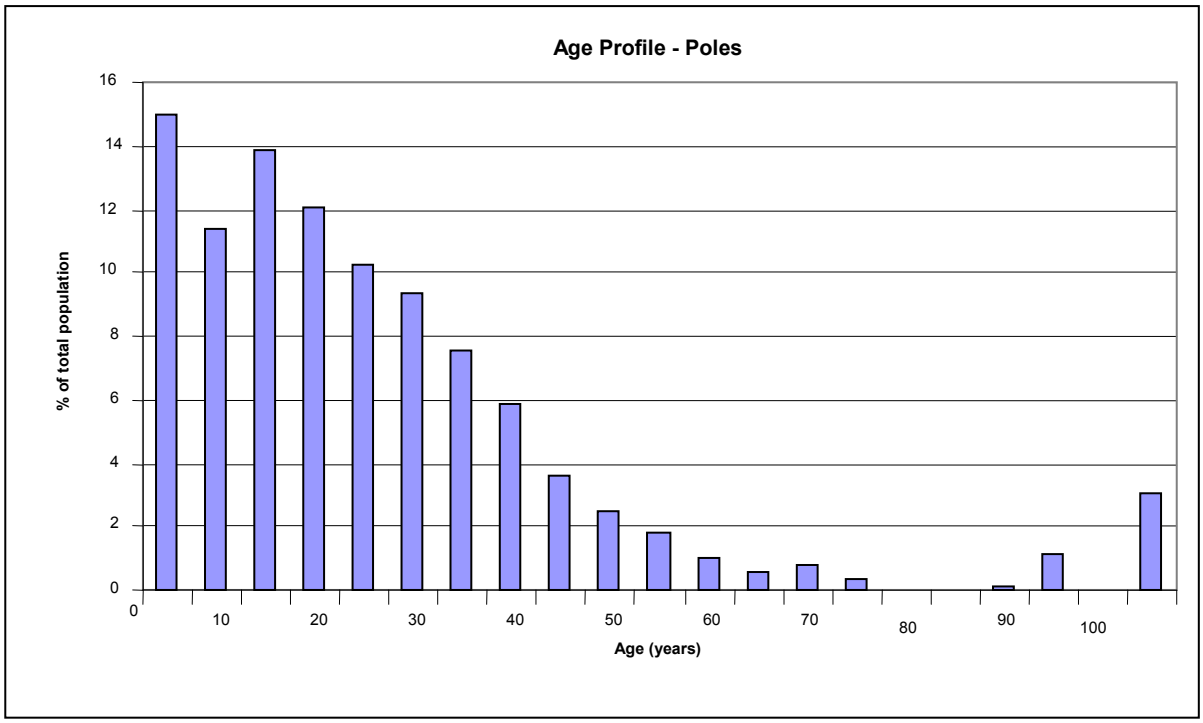
Table 6-2: Pole Type and Quantity

Asset	Qty.
Wood poles	428,699
Concrete poles	8,179
Aluminium poles	742
Steel poles	101,081
Total	538,701

6.3.2.2 Age Profiles

The age profile for poles is shown in the following figure:

Figure 6-2: Pole Age Profile



6.3.2.3 Condition

With current wooden pole management and maintenance procedures, Energex has consistently achieved a very low in-service pole failure rate (less then 0.004% per annum) over the current regulatory period.

From July 2000 to now, Energex has recorded a 4.6% p.a. condemnation rate in poles which are inspected. This is towards the high end of general industry performance but not excessive given the current age profile. Of these, approximately 18% were replaced and 82% were nailed. Energex has indicated that the condemnation rate is expected to remain at around 5% p.a. over the next regulatory period. The Consultant feels that increasing the proportion of poles which are chemically treated would reduce the rate of pole condemnation, but that this would be more than offset by the impact of the increasing age of poles. The Consultant considers that the condemnation rate is likely to increase to about 8% by 2009/10.

6.3.3 Pole Top Structures

6.3.3.1 Quantities

No information has been made available for this asset category. However, it can be assumed that the number of pole top structures will correlate with the number of poles.

6.3.3.2 Age profile

No age profile information has been made available for pole top structures. Again this information should be closely related to the age profile of the pole assets.

6.3.3.3 Condition

During routine inspections, it has been found that many LV and HV pole top cross-arms have deteriorated. As a policy these are being removed and LV Aerial bundled conductor is being installed as the preferred alternative. The preferred alternative for HV crossarms is a wider construction made of galvanised steel.

6.3.4 Line Conductors and Connectors

6.3.4.1 Quantities

Approximately 43,610 km of cable, both underground and overhead, is used to supply the Energex distribution network as detailed in Table 6-3.

Table 6-3: Line Conductor Type and Quantity

Asset	Qty. (km)
Overhead sub-transmission	2,708
Underground sub-transmission	1,193
Overhead distribution	15,853
Underground distribution	2,752
Overhead LV distribution	14,537
Underground LV distribution	6,567

6.3.4.2 Age profile

The age profiles of the Energex overhead ("OH") and UG sub-transmission feeders are given in Figure 6-3 and Figure 6-4 respectively. No information is available on the age profile of the Energex distribution cables. Given the importance of this asset group, it is unusual that Energex does not have this information recorded. The Consultant recommends that this problem be addressed over the next regulatory period.

Figure 6-3: OH Sub-transmission Age Profile

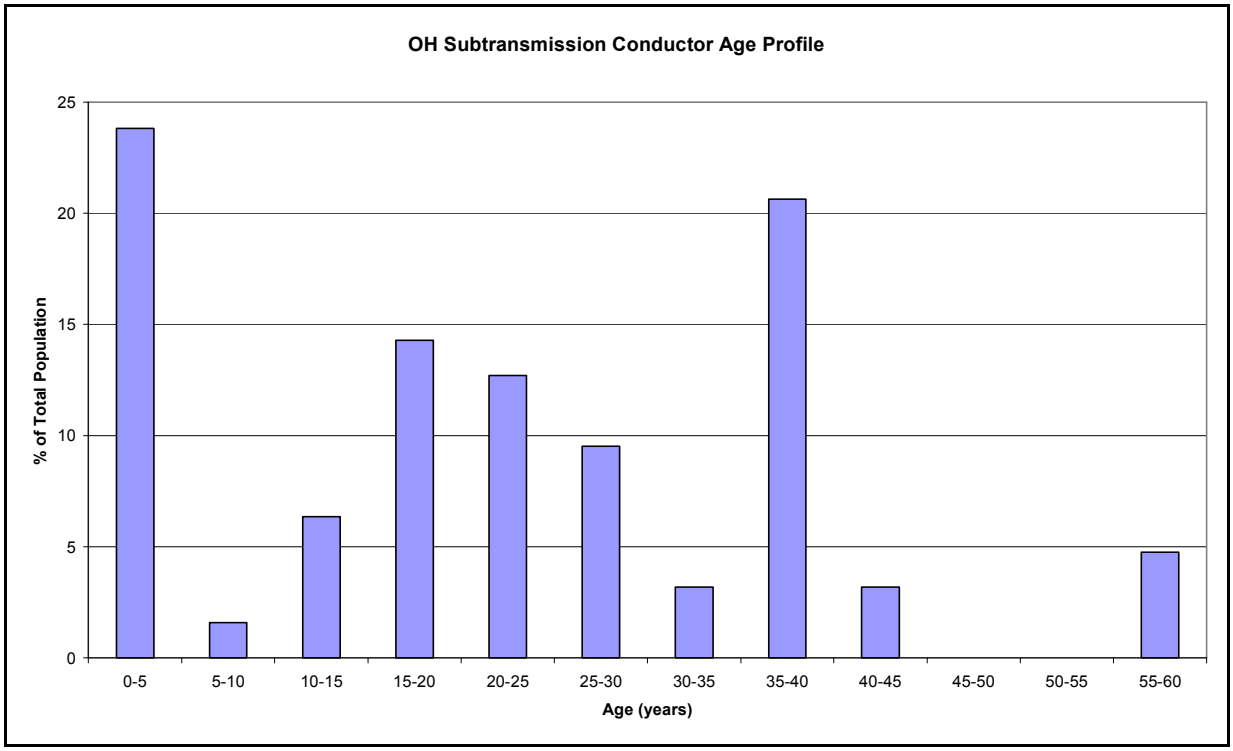
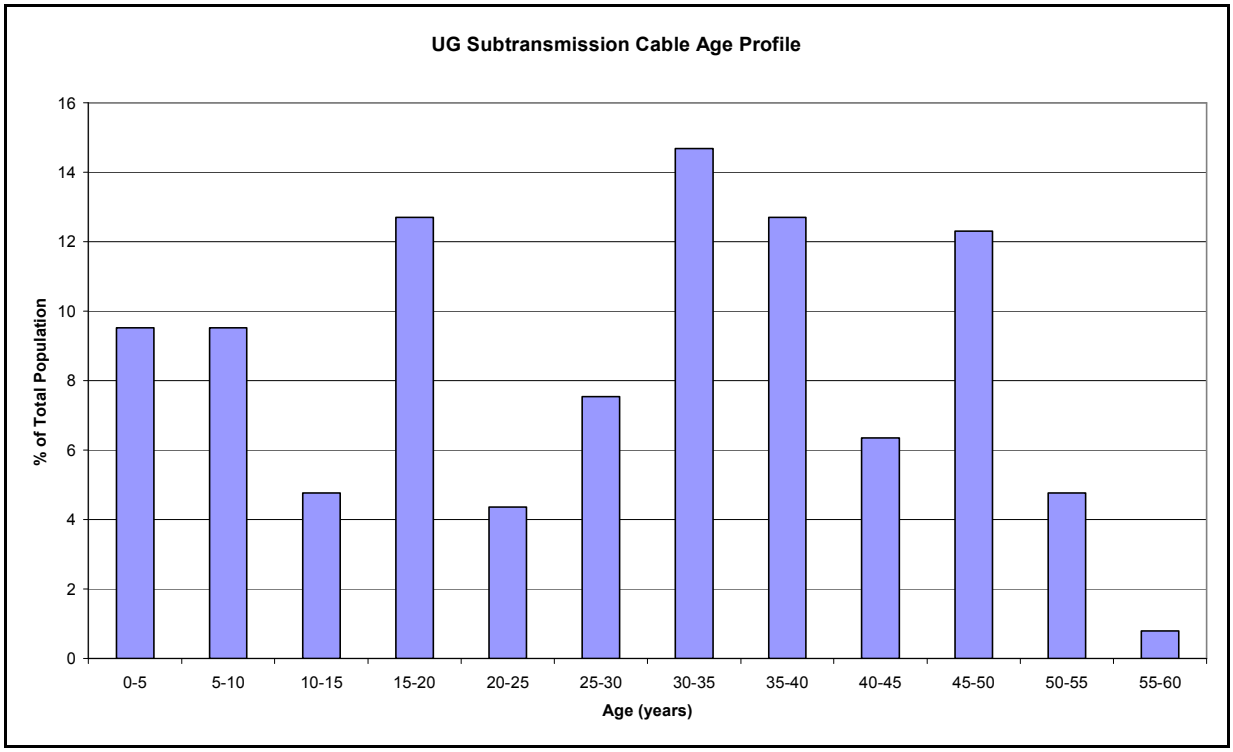


Figure 6-4: UG Sub-transmission Age Profile



6.3.4.3 Condition

A RCM study of the high number of 'wires down' that had been occurring over the last five years, found a number of instances of split clamps, rusted steel conductor, conductor damage due to lightning, undersize conductor in risk areas (for example schools, road crossings and shopping centres) and vegetation encroaching into clearance space. Inspection practices are being improved to identify these defects.

Following a number of electric shocks to Energex customers, an RCM study of LV services was undertaken to determine the cause. This revealed that in the period October 2002 to October 2003, 407 shocks were experienced by customers, 30% of which occurred near coastal areas. The following problems were recorded:

- Faulty neutral screens on concentric cables;
- Poor connection to the neutral; and
- The clearance to some aerial cables was insufficient.

An inspection and replacement program of service cables and connections has commenced, giving priority to coastal and waterway areas, and will continue into the future.

Defects associated with 33 kV underground gas pressure cables have been the cause of increased costs and poor reliability of the feeders concerned. These defects are due to a reduction in dielectric strength and gas leakage from 50% of feeder cables of this type. A program is in place to replace all of these cables in the next 18 months.

Aluminium sheath corrosion in oil and gas filled cable is also of concern. This is because the rubber over the cable sheath has been known to fail allowing moisture to penetrate and attack the aluminium. It is not possible to determine where this is occurring. These cables are being closely monitored to assist with any replacement strategy.

HV Cross-linked Polyethylene ("XLPE") cables have been found with signs of 'water trees' within the sheaths and there is concern that this may be due to poor workmanship. This problem is being investigated in conjunction with Queensland University and Ergon Energy.

All 110 & 33 kV feeders over 1.5km length have fibre optic cables attached to provide Distributed Temperature Sensing ("DTS") to allow future monitoring of cable operating temperatures. The fibre optic cable installed provides for four fibres for DTS and twelve fibres for Communications.

6.3.5 Distribution Network

6.3.5.1 Quantities

This section covers distribution network assets including distribution transformers, line enclosed HV switchgear, line reactors, LV services, street lighting and other ancillary equipment as summarised in Table 6-4.

Table 6-4: Distribution Line Equipment Type and Quantity

Asset	Qty.
1 ph. pole mount transformers	5,547
3 ph. pole mount transformers	23,707
Kiosk & pad mount transformers	6,497
Ground transformers	1,813
Total Distribution Transformers	**37,564**
C&I substation circuit breakers	960
Ring Main Units ("RMU")	7063
Air Break Switches ("ABS")	14,684
Automatic reclosers	376
Sectionalises	66
Regulators	142
3 ph. LV services	563,292
1 ph. LV services	128,855
Street lights	262,658
Cable boxes	1,781

6.3.5.2 Age profile

The age profile for distribution transformers, regulators, reclosers and sectionalises and ABS's are given in Figure 6-5, Figure 6-6 and Figure 6-7 respectively.

Figure 6-5: Distribution Transformer Age Profile

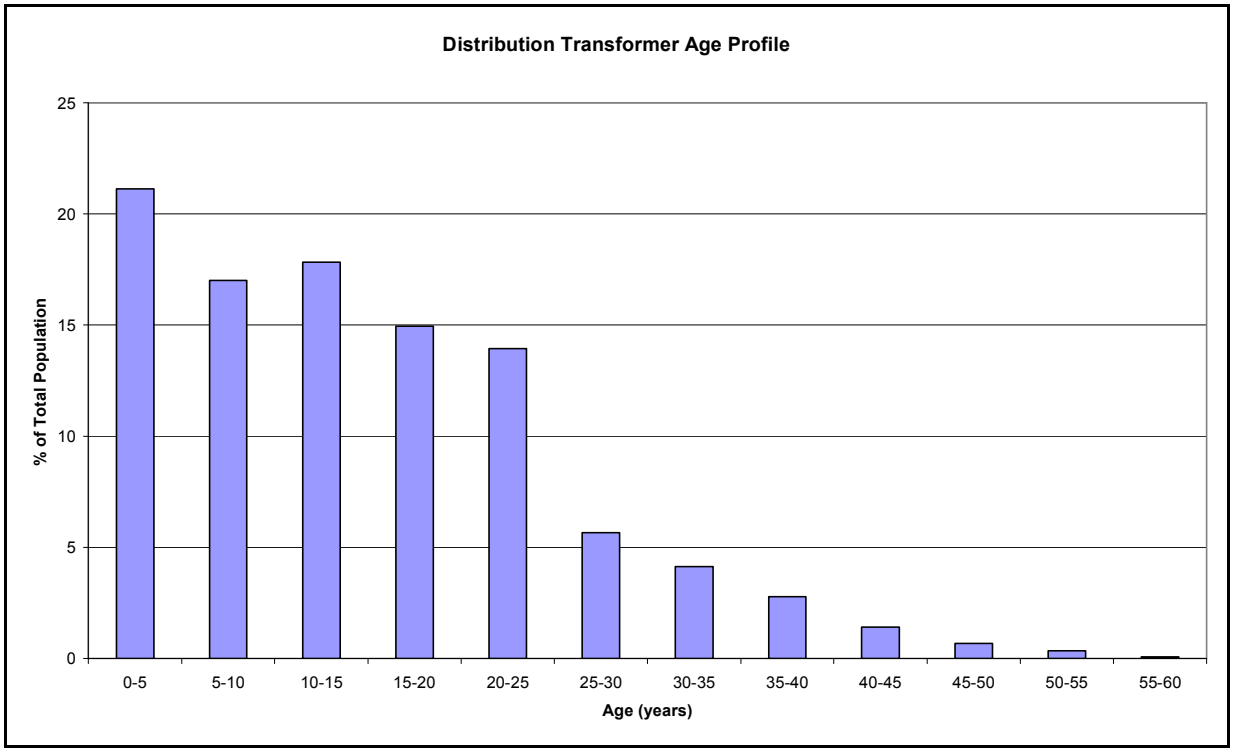


Figure 6-6: Regulator, Recloser and Sectionaliser Age Profile

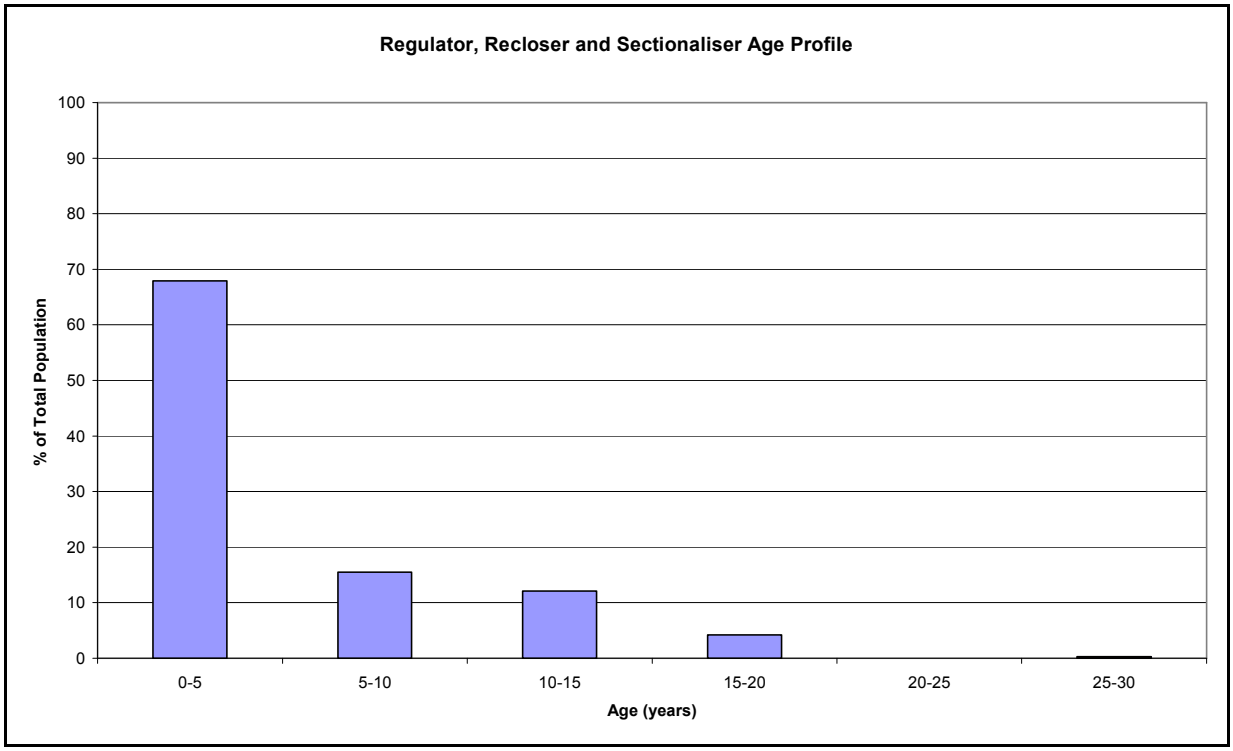
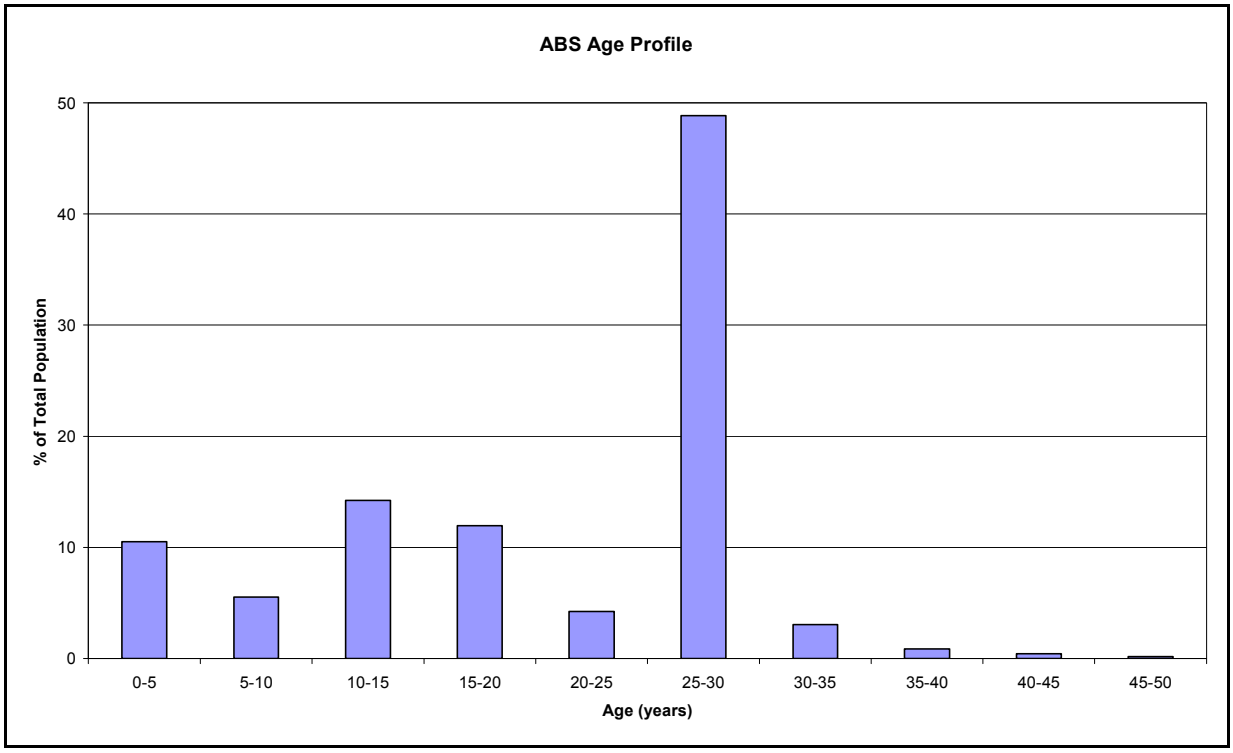


Figure 6-7: ABS Age Profile



6.3.5.3 Condition

No specific points have been made about the condition of the distribution transformers. At present Dissolved Gas Analysis ("DGA") condition monitoring is only performed on commercial and industrial distribution transformers under special circumstances.

A number of Krone RMU's have failed recently. While there have been no catastrophic failures, there has been a significant level of partial discharge. Consequently, live work bans on these items are in place. A program is in place to replace all of these over the next five years.

Energex has a number of Line Fault Indicators ("LFI)" installed predominantly on rural feeders. The performance of these has been less than desirable. A new type of LFI, manufactured by Merlin Gerin, has recently been evaluated involving a trial installation of 50 sets. Arrangements are in place to purchase and install a further 1000 sets of these new LFI's in rural locations by June/July 2004.

6.3.6 Zone Substations Primary Equipment

6.3.6.1 Quantities

Energex has 199 zone substations ("ZSS") and approximately 450 power transformers and 2,781 Circuit Breakers ("CBs") as described in Table 6-5.

Table 6-5: Zone Substation Equipment Type and Quantity

Asset	Qty.
Power transformers – 132 / 33 or 11 kV	22
Power transformers – 110 / 33 or 11 kV	62
Power transformers – 33 / 11 kV	366
Total ZSS Transformers	**450**
Circuit breakers – 132 / 110 kV	153
Circuit breakers – 33 kV	924
Circuit breakers – 11 kV	1,690
Circuit breakers – 6.6 kV, 5.5 kV, 3.3 kV	14
Total ZSS Circuit Breakers	**2,781**
Regulators – 33 kV	13
Capacitor banks – 33 kV	25
Capacitor banks – 11 kV	210

6.3.6.2 Age Profiles

The current age profiles of the Energex ZSS power transformers, CBs and capacitor banks are given in Figure 6-8, Figure 6-9 and Figure 6-10 respectively.

Figure 6-8: ZSS Power Transformer Age Profile

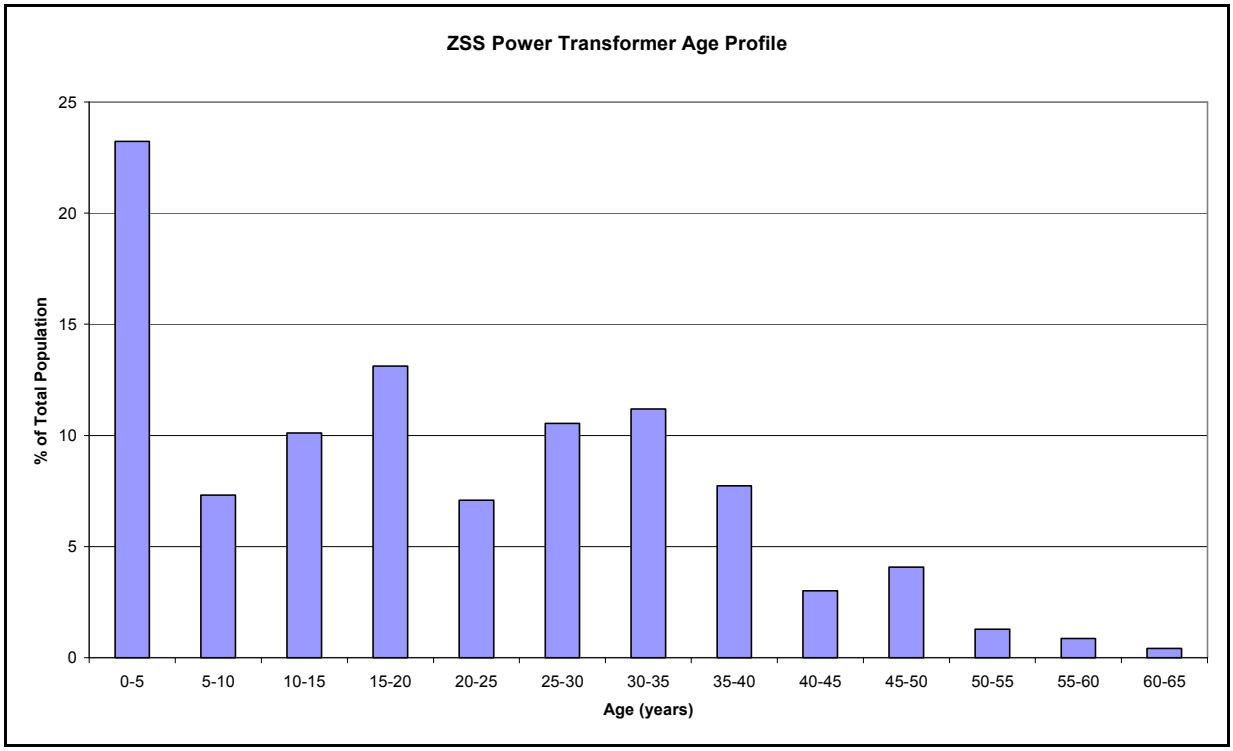


Figure 6-9: ZSS CB Age Profile

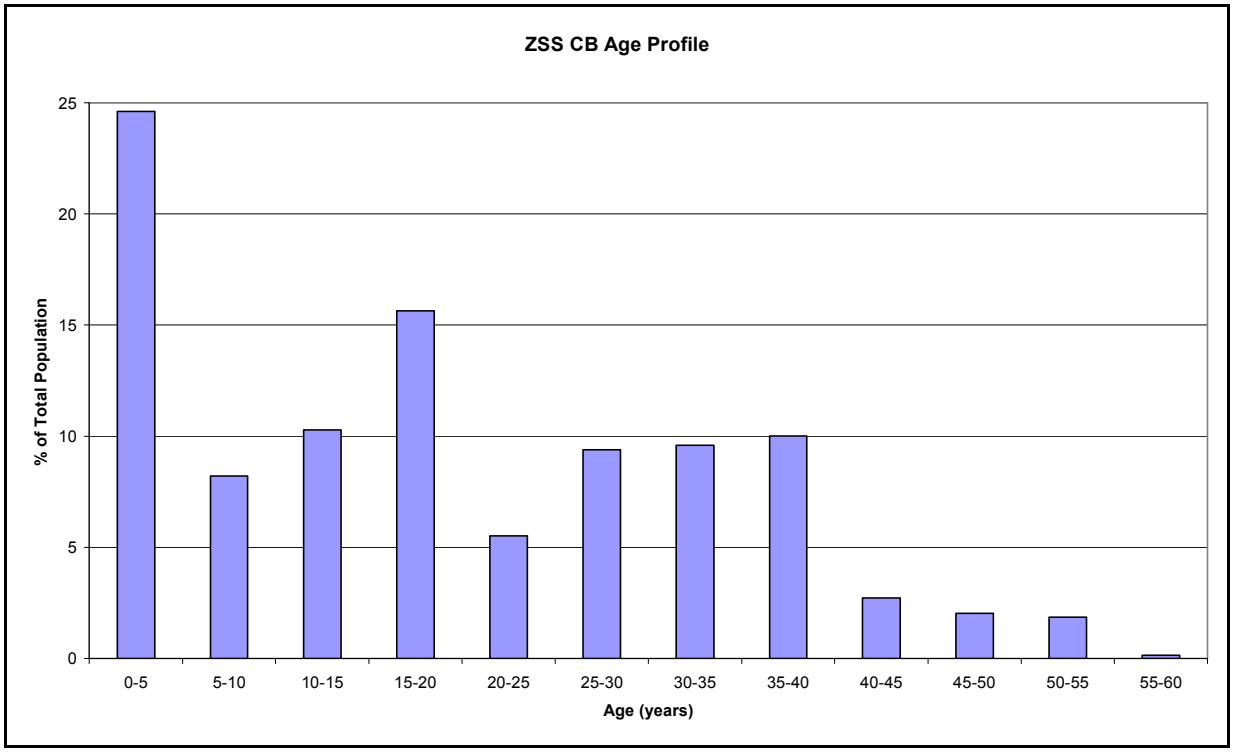
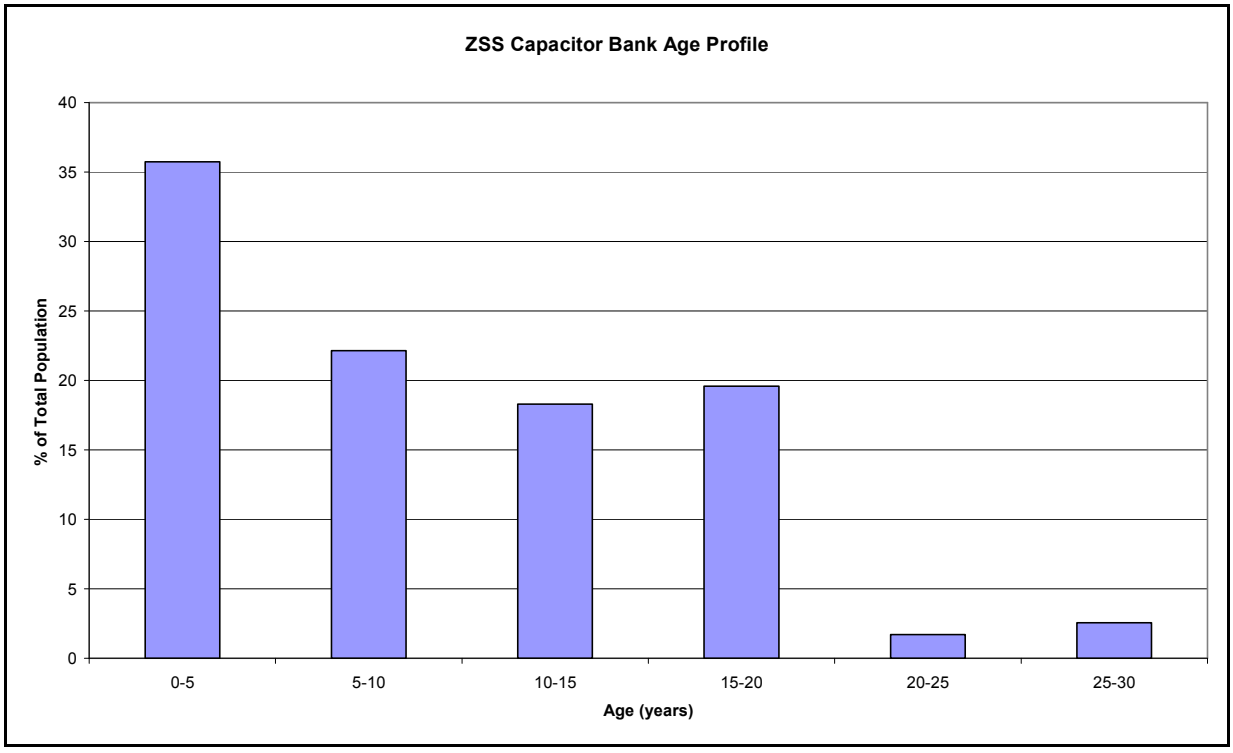


Figure 6-10: ZSS Capacitor Bank Age Profile



6.3.6.3 Condition

The condition of the zone substation power transformers is monitored using DGA. A number of transformers are reaching their 40 year life expectancy and signs of ageing are starting to appear. One particular problem which has been noted is that the cast epoxy barrier on AEI SDS28 on-load tapchanger ("OLTCs") is under mechanical stress. There are 11 of these units in total. To fix this problem, the entire tapchanging unit would need to be replaced as it is not possible to just replace this barrier. The expected cost of an OLTC replacement program is in the order of $100,000. Given that OLTC failures do not present a safety hazard and these transformers are reaching the end of their expected life, Energex has decided not to proceed with this program. This policy will be reviewed if the rate of failure increases significantly in the near future.

A number of technical issues with the zone substation CBs have been highlighted as described below.

- Following the explosive failure of a bushing on a Reyrolle 11 kV Type LMT CB in NSW, a program of inspection and testing of bushings has been carried out. This has resulted in changeover of bushings on a number of CBs. Eventually, it is planned that these units will be replace with vacuum CBs with electrical mechanisms. However, a definite time for this replacement program has not yet been proposed;
- Westinghouse Rosbery Type 345GC 33 kV CB bushings are subject to compound leaks and require refurbishment approximately every 15 yrs; and
- Following concerns regarding the dielectric strength of 110 kV ASEA CB bushings, a program of testing has been completed to determine their serviceability.

A manufacturing defect has been identified in Southwell Switchgear busbars. Southwell Switchgear is located in ten substations. The defect does not affect switching mechanisms in these items, so there is a program in place to replace the busbars. There is only one substation where the replacement is still to be completed.

6.3.7 Secondary and Auxiliary Equipment

6.3.7.1 Quantities

The approximate quantities for ZSS secondary equipment are given in Table 6-6.

Table 6-6: Zone Substation Secondary Equipment Type and Quantity

Asset	Qty.
Audio frequency load control ("AFLC") receivers	681,008
Pilot cable	5,166,143 m
Optic fibres	522,443 m

6.3.7.2 Age profile

No age profile information is available for ZSS secondary equipment.

6.3.7.3 Condition

Programs are in place to replace electromechanical and electronic relays that are causing protection malfunctions under fault conditions and/or high maintenance costs.

6.4 Summary of Overall Asset Condition

Generally the age profile of assets is not considered to be greatly different to other utilities and the overall condition of assets is considered to be basically good with some exceptions as noted in the preceding discussion.

Where issues have been identified, appropriate action is being taken, such as,

- Practices for treatment of poles are appropriate to arrest the high rate of condemned poles,
- Unreliable Krone RMU's and 33 kV gas filled cables are programmed for replacement,
- Industry maintenance practices have been adopted for monitoring and refurbishment of aging zone substation transformers.

There are a number of asset categories where age profile data is not available. The Consultant recommends that Energex address this problem over the next regulatory period, particularly in relation to LV meters and distribution cables, given the importance and size of these asset categories. In cases where records have not been kept, accurate age estimation techniques are available. While Energex has stated that these techniques are being applied for a number of asset categories, the Consultant has not seen evidence of this.

Finally it is noted that while Energex's assets are currently in good condition relative to other DNSPs, the Consultant believes that Energex has not committed enough resources to inspection and maintenance of the existing assets over the current regulatory period. Furthermore, Energex has not provided sufficient additional assets or upgraded the existing assets to meet load growth. If Energex does not begin to address these issues over the next regulatory period, it is likely that the existing assets will deteriorate to an unacceptable condition.

7 OVERHEAD AND CORPORATE SUPPORT COSTS

Energex's total indirect expenditure is derived by summating the support costs associated with the Holding Company, the Shared Services and the Regulated Groups. These cover the following range of areas:

- Holding Company:
    - Office of the CEO;
    - Legal and corporate affairs;
    - Corporate Development; and
    - Planning and Investments.
- Shared Services:
    - Management Office;
    - IT&T;
    - Human Resources;
    - Finance;
    - Procurement and Services; and
    - Property.
- Regulated Groups:
    - Asset Management;
    - Asset Services Management;
    - Asset Services Business Support;
    - Transmission Services;
    - Customer Connections and Gas Service;
    - Network Distribution Services; and
    - Network.

The support costs for Electricity are recorded separately from Gas and are categorised as either labour-related or contractor-related support costs. Energex advise that the labour-related support costs are allocated based on an hourly rate ($58.08/hour) and the contract-related support costs are allocated based on a percentage of total direct costs (54%). This results in an overall overhead rate of around 30% of total OPEX and CAPEX costs. In the Consultant's experience, Energex's overhead rate is in the mid range for electricity distributors and appears to be reasonable on that basis.

The QCA commissioned Sinclair Knight Mertz ("SKM") to develop a set of unit rates, including an approach to the allocation of overheads. SKM have proposed the allocation of overheads against labour only, based on market rates. Energex advise that, based on the detailed construction unit rates and examples provided to them by SKM, the overhead rates applied by Energex in their expenditure forecasts are equivalent to the rates using the SKM methodology. Although noting that the overhead rates now quoted are significantly different to those provided by Energex early in the review process, the Consultant accepts that the overheads applied by Energex are substantially the same as those used by SKM in the asset valuation exercise (although calculated on a different basis).

8 OPERATIONAL REVIEW

8.1 Purpose and Scope of Section

This section considers the functions and costs of maintenance and operations, the efficiency of these functions against industry standards, reasons for cost differentials and contractual arrangements. Based on the foregoing, a reduced expenditure on OPEX programs is recommended by the Consultant. These recommendations have been made in the context of the asset review which was presented in the previous section.

8.2 Review of Inspection and Preventative Maintenance Practices

Energex's current maintenance practices are described in the SAMP and MAMP documents. A summary of inspection and maintenance intervals is given in Appendix 14.4. Specific items will be described in greater detail in the following sections.

The Consultant is of the opinion that while Energex's documented maintenance practices and policies are generally sound and in accordance with current industry standards, the full potential of these policies has not yet been fully realised due to insufficient commitment of resources. As a consequence of this underspending in OPEX, the Energex network is in danger of deteriorating to an unacceptable level.

8.2.1 Poles

Energex participates in the ESAA Power Poles Committee and is guided by them in regard to maintenance practices.

The six sigma pole inspection program has been introduced for poles in risk areas, such as school crossings and major road intersections. These poles are inspected, assessed and if necessary, load bend test practices are adopted.

The in-service pole failure rate has a high profile within Energex. Specific procedures and investigation practices are used when this type of failure occurs. The in-service pole failure rate over recent years has been relatively low because of improved pole management and maintenance practices. A minimum three year rolling average reliability against pole failure of 99.99% per annum has been achieved. Practices for inspection of poles have been designed around ensuring that failure rates for poles are no less than 99.9999% in high risk areas. It is noted that Queensland legislation requires that it be no less than 99.99%.

Wooden poles are inspected on a cycle of five years. A below ground inspection, involving drilling or audible inspection, is made after the first ten years of life. The maintenance practices used on wooden poles are audited externally and an inspection failure rate of 0.004% per annum has been achieved.

If an internal or external fungal attack or termite infestation is identified during the inspection then an assessment of the mechanical strength is required. Chemical treatment using Polesaver rods drilled and plugged into the pole may be applied in some cases. In rural sites, Polesaver rods are always inserted into the holes drilled for testing.

The chemical treatment of poles commenced in the 1970's using an application of Creosote with about 3% Aldrin around the base of the pole. Dursban Micro-Lo was used for termite treatment up to and including 2000. Currently Energex uses Biflex for termite treatment, Polesaver Rods for internal rot treatment and Bioguard Bandages for external rod treatment. Energex also utilises Vacuum Pressure Impregnated hardwood poles treated with copper, chromium and arsenic ("CCA"). These are supplied according to a Queensland Technical Specification - TS07-01-01. From July 2000 to present, 57.7% of wooden poles inspected have received some form of chemical treatment.

Staking or nailing of poles may be used to strengthen the pole and extend its life. Also, rebutting the pole using a concrete extension and a sleeve can be applied in some situations, particularly if it is necessary to maintain supply during the changeover. It is noted that in the last three years 18% of poles condemned have been replaced and 82% have been nailed.

Fire ants are a significant safety hazard for any pole or underground work and specialised training regarding treatment and action is mandatory for all appropriate work parties.

8.2.2 Distribution Network Equipment

Energex is in the process of implementing a single pass approach to distribution network asset inspection which is due to commence in July 2004. This single pass inspection encompasses all distribution network assets including poles, pole mounted equipment, distribution transformers, switchgear, conductors, cables and LV service pillars. Pole inspection contractors perform the initial visual inspection and condition assessment of the distribution equipment. Energex asset inspectors validate items identified by the contractors; scope and package rectification works and perform Level 2 inspections (i.e. inspections which require an electrical worker). This program will have a five year full inspection cycle as well as a two and a half year interim inspection cycle.

Helicopter and car patrols will also be used, in rural and urban areas respectively, for an annual pre-storm check of assets. To date, the practice of patrolling transmission and distribution lines by helicopter has been adopted for approximately 36% of 33 and 11 kV lines and 25% of 132 and 110 kV lines.

Construction methods have been introduced to minimise the risk of flashover due to wildlife and other external factors. These include covered conductor systems, and the use of HV and LV spacers to reduce clashing and insulation of bridges on poles.

Thermo-scanning of overhead assets is seen as a worthwhile condition monitoring technique for improving reliability. A trial of improved techniques on the overhead network is being investigated.

8.2.3 Underground Sub-transmission Cables

Given that approximately 23% of the Energex asset base is underground, mainly in the major city areas, an emphasis is placed on the resources and systems required for their maintenance.

Energex carries out patrols of underground sub-transmission cable routes at intervals ranging between monthly and yearly depending on criticality and cable type. In addition, Energex has implemented a range of condition monitoring techniques for these cables including Residual Gas Pressure and DGA, monitoring fluid pressure and consumption, monitoring outer sheath resistance and paper sampling.

8.2.4 Zone Substations

These assets are inspected, tested and maintained according to the procedures described in the SAMP.

Thermo-scanning of substation equipment is seen as a worthwhile condition monitoring technique for improving reliability. A trial of improved techniques within substations is being investigated.

8.2.5 Vegetation Management

The Energex network is located in a subtropical area with ideal growing conditions for vegetation. 70% of this area is urban and 30% in the rural hinterland. The area is subject to extreme storm conditions in the summer months. Because of the humid conditions, there is no special legislation for bushfire mitigation, but special inspection and management programs have been prepared for the period before the summer months to prevent unwanted loss of supply and damage to assets.

Vegetation is managed by three approaches:

- Planned tree trimming. The objective of this program is to maintain clearance for a period of 12 months by trimming of trees;
- Planned vegetation management. This provides long term solutions for all overhead circuits, such as, trimming, removal or replacement of vegetation, rerouting, insulating or undergrounding of lines and is included in a two and a half year cycle performed by contractors; and
- Unplanned Vegetation Management. This may be initiated by customer request, protection operation or inspection patrol.

A series of profiles has been developed for different line voltages which detail the clearance zones, risk areas and low growth zones around structures and conductors. For some critical lines, clearing is being extended beyond base level profiles to improve reliability.

By legislation, Energex is responsible for the clearance of all vegetation from lines owned by Energex, including lines on private property. This does not provide a natural incentive for local government or the pubic to plant appropriate trees or to properly maintain trees so that they do not interfere with the overhead network. Consequently, an education program, 'Treesafe', has been devised for Councils and the public. This program has been very successful in achieving co-operation with the management of trees encroaching into the clearance zone.

The severe storm season over the summer months has lead to the development of a program of annual patrols. Cars are used for patrolling urban areas and helicopters are used for patrolling rural areas.

In addition to the routine programs for vegetation management, additional vegetation improvement works are performed on a project basis. These are designed to improve clearances in heavily vegetated areas in the hinterland areas, including, tree removal, profile widening and reducing the number of overhanging trees.

Energex also conducts a program to manage spot vegetation problems that are identified by the public or by staff during normal operations or maintenance. Energex is committed to rectifying customer issues within a period of 20 days.

8.2.6 Other Maintenance Practices

Reliability Centred Maintenance

Energex has adopted RCM in the development of its maintenance policies. The effective use of RCM allows maintenance policy to be determined on a logical and cost-effective basis, and includes consideration of important safety and environmental issues. By optimising the ratio of corrective to preventative maintenance costs, maximum return can be achieved. RCM also focuses on the outcomes of maintenance in terms of reliability and business performance.

Enterprise Bargaining Agreement

A number of achievements have been made to date through the EBAs including:

- Ten and eight day fortnights;
- Spread of hours (from 6am to 6pm) and flexibility of lunch breaks;
- 12 hour working day;
- No demarcation;
- Reduced crew sizes (from three or four man crews to two man crews);
- Multi-skilling;
- Reduced overtime (although overtime is currently being used to clear the backlog of maintenance work);
- Annual salaries for key staff;
- Rapid adoption of technical advances; and
- Starting work on job rather than at depot.

Areas which are being investigated for future EBAs include:

- Increasing spread of hours (from 6am to 8pm);
- Introducing a four day (Monday to Thursday) / three day (Friday to Sunday) working week shift roster; and
- Single person switching crew for switching on overheads and in control boxes.

Multi-skilling

Provisions in the current award allow for employees to be multi-skilled and a significant number of employees hold dual trade qualifications. This allows the flexibility of working under more than one discipline at any one time and assists in alleviating work type to discipline type mismatch. The systems based (single pass) approach to maintenance currently being introduced will require further multi-skilling in the areas of inspection and maintenance scheduling.

Live Line Work

Live line work for maintenance of lines is commonly used and 140 people are trained to work on equipment at voltages from 11 kV to 132 kV. There is a high level of willingness to perform this type of work in Transmission and Distribution networks. This type of work would account for 85% of the work that the trained staff performs.

New legislation has placed some restriction on this activity because of the fatalities that have occurred. Because of the value of improved reliability of supply, it is intended to continue to expand live line work, ensuring that appropriate safety procedures are applied.

Spare Equipment

Energex holds stocks of materials and plant that may be required for emergency replacement and a list of strategic spares has been created. The majority of the catalogued items are held at the Central Warehouse facility in Banyo and access to these items is available 24 hours a day / 7 days a week ("24/7").

Energex has negotiated "consignment" or "vender held" arrangements for some items (for example distribution transformers and underground cables). Access to these items is also available 24/7.

Strategic spare power transformers are held at the Ergon Energy's Northgate workshop facility. This arrangement with Ergon Energy also includes periodic maintenance of the units.

Energex does not have a periodic test/inspection program for general network materials.

8.2.7 Assessment of Maintenance Practices

Energex has been proactive in establishing practices for maintenance that is consistent with industry practice and which are appropriate to local conditions:

- Although chemical treatment of poles is well advanced, the condemnation rates have not achieved the same low figures as southern states. This can be explained by the local environmental conditions and the termite issue;
- The single pass approach to distribution network inspection has been the practice in the industry for some time and with this introduction improved efficiencies can be expected;
- The introduction of more frequent inspection cycles and improvement in construction methods for overhead lines, while increasing the cost, will have a positive effect on the reliability;
- The variety of types of cables and the developing issues generally has created the need to establish a knowledge base to maintain them;
- Zone substation maintenance practices are consistent with other utilities but it is felt that reliability could be improved by adjustment to some asset class practices, such as, transformer tapchangers, outdoor switches and protection schemes. There could be more of a move to condition monitoring of electrical performance and less emphasis on appearance;
- The approach adopted for vegetation management, although different to utilities in other states, is appropriate to the environment and weather conditions that exist in Queensland;
- Reliability Centred Maintenance has the potential to be used more extensively to achieve improved reliability and efficiencies;
- It is considered that emphasis could be placed on obtaining the full benefit of the conditions of employment that have been established through EBA's; and
- Live line work is well established and has achieved improved efficiencies and reliability.

It is noted that while these improved practices were implemented in the current regulatory period, their full potential has not been realised as yet. The Consultant believes that the previous implementation of maintenance policy and procedures has been inadequate, resulting in a degree of underspending in OPEX.

8.3 Review of Operating Practices

Energex has two primary standards for operating the electrical network, namely:

- High Voltage Isolation and Access Procedures ("HVIA"); and
- Operating Practices Manual ("OPM").

These standards form part of Energex's quality system, and as such are regularly audited. They are also regularly reviewed to ensure compliance with national standards.

Fault Evaluation staff, Loss of Supply staff and Network Operations staff are all co-located on the same floor at Victoria Park Control Centre.

8.3.1 Control Centre

Energex's main control centre at Victoria Park is a 24/7 operation. A second control centre is located at Nambour and this is control centre operates on a 16 hour / 7 days a week operation.

A SCADA based DMS is used to monitor and manage Energex's distribution network. The master station for the DMS is located at the Victoria Park Control Centre. It receives and processes information from field based RTU's and allows operators to monitor and manipulate certain devices within the network. To date, all network diagrams for 33 kV and above are electronically maintained in the DMS. While the DMS has some 11 kV coverage, outage co-ordination for the 11 kV network is still performed manually.

Currently, Energex has approximately 300 automated reclosers, a large number of which are remotely controlled and located on both urban and rural feeders. As part of reliability improvement initiatives, Energex has initiated a number of projects to increase the number of remote controlled reclosers, particularly in urban and urban/rural fringe areas.

Energex also has a number of LFI and arrangements have been made to install a further 1000 LFIs in rural networks by June/July 2004. It is expected that the LFI units will minimise restoration times and therefore improve network reliability.

Energex also has approximately 120 feeder management relays in a number of its substations, many of which have a remote dial up capability to provide information on fault location and fault type to minimise restoration times. There is a current project to retrofit a further 46 of these relays into existing substations.

8.3.2 Emergency Procedures and Load Management

Energex has established a documented emergency response for events that are beyond the capacity of the normal shift staff. Additional switching coordination resources are obtained from the Network Access Teams. Energex has an extensive training scheme to ensure that these staff have the requisite skills.

During periods of emergency activity or severe weather, additional customer service representatives, evaluators, controllers, coordinators, support staff and field crews are called in to assist with timely restoration of supply. A standby roster has been developed for the summer storm season from October to March each year.

8.3.3 Fault Call Centre

Energex has an integrated customer call management and fault response system. A direct contact line is available and is monitored 24/7. Customer call details are entered into the Customer Management System ("CMS"). If the customer is calling from an area where there is a known problem, an Interactive Voice Response ("IVR") system advises the customer of known outage details.

The CMS is automatically linked to an Service Call Management ("SCM") system which is part of the DMS. Evaluation Officers receive a service request which is evaluated using network connectivity and outage information and matched against other related customer calls. The information is then processed, given a distribution network transformer and feeder attachment point, and loaded into the SCM system. The service request is then either converted into a service order for dispatch to a repair crew or linked to an existing service order.

Energex uses a Computer Aided Schedule and Dispatch System ("CASAD") for dispatch to field crews in cases where a single customer has lost supply. If an outage affects more than one customer, the repair crews are notified via a TMR network, and the job is controlled via the Victoria Park Control Centre.

8.3.4 Complaint Management

The Energex complaint management processes have been developed in line with the requirements of Australian Standard AS 4269 – Complaints Handling, and are documented in the Energex Corporate Business Managements System.

Customers can register feedback directly to Energex (for example by phone, email, letter, internet, fax or in person) or through Government Departments or agencies or Ombudsman schemes.

All complaints are recorded in the FROG system, and are categorised for reporting purposes so that improvement opportunities can be identified. When a record is created, an email is automatically generated and sent to the appropriate Action Officer to ensure the complaint is actioned and the customer is given feedback within an appropriate time frame. Energex has a designated internal complaint management department which ensure this process is followed.

Energex has also established an insurance claims review panel to review decisions made by Energex relating to customer insurance claims.

8.4 Operational Budget

The OPEX estimates for Energex are given in the Energex budget for the next regulatory period. These figures have been constructed using a bottom up approach, that is, the 2004/05 Program of Works has been used to estimate the units of work required for each OPEX activity. Although a number of activities may be bundled as part of a single pass program (for example Line Asset Inspection), the costs are still allocated at the activity level. It is noted that the units of work are typically, although not always, aligned with the level of activity (for example, the number of items inspected). The unit costs are reviewed on an annual basis, in line with efficiency improvements, labour movement (for example, Consumer Price Index ("CPI"), EBA etc.), material movements, and external benchmarking.

Over the six year period 2004/05 to 2009/10, Energex has estimated that the annual OPEX expenditure will increase from $164.6 million (2004/2005) to $247.2 million (2009/2010). This OPEX forecast is charaterised by significant growth in 2003/04 (approximately 20%) as well as 2005/06 (approximately 9%). The Consultant is of the opinion that this step change in OPEX is due to:

- A backlog of inspection work that has arisen due to the occurrence of other priority work and underspending, particularly in the areas of service cable, sub-transmission line and pole top inspections, as well as thermo-scanning and vegetation management;
- The redefining of the inspection and planned maintenance work categories and a consequent increase in the volume of work required; and
- A more comprehensive listing of all categories of work for the 2005-06 period onwards giving a more accurate estimate of work volume.

Based on benchmark estimates, the Consultant is of the opinion the Energex has underspent on OPEX in the order of $140M over the 2001/2002 to 2004/2005 period. As a result, a significant OPEX expenditure is required over the next regulatory period to compensate for this previous underspending. While the majority of this work will be carried out in the early years of the regulatory period, it is reasonable to expect that some catch-up work will flow through to later years at a reduced rate. As such, the estimated OPEX growth falls to around 5% p.a. beyond 2005/06.

The required catch-up in OPEX expenditure tends to cloud an underlying OPEX growth which relates to the increasing size of the Energex network and customer base. This is particularly true during the earlier years of the regulatory period when the catch-up is most intensive. Given that a high growth in demand (approximately 5.9% p.a.) and customer numbers (approximately 2.5% p.a.) is predicted, it is reasonable to expect the OPEX expenditure to increase throughout the regulatory period as a result of this growth, irrespective of catch-up spending. However, the methodology which Energex has applied to forecast this growth requires further consideration, as discussed below.

Energex has used two general escalation factors to forecast the underlying OPEX growth over the next regulatory period in cases where specific escalation factors are not available. The Customer Unit Escalation ("CUE") factor is applied to categories which are most affected by the number of customers, for example Customer service, call centre, meter reading etc. The CUE is based on the total forecast customer growth which Energex originally submitted to the MMA i.e. 2.47%. The CUE is then obtained by applying a factor of 0.8 to the customer growth to give 1.98% p.a. The use of the customer growth figure is appropriate for escalating those categories of OPEX that are customer growth related. However, Energex's use of the 0.8 factor to derive the CUE is arbitrary and has not been substantiated.

The NUE factor is applied to categories associated with network expansion, for example network operations, streetlights, corrective repair etc. The NUE is obtained by applying a factor of 0.8 to the total forecasted growth in the Regulatory Asset Base to give 7.7% p.a.

The Consultant agrees that growth in asset quantities within a category can be considered to increase as a function of either growth in customer numbers or growth in maximum demand. However Energex's NUE escalation factor is considered too optimistic for this purpose. The Consultant has used an alternative approach to escalating the OPEX figures namely:

- Activities concerning assets whose quantities are related to customer numbers are escalated at the expected average customer growth rate over the regulatory period of 2.4% (the Consultant does not consider that a discount should apply). It is noted that this Customer Escalation Factor ("CEF") is equal to the revised customer growth value submitted by Energex to the MMA; and
- Activities concerning assets whose quantities are related to network demand are escalated at 2.5% which is just under half the predicted growth in MD. This alternate factor will be referred to in this report as the Network Escalation Factor ("NEF").

The figures used for the Consultant's escalation factors are based on the Consultant's industry experience and the rationale is explained below.

In the Consultants opinion the OPEX required for categories related to customer numbers, such as meter reading, street lighting, call centre, etc., will grow in direct proportion to the increase in customer numbers. For example, the meter readings unit cost will not decrease as the number of meters increases. Therefore, applying a discount factor to determine the escalation rate would be inappropriate for customer related categories.

New assets added to the network do not need the same level of OPEX as existing assets because:

- New items are designed to be maintenance free or at least require less maintenance than older types especially during the first regulatory period of their life;
- New items tend to be lower cost to maintain where maintenance is required;
- Earlier in their life plant items are generally less heavily utilised and require less monitoring; and
- New assets are less likely to fail when subject to external stresses and influences

These factors work towards requiring a lesser percentage increase in OPEX than the increase in asset quantity. However, new assets will require some inspection, maintenance and repair. A small number of new equipment items may fail early in their life and some will be subject to damage due to external influences. Therefore a certain level of inspection, planned maintenance and repairs will be required. Also new assets will not be skipped in the inspection cycles but inspected along with older assets according to the schedule used.

CAPEX programs for either network augmentation or asset replacement will take older, maintenance intensive equipment from the network thus tending to reduce the OPEX requirement overall. Therefore in escalating OPEX for the effect of increasing quantities, the Consultant's view is that Energex's use of the combined NUE and CUE factors for OPEX escalation gives a result that is too high.

Between 2003/04 and 2004/05 Energex implemented a change in OPEX budget categories, refer to Table 8-2. Energex has been unable to provide mapping between the historical and current categories. Therefore, only high level comparisons can be made between forecast and historical budget data. The Consultant's view is that Energex should have been able to provide this mapping as it would be an essential tool necessary for the effective management of OPEX expenditure through and after the transition.

The Terms of Reference ("TOR") issued by the QCA require the Consultant to provide an opinion on the efficiency of each DNSP's OPEX forecasts. In assessing efficiency, the Consultant has analysed the data provided and has made judgements based on its experience in the industry. Where applicable the Consultant has used the term "reasonable'' in the assessment of OPEX to convey the view that the expenditure is considered to be efficient, within these limitations, that is, available data and time.

Another notable change in Energex budget for the next regulatory period is the move towards a systems based (single pass) approach to distribution network asset inspection and maintenance, which is in line with DNSP industry practice. This strategy relies on equipping asset inspectors with a broad, but tailored, range of competency skills. The expected positive outcomes of the systems based approach include:

- More effective condition assessment;
- More efficient utilisation of resources through the consolidation of asset inspection programs and the bundling of corrective maintenance works; and
- Improved network performance and safety.

Energex's OPEX forecasts are presented in detail in Appendix 14.5, Table 14-2 and compared against the Consultant's OPEX forecasts in Appendix 14.5, Table 14-3. The techniques applied to obtain Consultant's forecasts are discussed for each OPEX category in the following sections. Finally, it is also noted that all the budget figures detailed in Table 8-1 and in the following sections are based on the total cost, i.e. including both direct and indirect costs.

Table 8-1: Basis of Operational Expenditure

		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10
Customers	No. (M)	1.103	1.130	1.159	1.189	1.219	1.246	1.276	1.309	1.340
	% increase		2.49	2.57	2.58	2.45	2.26	2.45	2.60	2.34
Max. Demand	MW		3,366	3,602	3,890	4,162	4,433	4,698	4,957	5,230
	% increase		7.01	8.00	6.99	6.50	6.00	5.50	5.51	7.01

Table 8-2: Energex's Proposed Operational Expenditure

		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Maintenance Budget											
Inspection	$M	2.72	12.80	11.16	12.68	19.45	24.82	26.51	28.52	30.18	129.49
Planned Maintenance	$M	33.65	48.69	18.80	33.57	38.53	43.37	44.91	47.78	50.47	225.06
Corrective Repair	$M			20.74	25.03	26.42	28.46	30.66	33.04	35.59	154.17
Emergency Response / Storms	$M	24.21	5.92	6.82	8.01	9.01	9.57	10.17	10.82	11.52	51.09
Vegetation	$M	21.62	27.11	37.50	46.36	44.52	46.46	46.46	46.46	46.46	230.34
Streetlights	$M	5.13	5.61	4.22	5.31	5.74	6.18	6.66	7.17	7.73	33.48
Customer Service	$M		5.89	9.83	9.04	9.18	9.45	9.74	10.04	10.35	48.75
Total Maintenance	**$M**	**87.34**	**106.02**	**109.07**	**140.00**	**152.84**	**168.31**	**175.11**	**183.82**	**192.29**	**872.38**
Operating Budget											
Network Operations	$M	51.09	18.58	15.33	11.22	12.15	13.09	14.10	15.19	16.37	70.91
Levies	$M					4.90	5.00	5.10	5.20	5.30	25.49
Call Centre	$M			6.51	6.51	6.51	6.64	6.77	6.90	7.04	33.85
Meter Reading - Franchise Customer	$M			6.00	6.00	6.12	6.24	6.36	6.49	6.62	31.83
Metering Dynamic	$M			0.89	0.89	1.06	1.17	1.23	1.29	1.35	6.10
Total Operating	**$M**	**51.09**	**18.58**	**28.73**	**24.61**	**30.74**	**32.13**	**33.56**	**35.07**	**36.68**	**168.17**
New Initiatives Budget											
DSM Initiatives	$M					2.00	2.00	2.00	2.00	2.00	10.00
Embedded Generators Payments	$M					0.16	0.16	0.16	0.16	0.16	0.81
Total New Initiatives	**$M**					**2.16**	**2.16**	**2.16**	**2.16**	**2.16**	**10.81**
Total OPEX Budget (excl. NRCR Products)											
Before OPEX Efficiency Savings	$M	138.42	124.61	137.80	164.61	185.74	202.61	210.83	221.05	231.13	1051.36
Efficiency Savings	$M					1.90	2.09	2.24	2.34	2.44	11.01
Total OPEX (excl. NRCR Products)	**$M**	138.42	124.61	137.80	164.61	183.85	200.52	208.59	218.71	228.69	1040.36
Non revenue Cap Regulated (NRCR) Products											
Recoverable	$M					13.07	14.08	15.17	16.35	17.61	76.29
Temporary Builders	$M					0.87	0.89	0.91	0.92	0.94	4.53
Total OPEX for NRCR Products	**$M**					**13.94**	**14.97**	**16.08**	**17.27**	**18.55**	**80.81**
Total OPEX Budget (incl. NRCR Products)											
Total OPEX (incl. NRCR Products)	**$M**	**150.58**	**140.24**	**147.92**	**182.78**	**197.79**	**215.49**	**224.67**	**235.98**	**247.24**	**1121.17**

All forecast and historical figures are in June 2004 dollars

8.4.1 Distribution Feeder

This category encompasses Distribution System ("DS") line asset inspections ("LAI") and patrols (both planned and unplanned), miscellaneous maintenance after line asset inspections, and DS emergency response. It is noted that a number of specific items associated with the LAIs have been identified and categorised separately (for example DS poles etc.). The OPEX expenditure in this category is planned to increase from $10.46M in 2004/05 to $15.64M in 2009/10. To determine the forecast budget for the next regulatory period, the NUE factor has been applied to each of the inspection, planned maintenance and emergency response activities associated with this category.

Table 8-3: Distribution Feeder Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Energex Forecast								
Inspection	$M	2.80	2.82	3.20	3.45	3.72	4.00	17.19
Planned Maintenance	$M	3.27	3.47	3.74	4.03	4.34	4.68	20.27
Emergency Response	$M	4.39	5.16	5.56	5.99	6.46	6.95	30.13
Consultant Forecast								
Inspection	$M	2.80	2.82	2.89	2.96	3.03	3.11	14.80
Planned Maintenance	$M	3.27	3.47	3.56	3.65	3.74	3.83	18.26
Emergency Response	$M	4.39	5.16	5.29	5.42	5.56	5.70	27.13

All forecast figures are in June 2004 dollars

As discussed previously, the Consultant is of the opinion that the NUE factor is too high for OPEX escalation. The Consultant has applied the alternative NEF of 2.5% to determine revised forecasts for this asset category as shown in Table 8-3. The alternate escalation results in a total saving of approximately $7.39M over the five year review period.

8.4.2 Distribution Poles

This maintenance category includes all pole inspections which are carried as part of the LAI by pole contractors. The forecast expenditure increases from $6.44M in 2004/05 to $9.85M in 2009/10. The NUE factor has been used to determine the escalation of activities in this category over the next regulatory period.

Table 8-4: Distribution Pole Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Energex Forecast								
Inspection	$M	6.44	7.31	7.88	8.49	9.15	9.85	42.69
Consultant Forecast								
Inspection	$M	6.44	7.31	7.50	7.69	7.88	8.07	38.45

All forecast figures are in June 2004 dollars

The unit rate for Pole Inspections for 2004/05 is approximately $12/pole. This unit rate is considered reasonable based on the Consultant's experience and as the work is done on contract, efficiencies from outsourcing have been obtained. Again, the Consultant considers that the NUE factor is too high for the OPEX escalation in this asset category. By applying the alternate NEF the forecast OPEX decreases by approximately $4.24M over the five year review period.

8.4.3 Distribution Pole Tops

This maintenance category includes live line pole top inspections which is a new inspection activity in the coming regulatory period. Significant planned maintenance costs are also allocated for the ongoing replacement of both LV and HV crossarms as detected through the inspection program. The OPEX expenditure on pole tops increases from $5.08M in 2004/05 to $6.98M in 2009/10. Again the NUE factor has been used to determine the increase in OPEX budget over the next regulatory period.

Table 8-5: Distribution Pole Top Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Energex Forecast								
Inspection	$M		0.12	0.13	0.14	0.15	0.16	0.71
Planned Maintenance	$M	5.08	5.06	5.45	5.87	6.33	6.82	29.54
Consultant Forecast								
Inspection	$M		0.12	0.13	0.13	0.13	0.13	0.64
Planned Maintenance	$M	5.08	5.06	5.19	5.32	5.45	5.59	26.60

All forecast and historical figures are in June 2004 dollars

The unit rate for this work in 2004/05 is approximately $9.50/pole top. This value is considered reasonable based on the consultants experience and as the work is done on contract, efficiencies from outsourcing have been attained. The NUE is considered by the Consultant to be too high for escalation in this asset category. By applying the alternate NEF a $3.00M saving over the five year review period is possible.

8.4.4 LV Services

This category includes the inspection and maintenance of LV service pillars and LV overhead services. Also included is the replacement of LV service neutral clamps, which have been identified as a particular safety hazard requiring attention. During the review period, there is a step change in OPEX expenditure between 2005/06 and 2006/07 of $4.72M. Thereafter, the forecast expenditure is escalated at the NUE rate.

Table 8-6: LV Service Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Energex Forecast								
Inspection	$M	0.40	2.55	5.90	6.36	6.85	7.38	29.03
Planned Maintenance	$M	2.66	3.30	4.67	5.03	5.42	5.84	24.26
Consultant Forecast								
Inspection	$M	0.40	2.55	5.90	6.04	6.19	6.33	27.01
Planned Maintenance	$M	2.66	3.25	4.50	4.60	4.70	4.80	21.83

All forecast figures are in June 2004 dollars

The Consultant is of the opinion that the expected growth in LV services is driven primarily by customer growth rather than network growth. Therefore, it would be more appropriate to apply the CEF of 2.4% to obtain forecasts costs rather than the NUE factor. The step change between 2005/06 and 2006/07 is considered reasonable by the Consultant, based on the need to contain safety risks from faulty neutral service clamps. The alternate escalation results in a total saving of approximately $3.62M over the five year review period.

Energex has a CAPEX program in place to upgrade 100,000 LV 40 A services over five years. Also, 13,000 concentric neutral services within one kilometre of the coast are to be replaced because of corrosion risks. The Consultant believes that there should be a corresponding reduction in planned maintenance expenditure which is not apparent in Energex's OPEX budget figures. While this may result in small savings in the LV service planned maintenance budget, it should also have a significant impact on Loss of Supply costs. This point will be discussed further in Section 8.8. The Consultant believes that a 10% p.a. saving in planned maintenance forecast is achievable which corresponds to a total saving of approximately $0.83M over the review period. It is noted that the program for neutral service clamp replacement has not been factored into this calculation. It is expected that this CAPEX program will also impact the budget figures for the Loss of Supply item in the Customer Service category as discussed in Section 8.4.17.

8.4.5 Other Distribution Equipment

This asset category includes pole mounted plant (for example DS transformers, reclosers, regulators, load break switches, capacitor banks, LFIs etc.) and ground mounted plant (for example DS transformers, RMUs etc.) as well as HV earthing systems. The inspection of this equipment is typically carried out during LAIs. Given the range of equipment covered, the OPEX for this category is affected by a number of influences, although the inspection of overhead HV earthing equipment makes up as much as 60% of the inspection budgeted and 40% of the planned maintenance budget. Details of the component programs are given in Appendix 14.6.

Forecast expenditure for corrective repairs is in line with historical trends, and is escalated by the NUE rate across the next regulatory period.

Table 8-7: Other Distribution Equipment Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Energex Forecast								
Inspection	$M	1.00	1.22	1.77	1.82	1.87	1.52	8.19
Planned Maintenance	$M	2.09	2.11	2.77	2.89	3.01	2.71	13.49
Corrective Repair	$M	19.01	22.05	23.75	25.59	27.57	29.70	128.65
Consultant Forecast								
Inspection	$M	1.00	1.22	1.77	1.82	1.87	1.52	8.19
Planned Maintenance	$M	2.09	2.11	2.77	2.89	3.01	2.71	13.49
Corrective Repair	$M	19.01	22.05	22.60	23.16	23.74	24.33	115.88

All forecast figures are in June 2004 dollars

The estimates for inspection and planned maintenance costs for other DS equipment are considered reasonable based on the Consultant's experience. However, the NUE is not an appropriate escalation factor for Corrective Repair in this asset category. Applying the alternate NEF results in a saving of approximately $12.77M over the review period. The Consultant also believes that savings could be made in the Corrective Repair budget based on the significant increase which has been allocated to inspection and planned maintenance between 2004/05 and 2006/07. This will be discussed further in Section 8.8.

8.4.6 Distribution Special Projects

Energex has introduced a range of initiatives in response to specific network, safety or customer issues or to improve network reliability in certain parts of the network. These include the items detailed below (further details are given in Appendix 14.6.6):

- Inspection and maintenance of waterway crossing signs;
- Six sigma pole inspection program for areas with high public exposure;
- Inspection and maintenance of Hazemeyer and Krone RMUs / enclosures;
- Inspection and maintenance of LFIs;
- Reading DS transformer MDIs;
- Non specified reliability improvement work;
- Inspect and repair of pre 1985 LV service pillars;
- Inspect and repair pre 1986 street light neutral links;
- Upgrading capacitive test points;
- Removal of graffiti; and
- Additional maintenance in sensitive areas that is, areas with high public exposure.

Given the specific nature of these projects, customised escalation factors have typically been applied to each project in order to obtain forecast expenditure. In general, the consultant considers the estimated OPEX for these projects to be reasonable.

Table 8-8: Distribution Special Project Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Inspection	$M	0.43	1.28	1.37	1.49	1.65	1.83	7.62
Planned Maintenance	$M	2.44	6.80	7.03	6.75	7.02	7.31	34.91

All forecast figures are in June 2004 dollars

8.4.7 Sub-transmission OH Feeders

OPEX expenditure on overhead sub-transmission feeders is projected to increase from $1.88M in 2004/05 to $3.24M in 2005/06 due to a significant increase in inspection and planned maintenance expenditure. This increase is driven by the critical nature of these feeders and the large costs associated with their failure. During the next regulatory period the costs increase by approximately 6% p.a. overall to $4.11M in 2009/10 with most activities being escalated at the NUE rate, as expected.

Table 8-9: Sub-transmission OH Feeder Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Energex Forecast								
Inspection	$M	0.48	1.19	1.26	1.30	1.35	1.40	6.50
Planned Maintenance	$M	0.88	1.39	1.50	1.61	1.74	1.87	8.12
Corrective Repairs	$M	0.26	0.34	0.37	0.40	0.43	0.46	2.00
Emergency Response	$M	0.26	0.28	0.30	0.32	0.35	0.37	1.62
Consultant Forecast								
Inspection	$M	0.48	1.19	1.26	1.30	1.35	1.40	6.50
Planned Maintenance	$M	0.88	1.39	1.43	1.46	1.50	1.54	7.31
Corrective Repairs	$M	0.26	0.34	0.35	0.36	0.37	0.38	1.80
Emergency Response	$M	0.26	0.28	0.28	0.29	0.30	0.31	1.46

All forecast figures are in June 2004 dollars

The Consultant considers that the estimate for sub-transmission OH feeder Inspection OPEX is reasonable. However, it would be more appropriate to apply the NEF rather than the NUE to determine the escalation for the Planned Maintenance, Corrective Repairs and Emergency Response OPEX. This gives a total saving of approximately $1.17M over the review period. The Consultant also believes that further savings could be made in the Corrective Repair budget based on the significant increase which has been allocated to inspection and planned maintenance between 2004/05 and 2006/07. This will be discussed further in Section 8.8.

8.4.8 Sub-transmission Poles and Structures

The sub-transmission pole and structure inspection budget increases from $0.04M in 2004/05 to $0.25M in 2005/06 due to the increased focus on the critical nature of these assets. It remains around this level for review period. The planned maintenance budget is escalated at the NUE rate from $1.43M in 2004/05 to $2.07M in 2009/10 which the Consultant considers appropriate.

Table 8-10: Sub-transmission Pole and Structure Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Energex Forecast								
Inspection	$M	0.04	0.25	0.26	0.29	0.27	0.31	1.38
Planned Maintenance	$M	1.43	1.54	1.66	1.78	1.92	2.07	8.97
Consultant Forecast								
Inspection	$M	0.04	0.25	0.26	0.29	0.27	0.31	1.38
Planned Maintenance	$M	1.43	1.54	1.58	1.61	1.66	1.70	8.08

All forecast figures are in June 2004 dollars

The Consultant considers that the estimate for sub-transmission pole and structure inspection related OPEX is reasonable. However, the NEF would be a more appropriate planned maintenance escalation factor than the NUE. Applying the NEF gives a total saving of approximately $0.89M over the review period.

8.4.9 Sub-transmission UG Cables

As discussed in Section 8.2.3, a large proportion of the Energex sub-transmission network is supplied by underground cables and as such Energex places a high priority on the maintenance of these assets. The total sub-transmission UG cable OPEX is expected to increase from $4.30M to $5.94M between 2004/05 and 2009/10. This expenditure is primarily associated with planned maintenance activities. There has also been a number of condition monitoring techniques (for example DGA, RGP, paper sampling etc.) recently introduced under the inspection expenditure.

Table 8-11: Sub-transmission UG Cable Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Energex Forecast								
Inspection	$M	0.43	0.42	0.45	0.48	0.51	0.58	2.44
Planned Maintenance	$M	3.02	3.62	3.90	4.21	4.53	4.88	21.15
Corrective Repair	$M	0.85	0.35	0.38	0.41	0.44	0.48	2.07
Consultant Forecast								
Inspection	$M	0.43	0.36	0.39	0.42	0.45	0.52	2.14
Planned Maintenance	$M	3.02	3.39	3.48	3.57	3.67	3.77	17.88
Corrective Repair	$M	0.85	0.19	0.20	0.21	0.22	0.23	1.06

All forecast figures are in June 2004 dollars

Energex currently has a program to patrol entire UG cable routes at intervals ranging from one month to one year depending on the importance of the cable. The Consultant believes that such patrol levels are excessive, particularly given the condition monitoring techniques which have been implemented. A small saving of approximately $0.15M p.a. could be made if these inspections were limited to the cable end points.

Energex also has a significant CAPEX program to replace some 33 kV gas filled cables. The impact of this CAPEX program has not been factored in to this program. The Consultant does not have sufficient information to make an accurate assessment of the OPEX savings which will result from this program. However, based on experience the Consultant believes that $0.15M inspection savings, $1.50M planned maintenance savings and $0.80M corrective repair savings are achievable.

In addition to these savings, the Consultant believes that the NEF, rather than the NUE, should be used to escalate the Planned Maintenance and Corrective Repair forecasts. This results in a total saving of approximately $2.31M. Finally, the Consultant believes that further savings could be made in the Corrective Repair budget based on the significant increase which has been allocated to inspection and planned maintenance between 2004/05 and 2006/07. This will be discussed further in Section 8.8.

8.4.10 ZSS Power Transformers

OPEX expenditure on zone substation power transformer inspection and maintenance is projected to be $2.25M in 2004/05 and $1.83M in 2005/06. It remains around this level for the review period. The program of works for this asset category is well defined so this expenditure forecast is less reliant on general escalation estimates than other categories.

Table 8-12: ZSS Power Transformer Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Energex Forecast								
Inspection	$M	0.32	0.44	0.47	0.41	0.53	0.47	2.31
Planned Maintenance	$M	1.94	1.39	1.60	1.44	1.88	1.61	7.91
Consultant Forecast								
Planned Maintenance	$M	1.94	1.28	1.48	1.31	1.75	1.46	7.29

All forecast figures are in June 2004 dollars

A number of Energex's zone substation transformers are operating outside of their normal rating limits due to the high level of demand growth in recent years. Therefore effective condition assessment and management of these assets is a critical OPEX component. Failure of zone substation transformers generally has a big impact on customer reliability. Energex has implemented a range of diagnostic techniques, including DGA, to quantify the condition of these items and estimate the expected remaining life.

Energex still programs transformer tap changer maintenance on a fixed time interval basis. The Consultant considers that some ongoing savings can be achieved through the introduction of operation plus condition based tap changer maintenance. The Consultant also considers that savings of approximately 20% can be made on oil leak repairs and general transformer maintenance (for example painting). This corresponds to a total saving of $0.62M over the five year review period.

8.4.11 ZSS Circuit Breakers

OPEX expenditure on zone substation circuit breaker inspection and maintenance is forecast to be $3.84M in 2004/05 and $2.61M in 2005/06. The OPEX expenditure remains at around this level for the review period.

Table 8-13: ZSS Circuit Breaker Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Inspection	$M	0.39	0.40	0.43	0.45	0.50	0.53	2.30
Planned Maintenance	$M	3.45	2.21	2.61	2.40	2.12	2.27	11.60

All forecast figures are in June 2004 dollars

The Consultant considers that the estimate for zone substation circuit breaker OPEX is reasonable.

8.4.12 Other ZSS Equipment

This OPEX category incorporates routine substation inspections and thermo-scans, miscellaneous maintenance on items including capacitor banks, switchgear and earthing equipment, as well as corrective and emergency repairs. The forecast OPEX expenditure increases from $6.23M in 2004/05 to $7.29M in 2005/06. It then increases at a rate approximately equal to the NUE factor throughout the review period. It is assumed that any plant replacement will have minimal impact on the inspection and monitoring of existing equipment in this time frame.

Table 8-14: Other ZSS Equipment Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Energex Forecast								
Inspection	$M	1.61	2.37	2.69	2.90	3.12	3.36	14.43
Planned Maintenance	$M	1.27	1.15	1.20	1.26	1.33	1.39	6.33
Corrective Repairs	$M	2.93	3.33	3.58	3.86	4.16	4.48	19.41
Emergency Response	$M	0.42	0.44	0.48	0.52	0.56	0.60	2.59
Consultant Forecast								
Inspection	$M	1.61	2.37	2.43	2.49	2.55	2.61	12.45
Planned Maintenance	$M	1.27	1.15	1.20	1.26	1.33	1.39	6.33
Corrective Repairs	$M	2.93	3.33	3.41	3.49	3.58	3.67	17.48
Emergency Response	$M	0.42	0.44	0.46	0.47	0.48	0.49	2.33

All forecast figures are in June 2004 dollars

Again, the Consultant believes that the NUE is too high for OPEX escalation, and has used the alternate NEF to determine the revised inspection, corrective repairs and emergency response forecasts. This gives a total saving of $4.16M over the review period.

The Consultant has identified a number of ZSS asset categories where the inspection and planned maintenance intervals are shorter than industry standards, as identified by shaded blocks in Table 14-1 of Appendix 14.4. This is an area of potential savings as discussed in Section 8.8. Similarly, the Consultant believes that further savings could be made in the Corrective Repair budget based on the significant increase which has been allocated to inspection and planned maintenance between 2004/05 and 2006/07 as will be discussed further in Section 8.8.

8.4.13 ZSS Secondary Equipment

This OPEX category includes battery, protection and pilot cable maintenance. The forecast OPEX expenditure increases from $2.37M in 2004/05 to $4.40M in 2009/10. This increase is attributed to the increasing quantity of equipment and the minimal impact of plant replacement and monitoring of older equipment in this time frame.

Table 8-15: ZSS Secondary Equipment Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Planned Maintenance	$M	2.37	3.06	3.58	3.62	3.82	4.40	18.48

All forecast figures are in June 2004 dollars

The Consultant considers that the estimate for zone substation secondary equipment OPEX is reasonable.

8.4.14 ZSS Site

The OPEX expenditure on zone substation sites decreases from $2.10M in 2004/05 to $1.97M in 2005/06. The inspection and corrective repair forecasts then increase at a rate equal to the NUE factor across the review period whereas the planned maintenance budget is based on itemised activities. This program includes attention to substation site fencing security.

Table 8-16: ZSS Site Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Energex Forecast								
Inspection	$M	0.01	0.01	0.01	0.01	0.01	0.01	0.05
Planned Maintenance	$M	2.09	1.88	2.00	2.24	2.40	2.55	11.08
Corrective Repair	$M	0.00	0.08	0.09	0.10	0.10	0.11	0.48
Consultant Forecast								
Inspection	$M	0.01	0.01	0.01	0.01	0.01	0.01	0.05
Planned Maintenance	$M	2.09	1.88	2.00	2.24	2.40	2.55	11.08
Corrective Repair	$M	0.00	0.08	0.09	0.09	0.09	0.09	0.44

All forecast figures are in June 2004 dollars

The Consultant considers that the NEF rate, rather than the NUE rate, should be used to escalate the inspection and corrective repair forecasts. This gives a total saving of approximately $0.05M over the review period.

8.4.15 Vegetation Management

The forecast vegetation management OPEX expenditure is approximately $46.5M p.a. over the next regulatory period. This is a significant increase compared to the previous regulatory period. The change in vegetation management philosophy was driven by the intense thunderstorms of January 2004 which highlighted the vulnerability of Energex's overhead networks to damage caused by vegetation during high winds. Indeed, the lack of tree clearing programs has had a significant impact on reliability during storm periods. The increase in expenditure is required to address the backlog of vegetation activities as Energex moves from a reactive approach to a comprehensive cyclic program. It is expected that the ongoing costs will fall in the next period once this backlog is cleared. The cyclic approach to vegetation management has become standard within the DNSP industry, particularly in Victoria where it has been used to address bush fire risk.

Table 8-17: Vegetation Management OPEX Budget

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Vegetation Management OPEX	$M	46.36	44.52	46.46	46.46	46.46	46.46	230.34

All forecast figures are in June 2004 dollars

The Consultant considers that the estimate for vegetation management OPEX is reasonable, although resourcing this level of work may be an issue. This is discussed further in Section 12.

8.4.16 Streetlights

OPEX expenditure for streetlights includes patrols, bulb replacement and fitting repairs. This expenditure is forecast to increase from $5.31M in 2004/05 to $7.73M in 2009/10 suggesting the NUE factor has been applied.

Table 8-18: Streetlight OPEX Budget

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Energex Forecast								
Streetlight OPEX	$M	5.31	5.74	6.18	6.66	7.17	7.73	33.48
Consultant forecast								
Streetlight OPEX	$M	5.31	5.74	6.02	6.31	6.62	6.95	31.64

All forecast figures are in June 2004 dollars

The Consultant is of the opinion that growth in streetlighting OPEX is primarily driven by customer growth rather than network growth. While revised Australian Standards requirements mean that streetlighting OPEX is expected grow at a faster rate than customer numbers over the next regulatory period, the Consultant believes that applying the NUE rate is excessive. A more appropriate figure would be a 4.9% p.a. growth which incorporates the CEF factor as well as a 2.5% growth allowance for Australian Standards changes. This corresponds to a total saving of $1.84M over the review period.

8.4.17 Customer Service

The Customer Service OPEX category covers the following activities:

- Loss of supply;
- Cold water complaints;
- Meter queries;
- Customer inquiries; and
- Shock and other safety incident response.

The forecast Customer Service OPEX Budget increases from $9.04M in 2004/05 to $10.35M in 2009/10. The average escalation over the review period is approximately 3.0%. This is consistent with the fact that these costs are primarily driven by customer numbers.

Table 8-19: Customer Service OPEX Budget

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Energex Forecast								
Customer Service OPEX	$M	9.04	9.18	9.45	9.74	10.04	10.35	48.75
Consultant Forecast								
Customer Service OPEX	$M	9.04	7.77	8.03	8.30	8.59	8.89	41.57

All forecast figures are in June 2004 dollars

Under the CAPEX program Energex will be replacing the following items in the regulatory period:

- 100,000 low rated (40A) service cables;
- 30,000 concentric neutral service cables; and
- 30,000 load control relays.

These would be expected to reduce the number of loss of supply complaints, cold water complaints and customer installation shock or safety incidents. The Consultant considers that a total OPEX saving of $7.18M over the five year review period is achievable as a result of these CAPEX programs.

8.4.18 Network Operations

The Network Operations OPEX budget includes costs required to run the control centres and associated activities including:

- HV access and isolation switching;
- Updating and maintaining panel drawings;
- Contingency planning;
- Evaluation of network incidences;
- Emergency response management;
- Quality of supply investigations;
- Reliability of supply investigations;
- EMF investigations; and
- AFLC investigations.

The forecast OPEX expenditure for this category increases from $12.15M in 2005/06 to $16.37M in 2009/10 in line with the expected network growth that is, costs are escalated by NUE factor.

Table 8-20: Network Operations OPEX Budget

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Energex Forecast								
Network Operations OPEX	$M	11.22	12.15	13.09	14.10	15.19	16.37	70.91
Consultant Forecast								
Network Operations OPEX	$M	11.22	11.81	12.11	12.41	12.73	13.05	62.10

All forecast figures are in June 2004 dollars

The Consultant considers that quality of supply, reliability of supply, Electro-magnetic Field ("EMF") and Audio Frequency Load Control ("AFLC") investigations are more related to customer numbers than network growth. Therefore, escalating these program budgets by the CEF rate rather than the NUE rate would be more appropriate. Similarly, the Consultant considers that escalation using NEF rate, rather than the NUE rate, would be more appropriate for general network operations activities. The Consultant considers that a total saving of $7.10M over the five year review period is achievable using these alternative escalations.

Finally, no allowance for productivity improvement in the network operations area has been factored in. The Consultant considers that a saving of $0.34M p.a. (or $1.70M in total) relating to network automation improvements should be achieved.

8.4.19 Levies

This OPEX category covers the Electrical Safety Office levy introduced in 2002/03 and the QCA levy introduced in 2003/04. In the current regulatory period, these costs were passed on separately to customers. However, given that the levies will be ongoing during the next regulatory period, it has been included in the OPEX budget.

The levy expenditure is expected to increase from $4.90M in 2005/06 to $5.30M in 2009/10. The CUE has been applied to determine this budget because these levies are allocated on the basis of customer numbers.

Table 8-21: Levy OPEX Budget

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Energex Forecast								
Levies OPEX	$M	-	4.90	5.00	5.10	5.20	5.30	25.49
Consultant Forecast								
Levies OPEX	$M	-	4.56	4.68	4.79	4.91	5.04	23.98

All forecast figures are in June 2004 dollars

QCA has informed the Consultant that these Levies should not be derived based solely on customer numbers. The QCA Levy has been derived using a formula related to the DNSP revenue, while the ESO Levy has been derived based on an escalation of historical levels. Using the forecast figures provided by QCA which are based on a CPI escalation gives a total saving of $1.51M over the review period.

8.4.20 Call Centre

The Energex call centre is common to both the network and retail businesses and costs are allocated using a methodology approved by the QCA. The forecast Call Centre costs allocated to the network business are $6.51M in 2005/06 and are expected to increase in line with customer growth, that is, the CUE factor has been applied to determine escalation.

Table 8-22: Call Centre OPEX Budget

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Energex Forecast								
Call Centre OPEX	$M	6.51	6.51	6.64	6.77	6.90	7.04	33.85
Consultant Forecast								
Call Centre OPEX	$M	6.51	6.51	6.62	6.82	6.99	7.15	34.13

All forecast figures are in June 2004 dollars

To obtain the forecast Call Centre OPEX, the Consultant has applied the CEF rather than the CUE. This results in a small increase of $0.28M over the review period.

8.4.21 Meter Reading - Franchise

Meter reading costs for franchise customers are borne by the network business. The expected OPEX associated with this activity is $6.12M in 2005/06 and the CUE factor has been applied to forecast future costs.

Table 8-23: Meter Reading - Franchise OPEX Budget

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Energex Forecast								
Meter Reading - Franchise OPEX	$M	6.00	6.12	6.24	6.36	6.49	6.62	31.83
Consultant Forecast								
Meter Reading - Franchise OPEX	$M	6.00	6.12	6.27	6.42	6.57	6.73	32.10

All forecast figures are in June 2004 dollars

Again, the Consultant has applied the CEF rather than the CUE to obtain the estimate the forecast OPEX. This corresponds to an increase of $0.27M over the review period.

8.4.22 Metering Dynamics

Metering Dynamics is the Data Warehouse Manager for all contestable customers and the Metering Provider for Bulk Supply Points. The network business pays a fee for the data management function and shares the costs associated with the wholesale metering with the retail business.

The OPEX costs associated with Metering Dynamics are expected to increase from $1.06M in 2005/06 to $1.35M in 2009/10. These figures take into account the new group of customers which will be offered contestability in July 2004.

Table 8-24: Metering Dynamics OPEX Budget

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Metering Dynamics OPEX	$M	0.89	1.06	1.17	1.23	1.29	1.35	6.10

All forecast figures are in June 2004 dollars

The Consultant considers that the estimate for the Metering Dynamics related OPEX is reasonable.

8.4.23 New Initiatives

New OPEX categories which are included in the next regulatory period include Service Quality Incentives ("SQI"), DSM and Embedded Generator Payment initiatives as described below.

The SQI initiatives have been introduced specifically to improve reliability, and thus this expenditure is related to Tier (b) and Tier (c) of the Service Quality Improvement program described in Section 5.6.3. Energex have proposed the following SQI initiatives in their OPEX program:

- Additional vegetation management - SQI spending will extend beyond compliance-required base level profile clearance to tree overhangs outside profile on critical lines, spot tree removals in urban areas and wider clearing profiles in rural and fringe urban areas.
- Live line pole top feeder patrols. This will target all 33kV feeders supplying predominantly urban substations and the worst performing 11kV urban feeders.
- Increased attention to the worst performing feeders. Improvement of 10 worst performing urban feeders and 10 worst performing rural feeders each year will be undertaken. OPEX spending will be tailored to identified problems on relevant feeders, but includes Thermo-scanning, Live Line feeder patrol/maintenance & yearly vegetation maintenance trim.
- Expansion of network operations. Establish a trouble call team to operate a 24/7 shift for metro (2) hubs, i.e. North and South.
- Thermo-scanning. This will target all 11kV feeders along the main backbone and up to the first isolator on all spurs.
- Improved Security for Regional Hospitals and Council Pumps. This involves Thermo-scanning, Live Line feeder patrol/maintenance and yearly vegetation maintenance trim of feeders supplying regional hospitals and council pumps to improve security of supply during adverse weather conditions. The Expected cost is $4m over the regulatory period.

The forecast OPEX for SQI increases from $3.89M in 2005/06 to $12.98M in 2008/09 and remains at this level for the remainder of the period. However, as this expenditure only relates to Tiers (b) and (c) of the SQI program it has been excluded from the OPEX forecast summaries given in this report. Further discussion regarding improvements to service quality which result from the SQI OPEX expenditure is contained in Section 11.

The DSM initiatives have been introduced to encourage demand side participation. These activities include:

- Subsidies for installation of energy efficient appliances;
- Payments to customers to convert electric appliances (for example hot water units) to gas;

- Public education campaign on greenhouse and energy efficiency issues; and
- Future network support payments.

The DSM forecast OPEX is constant at $2.00M for the entire review period.

Energex currently pays HydroPower a network deferral cost for embedded generation at Somerset Dam. This cost is expected to remain constant at $0.16M across the review period.

Table 8-25: New Initiatives OPEX Budget

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
SQI OPEX (Tier (b) & (c))	$M		3.89	6.39	12.98	12.98	12.98	49.23
DSM OPEX	$M		2.00	2.00	2.00	2.00	2.00	10.00
Embedded Generator Payment OPEX	$M		0.16	0.16	0.16	0.16	0.16	0.81

All forecast figures are in June 2004 dollars

The initiatives being undertaken for SQI and DSM are important factors in improving the quality of supply and efficient use of energy, are to be encouraged. The Consultant considers that the estimated costs and the embedded generation costs are reasonable.

8.4.24 Non Revenue Capped Regulated

The Non Revenue Capped Regulated ("NRCR") category includes Recoverable Works and Builders Temporary Services. Energex has forecast that the NRCR related OPEX will increase from $13.94M in 2005/06 to $18.55M in 2009/10. The Recoverable Works costs have been escalated at the NUE rate whereas the Builders Temporary Services costs have been escalated at the CUE rate.

Table 8-26: Non Revenue Capped Regulated OPEX Budget

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Energex Forecast								
NRCR OPEX	$M	-	13.94	14.97	16.08	17.27	18.55	80.81
Consultant Forecast								
NRCR OPEX	$M	-	13.94	14.29	14.65	15.01	15.39	73.28

All forecast figures are in June 2004 dollars

The Consultant agrees that Builders Temporary Services costs are related to customer numbers and that Recoverable Works costs are indirectly related to network growth. However, the CEF and NEF escalation rates are considered more appropriate than the CUE and NUE rates as has been discussed previously. This alternate escalation results in a total saving of approximately $7.53M over the review period.

8.5 Efficiency Assessed Against Industry Standards

A comparison of the Energex's actual operating expenditure for the 2002/03 period with the operating expenditure of comparable DNSPs that is, AGL, UE and Energy Australia indicates that the historical OPEX spending at Energex has been low, as shown in Table 8-27. This result supports the significant increase in OPEX which has been forecast for the next regulatory period. Indeed, the OPEX ratios which have been forecast for the 2005/06 period are more in line with the OPEX ratios of the comparable DNSPs. It should be noted that this comparison with other DNSPs can only be taken as an indicative assessment of Energex's OPEX efficiency because Energex is starting from a lower base value and requires additional expenditure to compensate for previous underspending. It is expected that this catch-up phase will extend throughout the next regulatory period, although it will be most intensive in the early years.

Table 8-27: Comparison of the Actual OPEX in 2002/03 and Forecast OPEX in 2005/06 with Comparable Expenditure of other DNSPs.

	OPEX ($M)	No. of Customers (M)	GWHr	Circuit km	OPEX / Circuit km	OPEX / customers	OPEX / GWHr
Energex (2002/03)	**121.09**	**1.13**	**17,936**	**41,146**	**2,943**	**107**	**6,751**
Energex (2005/06)	**197.79**	**1.22**	**20,234**	**44,310**	**4,464**	**162**	**9,775**
AGL	40.40	0.27	3,988	7,041	5,738	152	9,890
UE	75.62	0.58	7,108	12,198	6,199	130	10,650
Energy Australia	254.00	1.49	25,402	44,014	5,771	213	12,500
Ergon	165.70	0.52	13,251	143,000	1,159	322	12,504
Powercor	74.80	0.60	9,376	84,000	890	125	6,189
CitiPower	46.83	0.26	5,336	3,919	11,949	177	11,478
TXU	84.04	0.54	6,469	28,000	3,001	155	12,883
Country Energy	192.85	0.72	9,965	169,167	1,140	268	19,500

Examination of maintenance practices in Table 8-28 shows that the ratio of planned maintenance to unplanned maintenance in the forecast figures provided by Energex is significantly higher than industry practice. This may, in part, be explained by inconsistent category definitions across the DNSPs. Nevertheless, the Consultant considers that savings could be made by reducing the levels of planned maintenance by adopting more condition based rather than time based maintenance practices.

Table 8-28: Comparison of Energex's Planned and Unplanned Maintenance Plans in 2004/05 with Industry Practice

	Energex	Industry Practice
Planned Maintenance incl. Inspection	63%	56%
Unplanned Maintenance	37%	44%

8.6 Relationship Between Growth and OPEX

It can be expected that there will be an increase in OPEX over time due to growth in the size of the network. This can be related to both growth in customer numbers and growth in demand.

8.6.1 Relationship Between Customer Numbers & OPEX

Changes in the growth rate of customer numbers will directly affect the expenditure required in the following Energex categories:

- LV Services;
- Public lighting;
- Network Operations - Power Quality Investigations;
- Meter Reading;
- Call Centre; and
- Temporary Builders Supplies.

The strong relationship between customer growth and OPEX expenditure in these categories is demonstrated in Table 8-29. There is an initial step change in customer related OPEX from 2005/06, which is related to previous underspending. After this step change, the ratio between this OPEX and the customer growth is approximately 1:1. This is expected as most of these forecasts have been obtained by applying the CEF described in Section 8.4.

However, it should be recognised that the total OPEX for these customer related categories listed above as forecast by the Consultant is approximately $179.5M over the five year review period. This value corresponds to only 15% of the total forecast OPEX expenditure. Therefore, it is concluded that there is not a strong relationship between Energex's total OPEX expenditure and growth in customer numbers.

Table 8-29: Customer Driven OPEX Budget.

		05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Customer Driven OPEX (Consultant Forecast)	$M	30.30	35.75	36.76	37.80	38.87	179.47
	% Change		17.98	2.82	2.83	2.84	
% Change in Customer Driven OPEX divided by % Change in Customer Numbers			8.12	1.17	1.09	1.20	

8.6.2 Relationship Between Maximum Demand & OPEX

It is expected that changes in the maximum demand growth will affect the expenditure required in a range of Energex's OPEX categories including:

- Distribution and Transmission Overhead Feeders;
- Underground Cables;
- Distribution Poles and Pole Tops;
- General Distribution Equipment;
- Zone Substation Primary Equipment; and
- Network Operations.

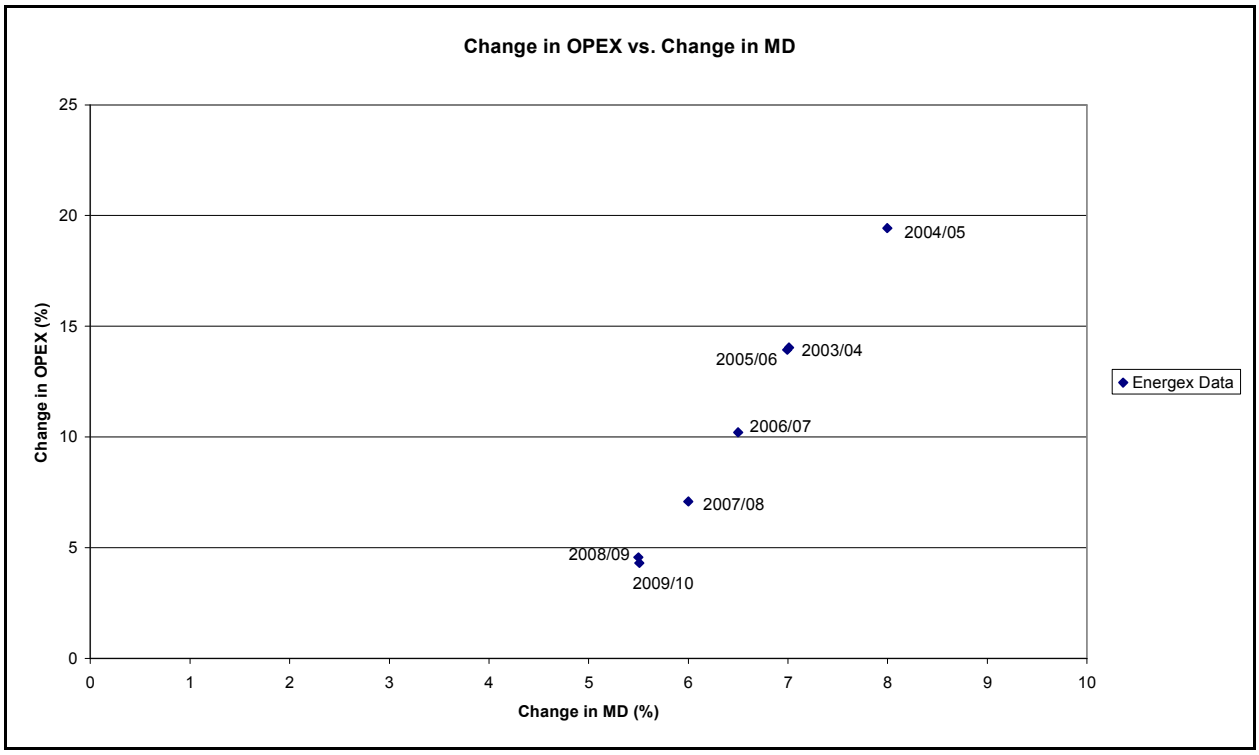
Figure 8-1 shows that the ratio of total OPEX to MD consistently decreases over the review period. This suggests that there is a relatively strong relationship between Energex's OPEX expenditure and demand. It also suggests that new efficiencies are being introduced to improve this relationship.

However, as was discussed in Section 8.4, the relationship between demand growth and OPEX expenditure is not a direct one and is influenced by a range of factors. In particular, new plant items typically have lower maintenance costs than older plant items. Therefore, the Consultant has applied a NEF of 2.5% to forecast the OPEX expenditure for the maximum demand related categories as was discussed in Section 8.4. The total OPEX expenditure forecast by the Consultant for these categories is approximately $387.9M over the review period as shown in Table 8-30.

Table 8-30: Maximum Demand Driven OPEX Budget.

		05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
MD Driven OPEX (Consultant Forecast)	$M	73.79	75.64	77.53	79.47	81.45	387.88
	% Change		2.5	2.5	2.5	2.5	
Change in MD Driven OPEX (%) vs. Change in Customers (%)			0.35	0.37	0.41	0.41	

Figure 8-1: Change in OPEX vs. Change in MD



8.7 Impact of Differences Between Forecasts

The demand forecasts have been separately reviewed by MMA who have forecast peak demands, energy consumption and customer numbers. MMA have predicted a 5.3% average growth in MD over the forecast period compared to Energex's predictions of 5.9%. Similarly, MMA has predicted a 2.0% average growth in customer numbers compared to 2.5% predicted by Energex.

The Consultant has estimated that the difference in the forecast MD equates to a reduction in the Consultant's estimates over the period 2005/06 to 2009/10 of approximately $2.0M for MD related categories and $2.8M for customer related categories. To determine the new estimates for the MD related categories, a revised NEF of 2.25% has been applied. This value is obtained by reducing the original NEF by the relative difference between the MMA and Energex estimates (i.e. ~10%). Clearly, these reductions are insignificant in relation to the total OPEX budget but this is expected given the relatively weak relationships that exist between OPEX and these quantities.

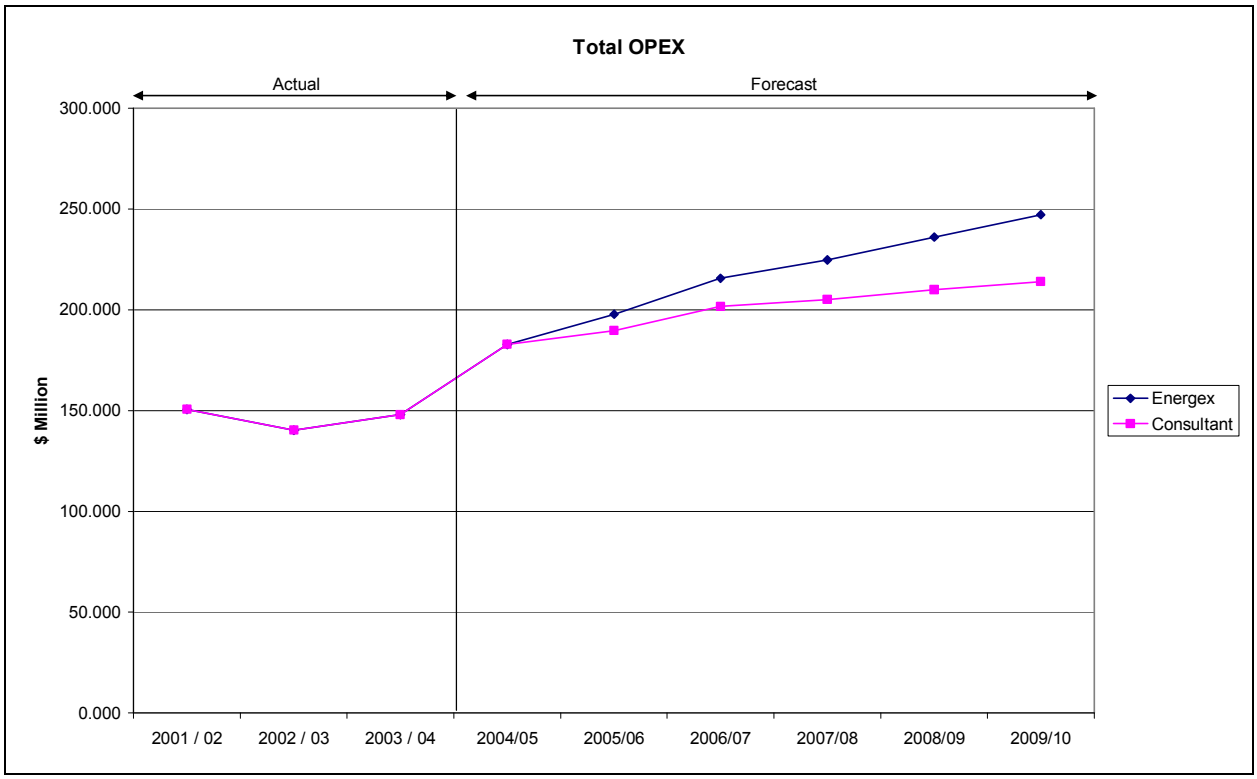
8.8 Efficient OPEX Program 2005/06 to 2009/10 - Summary

The Consultant has identified a number of potential savings in the Energex OPEX Program in addition to those detailed in Section 8.4. These include:

- The Consultant is of the opinion that as Energex moves towards a systems based (single pass) approach to asset inspection and planned maintenance of lines and services, that efficiencies and savings in the OPEX will result. While the Consultant appreciates that a significant increase in Energex's inspection and planned maintenance budget is warranted (refer to Section 8.5) for the coming regulatory period, the Consultant is of the opinion that the potential savings due to efficiency gains have not been fully factored into the budget. Given that Energex has maintained a unit based costing approach to the OPEX budget and very limited historical data has been made available, it is difficult to quantify these savings in detail. However, the Consultant considers that a 5% p.a. saving in the DS inspection and planned maintenance forecasts over the five years should be achievable. This corresponds to saving of approximately $11.40M over the five year review period.
- The Consultant has identified a number of asset categories where the inspection and planned maintenance intervals are shorter than industry standards. These have been identified in Appendix 14.4 by shading the relevant categories in Table 14-1. The Consultant considers that small savings of approximately 1% p.a. can be made in the inspection and planned maintenance budgets by extending these inspection intervals in line with industry standards. This corresponds to a total saving of approximately $3.55M over the five year review period.
- Energex has based the forecast expenditure for corrective repairs on historical trends and has escalated this expenditure based on the NUE factor. However, this methodology does not account for savings which will be made in this area due to the increased allocations given to inspection and planned maintenance. The Consultant considers that an extra 5% p.a. saving should be possible in the corrective maintenance budget for all asset categories. This corresponds to a total saving of $7.71M over the five year review period.
- It is recognised that Energex has had stable network boundaries for a number of years now, so potential efficiency improvements from rationalisation are limited. Nevertheless, the Consultant is of the opinion that small savings can be achieved by obtaining the full benefit of the EBAs that have been agreed, and which have not been fully implemented. These include spread of hours, multi-skilling, starting on the job and reduced crew sizes. Attempts will also be made at the next agreement to achieve further savings and these have not been factored into the estimates. The Consultant considers that efficiency savings of 2% p.a. should be achievable to account for these initiatives. This corresponds to an increase of 1% p.a. compared to the efficiency savings that Energex has already factored into the OPEX budget.
- Energex has allocated a sum of money to SQI initiatives. It is apparent that a number of these projects (for example live line pole top inspections, thermo-scanning, and non-specified reliability improvements) are also included as separate line items in the budget. While Energex has stated that these costs apply only to activities which result in reliability improvements above and beyond the current level, the Consultant is unable to confirm this assertion because a breakdown of the costs has not been provided. Further information would be required before the Consultant could make an informed assessment of this budget category.

The Consultant has constructed a revised OPEX forecast based on the savings which have been identified in Energex's program of OPEX works. This revised forecast is compared to Energex's proposed OPEX in Figure 8-2 and summarised in Table 8-32 and Table 8-32. It can be seen that the revised forecast is characterised by an intensive catch-up phase in the early years of the regulatory period to compensate for previous underspending. This catch-up phase tails off towards the end of the period. During this time the Consultant's forecast is determined primarily by the expected growth in the network and customer base which results in an OPEX escalation of approximately 2% p.a.

Figure 8-2: OPEX expenditure



All forecast and historical figures are in June 2004 dollars

Table 8-31: Energex's Proposed Operational Budget

		05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Maintenance Budget							
Inspection	$M	19.45	24.82	26.51	28.52	30.18	129.49
Planned Maintenance	$M	38.53	43.37	44.91	47.78	50.47	225.06
Corrective Repair	$M	26.42	28.46	30.66	33.04	35.59	154.17
Emergency Response / Storms	$M	9.01	9.57	10.17	10.82	11.52	51.09
Vegetation	$M	44.52	46.46	46.46	46.46	46.46	230.34
Streetlights	$M	5.74	6.18	6.66	7.17	7.73	33.48
Customer Service	$M	9.18	9.45	9.74	10.04	10.35	48.75
Total Maintenance	**$M**	**152.84**	**168.31**	**175.11**	**183.82**	**192.29**	**872.38**
Operating Budget							
Network Operations	$M	12.15	13.09	14.10	15.19	16.37	70.91
Levies	$M	4.90	5.00	5.10	5.20	5.30	25.49
Call Centre	$M	6.51	6.64	6.77	6.90	7.04	33.85
Meter Reading - Franchise Customer	$M	6.12	6.24	6.36	6.49	6.62	31.83
Metering Dynamic	$M	1.06	1.17	1.23	1.29	1.35	6.10
Total Operating	**$M**	**30.74**	**32.13**	**33.56**	**35.07**	**36.68**	**168.17**
New Initiatives Budget							
DSM Initiatives	$M	2.00	2.00	2.00	2.00	2.00	10.00
Embedded Generators Payments	$M	0.16	0.16	0.16	0.16	0.16	0.81
Total New Initiatives	**$M**	**2.16**	**2.16**	**2.16**	**2.16**	**2.16**	**10.81**
Total OPEX Budget (excl. NRCR Products)							
Before OPEX Efficiency Savings	$M	185.74	202.61	210.83	221.05	231.13	1051.36
Efficiency Savings (2%)	$M	1.90	2.09	2.24	2.34	2.44	11.01
Total OPEX (excl. NRCR Products)	**$M**	183.85	200.52	208.59	218.71	228.69	1040.36
Non Revenue Cap Regulated (NRCR) Products							
Recoverable	$M	13.07	14.08	15.17	16.35	17.61	76.29
Temporary Builders	$M	0.87	0.89	0.91	0.92	0.94	4.53
Total OPEX for NRCR Products	**$M**	**13.94**	**14.97**	**16.08**	**17.27**	**18.55**	**80.81**
Total OPEX Budget (incl. NRCR Products)							
Total OPEX (incl. NRCR Products)	**$M**	**197.79**	**215.49**	**224.67**	**235.98**	**247.24**	**1121.17**

Table 8-32: Consultant's Revised Operational Budget

		05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Maintenance Budget							
Inspection	$M	18.43	22.54	23.07	23.80	24.08	111.92
Planned Maintenance	$M	36.64	40.37	40.72	42.22	43.44	203.39
Corrective Repair	$M	24.94	25.51	26.10	26.69	27.29	130.51
Emergency Response / Storms	$M	9.01	9.26	9.52	9.80	10.09	47.68
Vegetation	$M	44.52	46.46	46.46	46.46	46.46	230.34
Streetlights	$M	5.74	6.02	6.31	6.62	6.95	31.64
Customer Service	$M	7.77	8.03	8.30	8.59	8.89	41.57
Total Maintenance	**$M**	147.04	158.19	160.48	164.17	167.19	797.06
Operating Budget							
Network Operations	$M	11.81	12.11	12.41	12.73	13.05	62.10
Levies	$M	4.56	4.68	4.79	4.91	5.04	23.98
Call Centre	$M	6.51	6.66	6.82	6.99	7.15	34.13
Meter Reading - Franchise Customer	$M	6.12	6.27	6.42	6.57	6.73	32.10
Metering Dynamic	$M	1.06	1.17	1.23	1.29	1.35	6.10
Total Operating	**$M**	30.06	30.89	31.67	32.48	33.32	158.41
New Initiatives Budget							
DSM Initiatives	$M	2.00	2.00	2.00	2.00	2.00	10.00
Embedded Generators Payments	$M	0.16	0.16	0.16	0.16	0.16	0.81
Total New Initiatives	**$M**	2.16	2.16	2.16	2.16	2.16	10.81
Total OPEX Budget (excl. NRCR Products)							
Before OPEX Efficiency Savings	$M	**179.27**	**191.24**	**194.31**	**198.82**	**202.67**	**966.28**
Efficiency Savings (2%)	$M	3.59	3.83	3.89	3.98	4.05	19.33
Total OPEX (excl. NRCR Products)	**$M**	**175.68**	**187.41**	**190.42**	**194.84**	**198.62**	**946.96**
Non Revenue Cap Regulated (NRCR) Products							
Recoverable	$M	13.07	13.40	13.73	14.08	14.43	68.71
Temporary Builders	$M	0.87	0.89	0.91	0.94	0.96	4.57
Total OPEX for NRCR Products	**$M**	13.94	14.29	14.65	15.01	15.39	73.28
Total OPEX Budget (incl. NRCR Products)							
Total OPEX (incl. NRCR Products)	**$M**	**189.62**	**201.70**	**205.07**	**209.85**	**214.00**	**1020.24**

All forecast and historical figures are in June 2004 dollars

9 CAPITAL INVESTMENT REVIEW

9.1 Purpose and Scope of Section

The Consultant is required to assess the efficiency of forward capital estimates, together with the impact of growth scenarios.

This section considers the current capacity of the network, growth predictions, the requirements for asset replacements, a detailed review of capital projects and the procedures for assessing capital expenditure. Based on the foregoing and the comparisons to best practice contained in Section 5.6, a revised CAPEX program is recommended by the Consultant.

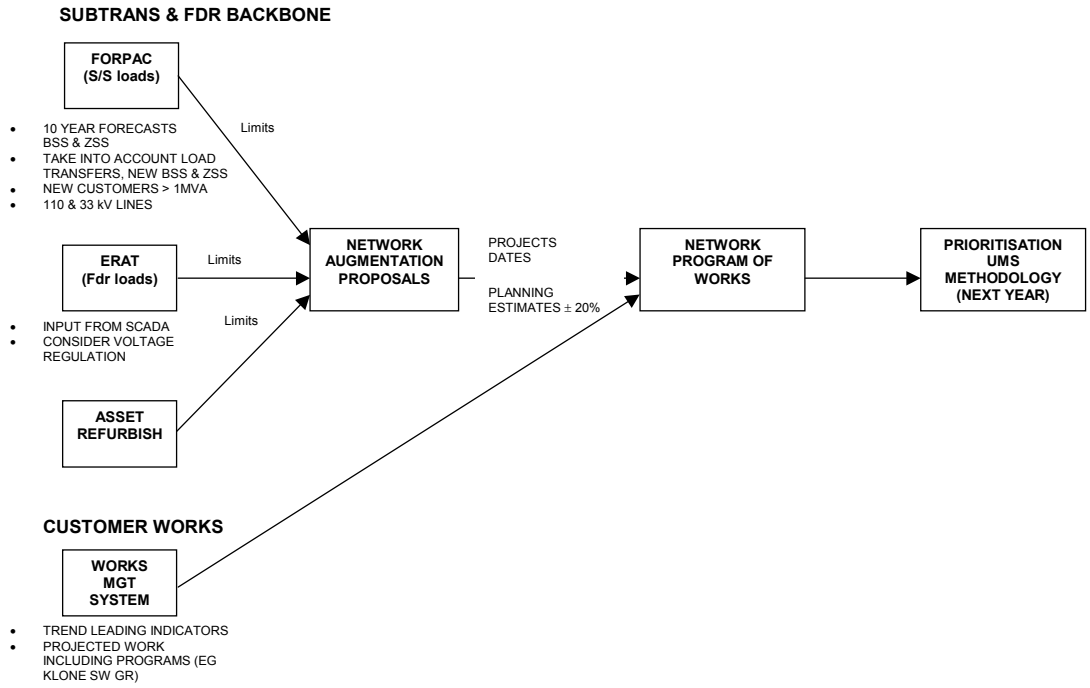
9.2 Energex Procedures for Assessing Capital Expenditure

The procedures for approval and prioritisation of capital expenditure are as follows:

9.2.1 Financial Budgets and Long Term Forecasts

The end-to-end processes for managing Network Initiated Capital Work and Customer Initiated Work are contained in BMS 2089 and BMS 2090 respectively. The approach taken is summarised in Figure 9-1.

Figure 9-1: Process for Capital Works



In the planning stage, ten year load forecasts are prepared for Bulk Supply and Zone Substations, based on data contained in the FORPAC system. The effect of load transfers and the planned installation of new substations are taken into account, together with known large customer loads (in excess of 1 MVA). Sub-transmission line limits are also identified through load flow studies. Limits at the 11 kV feeder level are identified based on data from the ERAT system. Asset refurbishment requirements are also identified.

The limits identified are detailed in an annual Network Development Plan, from which Network Augmentation Proposals are prepared for individual projects. Planning estimates are prepared to an accuracy of ±20%, and appropriate projects are included in the Network Program of Works.

This approach is essentially the same as that adopted by other DNSPs within the experience of the Consultant; however, in Energex's case, the effectiveness of the process is seriously affected by Energex's inability to process the most recent summer MD information in time to feed into the budget process. This has come about due to the timing of the system maximum demand in relation to the budget process and to reductions in system planning personnel, resulting in the need to estimate the impact on a macro basis (refer to Section 9.10.2.1). The Consultant considers that this significantly reduces the confidence in Energex's forecasts of demand related CAPEX, particularly in an environment of wide fluctuations in MD.

Budget requirements for customer and minor works are identified by trending leading indicators (mainly expenditures) and adjusting them to take account of known factors. This includes Programs (as opposed to specific Projects – for example, a Program to replace Krone switchgear). Customer and minor works requirements are then included in the Program of Works. The Consultant considers that a more rigorous approach is to trend physical quantities and multiply them by unit rates. The Consultant is concerned that this approach is not adopted by Energex, and that some of the basic physical quantities are not reliably recorded (for example, the number of URD lots reticulated and the number of poles nailed). Again, this erodes the level of confidence in Energex's estimates.

Projects for inclusion in the Program of Works are prioritised using a model developed by the UMS International Benchmarking and Management Consulting Company ("UMS"), which is discussed in the following section.

9.2.2 Project Prioritisation

Energex has recently adopted a proprietary methodology developed by UMS. This methodology operates in two key dimensions:

- Value analysis – to maximise the contribution to Energex's strategic objectives; and
- Risk analysis – examines the risk of not doing the project (not the project execution risk).

The value of a project or program is assessed against a set of weighted criteria for each strategic objective. The strategic objectives are in the following areas:

- Financial;
- Operational Excellence;
- Customers and markets;
- Staff safety and culture; and
- Community and environment.

This ensures that the value is being assessed on a "balanced scorecard".

Risks are assessed by use of a risk matrix, with six levels of consequences and six levels of likelihood of occurrence.

The model facilitates a risk/value trade-off to achieve the best value for a given budget amount. The model was used for the first time last year and it is planned to extend its use to include all projects and programs. Some modifications to the model may be necessary.

The Consultant considers that the UMS methodology is more sophisticated than the approach used by many Australian electricity distributors, and as such, project prioritisation is well handled by Energex.

9.2.3 Project Approval Process

The approval of Network Initiated Capital Works and Customer Initiated Works are included in BMS 2089 and BMS 2090 respectively. These documents detail the activities and control processes from start to finish, including project approval. Also included in BMS 2089 is the consideration of CAPEX/OPEX tradeoffs.

Energex has the following Financial Delegation policy:

> *"The expenditure of Energex funds and the disposal of Energex property requires the prior approval of a person in a position vested with the appropriate financial authority (Note:- Financial authority attaches to a position and not an individual occupying a position)."*

This policy is supported by a detailed listing of financial delegations for the various positions within the organisation.

Where economic evaluations are conducted, a discount rate (or hurdle rate) based on the Weighted Average Cost of Capital ("WACC") is applied, with a different rate prescribed for each of the business streams. The WACC provides that future cash flows are calculated on a nominal, after tax, un-leveraged basis. Where a particular investment has different risk or investment characteristics to that of the business stream, there is flexibility to vary the hurdle rate. In assessing network capital investment projects, a sensitivity analysis may also be applied, using discount factors of 8%, 10% and 12% (the Consultant saw evidence of this approach in some Planning Reports but not in the review of capital projects). The Consultant considers that the discount rates applied and their application are reasonable.

The fact that a project has been identified in the Network Development Plan and included in the financial budget of a specific year is not sufficient authorisation for expenditure to take place.

Once the preliminary work to support a project to be approved has been carried out, an approval form bearing the signature of the respective officers is submitted to the respective financial delegate for approval. The approval form includes amongst other things:

- A description of the works to be carried out;
- The reason the expenditure is required;
- The classification type of the project;
- An estimate of the costs of the works; and
- Where applicable, the calculation of the amount to be recovered as a Capital Contribution.

The project is then submitted to the manager with the appropriate level of financial delegation for their signature.

The capital project review (refer to Section 9.6) indicates that the approval process is generally followed.

9.2.4 Project Management & Financial Control

The key procedures for controlling capital expenditure are contained in BMS 1937 Project Management and BMS 1944 Variation Management. The former procedure details the key steps for managing engineering projects to deliver project outcomes on time, on budget and with quality, whilst the latter procedure outlines the process for Project Managers to appropriately manage and record variations in design, program, resources and budget.

The review of capital projects (refer to Section 9.6) indicates that variations are generally handled in accordance with the documented process, but that the process for project management could be more strictly applied.

Energex has advised that it will revise BMS 1937, in line with modified procedures currently being introduced.

The Consultant is satisfied that the procedures for project management and financial control are soundly based but has observed that the procedures are not always followed.

9.2.5 Conclusions

From the review of capital projects (as discussed in Section 9.6), the Consultant observed that the project approval process is largely being followed, but noted a few exceptions. The Consultant considers that the process would be enhanced by a more rigorous approach to the preparation of project justifications, through the more comprehensive economic evaluation of alternatives (including life cycle costs) and quantified risk assessment, and by the completion of all supporting material and including it in comprehensive and structured project files.

In addition, the Consultant considers that the project approval process would be further enhanced by the requirement for a formal business case to be prepared for all major projects (say, $500,000 and above), excluding Customer Initiated projects. The business case should include trade-offs between CAPEX and OPEX where appropriate.

For every project (including those on a fixed price basis and regardless of size), it is essential that a reconciliation be conducted after project completion to review costs and achievement of the project objectives. For each major project, a formal Post Implementation Review should be conducted to evaluate whether the costs and benefits projected in the business case were realised. Such reviews, whether for minor or major projects, provide the opportunity for learning and improvement for example, revisions to the estimating rates.

These modifications to the approval process would provide an enhanced level of rigour and improve the likelihood that capital expenditure is optimised.

9.3 Historical CAPEX values

Energex supplied the Consultant with various versions of Energex's historical CAPEX. The regulatory accounts contained insufficient detailed breakdown to allow comparison and analysis. For this reason, the most recent set of historical CAPEX values supplied by Energex that contain a detailed breakdown have been used by the Consultant for the analysis. The regulatory CAPEX and the CAPEX used for analysis are shown in the following table:

Table 9-1: Historical CAPEX Expenditure

		01/02	02/03	03/04
Regulatory CAPEX	$ M	287.4	289.9	300.0
Analysed CAPEX	$ M	281.8	289.7	296.2

All historical figures are in June 2004 dollars

9.4 Capital Expenditure Categories

Energex splits its capital expenditure into the categories shown in Table 9-2.

Table 9-2: Capital Expenditure Categories

CATEGORY	EXPLANATION	QCA CATEGORY
SUBTRANSMISSION & 11 kV BACKBONE		
CUSTOMER DRIVEN PRIMARY (CODE 311100)	Works required to connect individual customers to the sub-transmission (132, 110 & 33kV) & 11kV backbone network	Demand Related
DEMAND DRIVEN PRIMARY (CODE 311200)	Headworks on the sub-transmission & 11kV backbone network to meet the system forecast demands due to normal load growth. Work necessary to reinforce the system due to potential overload situations and/or maintain acceptable performance standards on the sub-transmission network & 11kV backbone due to normal load growth, including voltage regulation improvement & modification to the network to reduce losses.	
RELIABILITY IMPROVEMENT PRIMARY (CODE 311300)	Works to improve the reliability performance of the sub-transmission & 11 kV backbone networks (for example wildlife proofing). Also includes major safety and environment projects such as oil containment and substation fence upgrades.	Reliability/Quality Improvement

CATEGORY	EXPLANATION	QCA CATEGORY
REFURBISHMENT DRIVEN PRIMARY (CODE 311400)	Works to either replace ageing equipment or extend the life of existing equipment as reflected in the calculation of the equipment's value in the optimised replacement value database.	Asset Replacement
DEMAND DRIVEN PRIMARY, RELIABILITY DRIVEN SECONDARY (CODE 311500)	Works required under the above Demand Driven Primary but would equally be required/justified under the above Reliability Improvement Primary category.	Demand Related & Reliability/Quality Improvement
DEMAND DRIVEN PRIMARY, REFURBISHMENT DRIVEN SECONDARY (CODE 311600)	Works required under the above Demand Driven Primary but would equally be required/justified under the above Refurbishment Driven Primary category.	Demand Related & Asset Replacement
LAND & RGHT OF WAY (CODE 311700)	Acquisition of substation sites & easements required to expand the network due in general to increasing system load forecasts. (Included with Demand Driven Primary for Budget measurement purposes)	Demand Related
EASEMENTS (CODE 311750)	Work involved with the acquisition and management of easements.	Demand Related
COMMUNITY REQUIREMENTS (CODE 311800)	Works to be undertaken to improve network amenities as observed by the community, including transmission UG of OH.	Other
DISTRIBUTION AUGMENTATION		
DOMESTIC & RURAL CUSTOMER REQUESTED WORKS (CODE 312100)	Works to extend the network to connect domestic & rural customers, including subdivision works, excluding service connections.	Demand Related
OTHER WORKS – UG OF OH (CODE 312200)	Undergrounding of Overhead, mainly for local authorities. Covers all work in replacing overhead reticulation with underground cables. This work is usually initiated at the request of a local Authority or Government Department in which case a capital contribution is required.	Other
OTHER WORKS – OTHER CUSTOMER WORKS (CODE 312200)	Other capital works (that require a capital contribution) for customers, for example relocation of mains. The cost of works that are requested by, and for, Energex customers that are not covered by any other category.	
AGEING EQUIPMENT (CODE 312400)	Replacement of system elements. The capital cost associated with the replacement of major system components. Reinforcement can be due to potential safety hazards, excessive maintenance costs or reduction in reliability. Age alone is not an adequate reason for carrying out such reinforcement.	Asset Replacement
POLE REPLACEMENT & POLE NAILING (CODE 312450)	Work involved with replacing condemned poles & nailing of suspect poles.	Asset Replacement
COMMERCIAL & INDUSTRIAL CUSTOMER WORKS (CODE 312500)	Works to extend the network to connect commercial & industrial customers. The costs of Commercial/Industrial Customer requested extensions to the existing Distribution Network.	Demand Related & Reliability/Quality Improvement
PUBLIC LIGHTING (CODE 312600)	Works to add public lighting as requested by local & State authorities	
COMPANY INITIATED DISTRIBUTION AUGMENTATION (CODE 312650)	Provides for all work relating to augmentation of the distribution network (for example transformer upgrades). It excludes all work in zone substations & on the sub-transmission & 11kV backbone networks. Augmentation of the 11kV (spurs) and LV network due to quality of supply complaints or for reliability improvement purposes.	
SERVICE CONNECTIONS (CODE 312700)	Construction of new services for new customers & upgraded services for existing customers. The cost of works involved in connecting customers to the distribution network. Includes services, meters and relays.	Demand Related

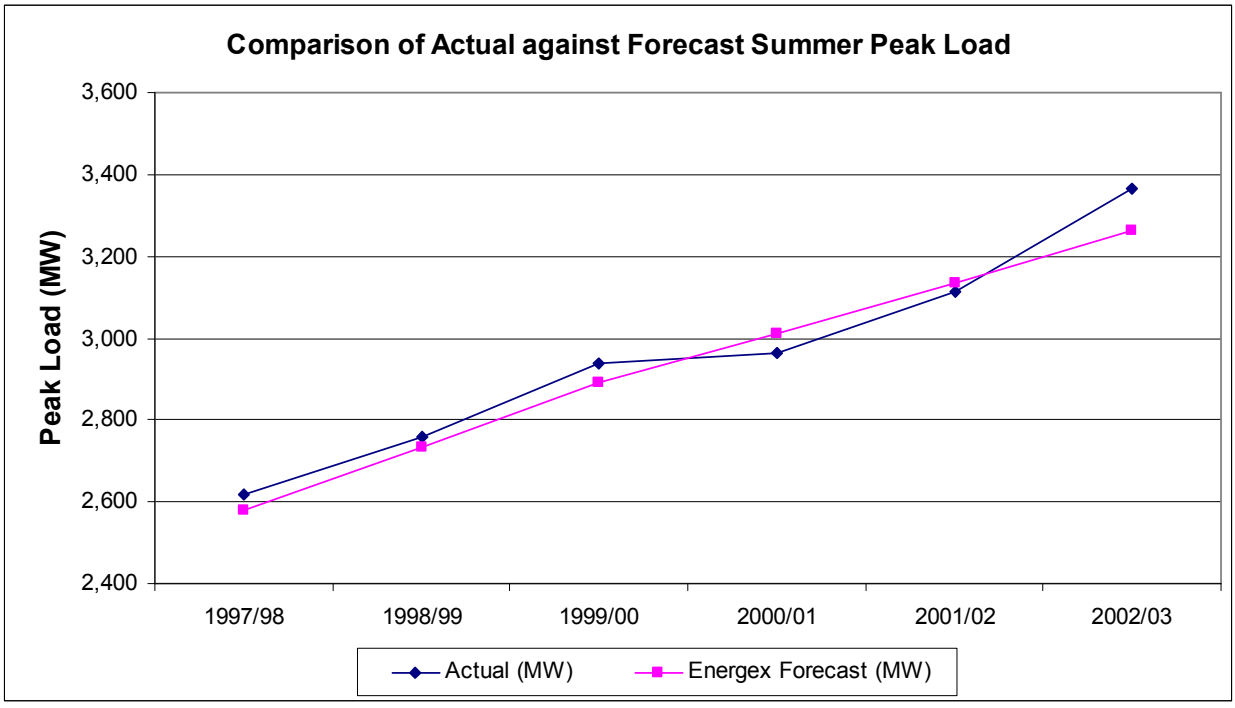
CATEGORY	EXPLANATION	QCA CATEGORY
NON-SYSTEM WORKS		
COMMERCIAL LAND & BUILDINGS		Other
IT&T		
MOTOR VEHICLES		
OTHER		

It can be seen that there are some difficulties in aligning Energex's expenditure to the four categories required by the QCA for reporting purposes. The QCA expenditure categories form part of national reporting requirements for all DNSPs. Further, Energex has made changes to its financial system and consistent historical data is not available. This reduces the Consultant's confidence in forecasts of future expenditure. To avoid these difficulties, the Consultant suggests that the QCA work with both Energex and Ergon Energy to develop a set of consistent expenditure categories.

9.5 Current & Projected Growth and Capacity

For the current regulatory period, demand growth was forecast by Energex at an average of 4.2% per annum, whereas for 2002/03 and 2003/04 years the increase in summer MDs were 5.1% and 8.1%. A comparison between forecast and actual peak summer loads is shown in Figure 9-2. The volatility of maximum demand since 1991/92 is apparent in Figure 9-5, with several reductions and large increases evident.

Figure 9-2: Comparison of Forecast and Actual Peak Summer Load



Energex attributes the significant increases in growth rates to the penetration of air conditioning, and predicts that this will continue for the next few years. Historical and Energex's forecast growth in customer numbers and MD are shown in the following graphs, namely Figure 9-3 and Figure 9-4 respectively:

Figure 9-3: Energex's Forecasts Customer Numbers

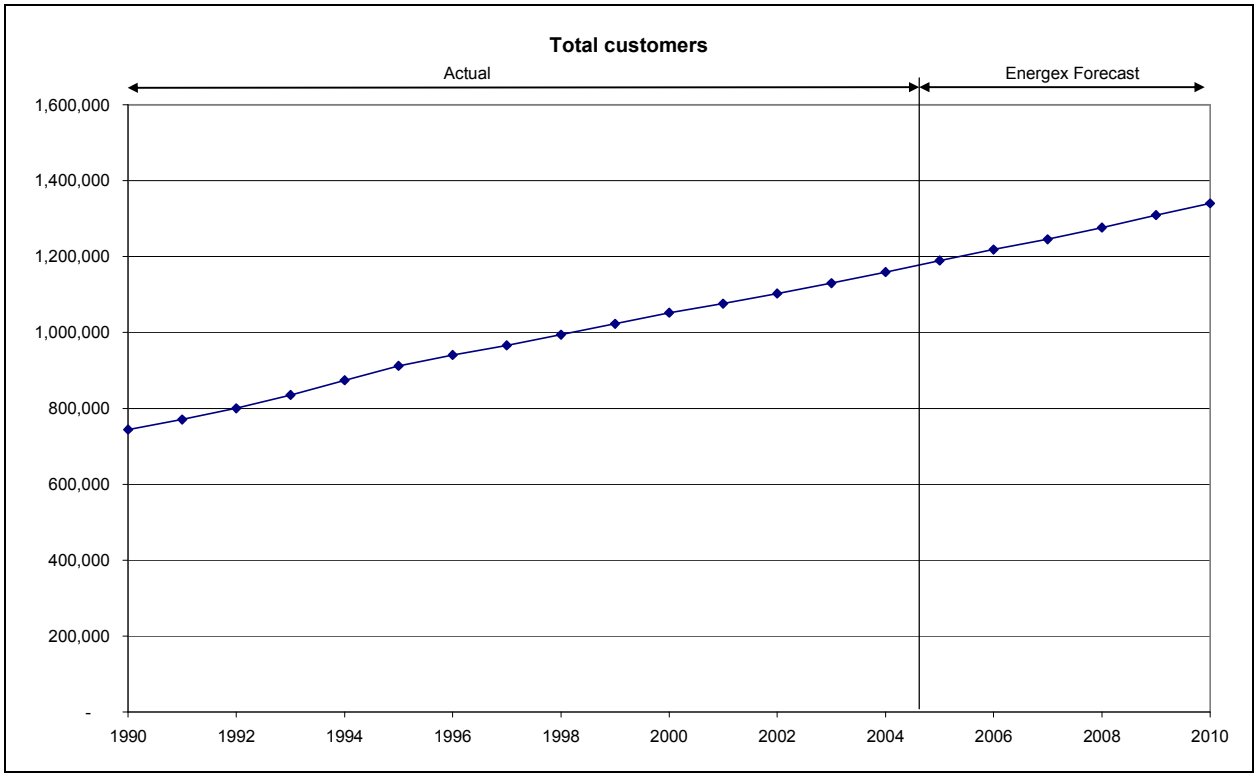


Figure 9-4: Energex's Forecast Maximum Demand (MW)

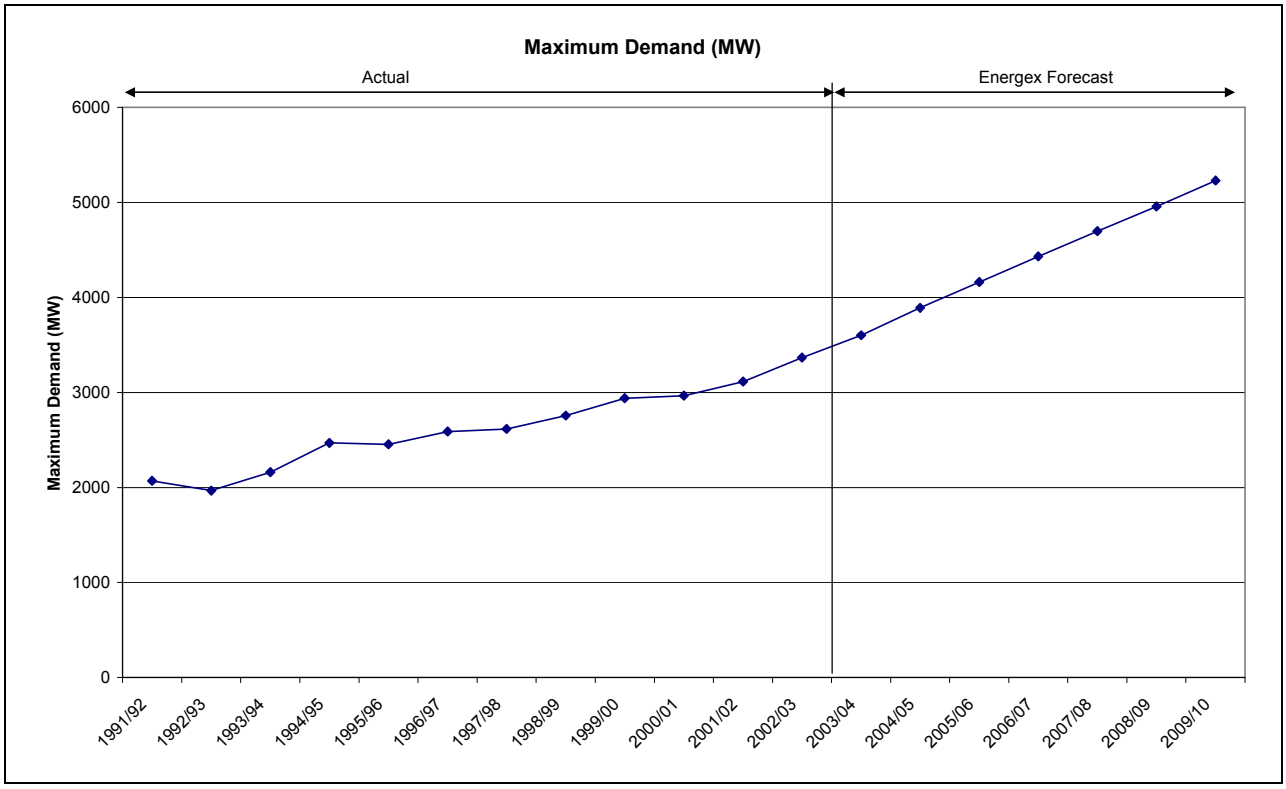
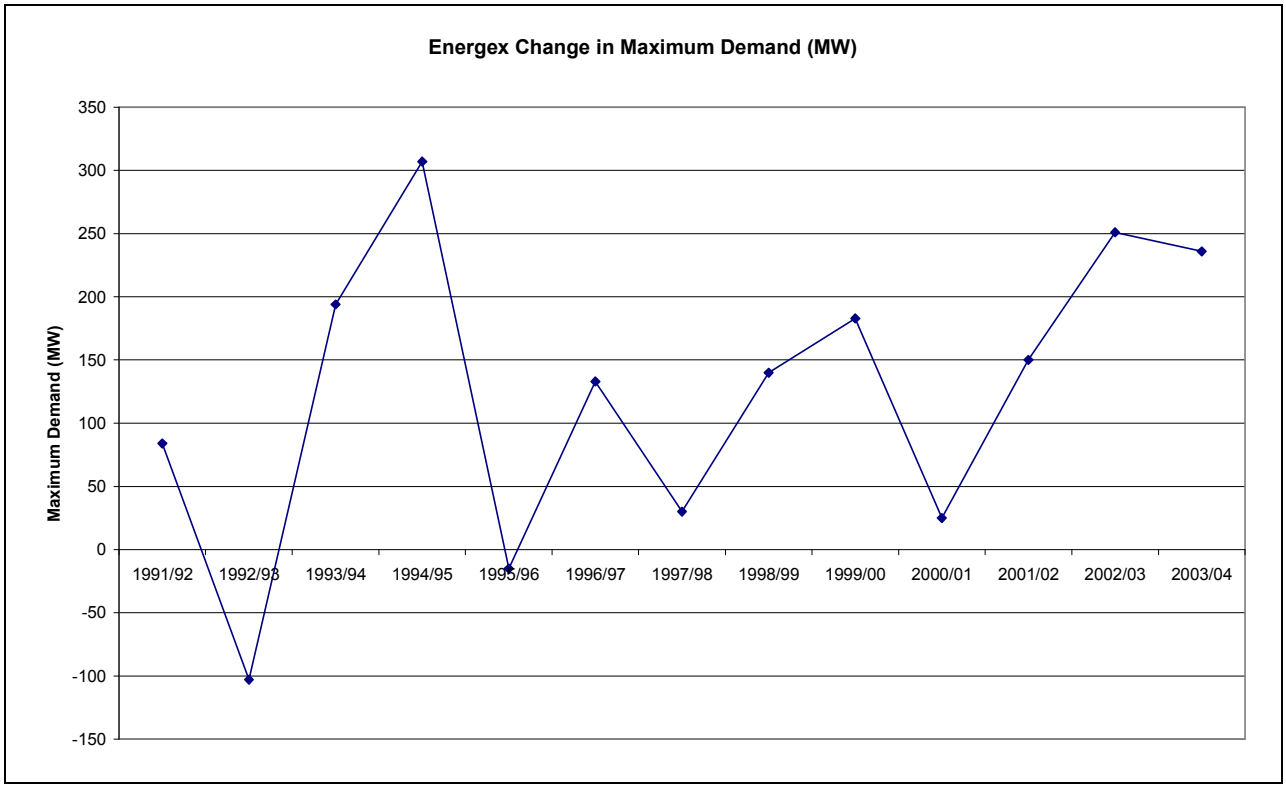


Figure 9-5: Change in Maximum Demand Growth Rate – Energex Actuals



The Consultant has prepared it's CAPEX estimates on the basis of Energex's forecasts for maximum demand and customer numbers. These have been separately reviewed by QCA's consultant MMA as discussed in Section 9.5.3.

Changes to the growth rate will result in changes to the requirement for capital spending.

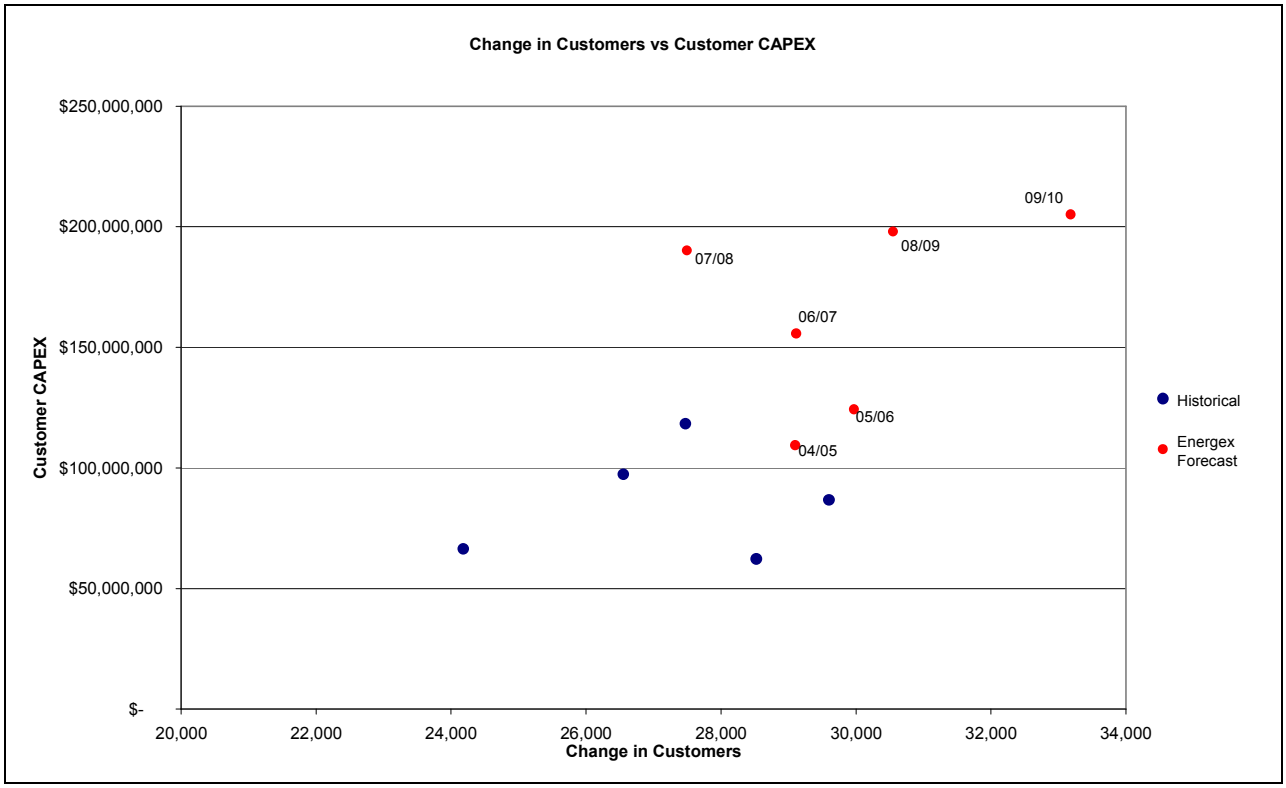
9.5.1 Relationship Between Customer Numbers & Customer Related CAPEX.

Changes to the growth rate of customer numbers will result in immediate changes to expenditure required in the following Energex categories:

- Customer Driven Primary;
- Domestic & Rural;
- Commercial & Industrial
- Public Lighting: and
- Service Connections.

The values of Customer CAPEX and change in customer numbers are shown in the following graph:

Figure 9-6: Change in Customer Numbers vs Customer CAPEX



All forecast and historical figures are in June 2004 dollars

The historical cost to connect additional customers is of the order of $3500 per new customer.

It can be seen that there is a fairly good correlation up to and including 2005/06 (at about $3,500 per new customer), but then a wider spread is evident, particularly with the 2007/08 year. The cost to connect a new customer is affected by a range of factors, including the following:

- The connection of large customers - it is often very expensive to connect a single large customer, which can skew the relationship; and
- The installation of air conditioning is forcing the upgrading of service connections. Thus, whilst the cost of the service upgrade would appear against “Service connections”, no new customer would be added to the network. (The category of “Service connections” is a significant proportion of the customer CAPEX expenditure to the extent of up to 40% in the years 2007/08, 2008/09 and 2009/10.)

For the forecast period, an approximate rate of $6,500 per new customer can be established.

The cost per new customer for the Victorian distributors over the current Determination period has been analysed. Energex is the same as AGL ($6,500) and similar to Powercor ($5,500 per new customer) and TXU ($8,100 per new customer).

9.5.2 Relationship Between MD & Demand Related CAPEX.

Changes to the growth rate of maximum demand will result in changes to the expenditure required in the following Energex categories:

- Demand Driven Primary;
- Land & Right of Ways;
- Easements;
- Demand Driven Primary, Reliability Improvement Secondary;
- Demand Driven Primary, Refurbishment Secondary;
- Company Initiated Distribution Augmentation.

The relationship between changes in the growth rate of maximum demand and Demand Driven CAPEX are not as straight forward as that between changes in growth of customer numbers and Customer Initiated CAPEX, due to uncertainties in the timing of the required CAPEX to meet the increased demand. In some cases, work will be required immediately, but in other cases there may be sufficient spare capacity to cope with the increased demand, deferring the need for increased CAPEX for many years. Further, two of the expenditure categories involved have mixed drivers, so assumptions have been made in regard to how much of the expenditure relates to demand (in each case, it has been assumed that 50% of the expenditure is demand related).

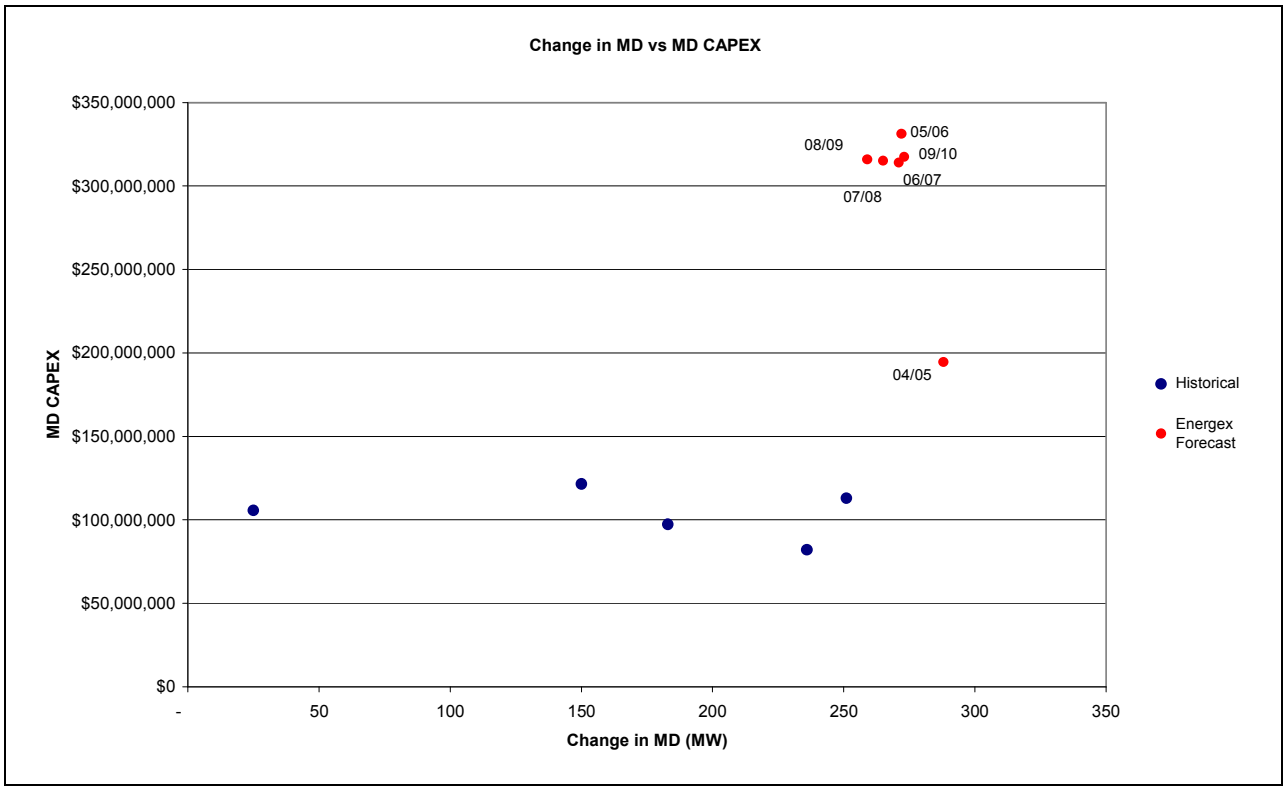
The expenditures for the total of these categories (in $ millions) and the increase in maximum demand (actual and forecast) are shown in the following table and graph:

Table 9-3: Change in Maximum Demand (MW) and Maximum Demand CAPEX

		99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10
CHANGE MD	MW	183	25	150	251	236	288	272	271	265	259	273
MD CAPEX	$M	97.3	105.6	121.5	113.0	82.0	194.5	331.4	313.9	315.2	315.9	317.5

All forecast and historical figures are in June 2004 dollars

Figure 9-7: Change in Maximum Demand vs Maximum Demand CAPEX



All forecast and historical figures are in June 2004 dollars

From the above graph it can be seen that very little grouping or relationship exists across the historical and forecast values of demand CAPEX. This supports the previous discussion that demand CAPEX and maximum demand in any one year may not be directly related. Assets that are installed in any one particular year may be required to meet the demand in that particular year but may not be fully utilised until later years. Thus the expenditure may not align with the maximum demand. There may also be the opposite occurring as assets that are currently overloaded are replaced or additional assets installed for which there is no increase in maximum demand in that year.

Energex, in their support documentation supplied to the Consultant have estimated that:

> *"a 1% increase* (in MD) *translates into the equivalent of 5 zone substations across each of the supply voltages (bulk, zone and distribution). The cost of these additional substations is estimated at approximately $70M pa."*

This equates to a cost of $1.8M per MW increase in MD. The cost for Energex's forecast demand CAPEX over the five year period is $1.2M per MW, which is significantly lower than the estimated rate for a 1% increase. Based on the Consultant's estimates for demand-related CAPEX, the cost per additional MW increase in demand should be $1.0M.

These costs have been compared to the costs for the Victorian distributors over the current Determination period. Energex is more expensive than any of the Victorian distributors (the most expensive of these is CitiPower at $0.7M per MW). The Consultant considers that much of the higher costs for Energex can be attributed to the need to address overloading on significant portions of the network. The Consultant considers that Energex have accepted an increased level of risk to reduce costs during the current period, resulting in overloads on the network. As a result they now have to spend significantly more than normal in order not just run their system in a sustainable manner but also to make up for previous under-spending. Energex claim that the level of underspending amounts to $923M, whereas the Consultant considers the amount is closer to $500M. The Consultant's analysis of this underspending was not related to the actual MDs, but rather to the levels of historical CAPEX, taking particular note of the reductions over the period 1990/91 to 1998/99.

9.5.3 Impact of Differences Between Forecasts

The demand forecasts have been separately reviewed by MMA who have forecast peak demands, energy consumption and customer numbers. MMA have predicted lower average growth over the forecast period than Energex, as shown in the following table:

Table 9-4: Energex and MMA Forecast for MD and Customer Numbers

	MAXIMUM DEMAND (MW)	CUSTOMER NUMBERS
ENERGEX FORECAST	5.9%	2.4%
MMA FORECAST	5.3%	2%

The Consultant has based its expenditure forecasts on the growth forecasts provided by Energex. The Consultant has estimated that the difference in the forecasts of customer numbers and MD equates to a reduction to the Consultant's estimates over the period 2005/06 to 2009/10 of:

- $8.5M for customer initiated works; and
- Approximately $125M for corporate initiated works.

Significant changes in expenditure requirements can result from relatively small changes in MD or customer numbers particularly changes in MD. To mitigate the impact of significant under or over spending due to changes in forecast growth rates, the Consultant suggests that the QCA consider some form of adjustment mechanism where growth rates differ significantly from forecast values.

9.6 Review of Projects – Prudency and Efficiency

The Terms of Reference issued by the QCA required the Consultant to ascertain the efficiency of the most significant capital projects having regard to:

- The existing infrastructure and renewals requirements;
- The demographic circumstances;
- Service quality and reliability (for a base level defined by current service quality and reliability standards and any alternative levels that the DNSP may propose);
- asset utilisation; and
- The potential for demand management and /or embedded generation solutions to defer capital expenditure.

In order to assess the efficiency of capital projects, the Consultant carried out a detailed review of a range of capital projects from the perspective of whether the expenditure was prudent (did the money need to be spent?) and efficient (was there value for the money spent?).

9.6.1 Projects Selected

The Consultant had proposed to the QCA to establish materiality thresholds for the various types of projects and to review a number of projects of each type above the thresholds. After discussion, the QCA expressed a preference for the project review to cover a wider range of project costs and so materiality thresholds were not established.

The Consultant nominated a number of projects in each category, ensuring a spread between geographic location, completed and current projects, project value and project type.

9.6.2 Methodology

The selected projects were reviewed against the five criteria listed by the QCA, as well as minimising life cycle costs/economic evaluation, risk analysis, environmental requirements and planning standards. Past projects were also evaluated in terms of their efficiency on the basis that the Consultant considers that past performance provides a key indication of likely future performance.

To ensure that a consistent approach was adopted by the review team, a pro-forma was developed and utilised to evaluate each project and record the information. A copy of the pro-forma is contained in Appendix 14.7. A total of 40 projects were reviewed, as listed in Appendix 14.8.

Given the significant number of projects sighted, the Consultant is confident that they have achieved an overview of the capital projects for the period 2001/02 to 2003/04. Detailed project information was not available for earlier or later periods.

9.6.3 Observations

The following observations were made in the course of the review:

- There was not a consistent approach to the project file recording process, for example:
    - For projects of similar value and complexity, records ranged from comprehensive to relatively sketchy.
    - Many files were disorganised, with material not in order (chronological or subject matter).
    - A lot of information was duplicated (sometimes three or four copies of the same document).
    - Many files contained checklists which were not used or only partially completed.
- There were many examples where there was little supporting detail, particularly in regard to:
    - Pre-project information, explaining the background and how the need for the project was identified;
    - Consideration of or details provided for alternative options; and
    - Quantified risk assessments, consideration of life-cycle costs, environmental assessments and the system planning/network capacity impacts. There is some evidence that the latter had been considered, but the information was not generally recorded in the project files.
- Projects were generally authorised in accordance with delegated authority. Exceptions were:
    - Several projects for which authorisations were not found in the material provided;
    - One project where the cost was outside the delegated level;
    - One project where the final cost ended up exceeding the delegated authority level due to scope changes. The Consultant considers that this project should have been re-authorised at the time the scope was changed.
- Project variations were generally documented.
- There were a number of issues with project reconciliations:
    - Reconciliations not endorsed that is, signed by Project Manager only;
    - Project closures and reviews were usually authorised at a lower level than the project authorisation;
    - No evidence of reconciliation being conducted (multiple examples);
    - Comment made that a reconciliation was not required as it was a fixed price job (several examples);
    - Instances of lack of explanations, even for some significant overspending;
    - An instance where a number of projects of differing categories were bundled together for the reconciliation;
    - An instance where the reconciliation was carried out in a later year and the labour rates applying in the current year were used, rather than the labour rate applicable at the time;

- A project review conducted prior to project closure provides an opportunity for improving the process (for example, to amend estimating rates or to change the project management approach). There was no evidence that this feedback was occurring.
- Several examples where the project was allocated to an incorrect category, based on the information presented.

9.6.4 Conclusions

The process of compiling project files to support capital expenditure is not well defined at Energex and should be improved. Despite this, there was sufficient evidence to suggest that for the existing infrastructure and renewals, service standards and asset utilisation are appropriately considered by Energex in the assessment and approval of capital projects.

The demographic circumstances were not relevant for individual projects in most cases, but were considered at a high level in network planning studies.

The process for project approval would be enhanced by the provision of pre-project information, use of quantified risk assessments, documented system planning/network capacity impacts and improved financial assessments.

The potential to contract for distributed (embedded) generation and demand management to defer or reduce network capital expenditure was not considered by Energex for any of the projects reviewed. This was not an option for many projects (for example; asset replacements, supply to new developments etc). For some major projects, Energex has issued a Request for Information, seeking input from interested parties regarding potential solutions to network limitations. Examples include the supply to the Gold Coast (in conjunction with Powerlink) and supply to the Brisbane central business district ("CBD') (also in conjunction with Powerlink). Energex has advised that they are currently reviewing options for Demand Side Management ("DSM") initiatives. Potential DSM initiatives being considered include:

- Air conditioning thermostat control;
- Ice chillers for air conditioning;
- Time of Use tariffs:
- Standby generation;
- Distributed generation (gas generation or fuel cells); and
- Fuel substitution.

The process for project reconciliations should be tightened up and it is suggested that reconciliations be signed off at the level at which the projects were authorised, in order to provide feedback at the appropriate level in the organisation.

Of the additional criteria considered in ascertaining the prudency of the capital expenditure, the Consultant has some concerns about the level of consideration given to minimising life cycle costs/economic evaluation and risk analysis. In the absence of such information, the need for a few of the projects has not been clearly established, based on the information contained in the project files, although it is possible that other supporting information exists elsewhere in the organisation. The review did not raise any concerns in regard to the consideration of environmental requirements and planning standards.

It is appreciated that the need for a customer initiated project is readily established by the request from the customer; however, the method by which that need is met must be justified for the expenditure to be considered prudent.

Notwithstanding the observations and concerns raised in the preceding paragraphs, the Consultant is of the view that the capital expenditure for the projects reviewed was generally prudent.

In assessing the efficiency of capital expenditure for the projects reviewed, the Consultant considered the basis for preparing the cost estimate, the comparison of actual with estimated cost (for completed projects), and the design/planning approach adopted.

Energex have developed a series of Compatible Units that identify the costs for standard network items. A comparison between actual and estimated costs for the projects reviewed, for which actual costs were available (22 completed projects), revealed that the total actual costs were $64.9M, against an estimated $62.2M (i.e. +4.3%), which gives confidence in the estimating process. The Consultant considers that the expenditure was consistent with the design and planning guidelines established by Energex. The Consultant has concluded that expenditure for the projects reviewed appeared to be efficient.

9.7 Projects Associated with Customer Contributions

The Terms of Reference required the Consultant to review and comment on the DNSPs' forecast level of customer contributed capital projects.

The principles and procedures by which Energex currently imposes capital contribution charges are detailed in Energex's Supply and Planning Manual, Sections 2.3, 2.4 and 2.5. Energex has recently reviewed its customer contributions methodology and has submitted the proposed amendments to the QCA for approval. Energex has advised that customer capital contributions are expected to increase by about 10-15% under the proposed arrangements, on the basis of customers making some contribution to the shared network, although such an increase is not reflected in Energex's forecasts.

The review of capital projects (refer to Section 9.6 of this report) indicated that customer contributions were in line with current policies.

Energex's current General Commercial Conditions of Supply states:

Tariff conditions alone apply where:

- *there are no existing agreements in the area, and*
- *supply is available from existing low voltage mains by means of a low voltage service; or*
- *where extension of mains is required, the estimated APR will provide sufficient revenue return on the capital cost of the extension.*

Supply is given under guarantee or guarantee and capital contribution conditions where:

- *agreement conditions exist in the area*
- *the estimated APR would provide insufficient return.*

A guarantee is an agreement between ENERGEX and an applicant or group of applicants to ensure a minimum annual return (i.e. the percentage return requirement) for a prescribed period:

- *a capital contribution is a cash contribution toward the capital cost of an extension and is required in conjunction with a guarantee agreement when the proposed annual guarantee will be less than the required percentage return*
- *a capital contribution may be required without a guarantee when:*
  - *the anticipated revenue from additional loading on an existing installation is less than 22.5 per cent of the estimated cost of supplying the additional loading (45 per cent for commercial and industrial loading)*
  - *underground mains are required in lieu of overhead mains*
  - *11kV mains are required in lieu of LV consumers mains*
  - *excess cable is required*
  - *special requirements apply (eg disturbing loads, special reliability of supply, standby plant capacity, multiple points of supply and padmount transformers in lieu of ground transformers).*

Projects associated with customer capital contributions fall into the following main categories:

- Supply to customer extensions
- Supply to residential, commercial & industrial subdivisions

Relocations where assets are replaced with like assets are treated as OPEX, even when old assets are removed and replaced with new assets. In the Consultant's experience, it is general practice to retire the old assets and capitalise the new assets.

Contributions are made up of in-kind contributions and cash contributions.

A comparison between Energex's actual (for 2001/02 and 2002/03) and budget (for 2003/04 and 2004/05) expenditure and the QCA Allowance for the current period for Customer Contributions (in $ millions) is shown in the following table:

Table 9-5: QCA Determination and Energex Projects associated with Customer Contributions

		01/02	02/03	03/04	04/05	TOTAL
QCA DETERMINATION	$M	23.3	24.0	24.6	25.1	97.0
ENERGEX ACTUAL/BUDGET	$M	23.9	24.8	44.2	33.0	125.9

All forecast and historical figures are in June 2004 dollars

It can be seen that the level of Customer Contributions has been higher than allowed for, which is broadly consistent with an increase in the level of Customer Initiated CAPEX. The 2003/04 projection is based on the year to date expenditure, and the significant increase is attributable to the extremely high level of subdivision activity.

Energex's forecasts are shown in the following table:

Table 9-6: Customer Contribution Forecast

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	33.0	34.9	37.1	39.3	41.7	44.2	197.2

All forecast and historical figures are in June 2004 dollars

The increased level of customer contributions is broadly in line with forecast increases in customer initiated work, and appears to be reasonable on that basis. Energex are of the view that there will be no change to the current rules regarding contestability of customer connection work in the next regulatory period and their forecasts reflect this.

9.8 Works in Progress & Commencement of Depreciation

Energex advises that Works in Progress ("WIP") has been trending upwards and this is expected to continue, from around $70M to a level of about $140M. This is driven by an increased number of projects and an increase in the length of projects. Energex reviews the status of WIP on a quarterly basis and reports this at General Management level. The Consultant considers that the expected increase in WIP is broadly consistent with the projected increase in the level of work.

Depreciation commences when the asset is put into service. Large projects are broken into sections and depreciation is started progressively as sections are placed into service. The Consultant considers that the commencement of depreciation is being appropriately applied.

9.9 Cost Pass-Through

In its Final Determination , Regulation of Electricity Distribution, May 2001, the QCA commented:

> *"A cost pass-through allows a regulated organisation to increase (decrease) its revenue cap in response to an increase (decrease) in a cost that is typically beyond the regulated organisation's control and is readily observable. Cost pass-through arrangements shift the risk associated with a specific cost from the regulated organisation to the customer. However, because cost pass-through usually only applies to costs that are beyond the regulated organisation's control, this approach is also a way to avoid regulated organisations being subject to windfall gains and losses*."

Energex supports the concept of some form of pass-through mechanism to cater for unpredictable projects beyond its control. The issue is the nature of mechanism for determining which projects should be eligible for pass-through consideration.

The development of a detailed pass-through mechanism is beyond the scope of this report. The Consultant recommends that QCA develops a detailed mechanism in conjunction with the two DNSPs.

9.10 Efficient CAPEX Program 2003/04 - 2012/13

Due to difficulties in aligning Energex's expenditure categories with those set by the QCA (refer to Section 9.3), it has not been practicable to make a meaningful comparison between the QCA allowance and actual/budgeted expenditure for the current period in several of the categories. A comparison for total CAPEX is shown in the following table:

Table 9-7: QCA Determination and Energex CAPEX Program

		01/02	02/03	03/04	04/05	TOTAL
QCA DETERMINATION	$M	255.4	260.0	256.5	260.2	1,032.1
ENERGEX ACTUAL/BUDGET	$M	270.6	281.7	300.0	446.6	1,298.9

For comparison purposes, all figures are in dollar of the day.

Energex changed its accounting policy at the start of the current regulatory period, in regard to capitalisation of pole replacements and replacement of under-height services – these items are now capitalised. The impact of this change is estimated to be an increase in capital expenditure of around $20M over the period 2001/02 to 2002/03.

On 1 May 2003, Energex introduced a new works management and scheduling software package to refine the management of its Work in Progress expenditure processes. Although the new system changed the basis of the allocation of overheads within the Regulated Line of Business, Energex advises that in total, there is no difference in allocations using the new system and those under the previous system over a year, but there may be minor differences in allocations between operating and capital. The magnitude of any such differences has not been quantified.

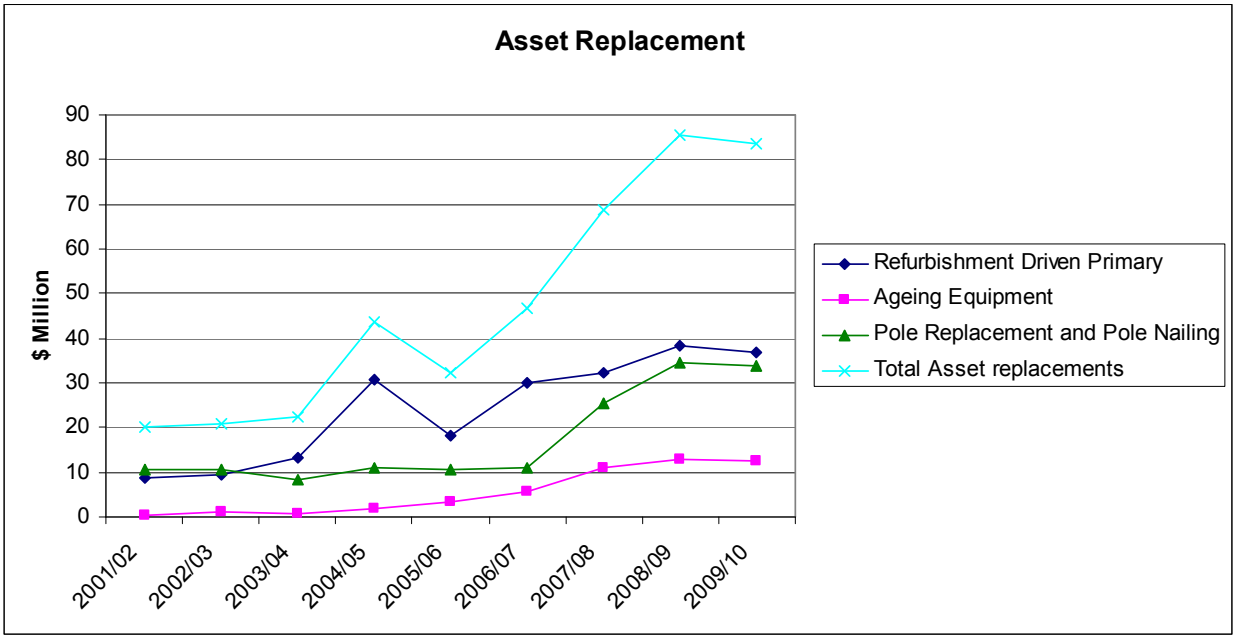
The TOR issued by the QCA require the Consultant to provide an opinion on the efficiency of each DNSP's CAPEX forecasts. In assessing efficiency, the Consultant has analysed the data provided, recognising the timeframes available, and has made judgements based on its experience within the industry. The Consultant has used the term "reasonable'' in the assessment of CAPEX to convey the view that the expenditure is considered to be efficient, within these limitations that is, available data and time.

9.10.1 Asset Replacements

Asset Replacements has been taken as the sum of Refurbishment Driven Primary (Code 311400), Ageing Equipment (Code 312400) and Pole Replacement and Pole Nailing (Code 312450). As noted in Section 9.29.3, there are difficulties in aligning Energex's expenditure to the QCA categories.

Energex's actual (for 2001/02 and 2002/03) and budget (for 2003/04 – 2009/10) expenditure for Asset Replacement CAPEX is shown in the following graph:

Figure 9-8: Asset Replacement Expenditure



All forecast and historical figures are in June 2004 dollars

It can be seen that Energex is forecasting very significant increases in expenditure in this area, from the current levels of around $20M per year ramping up to $85M by 2008/09. Each of the three component areas is discussed in more detail in the following sections.

9.10.1.1 Refurbishment Driven Primary (Code 311400)

Historical, projected and forecast expenditure for Refurbishment Driven Primary is shown in the following table:

Table 9-8: Refurbishment Driven Primary Expenditure

		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX	$M	8.8	9.3	13.4	30.9	18.3	30.1	32.4	38.2	37.0	156.0

All forecast and historical figures are in June 2004 dollars

Energex has based its forecast expenditure on a report prepared by Sinclair Knight Mertz ("SKM") that made recommendations for spending over the next five years. Most of the increase from 2003/04 to 2004/05 is due to replacement of aging 33kV gas insulated cables that have been experiencing high failure rates. Allocations for this activity are $18.5M in 2004/05, $10.1M in 2005/06, ramping down to $5.1M in 2009/10. The Consultant accepts the need for the replacement of this type of cable and considers that the costs are consistent with the route lengths involved.

Another significant item is the replacement of Krone 11 kV switchgear, at a cost of $4.3M per year for the period 2004/05 to 2007/08. The Consultant accepts the need for the replacement of this type of switchgear and considers that the costs are consistent with the number of units involved.

Energex plans to replace the motor-generator sets installed for load control purposes due to age and duty cycle limitations, at a cost of $12.5M. The Consultant accepts the need for the replacement of this equipment and considers that the costs appear to be reasonable.

Energex have also made allowance for increasing levels of expenditure to refurbish power transformers (unspecified projects), increasing from $1M in 2006/07 up to $10.4M in 2009/10. In the absence of information to support such a large increase, the Consultant has held this expenditure to $1M per year.

The following table compares Energex's and the Consultant's forecasts:

Table 9-9: Consultant's Refurbishment Driven Primary Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	30.9	18.3	30.1	32.4	38.2	37.0	156.0
CONSULTANT FORECAST	$M	30.9	18.3	30.1	28.3	30.6	27.6	134.9

All forecast and historical figures are in June 2004 dollars

9.10.1.2 Ageing Equipment (Code 312400)

Historical, projected and forecast expenditure (in $ millions) for Ageing Equipment is shown in the following table:

Table 9-10: Ageing Equipment Expenditure

		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX	$M	0.5	1.0	0.7	2.0	3.3	5.6	10.9	12.8	12.6	45.2

All forecast and historical figures are in June 2004 dollars

Energex have stated that SKM recommended a refurbishment CAPEX for overhead distribution lines of $17M in 2005/06 increasing to $21M in 2009/10. Energex have made a much lower allowance in their forecasts. The Consultant accepts Energex's assessment of the need for increased expenditure in this area, driven by an expected worsening of the condition of equipment as it ages.

Energex have made an allowance of $12M over the Regulatory period for a new program to replace open wire LV mains with Aerial Bundled Conductor ("ABC") where there is a safety risk of trees growing into LV mains. Due to the lack of detail from Energex to support this program, the Consultant has removed it from the forecasts.

The following table compares Energex's and the Consultant's forecasts:

Table 9-11: Consultant's Ageing Equipment Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	2.0	3.3	5.6	10.9	12.8	12.6	45.2
CONSULTANT FORECAST	$M	2.0	1.0	3.3	8.5	10.3	10.1	33.2

All forecast and historical figures are in June 2004 dollars

9.10.1.3 Pole Replacement and Pole Nailing (Code 312450)

Historical, projected and forecast expenditure (in $ millions) for Pole Replacement and Nailing is shown in the following table:

Table 9-12: Pole Replacement and Pole Nailing Expenditure

		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX	$M	10.7	10.5	8.3	11.0	10.7	11.1	25.3	34.4	33.9	115.4

All forecast and historical figures are in June 2004 dollars

From July 2000 to date, Energex has noted a condemnation rate of 4.6% p.a. of the wooden poles inspected but predicts a rate of condemnation of 5% p.a. Although there is an issue with recording of nailed poles, Energex has reported a nailing rate of about 80% of the condemned poles (i.e. 20% of the condemned poles are replaced and 80% are nailed). Energex currently inspects 122,500 poles per year.

Energex has based its forecast expenditure on an anticipated need to replace poles in excess of their economic life, reduced by resource constraints. The estimates assume very large increases in the number of condemned poles in 2007/08 and again in 2008/09, with a resultant increase in expenditure which is not consistent with a condemnation rate of 5% p.a.

The Consultant does not accept the projected increase in the number of poles condemned. Whilst some more gradual increase in failure rates could be expected due to the increasing age of poles, this would be offset to some extent by the impact of the recent program of chemical treatment. Poles are not condemned on the basis of their age, but purely on their condition and it is common for poles to last beyond their economic life. This is discussed in more detail in Section 6.3.2. The Consultant considers that a more realistic forecast is as shown in the following table:

Table 9-13: Consultant's Pole Replacement and Pole Nailing Expenditure

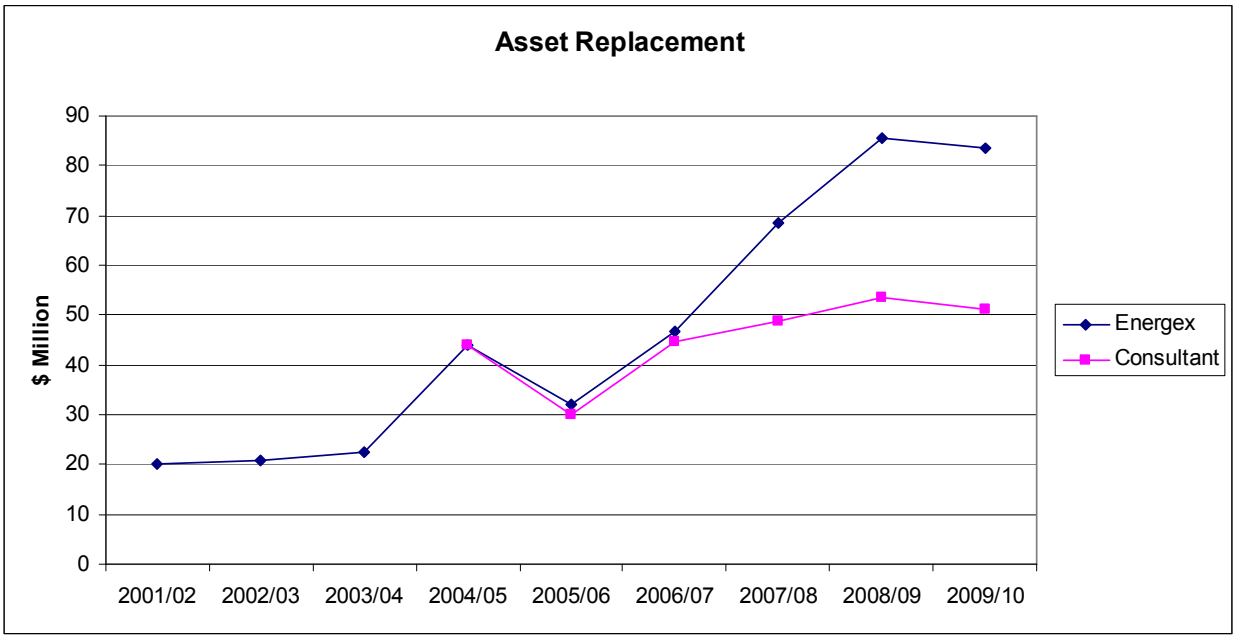
		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	11.0	10.7	11.1	25.3	34.4	33.9	115.4
CONSULTANT FORECAST	$M	11.0	10.7	11.2	11.9	12.6	13.5	59.8

All forecast and historical figures are in June 2004 dollars

9.10.1.4 Revised Total Asset Replacements CAPEX

A comparison between Energex's forecast expenditure and that proposed by the Consultant is shown in the following graph:

Figure 9-9: Consultant's Asset Replacement Expenditure



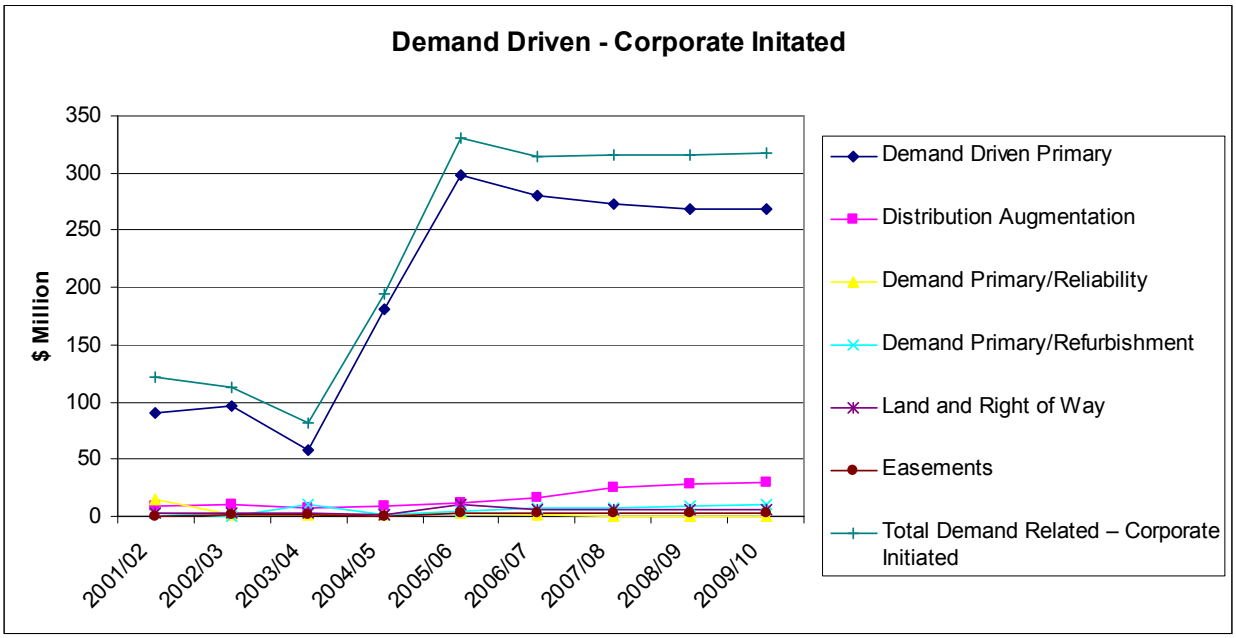
All forecast and historical figures are in June 2004 dollars

9.10.2 Demand Related – Corporate Initiated

This category has been taken as the sum of Demand Driven Primary (Code 311200), Demand Driven Primary Reliability Driven Secondary (Code 311500), Demand Driven Primary Refurbishment Driven Secondary (Code 311600), Land and Right of Way (Code 311700), Easements (Code 311750) and Company Initiated Distribution Augmentation (Code 312650).

Energex's actual (for 2001/02 and 2002/03) and budget (for 2003/04 – 2009/10) expenditure for Demand Related Corporate Initiated CAPEX is shown in the following graph:

Figure 9-10: Demand Driven – Corporate Initiated Expenditure



All forecast and historical figures are in June 2004 dollars

It can be seen that most of the expenditure in this category relates to Demand Driven Primary, and that very significant increases are forecast in this area.

9.10.2.1 Demand Driven Primary (Code 311200)

Historical, projected and forecast expenditure (in $ millions) for Demand Driven Primary is shown in the following table:

Table 9-14: Demand Driven Primary Expenditure

		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX	$M	91.2	96.8	57.4	180.5	298.0	279.6	273.2	268.5	269.0	1,388.2

All forecast and historical figures are in June 2004 dollars

Energex have stated that they developed their forecasts using a "top down, bottom up" approach, with individual projects identified from network limitations driven by forecasts of maximum demand. This rigorous approach was based on the demand forecasts as of July 2003, which were based on the MD experienced during the 2002/03 summer period. Energex has subsequently revised its MD forecasts, based on the more recent summer MD, but has not had time to re-assess network limitations with the level of planning resources available. The updated demand forecasts show an increase of about one percentage point higher than the previous forecasts. Energex has estimated that the one percentage point increase translates into the equivalent of five zone substations (with work spread across bulk, zone and distribution voltages), equating to about $70M per year. The Consultant is concerned at this less rigorous approach, and has concluded that the additional expenditure associated with the one percentage point increase in demand would be less than that forecast by Energex (refer to Section 9.5.2).

Energex has a documented process for developing its Annual Network Development Plan that is then used to develop its budget forecasts. This process identifies the network equipment limitations and develops proposals to overcome the limitations. On this basis, nearly all Demand Driven Primary expenditure for the forthcoming Regulatory period should have been identified and costed at the individual project level, leaving aside the increased expenditure for the revised MD forecasts.

The Consultant has cross-checked the projects listed in Energex's CAPEX program with those identified in its Annual Network Development Plan for the year 2004/05 and 2005/06. The results are shown in the following table:

Table 9-15: Comparison of CAPEX Program to Network Development Plan for 2004/05

	04/05		05/06	
	Project Value ($M)	**No. of Projects**	**Project Value ($M)**	**No. of Projects**
CAPEX Program	180.6	264	298	191
Network Development Plan projects included in CAPEX Program	111.3	141	171	125

All forecast and historical figures are in June 2004 dollars

This cross-check shows that of the 264 projects listed in the CAPEX program for 2004/05, 141 originate out of the Network Development Plan, with a difference in cost of $70M (this equates to the allowance made by Energex for the increase in MD of one percentage point, as discussed in Section 9.5.2). For the following year, the difference in cost increases to $127M, which raises concerns regarding the rigour of Energex's processes. For 2004/05 and 2005/06, the Consultant has taken the value of the projects identified in the Network Development Plan which are included in the CAPEX forecasts and added an allowance for the unidentified projects relating to the increased demand. The allowance for the increase in MD has been at the rate of $1M/MW (as discussed in Section 9.5.2). This approach has not been adopted for later years, due to the increasing uncertainties in regard to projects and timing.

The Consultant accepts the need for Energex to increase its level of CAPEX in this area, and that there are some short-term issues to address, resulting in the need for higher levels of spending as discussed in Section 9.5.2.

A comparison between Energex's and the Consultant's forecasts are shown in the following table:

Table 9-16: Consultant's Demand Driven Primary Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	180.5	298.0	279.6	273.2	268.5	269.0	1,388.2
CONSULTANT FORECAST	$M	150.2	209.9	253.5	238.3	232.6	233.2	1,167.5

All forecast and historical figures are in June 2004 dollars

9.10.2.2 Company Initiated Distribution Augmentation (Code 312650)

Historical, projected and forecast expenditure (in $ millions) for Distribution Augmentation is shown in the following table:

Table 9-17: Company Initiated Distribution Augmentation Expenditure

		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX	$M	9.2	10.1	8.1	8.5	12.2	16.5	25.0	28.4	28.9	111.1

All forecast and historical figures are in June 2004 dollars

The Consultant considers that Energex's forecast for Company Initiated Distribution Augmentation capital expenditure, for the roll-forward period 1 July 2004 to 30 June 2005, to be reasonable. Energex's estimates for the next regulatory period are based on a base spending of $10M per year, with escalation and an allowance of $25M over five years for higher After Diversity Maximum Demand ("ADMD"), adjusted for resource constraints. The Consultant has taken a base of $8.5M and does not accept the need to escalate expenditure, as the programs are primarily based on fixing up issues on the existing network. In the absence of supporting information, the Consultant has also reduced the allowance for the increase in ADMD. A comparison between Energex's forecast and that of the Consultant is shown in the following table:

Table 9-18: Consultant's Company Initiated Distribution Augmentation Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	8.5	12.2	16.5	25.0	28.4	28.9	111.1
CONSULTANT FORECAST	$M	8.5	12.2	14.1	20.4	21.7	21.7	90.2

All forecast and historical figures are in June 2004 dollars

9.10.2.3 Other Corporate Initiated Demand Driven

Historical, projected and forecast expenditure (in $ millions) for Other Corporate Initiated Demand Driven categories is shown in the following table:

Table 9-19: Other Corporate Initiated Demand Driven Expenditure

		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
Demand Primary/Reliability	$M	14.8	1.6	1.9	0.9	2.7	1.0	0.0	0.0	0.0	3.6
Demand Primary/Refurbishment	$M	3.4	0.2	10.9	2.0	4.6	7.2	7.1	9.2	9.6	37.8
Land and Right of Way	$M	2.3	3.1	2.8	1.9	10.5	6.3	6.3	6.3	6.3	35.7
Easements	$M	0.6	1.3	0.9	0.6	3.4	3.4	3.5	3.6	3.6	17.6
Total	**$M**	**21.1**	**6.2**	**16.5**	**5.4**	**21.2**	**17.9**	**16.9**	**19.1**	**19.5**	**94.7**

All forecast and historical figures are in June 2004 dollars

The increased expenditure for Land and Right of Way is attributed to the need to acquire identified substation sites in urban areas. The increase for Easements is attributed to the need to acquire missing easements and upgrade existing easements for 33 kV and 110 kV lines. The increased expenditure for Demand Driven Primary Refurbishment Secondary is attributed to the requirement to upgrade mains and replace 11kV and 33kV switchgear to address fault level problems.

The Consultant considers the forecast expenditure for these categories to be reasonable.

9.10.2.4 Revised Corporate Initiated Demand Driven CAPEX

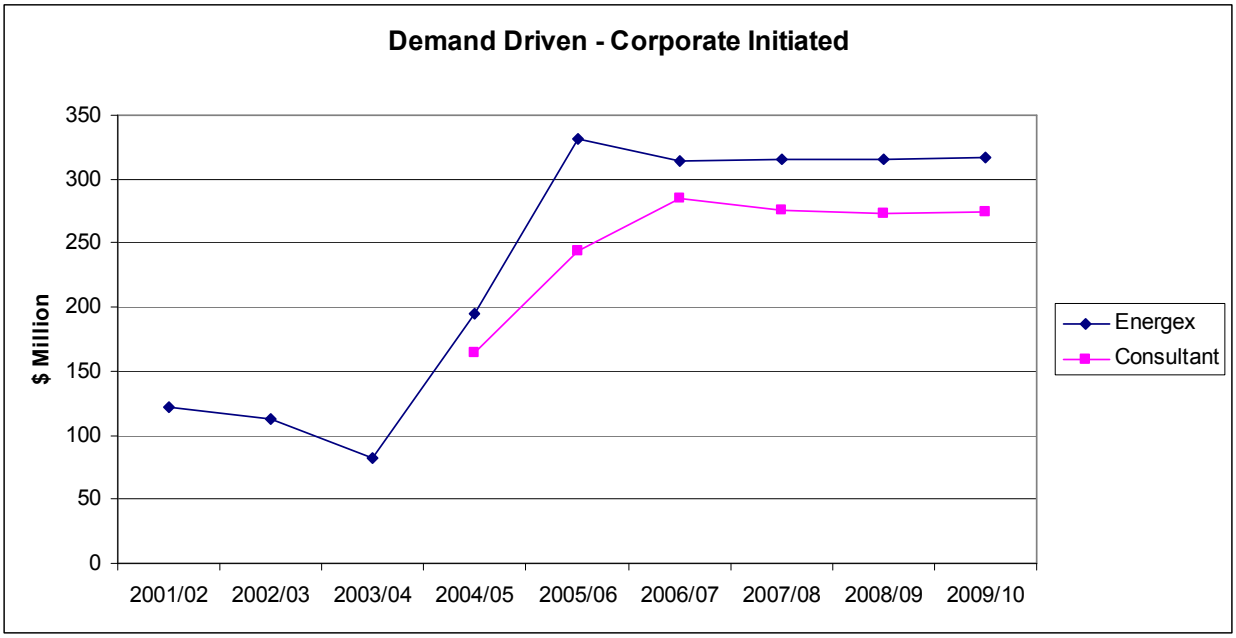
A comparison between Energex's forecast expenditure and that proposed by the Consultant is shown in the following table and graph:

Table 9-20: Consultant's Corporate Initiated Demand Driven Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	194.5	331.4	314.0	315.2	316.0	317.5	1,594.1
CONSULTANT FORECAST	$M	164.1	243.3	285.5	275.7	273.4	274.6	1,352.4

All forecast and historical figures are in June 2004 dollars

Figure 9-11: Consultant's Demand Driven – Corporate Initiated Expenditure



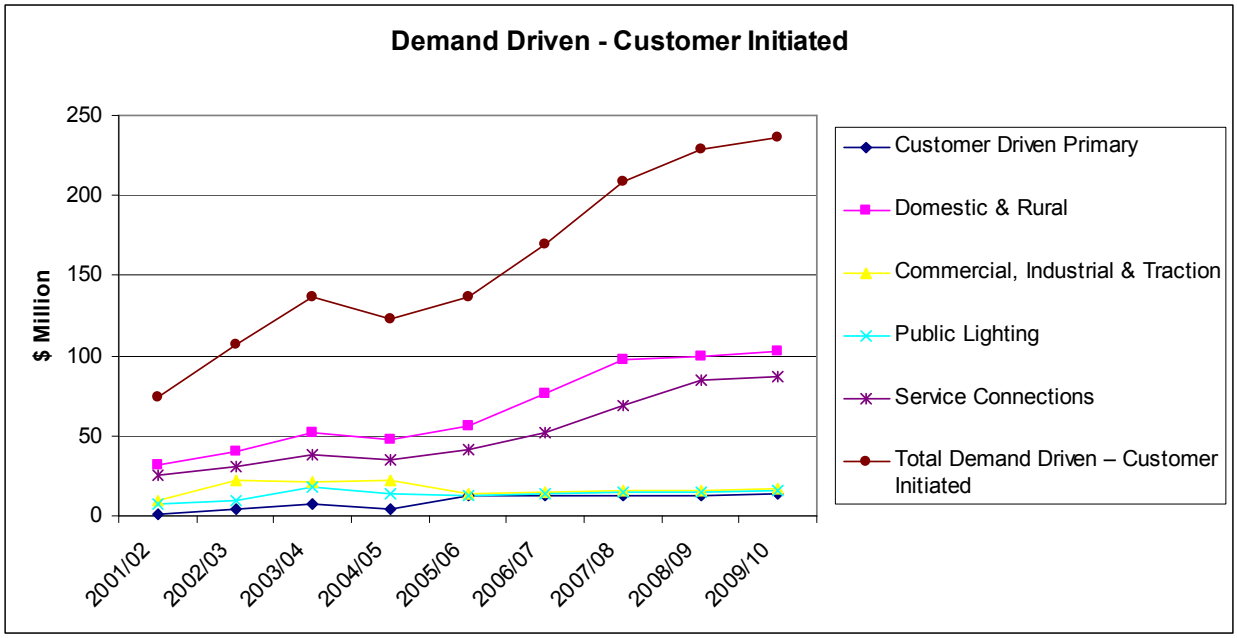
All forecast and historical figures are in June 2004 dollars

9.10.3 Demand Driven – Customer Initiated

This category has been taken as the sum of Customer Driven Primary (Code 311100), Domestic & Rural (Code 312100), Commercial, Industrial & Traction (Code 312500), Public Lighting (Code 312600) and Service Connections (Code 312700).

Energex's actual (for 2001/02 and 2002/03) and budget (for 2003/04 – 2009/10) expenditure for Demand Related Customer Initiated CAPEX is shown in the following graph:

Figure 9-12: Customer Initiated Expenditure



All forecast and historical figures are in June 2004 dollars

9.10.3.1 Customer Driven Primary (Code 311100)

Historical, projected and forecast expenditure (in $ millions) for Customer Driven Primary is shown in the following table:

Table 9-21: Customer Driven Primary Expenditure

		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX	$M	0.7	4.4	7.1	4.5	12.4	12.3	12.7	12.8	13.6	63.8

All forecast and historical figures are in June 2004 dollars

The forecast expenditure for 2004/05 is based on specific projects and appears to be reasonable. The expenditure for 2005/06 and 2006/07 is based on some identified projects plus an amount for unspecified projects, and the expenditure for later years is based on an escalated allowance for unspecified projects. In the absence of identified drivers to increase the level of expenditure, the Consultant has held the level of expenditure at the 2004/05 level for the regulatory period.

A comparison between Energex's forecast and that of the Consultant is shown in the following table:

Table 9-22: Consultant's Customer Driven Primary Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	4.5	12.4	12.3	12.7	12.8	13.6	63.8
CONSULTANT FORECAST	$M	4.5	4.5	4.5	4.5	4.5	4.5	22.5

All forecast and historical figures are in June 2004 dollars

9.10.3.2 Domestic & Rural (Code 312100)

Historical, budget and forecast expenditure (in $ millions) for Domestic & Rural is shown in the following table:

Table 9-23: Domestic & Rural Expenditure

		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX	$M	31.6	40.4	51.8	48.0	55.7	76.4	97.2	99.7	102.3	431.3

All forecast and historical figures are in June 2004 dollars

Energex has based its forecasts on previous expenditure trends with an escalation of 5% (made up of 2.5% for customer growth and 2.5% for increased air conditioning load), plus an allowance of $31M per year from 2007/08 onwards and a partial allowance for 2006/07 for an increase in the ADMD.

The Consultant considers that the main driver for the increase in ADMD is the air conditioning load, so it appears that there is double counting in this area. In the absence of other supporting information, the Consultant has removed the allowance for the increase in ADMD.

A comparison between Energex's forecast and that of the Consultant is shown in the following table:

Table 9-24: Consultant's Domestic & Rural Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	48.0	55.7	76.4	97.2	99.7	102.3	431.3
CONSULTANT FORECAST	$M	48.0	55.7	58.5	61.5	64.5	67.8	308.0

All forecast and historical figures are in June 2004 dollars

9.10.3.3 Commercial, Industrial & Traction (Code 312500)

Historical, projected and forecast expenditure (in $ millions) for Commercial, Industrial & Traction is shown in the following table:

Table 9-25: Commercial, Industrial & Traction Expenditure

		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX	$M	9.2	22.0	21.2	21.8	13.9	14.6	15.4	16.1	16.9	77.0

All forecast and historical figures are in June 2004 dollars

Energex has assumed an annual expenditure of around $15M with an escalation of 5%. Although the escalation is not in line with the escalation of customer numbers in this class (1.5%), the Consultant considers the forecasts to be reasonable based on historical spending.

9.10.3.4 Public Lighting (Code 312600)

Historical, projected and forecast expenditure (in $ millions) for Public Lighting is shown in the following table:

Table 9-26: Public Lighting Expenditure

		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX	$M	7.2	9.8	17.9	13.8	13.1	13.8	14.5	15.2	16.0	72.6

All forecast and historical figures are in June 2004 dollars

Energex has based its forecasts on a base expenditure of $10M, with an additional allowance of $3.8M for the recent change to Australian Standards and an escalation rate of 5% (made up of 2.5% for customer growth and 2.5% for Australian Standard changes). The two components for the recent changes to Australian Standards arise from the need to install additional lights in existing areas (the $3.8M allowance) and the increased costs for additional lights in new schemes (the escalation allowance).

The Consultant considers that the current spending is around $7M per year, giving a base of $10.8M for 2004/05 (rather than Energex's forecast of $13.8M) and has adjusted the forecasts accordingly. A comparison between Energex's forecast and that of the Consultant is shown in the following table:

Table 9-27: Consultant's Public Lighting Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	13.8	13.1	13.8	14.5	15.2	16.0	72.6
CONSULTANT FORECAST	$M	10.8	11.3	11.9	12.5	13.1	13.8	62.7

All forecast and historical figures are in June 2004 dollars

9.10.3.5 Service Connections (Code 312700)

Historical, projected and forecast expenditure (in $ millions) for Service Connections is shown in the following table:

Table 9-28: Service Connection Expenditure

		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX	$M	25.0	30.6	38.3	35.2	41.4	52.0	68.6	85.0	87.1	334.0

All forecast and historical figures are in June 2004 dollars

Energex has based its forecast on a base of around $35M with an escalation of 8%. The escalation is based on recent historical trends, and is driven by new connections and the need for service alterations due to air conditioning. The expenditure shown for 2003/04 is Energex's budget expenditure, whereas the projected expenditure for that year at the time of providing the estimates was $36M. The Consultant considers that the base of around $35M and the escalation rate to be reasonable.

In addition to the base rate, Energex has included under Service Connections, expenditure for Demand Side Management and Power Quality Improvement, as discussed below.

Demand Side Management ("DSM") Initiatives

Energex has included an allowance of $4.2M to replace some 30,000 K22 load control relays to overcome reliability and functionality issues. The Consultant considers this expenditure to be reasonable.

Energex proposes a limited roll-out of interval meters (25,000 meters at a cost of some $8M) to better understand the load profile of customers. Energex plans to use the data from the meters to facilitate the development of network price structures that send appropriate signals to customers to better manage their demand, including the possible development of a kVA network tariff. The Consultant considers that adequate levels of information could be obtained from a smaller sample size, and has reduced the expenditure by $4.4M accordingly.

Energex has proposed spending $15M on unidentified DSM projects. Energex has engaged expert consultants to prepare a list of viable DSM projects, but the report will not be available until late June. Given the amount of money involved, the uncertainty and the potential for offsetting savings, the Consultant has removed this allowance from the forecasts.

Power Quality Improvement

Energex proposes to spend $2.4M over the five year period for load rebalancing on substations in the worst affected parts of the network. The Consultant considers this expenditure to be reasonable.

Energex proposes to spend $2M over the five year period for the installation of power quality equipment at each zone substation, to allow monitoring and reporting on power quality issues. The Consultant considers this expenditure to be reasonable.

Energex also proposes to spend $37M over the five year period to upgrade 40A services in the inner city suburbs, to overcome an increasing number of loss of supply complaints, largely attributable to load increases due to air conditioning. Energex plans to replace nearly a third of the estimated 300,000 of these services over the forecast period, at a cost of $37M. The Consultant has reduced OPEX in this area as a result of this work, as discussed in Sections 8.4.4 and 8.4.17.

A comparison between Energex's forecast and that of the Consultant is shown in the following table:

Table 9-29: Consultant's Service Connection Expenditure

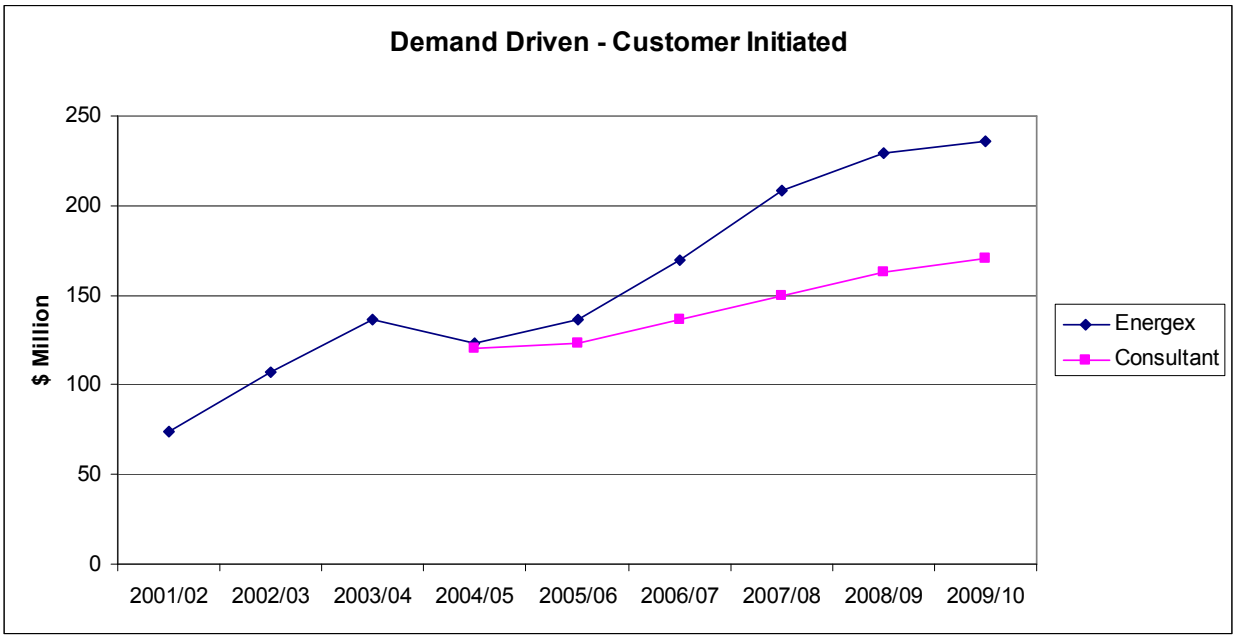
		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	35.2	41.4	52.0	68.6	85.0	87.1	334.0
CONSULTANT FORECAST	$M	35.2	38.0	46.6	56.0	64.4	67.6	272.5

All forecast and historical figures are in June 2004 dollars

9.10.3.6 Total Customer Initiated CAPEX

With the exception of public lighting, the Consultant considers that Energex's forecast expenditure for Customer Initiated works, for the roll-forward period 1 July 2004 to 30 June 2005, to be reasonable. The Consultant has reduced the allowance for public lighting by $3.0M in 2004/05 as discussed in Section 9.10.3.4. A comparison between Energex's and the Consultant's forecast of total Customer Initiated CAPEX is shown in the following graph:

Figure 9-13: Consultant's Customer Initiated Expenditure



All forecast and historical figures are in June 2004 dollars

9.10.4 Reliability/Quality Improvement

Capital expenditure on such items as asset replacement and asset augmentation, whilst not specifically directed at service quality improvement, may never-the-less indirectly improve service quality. The QCA recognised this relationship and indicated that the DNSPs' forecasts of aggregate capital (and operating) expenditure were required to be presented in terms of their impact on service quality outcomes. That is, expenditure required to:

- maintain the current service quality level - Tier (a);
- deliver network-wide service quality improvement (which may be somewhat higher than current service levels) - Tier (b); and
- deliver specific service quality improvement addressing identified customer requirements and including clearly identified service quality outcomes - Tier (c).

Energex's aggregate capital and operating expenditure and its relationship to service quality outcomes is discussed in Section 11.

As part of this aggregate expenditure there is also targeted expenditure which is specifically directed at service quality improvement (rather than say demand related or asset replacement expenditure). Energex has divided this specific reliability/quality improvement expenditure into Tier (a), (b) and (c) expenditure.

Reliability/Quality Improvement has been taken as Reliability Improvement Primary (Code 311300). As noted in Section 9.3, there are difficulties in aligning Energex's expenditure to the QCA categories.

Historical, projected and forecast expenditure (in $ millions) for Reliability Improvement Primary is shown in the following table. Expenditure for the period to 2005/06 to 2009/10 is for the base case, that is, Tier (a). While only those costs outlined below have been identified as being specifically for service quality improvements, these costs together with all other costs outlined in the report (except for costs under Tiers (b) and (c)) make up Energex's Tier (a) expenditure.

Table 9-30: Tier (a) Reliability/Quality Expenditure

		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX	$M	6.8	2.2	28.3	27.0	9.5	17.1	10.3	5.4	5.0	47.3

All forecast and historical figures are in June 2004 dollars

Of the $27M forecast for 2004/05, $12M is for specific projects, $7.6M is for unspecified network automation, $2.7M is for unspecified animal protection (animal proofing), $2.5M is for unspecified protection works and $2.1M is for other unspecified works. The Consultant has accepted the forecast expenditure of $12.1M for specified projects in 2004/05 but has reduced the allowance for unspecified works by $7.4M due to lack of supporting information.

Details of the annual expenditure for Tier (b) and Tier (c) separately have not been provided.

The forecast expenditure for Tier (a) and Tiers (b) and (c) combined is shown in the Table 9-31.

Table 9-31: Tier (a) (b) &(c) Reliability/Quality Expenditure

		05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
TIER (a)	$M	9.5	17.1	10.3	5.4	5.0	47.3
TIERS (b) & (c)	$M	0.0	0.0	22.7	34.1	31.7	88.5
TOTAL	**$M**	**9.5**	**17.1**	**33.0**	**39.5**	**36.7**	**135.7**

All forecast and historical figures are in June 2004 dollars

CAPEX forecast by Energex to maintain current levels of service quality over the five years (Tier (a)) includes $3,287.8M of demand related, asset replacement and other system and non-system expenditure plus the following specific service quality expenditure:

- $12M for a new Bulk Supply Substation (the Consultant considers this expenditure to be inappropriate for this category, and has removed it from the estimates, resulting in reductions of $0.6M in 2005/06, $8.7M in 2006/07 and $3.1M in 2007/08);
- $7M for 16 identified projects to maintain reliability of specific 11 kV feeders;
- $9M for ongoing works in sensitive areas to lift reliability to acceptable levels;
- $2M for an additional 3x1MW generators; and
- $18M for a range of programs to arrest declining service quality due to load growth.

CAPEX to improve average service quality Tier (b) includes:

- $55M for automation schemes;
- $10M for animal proofing;
- $11M for covered conductor, replacement of sub-transmission relays and installation of 11 kV spacers; and
- $9M for general programs.

CAPEX to improve service quality in targeted areas Tier (c) includes:

- $4M to address identified problems in poorly performing areas of the network; and

Although Energex contends that Tier (a) expenditure will only maintain the current levels of service quality, the Consultant believes that this expenditure will lead to significant improvements, as discussed in Section 11.

A comparison between Energex's forecast for Tier (a) and that of the Consultant is shown in the Table 9-32 and Figure 9-14.

Further discussion regarding improvements to service quality is contained in Section 11.

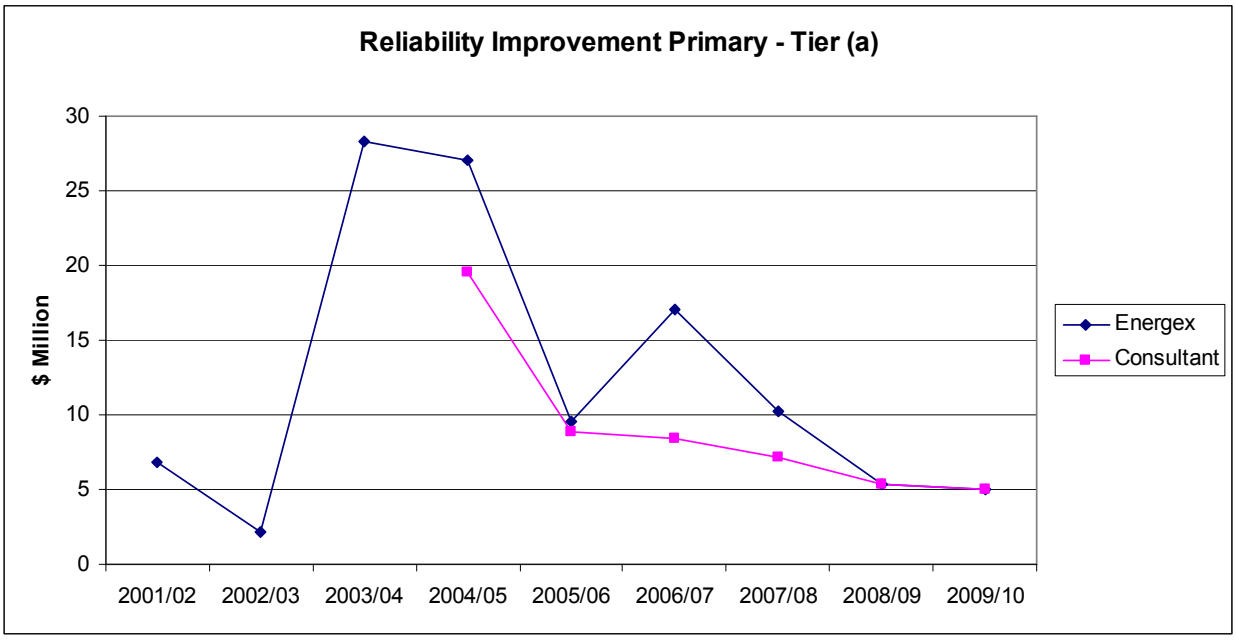
Table 9-32: Consultant's Reliability/Quality Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	27.0	9.5	17.1	10.3	5.4	5.0	47.3
CONSULTANT FORECAST	$M	19.6	8.9	8.4	7.2	5.4	5.0	34.9

All forecast and historical figures are in June 2004 dollars

For 2004/05, the Consultant has included expenditure relating to specified projects, but has reduced the allowance for unspecified works due to lack of supporting information. The reductions in 2005/06, 2006/07 and 2007/08 relate to the removal from the estimates of an allowance for a bulk supply substation, as previously discussed.

Figure 9-14: Consultant's Reliability Improvement Primary – Tier (a) Expenditure

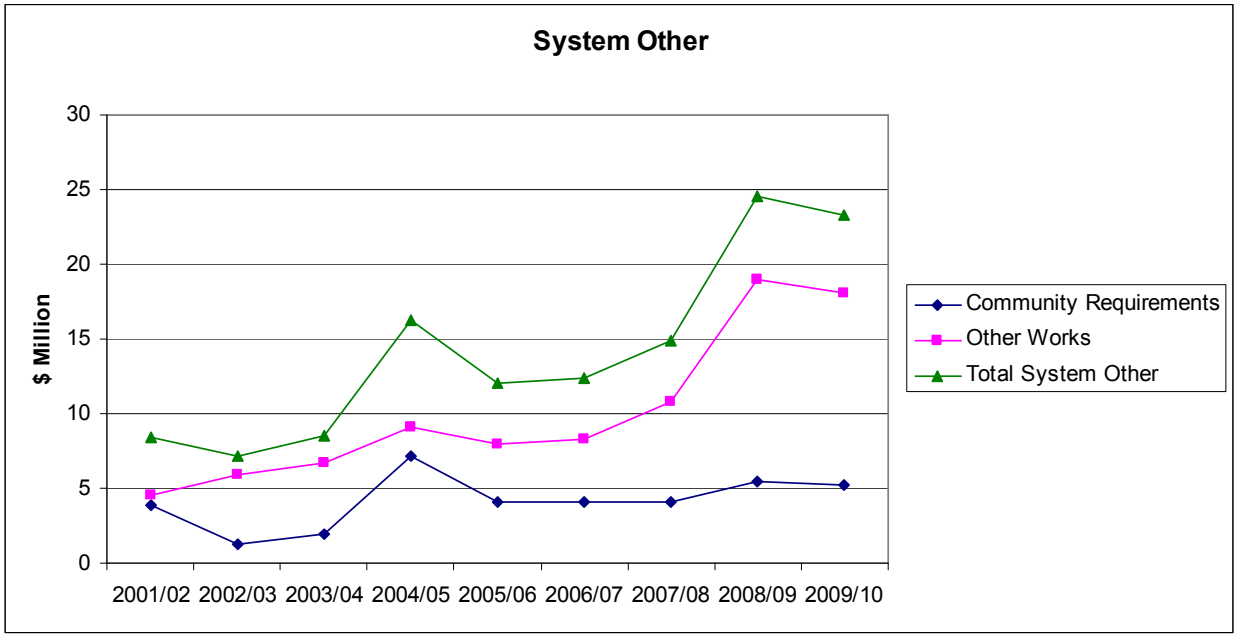


All forecast and historical figures are in June 2004 dollars

9.10.5 System Other

System Other has been taken as the sum of Community Requirements (Code 311800) and Other Works (Code 312200). Energex's actual (for 2001/02 and 2002/03) and budget (for 2003/04 – 2009/10) expenditure for System Other CAPEX is shown in the following graph:

Figure 9-15: System Other Expenditure



All forecast and historical figures are in June 2004 dollars

9.10.5.1 Community Requirements (Code 311800)

Historical, projected and forecast expenditure (in $ millions) for Community Requirements is shown in the following table:

Table 9-33: Community Requirements Expenditure

		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX	$M	3.9	1.3	1.9	7.2	4.0	4.1	4.1	5.5	5.3	23.1

All forecast and historical figures are in June 2004 dollars

The main programs in this category are:

- Beautification works;
- Installation of fire protection;
- Improved fences/security; and
- Installation of noise barriers.

The increased expenditure in 2004/05 is due to undergrounding works on the Belmont/Newstead 110 kV feeders ($4.5M) and the upgrading of zone substation fences and security ($1.9M). The Consultant considers the forecast expenditure for the period 2004/05 to 2009/10 to be reasonable.

9.10.5.2 Other Works (Code 312200)

Historical, projected and forecast expenditure (in $ millions) for Other Works is shown in the following table:

Table 9-34: Other Works Expenditure

		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX	$M	4.5	5.9	6.7	9.1	8.0	8.3	10.8	19.0	18.1	64.2

All forecast and historical figures are in June 2004 dollars

Energex has based its estimates on a base spending of approximately $5M per year and an additional $10M per year for accelerated undergrounding of overhead projects in years 2008/09 and 2009/10. The Consultant accepts the need for additional expenditure in this category in response to changing community expectations, but does not accept the further increase of $20M spread over the last three years due to lack of supporting substantiation.

A comparison between Energex's forecast and that of the Consultant is shown in the following table:

Table 9-35: Consultant's Other Works Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	9.1	8.0	8.3	10.8	19.0	18.1	64.2
CONSULTANT FORECAST	$M	9.1	8.0	8.3	8.6	9.0	9.3	43.3

All forecast and historical figures are in June 2004 dollars

9.10.5.3 Total System Other

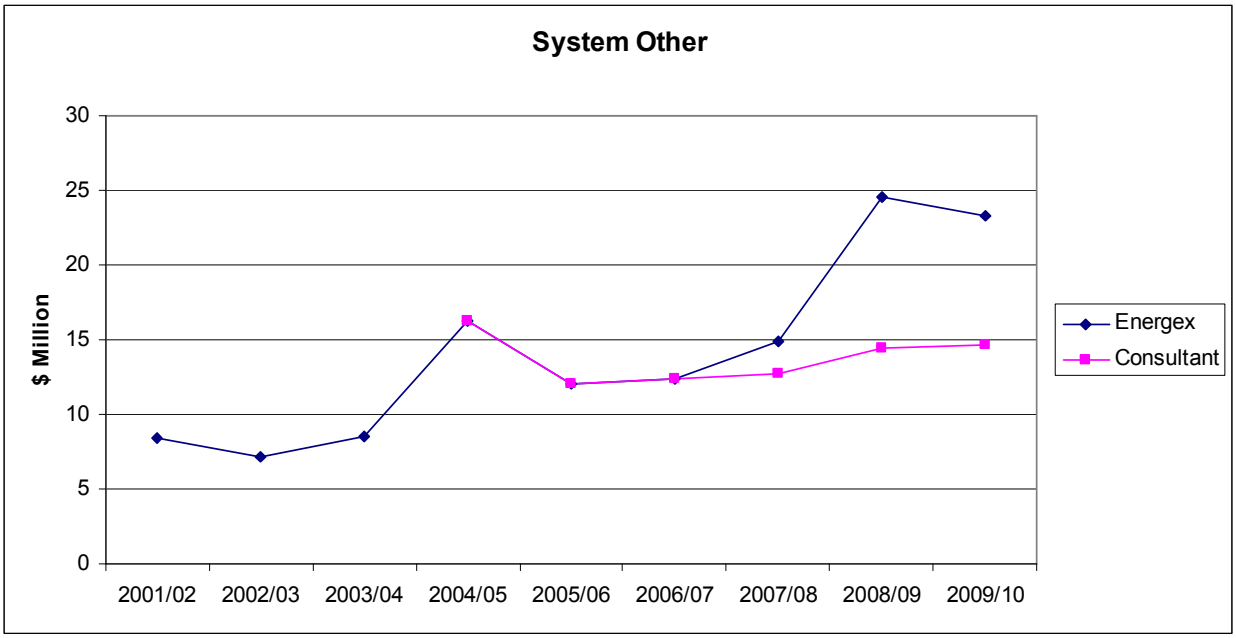
The Consultant considers that Energex's forecast expenditure for System Other works, for the roll-forward period 1 July 2004 to 30 June 2005, to be reasonable. A comparison between Energex's forecast and that of the Consultant is shown in the following table and figure:

Table 9-36: Consultant's Total System Other Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	16.3	12.0	12.4	14.9	24.5	23.3	87.2
CONSULTANT FORECAST	$M	16.3	12.0	12.4	12.8	14.5	14.6	66.3

All forecast and historical figures are in June 2004 dollars

Figure 9-16: Consultant's System Other Expenditure



All forecast and historical figures are in June 2004 dollars

9.10.6 Non-System

The breakdown of items and expenditures is shown in the following table and figure:

Table 9-37: Non-System Expenditure

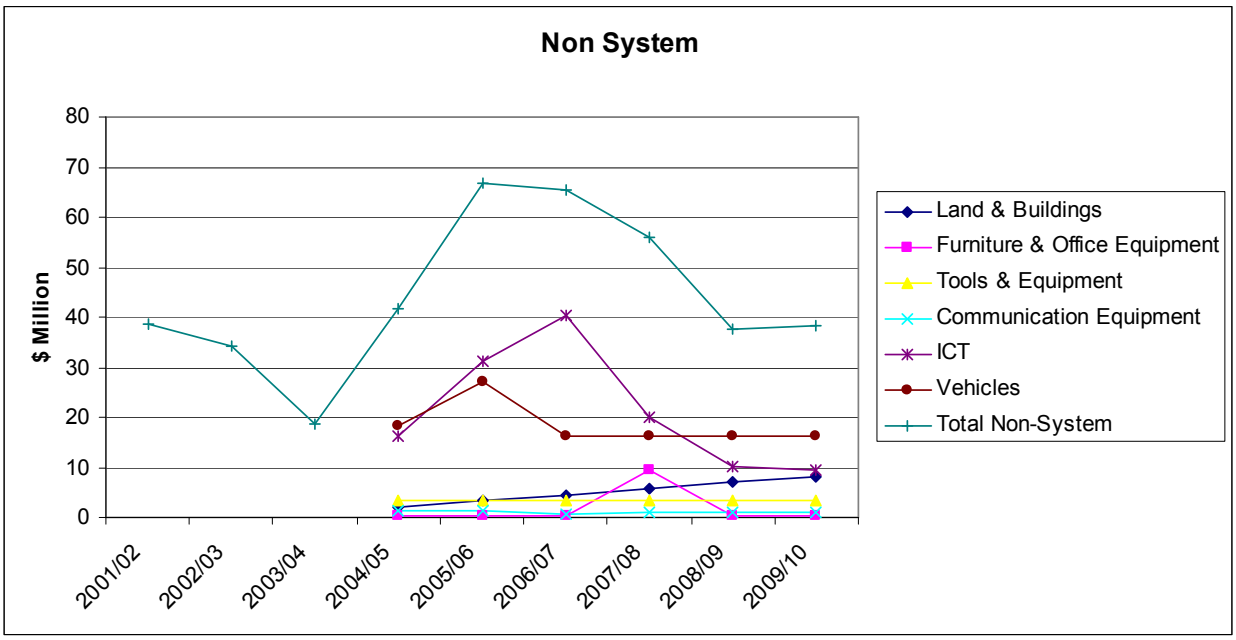
		01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
Land & Buildings	$M	1.2	3.7		2.2	3.4	4.6	5.8	7.0	8.2	28.8
Furniture & Office Equipment	$M				0.2	0.2	0.2	9.6	0.2	0.2	10.6
ICT (*See Note 1)*	$M	29.2	12.2		16.4	31.4	40.4	20.1	10.1	9.6	111.5
Vehicles	$M	7.4	13.6		18.4	27.1	16.1	16.1	16.1	16.1	91.7
Tools & Equipment	$M				3.3	3.3	3.3	3.3	3.3	3.3	16.7
Communication Equipment	$M				1.2	1.3	0.8	0.9	0.9	0.9	4.7
Other	$M	1.0	4.8								
TOTAL	**$M**	**38.8**	**34.4**	**18.6**	**41.7**	**66.7**	**65.4**	**55.8**	**37.6**	**38.3**	**263.9**

All forecast and historical figures are in June 2004 dollars

Note 1: Information & Communication Technology ("ICT")

Energex has been unable to provide a split into the categories contained in Table 9-37 for 2003/04.

Figure 9-17: Non System Expenditure



All forecast and historical figures are in June 2004 dollars

9.10.6.1 Land & Buildings

Energex has forecast expenditure in this area incrementing by $1.2M per year from a base of $2.2M. Energex has advised that 2004/05 is a low year because there are no major air-conditioning and security upgrades – these will occur in future years. The major increase in 2005/06 is $1M for a fire system upgrade at the Banyo depot, and the 2006/07 increase is for a new roof and upgrade of all the underground services at the Banyo depot. As well as security, fire services and air-conditioning upgrades in the 2007/08 - 2009/10 period, Energex has advised that there will be additions to current depots and additional depots to house the increase in staff required to deliver the capital and operating works programs.

In the absence of a detailed Land and Buildings program, the Consultant considers that the proposed forecasts appear to be somewhat arbitrary. The proposed timing for additions to and new depots would be too late to allow delivery of an increased works program. Also, the Consultant has recommended a reduced level of works over the period, thus obviating the need for some of the expenditure in this area.

A comparison between Energex's forecast and that of the Consultant is shown in the following table:

Table 9-38: Consultant's Land & Buildings Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	2.2	3.4	4.6	5.8	7.0	8.2	28.8
CONSULTANT FORECAST	$M	2.2	3.4	4.6	5.8	6.0	6.0	25.7

All forecast and historical figures are in June 2004 dollars

9.10.6.2 Furniture & Office Equipment

The proposed expenditure for Furniture and Office Equipment is shown in the table below:

Table 9-39: Furniture & Office Equipment Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	0.2	0.2	0.2	9.6	0.2	0.2	10.6

All forecast and historical figures are in June 2004 dollars

The large increase in 2007/08 is due to the need for significant refurbishment and/or relocation to a new building on the expiry of the current lease for the corporate office. The proposed program includes the proportion of the cost attributed to the Regulated Line of Business.

The Consultant considers the forecast costs to be reasonable.

9.10.6.3 Information & Communication Technology

Energex has prepared a detailed analysis of their requirements for ICT over the forecast period, with a total spending of nearly $130M. Major items are as follows:

- Replacement of RTUs ($18M);
- Field Force Automation ($10M);
- Geographical Information System ("GIS") and Facilities Management System replacement ($10M);
- DMS life extension ($5M);
- TMR replacement ($4); and
- System upgrades to support Full Retail Contestability ("FRC') ($5M in 2006/07). This expenditure has been removed from the estimates as it is not known whether FRC will proceed in Queensland. Energex could apply for a cost pass-through at the time on the grounds of a change in government policy.

The increase in expenditure from 2004/05 to 2005/06 is due to the timing of several large projects, namely Field Force Automation ($5M), GIS/Facilities Management System Replacement ($5M) and RTU ($3.5M).

The detailed report indicates expenditure of $14M less in 2006/07 than the amount included in Energex's forecast. In the absence of further supporting information, the Consultant has reduced the estimates by that amount for 2006/07.

A comparison between Energex's forecast and that of the Consultant is shown in the following table:

Table 9-40: Consultant's Information & Communication Technology Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	16.4	31.4	40.4	20.1	10.1	9.6	111.5
CONSULTANT FORECAST	$M	16.4	31.4	21.4	20.1	10.1	9.6	92.5

All forecast and historical figures are in June 2004 dollars

9.10.6.4 Vehicles

The proposed expenditure for Vehicles is shown in the following table:

Table 9-41: Vehicles Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	18.4	27.1	16.1	16.1	16.1	16.1	91.7

All forecast and historical figures are in June 2004 dollars

Energex has prepared a vehicle replacement program based on criteria recommended by Lease Plan. In addition, Energex's forecasts include an allowance for the purchase of an additional 90 trucks to cater for the additional work force associated with the increased works program, resulting in a large increase in expenditure from 2004/05 to 2005/06. The Consultant considers that the forecasts appear to be reasonable.

9.10.6.5 Tools & Equipment

The proposed expenditure for Tools and Equipment is shown in the following table:

Table 9-42: Tools & Equipment Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	3.3	3.3	3.3	3.3	3.3	3.3	16.7

All forecast and historical figures are in June 2004 dollars

The Consultant considers that Energex's forecasts are reasonable.

9.10.6.6 Communication Equipment

The proposed expenditure for Communication Equipment is shown in the following table

Table 9-43: Communications Equipment Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	1.2	1.3	0.8	0.9	0.9	0.9	4.7

All forecast and historical figures are in June 2004 dollars

The Consultant considers that Energex's forecasts are reasonable.

9.10.6.7 Total Non-System CAPEX

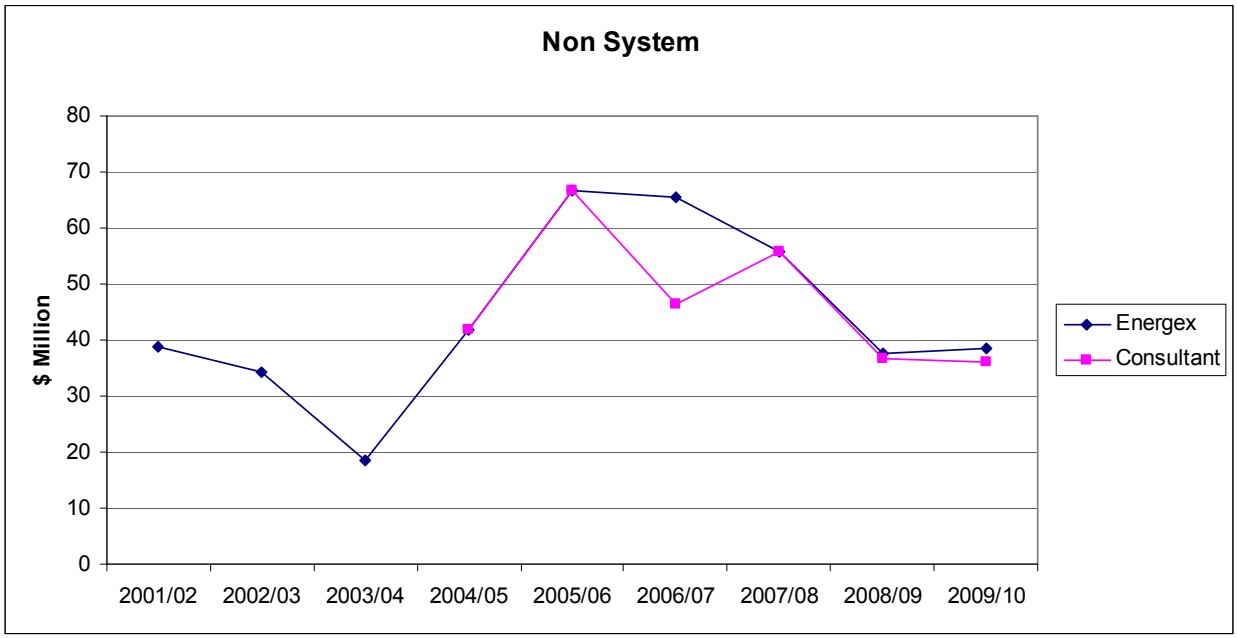
The Consultant considers that Energex's forecast expenditure for Non-System works, for the roll-forward period 1 July 2004 to 30 June 2005, to be reasonable. A comparison between Energex's forecast and that of the Consultant is shown in the following table and graph:

Table 9-44: Consultant's Non-System Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
ENERGEX FORECAST	$M	41.7	66.7	65.4	55.8	37.6	38.3	263.9
CONSULTANT FORECAST	$M	41.7	66.7	46.4	55.8	36.7	36.2	241.8

All forecast and historical figures are in June 2004 dollars

Figure 9-18: Consultant's Non System Expenditure



All forecast and historical figures are in June 2004 dollars

9.11 Consolidated CAPEX Program

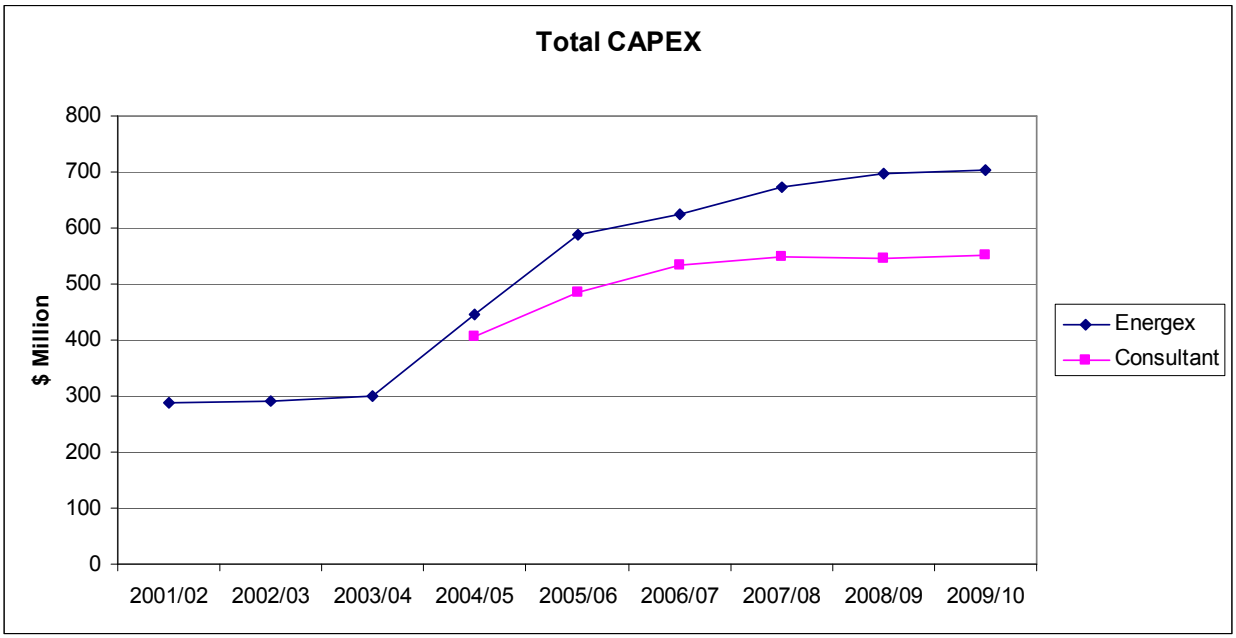
Energex's Consolidated CAPEX forecast spending pattern is shown in the table and graph below and in more detail in the table in Appendix 14.9. Note that expenditures for Tiers(a) and (b) Service Quality Improvement have been excluded.

Table 9-45: Energex and Consultant's Consolidated CAPEX

		04/05	05/06	06/07	07/08	08/09	09/10	TOTAL 05/06-09/10
Energex								
Asset replacements	$ M	43.9	32.2	46.8	68.6	85.5	83.6	316.6
Demand Related – Corporate Initiated	$ M	194.5	331.4	314.0	315.2	316.0	317.5	1,594.1
Demand Driven – Customer Initiated	$ M	123.3	136.6	169.0	208.3	228.8	235.9	978.7
Reliability Improvement – Tier (a)	$ M	27.0	9.5	17.1	10.3	5.4	5.0	47.3
System Other	$ M	16.3	12.0	12.4	14.9	24.5	23.3	87.2
Non-System	$ M	41.7	66.7	65.4	55.8	37.6	38.4	263.9
Total CAPEX	**$ M**	**446.6**	**588.4**	**624.8**	**673.1**	**697.9**	**703.7**	**3,287.8**
Consultant								
Asset replacements	$ M	43.9	29.9	44.6	48.7	53.5	51.1	227.9
Demand Related – Corporate Initiated	$ M	164.1	243.3	285.5	275.7	273.4	274.6	1,352.4
Demand Driven – Customer Initiated	$ M	120.3	123.5	136.1	149.8	162.7	170.5	742.6
Reliability Improvement – Tier (a)	$ M	19.6	8.9	8.4	7.2	5.4	5.0	34.9
System Other	$ M	16.3	12.0	12.4	12.8	14.5	14.6	66.3
Non-System	$ M	41.7	66.7	46.4	55.8	36.7	36.2	241.8
Total CAPEX	**$ M**	**405.8**	**484.3**	**533.5**	**549.9**	**546.2**	**552.0**	**2,665.9**

All forecast and historical figures are in June 2004 dollars

Figure 9-19: Consolidated CAPEX Program



All forecast and historical figures are in June 2004 dollars

10 CAPEX/OPEX TRADE-OFFS

There is a relationship between CAPEX and OPEX. Increased CAPEX can lead to a reduction in OPEX in the short term (for example, the installation of new equipment would reduce the requirement for maintenance) and a reduction in CAPEX may result in a short term increase in OPEX (for example, the deferral of a capital project may lead to increased maintenance costs). In the longer term, expenditure on CAPEX to install additional assets will result in an increase in operation and maintenance activity and thus an increase in OPEX. When developing expenditure proposals for CAPEX and OPEX, the whole-of-life costs should be considered, so for a capital project, the impact of the project on OPEX should be identified and vice versa.

In the Consultant's experience, this issue of CAPEX/OPEX trade-offs is not handled well by Australian distributors. The review of capital projects (refer to Section 9.6) indicates that Energex is fairly typical in this regard.

The following CAPEX items have been identified as resulting in reductions in OPEX:

- Replacement of 33 kV gas insulated underground cables. Proposed expenditure for this program is $58M over the six years, ramping down from $18.5M in 2004/05 to $2.8M in 2009/10. It can be expected that the replacement of these cables will result in significant reductions in OPEX. The Consultant has estimated a reduction of $2.5M and has reduced the OPEX expenditure accordingly;
- Replacement of Krone 11 kV switchgear. Proposed expenditure for this program is $4.3M per year for the period 2004/05 to 2007/08. Energex have taken this into account in reducing OPEX appropriately in this area;
- Replacement of 40A services in the inner urban areas. Proposed expenditure for this program is $37M over five years. The Consultant has estimated a resulting reduction in OPEX of $2M and has included this in the estimates;
- Replacement of 30,000 K22 load control relays, to overcome reliability and functionality issues. Proposed expenditure for this program is $4.2M over five years. The Consultant has estimated a resulting reduction in OPEX of $4M and has included this in the estimates;
- Replacement of 13,000 per year concentric services within one kilometre of the coast. Proposed expenditure for this program is $21M over five years. The Consultant has estimated a resulting reduction in OPEX of $2M and has included this in the estimates; and
- Network automation program. Energex have proposed expenditure of $8M over for 2004/05 for unspecified network automation projects. In the absence of more specific information, the Consultant has not been able to quantify the impact on OPEX.

There is a range of other programs where CAPEX can be expected to result in reduced OPEX in aggregate, but it is not feasible to estimate at the individual program level. Examples include animal proofing, replacement of CTs and VTs, installation of 11 kV spacers, protection and control upgrades, rectification of under-height services, installation of LV spacers etc.

It is the Consultant's experience that reductions in OPEX due to CAPEX programs are of a lower magnitude than the CAPEX involved – the driver for the expenditure is generally capacity, reliability or safety rather than reducing maintenance / operating expenditure.

The following items have been included in Energex's OPEX in lieu of CAPEX:

- Monthly payments (amounting to $0.2M per year) to Hydro Power Pty Ltd for network deferment charges as specified in the Generator Connection and Access Agreement between Energex and Hydro Power. Power generated from this facility is delivered into the Energex distribution network, allowing the deferral of network augmentation. The Consultant is not aware of specific projects (and their costs) that have been deferred, but accepts the general principle.
- Reliability improvement on feeders located in areas where there has been a history of tree related outages, where detailed analysis has shown that the reliability on these feeders could most effectively be improved through vegetation and maintenance management. It is not known what component of Energex's vegetation and maintenance management costs relate to this issue.

11 IMPROVEMENTS TO SERVICE QUALITY

Energex has advised that all of the OPEX and CAPEX for the forecast period, with the exception of that identified for Tiers (b) and (c), is required to maintain current service quality levels. The Consultant does not accept this position, as there will be improvements to service quality through expenditure in areas like augmentation and vegetation management, particularly in reducing the utilisation of the network. Rather than merely maintaining current levels of service quality, the Consultant is of the view that the expenditure proposals put forward by Energex under Tier (a) include amounts needed to restore the network to accepted standards. The Consultant has not been provided with sufficiently detailed information from Energex to quantify how much expenditure included by Energex as Tier (a) relates to improved levels of service quality and so the Consultant is not able to provide a robust estimate of the OPEX and CAPEX required to maintain service quality at current levels.

11.1 Tier (a)

Energex have forecast OPEX of $1,121 M and CAPEX of $3,288M for the period 2005/06 to 2009/10 for Tier (a) to maintain current network-wide reliability and reliability for the 10 worst rural and the 10 worst urban feeders.

Energex has proposed the following starting points for network-wide performance:

Table 11-1: Energex Network Performance for 2002/03 and 2003/04

INDICATOR	RECENT PERFORMANCE
Urban SAIDI	147.8
Urban SAIFI	1.780
Rural SAIDI	230.8
Rural SAIFI	2.319
Percentage of calls answered within 30 seconds	62.7

The establishment of appropriate starting points for SAIDI and SAIFI is difficult. Energex has put forward SAIDI and SAIFI indicators based on a 12 month rolling average for the 2002/03 and 2003/04 financial years, excluding exclusion events, transmission and generation outages. They are also based on the current reporting basis and assumptions.

The Consultant considers that the proposed starting points for SAIDI and SAIFI are too high, based on the reliability performance data provided to the QCA (these indicate that reliability for the proposed period is lower than previously i.e. SAIDI and SAIFI increasing). Another issue is the expected improvements in reliability performance resulting from the CAPEX included in Tier (a).

The Consultant recommends that the QCA sets targets for improvements to SAIDI and SAIFI to be achieved with the Tier (a) CAPEX, and then set targets for Tier (b) in the following regulatory period. The Consultant proposes the following targets, based on previous performance, benchmarks (refer to Section 5.6.3) and the proposed Tier (a) OPEX and CAPEX for the forthcoming period (i.e. the Consultant considers that these targets are achievable with the proposed levels of Tier (a) CAPEX and OPEX):

Table 11-2: Tier (a) Associated SAIDI Improvements

INDICATOR	TARGET 2009/10
Urban SAIDI	125
Urban SAIFI	1.42
Rural SAIDI	190
Rural SAIFI	1.95

The Consultant does not have historical data relating to the percentage of calls answered in 30 seconds.

11.2 Tier (b)

As discussed in Sections 8.4.23 and 9.10.4, Energex proposes the following expenditure to improve network-wide service quality (i.e. for Tier (b)), with the associated reductions in SAIDI over the period 2005/06 to 2009/10:

Table 11-3: Tier (b) Expenditure and Associated SAIDI Improvements

	TIER (b) EXPENDITURE ($M)	URBAN SAIDI REDUCTION (Minutes)	RURAL SAIDI REDUCTION (Minutes)
CAPEX	84.6	20.1	29.7
OPEX	40.4	7.8	6.1
TOTAL	125.0	27.8	35.8

All forecast figures are in June 2004 dollars

Energex proposes that targets be set for the end of the period rather than for each year, to take account of natural fluctuations. The Consultant would not recommend this approach, for the following reasons:

- The outcome could depend heavily on the performance in the final year of the period (e.g. an overall improving trend could be negated by a particularly bad final year); and
- A scheme with yearly incentives or penalties is likely to receive a greater level of management attention and commitment than one over the period of the Determination.

One of the assumptions made by Energex in proposing its targets is that the current reporting basis and assumptions remain in place. This includes the assumption that each customer consumes 2 kVA which needs to be reviewed in the light of Energex's significant increases in ADMD (it is recognised that there is a difference between consumption and maximum demand). The assumptions underpinning the reporting arrangements should be discussed further between the QCA and Energex.

Energex proposes the following targets for Tier (b):

Table 11-4: Tier (b) Network Performance Targets

INDICATOR	STARTING POINT	TARGET	% IMPROVEMENT
Urban SAIDI	147.8	120	18.8
Urban SAIFI	1.780	1.5	15.7
Rural SAIDI	230.8	195	15.5
Rural SAIFI	2.319	1.950	15.9
Percentage of calls answered within 30 seconds	62.7	70	11.6

As discussed in Section 11.1, the Consultant recommends that the QCA should not proceed with Tier (b) in the forthcoming regulatory period. Should the QCA wish to continue with Tier (b) in the forthcoming period, then the Consultant suggests that a three year average would be more appropriate for measuring performance (recognising the volatility of reliability indicators).

Energex contend that the cost of their CAPEX proposals, at $5,882 per MWh saved, is in the mid range of Victorian and NSW distributors. Based on this approach, the Consultant accepts the level of CAPEX required to achieve the quantum of change in SAIDI and SAIFI (i.e. reduction in SAIDI and SAIFI of 20.1 and 29.7 minutes respectively), but considers that the targets should be considerably more challenging than suggested by Energex as the starting points will be lower as proposed in the previous section.

In regard to the targets suggested by Energex, the Consultant notes that for SAIDI, Energy Australia and United Energy are already better than the proposed Energex target, and for SAIFI, Energy Australia is currently better whilst United Energy is about the same as the Energex targets. The Consultant considers that such "soft" targets are inappropriate for an organisation which is about to spend in excess of $2660M over the forthcoming regulatory period.

The OPEX programs proposed for improving service reliability for Tiers (b) and (c) are relevant and in the Consultant's view will lead to significant performance improvement.

Regarding the Tier (b) SQI initiatives, the Consultant makes the following observations:

- The activity involved in the initiative in terms of work detail and volume has not been quantified; and
- The quantification of service quality improvement for the programs of Thermo-scanning and Contact Centre operational response has not been given.

This has prevented an analysis of effectiveness and value for these programs. The Consultant's opinion is that the total OPEX for Tier (b) should deliver greater improvement in service reliability than that proposed by Energex.

11.3 Tier (c)

Energex has selected the 10 worst rural and the 10 worst urban feeders on the basis of their SAIDI performance in the 2002/03 financial year (as shown in Table 11-5 and Table 11-6) and proposes that these be adopted as the starting points for measuring improvement.

The Consultant considers that it is appropriate to select the worst feeders on the basis of performance in 2002/03 (for simplicity), but that the starting points should be on the basis of the three year average for 2001/02, 2002/03 and 2003/04 financial years for both SAIDI and SAIFI performance.

Table 11-5: Energex Worst Performing Urban Feeders for 2002/03

URBAN FEEDERS	FEEDER SAIDI
Coominya CMY2	1,411.707
Gympie GYM6	1,374.698
Postman's Ridge PRG2A	1,239.485
North Maclean NMC5A	1,184.753
Yatala YTA25A	1,152.217
North Maclean NMC3A	947.844
Boomerang Street BMG1A	914.273
Postman's Ridge PRG2B	884.967
Burleigh Heads BHD7B	853.740
Caloundra CLD8	753.931

Table 11-6: Energex Worst Performing Rural Feeders for 2002/03

RURAL FEEDER	FEEDER SAIDI
Gympie GYM9B	1,920.148
Mt Sylvia MSV2	1,882.811
Coominya CMY1	1,752.572
Mudgeeraba MGP4	1,237.293
Wivenhoe WHO2	1,200.434
Gympie GYM2A	1,164.410
Tarampa TRP3	1,162.920
Beerwah BWH3	1,103.462
Amberley ABL4	1,069.064
Woodford WFD2	899.890

Energex proposes the following expenditure to improve service quality on specific parts of the network:

Table 11-7: Tier (c) Expenditure and Associated SAIDI Improvements

	TIER (c) EXPENDITURE ($M)	URBAN SAIDI REDUCTION	RURAL SAIDI REDUCTION
CAPEX	3.6		
OPEX	8.8		
TOTAL	12.4	25% improvement for 10 worst urban feeders	25% improvement for 10 worst rural feeders

All forecast figures are in June 2004 dollars

CAPEX under Tier (c) is for improvements to the 10 worst urban and the 10 worst rural feeders. OPEX under Tier (c) is also for improvements to the 10 worst urban and the 10 worst rural feeders ($4.8M), together with improved service to regional hospitals and Council pumps ($4M).

The Consultant notes that Energex has not proposed any performance targets for the improvements to Regional hospitals and Council pumps. The Consultant considers that there should be measurable outcomes and quantified targets for this expenditure, for example, SAIDI improvement targets for nominated hospitals and pumps. Without such targets, the Consultant would not recommend that the proposal be accepted.

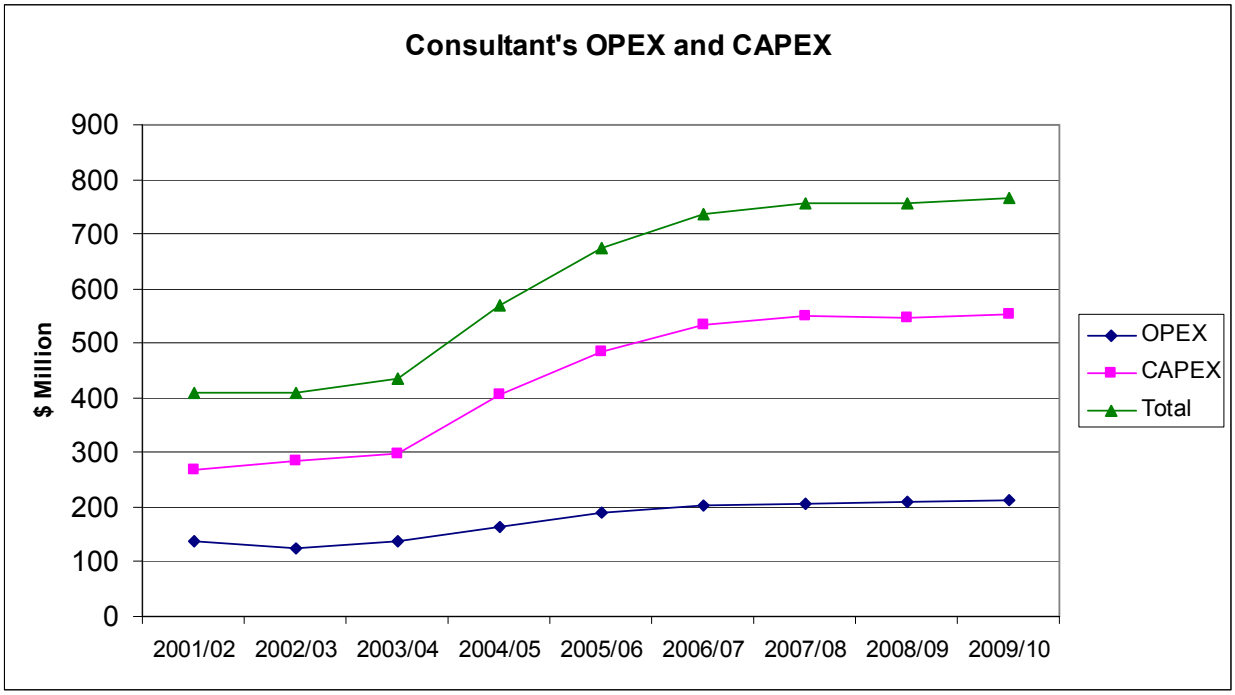
The Consultant considers that targets for reduction in SAIFI should also be applied to the worst performing feeders, in line with the network-wide targets, to reflect the importance to customers of the frequency of supply interruptions. Again, without such targets, the Consultant would not recommend that the proposal be accepted.

The Consultant does not have sufficient information to make a considered evaluation of the efficiency of the proposed Tier (c) expenditure, but has made a judgement based on experience that a 25% percent improvement in SAIDI and SAIFI for the specified feeders is commensurate with the proposed OPEX and CAPEX.

12 RESOURCE CAPABILITY

Energex has forecast significant increases in the level of CAPEX and OPEX spending, above current levels.

Figure 12-1: Total OPEX and CAPEX Expenditure



All forecast and historical figures are in June 2004 dollars

It can be seen that the Consultant's estimates of total expenditure show an increase in 2004/05 of around $180M (18%) above the levels in recent years and further increases over the forthcoming regulatory period.

Energex developed a resourcing strategy in early 2004 to deliver the increased workload and advised that the key elements of the strategy were:

- Assessing the projects in the program and the risks associated with deferring them;
- Reviewing internal and external resources to deliver the program; and
- Assessing the ramp up rate of these resources.

Energex also advised that the preliminary implications were:

- Deferral of some asset refurbishment projects and development of a detailed risk management strategy. This deferral of capital expenditure may result in a short-term increase in operating expenditure;
- Deferral of some Service Quality Initiatives;
- Deferral of some lower risk demand projects;
- Deferral of some Demand Side management projects;
- No significant change to OPEX forecasts; and
- Deferral of capital expenditure.

In the light of previous expenditure history and the absence of a detailed resource plan, the Consultant has grave concerns regarding Energex's capability to deliver the level of work proposed, particularly given proposed increases in forecast expenditure in other jurisdictions and the resulting shortage of skilled resources throughout Australia and New Zealand. The Consultant is confident that Energex could spend around 80% of the expenditure recommended by the Consultant, and considers that Energex may be able to spend more depending on how successful they are in finding the required skilled manpower.

On 31 August 2004, Energex provided a new document to the QCA regarding resourcing. The document was marked confidential and the QCA provided it to the Consultant under the conditions of confidentiality which apply to all the source documentation dealt with in this review.

By this time the Consultant had completed the field investigations and also completed the draft report. Nevertheless, detailed comments were provided to the QCA under separate cover.

In summary, the new report was still only a strategy at a high level, with little in the way of specific detail. As a result, the new document did little to increase the Consultant's confidence that Energex could appropriately manage their requested level of expenditure.

Accordingly, the Consultant recommends the following actions by the QCA:

- Require Energex to submit a detailed and comprehensive resourcing plan for review by the QCA; and
- Consider modifying the pricing mechanism to take account of significant under-spends in expenditure.

13 GLOSSARY

24/7	24 hours a day / 7 days a week
ABC	Aerial Bundled Conductor
ABS	Air Break Switch
ADMD	After Diversity Maximum Demand
AEF	Asset Energy Factor
AFLC	Audio Frequency Load Control
BRW	Burns and Roe Worley Pty Ltd
CAD	Computer Aided Dispatch
CAIDI	Customer Average Interruption Duration Index
CAPEX	Capital expenditure
CASAD	Computer Aided Schedule and Dispatch System
CB	Circuit Breaker
CCA	Copper, Chromium and Arsenic
CEF	Customer Escalation Factor
CMS	Customer Management System
CPI	Consumer Price Index
CT	Current transformer
CUE	Customer Unit Escalation
DGA	Dissolved Gas Analysis
DMS	Distribution Management System
DNSP	Distribution Network Service Provider
DPI	Department of Primary Industry
DS	Distribution System
DSM	Demand Side Management
DTS	Distributed Temperature Sensing
EBA	Enterprise Bargaining Agreement
EMF	Electro-magnetic Field
ESAA	Electricity Supply Association of Australia
EUF	Energy Utilisation Factor
FACOM	Customer and Retail Database
FRC	Full Retail Contestability
FROG	Feedback Register for Organisational growth
GIS	Geographic Information System
GSL	Guaranteed Service Level
HV	High Voltage
HVIA	High Voltage Isolation and Access Procedures
ICT	Information & Communication Technology

IT	Information Technology
IVR	Interactive Voice Response
KPI	Key Performance Indicator
kV	Kilo volts i.e. 1,000 volts
LAI	Line asset inspections
LAN	Local Area Network
LFI	Line Fault Indicators
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MAMP	Mains Asset Maintenance Policy
MD	Maximum Demand
MMA	McLennan Magasanik & Associates
MVA	Mega volt amp i.e. 1,000,000 volt amps
MWh	Mega watt hours i.e. 1,000,000 watt hours
MW	Mega watts i.e.1,000,000 watts
NEC	National Electricity Code
NEF	Network Escalation Factor
NFM	Network Facility Management
NLF	Network Load Factor
NRCR	Non Revenue Capped Regulated
NUE	Network Unit Escalation
OH	Overhead
OLTC	On-Load Tapchanger
OPEX	Operating expenditure
OPM	Operating Practices Manual
PUF	Plant Utilisation Factor
QCA	Queensland Competition Authority
RCM	Reliability Centred Maintenance
RMU	Ring Main Unit
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAMP	Substation Asset Maintenance Policy
SCADA	Supervisory Control and Data Acquisition
SCM	Service Call Management
SQI	Service Quality Incentives
TOR	Terms of Reference
TMR	Trunk Mobile Radio
UG	Underground
UMS	UMS Consulting Group

WACC	Weighted Average Cost of Capital
WIP	Works in Progress
XLPE	Cross-linked Polyethylene
ZSS	Zone Substation

14 APPENDICES

14.1 Site Visits and Interviews

DATE	CONSULTANT PERSONNEL	ENERGEX PERSONNEL	TOPIC
3/3/04 Brisbane	Bob Coulter Ian Marks Graham Batcheler Jeff Randles	Peter Turnball	Corporate Overview
3/3/04 Brisbane	Bob Coulter Ian Marks Graham Batcheler Jeff Randles	Martin Hoelscher	Network Story
3/3/04 Brisbane	Bob Coulter Ian Marks Graham Batcheler Jeff Randles	Mike Griffin	Asset Management
3/3/04 Brisbane	Bob Coulter Jeff Randles	Chris Dunn	Performance Measures
3/3/04 Brisbane	Bob Coulter Jeff Randles	Ray Pannam Paul Rainbird	Asset Management
3/3/04 Brisbane	Bob Coulter Jeff Randles	Darren Lloyd John Daley	Maintenance Management Systems Procurement and Spares
3/3/04 Brisbane	Bob Coulter Jeff Randles	Paul Rainbird	Maintenance backlogs
3/3/04 Brisbane	Bob Coulter Jeff Randles	Paul Blackmore	Vegetation Management
3/3/04 Brisbane	Ian Marks Graham Batcheler	Chris Delamont	Environmental Management
3/3/04 Brisbane	Ian Marks Graham Batcheler	Peter Gill	Integrated Planning Act
3/3/04 Brisbane	Ian Marks Graham Batcheler	Bevan Holcombe	Network planning
3/3/04 Brisbane	Ian Marks Graham Batcheler	Darren Lloyd Col Lee	Design Standards
3/3/04 Brisbane	Ian Marks Graham Batcheler	Jenny Hocking Scott Jamison	External Liaison Major Customers
3/3/04 Brisbane	Ian Marks Graham Batcheler	Jonathan Thompson Peter Finley	Basis of Cost Allocations
3/3/04 Brisbane	Ian Marks Graham Batcheler	Kevin Kehl	Customer Contributions
3/3/04 Brisbane	Ian Marks Graham Batcheler	Paul Rainbird Ken Pollock	Project Prioritisation and Approval

DATE	CONSULTANT PERSONNEL	ENERGEX PERSONNEL	TOPIC
4/3/04 Various	Bob Coulter Ian Marks Graham Batcheler Jeff Randles	Ron Barbagello John Adams Richard Jerks Neil Anderson Bevan Holcombe	Site Visits: Control Centre, Camp Hill, Creastmead, Caloomba, Cooporoo
3/3/04 Brisbane	Ian Marks Graham Batcheler	Warren Brewer	Post Implementation Review
3/3/04 Brisbane	Bob Coulter Jeff Randles	Bevan Holcombe Ken Pollock	Structure of OPEX
19/4/04 Brisbane	Ian Marks Graham Batcheler	Wayne Smith Rod Borrows	Project Management
19/4/04 Brisbane	Ian Marks Graham Batcheler	Bevan Holcombe	Network planning
19/4/04 Brisbane	Ian Marks Graham Batcheler	Ross Culpitt	Capital Contributions
20/4/04 Brisbane	Ian Marks Graham Batcheler	Chris Arnold	CAPEX
20/4/04 Brisbane	Ian Marks Graham Batcheler	Bevan Holcombe	Network Augmentation Forecasts Asset management plan Resources Pole replacements Project Categories
21/4/04 – 22/4/04 Brisbane	Ian Marks Graham Batcheler		Project Review
30/4/04 Brisbane	Bob Coulter Jeff Randles Erika Twining	Darren Lloyd Bevan Holcombe	OPEX budget details

14.2 Key Documents Accessed

Energex Corporate Planning – Regulated Line of Business Plan

Organisational Structure and Staffing

BMS 01454 - Customer Service Standards

BMS 01131 – Manage Customer Service Guarantee Claims

BMS 00826 – Manage Customer Feedback

BMS 1774 - Environmental Manual

BMS 1681 - Environmental Standard

BMS 1682 - Environmental Assessment

Hierarchy of ENERGEX Workplace Health and Safety Compliance Process

Corporate Occupational Health and Safety Policy

SP02 - Criteria For Loading of the Electricity Network

SP26 - Determination of Scope for Network Augmentation Proposals

SP24 – Provision of annual load forecast for Bulk Supply and Zone Substations

6056-A4 – Reliability Assessment Planning Guidelines (Rev 4)

SP14 – Determination of Ultimate Spatial Load Distribution and Zone Substation Loadings for an Area

SP15 – Production of a Strategic Network Plan

SP16 – Determination of Load Density and Load Curve for a Zoning Category

SP17 – Determination of Ultimate Bulk Supply Substation Sites and Loading for an Area

SP19 – Determination of Ultimate 11kV Feeders for an Area

SP21 – Determination for Ultimate Sub-transmission Feeders for an Area

SP25 – Production of the Annual Network Development Plan

SP6 – Development of Scenarios Focusing on Future Network Requirements

Plant Rating Manual

BMS 01615 – Standard Network Building Blocks

Annual Sub-transmission 10 Year Load Forecasts

Supply and Planning Manual : Sections 2.3, 2.4 and 2.5

Customer Contributions Methodology

BMS 2089 - Network Initiated Capital Work

BMS 2090 - Customer Initiated Capital

BMS 1937 - Project Management

BMS 1944 - Variation Management

Energex Monthly Reports (Corporate & Distribution)

Background Information for ADMD Changes

Changes to Distribution Network Design Requirement – ADMD and Cable Sizing

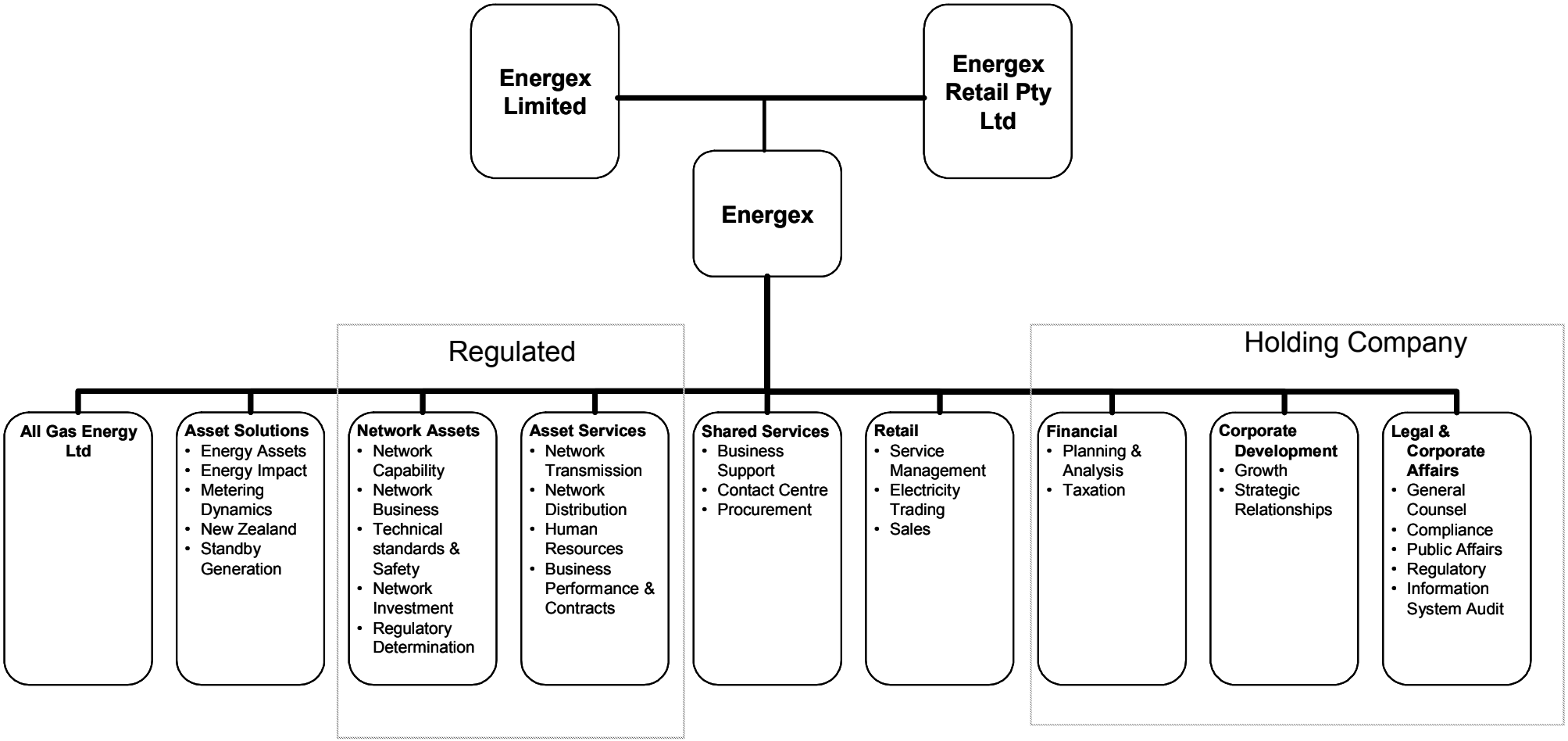
BMS00928 – Financial Delegation

Energex Network Development Plan 2004/05 to 2008/09

Overview of CAPEX program

Energex Information Request of Demand Forecasts

14.3 Organisation Structure



14.4 Summary of Current Maintenance Practices

Table 14-1: Summary of Inspection and Planned Maintenance Intervals

	Asset	Inspect	Planned Maintenance	Industry Practice
Transmission and Distribution	**Overhead Assets**			
	Transmission lines / Towers	5 years	Climb Towers every 5 years	6 years
	Pre-storm period	Yearly		Yearly
	Pole top	2.5 yrs with vegetation		6 years
	Poles	Below ground > 10 years age every 5 years	5 years	6 years Queensland legislation states 5 years.
	Service lines	5 years	N/A	6 years
	Line Thermovision	3 years	N/A	3 years
	Underground Cables			
	110 kV	Monthly	N/A	Reactive maintenance only. XLPE 2 yearly sheath test. Inspection with line and station assets.
	33 kV fluid filled & gas pressure	Monthly & 6 monthly	N/A	
	33 kV XLPE and mass impregnated	2 & 6 monthly	N/A	
	11 kV & LV including pillars.	5 years (Inspection with line assts)	N/A	
	Cable Systems			
	Fluid / Gas pressures / Consumption	Monthly	N/A	During station inspections.
	Test alarms / Inspect terminations etc.	Yearly	N/A	
	Thermal imaging	3 years	N/A	
	Gas pressure & DGA	2-6 years	N/A	
	Outer sheath resistance	Yearly / 2 years	N/A	Nil
Distribution Network	C&I Substation Inspections	6 months		
	Ring Main Units (RMU)			
	General	6 yrs	12 yrs	12 yrs
	Holec & Hazemeyer	3 yrs	6 yrs	
	Krone		4 yrs	
	11 kV Reclosers			
	McGraw Edison	N/A	12 yrs,	Inspect 12 years
	Nulec, Brush	6 mths	5 & 12 yrs	
	Pole Mounted Assets			
	Brush Pole Mounted Reclosers	Yearly	12 yrs	6 yrs
	Load break Switches / Sectionalisers	Yearly	4-5 yrs	6 yrs
	Distribution Earthing systems	10 yrs		6 yrs
	General			
	Distribution Transformers	6 yrs	12 yrs	6 yrs
	Ground Mounted Plant	6 yrs	4-12 yrs	Indoor and enclosed - 6 yrs Outdoor – 2 yrs

	Asset	Inspect	Planned Maintenance	Industry Practice
Zone Substations	Zone Substation Inspections	6 months		Mthly & 6 mthly
	Zone Substation property	3 months – inspection report 1 year – maintenance report 2 year – replacement report		1 year
	Thermo-scan	3 years		2 yrs
	Power Transformers			
	General Maintenance		10 years	At substation inspection.
	DGA >= 110 kV		2 years	2 yrs, oil test , incl. DGA
	DGA <110 kV		4 years	
	OLTCs (33/110/132 kV)		3-6 yrs (time based only)	Maintenance after designated operations only Oil sample only
	Selector switch compartment		6-8 yrs some makes	Oil sample only
	Circuit Breakers			
	11/33 kV CBs (general).	N/A	6 or 12 years depending on type	6 years
	33 kV Hitachi CB	6 years	18 years	
	33 kV Joslyn Sectionaliser		50 years	
	Most 110/132 kV CBs	4 yrs	16 yrs	4 & 16 yrs
	BB HB	N/A	20 yrs	
	CB maintenance after fault ops.	Nil.	Nil.	Maintenance according to points system based on fault currents.
	Ancillary Equipment			
	Exposed Busbars	3 years		6 yrs
	11/33 kV ABS and Isolators	3 years	N/A	6 yrs
	110/132 kV ABS and Isolators	3 years	6 years	6 yrs
	11/33 kV Disconnect Links and Dropout Fuses.	3 years	N/A	6 yrs
	110/132 kV Fault Throw Switches	N/A	6 yrs	6 yrs
	Neutral Earthing Resistors and Reactors	N/A	6 yrs	6 yrs
	Neutral Earthing Transformers	N/A	6-10 years to coincide with Power Transformer maintenance.	With associated equipment.
	Surge Diverters (>= 33 kV)	N/A	At same time as associated equipment.	With associated equipment.
	Lead Acid Batteries (vented)	(Level 1) 3 months	(Level 2) 12 months. (Level 3) 5 years. Replace batteries at 20 years.	Inspect at 3 mths & full check at 12 mths. Replace when required.
	Lead Acid Batteries (sealed)	(Level 1) 3 months	(Level 2) 12 months. Replace batteries at 5 years.	3 & 12 mths
	Alkaline Batteries	As part of routine substation inspections.	5 years.	3 & 12 mths

	Asset	Inspect	Planned Maintenance	Industry Practice
	11/33 kV Capacitor Banks	N/A	3 years	6 yrly
	Portable Earthing Equipment	6 months as per BMS Procedure 00764.	As per BMS Procedure 00764.	6 mthly
	Oil Containment Facilities	3 months	1 year and 2 year water test.	12 mthly
	Motor Generator AFLC	3 months	6 years	
	SFU's and SFU-G's AFLC	12 months	N/A	
	Instrument Transformers <66kV		6 yrs	4 yrly oil test, incl. DGA
	Instrument Transformers >66kV		2 yrs	2 yrly oil test incl. DGA.
	Protection Schemes			
	11 kV and 33 kV Non-critical		6 yrs	6, 8 & 10 yr intervals depending on points allotted according to age, customer impact and relay performance.
	33 kV Critical, 110/132 kV		<4 yrs	
Vegetation	Fast pre-storm patrol	Yearly		
	Planned vegetation management		15mth-trim 2.5 years clear	3 years

14.5 Consolidated OPEX Program

Table 14-2: Energex OPEX Expenditure

		05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
		Energex	Energex	Energex	Energex	Energex	Energex
Inspection	$M	19.452	24.825	26.511	28.518	30.180	129.486
Planned Maintenance	$M	38.527	43.365	44.915	47.783	50.469	225.059
Corrective Repair	$M	26.418	28.462	30.664	33.036	35.592	154.172
Emergency Response / Storms	$M	9.011	9.569	10.171	10.819	11.518	51.088
Vegetation	$M	44.517	46.457	46.457	46.457	46.457	230.343
Streetlights	$M	5.737	6.181	6.659	7.174	7.729	33.480
Customer Service	$M	9.180	9.452	9.737	10.035	10.347	48.752
Total Maintenance	**$M**	**152.841**	**168.311**	**175.114**	**183.823**	**192.291**	**872.381**
Network Operations	$M	12.150	13.090	14.103	15.194	16.369	70.907
Levies	$M	4.900	4.997	5.096	5.196	5.299	25.488
Call Centre	$M	6.507	6.636	6.767	6.900	7.037	33.846
Meter Reading - Franchise Customer	$M	6.120	6.241	6.364	6.490	6.618	31.833
Metering Dynamic	$M	1.062	1.168	1.227	1.288	1.352	6.097
Total Operating	**$M**	**30.739**	**32.132**	**33.556**	**35.069**	**36.676**	**168.172**
DSM Initiatives	$M	2.000	2.000	2.000	2.000	2.000	10.000
Embedded Generators Payments	$M	0.162	0.162	0.162	0.162	0.162	0.810
Total New Initiatives	**$M**	**2.162**	**2.162**	**2.162**	**2.162**	**2.162**	**10.810**
Before OPEX Efficiency Savings	**$M**	**185.743**	**202.605**	**210.832**	**221.053**	**231.129**	**1051.363**
Efficiency Savings	$M	1.896	2.090	2.238	2.340	2.441	11.006
Total OPEX (excl. NRCR Products)	**$M**	**183.846**	**200.515**	**208.594**	**218.713**	**228.688**	**1040.357**
Recoverable	$M	13.072	14.083	15.173	16.347	17.611	76.286
Temporary Builders	$M	0.870	0.888	0.905	0.923	0.941	4.528
Total OPEX for NRCR Products	**$M**	**13.942**	**14.971**	**16.078**	**17.270**	**18.552**	**80.813**
Total OPEX (incl. NRCR Products)	**$M**	**197.789**	**215.486**	**224.672**	**235.983**	**247.240**	**1121.170**

All forecast and historical figures are in June 2004 dollars

Table 14-3: Consultants OPEX Expenditure

		05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
		Consultant	Consultant	Consultant	Consultant	Consultant	Consultant
Inspection	$M	18.432	22.540	23.068	23.799	24.085	111.924
Planned Maintenance	$M	36.641	40.372	40.718	42.223	43.440	203.395
Corrective Repair	$M	24.938	25.513	26.095	26.686	27.286	130.508
Emergency Response / Storms	$M	9.011	9.261	9.523	9.798	10.086	47.679
Vegetation	$M	44.517	46.457	46.457	46.457	46.457	230.343
Streetlights	$M	5.737	6.018	6.313	6.622	6.947	31.637
Customer Service	$M	7.768	8.029	8.302	8.587	8.886	41.572
Total Maintenance	**$M**	**147.044**	**158.190**	**160.476**	**164.172**	**167.186**	**797.060**
Network Operations	$M	11.810	12.108	12.413	12.726	13.046	62.103
Levies	$M	4.561	4.675	4.792	4.912	5.035	23.975
Call Centre	$M	6.507	6.663	6.823	6.987	7.155	34.135
Meter Reading - Franchise Customer	$M	6.120	6.267	6.417	6.571	6.729	32.104
Metering Dynamic	$M	1.062	1.168	1.227	1.288	1.352	6.097
Total Operating	**$M**	**30.059**	**30.886**	**31.670**	**32.482**	**33.321**	**158.414**
DSM Initiatives	$M	2.000	2.000	2.000	2.000	2.000	10.000
Embedded Generators Payments	$M	0.162	0.162	0.162	0.162	0.162	0.810
Total New Initiatives	**$M**	**2.162**	**2.162**	**2.162**	**2.162**	**2.162**	**10.810**
Before OPEX Efficiency Savings	**$M**	**179.266**	**191.238**	**194.309**	**198.816**	**202.665**	**966.283**
Efficiency Savings	$M	3.585	3.825	3.886	3.976	4.053	19.326
Total OPEX (excl. NRCR Products)	**$M**	**175.681**	**187.414**	**190.422**	**194.840**	**198.611**	**946.958**
Recoverable	$M	13.072	13.399	13.734	14.077	14.429	68.711
Temporary Builders	$M	0.870	0.891	0.913	0.935	0.957	4.566
Total OPEX for NRCR Products	**$M**	**13.942**	**14.290**	**14.647**	**15.012**	**15.386**	**73.277**
Total OPEX (incl. NRCR Products)	**$M**	**189.623**	**201.704**	**205.069**	**209.851**	**213.998**	**1020.245**

All forecast and historical figures are in June 2004 dollars

14.6 Energex OPEX Forecasts

14.6.1 Distribution Feeder

Table 14-4: Distribution Feeder Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Inspection								
Annual LAI	Units	5,124	5,520	5,947	6,408	6,903	7,437	32,216
	$M	1.30	1.38	1.48	1.60	1.72	1.86	8.04
Annual fast feeder patrol	Units	18,573	20,010	21,558	23,225	25,022	26,958	116,773
	$M	0.82	0.88	0.94	1.02	1.10	1.19	5.14
Unplanned feeder patrol	Units	2,050	2,209	2,379	2,564	2,762	2,975	12,889
	$M	0.36	0.38	0.41	0.40	0.48	0.51	2.22
Thermo-scan	Units	285	300	323	348	375	404	285
	$M	0.31	0.18	0.36	0.39	0.41	0.45	1.78
Planned Maintenance								
Miscellaneous maintenance and repair after LAI	Units	2,350	2,532	2,728	2,939	3,166	3,411	14,775
	$M	3.275	3.474	3.743	4.032	4.344	4.681	20.275
Emergency Response								
DS Feeders	Units	66	79	85	91	98	106	459
	$M	4.39	5.16	5.56	5.99	6.46	6.95	30.13

All forecast and historical figures are in June 2004 dollars

14.6.2 Distribution Poles

Table 14-5: Distribution Pole Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Inspection								
Wood poles >10yrs	Units	83,444	89,899	96,854	104,346	112,419	121,115	524,634
	$M	5.09	5.62	6.05	6.52	7.02	7.57	32.77
Wood poles – visuals <10yrs	Units	25,286	27,242	29,350	31,620	34,066	189,645	311,923
	$M	0.19	0.21	0.23	0.24	0.26	0.28	1.22
Steel/Concrete poles	Units	17,700	19,069	20,544	22,134	23,846	25,691	111,284
	$M	0.53	0.59	0.63	0.68	0.73	0.79	3.42
Spot poles	Units	3,500	3,771	4,062	4,377	4,715	5,080	22,005
	$M	0.31	0.35	0.38	0.41	0.44	0.47	2.04
Mechanical wood pole testing >10yrs	Units	2,372	2,555	2,753	2,966	3,196	3,443	14,913
	$M	0.28	0.31	0.34	0.37	0.39	0.42	1.84
First property poles	Units	3,225	3,474	3,743	4,033	4,345	4,681	20,276
	$M	0	0.21	0.22	0.24	0.26	0.28	1.21
Wood poles after incident	Units	240	323	348	375	404	435	1,886
	$M	0.02	0.03	0.03	0.03	0.04	0.04	0.18

All forecast and historical figures are in June 2004 dollars

14.6.3 Distribution Pole Tops

Table 14-6: Distribution Pole Top Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Inspection								
Live line pole top inspections	Units	0	1,000	1,077	1,161	1,250	1,347	5,836
	$M	0*	0.12	0.13	0.14	0.15	0.16	0.71
Planned Maintenance								
Replace cross arms – LV	Units	2,225	2,397	2,583	2,782	2,998	3,229	13,989
	$M	2.66	2.83	3.04	3.28	3.53	3.81	16.49
Replace cross arms – 11 kV	Units	900	970	1,045	1,126	1,213	1,307	5,661
	$M	1.71	1.82	1.96	2.11	2.27	2.445	10.61
Replace cross arms – 66 kV	Units	305	184	198	214	230	248	1,074
	$M	0.70	0.42	0.45	0.49	0.52	0.56	2.44

All forecast and historical figures are in June 2004 dollars

14.6.4 LV Services

Table 14-7: LV Service Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Inspection								
LV overhead services	Units	0	96	10,724	32,321	34,821	37,515	115,476
	$M	0.00	1.03	3.10	3.34	3.60	3.88	14.95
LV service pillars (Level 2)	Units	0	7,500	16,160	17,411	18,757	20,209	80,037
	$M	0.00	1.08	2.33	2.51	2.70	2.91	11.52
LV service pillars (Level 1)	Units	33,012	35,566	38,317	41,281	44,475	47,916	207,555
	$M	0.340	0.44	0.47	0.51	0.55	0.59	2.56
Planned Maintenance								
Maintain and repair LV overhead services	Units	250	1,072	3,232	3,482	3,751	4,042	15,580
	$M	0.14	0.57	1.73	1.86	2.00	2.16	8.32
Replace suspect LV neutral service clamps	Units	20,000	21,547	23,214	25,010	26,945	29,029	125,745
	$M	1.45	1.60	1.72	1.85	2.00	2.15	9.32
Maintain and repair LV service pillars	Units	1,651	1,778	1,915	2,063	2,223	2,395	10,374
	$M	1.07	1.14	1.22	1.32	1.42	1.53	6.63

All forecast and historical figures are in June 2004 dollars

14.6.5 Other Distribution Equipment

Table 14-8: Other Distribution Equipment Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Inspection								
Inspect pole mounted plant	Units	652	702	757	815	878	946	4,099
	$M	0.16	0.17	0.18	0.20	0.21	0.23	0.98
Inspect and validate ground mounted plant (Level 2)*	Units	686	100	108	116	125	135	584
	$M	0.08	0.01	0.01	0.01	0.01	0.02	0.07
Inspect ground mounted plant (Level2)	Units	2,453	1,936	2,086	2,247	2,421	2,608	11,298
	$M	0.24	0.19	0.20	0.22	0.23	0.25	1.08
Inspect and test overhead HV earthing system	Units	11,411	8,198	14,698	14,697	14,697	9,457	61,747
	$M	0.52	0.63	1.13	1.13	1.13	0.73	4.74
Inspect and test ground based plant HV earthing system	Units	0	1,936	2,086	2,247	2,421	2,608	11,298
	$M	0.00	0.23	0.24	0.26	0.28	0.30	1.32
Planned maintenance								
Maintain and repair pole mounted plant	Units	21	23	24	26	28	30	132
	$M	0.03	0.03	0.03	0.04	0.04	0.04	0.18
Maintain and repair ground mounted plant	Units	422	455	490	528	569	613	2,653
	$M	1.06	1.12	1.21	1.30	1.41	1.51	6.56
Maintain and repair overhead HV earthing systems	Units	2,282	1,394	2,499	2,498	2,498	1,608	10,497
	$M	1.00	0.69	1.23	1.23	1.23	0.79	5.19
Maintain & Repair Ground based HV Earthing Systems	Units	0	387	417	449	484	522	2,260
	$M	0.00	0.27	0.29	0.31	0.34	0.36	1.57
Corrective Repair								
DS Equipment	Units	22,927	24,701	26,612	28,671	30,888	22,927	24,701
	$M	19.01	22.05	23.75	25.59	27.57	29.70	128.65

All forecast and historical figures are in June 2004 dollars

14.6.6 Distribution Special Projects

Table 14-9: Distribution Special Project Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Inspection								
Inspect waterway crossing signs	Units	0	84	91	98	105	113	490
	$M	0	0.02	0.03	0.03	0.03	0.03	0.14
Six sigma project	Units	2,800	3,340	3,598	3,877	4,176	4,500	19,490
	$M	0.34	0.36	0.39	0.42	0.45	0.49	2.10
Inspect Hazemeyer RMUs	Units	451	671	1,093	1,732	2,606	3,548	9,650
	$M	0.04	0.05	0.08	0.13	0.20	0.27	0.74
Inspect Krone RMUs	Units	776	926	556	186	0	0	1,668
	$M	0.06	0.07	0.04	0.01	0	0	0.13
Inspect & test LFIs	Units	0	120	129	139	150	162	700
	$M	0	0.01	0.01	0.01	0.01	0.01	0.03
Read MDIs	Units	0	5,000	5,387	5,804	6,252	6,736	29,179
	$M	0	0.77	0.83	0.89	0.96	1.03	4.48
Planned Maintenance								
Non-specified reliability improvement	Units	232	248	267	288	310	334	1,446
	$M	0.63	0.66	0.71	0.77	0.83	0.89	3.87
Maintain and repair waterway crossing signs	Units	40	44	48	51	55	60	258
	$M	0.28	0.31	0.33	0.36	0.83	0.41	1.79
Upgrade capacitive test points on ABB RMUs (over 12 years)	Units	1,320	1,422	1,532	1,651	1,778	1,916	8,299
	$M	0.38	0.41	0.44	0.47	0.51	0.55	2.24
Upgrade capacitive test points on ABB SFUs (over 3 years)	Units	390	420	453	488	525	566	2,452
	$M	0.19	0.20	0.22	0.23	0.25	0.27	1.17
Sensitive Area	Units	5	7	8	8	9	9	41
	$M	0.50	0.80	0.86	0.93	1.00	1.08	4.67
Inspect and repair street light n links (pre 1986)	Units	0	3,300	3,300	116	125	135	6,976
	$M	0	0.55	0.55	0.02	0.02	0.02	1.17
Inspect and repair LV service pillars (pre 1985)	Units	0	15,000	15,000	15,000	15,000	15,000	75,000
	$M	0	3.25	3.25	3.25	3 .25	3.25	16.27
Maintain and repair Hazemeyer RMUs	Units	44	47	51	55	59	64	277
	$M	0.12	0.12	0.13	0.14	0.15	0.16	0.71
Maintain and repair Krone RMUs	Units	39	42	45	49	53	57	245
	$M	0.10	0.11	0.12	0.12	0.13	0.14	0.63
Removal of grafitti (incl. Council MOU's)	Units	175	189	203	219	236	254	1,100
	$M	0.24	0.30	0.32	0.34	0.37	0.40	1.73
Maintain and repair LFIs	Units	0	100	108	116	125	135	584
	$M	0	0.09	0.10	0.10	0.11	0.12	0.52

All forecast and historical figures are in June 2004 dollars

14.6.7 Sub-transmission OH Feeders

Table 14-10: Sub-transmission OH Feeder Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Inspection								
OH Transmission Feeder Patrol	Units	74	153	159	165	172	180	829
	$M	0.48	1.16	1.19	1.22	1.26	1.30	6.13
Thermal Imaging	Units	0	25	58	63	68	73	286
	$M	0.000	0.032	0.075	0.081	0.087	0.094	0.370
Planned Maintenance								
Switching OH mains	Units	96	1	1	1	1	1	6
	$M	0.13	0.07	0.08	0.09	0.09	0.10	0.43
General Repairs	Units	36	87	94	101	109	118	509
	$M	0.75	1.32	1.42	1.53	1.65	1.77	7.68
Corrective Repair								
Sub-transmission OH Feeder	Units	1	1	1	1	1	1	6
	$M	0.26	0.34	0.37	0.40	0.43	0.46	2.00
Emergency Response								
Sub-transmission OH Feeder	Units	1	1	1	1	1	1	6
	$M	0.26	0.28	0.30	0.32	0.35	0.37	1.62

All forecast and historical figures are in June 2004 dollars

14.6.8 Sub-transmission Poles and Structures

Table 14-11: Sub-transmission Pole and Structure Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Inspection								
Pole / Tower Inspection	Units	179	648	639	742	621	773	3,422
	$M	0.04	0.25	0.26	0.29	0.27	0.31	1.38
Planned Maintenance								
Pole / Tower Maintenance	Units	621	215	232	250	269	290	1,257
	$M	1.43	1.54	1.66	1.78	1.92	2.07	8.97

All forecast and historical figures are in June 2004 dollars

14.6.9 Sub-transmission UG Cables

Table 14-12: Sub-transmission UG Cable Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Inspection								
Condition Monitoring (RGP&DGA) 110 kV	Units	8	4	4	5	5	5	23
	$M	0.01	0.01	0.01	0.01	0.01	0.01	0.03
Condition Monitoring (RGP&DGA) 33 kV	Units	9	8	7	2	0	18	35
	$M	0.01	0.01	0.01	0.00	0.00	0.03	0.06
UG Cable Patrol 110 kV	Units	288	288	310	334	360	388	1,681
	$M	0.04	0.04	0.04	0.05	0.05	0.05	0.23
UG Cable Patrol 33 kV	Units	1	288	310	334	360	388	1,681
	$M	0.05	0.04	0.04	0.04	0.05	0.05	0.21
Paper Sampling 33 kV	Units	0	13	14	15	16	17	75
	$M	0.00	0.01	0.01	0.02	0.02	0.02	0.07
Pressure Readings 33 kV	Units	0	154	166	179	193	207	899
	$M	0.00	0.15	0.16	0.18	0.19	0.20	0.88
General Inspections and Tests 110 kV	Units	89	188	202	218	235	253	1,097
	$M	0.24	0.09	0.09	0.10	0.11	0.12	0.51
General Inspections and Tests 33 kV	Units	270	69	74	80	86	93	401
	$M	0.08	0.08	0.09	0.09	0.10	0.11	0.46
Planned Maintenance								
Oil Topping	Units	2	2	2	3	3	3	13
	$M	0.53	0.56	0.60	0.65	0.70	0.76	3.27
General Cable Repairs	Units	68	1,435	1,545	1,659	1,785	1,941	8,364
	$M	2.49	3.06	3.30	3.56	3.83	4.13	17.88
Corrective Repairs								
Sub-transmission UG Cables	Units	4	2	2	3	3	3	4
	$M	0.85	0.35	0.38	0.41	0.44	0.48	2.07

All forecast and historical figures are in June 2004 dollars

14.6.10 ZSS Power Transformers

Table 14-13: ZSS Power Transformer Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Inspection								
Power Transformer DGA	Units	185	205	221	238	256	276	1,196
	$M	0.15	0.15	0.17	0.18	0.19	0.21	0.90
Test bushings	Units	30	32	35	38	40	44	189
	$M	0.17	0.18	0.19	0.21	0.22	0.24	1.05
Inspect OLTC	Units	0	47	61	15	63	13	199
	$M	0.00	0.10	0.11	0.03	0.11	0.02	0.37
Planned Maintenance								
OLTC Maintenance	Units	191	92	106	79	127	69	472
	$M	0.92	0.51	0.66	0.42	0.78	0.43	2.80
General Transformer Maintenance	Units	351	448	482	520	560	603	2,614
	$M	1.01	0.88	0.94	1.02	1.09	1.18	5.11

All forecast and historical figures are in June 2004 dollars

14.6.11 ZSS Circuit Breakers

Table 14-14: ZSS Circuit Breaker Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Inspection								
CB sub-diagnostic tests	Units	301	253	273	294	316	341	1,476
	$M	0.39	0.37	0.40	0.43	0.46	0.50	2.17
11/33 kV CB Inspections	Units	0	4	4	4	4	4	21
	$M	0.00	0.01	0.01	0.01	0.01	0.01	0.03
110 / 132 kV Inspections	Units	0	8	8	4	11	9	39
	$M	0.00	0.02	0.02	0.01	0.03	0.02	0.10
Planned Maintenance								
Maintain 11/ 33 kV CB	Units	466	443	618	392	191	224	1,868
	$M	0.97	0.83	1.12	0.79	0.39	0.40	3.53
Maintain 110/132 kV CB	Units	80	1	1	2	2	2	8
	$M	1.01	0.00	0.00	0.00	0.00	0.00	0.01
Maintain / Refurbish Insulators / Bushings	Units	26	38	41	44	48	51	222
	$M	0.06	0.09	0.10	0.11	0.12	0.12	0.54
General repairs (alarms)	Units	448	589	635	684	737	794	3,439
	$M	0.81	0.91	0.98	1.05	1.13	1.22	5.29
Other	Units	956	491	529	570	614	661	2,865
	$M	0.60	0.38	0.41	0.44	0.48	0.52	2.23

All forecast and historical figures are in June 2004 dollars

14.6.12 Other ZSS Equipment

Table 14-15: Other ZSS Equipment Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Inspection								
Miscellaneous Tests	Units	92	739	796	857	924	995	4,311
	$M	0.05	0.98	1.06	1.14	1.23	1.33	5.74
Thermo-scan	Units	83	60	144	156	168	181	708
	$M	0.07	0.10	0.25	0.26	0.28	0.31	1.20
Routine Inspections	Units	1,412	2,082	2,243	2,416	2,603	2,805	12,148
	$M	1.50	1.28	1.38	1.49	1.61	1.73	7.49
Planned Maintenance								
Miscellaneous Maintenance	Units	471	394	417	443	477	505	2,236
	$M	1.08	0.57	0.61	0.65	0.70	0.74	3.26
General Repairs	Units	150	604	627	652	679	708	3,271
	$M	0.19	0.58	0.60	0.61	0.63	0.65	3.07
Corrective Repairs								
ZSS Equipment	Units	15	14	15	16	18	19	82
	$M	2.93	3.33	3.58	3.86	4.16	4.48	19.41
Emergency Response								
ZSS Equipment	Units	1	1	1	1	1	1	6
	$M	0.42	0.44	0.48	0.52	0.56	0.60	2.59

All forecast and historical figures are in June 2004 dollars

14.6.13 ZSS Secondary Equipment

Table 14-16: ZSS Secondary Equipment Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Planned Maintenance								
Battery maintenance	Units	167	253	397	321	314	460	1,745
	$M	0.29	0.40	0.72	0.53	0.50	0.82	2.97
Protection maintenance	Units	100	124	133	145	156	168	726
	$M	1.19	1.69	1.82	1.96	2.11	2.27	9.84
Pilot Cable Maintenance	Units	75	81	87	94	101	109	472
	$M	0.89	0.97	1.05	1.13	1.212	1.31	5.67

All forecast and historical figures are in June 2004 dollars

14.6.14 ZSS Site

Table 14-17: ZSS Site Expenditure

		04/05	05/06	06/07	07/08	08/09	09/10	Total 05/06 – 09/10
Inspection								
Air conditioner inspection	Units	24	21	23	24	26	28	123
	$M	0.01	0.01	0.01	0.01	0.01	0.01	0.05
Planned Maintenance								
Fencing	Units	82	44	47	51	55	59	257
	$M	0.11	0.11	0.12	0.13	0.14	0.15	0.66
Building	Units	307	238	255	275	296	317	1,381
	$M	0.66	0.54	0.56	0.69	0.73	0.75	3.27
Servicing	Units	0	5	5	6	6	7	29
	$M	0.00	0.68	0.73	0.79	0.845	0.91	3.96
Fire Protection	Units	4	5	5	6	6	7	29
	$M	0.39	0.401	0.44	0.47	0.51	0.54	2.36
Surrounds	Units	103	84	90	97	105	113	490
	$M	0.83	0.10	0.11	0.12	0.13	0.14	0.61
Other	Units	54	26	28	29	31	33	148
	$M	0.09	0.04	0.04	0.05	0.05	0.05	0.23
Corrective Repair								
ZSS Site	Units	0	2	2	3	3	3	13
	$M	2.09	1.88	2.00	2.24	2.40	2.55	11.08

All forecast and historical figures are in June 2004 dollars

14.7 Review Pro-forma

CRITERION	RATING	COMMENTS
Consideration of impact on demand		
Current & projected capacity/asset utilisation		
Asset condition & renewal requirements		
Demographic circumstances		
Non-network alternatives		
Safety & service quality standards		
Accepted planning standards		
Policies re environmental requirements etc.		
Minimising life cycle cost/economic evaluation		
Risk analysis		
Correct project categories		
Correct allocation of overheads		
Efficient design/planning approach		

PROJECT NO ……...PROJECT CATEGORY…… PROJECT NAME……

PROJECT DESCRIPTION……

……

BUDGET COST……..…. ACTUAL COST…… APPROVED BY……..…..DATE……..…..

PROJECT REVISION YES /NO REVISION DATE…..…… APPROVED BY…… BASIS ……

COMPLETION DATE…… POST IMPLEMENTATION REVIEW DATE……..

PIR COMMENTS……

PROJECT CLOSURE DATE…….. AUTHORISED BY……..

BASIS FOR COSTING ……

OVERALL ASSESSMENT……..……..……

……..……

14.8 Projects Reviewed

MASTER PROJECT	ELLIPSE	PROJECT DESCRIPTION
CUSTOMER DRIVEN PRIMARY - 311100		
CPW0000011	C0015195	ABM – REPLACE T1 & T2
NMS1000271		EBV – EST NEW 11KV FDR TO AMH
DEMAND DRIVEN PRIMARY - 311200		
NSC1000017	C0006163	CRM – EST 33/11KV SUBSTATION
NMS1000085	C0006431	LYT – UPRATE 11KV FEEDER
NSC1000060	C0009180	MDR-EST NEW 110/11KV SUB
	C00309489	SJ077325 BINNA BURRA POLE CHANGE & COND
RELIABILITY IMPROVEMENT PRIMARY - 311300		
ELR1000143		MTT - RELIABILITYIMPROVEMENT
CPM0000054	C0037004	11KV MOBILE GENERATOR 1MW
REFURBISHMENT DRIVEN PRIMARY - 311400		
NMN1000084	C007460	T3/TRG – REPLACE AGEING 33KV FDRS
NMN1000099	C0008970	PRE-APPROVAL – F347 REP 33KV CABLE
C000004554		INA – REPLACE AGEING SWGR
DEMAND PRIMARY, RELIABILITY SECONDARY - 311500		
CPS0000114		BLH – UPGRADE FEEDER 704
NMN1000073		CST/VPK – EST 110KV UG CABLE
CB0000082	C0017031	HWD – 33KV OH WORKS
DEMAND PRIMARY, REFURBISHMENT SECONDARY - 311600		
NMS1000012		T142 (VARIOUS)
DOMESTIC & RURAL CUSTOMER REQUESTED - 312100		
NED1201561	C0023045	ADELAIDE & EDWARD STS CITY
NED1800937	C0027050	KAWANA ISLAND STAGE 6
NED1100532	C008471	TEEWAH VILLAGE
OTHER WORKS - 312200		
ELR1032411	C0015634	WILD LIFE PROOFING
NED1500368		GOLD COAST – SPRINGBOOK RD, CAR
EXTERNAL BUSINESS INCOME - 312300		
NED1300675		175 EAGLE ST BRISBANE CITY
NED1300759	C0011017	C&I SUB – CHARLOTTE ST, BRISBANE
AGEING EQUIPMENT- 312400		
	C0044350	GOWRIE ST, UPPER MT. GRAVATT – REPLACE GT
	C0049508	REPLACE LV STAY, GRENFALL ST MT GRAVATT E
D1502207		4 MILE LANE, BOYLAND – REPLACE 11 kV MAINS
POLE REINSTATEMENT - 312450		
	C0039705	ARCHER ST, WOODFORD – REPLACE 33 kV CONDEMNED POLE
	C0039717	NEURUM RD,VILLENUE – REPLACE 11kV POLE
	C0039756	MT NEBO RD, MT NEBO – REPLACE LV CONDEMNED POLE
	C0042545	GYMPIE RD, ASPLEY – REPLACE 2 CONDEMNED POLES
COMMERCIAL & INDUSTRIAL CUSTOMER REQUESTED - 312500		
NED1301327	C0016195	LPRJV CHIPPENDALL ST MILTON
NED1201487		CNR WICKHAM & ANN ST FORTITUDE
NED1301296		CAMPBELL & HAMILTON PL BOWEN H
PUBLIC LIGHTING - 312600		
NEL1003034		SLS SOMERSET DVE MUDGEERABA
NEL1005178		SLS STATION RD, WOOLRIDGE
COMPANY INITIATED - 312650		
NED1100313		SUNRISE HILLS
NED1101716		U/G OF OH DAVID LOW WAY & WILLIAM ST

MASTER PROJECT	ELLIPSE	PROJECT DESCRIPTION
NON-SYSTEM PROJECTS		
	C0017598	BANYO – UPGRADE SECURITY
NPJU190024		CITY OFFICE IMPROVEMENTS
		CUSTOMER MANAGEMENT SYSTEM
	C002571	MI PROJECT (INTEGRATED ASSET MANAGEMENT SYSTEM)

14.9 Consolidated CAPEX expenditure

Table 14-18: Energex CAPEX Expenditure

	04/05 Energex	05/06 Energex	06/07 Energex	07/08 Energex	08/09 Energex	09/10 Energex	TOTAL 05/06-09/10 Energex
Asset replacements							
Refurbishment Driven Primary (Code 311400)	30.869	18.272	30.132	32.401	38.222	37.013	156.041
Ageing Equipment (Code 312400)	1.984	3.257	5.593	10.912	12.820	12.625	45.207
Pole Replacement and Pole Nailing (Code 312450)	11.007	10.668	11.088	25.282	34.443	33.912	115.392
Total Asset Replacements	**43.860**	**32.197**	**46.814**	**68.595**	**85.485**	**83.550**	**316.641**
Demand Related – Corporate Initiated							
Demand Driven Primary (Code 311200)	180.540	298.005	279.609	273.175	268.477	268.980	1,388.247
Distribution Augmentation (Code 312650)	8.531	12.239	16.467	25.022	28.418	28.921	111.068
Demand Primary/Reliability (Code 311500)	0.861	2.676	0.956	0.000	0.000	0.000	3.631
Demand Primary/Refurbishment (Code 311600)	2.041	4.642	7.184	7.146	9.205	9.649	37.825
Land and Right of Way (Code 311700)	1.873	10.453	6.314	6.314	6.314	6.314	35.710
Easements (Code (311750)	0.628	3.379	3.446	3.514	3.582	3.649	17.570
Total Demand Related – Corporate Initiated	**194.476**	**331.393**	**313.976**	**315.172**	**315.996**	**317.514**	**1,594.051**
Demand Driven – Customer Initiated							
Customer Driven Primary (Code 311100)	4.470	12.405	12.276	12.666	12.831	13.600	63.778
Domestic & Rural (Code 312100)	48.014	55.744	76.393	97.156	99.677	102.325	431.295
Commercial, Industrial & Traction (Code 312500)	21.816	13.938	14.635	15.366	16.135	16.942	77.016
Public Lighting (Code 312600)	13.840	13.102	13.786	14.498	15.237	16.007	72.630
Service Connections (Code 312700)	35.152	41.398	51.960	68.598	84.953	87.058	333.966
Total Demand Driven – Customer Initiated	**123.292**	**136.587**	**169.049**	**208.284**	**228.833**	**235.932**	**978.685**
Reliability/Quality Improvement							
Reliability Improvement Primary (Code 311300) – Tier (a)	27.000	9.508	17.095	10.273	5.383	5.021	47.280
System Other							
Community Requirements (Code 311800)	7.200	4.037	4.128	4.139	5.500	5.272	23.076
Other Works (Code 312200)	9.100	7.989	8.308	10.794	19.020	18.063	64.174
Total System Other	**16.300**	**12.026**	**12.436**	**14.932**	**24.520**	**23.335**	**87.249**

	04/05 Energex	05/06 Energex	06/07 Energex	07/08 Energex	08/09 Energex	09/10 Energex	TOTAL 05/06-09/10 Energex
Non-System							
Land & Buildings	2.160	3.360	4.560	5.760	6.960	8.160	28.800
Furniture & Office Equipment	0.240	0.240	0.240	9.600	0.240	0.240	10.560
ICT	16.350	31.350	40.350	20.100	10.100	9.600	111.500
Vehicles	18.406	27.142	16.138	16.138	16.138	16.138	91.694
Tools & Equipment	3.330	3.330	3.330	3.330	3.330	3.330	16.650
Communication Equipment	1.200	1.275	0.775	0.875	0.875	0.875	4.675
Total Non-System	**41.686**	**66.697**	**65.393**	**55.803**	**37.643**	**38.343**	**263.879**
TOTAL CAPEX (*including Tier (a) Reliability/Quality Improvement)*	**446.613**	**588.407**	**624.764**	**673.059**	**697.860**	**703.695**	**3,287.785**

All forecast and historical figures are in June 2004 dollars

Table 14-19: Consultant's CAPEX Expenditure

	04/05 Consul	05/06 Consul	06/07 Consul	07/08 Consul	08/09 Consul	09/10 Consul	TOTAL 05/06-09/10 Consul
Asset replacements							
Refurbishment Driven Primary (Code 311400)	30.869	18.272	30.132	28.342	30.596	27.557	134.900
Ageing Equipment (Code 312400)	1.984	0.987	3.256	8.504	10.340	10.071	33.158
Pole Replacement and Pole Nailing (Code 312450)	11.007	10.668	11.201	11.873	12.585	13.466	59.793
Total Asset Replacements	**43.860**	**29.927**	**44.588**	**48.719**	**53.521**	**51.095**	**227.851**
Demand Related – Corporate Initiated							
Demand Driven Primary (Code 311200)	150.189	209.889	253.465	238.317	232.572	233.213	1,167.456
Distribution Augmentation (Code 312650)	8.531	12.239	14.127	20.366	21.738	21.738	90.208
Demand Primary/Reliability (Code 311500)	0.861	2.676	0.956	0.000	0.000	0.000	3.631
Demand Primary/Refurbishment (Code 311600)	2.041	4.642	7.184	7.146	9.205	9.649	37.825
Land and Right of Way (Code 311700)	1.873	10.453	6.314	6.314	6.314	6.314	35.710
Easements (Code (311750)	0.628	3.379	3.446	3.514	3.582	3.649	17.570
Total Demand Related – Corporate Initiated	**164.125**	**243.277**	**285.492**	**275.657**	**273.411**	**274.563**	**1,352.400**
Demand Driven – Customer Initiated							
Customer Driven Primary (Code 311100)	4.470	4.500	4.500	4.500	4.500	4.500	22.500
Domestic & Rural (Code 312100)	48.014	55.744	58.530	61.458	64.530	67.757	308.020
Commercial, Industrial & Traction (Code 312500)	21.816	13.938	14.635	15.366	16.135	16.942	77.016
Public Lighting (Code 312600)	10.800	11.340	11.907	12.502	13.127	13.784	62.661
Service Connections (Code 312700)	35.152	37.962	46.574	55.965	64.395	67.554	272.450
Total Demand Driven – Customer Initiated	**120.251**	**123.484**	**136.147**	**149.791**	**162.688**	**170.536**	**742.646**
Reliability/Quality Improvement							
Reliability Improvement Primary (Code 311300) – Tier (a)	19.600	8.888	8.418	7.174	5.383	5.021	34.884
System Other							
Community Requirements (Code 311800)	7.200	4.037	4.128	4.139	5.500	5.272	23.076
Other Works (Code 312200)	9.100	7.989	8.308	8.641	8.986	9.346	43.269
Total System Other	**16.300**	**12.026**	**12.436**	**12.779**	**14.486**	**14.618**	**66.345**

	04/05 Consul	05/06 Consul	06/07 Consul	07/08 Consul	08/09 Consul	09/10 Consul	TOTAL 05/06-09/10 Consul
Non-System							
Land & Buildings	2.160	3.360	4.560	5.760	6.000	6.000	25.680
Furniture & Office Equipment	0.240	0.240	0.240	9.600	0.240	0.240	10.560
ICT	16.350	31.350	21.350	20.100	10.100	9.600	92.500
Vehicles	18.406	27.142	16.138	16.138	16.138	16.138	91.694
Tools & Equipment	3.330	3.330	3.330	3.330	3.330	3.330	16.650
Communication Equipment	1.200	1.275	0.775	0.875	0.875	0.875	4.675
Total Non-System	**41.686**	**66.697**	**46.393**	**55.803**	**36.683**	**36.183**	**241.759**
TOTAL CAPEX (*including Tier (a) Reliability/Quality Improvement)*	**405.821**	**484.299**	**533.473**	**549.923**	**546.172**	**552.017**	**2,665.884**

All forecast and historical figures are in June 2004 dollars

14.10 GSL Comparison

UTILITY	ENERGEX	ERGON	CITIPOWER	POWERCOR	TXU	UNITED ENERGY	ETSA UTILITIES	ENERGY AUSTRALIA	ACTEWAGL
CONNECTIONS	Contact within 10 business days to advise what is required to make supply available	Supply available by the agreed date	Supply connected by agreed date	Supply connected by agreed date	Supply connected by agreed date	Supply connected by agreed date	Supply connected by agreed date or within 6 working days	Supply connected by agreed date	If premises physically connected to network: - same day if prior to 2 PM - next day if after 2 PM If not physically connected - by agreed date.
$	20/day up to 200	25/day	50/day up to 250	100/day up to 500	50/day up to 250	50/day up to 250	50/day up to 250	60/day up to 300	60/day
INTERRUPTION DURATION			Duration > 12 hours	Duration > 12 hours	Duration > 12 hours	Duration > 12 hours			Duration > 12 hours
$			80	80	80	80			50
INTERRUPTION FREQUENCY			Excludes momentary interruptions > 9 times/calendar year - urban	Excludes momentary interruptions > 9 times/calendar year - urban > 15 times/calendar year - rural	Excludes momentary interruptions > 9 times/calendar year - urban > 15 times/calendar year - rural	Excludes momentary interruptions > 9 times/calendar year - urban > 15 times/calendar year - rural			
$			80	80	80	80			
INTERRUPTION ADVICE	Provide at least 2 business days' notice of planned interruptions	Provide at least 4 business days' notice of planned interruptions						Provide at least 2 business days' notice. Duration not longer than specified	Provide at least 2 business days' notice of planned interruptions
$	20	20 res 50 bus						20	50
APPOINTMENTS	More than 15 minutes late		More than 15 minutes late	More than 15 minutes late	More than 15 minutes late	More than 15 minutes late	More than 15 minutes late	More than 15 minutes late	More than 30 minutes late. Provide 24 hours notice of cancellation
$	20		20	40	20	20	20	25	20

UTILITY	ENERGEX	ERGON	CITIPOWER	POWERCOR	TXU	UNITED ENERGY	ETSA UTILITIES	ENERGY AUSTRALIA	ACTEWAGL
PUBLIC LIGHTING		Repair by the agreed date	Repair within 2 business days	Repair within 2 business days	Repair within 2 business days	Repair within 2 business days	Repair within 5 business days for nominated major areas and 10 days elsewhere - recurring for each time the target is not achieved	Repair on or before agreed date	
$		10	10	40	10	10	20	15	
QUALITY OF SUPPLY	Investigate & respond within 10 business days								
$									
WRONGFUL DISCONNECTION	Disconnection in error								
$	100								
HOT WATER		Attend to enquiry within 1 day where it is due to a fault in Ergon's control system							
$		20/day							
TREES & O/H POWERLINES		Respond immediately if safety risk. If not urgent & not already on vegetation program, visit to assess within 20 business days							
$		20							

UTILITY	ENERGEX	ERGON	CITIPOWER	POWERCOR	TXU	UNITED ENERGY	ETSA UTILITIES	ENERGY AUSTRALIA	ACTEWAGL
WRITTEN CUSTOMER ACCOUNT QUERIES									Acknowledge within 10 business days and respond within 20 business days
$									20
WRITTEN CUSTOMER COMPLAINTS									If visit required or enquiries of 3rd party involved, then acknowledge within 10 business days & respond within 20 business days. In all other cases, respond within 10 business days.
$									20
NOTIFICATION BY CUSTOMER OF PROBLEM									If likely to affect public health or potential to cause substantial damage or harm to person or property, respond ASAP and within 6 hours. In all other cases, respond within 48 hours.
$									60/day
UPLANNED INTERRUPTIONS 24 HOUR TELEPHONE SERVICE									Within 1 hour of advice, establish 24 hour telephone service
$									20