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WESTERN POWER'S CAPITAL AND OPERATING EXPENDITURE PROGRAM

FOR THE SOUTH WEST INTERCONNECTED NETWORKS

Electricity Industry (Network Quality and Reliability of Supply) Code 2005

Prepared For
Access Arrangement Regulatory Period
2006/07 to 2008/09

May 2006

Capital and Operating Expenditure Program 2006/07 to 2008/09

Foreword

This report provides the detailed justification for Western Power's forecast capital and operating expenditures for the 3 year regulatory term commencing 1 July 2006.

The expenditure plans were originally developed using a "bottom up" approach in response to a range of key business drivers, based on sound analysis of needs and supporting justification, followed by review by an independent expert consultant.

Consideration was given to the current and assessed future resourcing capabilities available to Western Power, utilizing a range of internal and external resources, to produce the enclosed program of capital and operating expenditure which is practically achievable.

Table of Contents

Executive Summary

Western Power's charter is to operate a safe and reliable electricity network that services the majority of Western Australians. At the present time, the electricity industry in Western Australia is undergoing a period of intense change and Western Power is changing to meet the current and future requirements of customers and stakeholders.

Western Power is one of Australia's leading network providers and productivity is critical to maintaining that position. Comparative performance is a key guide in determining current levels of efficiency and Western Power has been involved in three industry benchmarking studies in recent times. The detailed results of these benchmarking studies are provided later in this report, and they consistently portray Western Power as an efficient/low cost provider.

Western Power is proposing to maintain the current levels of efficient performance over the regulatory period[1], while undertaking significantly higher levels of investment. The main areas contributing to an increase in expenditure requirements are;

- New Connections –Significant new connections are required to service a number of new generation plants that are currently committed and planned for construction in Western Australia. In addition, Western Power will be required to connect more new customers than it has connected in recent times and these customers are demanding more energy and capacity (individually and collectively) than at any time in Western Australian history.

- Network Reliability – Western Power's reliability does not currently meet the standards set out in the Electricity Industry (Network Quality and Reliability of Supply) Code 2005. Western Power has developed a detailed program to improve network reliability by 25% over a 4 year period compared with current levels. The service standards specified in the Access Arrangements have been formulated based on this improvement program. In addition, Western Power is working to better understand customers' needs to ensure that the reliability outcomes are matched with customer needs and expectations.

- Safety, Health, Environment and deregulation – Western Power maintains a close working relationship with all industry regulators including the safety and environmental bodies. In consultation with these bodies, Western Power has agreed to a number of key projects aimed at reducing the risk of loss, injury and death as well as addressing a number of key environmental and deregulation concerns.

[1] Noting that input labour costs are likely to increase above CPI for the forecast period.

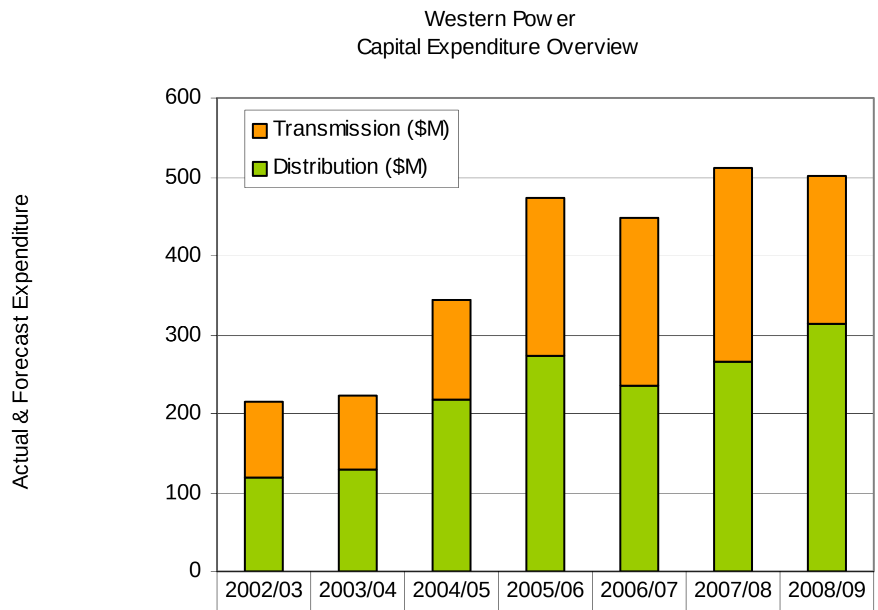
- Previously Constrained Expenditure – Customer growth in recent years has exceeded expectations. In particular, the growth has been well above the forecast budgets of the period. In order to meet its obligation to serve, Western Power has been required to focus its expenditure budgets on meeting new customer connections – often requiring the deferment of replacement and refurbishment works. The current high levels of deferred works are unsustainable and Western Power is working to reduce the backlog to appropriate levels.

The current economic growth in Western Australia and Australia has had a complicated effect on Western Power. Whilst the growth of the Western Australian economy has resulted in a continually increasing demand for electricity and new connections, it has also placed competing demands on industry resources and consequently limited Western Power's ability to undertake all the investments needed.

On this basis, Western Power has undertaken a detailed review of resource availability over the forecast period and has determined a realistic, deliverable expenditure plan.

The following tables summarise the resultant forecast expenditures;

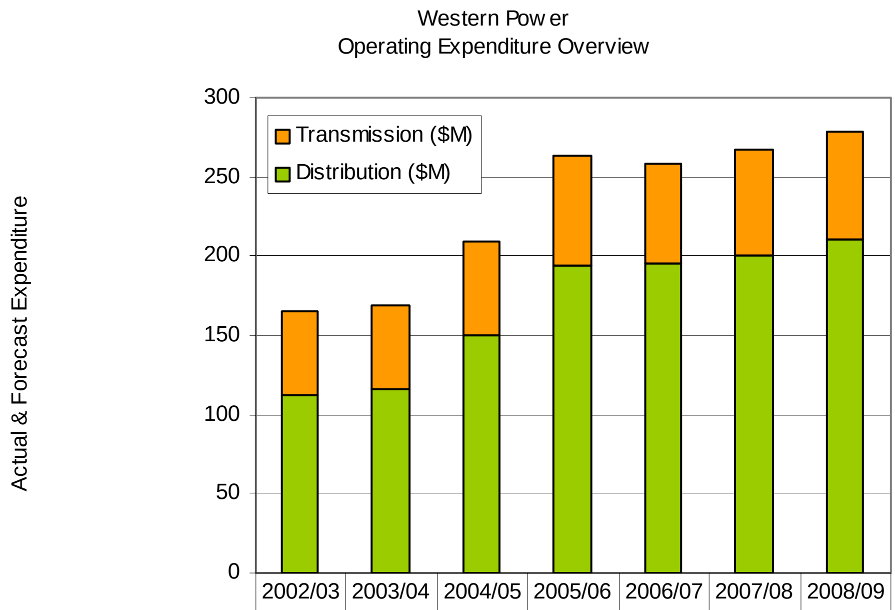
Figure 1 – Western Power Forecast Capital Expenditure



	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
Transmission ($M)	94.5	95.2	126.9	201.2	213.4	245.8	185.9
Distribution ($M)	120.2	128.8	218.4	272.6	235.0	266.8	315.0

Financial Year

Figure 2 – Western Power Forecast Operating Expenditure



	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
Transmission ($M)	52.1	53.9	60.0	68.2	62.6	66.2	67.8
Distribution ($M)	112.5	115.4	149.5	194.7	195.5	200.9	210.3

NOTE 1: The information contained in the subsequent sections of this report is a detailed explanation of the capital and operating expenditure needs of the business. All expenditure levels are expressed in nominal dollars with assumed inflation rates of 2.8%, 2.6% and 2.6% in years 2006/07, 2007/08 and 2008/09 respectively.

NOTE 2: A description of each expenditure category is provided in the following sections of this report including an overview of the total expenditure for that category. Appendix A contains a detailed project list including forecast expenditure amounts for each expenditure category for the period 2006/07 to 2008/09.

1. Introduction

In accordance with the Electricity Networks Access Code 2004 (“the Code”) Western Power must develop an access arrangement which describes the terms and conditions under which users can obtain access to Western Power’s South West interconnected system (SWIS). The Economic Regulation Authority (ERA) is the regulator responsible for ensuring that Western Power’s access arrangement complies with the code. The Access Arrangement defines network revenue projections and access tariffs, service standards and required capital and operating investment to meet these standards over the regulatory period.

The capital and operating expenditure program that has been forecast for the regulatory period from July 2006 to June 2009, represents a significant increase on previous expenditure levels. This increase is due to the need to meet the declared service standards that apply to Western Power in addition to meeting the obligation to connect new generators and loads, and maintaining reliability, safety, environmental and implementing market reform.

The paper explains the capital and operating expenditure program for the period 2006/07 to 2008/09 by expenditure category.

Business Responsibilities

Western Power is responsible for the regulated transmission and distribution network operations, network management and system management for activities in the SWIS. Operating in a competitive electricity market, it is independent of the competing generators and retailers and must provide network services for all participants on an equitable and transparent basis.

Western Power’s key business responsibilities are:

- Managing the development and operation for the transmission and distribution networks comprising the SWIS;
- Operating on a sound commercial basis;
- Providing even-handed network access to the networks for all applicants;
- Delivering levels of network performance prescribed by all external regulatory bodies; and
- Carrying out these functions safely and in accordance with safety and environmental legislation.

In meeting these responsibilities, Western Power must balance the requirements to operate commercially and meet regulatory, Government and community expectations for reliability of supply.

Regulatory Requirements

Western Power is regulated by the ERA in accordance with the Code. Under the Code requirements Western Power must develop and adhere to an Access Arrangement that defines the terms and conditions under which users may access the network. The Access Arrangement also defines the network revenue projections and tariffs, the service standards to be met by Western Power and the capital and operating investment expenditures required to meet these standards over the regulatory period. The ERA ensures that the Access Arrangement complies with Code requirements and will approve levels of expenditure that can be used in setting prices for the regulatory period.

In this environment, planning criteria, system performance standards, customer service and funding are all subject to external scrutiny and ultimately the judgement of external parties. This will have critical implications for funding and investment decisions, performance incentives and Western Power's relationship with its customers and stakeholders.

At the same time, the new market arrangements in the SWIS are being developed and implemented, with implications for the extent of ring fencing for the System Management function and the need to assist and work with the Independent Market Operator (IMO).

National Comparators

Western Power operates a large and expansive electricity network servicing the majority of the Western Australian population. The SWIS network includes the complex and critical Perth CBD all the way to the Eastern Goldfields and North to Geraldton.

Unlike networks in the Eastern states, Western Power is virtually unable to call on additional resources from its neighbours, or to share a large pool of independent contractors.

The physical environment that Western Power operates in also impacts business performance;

- Western Power often requires significant travel time to identify and rectify network events.

- Coastal exposure, an arid interior and prevailing on-shore winds contribute to a salt and dust pollution issue that is more widespread and intense than any other state in Australia.

Given the above factors, it would be reasonable to expect that Western Power would be challenged to be cost competitive with other Australian electricity networks. However, this is not the case and a number of recent studies completed by PB Associates, Meyrick & Associates and Benchmark Economics have all identified Western Power as a better than average performer.

A summary of the above studies is provided below. (The full reports on the Meyrick & Associates and Benchmark Economics studies are contained in Appendices 1 and 2 respectively of this Access Arrangement Information document.)

Benchmark Economics Benchmarking

Benchmark Economics is an independent consultant that has worked in the Australian energy industry for many years, supporting many regulators and network businesses in reviewing business performance. Following a similar exercise for the South Australia Electricity Distribution Price Review, Benchmark Economics undertook a benchmark review of the Western Power's expenditures across both the transmission and distribution networks[2].

The Benchmark Economics study is notable in that it recognises and adjusts for the variances in network operating voltages between distribution and transmission companies. With respect to Western Power, Benchmark Economics has adjusted the transmission expenditures to separately identify the sub-transmission voltages (e.g. 66kV) that are typically treated as distribution in the Eastern States.

The demarcation between transmission and distribution differs for Western Power from the other States. Sub-transmission forms part of the transmission business

[2] The information provided by Benchmark Economics is based on data available in the public domain.

in Western Australia whereas it is generally part of the distribution business in the other states. Effectively, based on asset values, this raises the cost base of the transmission grid by around 50 per cent, relative to those networks combining distribution and sub-transmission.

To allow comparison of the costs of Western Power's transmission plus sub-transmission business with businesses that provide a transmission service only, we have taken a two-step approach. In the first instance, we have compared the transmission only network on a similar basis with the other Australian businesses.

In contrast to the distribution sector, there is only one transmission network in each jurisdiction. This places Western Power on a more equal footing in network cost comparisons. However, given the considerable variation in population and geography, there are notable differences in the operating environments of the transmission businesses. The following table provides an overview of the scale and key operating conditions for the transmission networks included in the study.

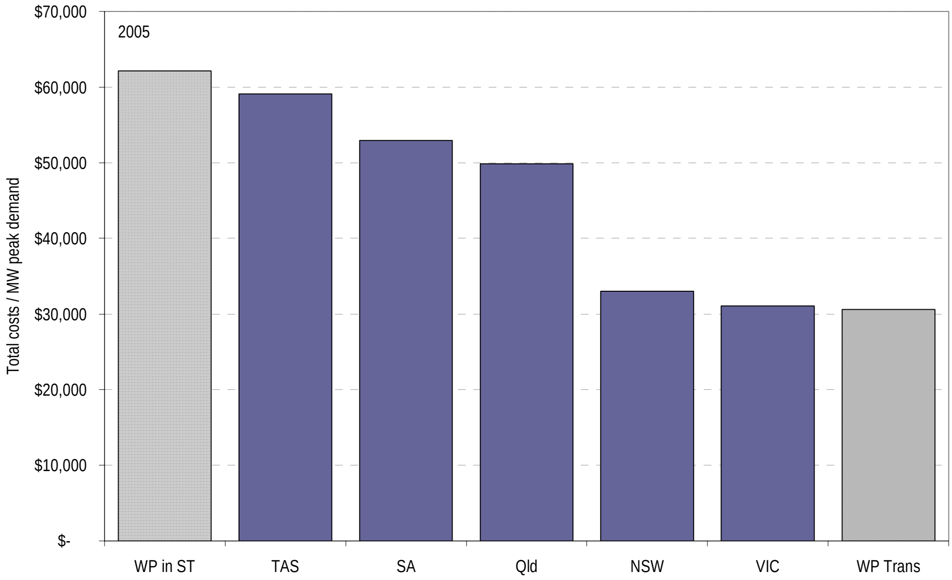
Figure 3 - Transmission networks in the study: scale and key operating conditions

	Length km	Peak demand MW	Average voltage kV	Energy density (MW/km)	Load factor
Western Australia -transmission only	3,655	2,924	196	0.80	56%
Western Australia - including sub-transmission	7,074	2,924	155	0.41	56%
NSW	12,570	13,100	250	1.04	62%
Victoria	6,619	8,974	289	1.36	59%
Queensland	12,107	8,200	220	0.68	66%
South Australia	5,635	3,026	193	0.54	47%
Tasmania	3,574	1,806	152	0.51	71%

Note, that the peak demand for both WA networks is 2,924 MW. That is, both networks share the same customer load. This configuration reduces the energy density for the sub-transmission network relative to transmission by 50 per cent.

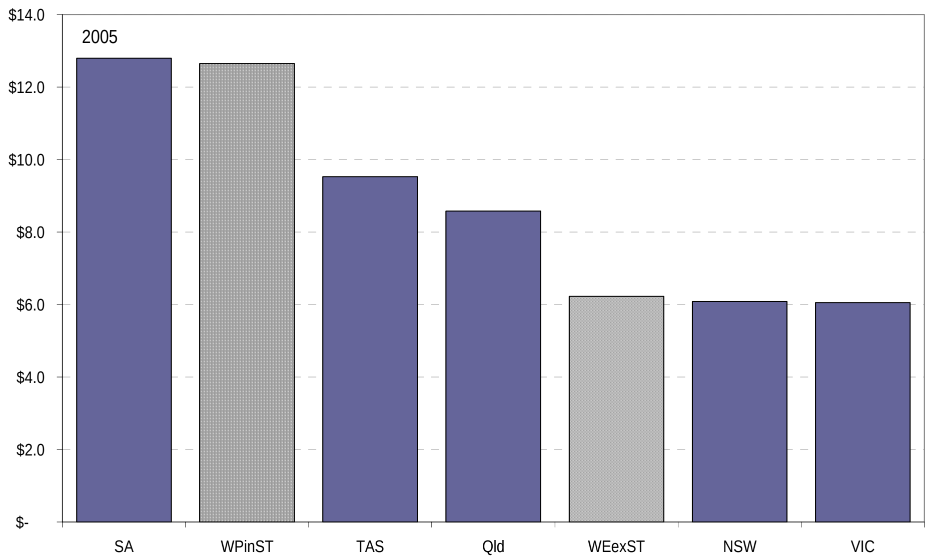
Average costs for the transmission networks, measured as total revenue/peak demand MW, are depicted in the following figure. The transmission network of Western Power exhibits the lowest average costs for the sample. Notably, even the cost of the combined transmission and sub-transmission networks is little more than that for either Queensland or South Australia transmission only. As different network configurations may give rise to different cost outcomes, the possible explanations for this outcome will be examined in the following section.

Figure 4 - Transmission costs – Total costs/peak demand MW



Transmission prices, measured as total revenue/MWh, are examined in the following chart. The slightly higher average price for Western Power is due to its lower load factor (56%) relative to NSW (62%) and Victoria (59%), this means that it has fewer throughput units (MWh) over which to average its capacity cost base.

Figure 5 - Transmission prices - Total costs/MWh

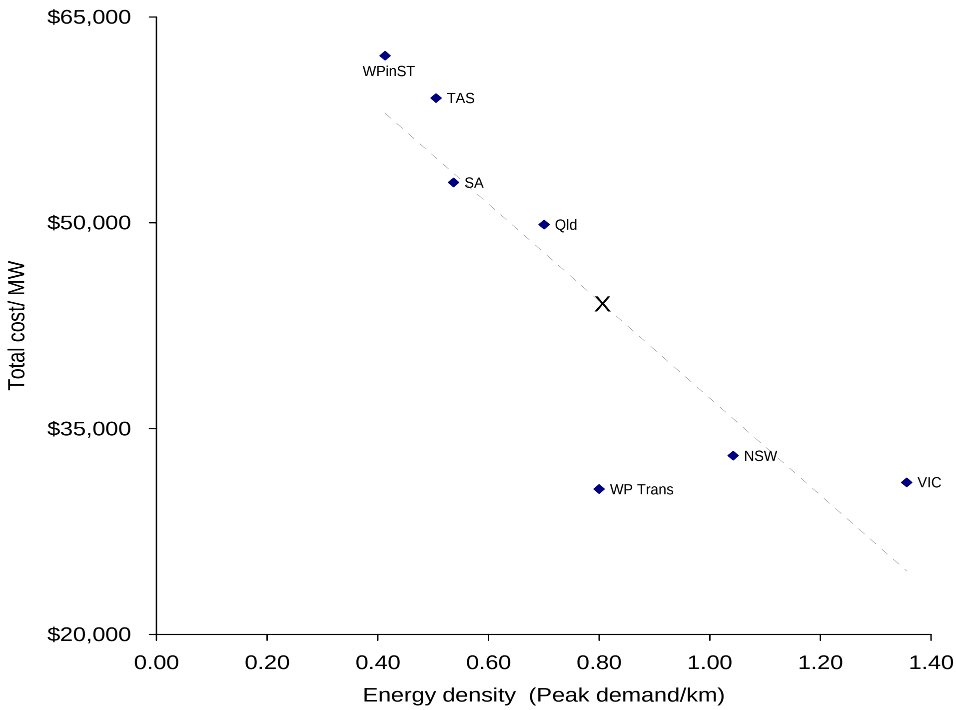


To assess the influence that operating conditions may have on Western Power's cost outcomes, the following section examines the link between energy density and load factor on total network cost.

Energy density: In connecting generators to bulk supply points, transmission investment will reflect not only the length of the network required to provide the connection but also the level of the load to be transported. The investment decision will be based on a cost effective trade-off between distance, load, and losses.

Overall, cost efficiencies are achieved as energy density increases; this has the affect of reducing costs per MW capacity provided (Figure 6) while at the same time raising costs per line length. The contrast in these outcomes is convincing evidence that the use of simple partial indicators to assess relative cost performance can be misleading.

Figure 6 - Energy density and network costs – MW/km and total costs km



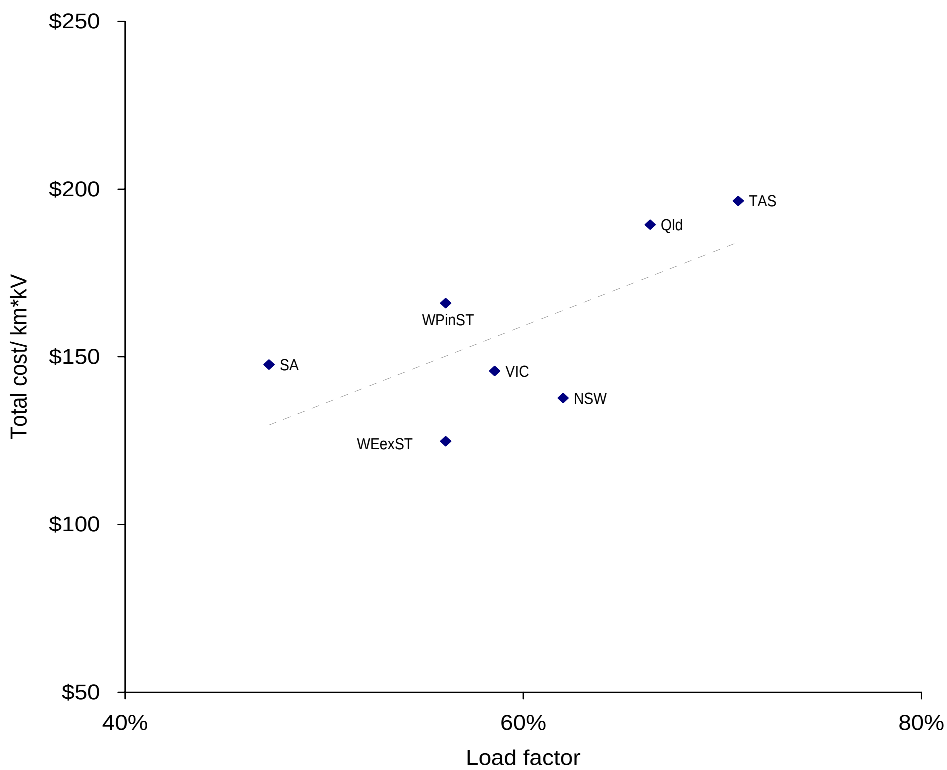
Measured against peak demand capacity (Figure 6), Western Power's transmission costs lie well below that expected for a network of its configuration. While Figure 4 (above) revealed a cost outcome similar to that for the NSW and Victoria networks, when the operating environment is taken into account, it appears that Western Power's costs should be substantially higher. Figure 6, depicting average line costs and energy density confirms this finding.

Though the sample in Figure 6 is limited, the trend line reveals a fit that is sufficiently robust to allow cost estimations for Western Power.

Equation 1: **Connection density and total revenue per MW**
Average capacity costs = -35401 + 72620, R^2 75%
Estimated cost/MW Western Power-Transmission = $44,296
Current cost /MW =$30,592

Load factor: As discussed above, transmission costs are not only influenced by energy density but also the distance over which the load must be transported, with the average weighted voltage level for the network reflecting the least cost trade-off. A useful measure of the transmission task is provided by the composite measure - line length x weighted average voltage level (km x kV). This variable is similar to that used by Powerlink in its 2001 application to the Australian Competition and Consumer Commission, and subsequently accepted as a fair proxy. It provides the best fit with load factor since it captures the load/distance/voltage trade-off.

Figure 7 - Load factor and network costs (total revenue/km*kV)



The chart in Figure 7 depicting load factor and total revenue per km x kV presents clearly the strong and positive link between these two variables.

Equation 2: Load factor and total revenue per km*kV

Average costs per km*kV= -231.47x + 20.297, R^2 44%
Estimated cost/km*kV Western Power-Transmission = $166
Current cost /km*kV = $125

Based on the cost estimates provided by Equations 1 and 2, a transmission grid with business conditions similar to Western Power Transmission would be expected to have annual revenues between $117M and $119M.

Total revenue: Line length - 3655 km @ $31,935 = $117M
Km*kV - 716563 @ $166 = $119M

This is 30 per cent above the current (transmission only) revenue of $89M, suggesting that Western Power is a relatively low cost provider of transmission network services.

PB Associates Benchmarking

PB Associates has undertaken a number of price and access arrangement reviews for Australian regulators. In undertaking these reviews, PB Associates has utilised benchmarking as a means to identify areas of the businesses requiring additional, or more intense, review.

PB Associates were careful to note that benchmarking is not utilised as a goal-setting exercise due to the number of unaccounted for factors that can influence results. For this reason, the PB Associates approach was to utilise a range of benchmarks so as to minimise the possibility of drawing erroneous conclusions through consideration of a single measure.

The PB Associates benchmark focussed on the distribution network and reviewed both capital and operating expenditure against the following measures;

1) Expenditure per Customer
2) Expenditure per kVA (energy delivered)
3) Expenditure per km (of distribution network)
4) Expenditure per RAB (Regulated Asset Base value)

The PB Associates analysis utilised regulatory expenditures for the majority of Australian Distribution networks adjusted to a common base. Western Power appears as a best performer in many of the measures and performs better than average in almost all.

Note 1: The information illustrated in Figures 8 to 15 inclusive (below) is based on data available in the public domain.

Note 2: The distributors shown in the following charts are ordered based on the load density (kVA per km) from lowest to highest, i.e. Country Energy being a distributor in mainly rural areas of NSW has a lower load density per km of line compared with United Energy which distributes electricity in mainly urban areas of Victoria. Western Power's SWIS network covers both urban and rural areas and falls about mid range in the sample in terms of load density.

Expenditure per Customer

The expenditure per customer measure provides an indication of the average annual expenditure per network customer[3]. In general, it would be expected that the cost per customer would increase for predominantly rural networks. The length of line and therefore number of assets required to service a rural customer is generally greater than that of the average urban customer.

Figure 8 - Total Capital Expenditure per Customer

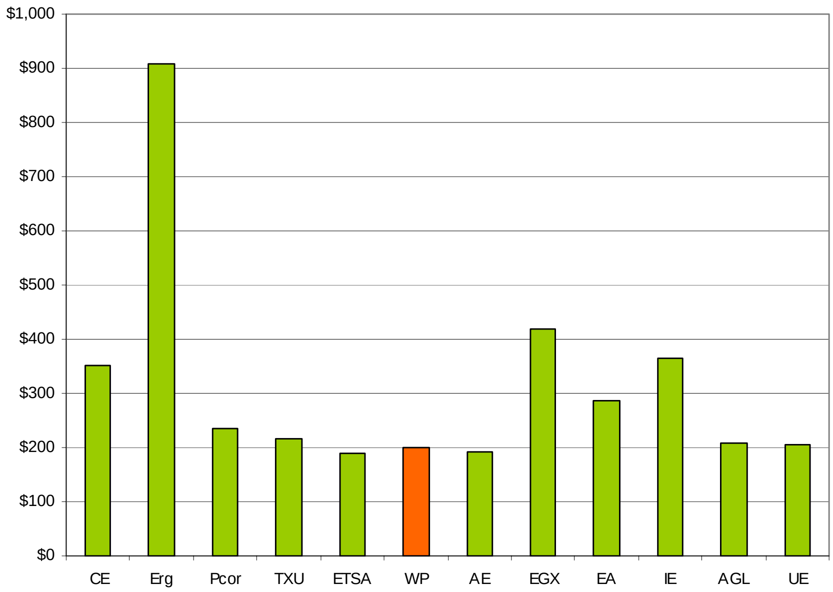
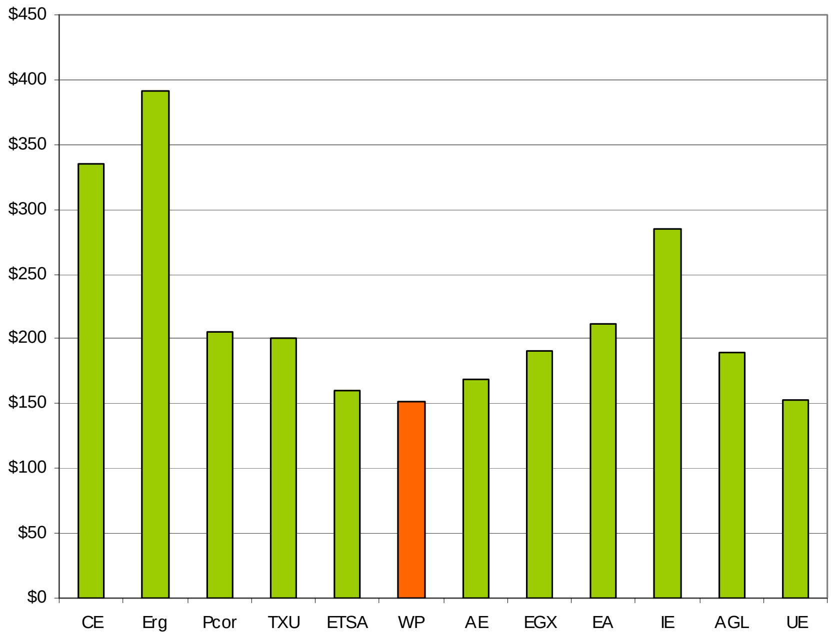


Figure 9 - Total Operating Expenditure per Customer



[3] Note: Network customer includes all end-users connected to the electricity network within the network franchise area. Customer numbers are counted irrespective of energy retailer.

Expenditure per kVA (energy delivered)

Maximum demand measures the peak utilisation of the electricity network. The unit of measurement is kilovolt-amps (kVA). This figure is usually[4] derived following a series of hotter than average days over the summer period. The electricity network is generally designed to be able to meet this peak demand period.

Figure 10 - Total Capital Expenditure per kVA

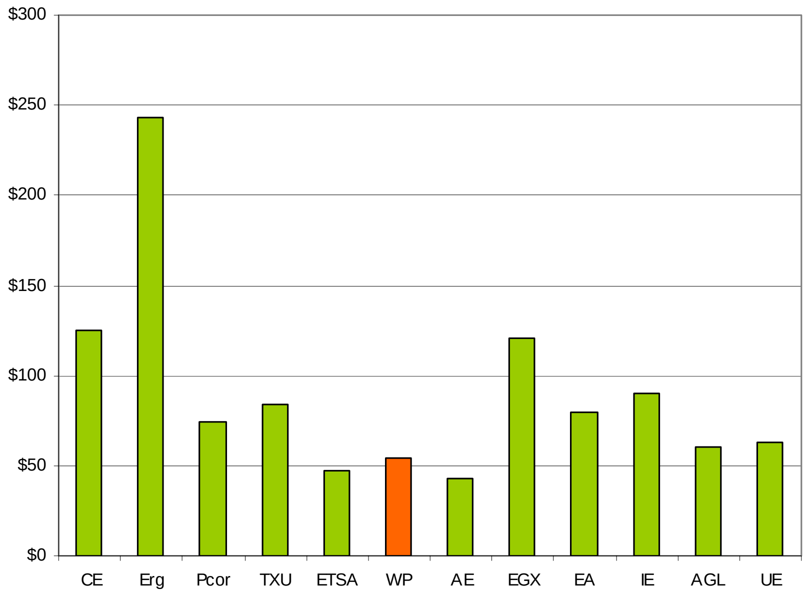
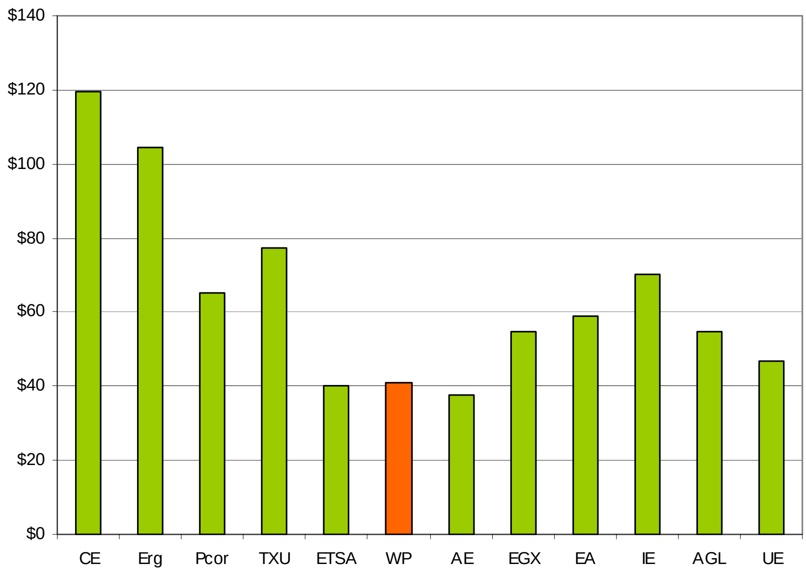


Figure 11 - Total Operating Expenditure per kVA



[4] With the exception of Aurora Energy in Tasmania

Expenditure per km (of distribution network)

The expenditure per kilometre of line measure provides an indication of the expenditure required for each length of overhead or underground line. There is a consistent trend to increasing expenditure per km of line as the kVA per kilometre increases. This is certainly related to the density of the network in terms of the greater propensity to underground lines in urban areas as well as the greater volume of assets per kilometre of line in more highly developed areas.

Figure 12 - Total Capital Expenditure per km of Line

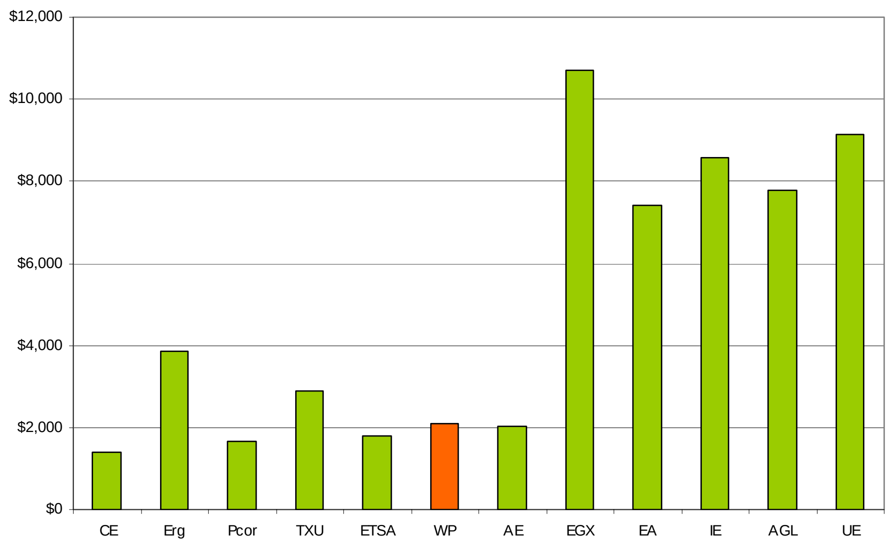
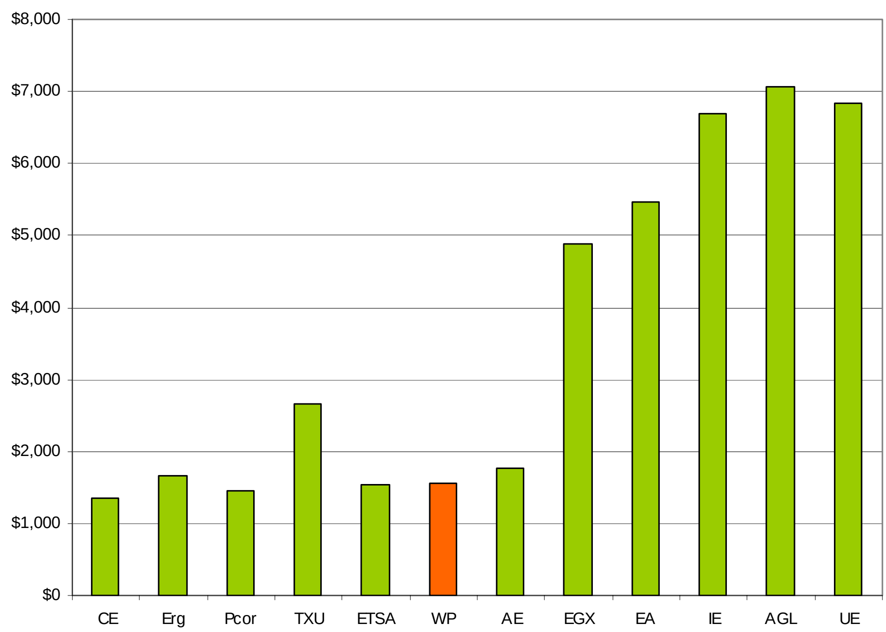


Figure 13 - Total Operating Expenditure per km of Line



Expenditure per RAB (Regulated Asset Base value)

The comparison of asset base value against annual expenditure provides a highly consistent means of normalising for the scale of the companies being compared. In this case, the asset value is based on the depreciated replacement cost of the network assets.

The measure is only useful for companies of similar network ages as is the case within Australia. The measure is also subject to impacts from higher growth rates causing increased capital expenditures.

Figure 14 - Total Capital Expenditure per RAB

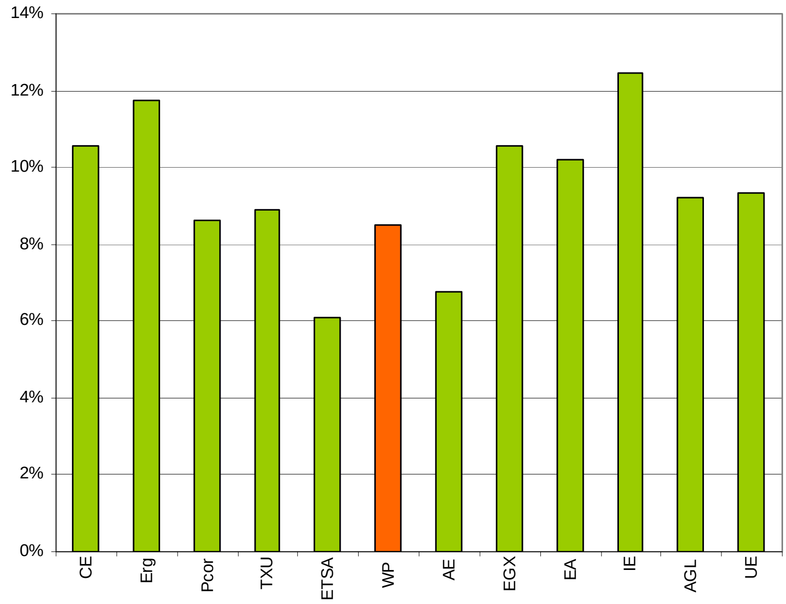
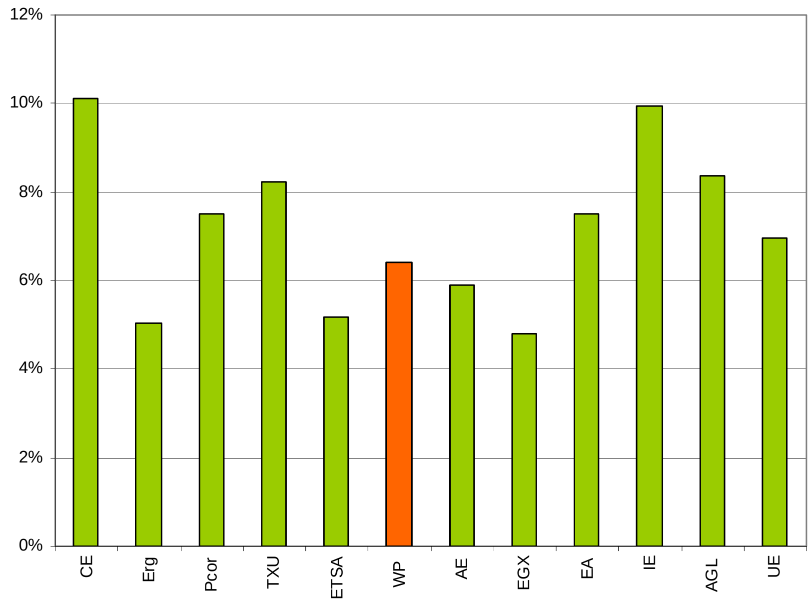


Figure 15 - Total Operating Expenditure per RAB



Meyrick & Associates Benchmarking

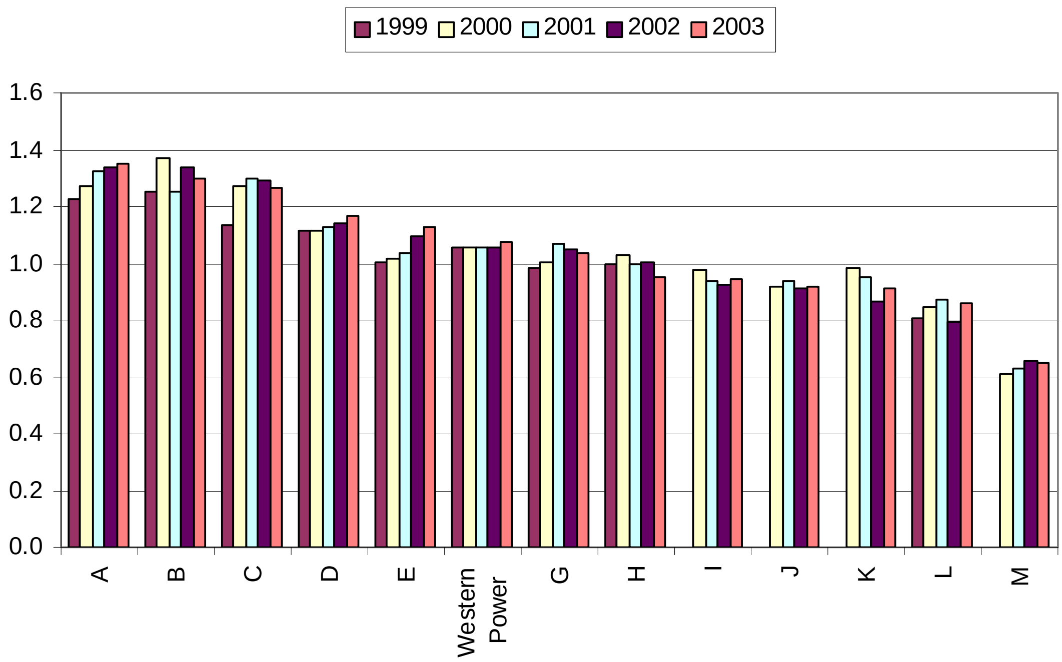
The Meyrick & Associates report reviews the performance of Western Power's distribution operations over the period 1999–2003 compared to 12 other Australian electricity distribution networks[5].

The report identified performance measures as follows:

- Operating environment features;
- Financial performance;
- Network charges;
- Reliability performance;
- Complaints;
- Total and partial productivity indexes;
- Labour productivity;
- Operating expenditure efficiency;
- Capital stock efficiency;
- Capital expenditure efficiency.

The comprehensive efficiency indicator utilised in the Meyrick & Associates study is total factor productivity (TFP), which is an index of the ratio of all output quantities (weighted by revenue shares) to all input quantities (weighted by cost shares). Western Power's TFP performance ranks fifth and is around 6 per cent lower than the group average.

Figure 16 - Multilateral total factor productivity indexes, 1999–2003

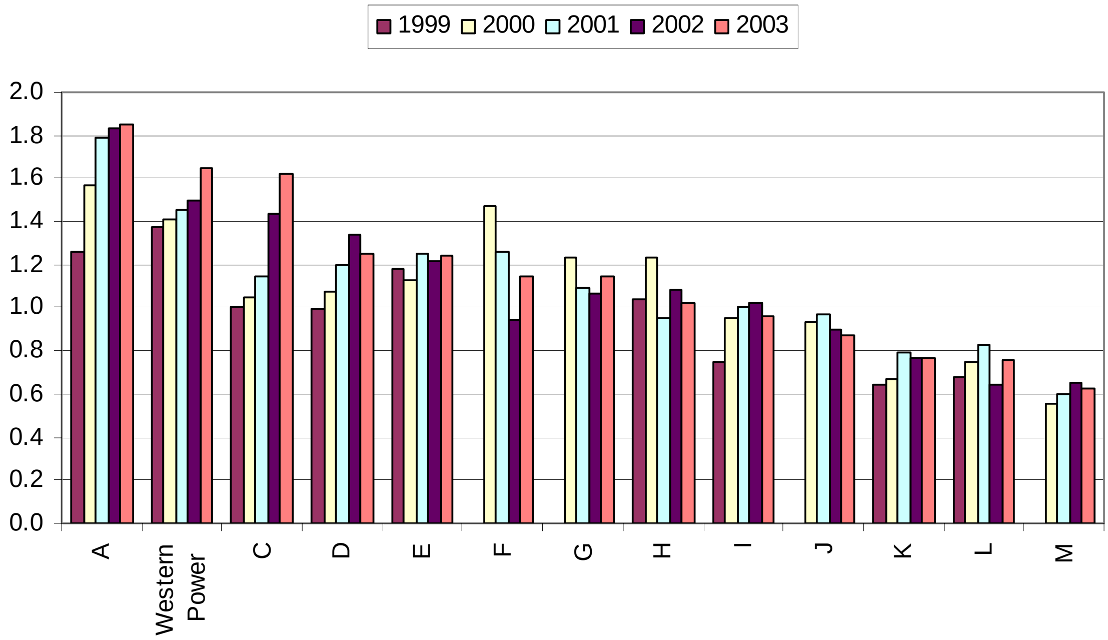


On operating and maintenance expenditure (opex) partial productivity (the total output index from the TFP analysis divided by the quantity of opex) Western Power

[5] Company names were withheld as part of the study conditions.

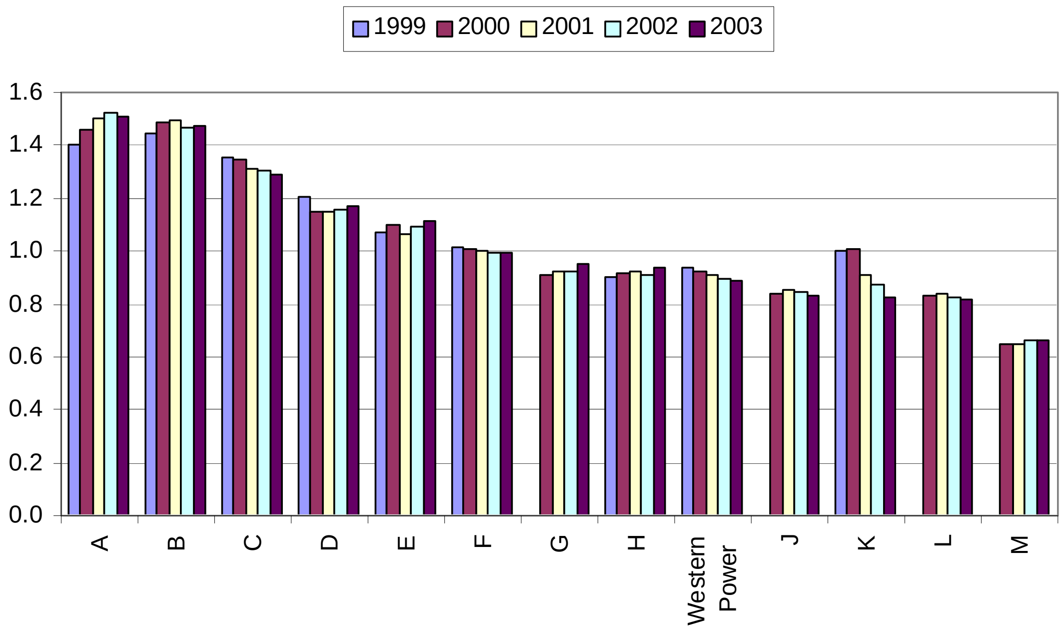
ranks second best out of the 13 included networks. It had a steady increase in its opex partial productivity over the 5 year period, with an overall increase of 20 per cent which is equivalent to an average annual growth rate of 4.6 per cent.

Figure 17 - Operating and maintenance partial productivity indexes, 1999–2003



Western Power had the ninth highest capital partial productivity of the 13 included networks.

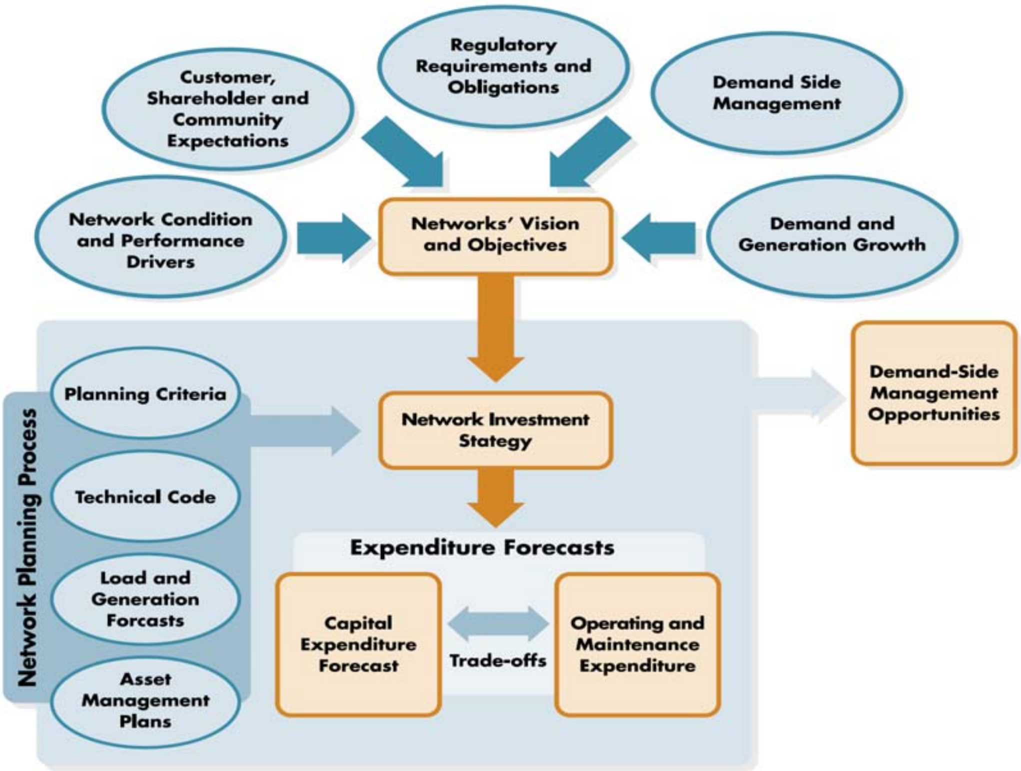
Figure 18 - Capital partial productivity indexes, 1999–2003



2. Systems, Processes and Procedures

The modern electricity business is required to operate in a complex multi-dimensional environment. Technical and engineering decisions must be made with consideration for the expectations of customers, shareholders and the community, and with respect to legislative and regulatory requirements.

In today's environment, the modern utility manager must operate the network within a large number of boundaries and recognise a large number of drivers. Some of these boundaries are non-negotiable, such as safety and reliability targets, while some boundaries are more flexible and allow trade-offs with other drivers.



Western Power undertakes its planning and network development activities in line with a number of legislative requirements including the Electricity Networks Access Code 2004, the Technical Rules and the Electricity (Supply Standards and System Safety Regulations) 2001. Together these documents define technical, customer access and public/network safety requirements. Western Power works within this framework to ensure the following outcomes:

- Adequate network capacity for network load and power transfer;
- Each individual piece of network equipment is operated within its design limits;
- The network can withstand credible faults and unplanned outages;
- Quality of supply is maintained to the appropriate standards;
- Future growth is adequately catered for;
- Environmental constraints are responsibly managed;

- Safety standards are maintained;
- Network access requirements are met;
- Required/declared service levels are achieved.

Asset Management Strategy

The Western Power operating environment is undergoing a period of rapid change. Recently the Networks, Generation and Retail arms of the former Western Power Corporation were separated and Western Power commenced operation as a transmission and distribution network business on 1 April 2006. In addition, the implementation of the Independent Market Operator (IMO) and the implementation of the Access Code and economic regulation are also changing the way Western Power operates.

In recognition of the fluid operating environment, Western Power is in the process of updating its Strategic Asset management Plan (SAMP) to ensure it is aligned with the new Access Code and the regulatory framework. It is anticipated that the updating of the SAMP will have a flow-on effect and require updating and alterations to related network documentation.

The optimisation of capital expenditure, operating expenditure and reliability outcomes is a difficult process for any electricity business. Western Power has implemented the use of the “asset mission” document to integrate the operations of the various network business units. Western Power is one of the first companies in Australia to implement the Asset Mission approach.

The transmission and distribution asset management strategy has been expressed as a series of principles upon which asset management procedures and decisions are based to support the Networks’ asset management policy:

Long term asset maintenance and renewal plans are prepared annually and are based on (where practicable):

- The asset’s age and condition;
- The asset’s expected system role taking into account the potential obsolescence;
- The probability and consequence of failure;
- The physical and system environment of the asset;
- Realistic asset decay predictions and subsequent life-cycle costs planning; and
- The need to ensure the long-term viability of the business, that is, to avoid reaching a situation where the overall condition of the network has declined to an unmanageable state.

Investment in the existing asset infrastructure is based on the need to:

- Maintain required service levels;
- Reduce servicing and operating costs;
- Optimise the economic life of equipment;
- Ensure safe operation of assets; and

- Meet regulatory and environmental requirements.

All proposals for major expenditure are prepared using Western Power's economic assessment and project approval processes. This includes a detailed operating and capital funding requirements review and prioritisation process, and feeding it into the overall Western Power budgeting framework.

Where economic, maintenance is completed for each type of equipment to:

- Achieve minimum maintenance costs;
- Ensure the condition is within acceptable limits;
- Operate the equipment at an acceptable level of risk;
- Meet required performance targets.

Maintenance plans take into account overall life-cycle plan for the assets, including renewal and disposal plans and future development plans.

Risk exposure is identified through:

- due diligence programmes;
- asset audits;
- analysis of performance history; and
- other specialised risk analysis projects.

Critical assets are treated in a standard risk management procedure. Special contingency plans are developed for significant risk scenarios.

All asset management work is carried out in accordance with relevant legislation and national standards and industry guidelines (including occupational health and safety, environment and employment).

Information systems have been developed to enable:

- Registration of Western Power's existing assets and their characteristics;
- Recording and management of asset management procedures and activities; and
- Provision and review of asset performance statistics.

Network Investment

As a prudent and efficient commercial organisation, Western Power applies a risk management approach when determining its network development options. Applying the network investment criteria in the Technical Rules, Western Power's planning process is strongly focussed on balancing networks costs against the impact of unreliable supply on its customers.

The primary drivers of network investments are as follows:

- Consistent growth in electricity demand;
- Customer initiated works for new connections;
- The ageing profile of the network assets;

- The State Underground Power Project (SUPP); and,
- An increasing emphasis on public safety and environmental compliance.

Access Code Investment Tests

Network investment is subject to two tests defined within the Access Code, namely the New Facilities Investment Test (NFIT) [6] and the Regulatory Test[7].

The NFIT is essentially a prudency and efficiency test to determine the appropriate value to roll into the asset base. The test defines reasonable prudency and efficiency with respect to factors such as minimisation of costs, economies of scale and reasonable forecasting horizons for new facilities investments. The test provides a prescriptive definition of investment considerations that are pertinent for an electrical network business. Specific examples of these issues are the adoption of standard transformer or conductor sizes within an organisation that may result in overall minimisation of costs rather than the specific optimised size for an individual project; and reasonable planning horizons to determine appropriate levels of investment capacity to account for forecast levels of demand growth to obtain economic life out of investments.

The test also defines the acceptable technical and economic criteria that must be satisfied to determine the appropriate new facilities investment. These broadly cover:

- the ability to recover the investment from the incremental revenue; or
- the investment provides a net benefit; or
- the investment is required to maintain reliability, safety or contracted services of the covered network.

The relevance of the NFIT to this access arrangement application is whether or not it is reasonable to consider that the capital expenditure proposed here will pass the NFIT. This in turn relates to the processes Western Power undertake to produce the forecast in the application.

The planning processes applied by Western Power to determine the need for network investment, and the evaluation of options are already well aligned with the intent of the NFIT with respect to business drivers, performance outcomes and the prudency and efficiency of the investments. The capital expenditure forecasts proposed in this assess arrangement application are based upon a “bottom up” build of investment requirements based largely on these planning processes. As such, Western Power is confident that the investments proposed in this access arrangement application satisfy the NFIT.

The regulatory test is a test which must be applied prior to the commencement of major augmentations ($5million for distribution project and $15million for transmission projects). This test is in place to ensure sufficient consultation and evaluation has been performed prior to the augmentation being undertaken. The

[6] Access Code Clauses 6.52 – 6.55 inclusive.
[7] Access Code Chapter 9.

test defines key undertakings and considerations that must be performed. These broadly cover the consultation process, the use of market development scenarios, and the maximising of the net benefit of the augmentation.

3. Expenditure Drivers

Western Power is proposing significant increases in both capital and operating expenditures for the initial access arrangement period. A number of factors have contributed to the overall expenditure increase including:

- New Connections;
- Network Reliability;
- Safety, Health, and Environment,
- Deregulation and Market Reform; and
- Constrained historical expenditures and high customer growth.

Each of the above drivers is detailed below. The framework for determining the network need in relation to these external drivers is based on an assessment of prudency and efficiency as follows;

(a) **Prudency** – Are the proposed works necessary, are there alternatives that would obviate the need for the proposed works?

(b) **Efficiency** – Are the proposed expenditures efficient both in terms of timing and overall expenditure? Could the works be deferred, or a more cost effective solution implemented?

Western Power operates in a relatively isolated environment with limited opportunity to share resources with other adjacent electric utilities. However, as can be seen from the comparative studies undertaken by PB Associates, Meyrick and Associates and Benchmark Economics, Western Power performs very well when compared to other Australian electricity networks.

New Connections - Reducing generation reserve margin

No significant large generation plant has been built in Western Australia for more than 5 years; however energy demand continues to grow at an increasing rate. The expansion of demand without an equal expansion in supply has reduced the reserve or spare capacity in the state and is approaching a period where these reserves will not be sufficient to maintain an adequate quality of supply.

Western Power is experiencing a significant level of activity in the generation connection area and is aware of a significant number of generation construction projects that are either committed or proposed.
This level of activity in the generation connection area has not been seen in Western Power in recent history and the proposed expenditures for both direct connection work and associated system reinforcement are therefore well in excess of historical expenditures.

Western Power is required to provide connection to new generation plant under the terms of the Access Code.

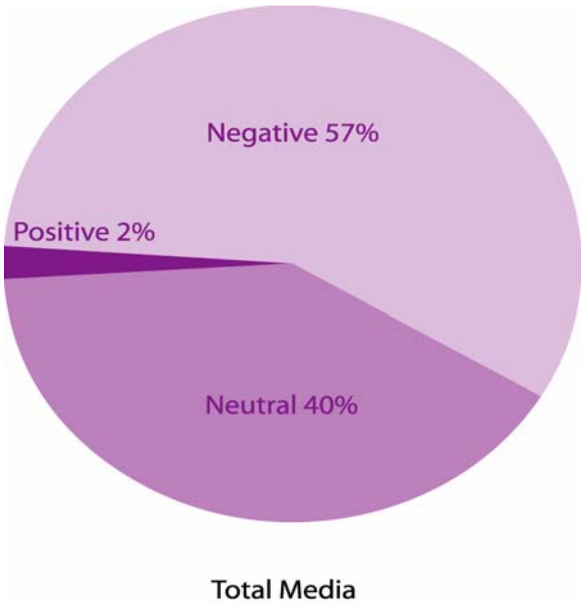
Network Reliability

Western Power's reliability does not currently meet the legislated targets set out in the Electricity Industry (Network Quality and Reliability of Supply) Code 2005. Western Power has developed a detailed program to improve network reliability by 25% over a 4 year period compared with current levels. The service standards specified in the Access Arrangements have been formulated based on this improvement program.

Further, in an effort to gauge public perception, Western Power has documented media coverage from the state media outlets. The overwhelming number of media articles relate to issues of reliability concerns and the public reaction to power outages. Western Australia's power network reliability generated almost 10,000 individual media reports during the period from January 1, 2004 to February 18, 2005. The media breakdown[8] for this coverage was 7,486 items in the electronic media (75 per cent of overall coverage) and 2,470 items in the print media (25 per cent of overall coverage).

As indicated in the following figure, the majority of the media coverage was of a negative tone.

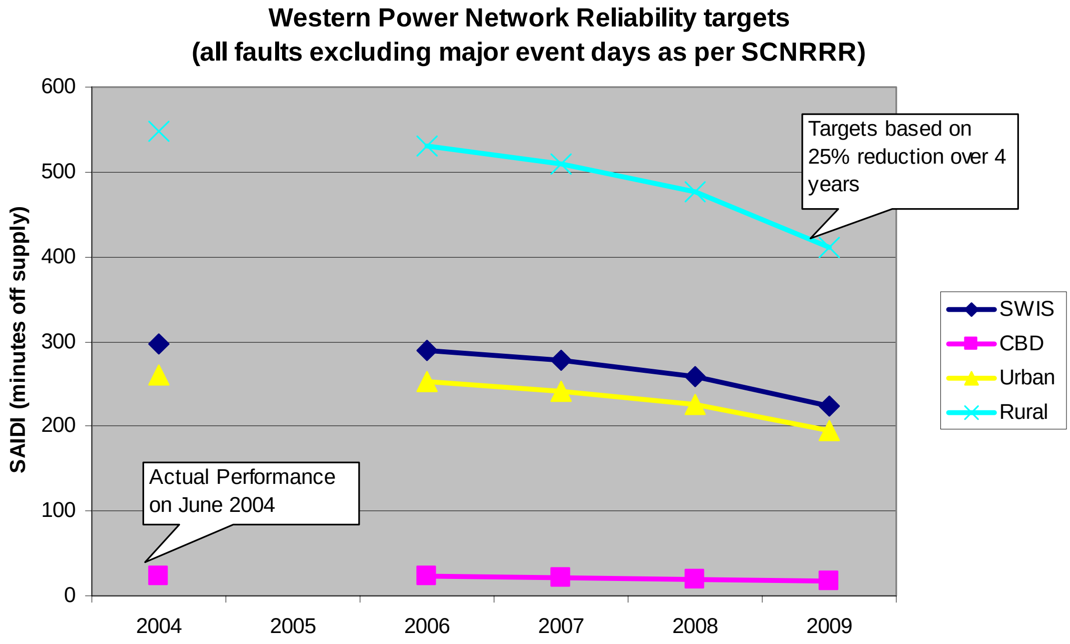
Figure 19 – Rehame Media Analysis Tonal Breakdown



Western Power considers that the current reliability performance of the network is not acceptable to its customers and stakeholders and is proposing to improve performance to meet the target SAIDI figure over two regulatory periods. The following chart highlights the significant reliability improvement program that Western Power is proposing to adopt. This is based on reasonable endeavours and would not include significant events e.g. a one in ten year storm. The proposed program represents a reasonable trade-off between the time to implement and resource availability.

[8] Rehame Western Power – WA Power Network Reliability, Media Appraisal Report, January 1, 2004 – February 18, 2005

Figure 20 - Western Power Reliability Targets (SAIDI)



Safety, Health and Environment

Safety and environmental considerations are already well embedded in Western Power's systems and processes. However, a number of new requirements have recently been imposed upon Western Power. These requirements are additional to the current Western Power requirements and will require additional expenditures to ensure the new minimum safety and environmental standards are met.

Examples of the additional safety and environmental requirements include:

- Bushfire mitigation;
- Overhead Service Wires;
- Conductive Metal Streetlight Poles;
- Poles Step and Touch Potential;
- Streetlight Switch Wires;
- URD Cable Pits;
- Henley Cable Boxes;
- Cattle Care;
- Reinforcing of Transformer Poles;
- Padmount Transformer Noise Abatement;
- Distribution Voltage Regulator Refurbishment; and
- River Crossing Safety.

Deregulation and Market reform

Western Power is required to support the implementation of market reforms including the enablement of competition and the disaggregation of Western Power Corporation. The market reforms will have the most significant impact upon Western Power in the Information Technology area, although structural changes will impact all areas of the business.

The projects that have been identified by Western Power as being required to facilitate competition or disaggregation include:

- Standalone business systems - Configuration of the corporate systems adopted by Western Power after corporate ring-fencing is complete. Works include Internet, Intranet, MIMS, Financial modelling, Treasury, DMS, Messaging.

- Networks Customer Information System - Replacement of current systems and processes with an off-the-shelf package that supports access billing, and provides Western Power with capability to manage customers (retailers and non-energy customers) in a de-regulated environment as an independent business unit.

- Interface to the Interim Market & Transitional Provisions – An information access portal that provides information sourced from operational systems to meet the Interim Market & Transitional Provisions as at July 2006.

- Systems to support the full Wholesale Electricity Market – An information system to meet the full wholesale market requirements commencing July 2008. Likely to include a package solution for the balancing/bidding system, plus replacement of existing systems, including Margins (Generation outage scheduling) and NOIW (Notice of Intention to Work).

- Metron – A Metering Business System to enable the dissemination of metering data to the Western Australian Energy Market participants.

- Compliance reporting – Works include determining compliance reporting needs and the implementation of a solution to best meet the needs of Networks and the Regulator.

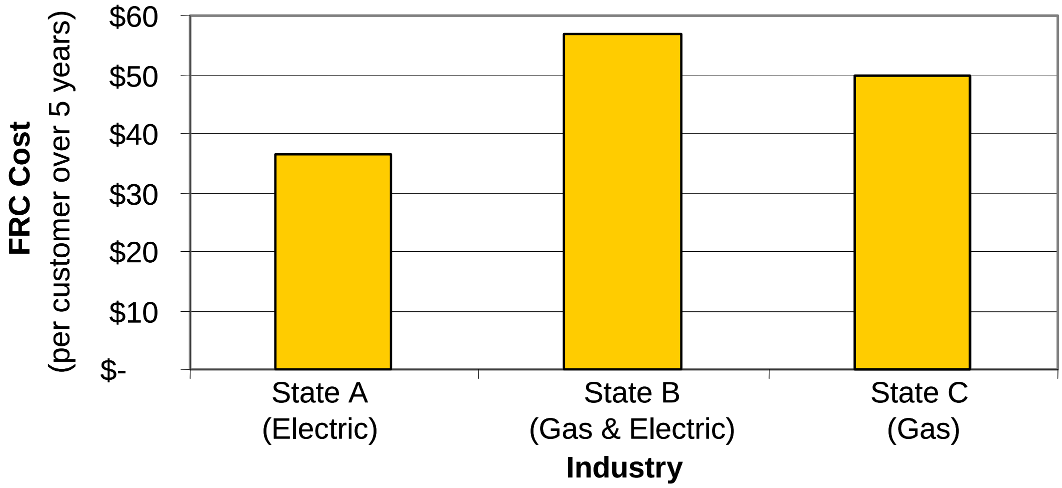
Significant market reform expenditures have been incurred in all states that have implemented retail competition in the electricity and gas markets. The vast majority of these expenditures have been incurred in the IT business groups due to the need to radically alter systems to meet the new working arrangements.

The system changes identified by Western Power relating to market reform are consistent with those required to meet market reforms elsewhere. The nature of these systems means that the requirements for partial or full retail competition are very similar.

Retail competition in the National Electricity Market (NEM) has been replicated in the gas industries where the networks have also been opened to competition.

The following table provides a summary of the state-by-state costs of these reforms.

Figure 21 - FRC Expenditures in other jurisdictions



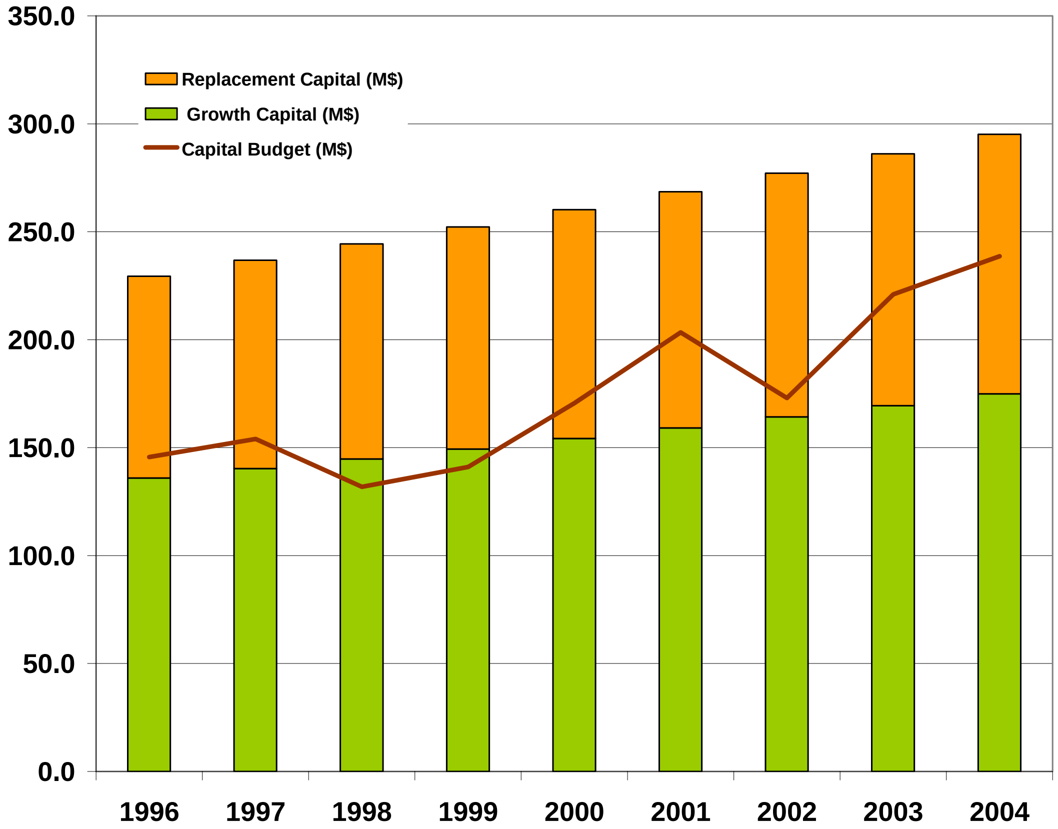
The projected Western Power expenditures associated with market reforms include instances of both disaggregation and competition reforms, whereas recent expenditures in other states primarily relate to competition reforms. On this basis, the Western Power forecast expenditure of less than $50 per customer compares favourably with the above inter-state comparisons.

Constrained Expenditures and Backlog

Figure 22 presents historical data for the ten years from 1995/96, the year in which Western Power Corporation was established. Prior to that time, detailed cost data that is consistent with Western Power's present reporting arrangements is not readily available.

Western Power operates with a clear obligation to connect new customers to the network. Customer connection activities can fluctuate from year to year depending on the levels of economic and population growth. Western Australia has been enjoying a period of relatively high growth and the Figure 22 clearly highlights that the capital budget has remained at a level that has barely allowed Western Power to meet new customer works.

Figure 22 – Growth and Replacement Budgets



Every electricity network business operates with a certain level of assets that are identified for repair and replacement. This is commonly referred to as backlog. Western Power has identified $40 million of backlog in the transmission network and $12 million of backlog in the distribution network. Under recent expenditure levels this backlog has continued to grow, the proposed asset replacement expenditure aims to contain further increases in backlog.

The average electricity network asset has an operational life of approximately 40-60 years. From an overly-simplistic analysis, this would mean that you would need to replace 2% of the network per year to maintain normal operations. However the network was built in phases with the greatest number of assets being installed 30 to 50 years ago. Western Power is now approaching a period where greater numbers of assets will require replacement than in any time in its history.

At present Western Power is currently replacing less than 0.5% of its system per year. Due to ongoing and recent expenditure constraints, the level of backlog continues to increase and is now at a level that is sub-optimal and clearly unsustainable.

Constrained Expenditure - System utilisation

In the late 1990's a policy was adopted to allowed certain substations to be loaded to 90% of the normal cyclic rating (NCR) if a rapid response spare transformer (RRST) was available in the event of a transformer failure.

Although the implementation of this policy has been successful in managing capital restrictions, it has resulted in an increasing utilisation of the substations. As more substations are now approach the planning limits, it is becoming increasingly difficult to reliably operate the network and the risk of loss of supply is increasing.

Following a number of widespread outages in Queensland, the respective state government commissioned a report into the state electricity networks; Energex and Ergon Energy. This report[9] highlighted substation planning practices and high levels of utilisation as key findings. Approximately 35% of the Queensland substations have N-1 spare capacity, whereas only approximately 20% of Western Power's NCR assigned substations have N-1 spare capacity.

An independent review commissioned by Western Power has determined that the NCR criteria as applied by Western Power has a higher level of associated risk compared with the criteria adopted by most other network businesses surveyed. Economic analysis conducted within this study also indicated that a more conservative NCR criterion may be more prudent.

This suggested policy change represents a significant change to Western Power and the Network implementation plan is to wind back to the new proposed criteria over a ten year period.

[9] Electricity Distribution and Service Delivery for the 21st Century, prepared for the Queensland Government, July 2004.

4. Customer Outcomes

Past Reliability Performance

The principle measure of performance of an electricity network is its level of reliability. The traditional reliability measures include frequency of outages, duration of outages and the cumulative duration of outages in a year.

Any reliability measure is highly impacted by weather and other natural events. However, a review of the recent history of Western Power's reliability indicates a trend of worsening performance[10].

Figure 23 - Western Power SAIDI Performance 1996 to 2005

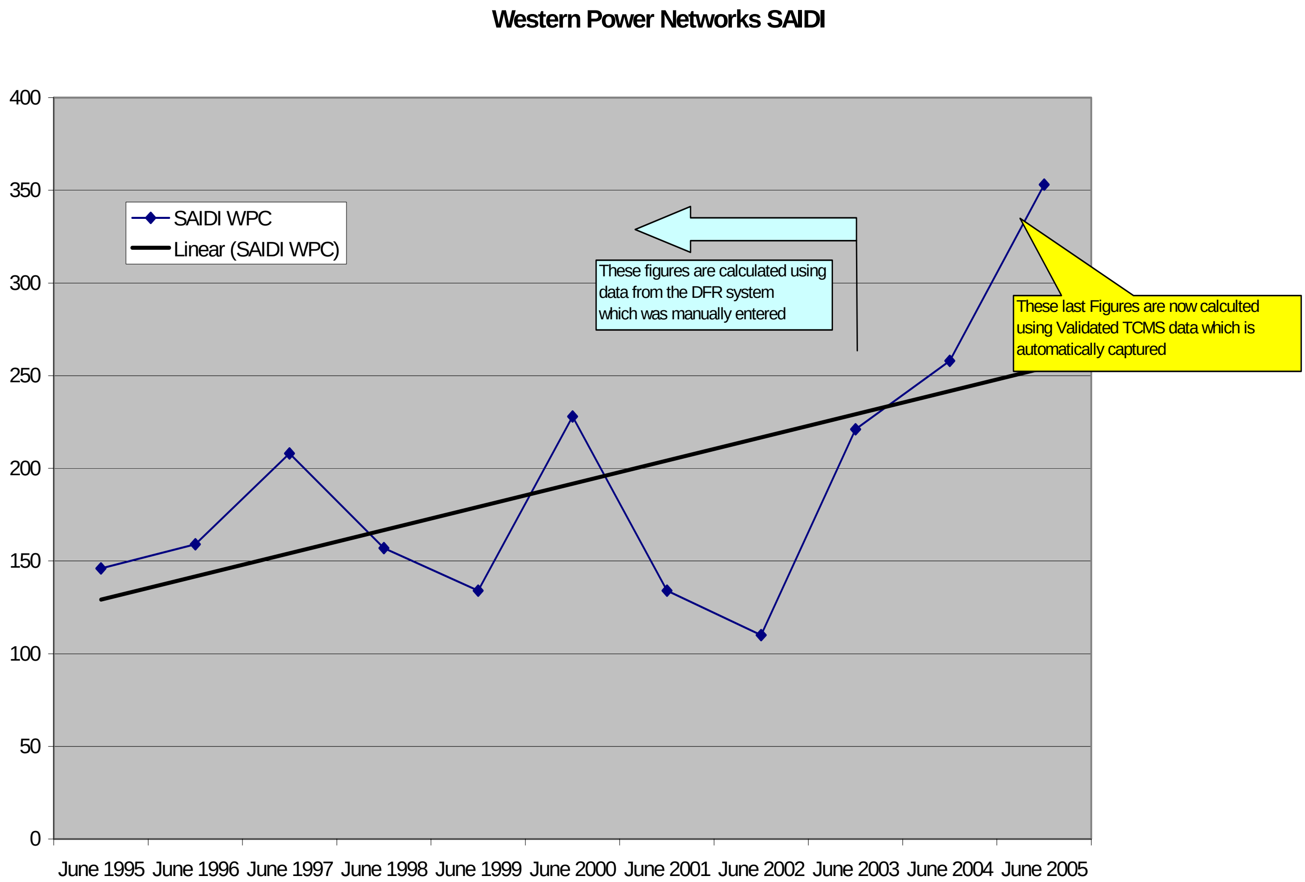
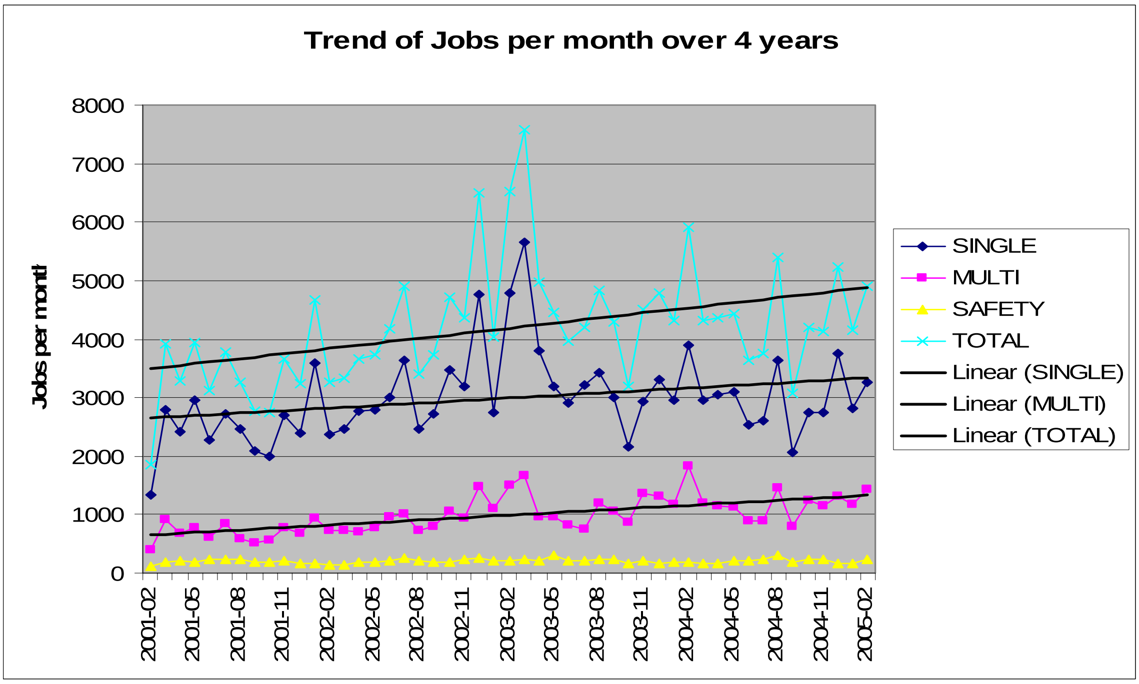


Figure 24 details the number of network faults or incidents that Western Power has responded to over the previous 4 years. It is evident from this chart that Western Power is attending more faults with a trend increase of over 35% over the 4 year period.

[10] The SAIDI numbers provided in Figure 23 are sourced from the Western Power's now superseded DFR system. These numbers are therefore not directly comparable to the Western Power target SAIDI.

Figure 24 - Fault Jobs Trends



The principal driver of this increased exposure is recent expenditure constraints. The history, impact and outcomes of these expenditure constraints are discussed in more detail in the expenditure sections of this paper.

This position poses two challenges for Western Power;

1. How to arrest the decline in overall network performance, and

2. How to return the network to an acceptable level of performance.

Customer Perceptions

The Western Power electricity network is designed, constructed and operated to provide customers with a safe and reliable service.

Determining the appropriate level of service requires consideration of both the legislated requirements (discussed later in this section) and the needs of the customers. Western Power is obliged to use best endeavours to meet the legislated minimum service standards, and is committed to also achieving the needs of its customers.

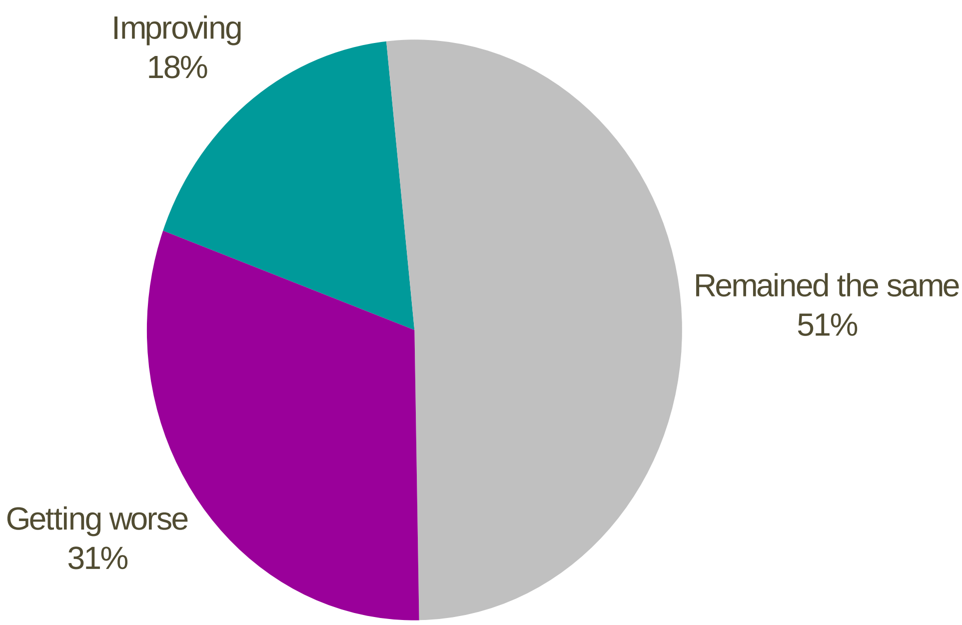
The determination of customer needs is not a simple task; there is a wide diversity in the needs of individuals and customer groups. In recent times, willingness to pay studies have sought to identify and quantify the needs of customer groups. Western Power has a strong history of surveying customer attitudes and continues to work with customer groups to identify the optimal price/service offering.

A recent survey of Western Power customers identified the consistency and reliability of supply as the overwhelming issue of importance to them.[11] Over 85% of customers identified "Consistency/reliability of supply" as the principal issue facing Western (refer to Figure 25). When surveyed as to whether Quality of Supply was improving, 82% said it was remaining the same or getting worse (refer to Figure 26 - Customer Perceptions of Quality of Supply).

Figure 25 - Customer Issues

Customer Identified Issue	Respondents %
Consistency/reliability of supply	86
Price	20
Frequency of outages	14
Quality of supply	10
Duration of outages	7
Shortage of supply in the future	5
Environmental concerns	4
Other (e.g. customer service, good maintenance and power surges)	5
Don't know	2

Figure 26 - Customer Perceptions of Quality of Supply



[11] Market Equity Customer Survey – April 2005

In addition, when asked concerning the factors that affected the performance of the network, customers appeared very aware of the issues facing Western Power.

Figure 27 - Factors Impacting Reliability

Factors Impacting Reliability	Respondents %
Lack of maintenance	43
Bad weather (i.e., storms)	34
Excess demand/fuel shortage	19
Hot weather	18
Mismanagement	16
Poor infrastructure	16
Accidents	12
Pole-top fires	11
Other (e.g. forward planning, bush fires)	6
Don't know	5

Western Power has undertaken to address the issues and concerns raised by its customers. The targeted expenditures detailed in this paper will directly improve the impacts of historically low maintenance and bad weather in particular.

Legislated Targets

Electricity Industry (Network Quality and Reliability of Supply) Code 2005 sets supply reliability standards that Western Power must use all reasonable endeavours to meet. These standards equate to a SAIDI figure of 30 minutes for CBD, 160 minutes for urban areas and 290 minutes for rural areas, but the Code is silent on the timeframe for attaining these standards.

Western Power management has set a target reliability improvement of 25% across the SWIS, with the improvement being implemented in stages over a 4 year period commencing during 2005/2006. This is based on reasonable endeavours and would not include in the targets one in ten year events. The SAIDI improvement is to be measured using the SCNRRR[12] definition and IEEE 1366 Guide for Electric Power Distribution Reliability Indices for major event days known as the Beta method[13].

A 25% improvement in reliability is a significant step, and it is acknowledged by Western Power that the target will not be achieved within the initial regulatory period.

[12] Steering Committee for National Regulatory Reporting Requirements.

[13] Beta method is used to identify major event days which are to be excluded from the minimum service standards as per SCNRRR.

5. Business Support Costs

The Western Power network business has recently been separated from the generation and retail arms of the former Western Power Corporation. As a result, significant changes were required to the structure of the business in order to manage corporate functions such as finance, accounting, human resources, and business systems which were previously centralised.

New Company Structure

Western Power has implemented new organisation arrangements designed to meet its strategic objectives and ensure the delivery of the outcomes sought by the State Government's ongoing electricity reform program.

The organisation structure has been implemented in support of an Operating Model comprising a "Works Engine", System Management and the support Divisions. The Works Engine comprises three operational divisions:

- Asset Management Division has accountability for the work plan requirements;
- Works Delivery Division is responsible for the delivery of the work program; and
- Field Services Division provides field workforce capability to support this.

The principal role of the Works Engine is to collaboratively deliver the work program over the review period, agree the future program and position future capability.

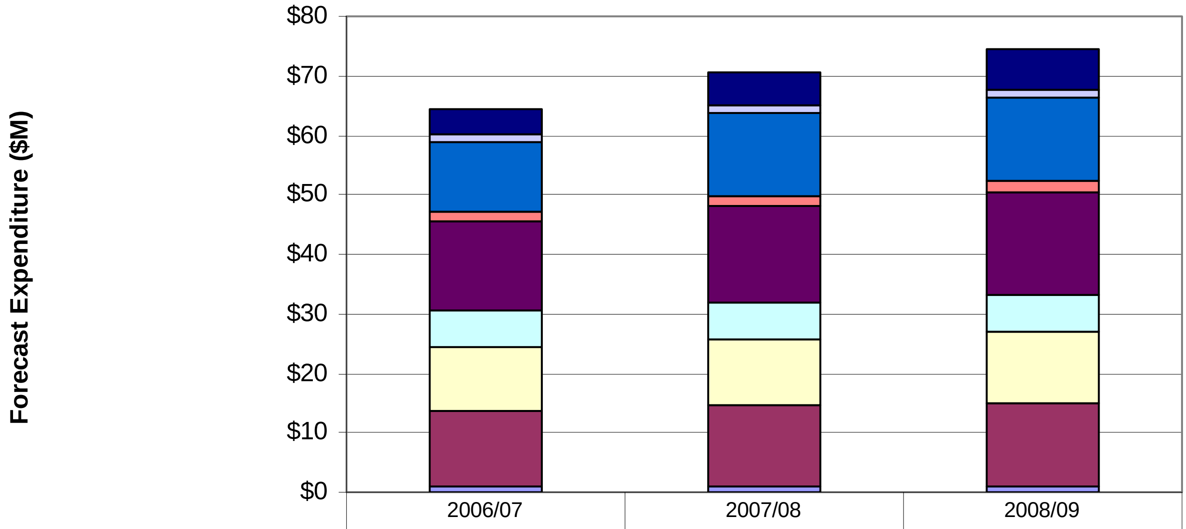
The supporting Divisions include Strategy and Corporate Affairs, Human Resources, Finance and Business Transformation. Their role is to enable the long term positioning of the Works Engine with a focus on the strategic development of the organisation.

The forecast business support costs support both the transmission and distribution businesses that are operated by Western Power. An allocation between the transmission and distribution components is made based on the percentage of labour and materials for the non support activities in the overall transmission and distribution forecast. The exception to this allocation method is insurance, rates and taxes which are allocated to the districts based on the specific policies. The resulting allocation of overall business support costs is approximately 25% to transmission and 75% to distribution.

Support costs can be split into a number of high level categories including: Human Resources, Finance, Strategy and Corporate Affairs, Capital Planning, Design and Estimating, Insurance, Rates and Taxes. An overview of forecasts for each area is provided in Figure 28. A description of each of the areas' business support function is provided in the following sections.

Note: Western Power presently provides some corporate services to the business entities Synergy, Verve Energy and Horizon Energy such as payroll services and head office accommodation. While the costs for these are included in Western Power's forecast Support costs, the associated revenue is recognised as an offset in the regulated revenue forecasts.

Figure 28 Western Power Business Support Costs Overview



	2006/07	2007/08	2008/09
Rates & Taxes	$4.340	$5.440	$6.520
FBT	$1.300	$1.336	$1.371
Insurance (Premiums & SIL)	$11.622	$13.829	$14.162
Design & Estimating	$1.751	$1.834	$1.909
Strategy & Corporate Affairs	$15.027	$16.022	$17.100
Business Transformation	$5.995	$6.208	$6.405
Finance	$10.643	$11.255	$11.746
Human Resources	$12.941	$13.670	$14.182
CEO	$0.841	$0.887	$0.927

Human Resources

Human Resources incorporates activities for administrative services, employee relations, HR Operations and Organisational Development, Safety and Health, and workforce capability. A brief description of each of these areas follows.

Administrative Services

Administrative Services incorporates the facilities management of Head Office and Murray Street buildings. This encompasses security, cleaning, mailroom, switchboard, ground floor reception & general maintenance & accommodation coordination and execution. Administrative services also funds major parts of Head Office electricity charges & telephone charges.

Major expenditure items include:

Labour	$0.433M
Contractors	$0.132M
Electricity Charges	$0.940M
Telephone Charges	$1.135M
Security	$0.410M
Cleaning	$0.385M

Mail Room	$0.110M

Employee Relations

Major expenditure items include:

Labour	$0.528M
Consultants	$0.165M (remuneration, IR/Legal, pulse survey)
Printing	$0.050M

HR Operations & Organisational Development

HR Operations & Organisational Development encompasses Payroll Services, Health Services & HR Consulting.

Payroll Services provide fortnightly payroll processing, special pays, complex pays, labour appropriation, superannuation payment management, leave & competency administration, salary packaging & a payroll help desk for employee queries.

Health Services coordinate the Employee Assistance Program, Corporate Wellness Program, injury management & management of pre-employment requirements.

HR Consulting provide generalist operational HR advice and support to line management and staff on the full range of HR related issues.

Major expenditure items include:

Labour:	$2.237M
Contractors	$0.420M

Safety & Health

Safety & Health manage the OHS Strategy for Western Power along with the development of safety & health policies & practices and the facilitation of policy across the business. OHS reporting and the development of Safety Training programs is also managed by Safety & Health.

Major expenditure items include:

Labour	$1.233M
Consultants	$0.050M (IFAP Audit)

Workforce Capability

Workforce Capability is responsible for the creation of organisational development initiatives that support Western Power's strategic plan.

It has three main functions: Organisational and Talent Development, Employee Resourcing and Engagement and Employee Development.

Major expenditure items include:

Labour	$0.928M
Contractors	$0.130M
Consultants	$0.450M (recruitment & development)
Advertising	$0.100M (recruitment)

Finance

The Finance forecasts include expenditure for activities including Business analysis, financial control, risk management, treasury, network IT and the Chief Financial Officer (CFO) group. A brief description of each of these areas follows.

Business Analysis

Business Analysis is accountable for the capital & operating financial budgeting process (financial & economic modelling and interfaces to Dept of Treasury & Finance), business performance reporting, forecasting, business operational & strategic planning, KPI development, regulatory support and management accounting.

Major expenditure items include

Labour	\$1.938M
Contractors	\$0.446M

Financial Control

Financial control is responsible for financial and compliance reporting, financial policy creation, review, maintenance and implementation, asset accounting, accounts receivable, accounts payable, credit management & taxation.

Major expenditure items include

Labour	\$1.384M
Contractors	\$0.087M

Risk

Risk incorporates management of the Risk Management framework and reporting, business continuity & crisis management plans & framework.

Major expenditure items include

Labour	\$0.132M
Consultants	\$0.160M

Treasury

The Treasury branch is made up of four sections, Treasury Analysis, Economic Modelling, Insurance and Claims Management.

Treasury Analysis provides the cash management function, debt portfolio management, annual refinancing & hedging strategy, management of interest rate, commodity & foreign exchange risk, and the establishment & maintenance of relationships with financial institutions. Economic Modelling is responsible for the operation of the Treasury long-term financial models and analytical and financial support.

The Insurance section is accountable for insurance brokerage, insurance relations and risk analysis, and the annual review and renewal of insurance programs and policies.

Claims Management provide coordination and resolution of customer complaints, claims and investigations.

Major expenditure items include:

Labour	$1.394M
Consultants	$0.256M

IT Strategy

This group guides the strategic IT development (systems and service provision) to meet future business needs.

It also includes provision of the company's document management, library, research and archiving services.

Major expenditure items include:

Labour	$1.593M
Consultants	$0.175M
Subscriptions	$0.177M

Insurance

Insurance covers the following policies and related brokerage fees along with Western Power's Self Insured Loss. Workers Compensation, Motor Vehicle (Low Value), Non-owned Aviation, Marine, Motor Vehicle Workshops, Directors & Officers, Contract Works 3rd Party, Fire & Perils, Motor Vehicle (High Value), Public Liability, Contract Works Own and other minor policies.

Major expenditure items include:

Workers Compensation	$3.077M
Motor Vehicle (LV)	$0.883M
Directors & Officers	$0.658M
Fire & Perils	$1.274M
Public Liability	$2.576M
Self Insured Loss	$2.400M

Business Transformation

Business Transformation is accountable for developing and delivering an organisational change program that ensures the business is positioned to be a customer focused, best in class, networks services and infrastructure corporation.

A core accountability is the execution of the One Step Ahead program as a key enabler to establishing Western Power as a stand-alone entity and to deliver substantial operational efficiencies and efficiency gains.

Major expenditure items include:

Labour	$1.409M
Consultants	$1.574M

Strategy & Corporate Affairs

Strategy and Corporate affairs conduct activities related to audit of the business, corporate affairs, Legal and secretariat, and pricing, regulation and access development as described below.

Audit

Audit is accountable to provide independent, objective assurance services that adds value and improves Western Power's operations, regulatory obligations and stakeholders' aims.

Major expenditure items include:

Labour	$0.538M
Consultants	$0.556M (OAG etc)

Corporate Affairs

Corporate Affairs manages stakeholder relations, media relations, issues management (excluding customer complaints), internal communications, branding, World of Energy ("Shockproof" schools safety program), sponsorship and advertising.

Major expenditure items include:

Labour	$1.180M
Advertising	$1.765M (includes rebranding)
Sponsorship	$0.796M
World of Energy	$0.409M (materials & services)

Legal & Secretariat

The Legal & Secretariat branch provide support across the entire corporation in relation to its need for (i) legal and compliance services; and (ii) corporate governance and secretariat support, in particular in supporting the Board, standing committees and the Executive.

The secretariat and governance function comprises ensuring that the corporation's business comes before the Board for consideration/approval in an ordered and timely fashion and also that accurate records are kept of decisions made. In addition, the secretariat function is responsible for providing advice to the Board and management in relation to the organisation's governance processes, ensuring that Board succession planning is monitored and actioned as and when appointments are due to become vacant and for establishing and maintaining the corporation's central policies register.

Major expenditure items include:

Labour	$1.194M
Legal Fees	$4.000M
Consultants	$0.985M

Pricing, Regulation & Access Development

Pricing, Regulation & Access Development undertakes the role of coordinating the regulatory strategy & interface, revenue & pricing strategy, customer & commercial policies, technical rules, access development, Transmission & Distribution licences and compliance monitoring & ERA reporting.

Major Expenditure items include:

Labour:	$0.643M

Consultants: $0.120M

Design and Estimating

Design & Estimating costs covers an allowance for the expending of capital project design costs which do not proceed to the construction stage.

Rates and Taxes

Rates & Taxes includes water rates, shire rates, FESA Levy, Land Tax and Local Government rates equivalent for all substations, depots & other Western Power owned properties.

Fringe Benefits Tax (FBT)

This item covers forecast FBT liabilities of $0.9M per annum.

Comparison of Corporate Costs

As a separate basis for considering the reasonableness of corporate allocations for the network businesses, Western Power has reviewed levels in other Australian states where information is publicly available. The most comparable sources of corporate overhead figures were identified for NSW electricity distribution businesses, as well as information for gas distributors in reports presented by IPART. The following table shows the ratio of corporate costs to total operating and maintenance costs for a range of utility businesses.

Figure 29 - Corporate Cost Allocations Rates

Electricity Distribution[14]	
Energy Australia (2003)	26.70%
Country Energy (2003)	49.35%

Gas distribution (2000)[15]	
Multinet	20.50%
Westar	29.10%
Stratus	27.90%

The above figures would appear to indicate that corporate cost allocations of between 20% and 30% of overall operating and maintenance costs would be an indication of industry expectations. Country Energy's levels appear to be inconsistent although it has not been possible to fully ascertain the reasons behind its high levels.

[14] Electricity distribution figures extracted from regulatory accounting information available on the IPART and QCA websites.

[15] Gas ratios quoted in IPART 1999 Draft Gas Access Decision for AGLGN.

In comparison, Western Power's distribution corporate costs, including network management and administrative costs are shown in the following table.

Figure 30 – Distribution Corporate Costs and Overhead Proportion

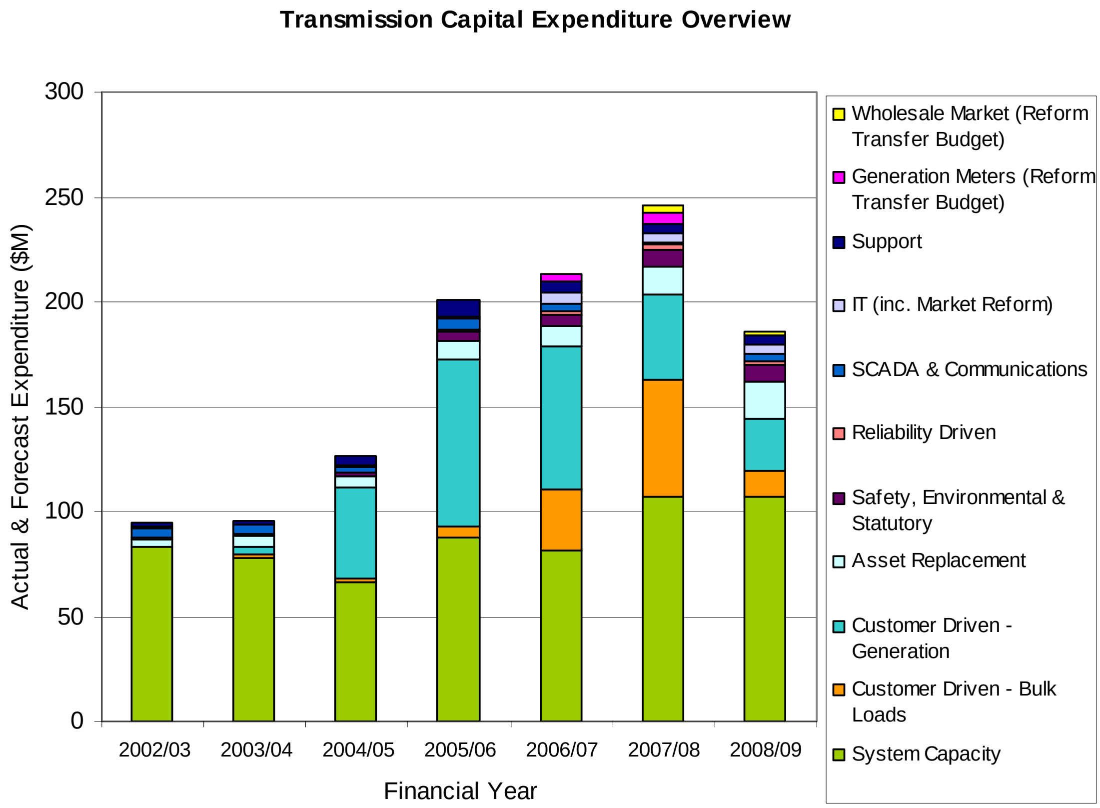
Distribution	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
Total Corporate Costs	22.2	26.2	26.6	25.1	45.8	50.1	53.5
Total Operating and Maintenance Costs	112.5	115.4	149.5	155.2	195.5	200.9	210.3
Corporate Overhead Rate	19.8%	22.7%	17.8%	16.2%	23.5%	25.0%	25.4%

Figure 30 shows Western Power's Network distribution corporate overhead costs are well within the 20-30% range during the regulatory period and significantly below this range during the last 4 years when Western Power was operating as a vertically integrated business. These forecast levels based on operation as a standalone network business compare favourably with those presented by IPART for NSW businesses and indicate that Western Power's Network corporate cost allocations are similar to those determined in other jurisdictions.

6. Transmission Forecast Capital Expenditure

Western Power is proposing a significant increase in overall transmission capital expenditure. However, the majority of the increase relates to customer driven work and there is little change to expenditure levels in other categories.

Figure 31 - Transmission Capital Expenditure



DEMAND RELATED	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
System Capacity	83.0	78.0	66.2	87.3	81.2	107.5	107.0
Customer Driven - Bulk Loads	0.3	2.1	2.2	5.8	29.2	55.3	12.2
Customer Driven - Generation	0.3	2.9	42.9	79.1	68.3	40.8	24.7
NON DEMAND RELATED							
Asset Replacement	3.3	5.2	5.5	9.0	9.9	13.5	18.0
Safety, Environmental & Statutory	0.1	0.2	1.5	4.2	5.4	8.1	8.1
Reliability Driven	0.9	1.3	0.7	1.6	1.8	1.8	1.8
OTHER							
SCADA & Communications	4.5	3.8	2.0	4.9	3.2	1.5	3.4
IT (inc. Market Reform)	0.5	0.4	1.1	0.9	5.9	4.2	4.8
Support	1.6	1.3	4.9	8.4	4.5	4.1	4.1
Generation Meters (Reform Transfer Budget)					4.0	5.3	-
Wholesale Market (Reform Transfer Budget)					0.1	3.7	1.9
Transmission ($M)	**94.5**	**95.2**	**126.9**	**201.2**	**213.4**	**245.8**	**185.9**

Western Power is proposing to increase average expenditure by approximately 65% during the regulatory period compared with average expenditure levels over the last 4 years. The expenditure categories showing the biggest increases are:

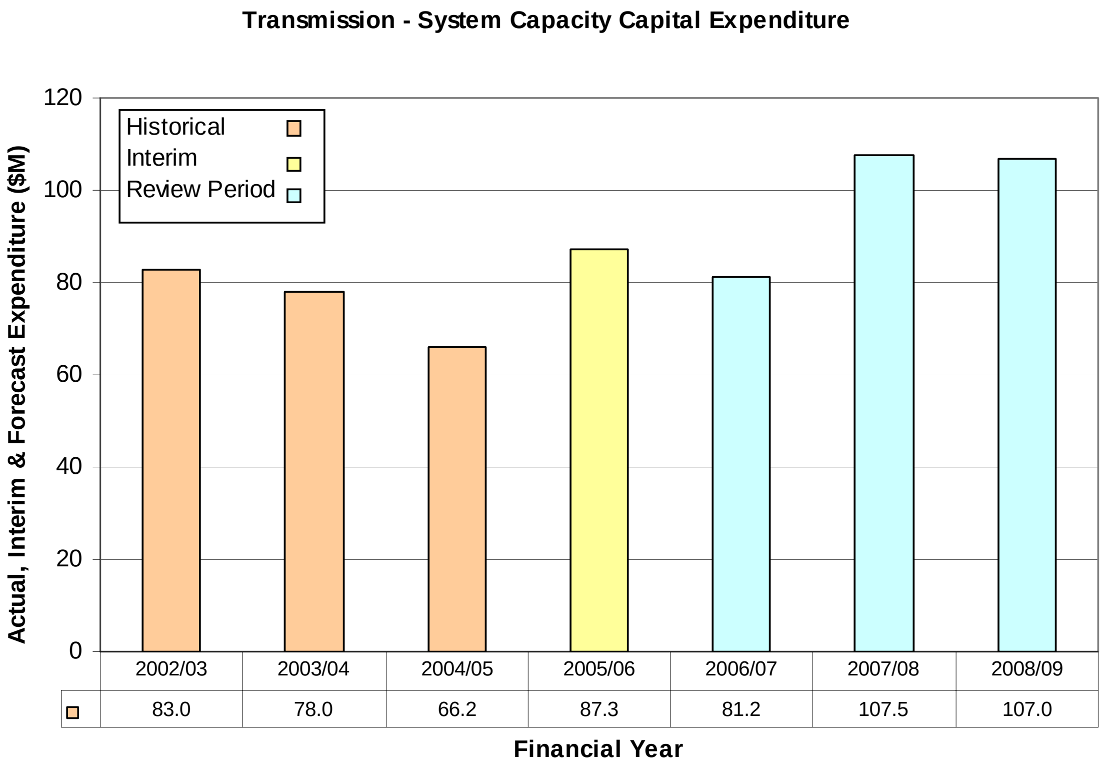
1. Generation and bulk load connections.
2. System capacity projects including Zone substation Normal Cyclic rating “wind back” and line capacity and undergrounding.
3. Asset Replacement.

4. Safety, Environmental & Statutory.
5. IT including market reform.

System Capacity Expenditure.

The System Capacity expenditure category includes all demand-driven reinforcement of the transmission and sub-transmission systems, including zone substations, but excludes the work for generation and customer driven reinforcements. The primary driver for system capacity expansion is growth of the peak demand in the South West System Load.

Figure 32 Transmission System Capacity

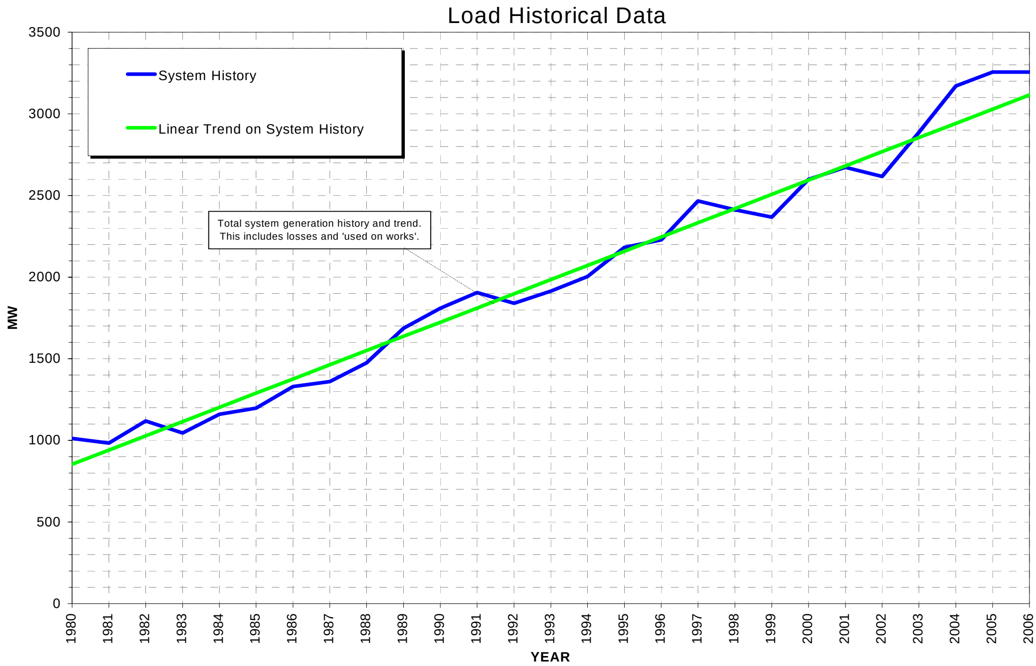


The main impetus for this increase in load growth is:

- Increasing penetration of air conditioning systems into residential and commercial customers,
- New residential developments,
- In-fill growth in mature suburbs,
- Isolated larger customers such as retail, industrial and mining developments,
- Higher state economic development,
- The historic high level of asset utilisation presently being experienced, reflecting a lack of adequate expenditure in this area over recent years and a consequential lack of available capacity to meet recent, rapid, load growth.

The peak load on the system has been growing consistently over the last 20 years. Figure 33 illustrates the historic peak load in the SWIS for the last 20 years. The growth rate has been reasonably consistent during this period with the exception of the last three years. In the last three years the rate of load growth has increased due to higher economic activity and increased penetration of air conditioning. The increased penetration of air conditioning and high economic growth in Western Australia has resulted in an unexpected increase in the peak demand for electricity, which is reflected in the NIEIR's load forecast for Western Australia.

Figure 33 – Western Power Transmission System Load History.



Capacity driven expenditure forecasts are based on a load forecast for the South West System developed by an independent source (NIEIR) for the IMO, and is made available via the IMO's Statement of Opportunities publication. The forecast is based on a 10% probability of exceedance of peak load. That is there is a 10% probability that the load will exceed the forecast. Hence the network and the expenditure program have been constructed to meet only this 10 POE forecast. With this forecast it is expected that load in one year in 10 may exceed the forecast.

A higher than expected load growth has been developing in Western Australia over the last few years. Each subsequent NIEIR forecast has consistently upgraded the forecast load growth for the state. The following list illustrates the magnitude of the increase in load forecasts over the last three years:

- 2003 step increase in peak demand of 50 MW[16] over the previous forecast. This represents an increase in annual demand in one year of approximately 140%.

[16] 50 MW is based on the 2003 GSR page 26 "Comparison to Previous Results".

- 2004 step increase in peak demand of 50 MW[17] over the previous forecast. This represents an increase in annual demand in one year of approximately 140%.
- 2005 step increase in peak demand of 120 MW[18] over the previous forecast. This represents an increase in annual demand in one year of approximately 200%[19].

(It is noted that the IMO is expected to publish its 2006 Statement of Opportunities and new demand forecasts in June 2006 which may impact on Western Power's capital expenditure program.)

The rapid increase in forecast load has resulted in the need to accelerate the work program to meet the escalating demand. With nearly 5 years average growth to be accommodated in the space of three years a significant proportion of the network reinforcement programs will need to be accelerated to meet the load growth. In addition the booming state and worldwide demand for materials and labour has resulted in an increase in project costs. The forecast expenditure levels in this category are therefore considered by Western Power to be conservative.

The Western Power system is significantly loaded. Western Power has historically used a policy of managing capital restrictions by applying high utilisations to its assets. Two of these policies are the use of the total capacity at its zone substations (NCR policy) and the high utilisation of its transmission lines. The nature of these policies and current plans in relation to highly loaded assets is discussed in the following sections.

<u>Zone substation Normal Cyclic Rating (NCR) "wind back"</u>
The NCR policy was introduced in the late 1990's to manage capital restrictions. This policy allowed certain substations to be loaded to 90% of the normal cyclic rating if a rapid response spare transformer (RRST) was available in the event of a transformer failure.

Although the implementation of this policy has been successful in managing capital restrictions whilst minimising performance deterioration of the subtransmission system, it has resulted in an increasing utilisation of the substations. As more substations are now approaching the existing NCR criteria, it is becoming increasingly difficult to operate the network, and the risk of loss of supply increases. These high transformer loading levels are physically demonstrated on the system by the alarms and tripping of transformers.

Figure 34 demonstrates the high loading of NCR sites and shows the number of alarms that have been recorded due to high loading of the system.

[17] 50 MW is based on 2004 GSR page 3 "Changes to GSR"
[18] 120 MW is based on page 20 of the IMO's Statement of Opportunities.
[19] Base on the IMO's Statement of Opportunities page 29 average growth from 2008/09. Average growth of 120 MW

Figure 34 Western Power Historic Zone Substation Transformer Overloads and Alarms.

Year	Number loaded over 90% of rating	Number loaded above Emergency rating.	Number tripping due to over load.
2004	15	9	2
2005	20	4	0

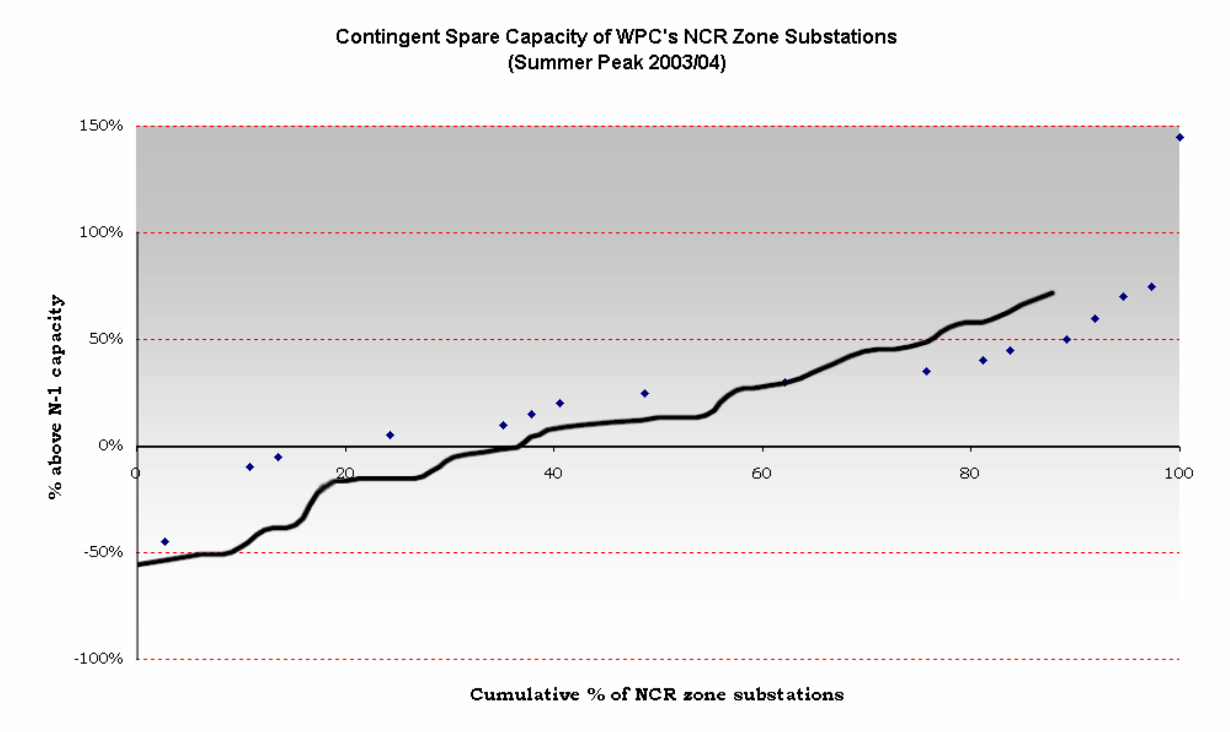
The trip of a zone substation transformer has a significant impact on Western Australian consumers, a typical zone substation transformer is rated at 33 MVA and supplies around 7000[20] consumers.

Transformer loadings are high. The average loading of zone substation transformers in NCR[21] sites has consistently been above 77% for the last two years. The "Detailed report of the Independent Panel for Electricity Distribution and Service Delivery for the 21st Century[22]" known as the "Somerville report" found that the utilisation of the Queensland transformers averaged 76%[23] when Queensland experienced significant supply reliability problems. The Somerville report found that the Average Australian utilisation of zone substations was 56% and the report recommended a significant reduction in loading to return to a more sustainable loading level. This has been followed by action by the Minister for Energy and Utilities of NSW[24] to significantly reduce the loading of NSW zone substations. In both cases the loading levels are to be reduced towards the Australian average.

Figure 35 shows a comparison of the Queensland substation utilisation (solid line) with the Western Power NCR substations indicated (+ mark). This graph indicates that approximately 35% of the Queensland substations have N-1 spare capacity, whereas only approximately 20% of Western Power's NCR assigned substations have N-1 spare capacity.

[20] Based on a peak consumption of 4.5 kw per consumer.
[21] It should be noted that the bulk of Western Power's substations are now designated as NCR. Currently the NCR substations are restricted to the metropolitan area.
[22] Electricity Distribution and Service Delivery for the 21st Century, prepared for the Queensland Government, July 2004.
[23] Utilisation values from "Detailed report of the Independent Panel for Electricity Distribution and Service Delivery for the 21 Century"-July 2004. Page 12.
[24] Design, Reliability And Performance Licence Conditions Imposed On Distribution Network Service Providers By The Minister For Energy And Utilities 1 August 2005

Figure 35 - Contingent spare capacity of existing substations Queensland compared to Western Australia



Following the findings of the Somerville report[25] on capital investment planning practices in Queensland, Western Power commissioned an independent review of its substation planning criteria and comparison with other network businesses in the Eastern States[26]. The finding of this independent review was that the NCR criteria as applied by Western Power are more aggressive then the criteria adopted by most other network businesses surveyed. Economic analysis conducted within this study also indicated that a more conservative NCR criterion may be more prudent.

Based upon the finding of the above independent review, Western Power has conducted a further investigation into the prudency of the existing NCR criterion[27]. This review examined a number of options with respect to the existing NCR policy and recommended that Western Power reduce the NCR criteria from 90% to 75% of the NCR.

The revised NCR criterion is defined within the proposed Technical Rules. The adoption of the revised NCR criteria will require an increase in capital expenditure over historical levels whilst substation loadings are reduced via the installation of additional transformer capacity and the establishment of new substations.

The Western Power plan is to wind back to the new proposed criteria over a ten year period. The increase in expenditure should be balanced by the ability to maintain the performance of the sub-transmission system as peak demand grows.

<u>Line capacity and undergrounding</u>

Over the last decade, the maximum operating temperature of many of Western Power's critical lines has been raised from 65^{0}C to 100^{0}C, as an effective low cost option for increasing capacity. Spare capacity via other low cost options is becoming exhausted. Examples of the recent projects that released capacity are:

- KEM-KW stringing underway;
- Shotts to KEM to be strung;
- ST-Kenwick 91 to be strung;
- ST-EP split phase line converted to double circuit;
- KW-SF split phase line converted to double circuit.

Western Power is entering a period where the low cost options for releasing additional capacity are no longer available. This results in practical options to relieve network limitations, invariably requiring higher cost up-rates that require major rebuilds or new lines.

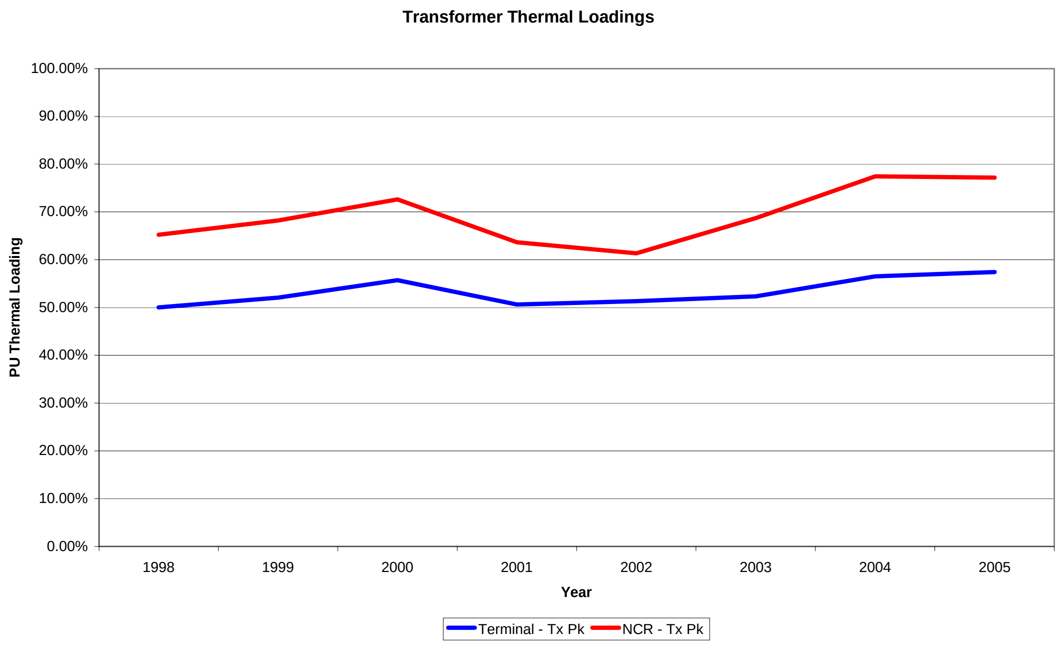
[25] Electricity Distribution and Service Delivery for the 21st Century, prepared for the Queensland Government, July 2004.
[26] Review of RRST Zone Substation Planning Criteria – December 2004
[27] This review is documented in the Western Power document, Review of the NCR Criterion – A Re-examination of the Risks of Load Shedding and Transformer Loading Levels.

To exacerbate this problem further, increasing environmental planning requirements and public awareness are resulting in an escalating need to underground new lines.

Capacity of Network to absorb un-forecast load increases.

Because of the high load growth over the last few years the loading of many transmission elements are at saturation levels and there is little capacity to absorb additional load growth without additional reinforcement. This is demonstrated in Figure 36 showing the historic terminal and NCR transformer loading levels.

Figure 36 – Western Power Historic Terminal and NCR Transformer Loading Levels.



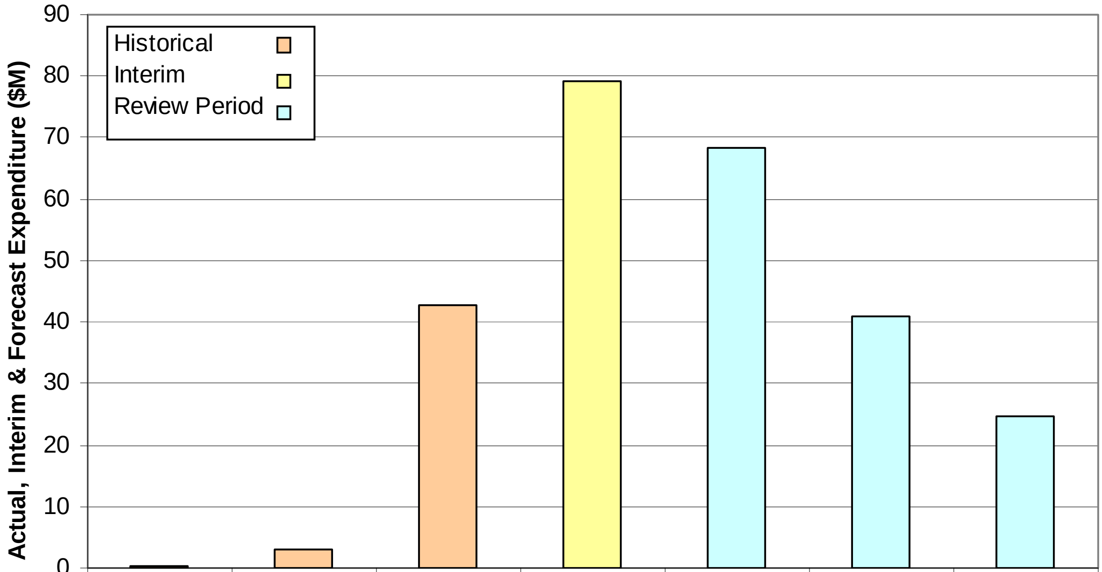
The lack of spare capacity is further demonstrated by Figure 35 which shows the comparison to Western Power's NCR zone substation with the situation in Queensland in 2003/4 when the Somerville report concluded that a significant reduction in load was required. Figure 35 shows that nearly 80% of Western Power's NCR zone substations are loaded above their N-1 capacity as opposed to the Queensland case where about 65% were loaded above their N-1 Capacity. Both the Somerville report and NSW's government have recommended that substation loadings should be reduced to about the N-1 level. The Western Power substations are well above this level and this has resulted in a number of overloads and transformer trips. The increased load forecast will exacerbate this situation unless sufficient funding and resources are provided to at least limit the overload of substations.

The Western Power Network has very limited capacity to meet increased load without overloading of plant.

Customer Driven Generation

Customer driven generation includes the connection of new generation to the system. This includes the upgrades and augmentations necessary to move power from the generation point to the load centre and the cost of connecting the generation to the system.

Figure 37 Customer Driven Generation Capital Expenditure



	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
	0.3	2.9	42.9	79.1	68.3	40.8	24.7

The main drivers of expenditure in this category are:

- Installation of generation for the development of a competitive electricity market,
- Installation of generation to meet forecast load growth. The 2005 IMO load forecast increased load by 120 MW.
- The need to connect additional plant to replace the retirement of generating plant.
- Installation of transmission plant to facilitate the connection of the generation to load.

This category contains two main components; the transmission network reinforcements needed to move power to the load centre, and the connection of generation to the system. The expenditure in this category is highly dependent on the location and timing of generation reinforcements. For commercial reasons potential generators are unwilling to provide long lead time advice on the location and timing of the new generation. For this reason the prediction of expenditure is uncertain in the later period of the regulatory period.

Basis of Expenditure Forecast.

This program of work has been increased following the release of the 2005 IMO Statement of Opportunities. The increase in the peak demand forecast has contributed to a number of potential projects becoming firm commitments in the work program, including the establishment of a new terminal station at Neerabup. Western Power anticipates that with the release of the 2006 SOO further additional projects may be required but the details, cost and timing of these are uncertain at this stage. The program of work developed will provide the best option to minimise risk of load shedding and of meeting the growing system load.

While the proposed expenditure is clearly higher than recent historical levels, Western Power does not expect this level of expenditure to be sustained. The nature of generation construction activity is relatively cyclic, and is triggered when utilization of existing generation assets becomes high.

The last major project prior to 2002 driven by generation connections was the SHO-ST 91 330 kV transmission line, which was constructed in 1998 to accommodate the Collie Power Station. In 2004/05 and 2005/06 investment increased to construct the KEM-KW 91 330kV transmission line, to establish Guildford Terminal and to provide reactive power support to the network to accommodate new generators at Kemerton, Pinjarra and Walkaway.

The present supply/demand balance on the SWIS and the transmission system underpinning this are at a pivotal point in time. The SWIS system is approaching a time when it will be requiring significant additional capacity to maintain system security standards, and at the same time there is a need for new generation input to the network. The overall program is being significantly impacted by increased costs due to high world demand for power system plant, materials and labour. The bulk transmission network that underpins this generation capacity, allowing the reliable supply from the generation to the load centres, will consequently require a significant level of network investment to allow the system to accommodate the increased generating capacity and still achieve the performance levels specified in the Technical Code.

Main driver and process summary

The primary driver behind the need for these generators is the forecast peak demand growth. The peak demand and the demand profile determine the level and type of generation that is required to reliably and economically supply consumers with electricity.

In order to maintain a reliable power system, a level of generation capacity above the peak demand must be maintained[28]. The difference between available capacity and unrestricted demand at peak time, allowing for curtailable and interruptible loads, is known as the reserve margin, and a minimum reserve margin is set to ensure a reliable SWIS system.

The reserve margin prior to 2006 was 304 MW, plus a further 30 MW of regulating reserve i.e. 334 MW total. The IMO has determined that the reserve

[28] This is to allow for the possibility of the unavailability of generations capacity, forced generation outages, and uncertainty in peak demand due to effects such as weather..

margin for 2006 onwards should be 345 MW. Future changes in reserve margin will be subject to determination by the IMO.

In addition to the new generation capacity required to meet growing load, new generation will be required to compensate for the retirement of aging generation plant. There are also plans published in the IMO 2005 Statement of Opportunities (SOO) to retire certain old and inefficient generating plant, namely:

- 2008: Muja A/B is approx. 40 years old with sent-out capacity of 202 MW;
- 2009: Kwinana B is approx. 35 years old with sent-out capacity of 189 MW;
- 2010: Kwinana A is approx. 35 years old with sent-out capacity of 199 MW.

At this point in time, the committed generation projects are:

- 2006: Alinta 2 - 140 MW;
- 2006: Emu Downs Windfarm - 80MW (note: intermittent capacity);
- 2008: Bluewaters 1 - 220 MW;
- 2008: Newgen - 320 MW.

As the existing and committed generation capacity, was below the minimum reserve margin for the forecast in peak demand for 2007/08, the IMO assigned reserve capacity credits to the following additional generators not listed above:

- 2007: Alinta Wagerup 1 & 2 - 351 MW.

Preparation of generation scenario

In order for Western Power to produce its forecast capital expenditure for this expenditure category, it must produce a future generation scenario. This scenario must meet the system security criteria such as the minimum reserve margin. The scenario can then be used in planning studies to determine network augmentations required to allow a reliable system to be achieved.

The SWIS is about to begin a competitive market in generation, and as such, Western Power cannot control the location, timing, size etc. of new generation plant connecting to its network. To this end, Western Power is entering a period of much greater uncertainty with respect to generation connection capital expenditure, both with respect to connection costs, and shared network augmentations.

Forecasting shared network augmentations can be particularly difficult as new shared network capacity is required to be in service for connection of the new generation. However, the lead times for major augmentations (such as transmission lines) can be much greater then the lead times for new generation plant.

Western Power has produced a generation scenario based upon its knowledge of the announced projects and high probability locations[29]. Generation was selected for inclusion in the generation schedule to ensure that the minimum reserve margin would be met in each year. The general guidelines for selection of generation proposals inclusion in future generation schedule were as follows:

- precedence was given to generation proposals contained in the 2005 Statement of Opportunities (SOO) or well developed proposals that have been made since publication of the 2005 SOO;

- precedence was given to generation proposals that are well developed and are currently making progress with access studies and applications;

- precedence was given to generation proposals that are of a size that will provide a substantial portion of the new capacity required to meet the reserve margin each year; and

- generation proposals not included were either relatively undeveloped proposals, proposals that were relatively small in size and insignificant to overall generation planning, or proposals with a history of deferral.

Based upon this assessment, Western Power considers the most likely generation scenario to be one in which the predominant location for the connection of new generation will be to the south of Perth.

Figure 38 below lists the generation connections, in addition to the committed generation connections listed above, that have been assumed to ensure a minimum reserve margin is maintained. These projects have then been used to forecast the connection works and shared network augmentations in the application.

The maximum demand forecast from the IMO 2005 SOO was used as the basis for determining the required generation capacity. One large block load (Boddington gold mine) that has been announced as approved since the publication of the 2005 SOO has been added to the demand forecast due to the significance of this load relative to the total system demand.

[29] The probability is assessed based upon factors such as type of generator, fuels supplies, local customer types, etc.

Figure 38 - Assumed generation connections & decommissioning [30]

Generation Connection	Access Agreement Signed	Target Date	MW
Albany Windfarm Stage 2	No	Nov 2006	14
Alinta 1 & 2 Wagerup	No	Nov 2007	360
Worsley	No	Nov 2007	120
Kwinana B	-	June 2008	-189
Kwinana A	-	June 2009	-199
Bluewaters 2	No	Nov 2009	220
Collie 2	No	Nov 2010	320
Collie 3	No	Nov 2012	320

It is important to note that although there are assumptions within the generation scenario development of particular generation connections, most of which are only at an announced status, the predominant and realistic location for the connection of sizable new generation is in the South West. The main factors driving this predominant location in the South West are:

- Major proponents proposing new generation in South West.
- Developed coal source.
- Access to Dampier-Bunbury gas pipeline.
- Access to renewable energy wind and biomass.
- Major established industries requiring steam with an option for cogeneration.
- Lower environmental hurdles to achieve.
- Access to land, water and infrastructure.

The development of the generation scenario used by Western Power to produce the capital expenditure in this category is discussed in more detail in the Western Power document – Development of Generation Scenarios for use in Network Reinforcement Plans[31].

Planning studies

The process adopted by Western Power to produce the bulk transmission system augmentation forecast is very much based around Western Power's normal planning cycle. This is described in the Transmission and Distribution Annual

[30] Projects in bold indicate a South West location.
[31] DMS# 2193620v1

Planning Report (APR) which is a public document produced by Western Power. This is also similar to the process followed to assess system capacity.

In this planning cycle the bulk transmission system capacity is assessed against the planning criteria, forecast peak demand growth and generation dispatch scenario to determine forecast violations of planning criteria[32]. This analysis is carried out via power system modelling of the bulk transmission system. A range of options to alleviate the network violations is considered. These options are then costed, and both technical and economic evaluations are performed to determine the most prudent and efficient solution.

The analysis defining the needs, the options and the evaluation are discussed in the Bulk Transmission System Long term Development Study Notes report[33]. This report is updated each year. Other more detailed reports may also be produced to discuss and summarise significant issues and projects.

A separate project data sheet has also been produced for each project that builds the shared network forecast. These sheets provide an overview of network issues and related Western Power reports. They also summarise the main driver, planning criteria, options considered, and scope and cost of the preferred option.

There is a high level of uncertainty associated with the proposed work plan for the bulk transmission network as a consequence of the uncertainty associated with the location and timing of new generation and large load proposals. This is particularly the case for the later years of the regulatory period as very few applications have been received.

The shallow connection based works of the generation connection are determined based upon known scoped connection projects and assuming similar connection scopes for the assumed projects in the later years of the scenario.

Key factors driving increasing needs

Figure 39 below shows the historical and forecast level of generation capacity and the associated system peak demand. This graph clearly shows that recent historical generation has generally connected in discrete large blocks with periods of 3 to 5 years in between. The last significant connection was 2003, with significant connections in 1999 and 1996 prior to this.

The introduction of the market to the SWIS, particularly at a time when reserve margins are low, introduces a new dynamic to generation planning. At this time it appears that the majority of new generation connections will be of a smaller size and/or in different locations, rather than the more lumpy additions of larger generators or multiple generators at the same site. This can be seen in the forecasts for years 2006 to 2010 in Figure 39. The impact of these multiple smaller connections is total connection costs higher than recent historical levels.

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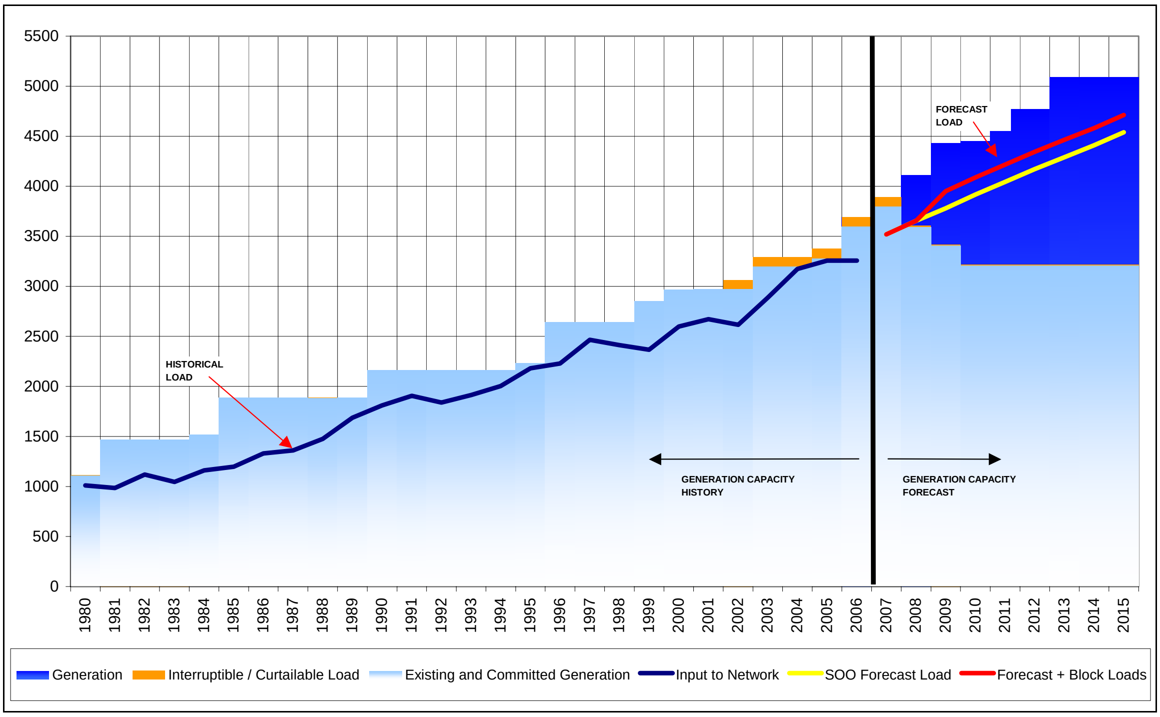
[32] It should be noted that other generation scenarios are also studied by Western Power to determine network needs and these other scenarios and related network need are discussed in Western Power's planning documents.

[33] DMS# 1934690v2A

Figure 39 - Historical and forecast generation connections.



More significant than this connection issue, is the historical level of shared network reinforcement and forecast level of reinforcement. Due to the lower levels of new connections in the recent past, little significant bulk transmission network reinforcement has been required.

Figure 40 (below) provides a breakdown of the recent historical generation connections and associated network reinforcements. This shows that the last major reinforcement of the bulk transmission system prior to 2004/05 was in 1999, and prior to this 1990.

Figure 40 - Historical generation connections and associated network reinforcements

Generator	Year connected	Capacity	Major Network Reinforcements
Pinjar A/B	1990	193 MW	NT-PJR 81 & 82 double circuit transmission line
Pinjar C	1996	202 MW	
Collie	1999	304 MW	SHO-ST 91 330kV transmission line
SWJV	2000	111 MW	
Cockburn 1	2003	229 MW	
Kemerton	2005	240 MW	KEM-KW 91 330kV transmission line, Guildford Terminal 330/132kV transformer
Walkaway	2005	90 MW	Reactive Power support
Alinta	2005	140 MW	

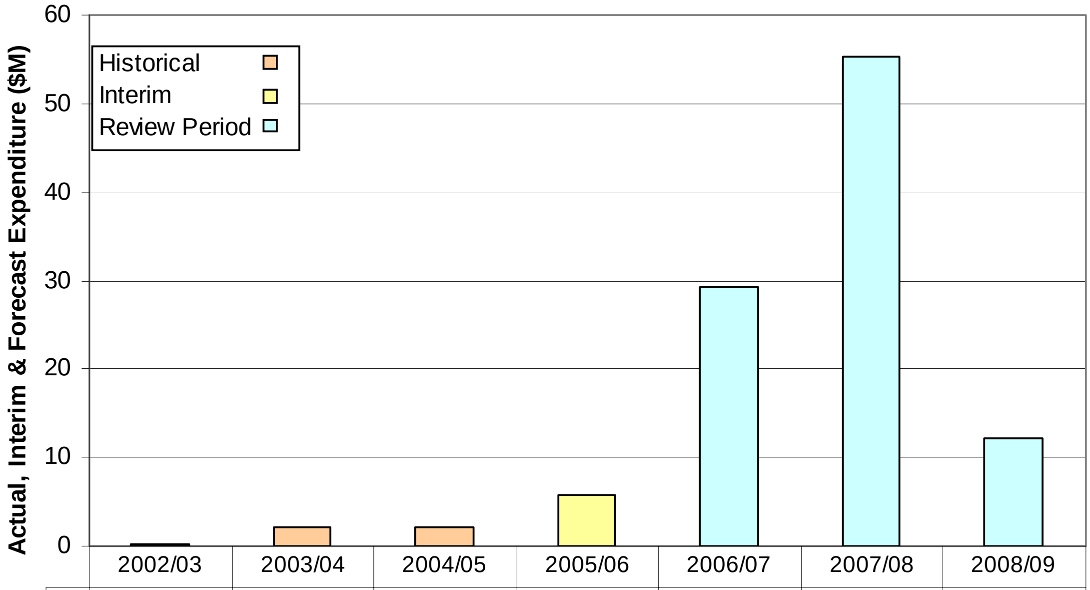
The most likely location for new generation is in the South West for the reasons discussed above. Projections prepared by Western Power indicate that this may well result in approximately 1000 MW of additional generation capacity in the South West by around 2010.

The existing network is nearing full capability with existing generation levels. The new generation capacity that is necessary to meet forecast demand growth will require major reinforcements of the corridors transferring power from the South West to the major load centre at Perth.

Customer Driven - Bulk Loads

The capital expenditure in this category relates to work required to maintain compliance with network planning criteria and meet load growth needs caused by discrete customer load (Block Loads).

Figure 41 – Transmission – Customer Driven Bulk Loads - Capital expenditure



	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
	0.3	2.1	2.2	5.8	29.2	55.3	12.2

Figure 41 shows an increasing capital expenditure need compared with recent historical levels, with capital expenditure dropping off in the later years of the review period. Bulk load connection capital expenditure is invariably lumpy as it is driven by connections of a small number of individual bulk loads to the transmission system.

The above forecast is based upon enquiries made to Western Power for bulk load connections with a high probability of proceeding. The main projects include:

- Southern Suburbs Railway (approved) – 2006/2007.
- Kwinana Desalination Plant (approved) – October 2006.
- Westralia Airports Stage 2 (approved) – 2007.

- Boddington Gold Mine (approved) – Majority of expenditure in 2007/08 – Completion September 2008.

The project list is provided in Appendix A and includes the recently approved Boddington Gold Mine which accounts for the majority of the forecast expenditure.

It is noted that the Southdown Magnetite Mine (near Albany – December 2008) is not included in this forecast. If this project eventuates then network reinforcements in the order of $200M may be required.

Asset Replacement - Transmission

Asset replacement relates to the replacement of existing assets at the end of their useful life with a modern equivalent asset.

Figure 42 – Transmission – Asset Replacement- Capital expenditure

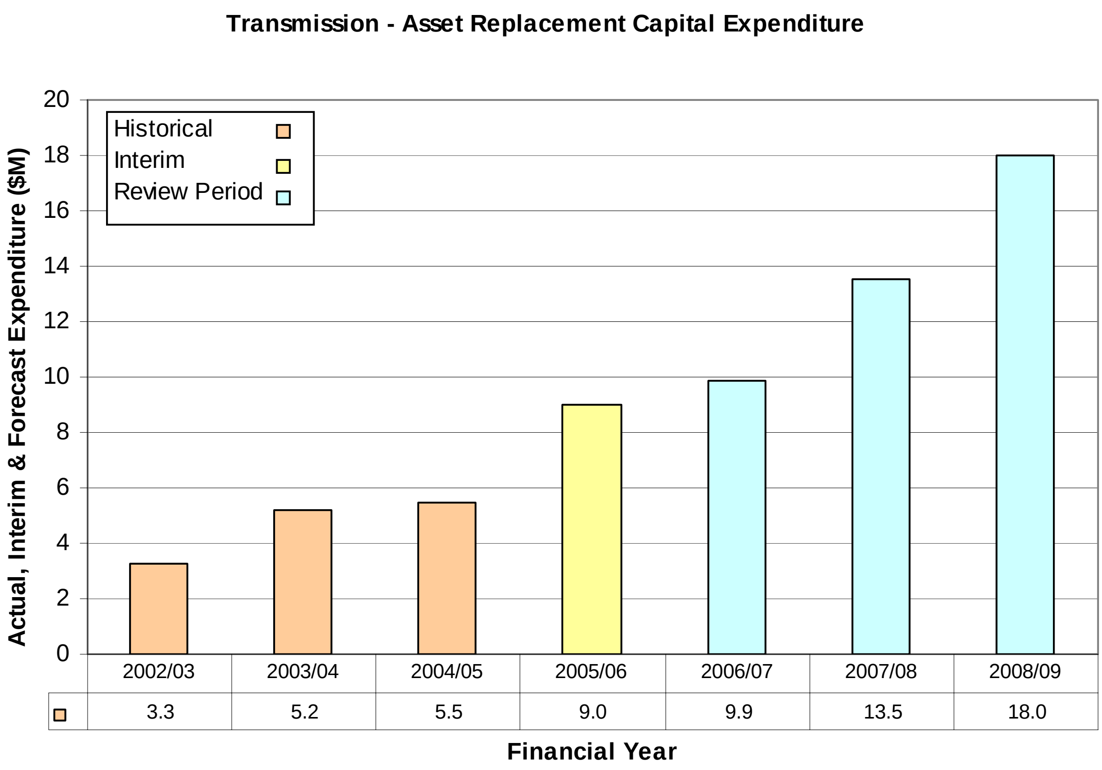


Figure 42 clearly shows a forecast increase in asset replacement expenditure compared with recent historical levels. To put this increase into perspective the gross replacement cost of the SWIS transmission network of $2.86 billion should be considered. Maintaining replacement expenditure at recent historical levels would indicate an average asset life in the order of 300 years which is unrealistic. The typical life for transmission assets is between 40 and 60 years, and as such, asset replacement expenditure at existing levels is clearly unsustainable without a significant impact on the performance of the network and operating expenditure requirements.

Key factors driving increasing needs

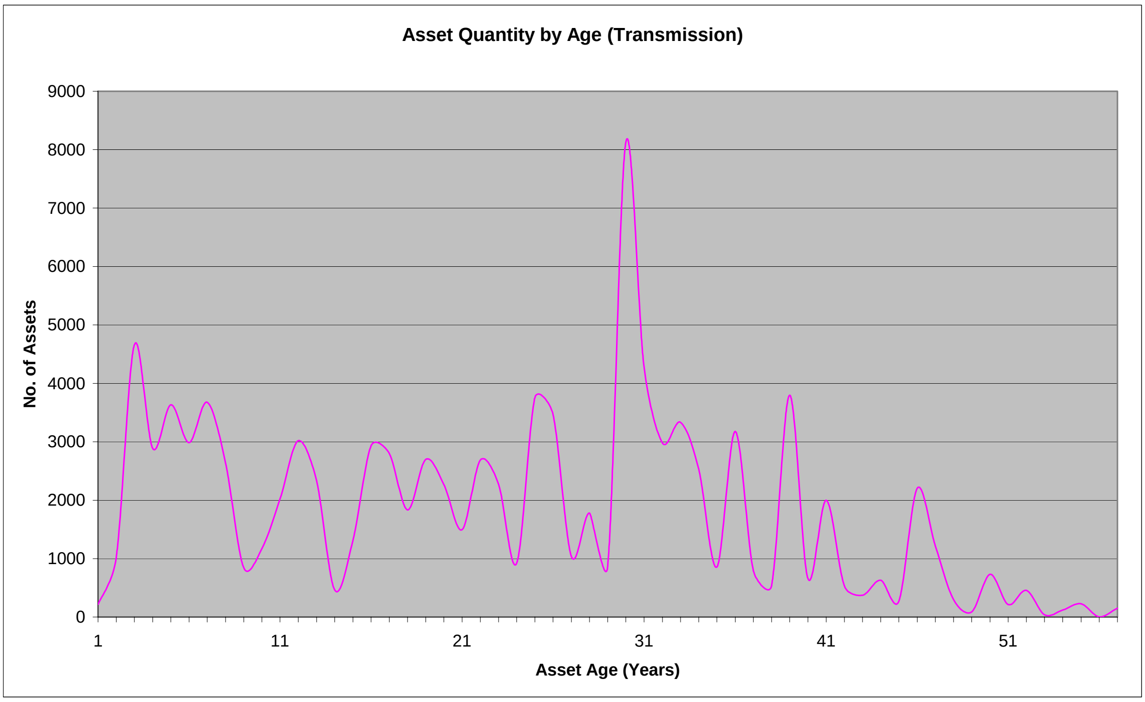
There are two main factors driving the need for an increase in expenditure:

- the age profile of assets in service based on their installation dates. This age profile predicts a wave of asset replacement is required which would parallel the historical installation dates of major asset categories; and

- the level of backlog of assets that are overdue for replacement but remaining in service on the network due to budget and resource constraints. This backlog and the associated risks to the network should be reduced.

The advancing age of the network indicates that within the next 10 to 15 years, Western Power will need to replace much greater volumes of assets than have been required to be replaced in the last ten years. Figure 43 shows an installation age profile for the transmission assets. This graph indicates the large number of assets that were installed around 30 years ago. Noting that transmission asset economic lives are generally in the order of 40-60 years, the graph indicates that Western Power is entering a period of increasing need for asset replacement and this correlates with the increased forecast expenditure levels.

Figure 43 - Transmission asset age profile



In addition to the network aging effect, budgetary constraints have contributed to the recent low levels of asset replacement and the lack of appropriate asset condition monitoring and tracking. This has resulted in increasing amounts of transmission assets remaining in service that are overdue for replacement. The increased backlog of assets due for replacement has increased the levels of assets at risk of in-service failure, the associated possibility of higher emergency replacement costs on failure, and also higher maintenance costs for the aging assets.

The transmission system operates to an N-1 regime, and as such, the failure in service of one component should not result in loss of supply to customers. However, as the levels of assets overdue for replacement increases, the risk[34] of loss of supply increases also. At a transmission level, due to the much greater scale of loss of supply, in some cases the economic risk costs of a loss of supply to customers can be the driving factor in the need for scheduled replacement.

Western Power does not consider the existing level of assets overdue for replacement to be prudent. The overarching philosophy of this asset replacement foreast is to improve network performance and reduce the existing levels of risk within Western Power to manageable levels. The Western Power plan is to “wind back” the existing level of assets overdue for replacement to a more prudent level over the three year regulatory period.

Process summary

In order to better monitor and record transmission asset information and condition, Western Power introduced the Transmission Investment Planning Database (TIPD). This database holds information on every transmission asset in the Western Power SWIS and can be used to forecast capital expenditure.
The basis of the methodology Western Power has applied to determine its asset replacement capital expenditure is detailed in the SWIS Transmission Network Asset Management Plan (TNAMP)[35].

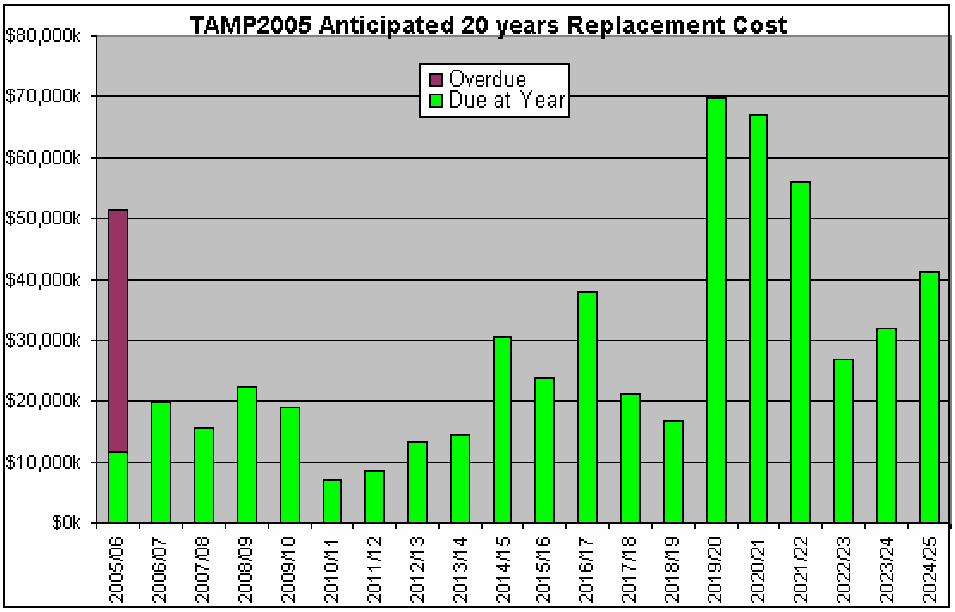
All assets are assigned an expected life by asset type[36], based upon the actual age of the asset a provisional remaining life can be defined. For primary substation plant, this remaining life is further adjusted based upon known historical defects within an asset population. Condition information from testing and inspections is also applied to adjust the expected life of the assets and hence the remaining life.

Based upon this analysis, the assets can be prioritised for replacement or further investigations. For all assets overdue for replacement (based upon the above analysis) and those predicted for replacement within the next five years, Western Power maintains paper files detailing the analysis of these assets[37].

Figure 44 shows the 20 year asset replacement forecast based upon the Western Power methodology. This graph clearly indicates the predicted rising trend in asset replacement requirements for transmission assets. The forecast indicates in excess of a ten fold increase over the next 20 years in asset replacement needs compared to recent historical levels ($3 to $5 million p.a.). The red bar in the first year indicates the level of assets that are currently considered overdue for replacement, this equates to approximately $40 million. Western Power is proposing to reduce the level of overdue assets during the review period to 60% of the existing level.

[34] Risk can be considered to be probability x consequence.
[35] DMS# 906804v7C – July 2004.
[36] Asset expected lives are provided in Appendix B of DMS# 906804v7C (TNAMP).
[37] The file reference for each asset type is detailed in DMS# 906804v7C (TNAMP).

Figure 44 - Transmission asset replacement forecast.



Discussion of forecast build-up

The Western Power forecast has been developed in three main categories, namely primary, secondary excluding 66 kV, and 66 kV. The 66 kV has been considered separately as this relates to the SWIS zone substation and sub-transmission system. There is a significant program to upgrade this 66 kV system due to load growth and capacity drivers, and as such, these assets have been analysed separately to allow a more detailed optimisation with the demand related augmentations.

Figure 45 and Figure 46 show a breakdown of asset capital expenditure during the review period for the non-66 kV primary and secondary assets. These figures show that primary plant capital expenditure is approximately twice that of secondary plant. The most significant asset groups being circuit breakers, current and voltage transformers, and surge arrestors.

Figure 45 - Primary (non 66 kV) asset breakdown.

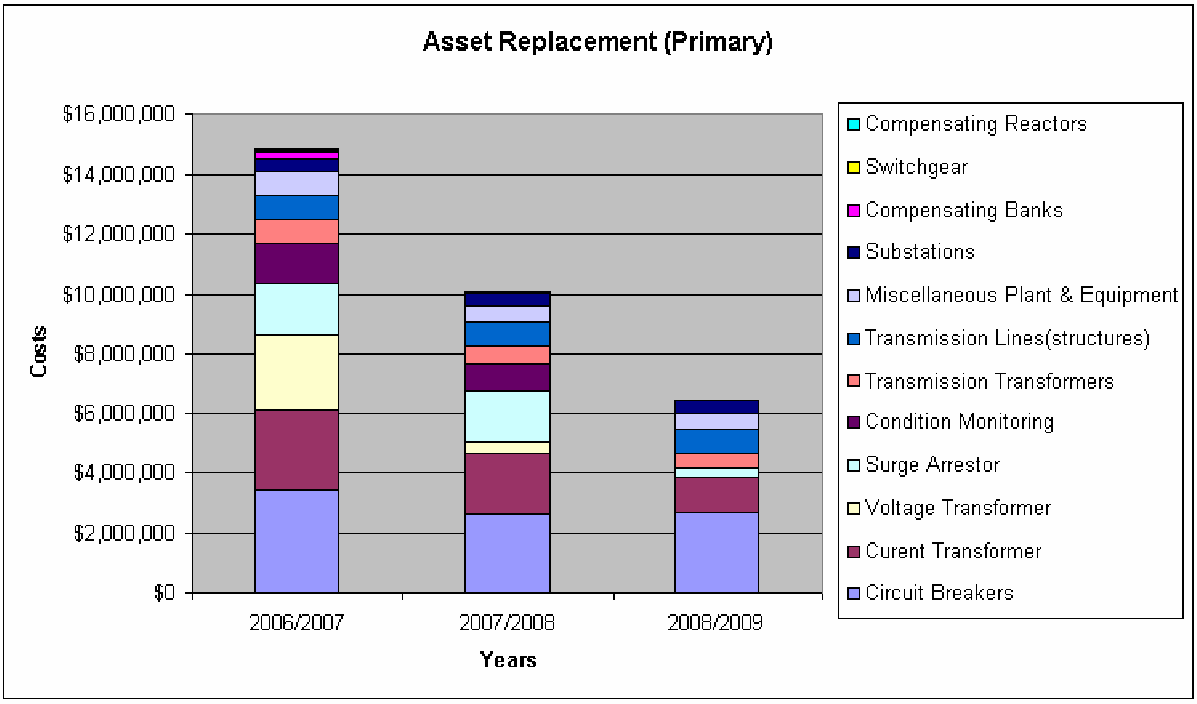
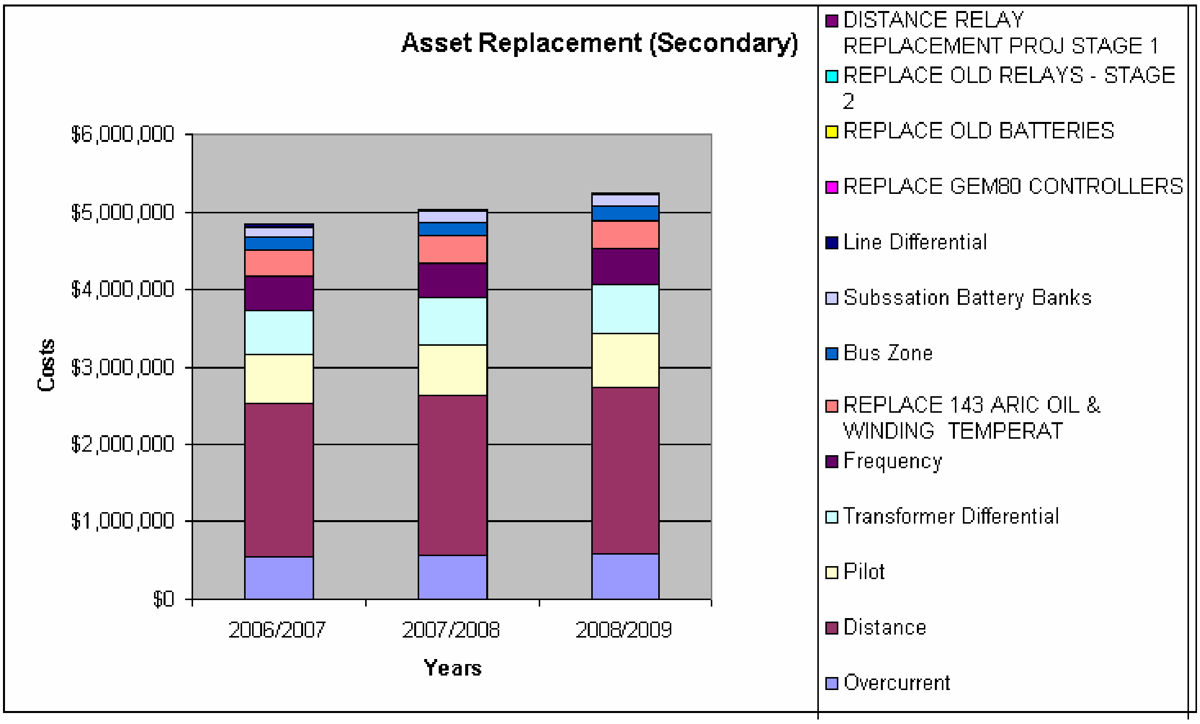


Figure 46 - Secondary (non 66 kV) asset breakdown



The Western Power long-term plan is to upgrade 66 kV zone substations to 132 kV to increase the capacity of this system. The condition of 66 kV substations has been assessed to determine substation replacement and upgrade requirements. This plan has been coordinated with system planning capacity upgrade requirements to determine the optimal replacement plan for this set of assets. The result of this joint planning is a deferment of $19.8M in asset replacement over a 5 year period.

Figure 47 and Figure 48 show a breakdown of asset capital expenditure during the review period for the 66kV primary and secondary assets. These figures show that primary plant capital expenditure is approximately twice that of secondary plant. The most significant asset groups being; circuit breakers, current transformers, transmission line structures, and overcurrent relays.

Figure 47 - 66 kV Primary

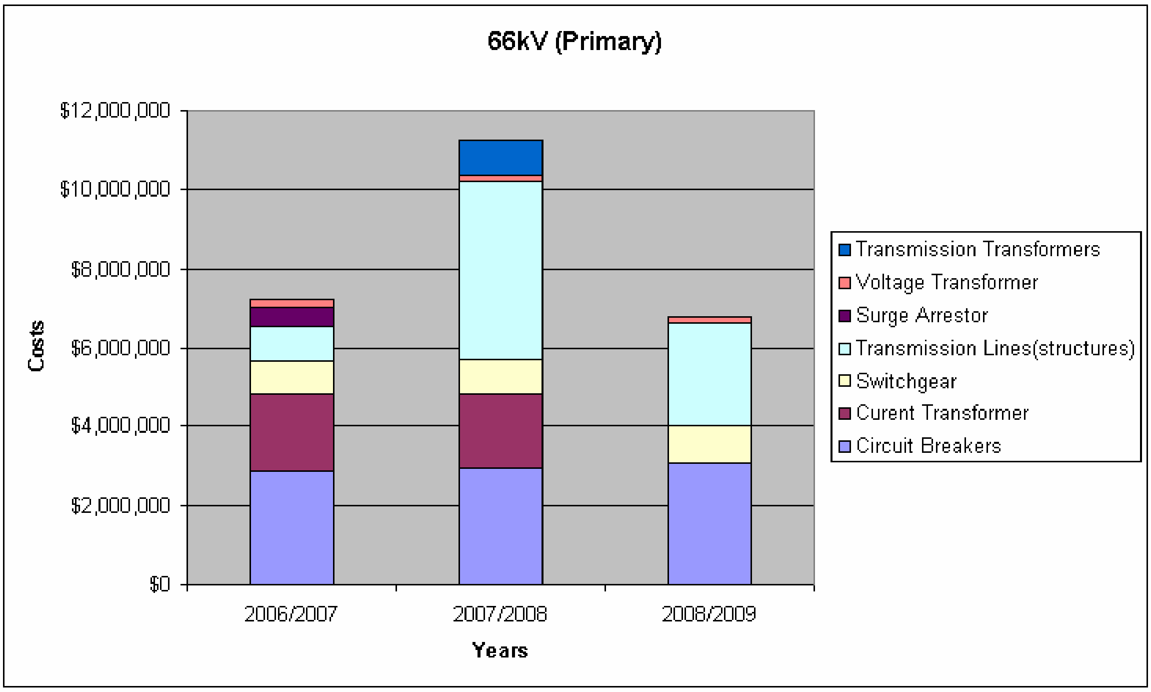
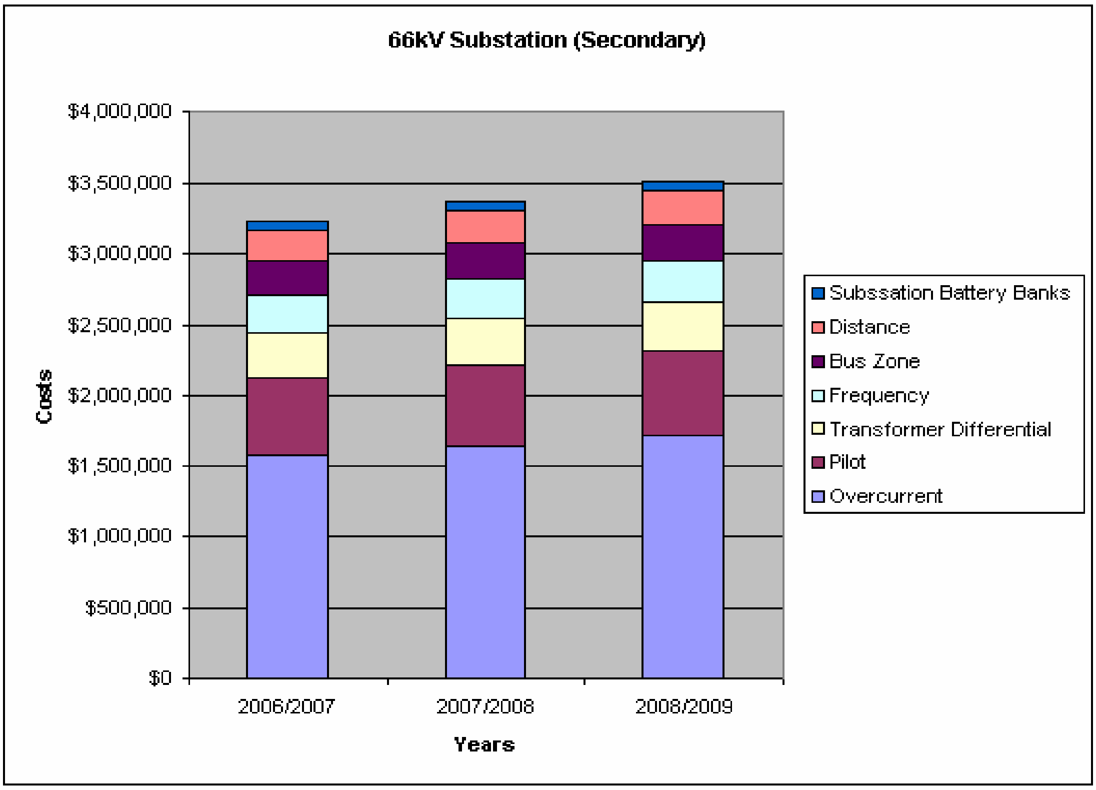


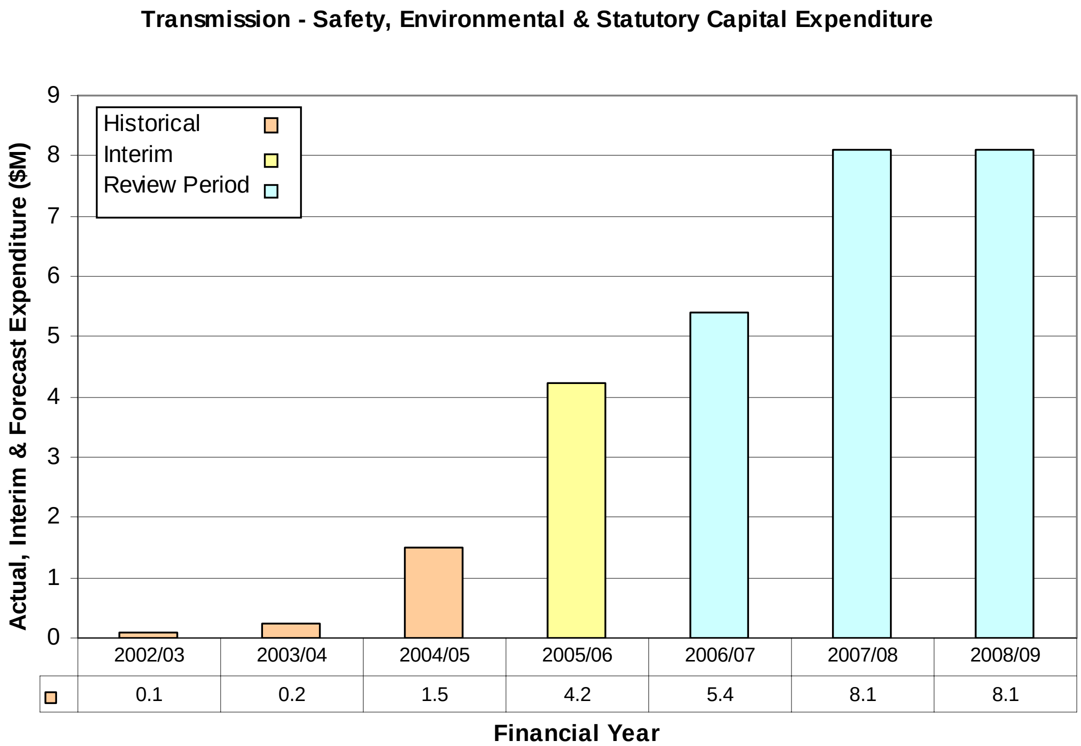
Figure 48 - 66 kV secondary



Safety, Environmental & Statutory

The capital expenditure in this expenditure category relates to meeting external obligations including technical and safety requirements. Figure 49 clearly shows a significant increase from recent historical expenditure levels. This increase is very much driven by specific needs due to new safety, environmental and regulatory requirements that will need to be met in the coming period. These specific projects and programmes are discussed in more detail in the section below.

Figure 49 – Transmission – Safety, Environmental & Statutory- Capital expenditure

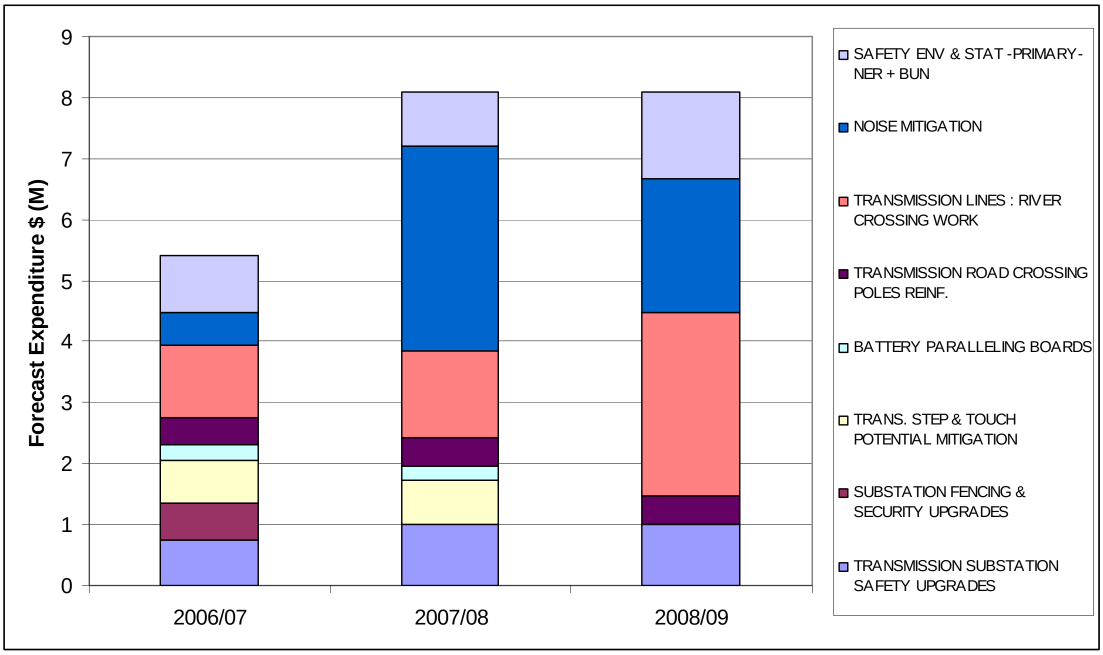


Programme breakdown

The majority of capital expenditure in the Safety, Environmental and Statutory category is due to health and safety related projects on the primary assets. Figure 50 shows the project level breakdown. This shows the major portion of this capital expenditure to be related to 5 specific projects:

1. Noise Mitigation;
2. Transmission line river crossing;
3. Transformer neutral earthing resistors and bunding (safety);
4. Transmission substation safety upgrades; and
5. Transmission step and touch potential mitigation.

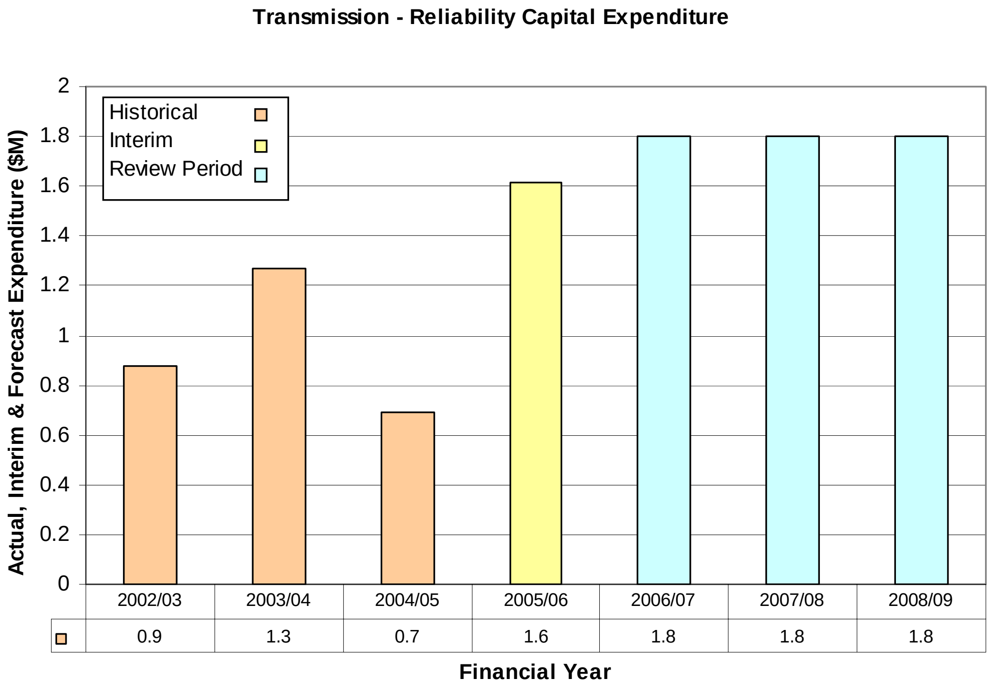
Figure 50 – Safety, Environmental and Statutory project breakdown



Reliability

Transmission reliability improvement programs have a forecast capital expenditure of $1.8M per annum during the regulatory period. The majority of this expenditure is for replacement and reinforcement of poles and crossarms. This work is specifically targeted to improve reliability.

Figure 51 Reliability Capital Expenditure

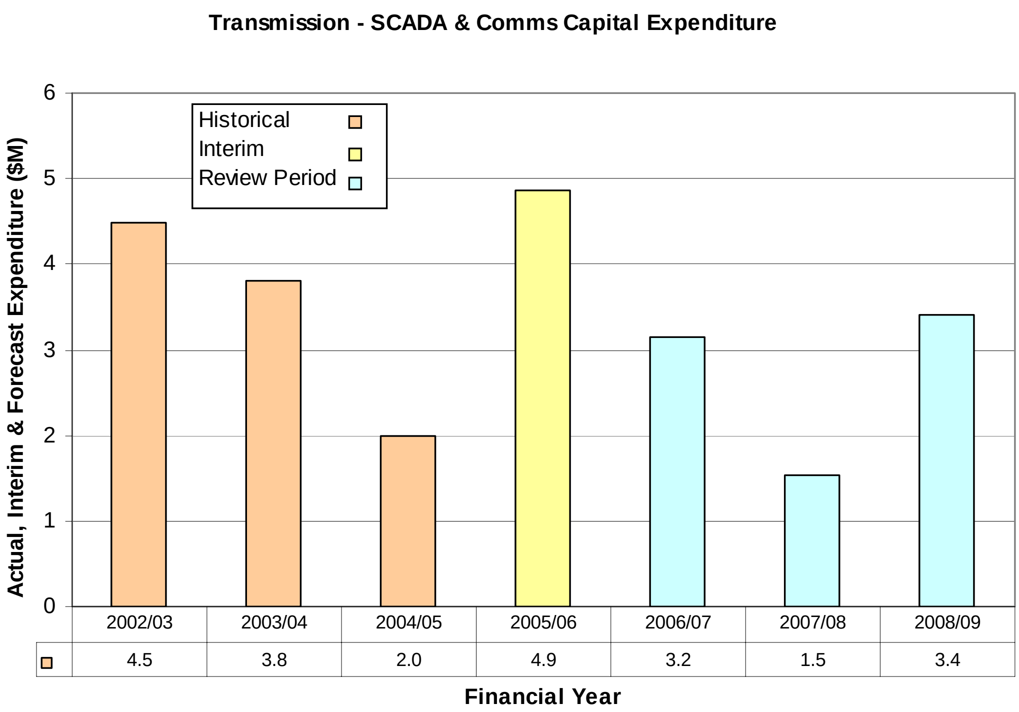


Scada & Communications

The projected capital expenditures in this category include all capital SCADA & Communication projects relating to safety and regulatory, asset replacement and strategic communications network enhancements which are necessary to ensure adequate reliability of these networks. Capital projects included are:

- Communications asset replacement projects (eg Teleprotection, DC Power Supplies, and Microwave Radio Bearers).
- Strategic communications projects which provide suitable capacity, reliability and availability (eg HO – EP and WT – NT wide bandwidth communications capacity).
- Projects which facilitate the transfer of high speed real time data for power quality, network analysis and condition monitoring (SEAL $1M over 4 years).

Figure 52 – SCADA & Communications Capital Expenditure



Due to the specialised technical nature of the SCADA and Communications projects, each project is individually designed and costed.
The SCADA and Communications Group has demonstrated its competitiveness on the open market, including the ability to design and project manage substantial SCADA and Communication projects.

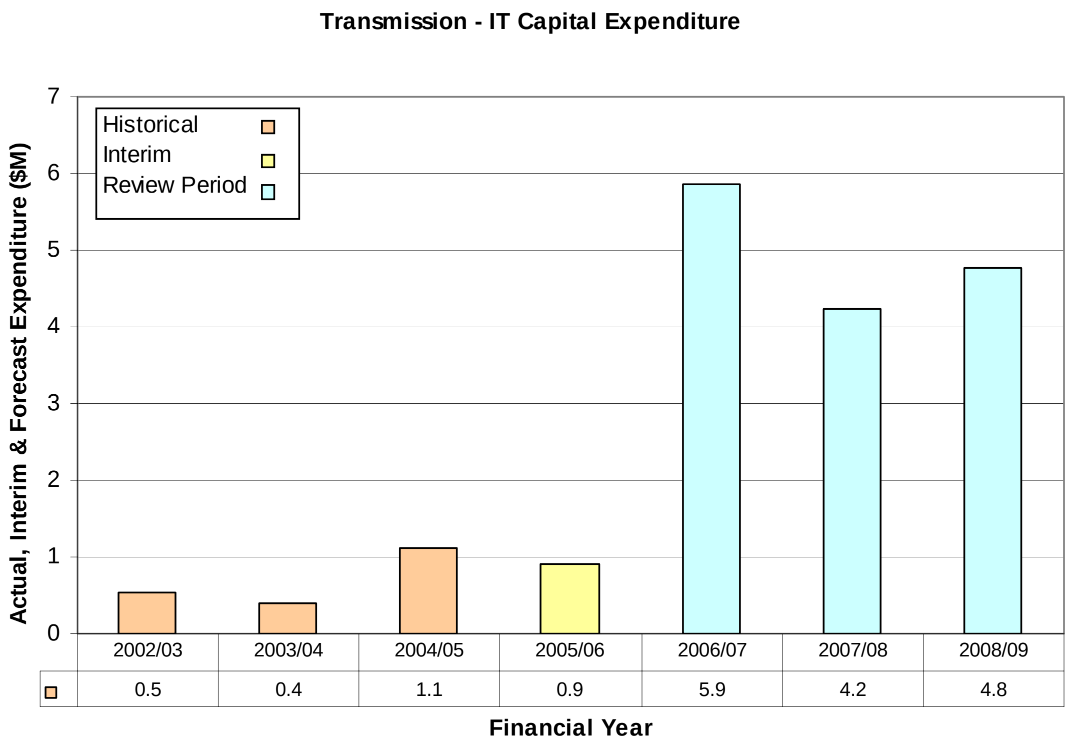
As the System Operator, Western Power is responsible for the reliability and stability of the entire SWIS. This responsibility requires and relies on the existence of a robust communications network interconnecting major terminals, generators and control centres. The SCADA and Communication Group provide this level of communication network reliability by installing and maintaining wide band self healing ring topologies between all the major centres. It mitigates the risk of these communication networks failing by the application of best practice asset management techniques to the essential infrastructure assets.

A well developed and maintained Strategic Asset Management Plan underpins the management of the SCADA and Communication infrastructure. Overall expenditure efficiency is supported by the fact that the SCADA and Communications Group provide specialist services to customers outside Western Power via competitive tendering processes.

Information Technology

The forecast IT expenditures include all Information Technology capital projects (excluding SCADA) and all capital purchases for printers, PDAs, software etc. The Western Power personal computer (PC) fleet is leased and the associated expenditures therefore appear as operating expenditures.

Figure 53 Information Technology Capital Expenditure



Electricity market design[38] requires that System Management is ring-fenced and it is expected to have significant Information Technology reform costs to meet wholesale market needs.

The forecast expenditures are required to increase above present levels based on a number of key drivers;

[38] KEMA Consulting 4th November 2003

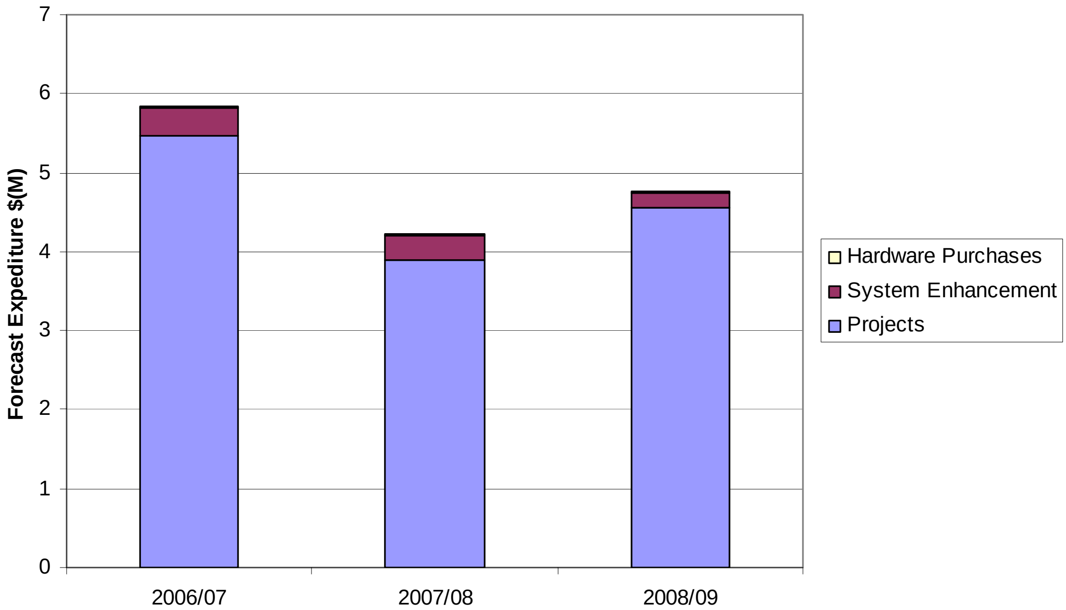
- **Regulatory Project Plan Completion Projects & Business Strategic Project Plan** - Expenditure associated with market reform projects, replacement of existing Information Technology systems as they approach or have passed the end of their economical and useful life, and

- **Application Enhancements** – Modifications of existing systems to maintain regulatory and operation function and compliance, and

- **Hardware Purchases** - A return to sustainable maintenance levels following a period of constrained expenditure.

Figure 54 provides a breakdown of the relative contributions of the above drivers to the overall transmission capital expenditure forecasts.

Figure 54 - Information Technology Transmission Capital Expenditure



<u>Regulatory Project Plan</u>

A number of reform projects are associated with the implementation of government directives to establish Western Power as a separate corporation and facilitate competition and open access in line with federal COAG directives. These directives cover both Distribution and Transmission and can be summarised as Interface to the Interim Market & Transitional Provisions. The works required include the planning, development and implementation of an information access portal that provides information sourced from operational systems to meet the Interim Market & Transitional Provisions as at July 2006.

<u>Strategic Project Plan</u>

Over the past 2-3 years, Western Power Corporation's (WPC) and Network's Business Unit charter and strategic direction have been significantly impacted by the State's Electricity Reform agenda. A number of major IT&T initiatives have been deferred whist Reform projects were planned and implemented. These deferments include upgrades or replacements of a number of major Information Technology systems. A number of these systems are 10-12 years old or greater, well in excess of industry norms.

The existing IT&T infrastructure is predominantly legacy, including platforms and software that, in some cases, constrains flexibility and presents a risk to business continuity.

As a consequence of the anticipated business and energy market environment, Information Technology functions/ processes will need to be upgraded to support the emerging business model.

Maintenance and Hardware Purchases

IT&T expenditure has come through a recent history of imposed budget constraints and a deferred disaggregation program that limited opportunities to implement strategic IT&T initiatives.

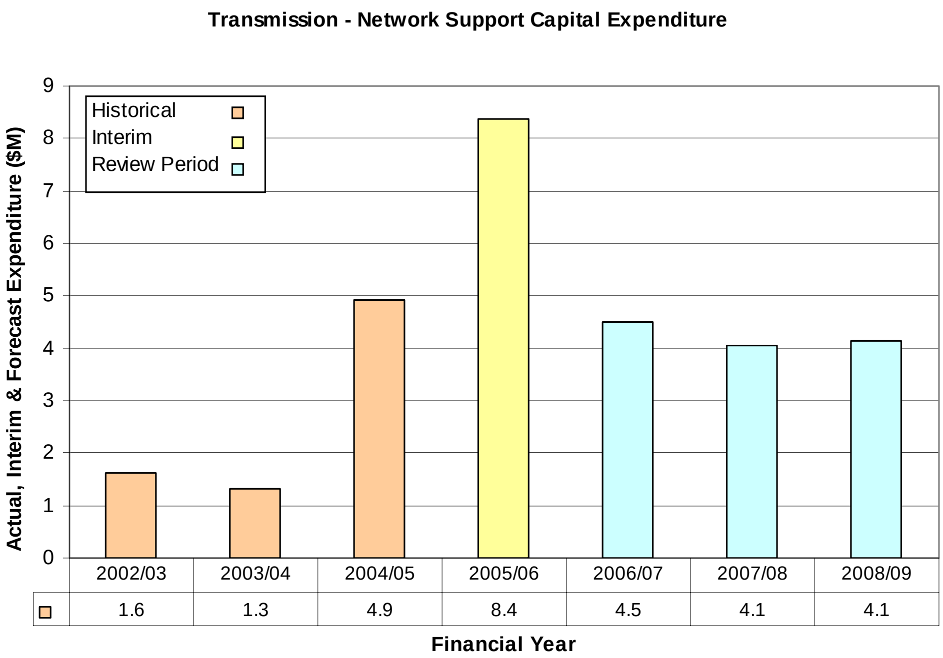
The base levels of IT&T maintenance and hardware purchases projected for the regulatory period are consistent with the ongoing expenditures associated with maintaining network Information Technology systems.

Support

The Transmission Support capital budget includes expenditure requirements for capital items to support and maintain office and depot accommodation. Budget items include refurbishment and enhancement of office and depot accommodation, establishment of new accommodation where required, tools and equipment required for construction, commissioning and maintenance functions and labour costs for the management of the capital works processes and programs.

An average expenditure of $4.2M per annum has been forecast which is in line with recent historical expenditure levels (excluding Reform related expenditure).

Figure 55 Network Support Capital Expenditure.

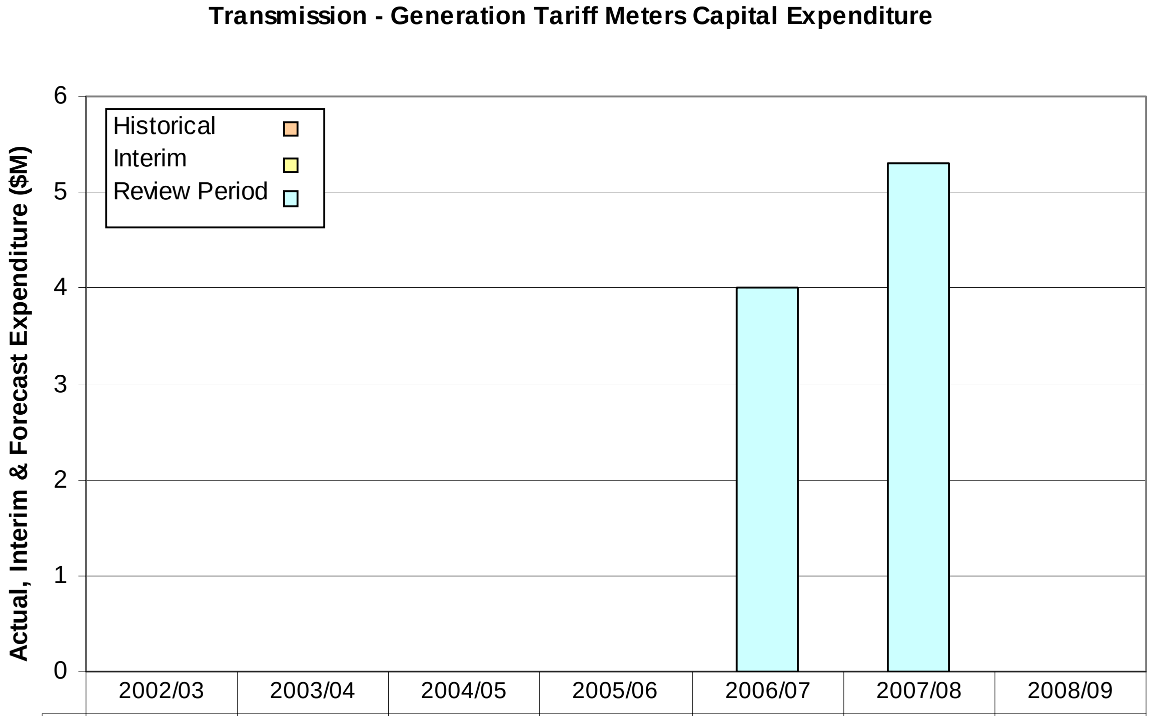


Generation Tariff Meters

Western Power will be required to install revenue class metering at various major generation sites in Western Australia to comply with the Metering Code 2005 and allow operation of the energy market. It is essential to have accurate measurement of generation output for financial and market management purposes.

The project covers the design, specification, procurement, contract supervision, installation and commissioning of metering plant associated with the installation of tariff metering for generation assets. The forecasts are based on an assessment of the number of installations required and the potential requirement for substation works at some locations to accommodate the metering facilities.

Figure 56 Generation Tariff Meters Capital Expenditure



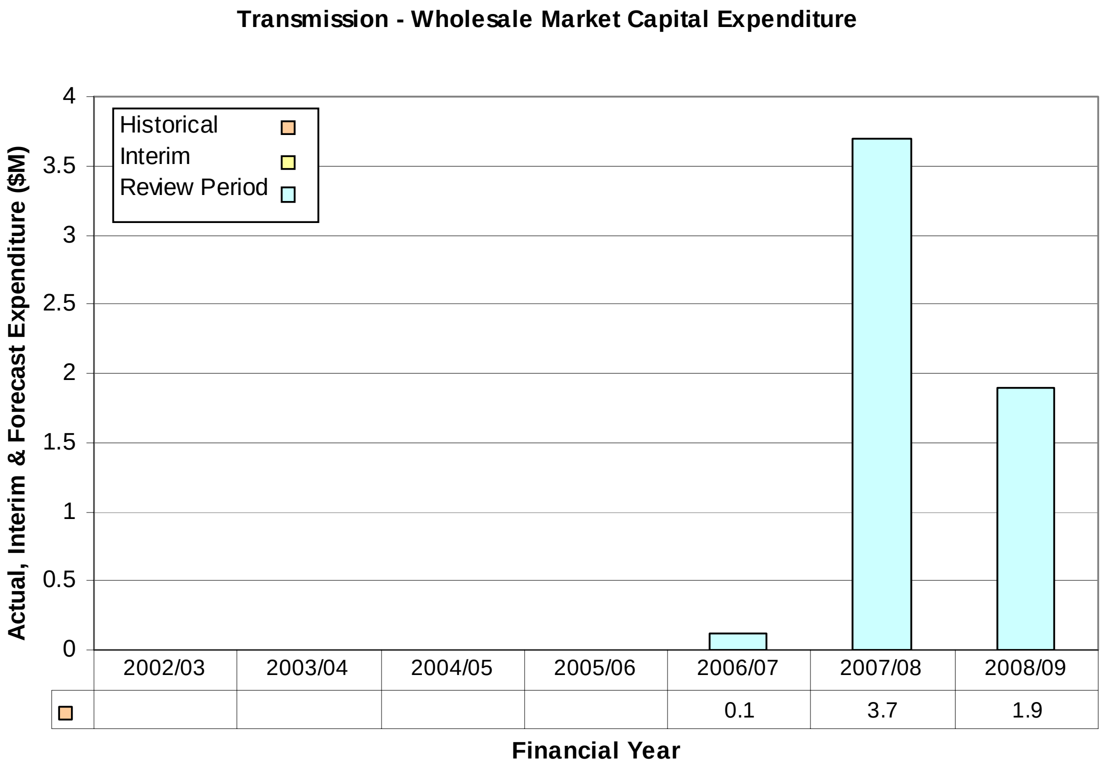
	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
					4.0	5.3	-

Wholesale Market

A full wholesale electricity market is scheduled to be in place for Western Australia in July 2008. A budget of $5.7M during the regulatory period has been forecast to enable the planning, development and implementation of Western Power's information systems to meet the full wholesale market requirements. As the exact requirements are yet to be defined, these forecasts are budget estimates.

Western Power expects that this is likely to include a package solution for a balancing/bidding system to manage generation scheduling, as well as replacement of existing systems including Margins (Generation outage scheduling) and NOIW (Notice of Intention to Work).

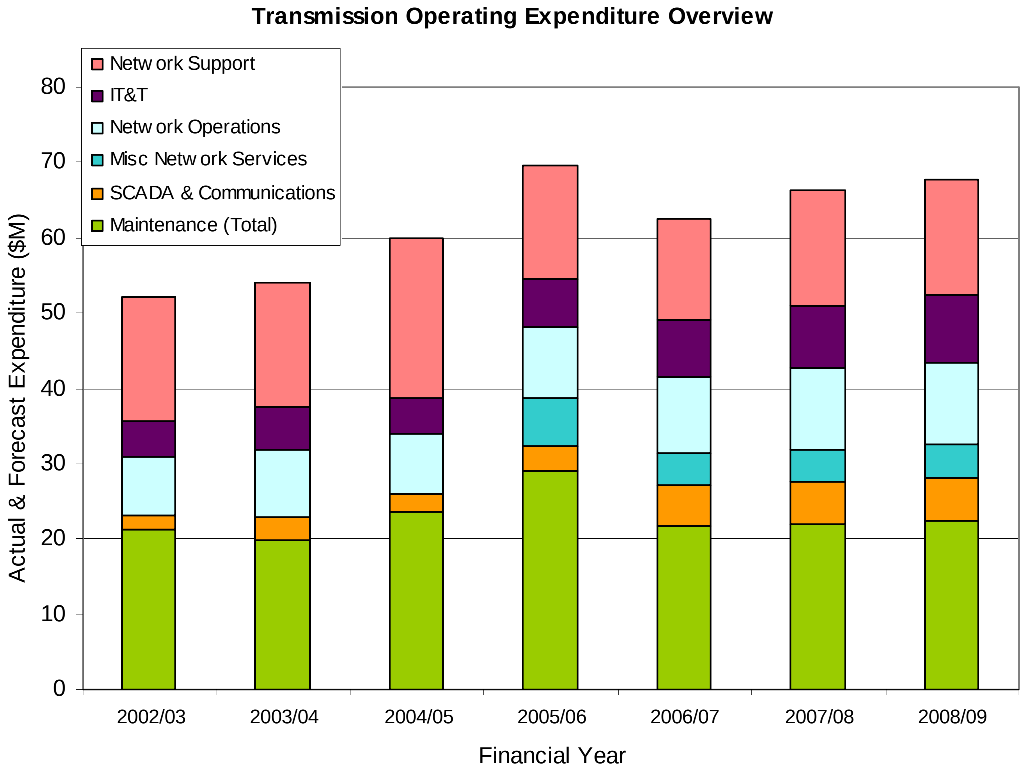
Figure 57 Wholesale Market Capital Expenditure



7. Transmission Forecast Operating Expenditure

Operating expenditure is required for all maintenance and operational activities for the Western Power transmission business. Operating expenditure has been forecast against a number of categories including maintenance (corrective and preventive), SCADA and Communications, Network Operations, IT, and network Support. Figure 58 shows a graph and table detailing the forecast operating expenditure levels for the regulatory period.

Figure 58 - Transmission Operating Expenditure



	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
Maintenance Strategy	2.5	3.8	3.8	3.6	4.0	4.1	4.2
Preventative Condition	5.9	5.9	7.0	10.0	6.1	6.2	6.4
Preventative Routine	7.8	6.6	7.9	10.1	8.4	8.6	8.8
Corrective Deferred	3.1	2.9	3.7	4.0	2.3	2.1	2.0
Corrective Emergency	2.0	0.6	1.1	1.4	1.0	0.9	0.9
Maintenance (Total)	**21.3**	**19.8**	**23.5**	29.1	**21.8**	**21.9**	**22.4**
SCADA & Communications	1.9	3.1	2.4	3.2	5.4	5.6	5.7
Misc Network Services				6.4	4.2	4.4	4.5
Network Operations	7.7	8.9	8.2	9.5	10.0	10.9	10.9
IT&T	4.8	5.7	4.6	6.3	7.5	8.2	8.8
Network Support	16.4	16.4	21.3	15.1	13.6	15.2	15.5
Transmission ($M)	**52.1**	**53.9**	**60.0**	**69.6**	**62.6**	**66.2**	**67.8**

Western Power is proposing to increase average transmission operating expenditures by 11%, to $65.5M, per annum during the regulatory period compared with the average expenditure level of $58.9M from 2002/03 to 2005/06. This increase is in response to a number of key drivers that are already or will impact the business over the next 3-5 years.

The drivers for change are;

1. **Regulatory compliance** - particularly relating to the need for additional network inspections and associated follow-up maintenance work to meet prescribed maintenance standards;

2. **Safety** - Public safety and also includes bushfire mitigation programs for vegetation management;

3. **Whole of Life Efficiencies** - Longer term efficiencies in "whole of life" costs for network assets. Improved preventive maintenance programs have been introduced to achieve an optimal balance between maintenance and asset lifecycle costs. These programs are expected to allow Western Power to extend the operational lives of some assets whilst minimising service interruptions and corrective maintenance costs;

4. **Corporate Support** - Additional corporate support required to service the increased capital and maintenance resources proposed, as well as accommodate the needs of the newly formed Western Power business;

5. **Insurance** - Additional insurance costs resulting from a tightening market and the impacts of further regulatory restructuring and reforms.

The following sections provide a breakdown of the transmission operating expenditure cost categories.

As noted in the executive summary of this report, Western Power has undertaken a detailed review of resource availability over the forecast period and has determined a realistic, deliverable expenditure plan. There are a number of other maintenance related activities that Western Power would carry out if resource availability allowed, however maintenance programs have been prioritised to ensure the most critical and cost effective activities are included in this deliverable work plan.

The information and analysis contained in the subsequent sections of this chapter describes the maintenance activities required to satisfy the key business drivers.

Network Maintenance

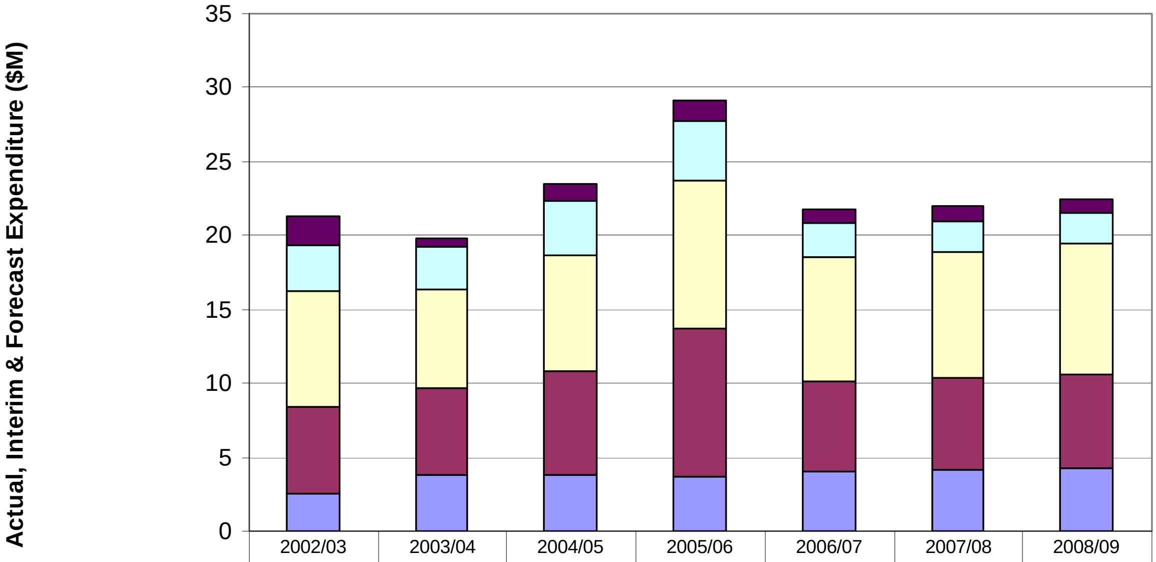
Network maintenance costs are reported under five key groupings of:

- Preventive Routine
- Preventive Condition
- Corrective Deferred
- Corrective Emergency
- Maintenance / Strategy

Each of these groups is further dissected in the management accounts into specific work areas to enable tracking of individual jobs and work orders.

Projected transmission network maintenance costs are shown in Figure 59.

Figure 59 – Projected Transmission Maintenance Expenditures ($M)[39]



	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
Corrective Emergency	2.0	0.6	1.1	1.4	1.0	0.9	0.9
Corrective Deferred	3.1	2.9	3.7	4.0	2.3	2.1	2.0
Preventative Routine	7.8	6.6	7.9	10.1	8.4	8.6	8.8
Preventative Condition	5.9	5.9	7.0	10.0	6.1	6.2	6.4
Maintenance Strategy	2.5	3.8	3.8	3.6	4.0	4.1	4.2

Figure 59 shows overall decreases in average forecast expenditure of $1.39M compared with the average expenditure levels from 2002/03 to 2005/06. This represents approximately -6% decrease during the regulatory period. In real terms, therefore, transmission maintenance costs are forecast to fall over the period. The key nominal increases in costs occur in preventive maintenance and maintenance strategy and these are largely offset by anticipated reductions in corrective maintenance which are expected to decrease over the period as a result of strategically targeted preventive maintenance programs.

The increases in preventive maintenance program areas are targeted to achieve future benefits through:

- Reduced corrective maintenance costs (supply restoration);
- Fewer outages and subsequent improved SAIDI results;
- Improved public and staff safety;
- Environmental benefits;
- Compliance with regulatory requirements.

These expected benefits are discussed within each of the key maintenance areas. In addition, maintenance costs will generally rise in line with the addition of assets

39 Note that these figures include street lighting maintenance.

to the network and increases in average unit rates relating to changes in labour rates and contractor costs.

Preventive Routine

Preventive Routine Maintenance is the proactive maintenance carried out to reduce the probability of failure or the performance degradation of an item and is targeted to occur just prior to the expected need for corrective work. The activities include the monitoring or maintenance of equipment that is carried out at predetermined intervals. This work is generally of short duration and typically includes visual inspections, some lubrication regimes and routine minor part replacement.

The following table sets out the quantities of transmission assets which are covered through maintenance programs.

Figure 60 - Transmission Line Primary Asset Quantities

	Voltage				
	66kV and below	132kV	220kV	330kV	Total
Conductor Length	1,264	3,814	655	795	**6,528**
Structures					
Concrete	66	1,490			**1,556**
Lattice	77	2,231	1,607	2,346	**6,261**
Tubular	1,540	3,522	2		**5,064**
Other non-wood	239	499	10	11	**759**
Wood	7,718	17,393			**25,111**
Aux Structures	572	8,466			**9,038**
Total	**11,476**	**37,415**	**2,274**	**3,152**	**54,317**

In addition to these assets there is a small amount (22km) of underground cable.

Western Power's substation asset quantities are shown in the following table.

Figure 61 -Substation Primary Asset Quantities

	Voltage				
	66kV and below	132kV	220kV	330kV	Total
Power Transformers	1,122	183	11	13	1,329
Circuit Breakers	1,403	507	17	32	1,959
Disconnectors	4,975	3,158	111	327	8,571
Reactors	514	15			529
Capacitors	238	5			243
Current Transformers	2,340	1,485	72	117	4,014
Voltage Transformers	393	759	36	86	1,274
Surge Arrestors	539	875	33	150	1,597
Other Primary Assets	255	90	4	20	369
Total	11,779	7,077	284	745	19,885

As the above tables show, wood poles represent a significant proportion of maintainable transmission line items. Pole inspections and maintenance therefore form a key component of the asset maintenance strategy for Western Power. The remaining 22,000 structures consist of a range of largely steel and concrete arrangements.

Transmission Outages

Preventive routine expenditures have decreased from 2003 levels but are planned to increase significantly in 2006. These increases are required in order to achieve overall network performance improvements as well as to address the key controllable outage areas and to manage the safety, environmental and regulatory risks faced by the business. Budgetary constraints in past years have not enabled Western Power to achieve full inspection programs which has led to greater risks of equipment failure as well as increased safety and operational risks. Western Power has formulated programs for increased asset inspections which are targeted to provide more timely information for undertaking rehabilitation works prior to assets failing. The key Preventive Routine programs proposed are listed below:

Substation Primary Plant Maintenance

This activity includes maintenance of switchgear, disconnectors, transformers and other associated transmission primary plant in order to meet the requirements specified within the asset missions.

Line Patrol / Pole Top Inspection

This activity covers all transmission lines each year, and includes the inspection of overhead lines and pole top hardware from EPVs, helicopters or light aircraft. These patrols are necessary to ensure that Western Power meets its regulatory requirements as well as reducing the potential risks of fire, outages or injury to staff and the public. These inspections help detect sagging or aged conductors or poor condition pole tops so that action can be taken prior to equipment failure.

Substation HV Equipment Testing

This activity includes routine maintenance and electrical testing of CTs, VTs, CVTs, SAs and indoor switchboards in order to meet the defined asset mission criteria.

Line Washing / Insulator Silicone

This activity includes the washing of line insulators from elevated platform vehicles (EPV) or helicopters. This covers most critical transmission lines close to the coast to reduce the number of outage incidents. Western Power has experienced a significant number of supply interruptions caused by flashovers and pole top fires resulting from the accumulation of pollutants on insulators and conductors. The silicone coating of insulators will be re-applied every 3 to 5 years to maintain the appropriate condition of the insulators.

Line Easement Vegetation Maintenance

This activity covers the clearing of vegetation infringing clearance zones under transmission lines that have been identified from inspections or other preventive routine maintenance activities. This clearing is intended to reduce exposure to bushfires and reduce the number and severity of system interruptions. Recent surveys have indicated that vegetation has encroached on minimum clearances and this has contributed to a number of outage incidents. Western Power has formulated new vegetation management contracts to effectively manage these risks.

Plant Modification and Refurbishment

This activity includes any works to bring plant up to an acceptable condition and meet new compliance requirements, as identified from reviews and inspections. Some examples include re-clamping windings on specific transmission power transformers, removal of redundant transmission lines and refurbishment of transformers (66kV).

Preventive Condition

Preventive Condition Maintenance costs relate to the follow-up activities performed as a result of work identified through preventive routine maintenance programs.
Preventive Condition costs are expected to increase substantially in 2007 as a result of additional follow-up work identified through increased inspections and a catch-up of the backlog. However these costs should remain stable over the regulatory period as the benefits of more frequent inspections begin to be realised and the backlog is removed.

Western Power is continuing to analyse this area of its maintenance expenditure projections in order to ascertain rigorous data on the relationships between maintenance inspections and follow-up work so that inspection programs can be continually optimised.

The sum of Preventive Routine and Preventive Condition maintenance projections is shown in the following table.

Figure 62 – Projected Preventive Maintenance Expenditures ($M)

	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
Preventive Routine	7.8	6.6	7.9	10.1	8.4	8.6	8.8
Preventive Condition	5.9	5.9	7.0	10.0	6.1	6.2	6.4
Total Preventive	13.7	12.5	14.9	20.1	14.5	14.8	15.2
% Change compared to previous year		-8.8%	19.2%	35.0%	-27.9%	2.3%	2.8%

The above table shows substantial overall decreases in preventive maintenance between 2003 and 2004, followed by significant increases proposed for 2005 and 2006 followed by a levelling of expenditure over the remainder of the regulatory term. These proposed expenditures are intended to establish a consistent program for preventive maintenance over the regulatory period which places appropriate importance on maintaining preventive programs to preserve and maximise the operational lives of network assets. The proposed increases in 2005 and 2006 reflect the implementation of the new preventive maintenance programs.

Corrective Deferred

Corrective Deferred Maintenance includes those activities that are scheduled to repair failed or damaged equipment but which no longer presents an emergency situation. These works usually arise following an emergency supply restoration where the supply is restored and/or the situation has been made safe and crews can be scheduled to complete the work at a later stage.

As shown in Figure 59, historical levels of corrective deferred expenditures reduced between 2003 and 2005, spiked in 2006 and are projected to further decrease in real terms from 2007 onwards. These reductions reflect to some extent the vagaries of corrective maintenance which are somewhat dependent on unpredictable events such as storms, bushfires and equipment failures. It is not expected that the periods of lower corrective maintenance will continue, despite concerted efforts proposed to lift inspections and preventive maintenance. Western Power is projecting a slight decrease in Corrective Deferred expenditures during the regulatory period then remain relatively stable.

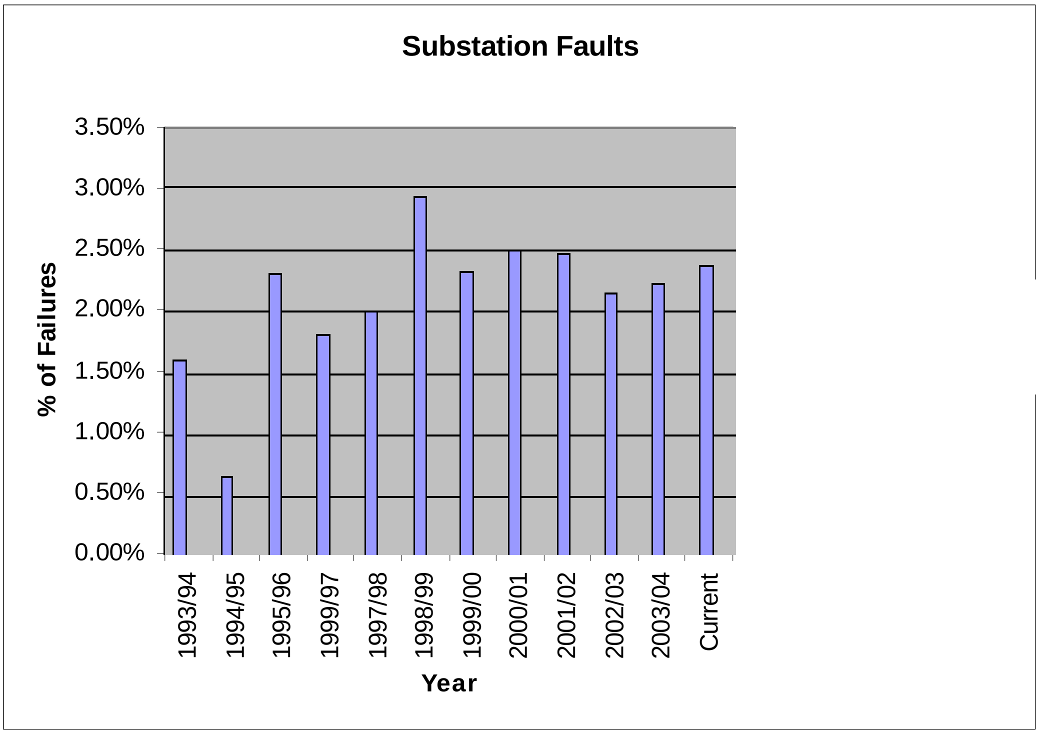
Corrective Emergency

Corrective Emergency maintenance includes those maintenance activities carried out to immediately rectify an equipment failure and/or to make the site safe following an incident. This type of work generally occurs without warning and is performed immediately to ensure safety of the public and personnel, prevent further damage to equipment or degradation of system performance and to return supply to customers.

Western Power is projecting for expenditures on Corrective Emergency to reduce from an average of $1.3M from 2002/03 to 2005/06 to an average of $1.0M during the regulatory period. These reductions are premised on increases in preventive maintenance programs such as additional line inspections, increased vegetation management, insulator washing and silicone treatments. The proposed nominal reductions provide challenging targets for Western Power and reflect our commitment to improving network performance for customers. Western Power has investigated the causes of emergency maintenance costs where possible and has identified key areas where preventive programs can be cost effective. Network outage figures indicate that primary causes of emergency maintenance costs relate to storms, equipment failures, pole down, pole top fires and trees and vegetation.

Western Power is now in the process of identifying the corrective maintenance costs associated with these outages to enable preventive maintenance programs to be tailored to achieve an optimal commercial and service level outcome. Information on substation faults, for example are shown in the chart following.

Figure 63 – Historical Records of Substation Faults



As the above chart shows, substation faults were trending down during the period 1999 and 2003, however 2004 and the current year appears to have altered that trend. The programs proposed for Substation HV Equipment Testing and Substation Primary Plant Maintenance are designed to address these issues.

Similarly, information on circuit breaker defects has been recorded as per the following figure.

Figure 64 - Historical Records of Circuit Breaker Defects

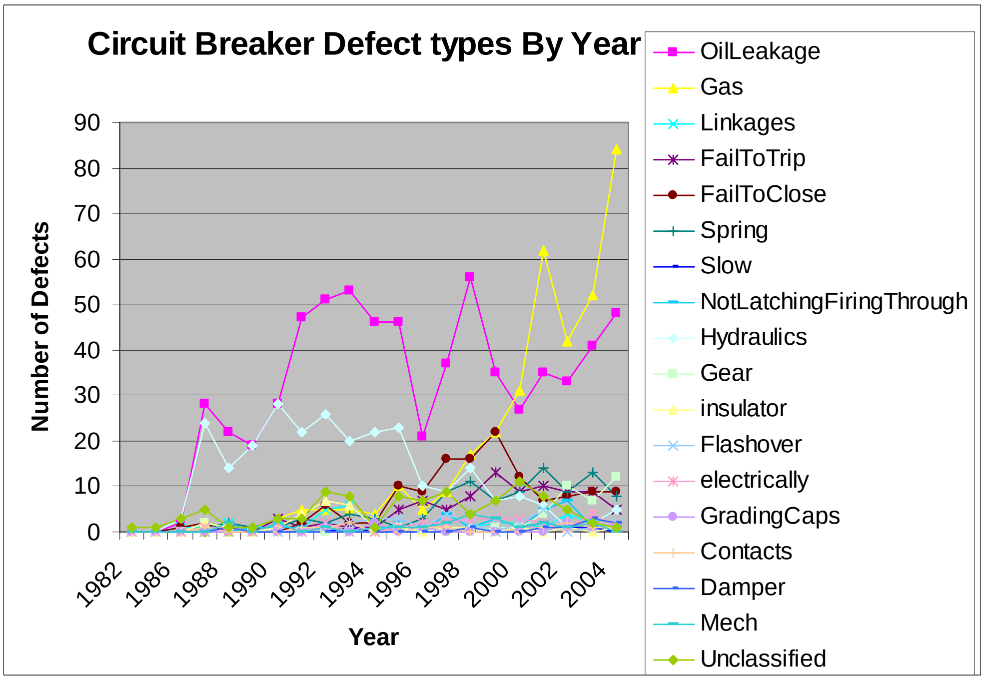


Figure 64 shows the trends for a number of key items. In particular, gas filled CB's have recently displayed a marked increase in the number of incidents which reflects both the quantities in service and issues relating to the characteristics of these items. Western Power is in the process of identifying the causes of these defects so that appropriate measures can be undertaken to manage these faults.

The sum of corrective maintenance costs is shown in the following table.

Figure 65 - Historical and Projected Corrective Maintenance Expenditures ($M)

	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
Corrective Deferred	3.1	2.9	3.7	2.0	2.3	2.1	2.0
Corrective Emergency	2.0	0.6	1.1	1.0	1.0	0.9	0.9
Total Corrective	5.1	3.5	4.8	3.0	3.3	3.0	2.9
% Change		-31.5%	38.2%	-37.9%	9.9%	-9.0%	-1.8%

As the above table shows, corrective maintenance levels in 2008/09 are below actual 2002/03 levels in nominal dollars. This decrease represents a challenging target for Western Power which we believe is achievable barring major storm, bushfire or other uncontrollable incidents. It should be noted, however, that these projections do not incorporate any allowance for unexpected and infrequent major contingencies such as one in ten year events.

Maintenance Strategy

This cost area is a relatively new initiative for Western Power. Theses costs relate to the management of asset strategy development as well as short duration specific projects or asset evaluations which are targeted to assess opportunities for improving the management of assets through strategic initiatives. The expenditures shown in Figure 59 indicate that Western Power is projecting to increase costs in this area of 19% compared with the average expenditure during the 2002/03 to 2005/06 period. This increase is premised in a similar fashion to preventive maintenance programs, in that they are designed to deliver benefits through reduced whole of life asset costs and improved service and network reliability levels.

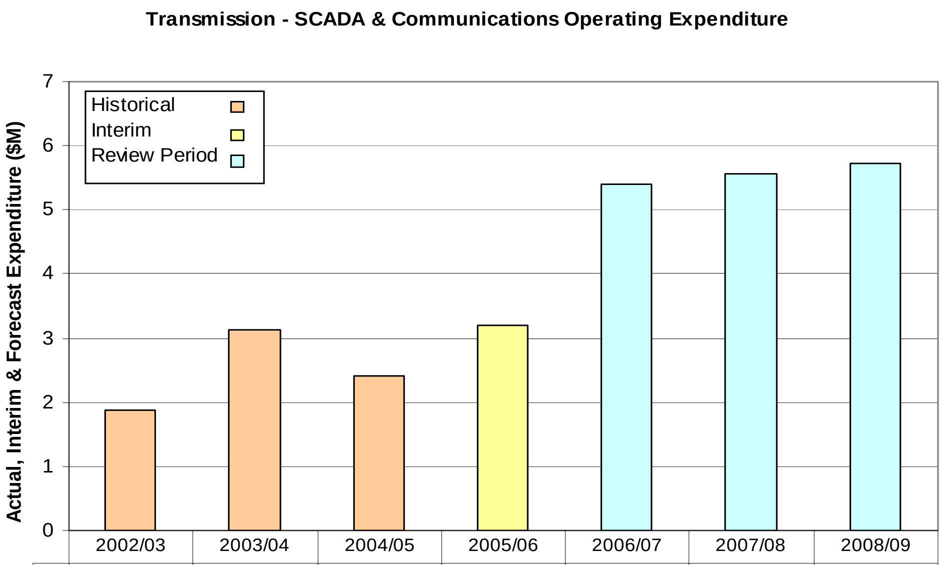
Western Power believes it is essential that strategic asset management receive this level of attention so that the business can continually identify efficiency and network performance opportunities that improve services for customers. When these costs are viewed in conjunction with other preventive maintenance expenditures and the anticipated performance and cost benefits which have been proposed, Western Power is confident that these costs are soundly justified.

Scada & Communications

The SCADA and Communication Systems Strategic Asset Management Plan 2005/2006 was recently reviewed by an independent consultant and Western Power believes that the Asset Management Plan currently provides "best practice" asset management of the SCADA and Communication assets by optimising asset lives whilst minimising operating costs and providing high levels of reliability and availability.

Western Power's historical, interim, and projected operating expenditures over the review period for transmission SCADA and communications are detailed in the chart below. The data indicates an increase in operating expenditures between 2004/05 and 2005/06 followed by a forecast expenditure that remains fairly steady during the regulatory period. The increase is due to the large number of SCADA and Communications facilities currently being installed and proposed to be installed associated with the transmission works described in other sections of this report.

Figure 66 - SCADA & Communications Expenditure



	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
	1.9	3.1	2.4	3.2	5.4	5.6	5.7

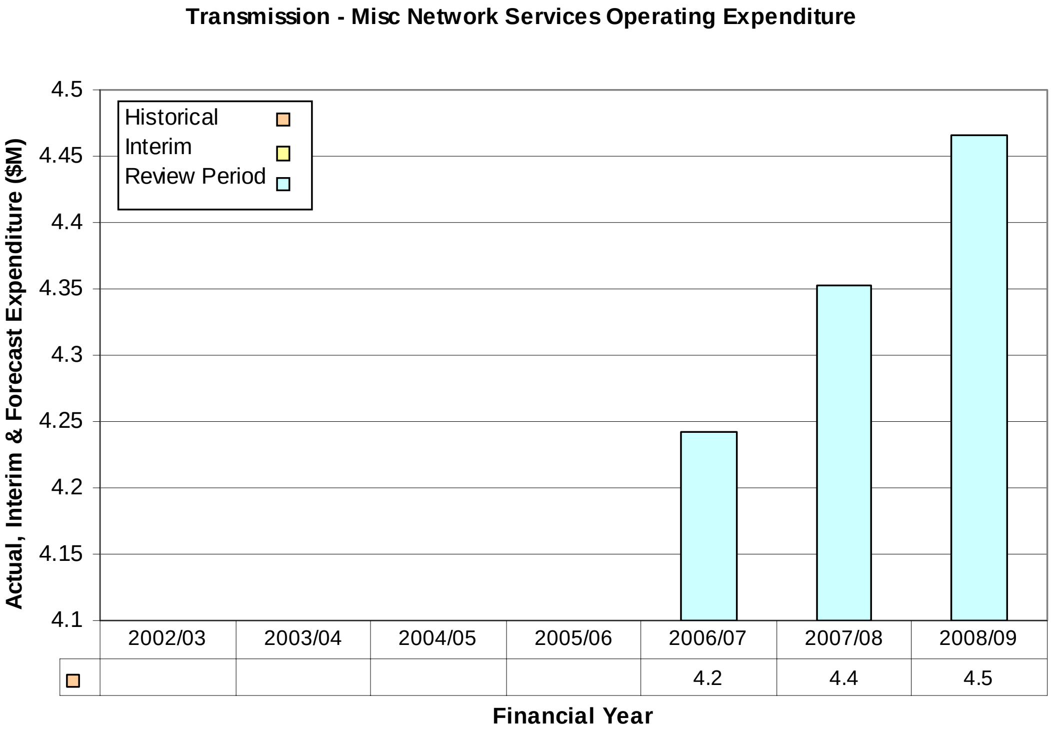
Miscellaneous Network Services

A variety of miscellaneous transmission network services are provided to customers, including:

- Requested relocation of assets;
- Network planning studies; and
- Requested network switching/isolation.

The forecast expenditures reflect historical levels of services provided, noting that the costs and associated revenues have not previously been accounted for within regulated revenues.

Figure 67 Transmission Miscellaneous Network Service Operating Expenditure



2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
				4.2	4.4	4.5

These work activities are included in the “non-reference services” listed in the Access Arrangement.

Network Operations

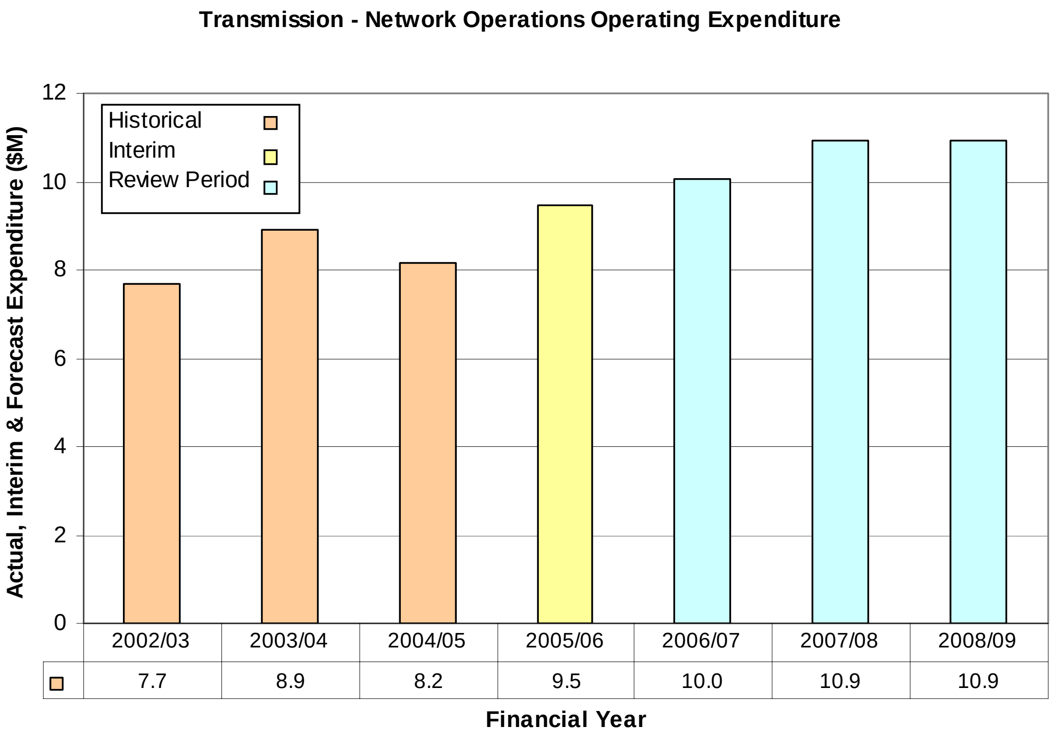
The System Operations group provides control, switching, operations planning and monitoring for the Western Power transmission and distribution networks. Government mandated reforms will impact significantly upon the future expenditures of the System Operations group with the need to facilitate the implementation of an Independent Market Operator and other industry changes.

System Operations group also provides System Management functions for the IMO (generation dispatch, etc.) and the associated costs are recovered through market mechanisms and are therefore not included in these expenditure forecasts.

Western Power is also proposing the implementation of additional SCADA assets, resulting in an associated increase in System Operations operating costs.

The Network Operations expenditures show a steady increase into the regulatory review period. The system operations expenditures can be categorised as "business as usual" and "market reform" and the reasons for slight increases in each of these categories are outlined below.

Figure 68 – System Operations Transmission Operating Expenditure



	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
	7.7	8.9	8.2	9.5	10.0	10.9	10.9

The business as usual activities are impacted by three cost drivers;

- a projected increase in labour costs and material costs of 4% and 1% respectively,

- a general increase in network asset associated with the capital program is also projected to require an incremental increase in System Operations operating expenditures - two additional SCADA support staff are required as there are two SCADA systems to maintain and operate from 2005/06, and

- The IDES SCADA capital project is nearing completion. Therefore operational personnel will be required to carry out system administration and data uptake. This will effectively transfer staff from current capital related activities to operational activities.

The market reform costs have been assessed based on identified labour resource requirements as follows;

- Additional SCADA personnel
  - 2005/06 – 2008/09
    - 1 Planning & Development Officer
  - 2005/06
    - 3 Planning Engineers
    - 2 Analyst
    - 1 Compliance Officer
  - 2006/07
    - 1 Analyst
  - 2007/08
    - 1 Compliance Officer

Market reform requirements are still being refined by the respective government and regulatory bodies.

Information Technology

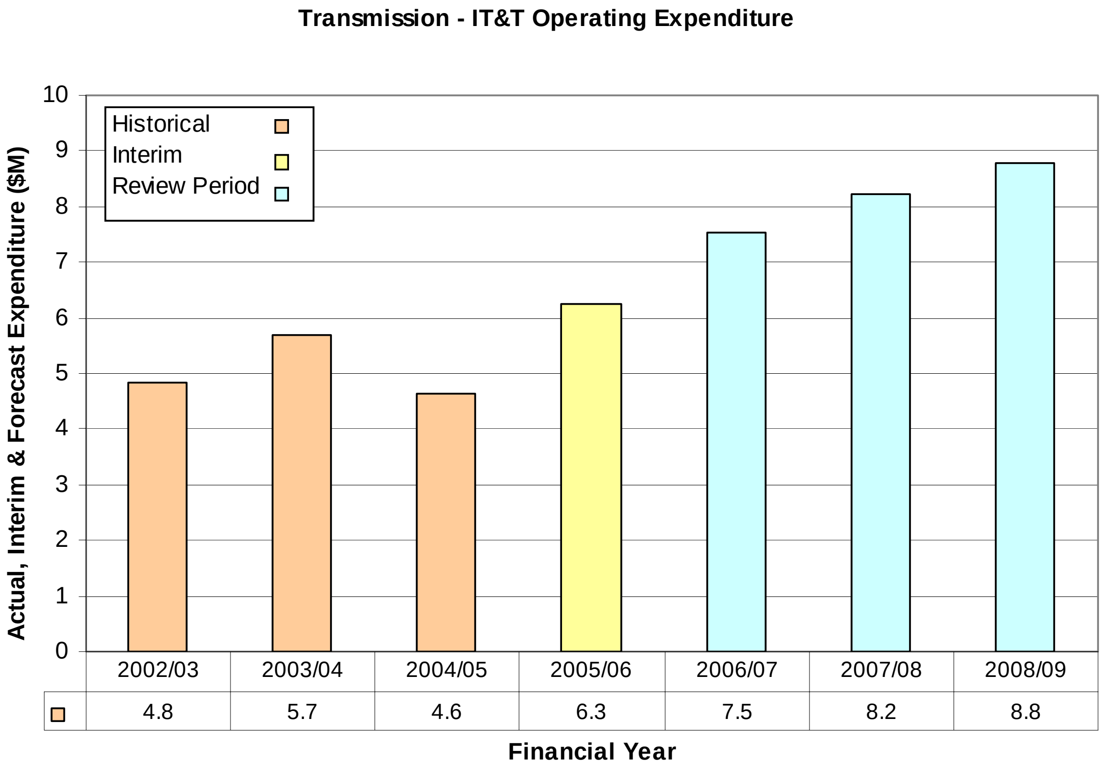
It is noted that the Information Technology group is not responsible for the control system (eg. SCADA) or the Telecommunications network supporting the control system.

The following table provides the current and projected expenditure relating to Information Technology Transmission operating expenditure.

The Western Power personal computer (PC) fleet is leased and the associated expenditures are therefore captured as operating expenditure.

The general trend for Western Power's Information Technology operating expenditure is slightly increasing as highlighted in the following figure.

Figure 69 - Information Technology Transmission Operating Expenditure



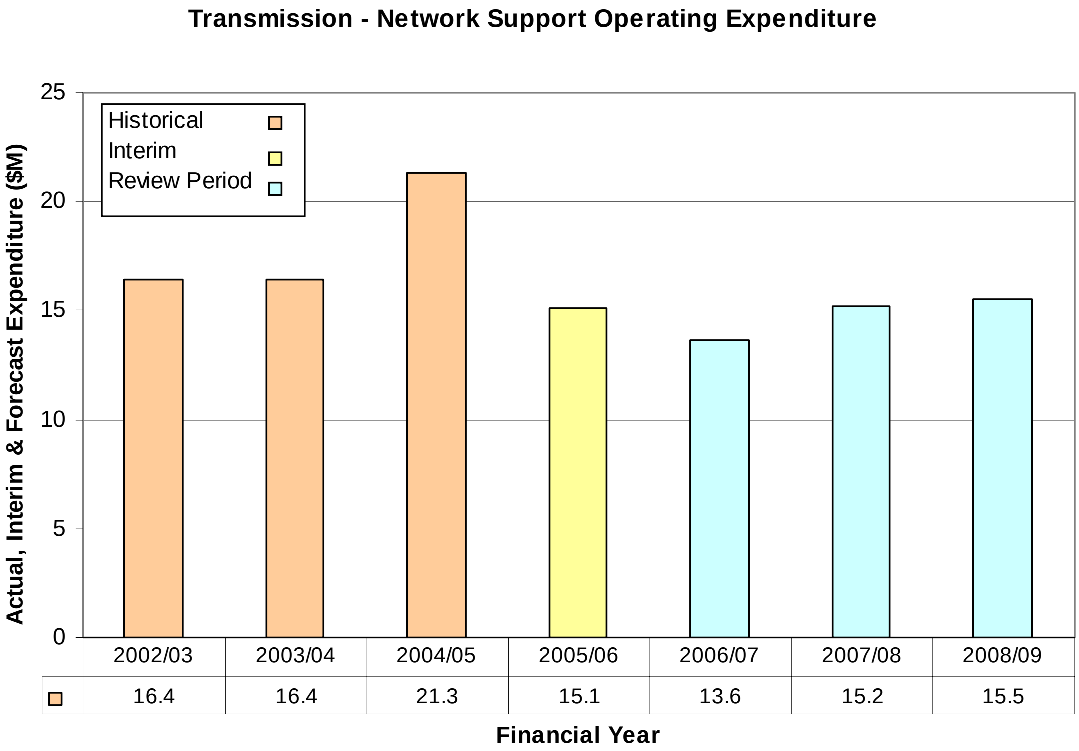
Base IT&T maintenance is projected to grow at 4% per annum for the forecast period. This projection includes adjustments for labour and material inflation and increases in overall employee numbers.

The proposed expenditures associated with the regulatory and strategic project plans (Figure 69 above) are based on individual project plans. These project plans provide detailed justifications and documentation supporting the overall IT expenditure levels.

Network Support

Network support functions are conducted to support both the transmission and distribution businesses operated by Western Power. Network Support includes items such as Human Resources, Finance, Strategy and Corporate Affairs, Design and Estimating, Insurance and rates and taxes. A full description of the overall expenditure is provided in section 5 Business Support Costs. A summary of the allocation of Network Support costs to the transmission business is shown in Figure 70.

Figure 70 Network Support Operating Expenditure

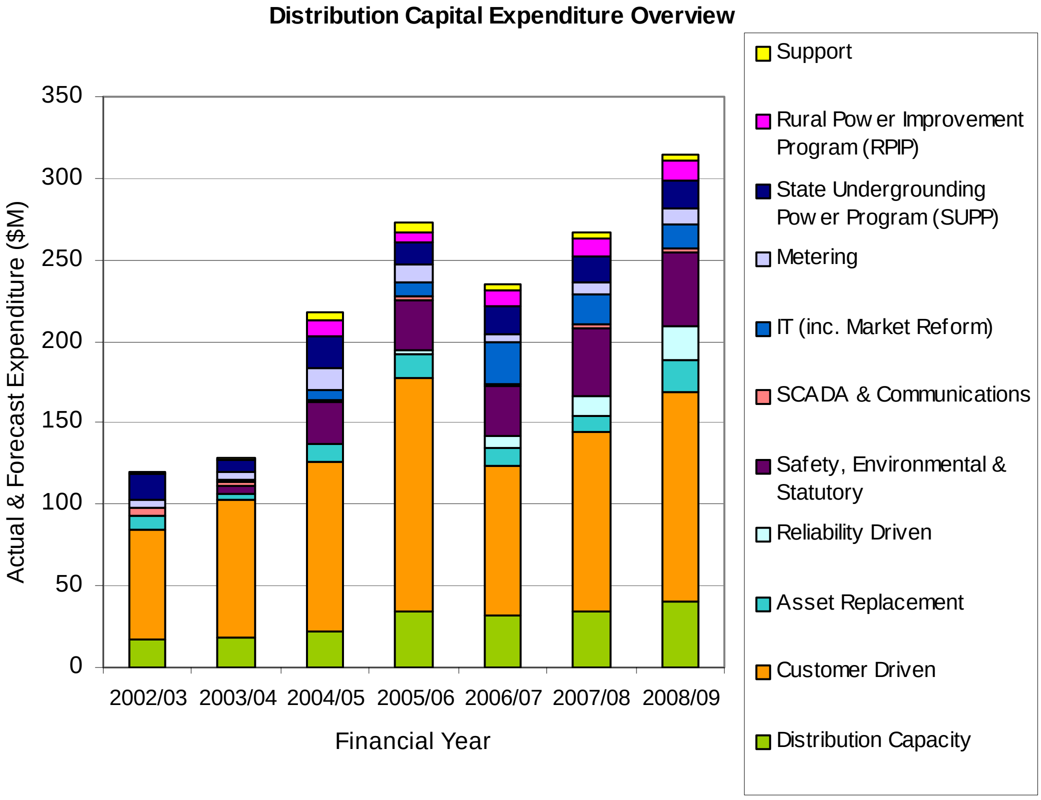


	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
	16.4	16.4	21.3	15.1	13.6	15.2	15.5

8. Distribution Forecast Capital Expenditure

The following chart and table provide the historical and projected capital expenditures for the Western Power distribution business.

Figure 71 - Distribution Capital Expenditure



Year	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
DEMAND RELATED							
Distribution Capacity	17.3	18.1	22.5	34.7	31.3	34.0	40.3
Customer Driven	67.8	84.6	103.7	142.9	92.7	110.5	129.1
NON DEMAND RELATED							
Asset Replacement	8.2	4.0	11.0	14.4	10.3	10.0	19.0
Reliability Driven	0.0	0.3	0.1	2.9	7.7	12.0	21.4
Safety, Environmental & Statutory	0.0	4.3	25.1	30.3	30.2	41.7	44.7
OTHER							
SCADA & Communications	4.5	2.5	2.2	2.6	2.1	1.8	1.9
IT (inc. Market Reform)	0.7	1.1	5.2	8.4	25.7	18.3	15.6
Metering	4.5	4.5	13.6	11.1	4.4	8.1	10.0
State Undergrounding Power Program (SUPP)	16.0	8.2	19.3	13.6	17.1	16.3	17.1
Rural Power Improvement Program (RPIP)	-	0.0	10.4	6.0	10.3	10.6	12.0
Support	1.2	1.3	5.4	5.8	3.2	3.5	3.8
Distribution ($M)	**120.2**	**128.8**	**218.4**	**272.6**	**235.0**	**266.8**	**315.0**

Western Power is proposing to increase average distribution capital expenditure by 69% over the regulatory period compared with average expenditure between 2002/03 and 2005/06. This level of expenditure has been determined by utilising a two step approach. Firstly, a “bottom up” approach was used to identify individual capital projects that should be included in the distribution capital works program based on safety, environmental, statutory, supply quality and load/customer growth requirements. Then the projects were prioritised and the lower priority projects deferred until a works program was developed that was deliverable with the resources available to Western Power. The increase in overall distribution capital expenditure is in response to a number of key drivers that have already or will impact the distribution network business over the next 3-5 years.

The drivers that have resulted in Western Power having to increase distribution capital expenditure levels over the regulatory period are:

Driver 1 – Load Growth.
This driver relates to the necessity to provide additional infrastructure to cater for the connection of new customers or the augmentation of the existing network in order to cater for the additional load generated by new customers coupled with the intrinsic load growth of existing customers.

Western Power currently designs and constructs a large proportion of the connection assets for new residential, industrial and commercial customers even though it is operating in a contestable environment. Connection assets constructed by external contractors are "gifted" to Western Power and are not included in this category.

As a result of Western Australia's unprecedented high levels of population growth and the high levels of load growth generated primarily by new air conditioning load, including its effect on load factor, Western Power has a substantial amount of new distribution assets to construct and commission over the regulatory period. In addition there is a substantial amount of augmentation work required on existing distribution feeders and zone substation integration to cater for the additional load. This augmentation includes a substantial amount of backbone feeder conductor replacement to improve both capacity and fault level rating.

Driver 2 – Reliability
This driver relates to the decision Western Power made in January 2005, to target a 25% improvement in SAIDI across the SWIS – over the next 3 years (all faults statistics are to be calculated using the SCNRRR[40] definition and IEEE 1366 Guide for Electric Power Distribution Reliability Indices for major event days known as the Beta method). This target represents the first step in meeting the Electricity Industry (Network Quality and Reliability of Supply) Code 2005 standards.

Some of the capital works projects included in the Access Arrangement Submission primarily to cater for increased load growth or increased fault levels have an impact on network performance. Their contributions to meeting the target reduction in SAIDI have been acknowledged and identified.

The projects included in this category have been primarily designed to achieve reductions in SAIDI of sufficient magnitude to bridge the gap between the reductions achieved by the capital projects with a secondary impact on network performance and the reductions required in order to achieve the targeted 25% improvements.

[40] Steering Committee for National Regulatory Reporting Requirements.

Driver 3 – Asset Condition

Western Power's distribution assets have a weighted average remaining life of 56% in 2005. When poor asset condition is assessed and cannot cost effectively be corrected through maintenance activities, Western Power must replace network assets at the end of their service life with modern equivalent assets in order to ensure a continued safe and reliable operating environment assets.

In order to determine the appropriate level of investment required to be made on the distribution infrastructure Western Power engaged PB Associates to develop an age, condition and risk based replacement model. This model was populated with Western Power's distribution asset data and the replacement capital expenditures determined by the model were compared with bottom up estimates as part of the process of determining the forecast Asset Replacement expenditure levels for the Access Arrangement Submission.

The levels of expenditures included in the Access Arrangement Submission for Asset Replacement do not arrest the decline in weighted average asset age, with the weighted average remaining life decreasing from 56% to 52% over the regulatory period.

Driver 4 – Safety, Environment and Statutory

This Driver relates to Western Power's compliance with directives and remedial actions agreed with the ESD, and compliance with statutes, acts, regulations, codes and standards, in particular the Electricity (Supply Standards & System Safety) Regulation 2001.

Some of the remedial actions agreed with the ESD have been instigated in accordance with recommendations made by the State Coroner and others have been instigated by Western Power to minimise safety and environmental risks in accordance with good industry practice. All the projects included in this category directly relate to the achievement of mandated safety, environmental, and compliance outcomes or industry accepted prudent avoidance of adverse outcomes.

The impact of each driver is;

1. **Load Growth.** The average capital expenditure over the regulatory period will increase from an average expenditure of $122.9M per annum during the 2002/03 to 2005/06 period to a forecast expenditure of $146.0M per annum during the regulatory period, an increase of approximately 19%.

2. **Reliability.** The capital expenditure over the regulatory period will increase from an average expenditure of $1.0M per annum from 2002/03 to 2005/06, to an average forecast expenditure of $13.7M per annum during the regulatory period. This represents a large increase on a relatively new expenditure category.

3. **Asset Condition.** The average capital expenditure for asset replacement due to poor condition over the regulatory period will increase from an

average of $8.4M per annum from 2002/03 to 2005/06, to a forecast expenditure of $13.1M[41] per annum, an increase of approximately 56%.

4. Safety, Environment and Statutory. The average capital expenditure over the regulatory period will increase from an average of $9.8M per annum from 2002/03 to 2005/06, to a forecast expenditure of $38.9M per annum during the regulatory period, an increase of 192%.

Load Growth

The average expenditure over the regulatory period will increase from an historical $107.9M to a forecast expenditure of $170.6M per annum, an increase of approximately 58%.

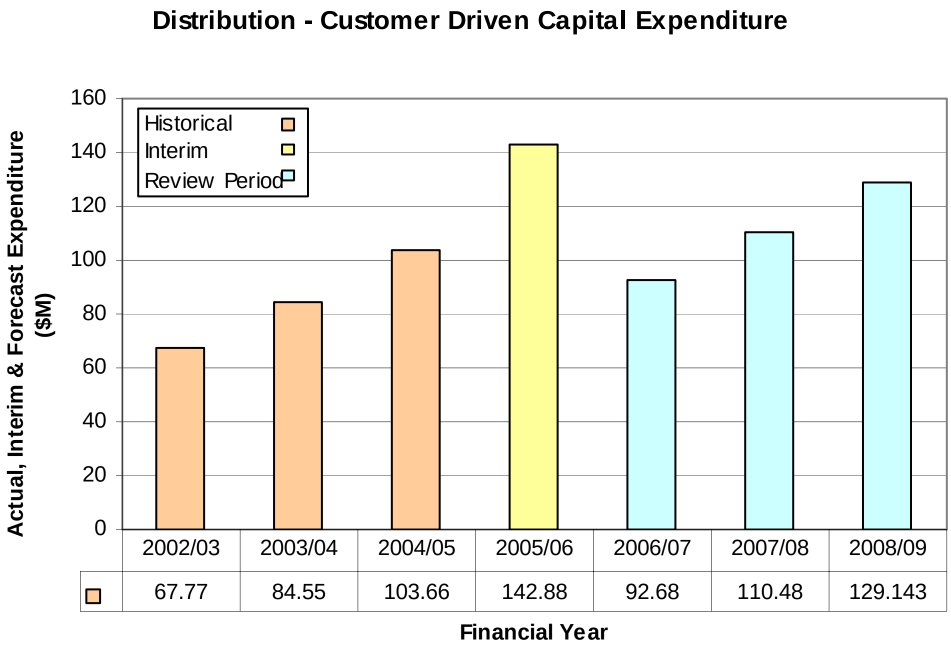
There are two significant components of distribution capital expenditure associated with load growth. The direct works associated with connecting new customers to the network (customer driven works) and the indirect works associated with augmenting the existing network to cater for both the new customers and the intrinsic load growth of the existing customers (capacity driven works).

Customer Driven

Customer driven expenditure includes forecast expenditure associated with connecting new customers to the network. In recent years expenditure in this category has increased to cater for the increasing number and cost of customer connections. A significant further increase in cost is anticipated due to changes to the standards and policies (including the Technical Rules) affecting the design requirements for network and connection assets. These increases are offset by expectations of some steadying of the growth rate of new connections and an increasing proportion of land subdivision infrastructure being provided by developers.

[41] Note Asset Replacement category includes $300K per annum for Wildlife Proofing and Emergency Response Generation which are not strictly Asset Replacement activities.

Figure 72 Distribution Customer Driven Capital Expenditure



Increasing number and costs for customer connections:

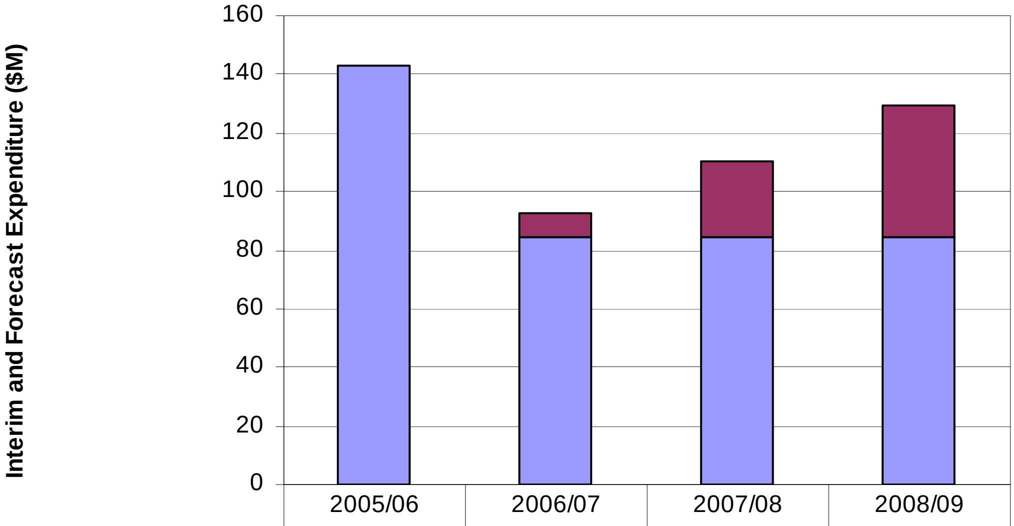
As mentioned in previous sections, Western Australia is currently experiencing a period of high growth which is reflected in a continued growth in the quantity of new underground residential subdivisions (URD) being commissioned and a sustained growth in the number of commercial and industrial connections.

The underlying expenditure trend has been analysed using linear regression analysis and historical expenditure data to predict future expenditures resulting in projected expenditure for basic customer connections in the range $111M to $129M per annum. However, as continuation of these high rates of growth in customer connections is uncertain and, in anticipation of developers opting to provide a growing proportion of subdivision infrastructure themselves, a forecast of $84.5M per annum has been proposed for new customer connections during the period 2006/07 to 2008/09.

Western Power has found it necessary to revise the electrical design standards applicable to new customer connections to compensate for the high penetration of reverse cycle air conditioning loads. These air conditioning loads have a major impact on the after diversity maximum demand (ADMD) assumptions which determine the electrical capacity of the connection assets and avoid the need for further investment in the distribution infrastructure for power quality reasons. Catering for these increased loads has increased the cost per customer connection.

The total forecast annual expenditure for this category is in the range $92.7M to $129.1M during the regulatory period. Approximately $26M per annum (average) is due to changes in the standards and policies applicable to customer connection assets. Figure 73 illustrates the breakdown of the expenditure forecast between the continuation of customer connection works and the additional costs required to cater for the changes to standards and policies. In particular, it is noted that implementation of the new standards and policies will occur progressively, and this is reflected in the related expenditure forecasts in the first two years. The following section details the specific changes that have contributed to the additional expenditure requirements.

Figure 73 Customer Driven forecast expenditure breakdown



	2005/06	2006/07	2007/08	2008/09
Changes to Stds & policies		8.2	26.0	44.7
New connections	142.9	84.5	84.5	84.5

Changes to Standards and Policies:

The further development of the new Technical Rules and other legislation requires a number of changes to design policies and standards, changes include:

- reduction of padmount substation noise,
- reduction in the number of customers on radial feeders,
- increased design loads for commercial and industrial customers,
- underground pole to pillar connections,
- installation of remote monitoring and control of ring main switches (RMU),
- changes to street light designs, and
- fireproof construction in fire risk areas.

The individual design changes and associated costs are detailed below and where relevant the sections of the Technical Rules which require Western Power to implement these changes are quoted.

Transformer Noise Abatement.

Technical Rules Requirement[42]:

1.8.1 General
(a) *Users and the Network Service Provider* must maintain and operate (or ensure their authorised *representatives* maintain and operate) all *equipment* that is part of their respective *facilities* in accordance with:
(1) relevant laws;

2.7 *TRANSMISSION AND DISTRIBUTION SYSTEM* DESIGN AND CONSTRUCTION STANDARDS
The *Network Service Provider* must ensure that the *transmission and distribution system* comply with relevant codes standards and regulations, including the *Access Code*; the "Guidelines for Electricity Transmission and Distribution Work in Western Australia" issued by Energy Safety and relevant ESAA Guides, Australian and International Electricity Commission (IEC) Standards, the *Network Service Provider's* fire-proofing requirements and any relevant requirements of the *WA Electrical Requirements*.

Recent EPA legislation has been introduced that substantially reduces the permissible ambient noise from transformers in residential areas. Industrial and commercial areas are not affected by this legislation as the background ambient noise in these areas is high enough for the transformer noise not to be a problem. To mitigate the noise in residential areas brick enclosures need to be constructed. Locating the transformer across the street is not sufficient to mitigate the noise to acceptable levels.

For residential subdivisions there will be no additional cost to Western Power as the developer will need to construct these enclosures and it will be part of the civil works for the subdivision.

For residential supply upgrades it is assumed the majority of these enclosures will need to be built by Western Power. The noise mitigation requirements will affect 50% of all individual domestic jobs in the Metro (approximately 37 jobs per year) and 10% of individual domestic jobs in the country (approximately 19 jobs per year).

The cost of enclosures is estimated to be $15,000. It is assumed no other work categories are affected by this noise mitigation requirement.

This change will increment costs by $0.84 M per year, once fully implemented.

Reduced Number of Customers on a Radial Feed.

Technical Rules Requirement:

2.5.4.4 Radial Distribution Feeder Loads in the Perth Metropolitan Area
For all *distribution feeders* within the Perth metropolitan area, the *Network Service Provider* must limit the number of domestic customers in a switchable feeder section to 860, if the switchable feeder section is not able to be energised through a backup normally open interconnection.

2.5.5 Low Voltage Distribution System
(b) For underground residential subdivisions, the *Network Service Provider* must ensure that all *low voltage* circuits have a switching point for every 16 *Consumers*.

To improve reliability and operational flexibility fewer customers are permitted on both HV radial feeders, and greater interconnection is to be available on the LV. This will improve reliability as fewer customers will lose supply when an equipment failure occurs.

[42] Draft Technical Rules, Western Power, 11 April 2006. Specific clauses relating to changes which impact the cost of customer connection works have been extracted from the Draft Technical Rules and reproduced in italic font in the following sections.

For HV feeders the design will be changed so that there will be a maximum of 860 customers on a spur. When there are more than 860 customers, a feeder interconnector will be required. A feeder interconnector typically requires 800 metres of additional cable and extra switchgear, at both ends of the interconnector. It is estimated that an average of 29 metro, and 3.3 country, interconnectors will be required each year. The cost for each installation is expected to be $80,000/year.

For LV feeders greater switching ability will be achieved by installing a universal pillar every 4th lot (16 customers). The universal pillar will allow greater switching and connection of portable generation.

Using a uni pillar every 4th lot will increase the lot cost by $100 for both domestic and commercial/industrial lots. It is estimated this will effect 25,200 lots in the metro and 2,800 lots in the country.

These changes will increment costs by $5.4 M per year, once fully implemented.

Increased ADMD Design Criteria.

Technical Rules Requirement:

2.6 *SUBDIVISION* DESIGN CRITERIA
(a) All residential commercial and industrial subdivision *distribution systems* must be designed to *supply* the maximum reasonably foreseeable *load* anticipated for that subdivision. The maximum reasonably foreseeable *load* for the subdivision shall be agreed by the *Network Services Provider* and the developer and must be determined by estimating the *peak load* of the subdivision after it has been fully developed, assuming the current electricity consumption patterns.

Over recent years there has been a substantial increase in the ADMD loads of residential customers. This has resulted in many transformers overloading and customers losing supply for many hours while the transformers were replaced. The principal cause of the increased ADMDs has been an increase in air-conditioning load.

Western Power studies have shown that the residential loads have increased between 2 to 4 times the values previously used. The higher load values are typically found in the more expensive suburbs. The difficulty is to anticipate the mix of housing lots that will be released over the coming years. For modelling purposes it has been assumed the majority of lots released will be mid-range which means a load increase of around 2.7 times that currently used. This does not result in a 2.7 times increase in lot costs it has been estimated the lot increase will be 1.5 times the existing values. The additional costs are for more transformers, more or larger HV and LV cables and more switchgear. These additional costs will increase the capital expenditure for all residential and broad acre subdivisions.

Based on a quantity of 19,200 lots in the metro and 3,400 lots in the country per year this change will increment costs by $19.1 M per year, once fully implemented.

Increased Minimum Design Load Industrial / Commercial Lots.

Technical Rules Requirement:

2.6 *SUBDIVISION* DESIGN CRITERIA
(a) All residential commercial and industrial subdivision *distribution systems* must be designed to *supply* the maximum reasonably foreseeable *load* anticipated for that subdivision. The maximum reasonably foreseeable *load* for the subdivision shall be agreed by the *Network Services Provider* and the developer and must be determined by estimating the *peak load* of the subdivision after it has been fully developed, assuming the current electricity consumption patterns.

As with residential subdivisions, loads in commercial and industrial subdivisions have increased in recent years. This has been due to greater use of air-conditioners as well as the use of computers and other electronic technology in these premises.

Previously Western Power allowed a flat 200 kVA/ha rate to determine the load. However, for the smaller lots, around 1,000 m^2 to 2,000 m^2, this has resulted in a power supply of 10-20 kVA which is insufficient to supply the loads that are typically installed. To correct this the minimum load will be increased to 110 kVA, that is 150A 3 ǿ load, with 200 kVA/ha used where lots are greater than 5,500 m^2.

The application of this design change should avoid likely future overloading of distribution transformers and LV circuits which are extremely difficult and hence expensive to retrospectively augment.

The increased design load will affect about 70% of all Metro lots and 10% of country lots and increase the cost for those lots by about 2 times.

Based on 7,200 lots in the metro and 800 in the country per year this change will increment costs by $5.2 M per year, once fully implemented.

Using Pole to Pillar (P2P) to replace Overhead services.

Technical Rules Requirement:

2.5.6 Pole to Pillar Connections Mandatory
All new *Consumer connections* and upgrades to existing overhead services due to capacity increases, must be underground, even if the service mains are to be connected to an overhead *distribution line*.

The provision of underground service connections for all new installations in metropolitan Perth has been mandatory for the last 8 years. This project involves making the provision of all new and replacement services in country areas also mandatory. This approach will also eliminate the Twistie problem on those services utilising this termination clamp and will also substantially reduce the probability of any further single customer outages which historically relate to service wires and their connections.

The purpose of this program is to improve reliability to customers. The reliability is improved as the service leads are undergrounded. This means the supplies to individual houses or commercial/industrial premises are not damaged during storms due to trees breaking or debris damaging service leads causing a ‘wire down’ situation. These wire down faults were accounting for 60% to 70% of the faults during a storm and were the lowest priority in the network restoration as when they are fixed only one customer’s supply is restored. Additionally two children were recently electrocuted as the overhead service lead had been damaged with the constant movement overhead services experience. Undergrounding of service connection is considered to be the best way to eliminate this risk of this situation recurring. Eliminating overhead service leads and by replacement with underground service connections improves reliability and safety of the network for the customer.

The proposal also includes making it mandatory to install underground services when upgrading existing residential, commercial and industrial services in metropolitan Perth.

The additional cost per connection is approximately $1,600. Based on 3,654 metro and 1,368 country connections per year the additional cost for making it mandatory in the country for P2P Policy is $2.2M per year. The additional cost for metro is $5.8M per year.

Western Power has estimated that adoption of this proposal will incur additional capital expenditures of $8.0M per annum, once fully implemented.

DCRM of Switchgear and Transformers.

Technical Rules Requirement:

2.5.7 Distribution Remote Control and Monitoring
(a) All new and replacement switches (including ring main units) must be capable of being remotely operable.Switches in key network positions will need to be controlled from the *distribution system control centre. All switches are to* be fitted with fault passage indication; and
(b) All new and replacement *distribution transformer*s must be fitted with load monitoring facilities which are capable of being modified for monitoring from the *distribution system control centre*.

This proposal is essentially designed to improve supply reliability and consists of the remote supervision and operation of switchgear and transformers in suburban Perth.
The project involves the installation of distribution remote control and monitoring equipment at the time of installation. Remotely readable meters will be installed on all switch gear and transformers which will be connected to the SCADA system, fault indicators will be installed on all RMU feeder cables and actuating devices are to be installed on all switches on the HV and LV network. The anticipated cost for RMUs DCRM is $26,000 and for transformer installations, $20,000.

Assuming 140 customers per transformer and 280 customers per RMU there will be approximately 200 transformers and 109 RMUs installed per annum that are DCRM enabled. The total forecast costs are $6.0M in the metro and $0.8M in the country.

Western Power has estimated that the capital expenditure associated with the implementation of this proposal is $6.8M / year, once fully implemented.

Street Light Changes.

Technical Rules Requirement:

2.7 *TRANSMISSION AND DISTRIBUTION SYSTEM* DESIGN AND CONSTRUCTION STANDARDS
The *Network Service Provider* must ensure that the *transmission and distribution system* comply with relevant codes standards and regulations, including the *Access Code*; the "Guidelines for Electricity Transmission and Distribution Work in Western Australia" issued by Energy Safety and relevant ESAA Guides, Australian and International Electricity Commission (IEC) Standards, the *Network Service Provider's* fire-proofing requirements and any relevant requirements of the *WA Electrical Requirements*.

This design change reflects changing community and local government requirements in relation to streetlighting design. Generally there has been a move Australia wide to design all new streetlighting in accordance with the current Australian Standards and the costs for this design change have been incorporated into this capital expenditure category. This move is driven by coronial inquiry recommendations, as well as motorists and pedestrian security expectations. Higher illumination levels have typically increased costs by around 17%.

In addition local councils are demanding more control over the visual landscape in the CBD and other community spaces such as parks and gardens. As distributors are the major and in many instances the only supplier of these lighting services there is increasing pressure to provide a greater range of lighting options which usually involve higher capital and operating costs. Western Power has now included a range of more decorative luminaires to cater for this need and developed new streetlighting tariffs for these fittings. The impact on the cost of street light work would be a 2.5 times cost increase for all Country street light projects and 10% of Metro projects for those Councils on the Metro fringe.

These luminaires will be used at road upgrades, roundabouts and street beautification projects.

Western Power has estimated that the additional capital expenditures associated with streetlighting design changes are $1.8M / year, once fully implemented.

Fireproof Design/Construction.

Technical Rules Requirement:

2.7 *TRANSMISSION AND DISTRIBUTION SYSTEM* DESIGN AND CONSTRUCTION STANDARDS
The *Network Service Provider* must ensure that the *transmission and distribution system* comply with relevant codes standards and regulations, including the *Access Code*; the "Guidelines for Electricity Transmission and Distribution Work in Western Australia" issued by Energy Safety and relevant ESAA Guides, Australian and International Electricity Commission (IEC) Standards, the *Network Service Provider's* fire-proofing requirements and any relevant requirements of the *WA Electrical Requirements*.

This design change relates to the installation of either covered conductor, ABC or underground cable in areas subject to high fire risk. These design changes complement the intent of the strategies outlined in the Bushfire Management Plan and also fall into the category of design criteria that a prudent operator would be expected to utilise in bushfire prone areas.

- It is expected the fire proofing will affect a greater percentage of country work and to a lesser extent the in urban fringe areas. It will only be applicable where Western Power runs overhead for individual customer type loads, e.g. SES, Commercial/Industrial, 20/80 and Full Cost.
- In the metro fireproofing is expected to be required for 5% of the jobs costing an additional $1.5M per year. In the country it is expected to effect a higher percentage of jobs (20%) costing an additional $0.8M per year. Although there is a lower percentage of jobs affected in the metropolitan areas than the country areas the dollar value of the metro work is greater due to the volume (and dollar value) of the metro work.

The expected increase is to double the cost of the work.

Western Power has estimated the implementation of this design change would incur additional costs of $2.3M per annum, once fully implemented.

Distribution Capacity Expenditure

In addition to the expenditures Western Power incurs in the connection of new customers it also incurs expenditures increasing the capacity of the existing network infrastructure to cater for the additional load imposed by the connection of these new customers and the intrinsic load growth of existing customers.

Western Power uses a bottom up approach to determine the location and the magnitude of specific augmentation and replacement projects. Each augmentation project is supported by a concise planning project identifying the issues requiring resolution, possible solutions and selection of the preferred option.

The underlying reasons for these augmentation projects are as follows:

- The presence of small cross section conductor in close proximity to zone substations which impose thermal constraints on feeder ratings and/or cannot sustain the fault levels at that location;

- Distribution feeder thermal overloading due to customer load growth in the area resulting in either the construction of additional feeders or increasing the HV distribution feeder voltage from 6kV to 11kV or 22kV;

- Distribution feeder voltage constraints due to load growth in rural areas resulting in either the installation of voltage regulators, capacitors, or the construction of additional feeder sections;

- Exceeding the distribution planning guidelines requiring feeder loads to be kept below 80% of their NCR, so that one feeder can be offloaded to four other feeders. The zone substation NCR capacity criterion has driven up the loading on existing feeders significantly;

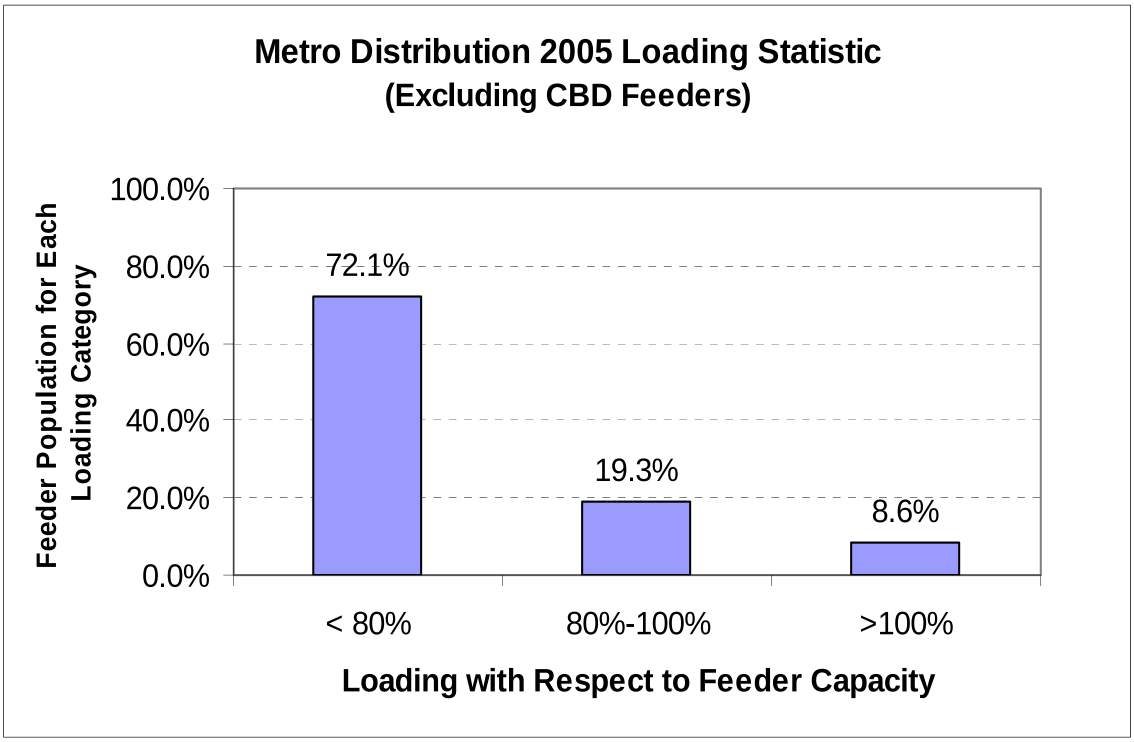
- The need to integrate (over 4 year period) 13 new greenfields zone substations into the distribution network and 5 new replacement zone substations requiring conversion of distribution feeder voltage from 6kV to 11kV or 22kV. Each new greenfield zone substation requires an additional three or four feeders to be constructed and commissioned;

- Increasing fault levels in the metropolitan area due to the penetration of UG cables and the integration of new zone substations. The existence of underrated conductors can also cause under voltage situations which impact on power quality.

The following graph clearly illustrates the current situation in regard to the loading of distribution feeders in the Perth Metropolitan area excluding the Central Business District, with 27.9% of these feeders exceeding 80% of their capacity and 8.6% overloaded. This situation also impacts on CAIDI by limiting the number of feeders that can be backed up during outages.

The reason for this situation is the under investment that has occurred in the past due to the high level of expenditures required for customer connection works, as a result of the very high customer and peak load growth that Western Australia has experienced over recent years.

Figure 74 - Metropolitan Distribution Feeder Loading



Western Power has developed a software program that is very successful in predicting the location of potential overloaded distribution transformers based on customer connection data. The high penetration of air conditioners over the last few years (due their lower purchase prices) has resulted in the demand of existing customers in developed areas increasing rapidly. A similar phenomenon has occurred in all other states but is particularly evident in the current load factor of Western Australia's closest neighbour, South Australia. Western Power has had to react to transformer overloads as they occurred during recent summer periods but this software facilitates a far more orderly proactive program to be implemented. This planned approach allows optimised distribution transformer utilization as replaced transformers can be rotated into appropriately loaded substations.

Western Power plans to replace 180 distribution transformers in 2005/06 at an estimated expenditure of $4.7M and a further 712 distribution transformers over the regulatory period (270 units in 2006/07, 188 units in 2007/08 and a further 254 units in 2008/09) at an estimated cost of $17.1M over the three year control period.

LV circuit monitoring by Western Power when changing overloaded transformers has indicated that 50% of the low voltage circuits connected to these overloaded transformers are also overloaded and require some rectification works (e.g. reconfiguration and/or reinforcement). Individual LV circuits can exhibit extremely high load growth, far higher than general system load growth, due to the limited diversity of connected loads. Based on the transformer replacement program, Western Power has programmed to rectify 440 residential LV circuits and 140 commercial LV circuits over the three year control period.

Based on historical costs an allowance of $70 per meter (average) has been allowed for the rectification of LV circuits. The proposed spend on removal of LV circuit overloads is $0.216M in 2006/07, $0.236M in 2007/08 and $0.350M in 2008/09.

Historical and forecast expenditures (nominal dollars) for distribution capacity related expenditures, i.e. works associated with augmenting the existing network are shown in Figure 75.

Figure 75 - Distribution Capacity Related Expenditure

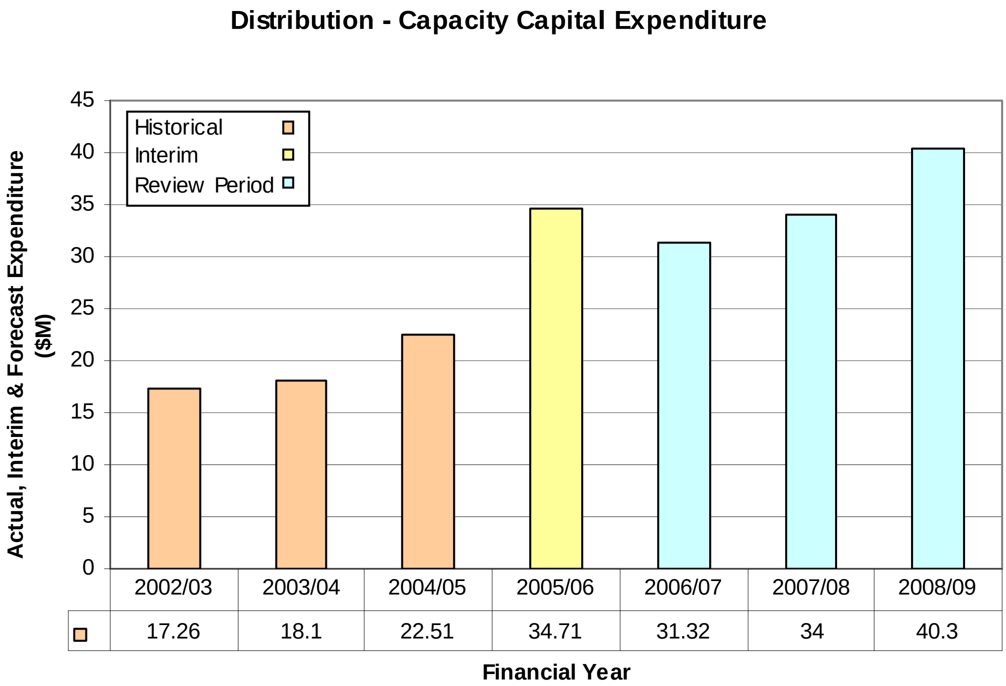
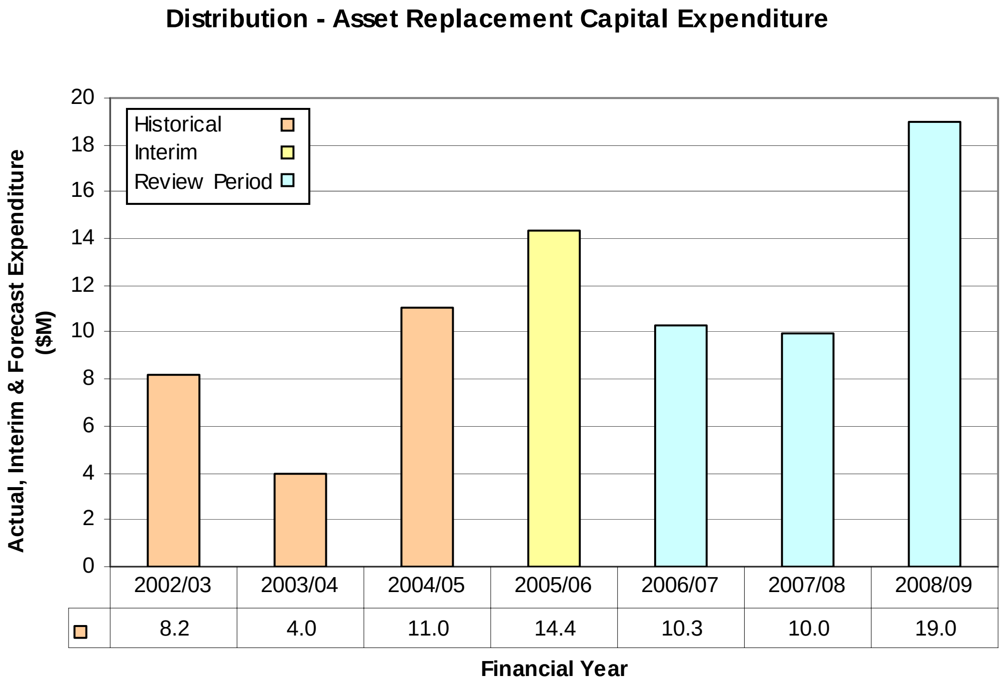


Figure 75 highlights the steady increase in expenditure from 2003/04 to 2006/07 when the higher level of expenditure is maintained over the review period. Western Power acknowledges that over the past decade network capacity enhancement has not kept up with load and customer growth. This is highlighted by the large percentage of distribution feeders currently loaded above the planning limit of 80% of normal rating and also the large number of locations where the existing conductor fault capacity is less than the fault level

The adoption of the NCR criteria has resulted in increased utilization of substations up to 90% of total capacity where the number of feeder circuits provided corresponds to the original N-1 substation loading cap (resulting in high feeder utilization). Western Power has prioritised projects to target overloaded feeders to avoid asset failure.

HV augmentation projects are expected to continue at a similar level after 2008/09 as the same drivers for HV distribution capital expenditure are anticipated to be ongoing. Western Power notes that the exact nature and timing of capacity related projects may change as the actual capacity increases occur and that this may impact the required expenditure levels. As recent load growth has been higher than forecast it is likely that expenditure in addition to that forecast may be required.

Asset Replacement



The average capital expenditure over the regulatory period will increase from an average \$8.4M from 2002/03 to 2005/06 to an average expenditure of \$13.1M per annum during the regulatory period, an increase of approximately 56%. Modelling of the expenditure requirements for distribution asset replacement suggested far higher expenditure was required in the medium term (\$42M per annum) hence the average forecast of \$13.1M per annum based on bottom up assessment using actual condition assessment data is considered to be extremely prudent.

The age, condition and risk associated with failure of distribution assets triggers replacement capital expenditures on distribution infrastructure. Some types of assets are run to failure and do not form part of the capital program for asset replacement. Run to failure assets are replaced upon failure and the replacement costs expensed.

In order to determine the magnitude and timing of asset replacement expenditure Western Power engaged PB Associates to develop an age, condition and risk distribution asset replacement model. This model was populated with Western Power's asset data including asset quantities, age profiles, and with modern equivalent replacement costs.

The model was used to provide an indication of the level of asset replacement expenditure that could be expected over the next 20 years and to provide an indication of the weighted average remaining life of Western Power's distribution assets. Based on the asset data and nominated asset lives, Western Power's distribution assets have a weighted average remaining life of 55% in 2005. Western Power's distribution assets have a current Replacement Cost of $2.86 billion (from AMP 2005) and an ODV $1.7 billion. Recommended asset replacement expenditures of, on average, $42.26M per annum infer that the assets have a service life of between 50 and 100 years and therefore do not appear unreasonable.

Whilst the PB Associates model provides a reference point, the condition/replacement capital forecasts presented in this program have been developed using a bottom up approach. Each major category of assets has been considered and the combination of Western Power's asset management expertise, asset condition information, failure rates, and other asset information was used to develop a forecast capital expenditure plan for the regulatory period. The details of this plan are outlined in the following subsections. However it is noted that based on the asset replacement modelling, maintaining asset replacement expenditure at the levels forecast for the regulatory period is not considered to be sustainable in the long term.

Distribution Poles

There are over 600,000 wood poles that support the overhead distribution network at safe height, support other poles that otherwise have an excessive lateral loading and provide additional ground clearance beyond that required for safety to suit the required thermal rating of the network by allowing for sag of the conductors.

Poles typically have a life expectancy of 35 years. In practice it is expected that good quality poles which are appropriate for the mechanical loading placed on them will last an average of 40 years, but if they are reinforced at ground level and also effectively treated against fungus and wood rot they should last significantly longer.

Western Power's criteria for pole replacement is that reinforced poles that fail the "good-wood" test must be replaced and non reinforced poles that fail the "good-wood" test and have insufficient good wood to warrant reinforcing must also be replaced.

Based on pole inspections conducted and projected pole failure rates the total projected expenditure over the regulatory period for pole replacement is $14M.

Ring Main Units

There are 2,500 sites with ring main units that provide ground-mounted switchgear to allow operators to safely and efficiently isolate and interconnect high voltage underground distribution networks and to allow for automatic isolation of faults on the high voltage underground distribution networks. In some instances high voltage metering units are installed with this switchgear.

There are 11 switchgear types used on the network with varying degrees of reliability. Typically switchgear is expected to last 50 years although some units have failed (seizure or catching alight) after two years of service.

Replacement is used as a last resort when maintenance is inappropriate or for switchgear that does not meet the required standard for safety and reliability.

The total projected expenditure over the regulatory period for ring main unit replacement is $6M.

Carriers

There is in excess of 68,000km of high and low voltage conductors used in the SWIS system. The conductor types used in the overhead networks include Aluminium Conductor Steel Reinforced (ACSR), All Aluminium Conductor (AAC), All Aluminium Alloy Conductor (AAAC), Hard Drawn Bare Conductor (HDBC), Galvanised Steel (FE/GZ), Steel Conductor Aluminium Clad (SC/AC). Aerial Bundled Conductor (ABC) and Copper Conductors (Cu). Accessories used in conjunction with these conductors include various types of line clamps insulator clamps, line taps, joints and conductors ties.

The nominal life of overhead conductors is 55 years. However the anticipated mean asset life could range from 40 to 60 years, the lower end being for the heavily polluted conditions. Overhead conductors are replaced after identification during routine line inspections within 12 months of the inspection.

The total projected expenditure over the regulatory period for carriers is $5M.

Distribution Pole Reinforcement

Approximately 50% of all wood poles in service in the network are currently reinforced (289,424 out of 600,421). Reinforcement along with appropriate maintenance increases the pole lifetime from 40 to 60 years. Poles are inspected every 4 years for “good-wood” assessment and reinforced where necessary or replaced if the pole is no longer reinforceable. In some instances previously reinforced poles require further reinforcing steels in light of the loading on the poles.

There are currently 11,837 (not including 3,000 transformer carrying poles) poles identified as requiring reinforcement to a new reinforcement specification at a cost of $1,030 per pole. This quantity includes poles carrying conductors as identified by the inspection cycle and poles supporting conductors crossing streets.

The total projected expenditure over the regulatory period for pole reinforcement (not including 3,000 transformer carrying poles) is $11M.

Distribution Transformers

Distribution transformers are those in the range of 240V to 33kV and number 55,974 in the SWIS. The primary purpose of the distribution transformer is to step the MV voltage down to an LV quantity that is suitable for consumption by residential, commercial and industrial customers, step up voltages from LV to MV and to change from one MV level to another e.g. 22kV to 33kV.

Transformers with a rating below 300kVA are allowed to “run to failure” whilst larger transformers are evaluated for overloads (desk top studies with field load measurement confirmation) age and condition reports to determine replacement requirements. This is considered to be the optimum option in terms of cost effectiveness and minimising interruptions to the system.

The total projected expenditure over the regulatory period for distribution transformer replacement is $1.7M.

Distribution Equipment – Reclosers/Compensators & LV - Frames

There are 1,197 reclosers, 3,722 LV distribution frames and 252 compensators (161 Capacitor banks & 91 reactors) used in the SWIS distribution system.

Reclosers are used for isolation of momentary faults on the distribution system and can also be used manually to safely and efficiently disconnect sections of the high voltage distribution network.

Compensators are used to correct for leading or lagging vars on the system due to long lines or switching spikes in the vicinity of customer loads.

LV distribution frames are used in substations to allow for interconnection of supply conductors and radial feeds and also to provide a point of isolation.

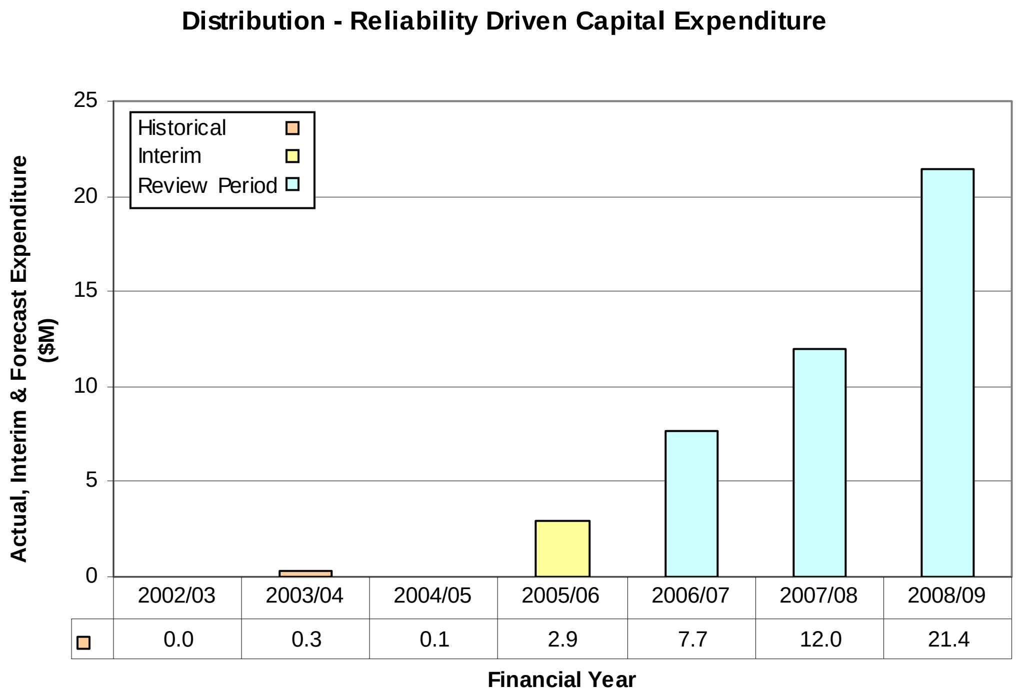
The total projected expenditure over the regulatory period for replacement of distribution equipment is $0.6M.

Other – Additional expenditure of approximately $1M over the 3 year period has been included for wildlife proofing of pole tops in susceptible areas and Emergency Response Generation to maintain customer supply during asset replacement.

Reliability

The average capital expenditure over the regulatory period will increase from an average of $2.0M per annum during the 2002/03 to 2005/06 period, to a forecast expenditure of $13.7M per annum, reflecting Western Power's increasing focus on improving network reliability.

Figure 76 Reliability Driven Capital Expenditure



In January 2005, Western Power management set a target of 25% improvement in SAIDI across the SWIS – over the next 4 years (commencing during 2005/2006). Western Power's SAIDI performance targets are shown in Figure 77 and achievement of these targets will represent the first step in meeting the targets in the Electricity Industry (Network Quality and Reliability of Supply) Code 2005.

Figure 77 - Western Power SAIDI Performance Targets[43] (Regulatory Period)

SAIDI	SWIS	CBD	Urban	Rural
June 2006	289	22.3	252	531
June 2007	277	21.4	242	509
June 2008	259	20.0	226	476
June 2009	224	17.3	195	410

[43] All faults excluding major event days in accordance with SCNRRR and IEEE1366 definitions.

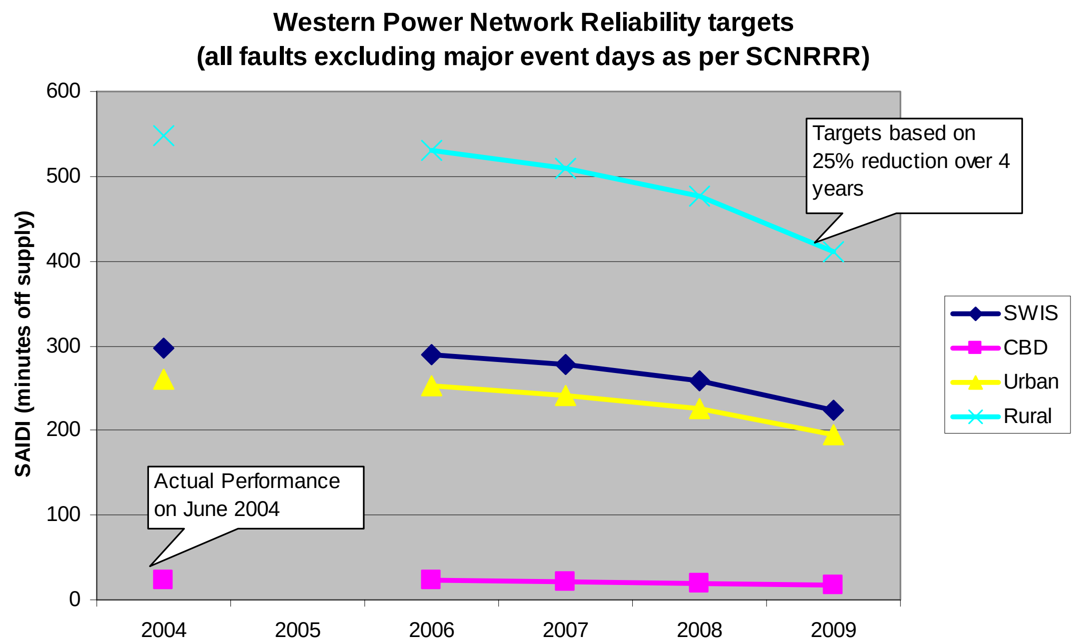
Western Power's current network performance based on all faults statistics[44] as at June 2004, is detailed in Figure 78.

Figure 78 - Western Power Performance Figures – June 2004

Region	SAIFI	SAIDI	CAIDI
Urban	3.61	260	72
Rural	4.43	547	124
CBD	0.34	23	67
SWIS	3.70	298	81

The targets outlined in Figure 77 therefore represent a total improvement of 74 SAIDI minutes across the SWIS. The planned reductions in SAIDI over the Review Period are shown graphically in Figure 79.

Figure 79 - Western Power SAIDI Targets

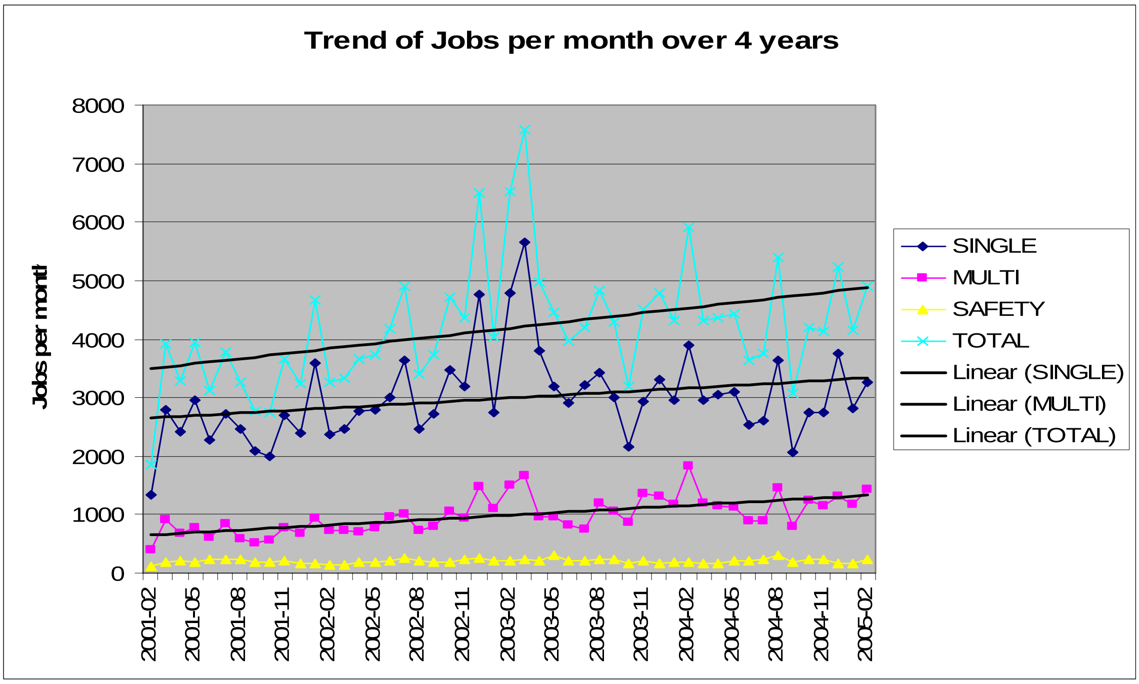


Western Power management adopted the targeted 25% reduction in SAIDI because substantial evidence exists that the current level of network reliability is unacceptable to customers. Western Power has a substantial press clipping register which clearly illustrates that the current number of unplanned outages and outage duration is unacceptable to the general public. In addition comments made by political parties during the last election indicate that other key stakeholders believe that the current level of supply reliability is unacceptable.

Other key indicators are exhibiting a worsening trend such as the total number of emergency jobs being received as indicated by the graph below.

[44] Excluding major event days in accordance with SCNRRR and IEEE1366 definitions.

Figure 80 - Western Power Fault Job History



Furthermore, a third of overall customers believe that the quality of supply has declined, in past years. This was illustrated in the Retail tracking survey carried out for Western Power which identified a steep decline in the last 6 months in relation to perceived reliability performance, both in terms of the number of outages and fluctuations - declining 13%.

Western Power has carried out a customer survey that indicates that 49% of customers do not feel favourably towards Western Power. This figure reflects a declining level of customer satisfaction over recent months. Whilst reliability of supply is important to most customers (86%) many customers believe that a lack of maintenance is the main contributor to poor reliability (43%). Furthermore 58% of respondents who had experienced an outage in the last 12 months were not satisfied with Western Power's response to their outage.

In order to achieve the target improvements described above Western Power has reviewed the proposed capital and operating projects in the Access Arrangement Submission and identified those projects that have some secondary impact on system performance and reliability (Indirect Strategies). The impact of these projects on the overall SWIS SAIDI has been assessed in order to determine the quantum of specific reliability improvement projects required to achieve the desired outcome.

The Direct Strategies, in combination with the Indirect Effect Strategies, are designed to achieve the desired 25% reliability improvement across the SWIS as measured by SAIDI. A detailed description of the Direct Strategies planned to be implemented over the regulatory period follows:

Distribution Automation Strategies.

This strategy will introduce smart mechanisms and remote control methodologies for the prompt identification of faulted network sections and supply restoration to un-faulted sections. The strategy will be approached in two phases: ***Phase 1*** – Pilot Project Initiatives and ***Phase 2*** – Distribution Automation Rollout.

Phase 1 of this project involves targeting equipment such as remote-control load break switches, reclosers, fault indicators, sectionalisers, etc. The remote control of these devices will considerably enhance Western Power's ability to respond to faults quickly, thus minimising outage durations, particularly for those customers connected to sections of a feeder not affected by a fault.

The pilot program will concentrate on a small sample of feeders (1-2) with poor reliability performance and test automation techniques in order to monitor performance and outcomes in a controlled situation. Western Power has estimated that Phase 1 will cost $200,000 per annum.

It is expected that the pilot program will reduce system SAIDI by 1 minute over 4 years.

Phase 2, the rollout of any remote control and/or automation technology, will be dependant on the successful outcome of the pilot Project Initiatives. Assuming that the pilot program is successful it is expected that rollout of Phase 2 can contribute to a SWIS SAIDI improvement of up to 25 SAIDI minutes over the next 3 years.

Phase 2 will include the rollout of approximately 400 Line Fault Indicators (LFI) over the next three years at an estimated cost of $3.8M, the installation of 80 remote controlled pole top switches (PTS) per annum over the next three years at an estimated cost of $2.5M, and the installation of 60 additional reclosers over the next 3 years at an estimated cost of $2.3M.

Worst Performing Feeder Program

In order to substantially improve the SWIS SAIDI quickly it is planned to identify and implement technical solutions for the top 40 worst feeders. The work will include activities such as targeted siliconing, bird-proofing, fitting tightening, surge arrestor installation, spreader installation, line patrol, line thermographic surveys, spreader/spacer installation, vegetation control etc. In addition the work will include targeted conductor replacement including undergrounding and the use of covered conductors as appropriate.

This strategy will target the worst 20 Metro, worst 10 North Country and the worst 10 South Country feeders. The cost is expected to be $30.5M over the next 3 years and is forecast to result in a 21 minute improvement in SAIDI over 3 years.
Figure 81 presents the 40 worst performing feeders at the start of the regulatory period and provides the current position with respect to SAIDI and SAIFI. The criterion used for the selection of the 40 Worst Feeders is based on total contribution to System SAIDI.

It is important to highlight that this list is subject to change, and may be updated as a result of thorough network analysis indicating that a feeder has improved and/or worsened.

Figure 81 Worst Performing Feeders

Geographical Area	40 Worst Feeders	Feeder SAIDI 2004-06	Feeder SAIFI 2004-06
Metro	RO509 BROUGHTON	1588.25	14.18
Metro	H514 SCADDEN ST	767.66	8.75
Metro	MH516 THOMPSON	834.58	12.40
Metro	CC501 RUSSELL RD WEST	698.20	5.23
Metro	SV501 CHIDLOW	774.77	8.75
Metro	RO522 MCLEAN	445.04	5.22
Metro	CVE516 NICHOLSON RD	472.80	9.63
Metro	TT514 TATE ST	440.78	4.69
Metro	YP514 KAROBORUP RD	592.83	9.19
Metro	BYF505 ALEXANDER RMU	631.51	7.48
Metro	D501 VICTOR ROAD EAST	922.49	9.26
Metro	MH517 DOWER.N	274.91	4.14
Metro	MH501 ELIZABETH	246.68	3.99
Metro	YP505 WANNEROO RD NTH	1395.83	11.77
Metro	MED514 LITTLEMORE RD	269.15	4.82
Metro	A506 WADHURST ST	264.38	3.97
Metro	BYF503 ALEXANDER/GEOR	477.97	6.10
Metro	MJ510 SWANVIEW	221.98	3.78
Metro	A503 ARKANA RD EAST	248.77	4.65
Metro	NB504 BRADWELL ST	169.94	2.73
North Country	NOR540 YORK	547.45	2.43
North Country	NOR535 TOODYAY	604.32	6.66
North Country	MOR610 DALWALLINU	1284.85	9.82
North Country	ENB614 JURIEN	618.32	3.67
North Country	GTN602 NORTHAMPTON	663.29	7.88
North Country	KDN603 CORRIGIN	1022.66	8.49
North Country	GTN610 DONGARA	317.26	1.75
North Country	KDN611 KULIN	832.94	5.49
North Country	TS611 MORAWA	681.40	5.62
North Country	GTN620 MULLEWA	382.62	2.56
South Country	ALB514 WILLYUNG	1982.34	12.43
South Country	NGN513 BROOKTON	1330.41	5.64
South Country	BUH525 BUNBURY SOUTH	371.71	3.34
South Country	BNP521 BEENUP	834.24	9.80
South Country	PIC513 KIRUP	601.01	4.57
South Country	BTN516 BOYUP BROOK	1340.55	7.89
South Country	KAT509 GNOWANGERUP	1095.47	9.16
South Country	MJP507 PEMBERTON	1369.14	8.85
South Country	BUH514 CAREY PARK	154.84	3.30
South Country	CLP508 DWELLINGUP	559.43	6.99

Rural Power Improvement Project (RPIP) Stage 2

Stage 2 of this project will provide visibility and control to 78 existing reclosers which will substantially reduce response times after a fault has occurred. It is anticipated that the program will improve SAIDI by 2 minutes over 3 years.

Emergency Generator Project

This strategy is designed to reduce the impact of unplanned outages on SAIDI by providing back up supply to customers via a mobile generator set. In addition customers can at times be supplied via a mobile generator set when restoration times associated with restoring permanent supply are expected to be lengthy such as repairing cable faults in URD subdivisions. This technique is accepted practice in other distribution businesses.

The cost of purchasing the mobile generators is $1.2M in 2006/07 and their use is expected to improve SAIDI by 6 minutes over the next 3 years.

Power Quality Upgrades

This expenditure is associated with the resolution of customer enquiries and complaints relating to power quality and in particular to voltage levels. The expenditure is associated with the remedial works associated with the maintenance of voltage levels within statutory limits.

Expenditures have been relatively constant over recent years and Western Power is predicting that they will remain at approximately the same levels over the review period, namely $4M per annum. Whilst this expenditure is necessary to maintain voltage levels within statutory limits it would have negligible to no impact on system reliability.

Expenditures

The projected expenditures for Reliability Driven expenditures for the Review Period are shown in the chart below. They include expenditures for the distribution automation strategies and worst performing feeder improvement program.

Figure 82 - Reliability Driven Expenditure

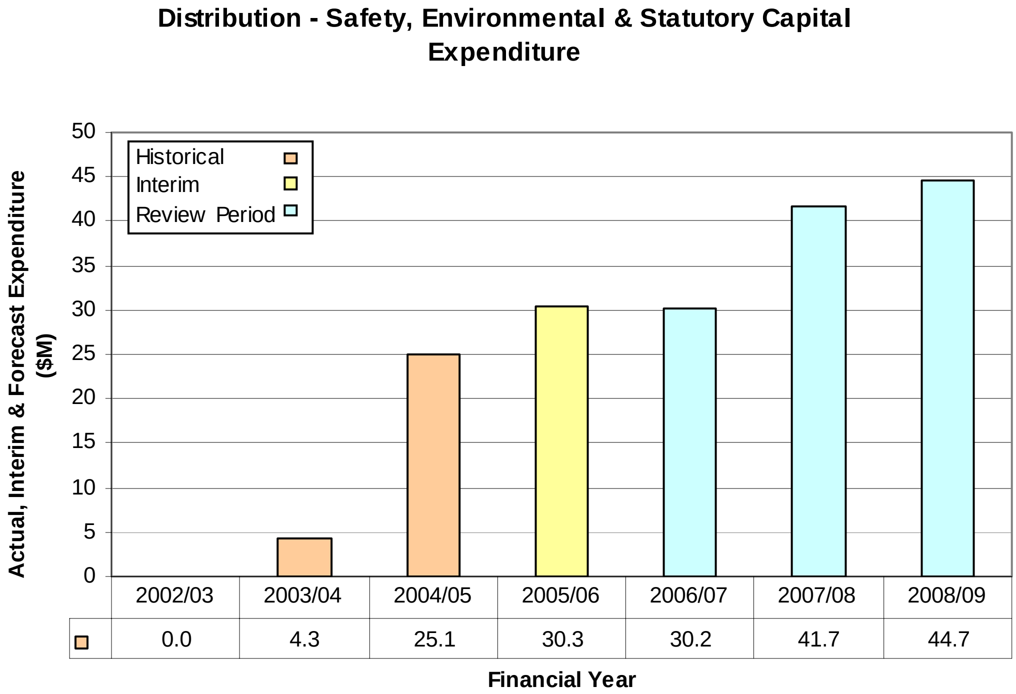
	Year		
	2006/07	2007/08	2008/09
Total Cost per annum ($M)	$7.0	$12.0	$21.4
SAIDI minutes improvement (Reliability Driven/Direct Strategies)	5.5 minutes	8.3 minutes	41.8 minutes
SAIDI minutes improvement (Non-Reliability Driven/Indirect Strategies)	1.7 minutes	2.5 minutes	12.5 minutes

Note: the figures in the above table do not include RPIP Stage 2, Rapid Response Generators and Power Quality Upgrades as these have been budgeted under a different driver.

Safety, Environment and Statutory

The average capital expenditure on safety, environment and statutory capital works over the regulatory period will increase from an average of $13.3M from 2002/03 to 2005/06 to a forecast expenditure of $38.9M per annum, an increase of approximately 192%. A total projects list to a value of $54M per annum was initially constructed and this has been prioritised to produce the remaining project list as described below.

Figure 83 – Safety, Environmental & Statutory Expenditure



Western Power has included the following safety, environmental and statutory projects in the Access Arrangement Submission.

Overhead Service Wires with Twisties

The recent double fatality in Wyndham prompted a capital replacement program to replace services with twistie connections. In 2003/2004 a pro-active pilot test program commenced to gather data on the condition of these assets. Subsequently, survey and inspection work was conducted and a number of replacement options were considered. Western Power decided to replace all existing PVC services with Cross Linked Polyethylene insulated service cable terminated with approved wedge type clamps.

The total projected expenditure over the regulatory period for twisties replacement is $33.8M.

Conductive Metal Streetlight Poles

A number of electric shock incidents have been experienced by members of the public from contact with metal streetlight structures. These incidents seem to have been due to inadequate earthing and/or deterioration or damage of insulation through abrasion inside the metal streetlight arm or luminaire thereby energizing the metal structure.

As a result, a 'design-out' solution has been developed for all new and replacement metal streetlight poles and an inspection program undertaken to identify and rectify any existing metal street light poles with either inadequate earthing or wiring with deteriorated insulation. All new installations, including the luminaries will be double insulated. There are approximately 60,000 existing metal streetlight poles in the SWIS which will be inspected and where necessary maintained.

The total projected expenditure over the regulatory period for the identification and rectification of conductive metal streetlight poles is $5.0M.

Distribution Conductive Power Poles Step and Touch Potential Mitigation

The step and touch risk was highlighted during the investigation of 3 potentially fatal electric shocks to members of the public in the Perth metropolitan area. An estimated 51,000 poles in the SWIS are at special or frequented locations that need to meet the ESAA C(b)1 limits for touch and step potential. The risk is likely to be greater at locations far from the source of supply because the fault level will be lower and there will be less chance of detecting and clearing a fault. A replacement/bonding (CMEN) program is planned to address the problem.

The rectification of this safety issue is also clearly required under the provisions of the Electricity (Supply Standards & System Safety) Regulation 2001.

The total projected expenditure over the regulatory period for the identification and rectification of conductive power poles step and touch potential is $2.3M.

Streetlight Switch Wires

There have been 2 fatalities in the last 10 years and 2 potentially fatal electric shock incidents involving the public in the past 4 years from fallen streetlight wires. Almost two years ago a member of the public received an electric shock from a fallen corroded copper streetlight switch wire close to the coast in Geraldton. It is estimated that there are 250,000 metres of old small-gauge copper switch wires for controlling streetlights in the SWIS that has been corroding and is at risk of failing. When failure occurs the switch wire may fall to the ground and pose a significant risk of electrocution while the switch wire is energised.

The rectification of this safety issue is clearly required under the provisions of the Electricity (Supply Standards & System Safety) Regulation 2001.

The total projected expenditure over the regulatory period for the identification and replacement of corroded small gauge streetlight switch wires is $1.6M.

URD Cable Pits

There are 5,711 below-ground cable pits with insulated piercing connectors (IPC's) used to supply power mainly to residential customers that have been installed in the SWIS as part of the Retrospective Underground Power program. A number of electric shock incidents have been reported by the public and Western

Power employees resulting from such installations. These incidents were caused by either the degradation of the IPC insulation or the incorrect installation of the IPC where not all the available connections were required to be used.

A program to replace these URD cable pits with above ground pillars has commenced and up until March 2005 approximately 25% of these pits had been replaced in accordance with the solution agreed with the ESD.

The total projected expenditure over the regulatory period for the replacement of these URD pits with aboveground pillars is $1.1M.

Henley Cable Boxes

There have been a number of Henley cable box explosive failures in public areas resulting in shrapnel (metal) spread over a wide area. Such failures could have serious consequences, especially in high traffic areas (e.g. shopping centre car parks) where there is a high risk of injury to the public or damage the vehicles. There are an estimated 2,000 Henley cable boxes, which need to be replaced based on site location and traffic with the more critical known sites being resolved first.

This is an industry wide issue and the replacement of the Henley cable boxes is required in accordance with the provisions of the Electricity (Supply Standards & System Safety) Regulation 2001.

The total projected expenditure over the regulatory period for the replacement of these Henley cable boxes is $6.1M.

Cattle Care

The aim of the project is to deny cattle access to the Aldrin/Dieldrin that was applied to the base of wooden poles of power lines that were built prior to 1986. The project is largely reactionary and based on farms that are seeking quality assurance systems.

The project has been initiated to comply with prudent avoidance requirements of Quality Assurance Accreditation Schemes and mitigate the risk of potential contamination of beef with chlorinated hydrocarbon pesticides. The consequences of not taking action include potential loss of shipments of beef at market door (e.g. USA) and potentially disastrous flow on effects for the export market in this commodity and possibly other farm produce.

As the provision of barriers is dependent on customer requests, an allowance of 3,000 barriers at current cost of approximately $470 each has been included in the projected expenditures for the regulatory period.

The total projected expenditure over the regulatory period for the installation of concrete barriers is $1.4M.

Pole Top Switch (PTS) Earthing Mats

Five years ago a Western Power operator received a near fatal electric shock due to an ineffective pole top switch earthing mat. Temporary measures have been taken to safeguard staff until a permanent solution is implemented. About 3,000 pole-top switches in the metro area have ineffective earthing mats and so pose a significant risk of injury to switching operators. This project is on-going and as field inspections reveal problems, the appropriate technical solution is implemented.

The rectification of this safety issue is clearly required under the provisions of the Electricity (Supply Standards & System Safety) Regulation 2001.

The total projected expenditure over the regulatory period for the installation of earthing mats underneath PTS operating handles is $6.7M.

Live-frame Shrouding

Many of the LV frames in district substations have exposed bare live copper busbars. This has been recognised as hazardous to personnel accessing the site and must be rectified so as to protect switching operators and substation inspectors from unnecessary risk of electrocution. The program will involve shrouding the busbars or installing barrier boards. Initial estimates suggest that around 2,500 units will require upgrading.

The solution agreed with the ESD involves shielding the exposed unprotected live busbars to prevent inadvertent contact and revising access locking and permit requirements.

The rectification of this safety issue, which has already caused one electrocution, is clearly required under the provisions of the Electricity (Supply Standards & System Safety) Regulation 2001.

The total projected expenditure over the regulatory period for the installation of the shielding is $1.7M.

Inadequate Reinforcing of Transformer Poles

Recently a transformer pole with limited reinforcement fell over into the middle of a suburban street. Western Power has engaged GHD to re-evaluate the strength of its pole top substation structures and they have indicated that these structures need to be reinforced by installing additional ground line reinforcements.

It is estimated that around 3,000 poles may not be suitable for carrying the weight of 50kVA or larger transformers, and need to be refurbished. This will upgrade the mechanical strength of the respective structures preventing failure with the attendant damage to transformers and reduction of risk to public.

The rectification of this safety issue is clearly required under the provisions of the Electricity (Supply Standards & System Safety) Regulation 2001.

The total projected expenditure over the regulatory period for the additional ground line reinforcement is $2.6M.

Padmount Transformer Noise

The project consists of the construction of noise barriers around padmount substation transformers to reduce noise emissions such that they comply with the requirements of the Environmental Protection (Noise) Regulations. The program of noise mitigation work is to be completed at 26 substations over a 4-year period and is to be completed by the end of 2008.

Non compliance with the requirements of the Western Australian Noise Regulations to reduce the impact of noise emissions on substation neighbours could result in fines of $25,000 and $5,000 per day under Section 51 of EP Act or fines of $5,000 under Sections 79, 80, 81 and 82 of EP Act.

The total projected expenditure over the regulatory period for the installation of sound barriers is $4.0M.

River Crossings

The ESD has advised Western Power that it requires all bare conductor river crossings to be either placed underground or in some agreed circumstances replaced with Hendrix cables installed with substantially increased height above MHW.

Western Power has commenced a program to replace the river crossings in the SWIS and the projected expenditure for the regulatory period is $0.7M.

Bushfire Mitigation

Bushfire Mitigation includes the following expenditure categories in accordance with the Bushfire Management Implementation Plan 2004/05:

Bushfire Mitigation:

- wires down
- pole over
- conductor clashing HV
- conductor clashing - LV
- fire safe fuses
- line fireproofing

This project has been instigated as a result of the desire of both the Western Australian Government and Western Power to reduce the potential for either loss of life and/or property as a result of bush fires initiated by either the transmission or distribution network infrastructure.

All of the individual projects that in combination comprise the Bushfire Mitigation works would fall under the provisions of the Electricity (Supply Standards & System Safety) Regulation 2001.

The total projected expenditure for bushfire mitigation over the regulatory period is $36.2M.

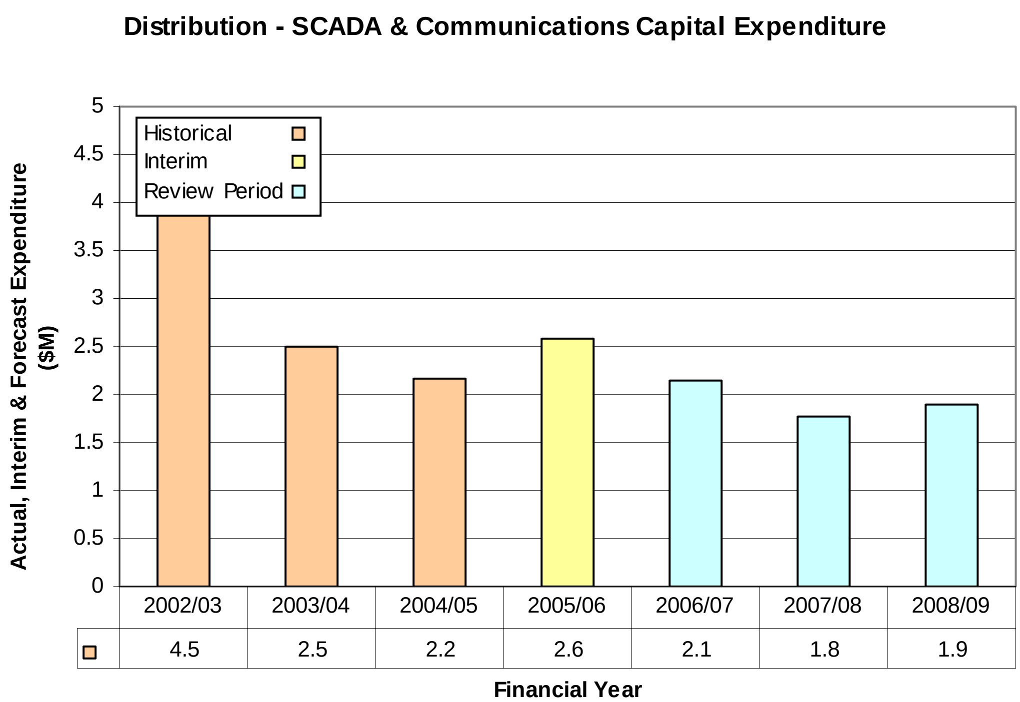
Scada & Communications

The Western Power SCADA and Communications group is responsible for the asset replacement of distribution infrastructure (e.g. CBD SCADA communications fibre, pole-top automation equipment, etc.) and implementation of new infrastructure which complements electricity infrastructure (e.g. optical fibre infrastructure interconnecting distribution substations, mobile radio etc). It does not include SCADA and communication components of capital works sponsored by others for example pole top automation projects including RPIP.

The projected capital expenditures relate primarily to the provision of 'backbone" infrastructure and not to individual SCADA and communication expenditures associated with individual projects which are included in the project expenditures. The capital projects scheduled for commissioning during the review period are as follows:

- Communications asset replacement projects supporting the distribution system (e.g. mobile radio - $1.9M over 6 years to ensure continuity of critical services at end of life).
- SCADA asset replacement projects supporting the distribution system (e.g. replacement of the metro recloser network - $0.8M over 2008 - 2010).
- Communications enhancement projects for mobile radio and distribution automation (e.g. Northcliffe Mobile Radio base and Mt Barker district recloser automation).

Figure 84 - SCADA & Communications Expenditure



It is notable that there are no major capital projects planned over the review period. The ENMAC master station is scheduled for commissioning in 2005/06, and the projects included in the review period relate primarily to minor asset replacement and enhancement projects.

Due to the specialised technical nature of the SCADA and Communications projects, each project is individually designed and costed. Western Power is confident in the efficiency of the SCADA and Communications Group as they have demonstrated their competitiveness on the open market.

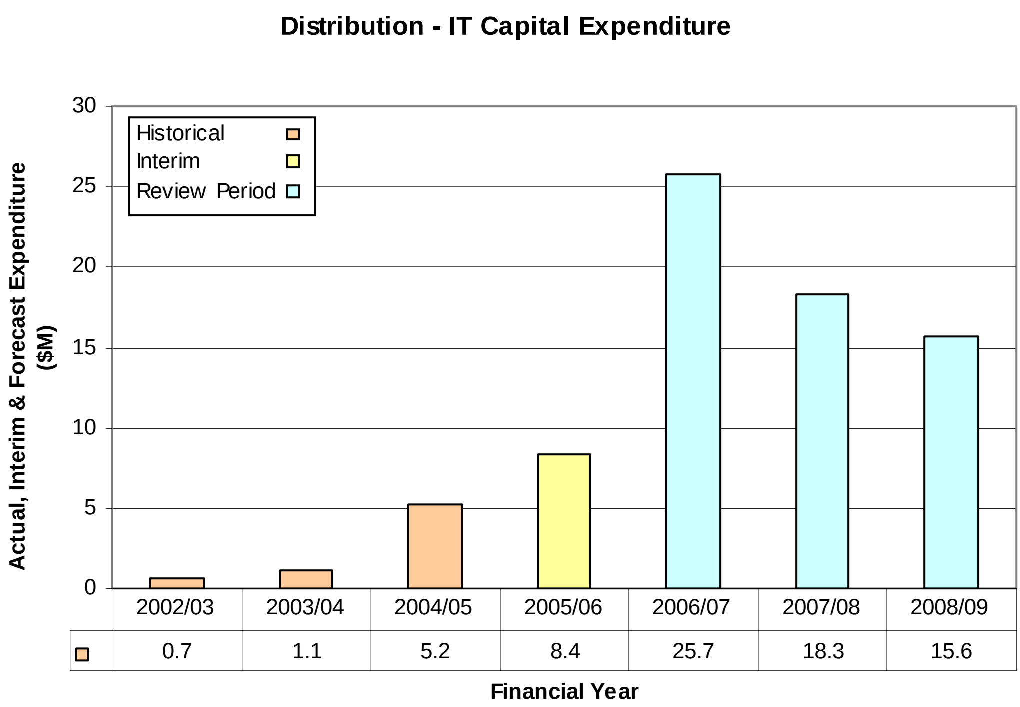
Although SCADA and communications infrastructure in isolation have only minimal impact on safety, environment and reliability, with the notable exception of the radio network, they are essential elements in the overall delivery of these outcomes. They provide the links between system operations and the primary power system assets, enabling remote supervision and control which have major impacts on supply reliability, operator safety, and environmental outcomes.

Information Technology

The Western Power IT capital expenditure includes all:

- Information Technology projects,
- all capital purchases for printers, PDA's,
- software, and
- specialised IT based hardware such as Power Quality recorders and mobile work management hardware.

Figure 85 Distribution IT Capital Expenditure



The Western Power personal computer (PC) fleet is leased and the associated expenditures therefore appear as operating expenditures.

Following the separation WPC, Western Power now includes the IT requirements of the Logistics branch and Metering Services Branch which has contributed to higher forecast expenditures over the regulatory period.

Historically IT expenditure has been low, constrained by business reform and restructuring. Significant increase was required in 2005/06 in preparation for disaggregation and ongoing increased expenditure is required to meet the operational requirements of the new business. The IT forecast expenditures are then expected to decrease over time as the strategic and operational projects are implemented. Key projects and drivers are outlined in the following points:

- Regulatory Project Plan Completion Projects & Business Strategic Project Plan - Expenditure associated with market reform projects, replacement of existing Information Technology systems as they approach or have passed the end of their economical and useful life,

- Application Enhancements – Modifications of existing systems to maintain regulatory and operation function and compliance, and

- Hardware Purchases - A return to sustainable maintenance levels following a period of constrained expenditure.

Regulatory Project Plan

The Western Power reform projects are associated with the implementation of government directives to disaggregate Western Power Corporation and facilitate competition and open access in line with federal COAG directives.

The proposed Western Power Information Technology projects associated with market reform are as follows;

1. Metron - Works include the planning, development and implementation of a Metering Business System to enable the dissemination of metering data to the Western Australian Energy Market participants.

2. Compliance reporting – Works include determining compliance reporting needs and the implementation of a solution to best meet needs of Western Power and the Regulator.

3. Standalone business systems - Configuration of the corporate systems adopted by Western Power after corporate disaggregation is complete. Works include Internet, Intranet, MIMS, Financial modelling, Treasury, DMS, Messaging.

4. Networks Customer Information System - Replacement of mostly manual processes with an off the shelf package that supports access billing, and provides Western Power with capability to manage customers (retailers and non-energy customers) in a de-regulated environment as an independent business unit.

Significant market reform expenditures have occurred in all states that have implemented retail competition in the electricity and gas markets. The vast majority of these expenditures have been incurred in the Information Technology business groups due to the need to radically alter systems to meet the new working arrangements.

The systems identified by Western Power relating to market reform are consistent with meeting the government reforms.

The projected Western Power expenditures associated with market reforms include both disaggregation and competition reforms. On this basis, the Western Power expenditure compares favourably with state-by-state comparisons.

Strategic Project Plan

Over the past 2-3 years, Western Power Corporation's (WPC) and Networks' Business Unit charter and strategic direction have been significantly impacted by the State's Electricity Reform agenda. A number of major IT&T initiatives have been deferred whist reform projects were planned and implemented. These deferments include a number of major Information Technology systems. A number of these systems are 10 years old or greater[45], well in excess of industry norms.

Examples of projects that were placed on hold, or did not commence include Workforce Management, and GIS Review/Replacement, as well as significant asset management and decision modelling initiatives.

The proposed Western Power Information Technology projects associated with strategic system replacement are as follows;

1. Trouble Call Management System – Replacement of the existing outage management systems with a system that is able to provide a higher level of availability than the current systems and that enables system operations to meet regulatory reporting requirements and monitor minimum response times required to restore outages.

2. Work Force Management – Replacement of the mostly manual processes with an automated off the shelf package that supports construction, maintenance, and connection work. The proposed package includes demand forecasting, resource planning and work scheduling as well as including mobile communications for the field workforce.

3. GIS replacement – The current networks GIS Suite has a diminishing ability to support business processes and goals. This project seeks to rationalise Western Power's GIS applications to meet the core business requirements, and to move from platforms that are no longer supported.

The existing IT&T infrastructure is predominantly legacy, including platforms and software that, in some cases, constrains flexibility and presents a risk to business continuity.

Maintenance and Hardware Purchases

IT&T expenditure has come through a recent history of imposed budget constraints and a deferred disaggregation program that limited opportunities to implement strategic IT&T initiatives.

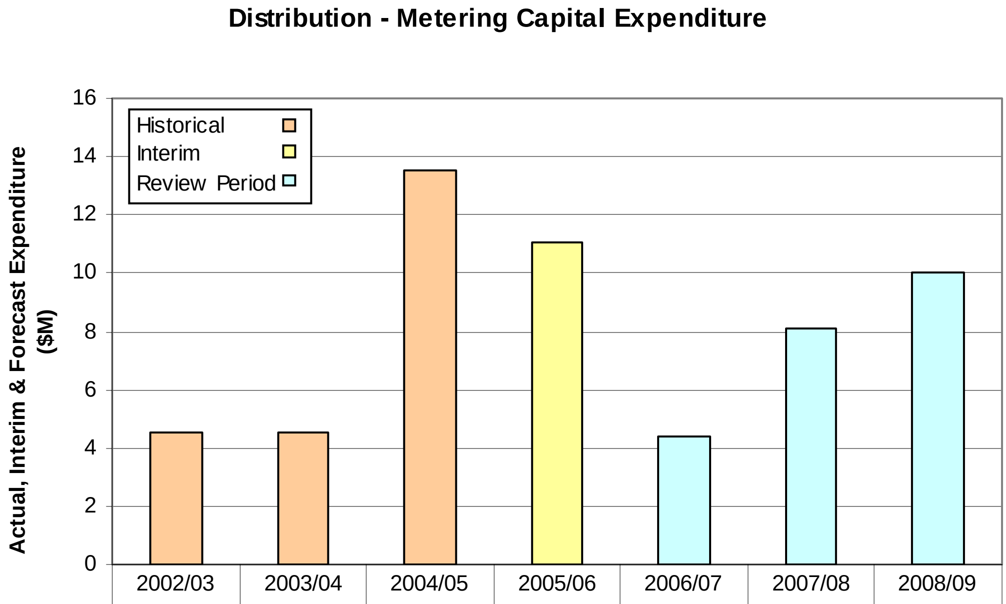
The base levels of IT&T maintenance and hardware purchases projected for the regulatory period are consistent with the ongoing expenditures associated with maintaining network Information Technology systems.

[45] The Graphical Information System (GIS) is in excess of 20 years old.

Metering

Metering Capital expenditure includes all expenditures relating to the supply of meters and communications equipment, capitalised meter installation and commissioning activities for new CT metered installations, and the creation of the network connection point. The forecast presented in the table below includes expenditure for new connections, and a compliance meter change program required for regulatory compliance.

Figure 86 - Metering Capital Expenditure



	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
	4.50	4.50	13.55	11.07	4.40	8.09	10.00

The two main components of the metering expenditure are very different in nature. The new connections component is an ongoing expenditure type for the network business which has shown a gradual increase over the last few years. Generally, Western Power have found the increase in new connection requirements to be in line with increases in Gross State Product (GSP) and have therefore used the forecasts for GSP as a basis to forecast the expected increases in the volume of new connections.

Figure 87 – New Connections Volume

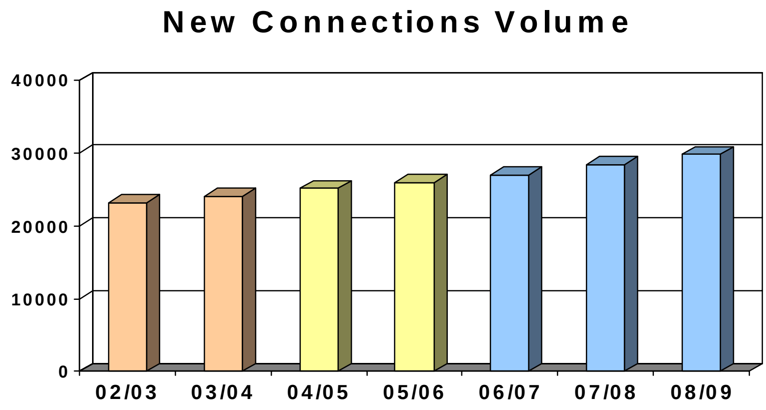
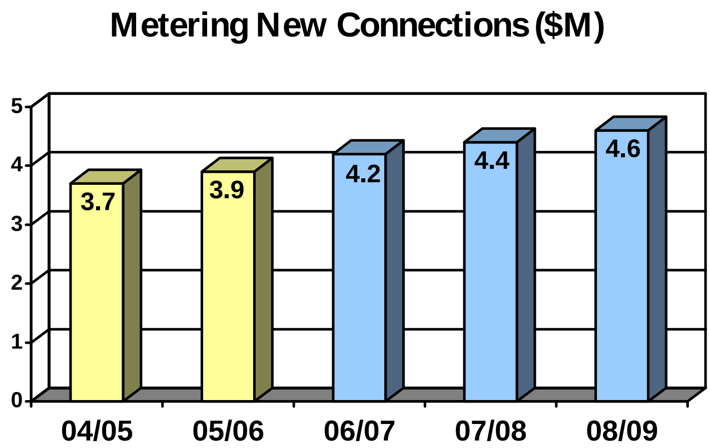


Figure 88 – Metering New Connections



The second main component of the Metering capital program is a meter replacement program required to comply with the Electricity (Supply Standards and System Safety) Regulations 2001 - regulation 9(1). This regulation requires the network business to conduct testing of the accuracy of meters and where a meter population is identified as falling outside the accuracy requirements, based on a sample testing program, the population of meters must be replaced within a three year period. This expenditure type is not regular but is mandatory to maintain compliance as inaccurate meter populations are identified through the testing program.

The sample test program has identified approximately 100,000 single phase meters which must be replaced and expenditure of $9.8 million for replacement of these meters has been forecast between 2004/05 and 2006/07.

A testing program for 3 phase meters is currently in progress and due to the similarity in age and quality of the 3 phase and single meter populations, Western Power has assumed that a similar number of 3 phase meters will require replacement. If this is the case then an expenditure of approximately $16.5

million will be required for the replacement of 3 phase meters and this replacement program will be spread over a 3 year period commencing in 2007/08. As the testing program is still in progress the need for this expenditure is not yet confirmed and has not been included in the forecast expenditure, however it is likely that an increased expenditure level will be required. Once these replacement programmes are completed it is expected that expenditure for compliance with the Electricity Regulations will decrease markedly.

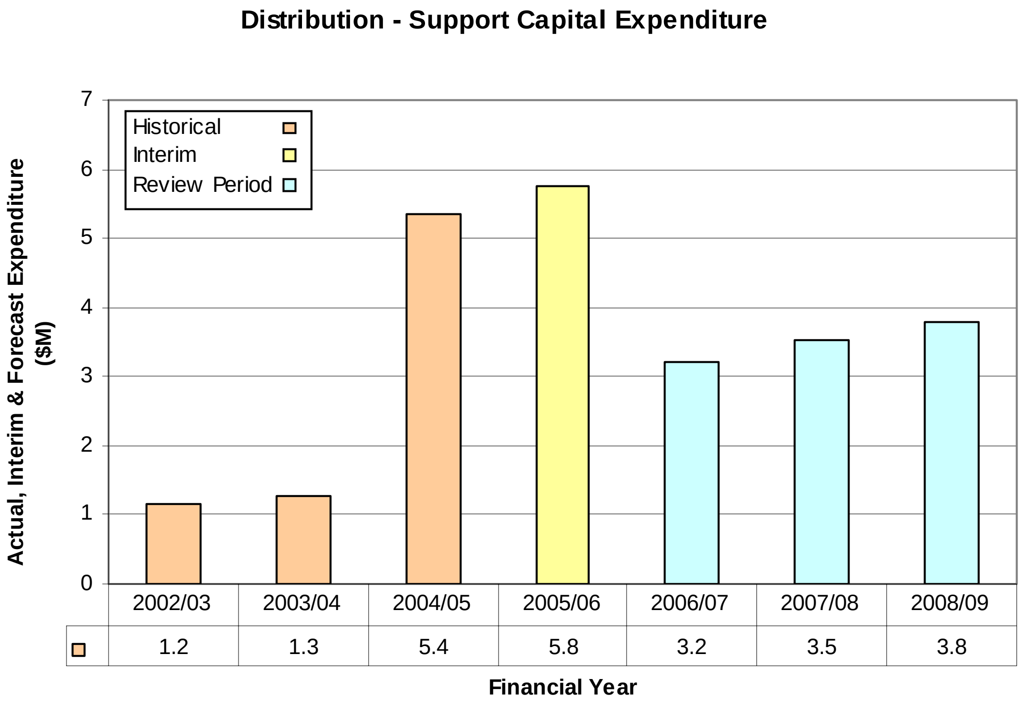
The forecasts for the bulk replacement program are based on replacement of existing electro-mechanical meters with electronic interval meters (both single phase and 3 phase). Western Power has chosen to install electronic interval meters, as the additional time of use data may assist with demand side management and therefore delay augmentation related capital works. These meters are only marginally more expensive than electro-mechanical meters.

Support

The Distribution Support capital budget includes expenditure requirements for capital items to support and maintain office and depot accommodation. Budget items include tools and equipment required for construction, commissioning and maintenance functions and labour costs for the management of the capital works processes and programs.

An average expenditure of $3.5M per annum has been forecast which is in line with recent historical expenditure levels.

Figure 89 Distribution Support Capital Expenditure

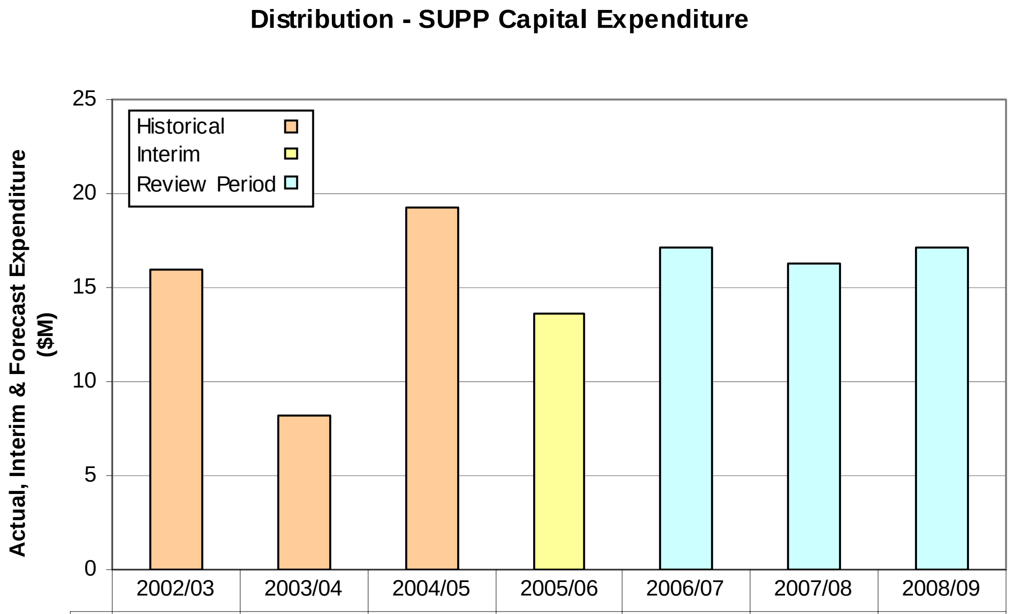


Special Programs

State Underground Power Program (SUPP)

The State Underground Power Program (SUPP) is a WA government initiative to underground 50% of the Perth metropolitan area with a corresponding increase in regional areas by 2010. SUPP capital and operating expenditure includes all expenditures relating to retrospective undergrounding of overhead power systems for selected project areas in the Perth metropolitan and regional areas. The committed total capital budget $17 million per annum.

Figure 90 – SUPP Capital Expenditure



	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
	15.99	8.17	19.30	13.59	17.09	16.29	17.10

The Western Australian Government commenced the SUPP program in 1996 to retrofit metropolitan areas with underground power for network reliability and amenity reasons. A commitment was made to achieve 50% of Perth with underground power by 2010. The funding arrangements for this program are 25% from WA Government, 25% from Western Power and 50% from the Local Government Authority (LGA). Award of the funding is competitive and LGA's are required to apply for inclusion of specific areas in the program.

The recently re-elected government has committed to a continuation of SUPP with election promises including a continuation of current funding levels.
The selection process for Round 4 of SUPP was completed in February 2005. Seven proposals were shortlisted from a total of 89 expressions of interest received. The two stage selection process involved the assessment of proposals against power system reliability criteria and project feasibility criteria.

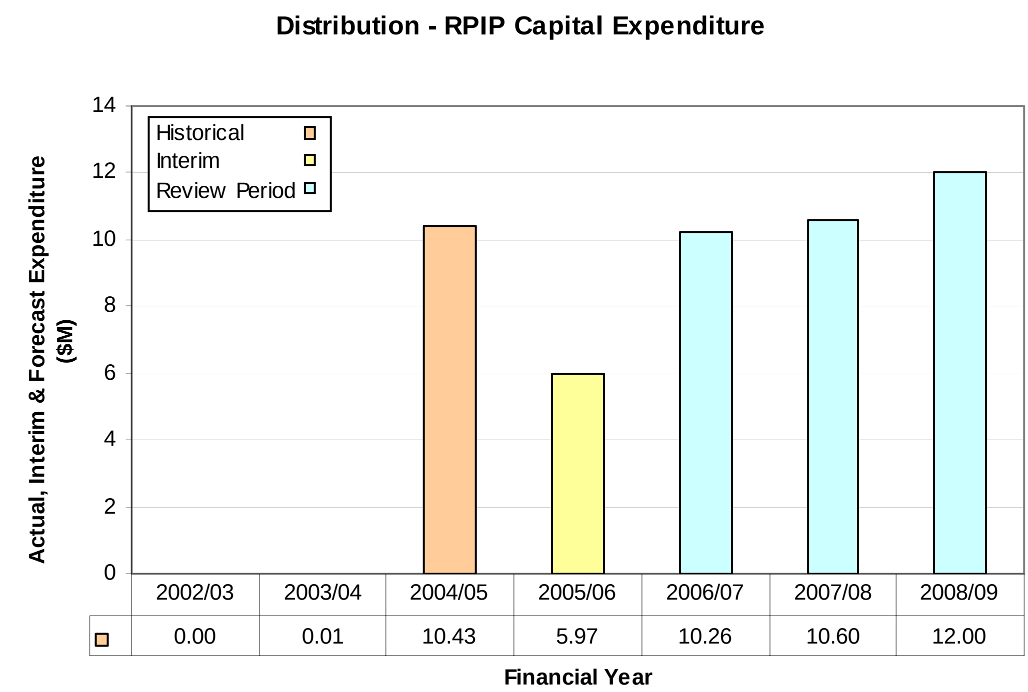
The first stage of the assessment required a comparative analysis of the overhead distribution network in areas nominated by the local governments. The assessment required the network reliability (SAIDI) within these areas to be within the bottom 40%.

The second stage of the process involved the assessment of each proposal against feasibility criteria such as project cost and nominated areas requirements that ultimately determined projects as feasible or not feasible.

Rural Power Improvement Program (RPIP)

The Rural Power Improvement Program (RPIP) is a targeted 4-year, $48M capital expenditure program, partially funded by the State Government in the form of an equity contribution. The broad objective of the program is to enhance power supplies in country areas. The program commenced in 2004/05 and is scheduled to be completed in 2007/08. Due to the success of the project Western Power expects that funding will be extended and has forecast $12M for the extension of the program into 2008/09.

Figure 91 RPIP Capital Expenditure



The RPIP expenditure shown in the above chart and table is broken into 3 phases:

- Phase 1 – projects with a value of $17.6 million have been selected and approved by OoE and are currently in progress. Completion is expected in 2005/06;

- Phase 2 – $20 million worth of projects have been selected and approved by OoE and will commence in 2005/06, a further $10.4 million will be allocated to projects later in the period. Completion of Phase 2 projects is expected in 2007/08.

- Phase 3 – a third phase has been included in the regulatory period forecasts based on the assumption that this successful government endorsed program will be extended with a similar funding level. Projects for Phase 3 would commence in 2008/09.

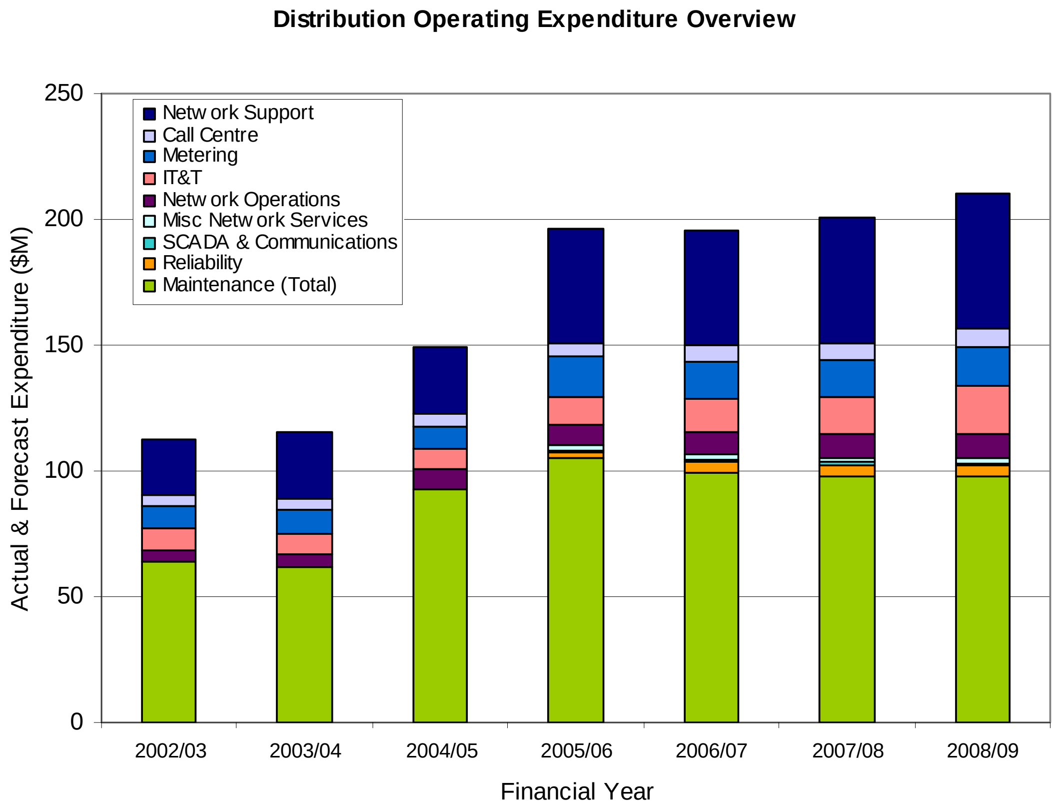
RPIP is a broad scale reliability enhancement program with emphasis on targeting poorly performing feeders in rural areas. The program does not include projects in Metro and CBD areas of the network. The program budget has been evenly split between projects with a capacity enhancement benefit and asset renewal projects. The typical result of these projects is significant improvement in the number and frequency of interruptions to supply, experienced in the targeted local area.

RPIP is a committed program throughout the first 2 years of the regulatory period and provides benefits to customers in rural areas. Based on the extension of other targeted programs such as SUPP, it is anticipated that the WA Government will extend this program for a further period and therefore an additional $12 million has been included for 2008/09.

9. Distribution Forecast Operating Expenditure

Operating expenditure has been forecast for all distribution maintenance and operational activities including maintenance (corrective and preventive), reliability, SCADA and Communications, Network Operations, IT, Metering, Call Centre and Network Support. Figure 92 shows a graph and table detailing the forecast operating expenditure levels for the regulatory period.

Figure 92 - Distribution Operating Expenditure



	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
Maintenance Strategy	3.0	3.6	3.8	5.3	6.3	6.3	6.3
Preventative Condition	8.6	8.9	16.3	18.7	23.0	23.3	22.8
Preventative Routine	8.9	9.3	26.6	28.1	30.3	30.9	31.8
Corrective Deferred	13.2	13.3	15.8	18.4	12.4	11.6	11.4
Corrective Emergency	30.6	27.0	30.0	34.9	27.4	25.9	25.4
Maintenance (Total)	**64.3**	**62.1**	**92.5**	**105.3**	**99.3**	**98.0**	**97.7**
Reliability	-	-	-	2.1	4.5	4.5	4.5
SCADA & Communications	-	-	0.5	0.8	0.9	0.9	0.9
Misc Network Services				2.0	2.0	2.0	2.1
Network Operations	3.9	5.2	7.4	8.5	8.8	9.3	9.7
IT&T	8.8	8.0	8.2	10.7	13.3	14.9	18.8
Metering	8.8	9.2	9.3	15.9	14.4	14.4	15.9
Call Centre	4.5	4.7	5.0	5.7	6.6	6.9	7.2
Network Support	22.2	26.2	26.6	45.4	45.8	50.1	53.5
Distribution ($M)	**112.5**	**115.4**	**149.5**	**196.4**	**195.5**	**200.9**	**210.3**

Western Power is proposing to increase the average distribution operating expenditures by 41%, to $202.2M, during the regulatory period compared with average expenditure levels of $143.4M from 2002/003 to 2005/06. This increase is in response to a number of key drivers that are already or will impact the business over the next 3-5 years.

The drivers for change are:

a) **Regulatory compliance** - particularly relating to the need for additional network inspections and associated follow-up maintenance work to meet prescribed maintenance standards;

b) **Safety** - Improved safety for staff and the public following the identification of a number of key risk areas which require specific remediation programs, particularly relating to incidents of line and pole failures, as well as pole top fires of the overhead distribution system. This also includes bushfire mitigation programs for vegetation management and sparkless fuses;

c) **Reliability** - Increased demands and targets for improved network performance, particularly relating to reliability levels. Some network maintenance programs have been developed to assist Western Power in achieving the significant reductions in interruptions required to meet new reliability targets;

d) **Whole of life efficiencies** - Longer term efficiencies in “whole of life” costs for network assets. Improved preventive maintenance programs have been introduced to achieve an optimal balance between maintenance and asset lifecycle costs. These programs are expected to allow Western Power to extend the operational lives of some assets whilst minimising service interruptions and corrective maintenance costs;

e) **Increasing Asset Base** - Additional assets connected to the network through an increased capital expenditure program;

f) **Increasing Resource Costs** - Increases in average costs for maintenance due to competition for resources and contractors;

g) **Catastrophic Events** - Recognition of the potential for major uncontrollable events such as floods, storms, bushfires and critical equipment failures. There is always a slight probability that a major event could cause substantial cost impositions for Western Power. Whilst the timing of such events is unknown, it is prudent to allow a probability weighted cost factor to mitigate the financial impact of such events on Western Power and its customers;

h) **Corporate Support** - Additional corporate support required to service the increased capital and maintenance resources proposed, as well as accommodate the needs of the newly formed Western Power network business;

i) **Insurance** - Additional insurance costs resulting from a tightening market and the impacts of further regulatory restructuring and reforms.

The following sections provide a breakdown of the distribution operating expenditure cost categories.

As noted in the executive summary of this report, Western Power has undertaken a detailed review of resource availability over the forecast period and has determined a realistic, deliverable expenditure plan. There are a number of other maintenance related activities that Western Power would carry out if resource availability allowed. However, maintenance programs have been prioritised to ensure the most critical and cost effective activities are included in this deliverable work plan.

The information and analysis contained in the subsequent sections of this chapter describes the maintenance activities required to satisfy the key business drivers.

Network Maintenance

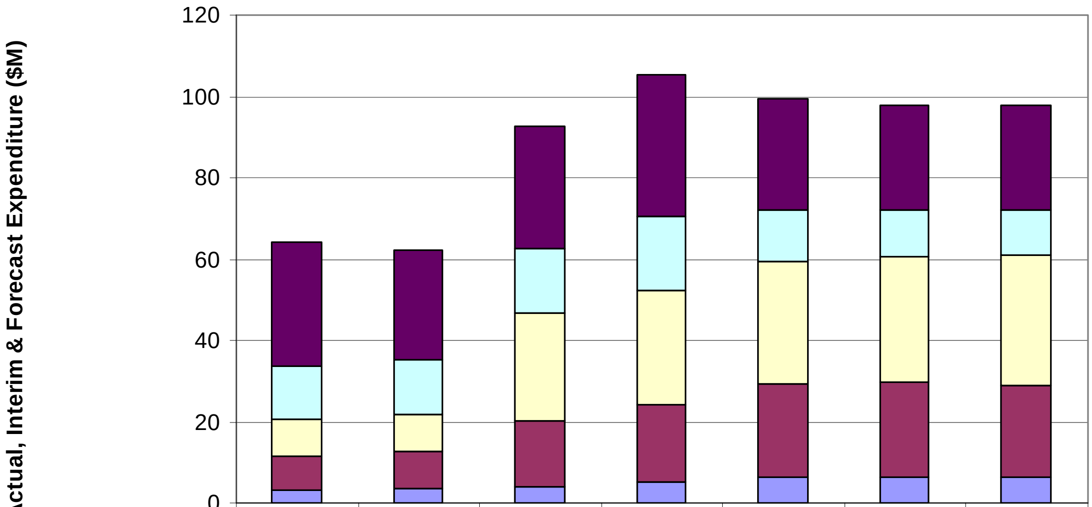
Network maintenance costs are reported under five key groupings of:

- Preventive Routine
- Preventive condition
- Corrective Deferred
- Corrective Emergency
- Maintenance / Strategy

Each of these groups is further dissected in the management accounts into specific work areas to enable tracking of individual jobs and work orders.

Distribution network maintenance costs are projected as shown in Figure 93.

Figure 93 - Historical and Projected Maintenance Expenditures ($M)



	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
Corrective Emergency	30.6	27.0	30.0	34.9	27.4	25.9	25.4
Corrective Deferred	13.2	13.3	15.8	18.4	12.4	11.6	11.4
Preventative Routine	8.9	9.3	26.6	28.1	30.3	30.9	31.8
Preventative Condition	8.6	8.9	16.3	18.7	23.0	23.3	22.8
Maintenance Strategy	3.0	3.6	3.8	5.3	6.3	6.3	6.3

Figure 93 shows that Western Power is proposing to increase the average expenditure during the regulatory period to $98.7M compared with an average expenditure of $81.1M from 2002/03 to 2005/06, an increase of 21.3%. These increases are required in order to achieve and support overall network performance improvements as well as to manage the safety, environmental and regulatory risks faced by the business. Some of the key drivers of these cost increases are:

- Asset aging and subsequent increased maintenance requirements of existing assets;
- Addition of new assets and customer connections;
- Improved system performance and reliability levels;
- Focus on improved staff and public safety following the identification of a number of key risk areas;
- Compliance with regulatory requirements;
- Addressing identified maintenance backlogs which have emerged following periods of budget constraints;
- Key new asset management maintenance initiatives identified through the ongoing reviews of the network, such as Bushfire and vegetation management initiatives, aerial inspections, and washing and silicon coating of insulators;
- Increasing average maintenance costs for many of the maintenance programs as a result of resource constraints for contract services and skilled labour.

Each of these key drivers is discussed in more detail in the following sections.

As demonstrated by the benchmarking data presented earlier in this report in the section "National Comparators", Western Power has generally operated as a relatively low operating cost network with commensurately poorer levels of network reliability. The proposed increases in operating costs, in conjunction with projected capital investments, are intended to deliver a more appropriate balance between service and costs.

<u>Preventive Routine</u>

Preventive Routine Maintenance is proactive maintenance carried out to reduce the probability of failure or degrading performance of specific network assets and is targeted to occur just prior to the expected need for corrective work (asset failure). The activities relate primarily to the monitoring or maintenance of equipment that is carried out at predetermined intervals. This work is generally short duration and typically includes visual inspections, some lubrication regimes and routine minor part replacement.

Western Power has a large and diverse asset base which includes some 57,000 kilometres of HV overhead line, 660,000 distribution wood and metal poles and 65,000 distribution substations and transformers. The environmental characteristics in which these assets operate, along with the remoteness of some areas of line, introduce unique challenges for maintenance of these assets.

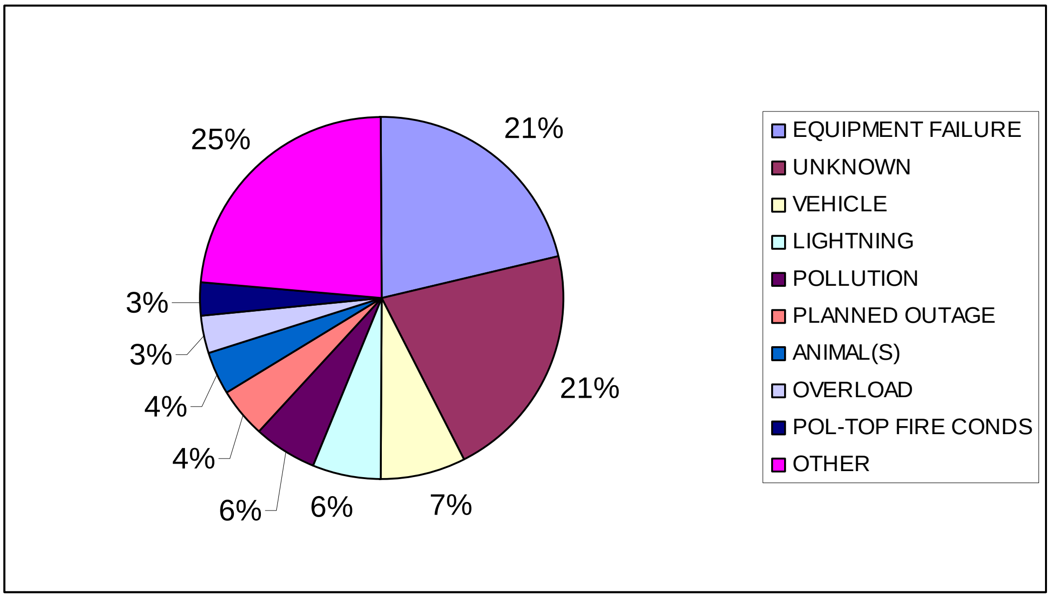
Preventive routine expenditures have increased considerably over the past 3 years. A key feature of past expenditures has been constraints on preventive maintenance budgets which have resulted in a suboptimal mix between preventive and corrective programs. Western Power is proposing to improve this relationship and overall network performance by devoting additional resources to preventive programs. A longer term objective of this strategy is to reduce equipment failure and associated corrective maintenance costs.

This strategy is also expected to deliver improvements in safety, as well as enable effective management of network asset risks. Western Power has formulated programs for increased asset inspections which are targeted to provide more timely information for undertaking rehabilitation works prior to assets failing. This information will be critical to enabling the continual adjustments to maintenance and capital expenditure programs to achieve an optimal balance and cost efficiency.

Western Power has devoted considerable effort to identifying the optimal preventive maintenance programs for each asset class. These have been specified in the Missions for these assets which reflect the "whole of life" cost balancing between maintenance and asset replacement.

The following chart shows the causes of supply interruptions which Western Power has used, in conjunction with costing and other information, to target preventive maintenance programs.

Figure 94 – Supply Interruption by Cause



The chart shows that the predominant causes of supply interruptions are equipment failure (21%) and unknown (21%). Western Power has investigated the unknown events and believes that many of these relate to partially preventable conditions such as equipment failure or debris. In addition to these areas there are further significant interruptions caused by pollution (6.6%), pole top fires (3.2%), and trees in mains (2.3%), which can all be impacted through effective preventive maintenance.

Western Power has increased the volumes of inspections and as a result the overall costs of preventive routine maintenance have increased. This is consistent with Western Power strategy to reduce corrective maintenance and improve asset performance. The key areas targeted which were identified through outage figures and corrective maintenance costs were storms, bushfire mitigation and equipment failures.

The increased inspections have been targeted to achieve regulatory compliance and improve reliability, safety and environmental outcomes as well as reduce the costs of corrective maintenance.

In particular, wood pole inspection requirements designate a 4 year inspection cycle. In 2004 Western Power only achieved inspections of 86,685 poles - approximately 14% of the wood pole population. Western Power is targeting to achieve 25% of the pole population per annum. Western Power has commenced using aerial inspections to achieve its inspection cycles.

Another driver for cost increases over previous years is that the latest available cost information has been used, where we have seen significant cost pressure on unit rates for externally contracted work.

Preventive Routine Maintenance Activity	2006/07	2007/08	2008/09
Pole Base Inspection & Treatment	6.451	6.583	6.778
Insulator Siliconing	4.082	4.174	4.309
Pole Top Inspect & Line Patrols	5.240	5.259	5.657
Vegetation Inspect	3.531	3.589	3.675
Fuse Pole Inspect	4.074	4.141	4.239
OH Switchgear Inspect	0.291	0.299	0.310
Misc OH (OH Service Connections inspections)	0.723	0.923	0.723
G/mounted Switchgear/Substation Inspections	3.100	3.079	3.212
Bulk Globe Replacement	2.788	2.832	2.898
Total Preventive Routine	**30.281**	**30.882**	**31.803**

Preventive Condition

Preventive Condition Maintenance costs relate to the follow-up activities performed as a result of work identified through preventive routine maintenance programs.

As with preventive routine expenditures, preventive condition costs have increased considerably over the past 3 years and are projected to remain at these levels in real terms. This is based on established relationships between inspections, which are projected to increase, and the volume of follow-up.

Backlog

The lower levels of funding for preventive maintenance follow-up works in previous years resulted in some areas of backlog which Western Power is proposing to address over the next few years. The backlog relates to assets that have been identified through inspections as requiring further maintenance or further works but have not as yet been undertaken.

It is evident from the nature of this work that a backlog will always exist. What is critical for Western Power is to establish processes for addressing these identified works in an appropriate timeframe and effectively managing the identified risks and potential impacts relating to each area. Western Power has established a program to reduce the preventive routine maintenance backlog to around one third of the existing levels in each area. This level is considered a reasonable yet manageable proportion which balances the costs and risks. Western Power intends to monitor each area of the backlog to continually re-evaluate the most effective levels of preventive maintenance and has commenced work to assess the risks of outstanding preventive maintenance and determine criteria for initiating this maintenance in the most cost effective manner.

Figure 95 - Backlog Program for Preventive Condition Maintenance

Preventive Routine Maintenance Activity	Current Backlog	2/3 of Backlog	Annual backlog catch up over 4 years
Pole Maintenance	6,118,278	4,078,852	1,019,713
Line Easement Vegetation Maintenance	980,842	653,895	163,474
OH Switchgear Maintenance	1,898,545	1,265,697	316,424
Groundmounted Switchgear Maintenance	270,746	180,497	45,124
Substation Maintenance	337,089	224,726	56,182
Earthing Maintenance	2,862,306	1,908,204	477,051
UG System Maintenance	18,293	12,195	3,049
Street Light Maintenance	8,143	5,429	1,357
Minor Asset Replacement	762,878	508,586	127,146
Total Preventive Condition	**13,257,120**	**8,838,080**	**2,209,520**

Western Power believes it is prudent to establish stable and controllable backlog levels that reflect the risks relating to the nature and class of assets. As indicated inFigure 95, the backlog reduction is scheduled to occur over a four year period from 2005/06 to 2008/09.

Incorporating the backlog catch-up into the baseline figures provides the following projections.

Figure 96 - Baseline and Projected Expenditure for Preventive Condition Maintenance

Preventive Condition Maintenance Activity ($M)	Annual Baseline Cost	Backlog Catch up	Total annual cost	2005/06	2006/07	2007/08	2008/09
Pole Maintenance	3.150	1.020	4.170	5.610	5.670	5.798	5.946
Line Easement Vegetation Maintenance	12.061	0.163	12.224	9.867	14.600	14.771	13.983
OH Switchgear Maint	0.125	0.316	0.442	0.465	0.420	0.431	0.447
Groundmounted Switchgear Maintenance	0.181	0.045	0.226	0.215	0.217	0.223	0.232
Substn Maintenance	0.848	0.056	0.905	0.889	0.845	0.868	0.896
Earthing Maintenance	0.785	0.477	1.262	1.262	1.189	1.220	1.262
UG System Maintenance	0.000	0.003	0.003	0.000	-	-	-
Street Light Maintenance	0.000	0.001	0.001	0.000	-	-	-
Minor Asset Replacement	0.000	0.127	0.127	0.336	-	-	-
Total Preventive Condition	**17.151**	**2.210**	**19.360**	**19.144**	**22.972**	**23.310**	**23.767**

The sum of Preventive routine and Preventive deferred maintenance projections are shown in the following table.

Figure 97 - Projected Preventive Maintenance Expenditures

$ million	2005/06	2006/07	2007/08	2008/09
Total Preventive Routine	$23.8	$30.3	$30.9	$31.8
Total Preventive Condition	$18.4	$23.0	$23.3	$22.8
Total Preventive Maintenance	**$42.2**	**$53.3**	**$54.2**	**$54.6**

In viewing these figures it should also be kept in mind that the backlog catch-up program is scheduled to be completed by the end of 2008/09 and that the preventive maintenance expenditures should then reduce by around $2.2m in following years. There has been no allowance made for addressing backlogs of Preventive Routine Inspection work as the new cycles will effectively ensure that a manageable level of backlog will be achieved by the end of 2008/09.

Corrective Deferred

Corrective Deferred maintenance includes those activities scheduled for the repair failed or damaged equipment but which do not present an emergency outage. These works usually arise following an emergency supply restoration where the supply is restored and/or the situation has been made safe and crews can be scheduled to complete the work at a later stage.

Historical levels of corrective deferred expenditures are provided in Figure 98.

Figure 98 - Historical Corrective Deferred Maintenance Expenditures ($M)

Preventive Routine Maintenance Activity ($M)	2003	2004
Asset Damage - Known Perpetrator	1.40	0.98
Environmental Cleanup	0.12	0.25
Minor Defects	0.33	0.47
PQ Audit	0.00	0.00
PQ Investigation	1.55	1.58
Emergency Follow-Up/Correct Maint O/H	3.64	3.09
Emergency Follow-Up/Correct Maint U/G	1.74	1.86
TVI Investigation	0.25	0.15
TVI Repair	0.26	0.47
Perth One Call	0.18	0.31
Data Correction	0.47	0.31
Data Maintenance	0.06	0.18
Graffiti Cleanup	0.07	0.13
SOII	0.48	0.70
Emergency Follow-Up Asset Replacement	0.77	0.64
Car Versus Pole	1.06	1.03
Asset Damage - Known Perpetrator	0.01	0.71
Vandalism	-	-
Total (excluding metering and chargeable works)	12.38	12.86

As previously discussed, past budgetary constraints in preventive maintenance programs have resulted in some additional corrective expenditures. As a result of the proposed increases in preventive maintenance and inspections Western Power is projecting for corrective maintenance requirements to fall. The levels of reductions are based on estimations of outages and associated restoration works which indicate that savings of around $1.3m or 10.4% in nominal terms can be achieved in corrective deferred maintenance. The majority of these savings are expected to occur in 2007 as a result of the targeting of preventive maintenance programs to higher impact areas. From that time on the anticipated levels of expenditure should remain consistent with asset quantities and unit costs.

It is noted that corrective maintenance is often subject to significant volatility due to the occurrence of major external events such as storms, floods, fires and major equipment failures. Western Power has not incorporated allowances in these projections to account for such events. This is an area which requires further consideration and Western Power is reviewing probability data to assess the impact and likelihood of these occurrences.

Corrective Emergency

Corrective Emergency maintenance includes those maintenance activities carried out to immediately rectify an equipment failure and/or to make the site safe following an incident. This type of work generally occurs without warning and is performed immediately to establish restoration of supply, ensure safety to the public and personnel, and prevent further damage to equipment.

A breakdown of historical emergency costs by cost code is provided in the table below.

Figure 99 - Historical Corrective Emergency Maintenance Expenditures ($M)

Corrective Emergency Maintenance Activity ($M)	2003	2004
Primary Response Assistance	11.47	8.46
Primary Response Group	6.24	8.02
Streetlight	3.83	3.69
Storms	7.88	5.78
Truck Items & Minor Consumables	1.25	1.08
Total	30.62	27.03

As the above table shows, most emergency costs are recorded as either Primary Response Assistance (PRA) or Primary Response Group (PRG). This reflects the practice of Western Power to firstly identify the nature of the incident and then deploy the resources necessary to best address the emergency. The identification of storms as a specific cost code has also enabled Western Power to analyse these costs, which are difficult to control, and to isolate these costs from other emergency situations.

Western Power has investigated the causes of emergency maintenance costs where possible and has identified the following key areas from work orders and job sheets.

- Storms,
- Bushfires,
- Equipment failures,
- Pole down,
- Trees and vegetation.

Western Power is now in the process of identifying the corrective maintenance costs associated with these outages to enable preventive maintenance programs to be tailored to achieve the most cost effective asset management strategies. This approach is similar to that adopted by other Australian electricity distribution businesses. Based on the analysis of existing information Western Power has introduced the following programs with the aim of reducing corrective emergency and deferred maintenance, as well as achieving the additional benefits of improved reliability, regulatory compliance, safety and environmental sustainability.

Pole Base Inspection and Treatment

Preventive routine inspection of pole from the ground and sound wood testing of poles have been increased to comply with regulatory requirements and to reduce corrective maintenance costs. Adhering to a four yearly cycle is anticipated to reduce pole failures. The program also involves the chemical treatment for wood rot and termite infestation.

Vegetation Inspection

Routine 'vegetation spotting' patrols have been increased to identify vegetation encroachment into clearance zones, with specific emphasis on extreme and high fire risk areas. Medium and low fire risk areas are also included on a reduced inspection frequency.

Insulator Silicone Coating

Pole top fires have been identified by Western Power as a considerable factor in both the level and cost of supply restoration. The application of silicon grease to insulators has been introduced in order to reduce the incidence of pole top fires. This covers most critical feeder sections close to the coast or in significant pollution zones. Pole top fires also represent a considerable safety and bushfire risk.

Line Patrols / Pole Top Inspection

This activity includes the inspection of overhead lines and pole top hardware from helicopter, light aircraft and EPVs. The inspections cover:

- Conductors and earth-wires;
- Cross-arms and insulators;
- Cable terminations;
- Capacitor banks;
- Surge arrestors; and
- Transformers.

Pole top inspection programs cover approximately 200 feeders annually, representing one quarter of the feeders (or a four-year cycle). This activity is considered important by Western Power in detecting sagging or deteriorating conductors, long bays or poor condition pole tops in order for preventive action to be taken before conductors clash or fall.

Ground Mounted Switchgear and Substation Inspections

This activity includes the inspection of substations and HV/LV ground mounted switchgear housed in indoor substations, compounds and kiosks. It also covers the four yearly routine maintenance of Ring Main Units (RMU) and is intended to identify equipment that is in poor condition.

<u>Summary of Corrective Maintenance</u>

Based on the introduction of these preventive maintenance programs Western Power has targeted to reduce corrective emergency maintenance to from $32.4M in 2004/05 to $25.4M in 2008/09, a reduction of 28%.

Maintenance Strategy

These costs reflect a relatively new initiative of Western Power. The work relates to the management of asset strategy development as well as short duration specific projects or asset evaluations which are targeted to identify opportunities for improving the management of assets through strategic initiatives. The table below shows the recent historical and projected costs for Maintenance Strategy.

Figure 100 - Historical and Projected Maintenance Strategy Expenditures ($M)

$M	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
Maintenance Strategy	3.1	3.6	3.8	5.3	6.3	6.3	6.3

Western Power has developed this category to provide a conduit for strategic consideration of asset maintenance and improving the overall efficiency and effectiveness of asset maintenance programs. As such, Western Power is expecting benefits of these expenditures to manifest in terms of reduced maintenance costs, reduced network interruptions, better environmental management, full regulatory compliance, and improved public and staff safety. These costs, therefore, can best be viewed in conjunction with the preventive maintenance program with the clear expectation that the desired benefits will emerge.

Western Power has formulated numerous initiatives over recent years and recognises that it will require time for the results of these initiatives to be fully realised. It is critical in our view that a long term perspective be applied in assessing the effectiveness of such strategies. Western Power considers the focus on strategic asset management as a corner stone of its plan for improving the efficiency and performance of the network.

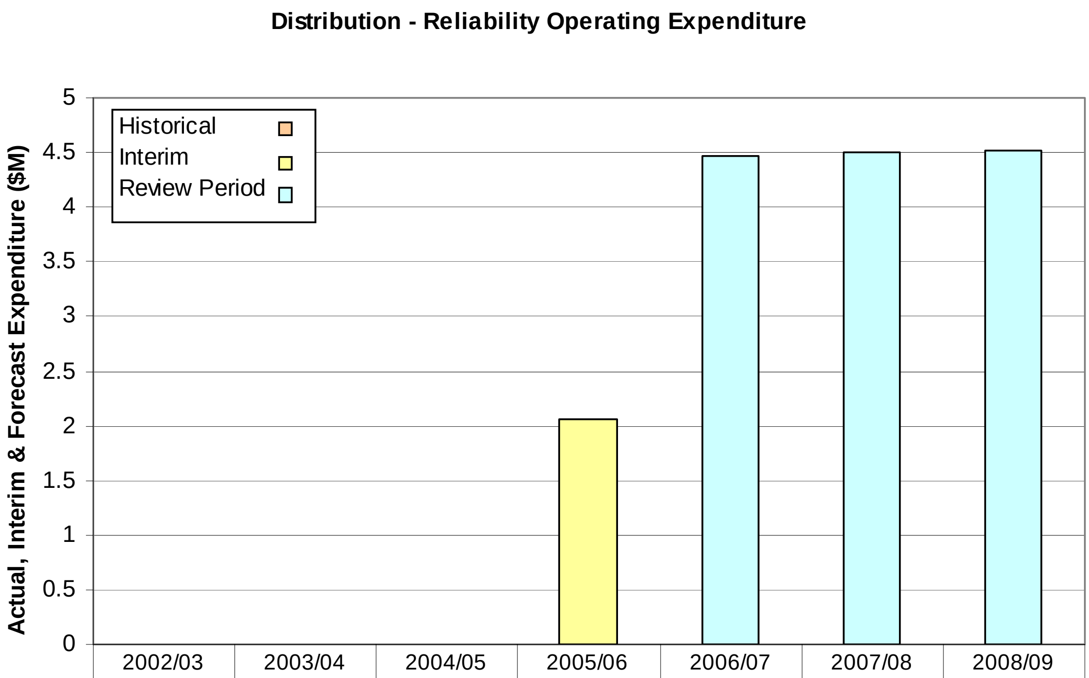
Reliability

Western Power's efforts to improve network reliability for both transmission and distribution networks are discussed in section 4 of this report and in the capital expenditure sections for both transmission and distribution.

An operating expenditure provision of $4.5 million per annum has been made relating to the forecast cost to be incurred as direct result of the implementation of the Extended Outage Penalty Scheme, an element of the Electricity Industry (Network Quality and Reliability of Supply) Code 2005. The forecasts are based on estimates of 20,000 claims received over a 12 month period and include all the necessary related resources (staff and systems) required to administer the scheme.

Figure 101 illustrates that this is a relatively new expenditure category introduced in 2005/06 specifically to cater for the Extended Outage Penalty Scheme.

Figure 101 Distribution Reliability Operating expenditure



	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
	-	-	-	2.1	4.5	4.5	4.5

SCADA & Communications

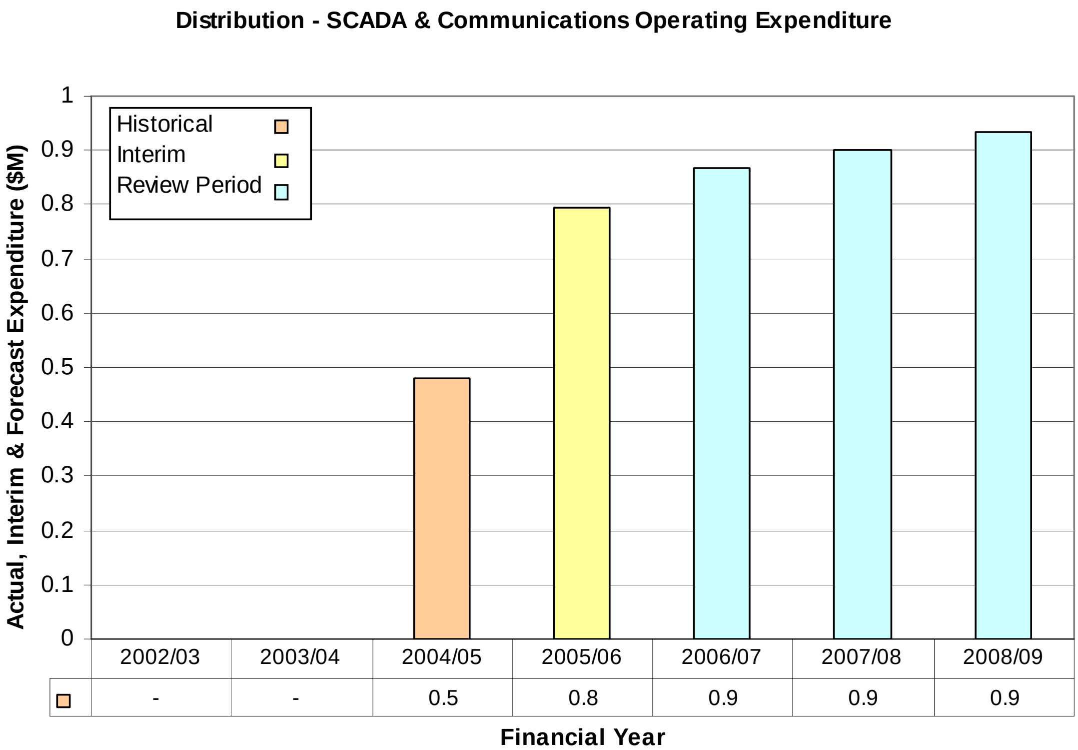
The Western Power SCADA and Communications group provides Strategic Planning, Communications Network Design and Optimisation, Maintenance & Operations, Radio Communication Licenses for the Western Power Transmission and Distribution network.

Projected operating costs for Distribution SCADA and Communications over the review period include the operations and maintenance of the radio network, strategic planning and network optimisation, and the design and estimating for Distribution automation projects.

Staff training costs are also included which minimises the impacts of staff turnover and the increased workload associated with increase in the infrastructure assets and changing technologies. It is anticipated that staff numbers will stabilise in 2005/06 and expenditure will increase only marginally from this point.

Western Power projected expenditures for Distribution SCADA and Communications operating expenditures are detailed Figure 102. The data indicates a step increase in operating expenditures between 2003/04 and 2004/05 due to the implementation of the new SCADA Distribution master station. The expenditures are relatively constant from 2005/06 onwards.

Figure 102 - SCADA & Communications Distribution Operating Expenditure



Although SCADA and Communications infrastructure in isolation have only minimal impact on safety, environment and reliability, with the notable exception of the radio network, they are essential elements in the overall delivery of these outcomes. They provide the links between system operations and the electrical assets enabling remote supervision and control which has major impacts on supply reliability, operator safety, and environmental outcomes.

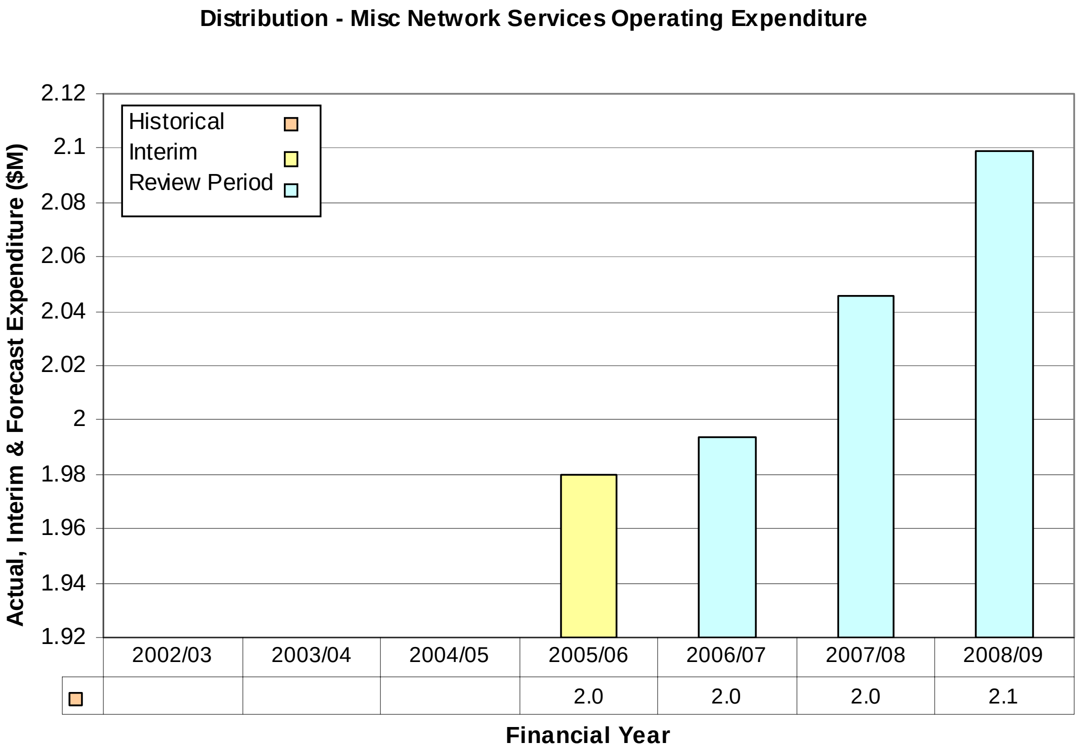
Miscellaneous Network Services

A variety of miscellaneous distribution network services are provided to customers, including:

- Requested relocation of assets;
- Network planning studies;
- Requested network switching/isolation;
- Temporary builders supplies; and
- Escorts for transport of high loads.

The forecast expenditures reflect historical levels of services provided, noting that the costs and associated revenues have not previously been accounted for within regulated revenues.

Figure 103 Distribution Miscellaneous Network Services Operating Expenditure



These work activities are included in the “non-reference services” listed in the Access Arrangement.

Network Operations

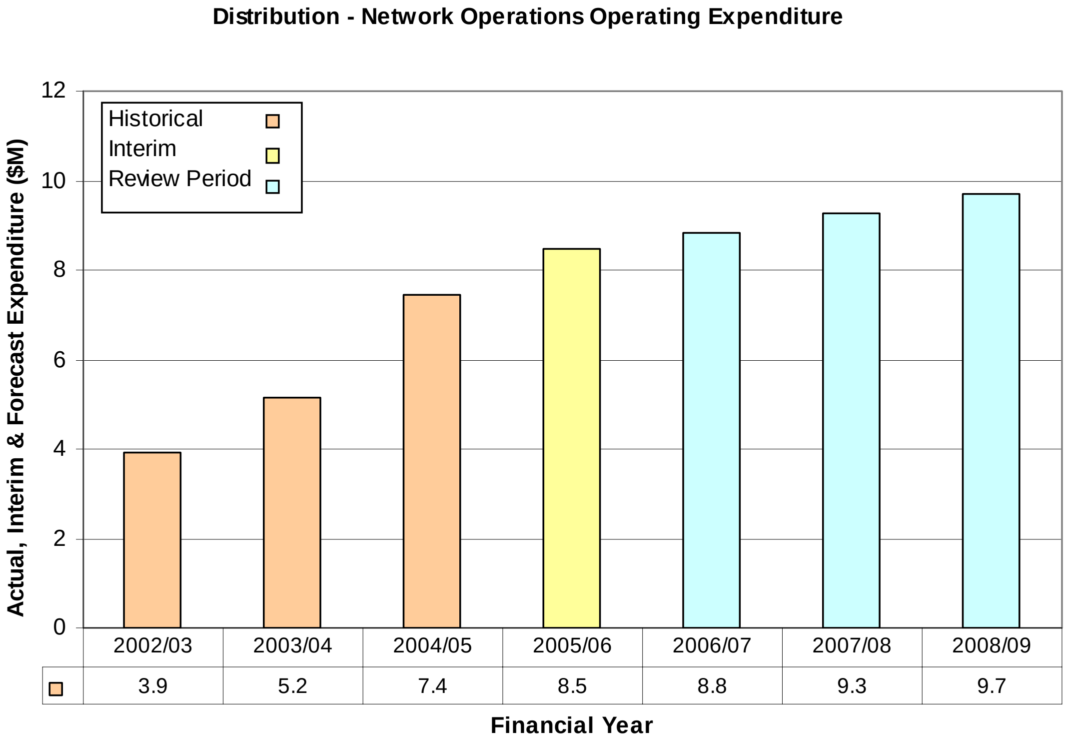
The System Operations group provides control, switching, operations planning and monitoring for the Western Power transmission and distribution networks. The forecast expenditures do not include the telecommunications side of IT&T or SCADA.

Government mandated reforms will impact significantly upon the future expenditures of the System Operations group with the need to facilitate the implementation of an Independent Market Operator and other industry changes.

Western Power is also proposing the implementation of additional SCADA assets, resulting in an associated increase in System Operations operating costs.

The Network Operations expenditures show a steady increase into the regulatory review period. The increases are in part based on the overall increase in business as usual activities as well as fuel costs and market reforms.

Figure 104 – System Operations Distribution Operating Expenditure



Business as usual activities are impacted by a projected increase in labour costs and material costs of 4% and 1% respectively. Fuel costs associated with Bremer Bay have been included in the Network Operating expense.

As indicated by the increase in expenditure levels, there have been significant changes to Network Operations since 2003. Network Operations has incorporated some of these changes and is currently operating with a staffing level of 39 FTEs, there is a further requirement to increase staffing levels by a further 13 FTE's by the end of the regulatory period in order to fully manage the changes to network operations activities required. Implementation of the following changes and improvements is in progress:

- centralising monitoring and control;
- centralising switching schedule writing;
- increased network operations resources to provide safe access to the electricity network to accommodate the proposed increased level of capital and operating expenditure programs such as RPIP, customer funded work and network reinforcement;
- significant increase in the workload of Network Operations due to the outsourcing of maintenance programs such as pole top switch maintenance and vegetation management;
- Improved coverage of Call Centre activities;
- Regulatory and market reform changes.

A detailed outline of each of these activities and its impact on network operations is provided in the following sections:

<u>Centralising of Switching Schedule Writing</u>

The writing of electrical switching schedules has been centralised as part of the new distribution management system. Centralisation of this activity is in line with national trends for other network operators where centralisation provides efficiencies of scale, consistency, quality and safety benefits.

Centralisation of this activity has resulted in 6 new positions for Schedule Writers. These positions were not displaced from other parts of the organisation because this work was spread through a large number of field operators where it represented only a portion of their total time. Additional staff are required to achieve the improvements in consistency, quality and safety.

<u>Centralised Monitoring and Control</u>

In the 2003/04 period only the Perth metropolitan area was under centralised control. The control of the SWIS country areas, North Country and South Country had always been delegated to the local depots. Historically there has been a high degree of variability in data quality, work practices and the ability to audit activities across the regional depots.

With the increasing customer expectations and regulatory requirements it is essential that record keeping, data quality and operating practices be standardised across Western Power’s business. The RPIP project and reliability initiatives, such as the 25% improvement, have significantly increasing the amount of telemetry and the requirements for 24x7 monitoring and control. This necessitates the centralisation of control to Network Operations at East Perth for resource efficiency, management and security.

To provide an adequate service to field staff requires two day-shift control desks, one North one South. This has resulted in 4 new day shift positions for country controllers because this is a seven days a week position, and 1 new support position for schematic and operational display maintenance. At this stage, it is assumed that the existing staff will cover night shift, storm escalations and leave periods.

<u>New Distribution Management System</u>

The introduction of the new distribution management system has resulted in the need for more engineering support for the control room to support advanced network modelling tools such as Distribution Power Analysis (DPA) and other tools.

DPA is the real time load flow tool that is part of the ENMAC™ Distribution Management System (DMS). DPA allows the controllers and operational engineers to take much of the guess work out of supply restoration following faults and manage the network better for planned work. DPA allows network operations staff to predict and analyse potential problems before they become real ones. This is starting to significantly improve outcomes for customers in terms of power quality and reliability and also places less stress on network assets by allowing the operators to run the distribution assets within their limits.

Western Power is the first utility to successfully implement DPA on ENMAC anywhere in the world and we believe the only network operator in Australia with a similar facility of this kind. The introduction of the new distribution management system has resulted in 1 new support engineer to support advanced network modelling tools such as Distribution Power Analysis (DPA).

<u>Significant increases in maintenance, customer funded CAPEX and network reinforcement CAPEX</u>

Compared to the 2003/04 period there has been a significant increase in 'business as usual' network operation activities. Network Operations controls and coordinates the safe access to the distribution network for all planned and unplanned work and 'sees' all of the extra CAPEX and OPEX work. The increased asset maintenance OPEX and the outsourcing of maintenance programs such as pole top switch maintenance and vegetation management have all resulted in an increased workload for network operations, as they all require safe access to the electricity network.

This has resulted in 2 new positions for Network Officers writing switching schedules and 1 new support position for schematic and operational display maintenance, due to the increased number of system changes. Any reduction in this area is likely to result is bottlenecks being created and will impede the ability of Western Power's asset managers to complete the increased opex and capex programs.

<u>Call Centre Activities</u>

Compared to the 2003/04 period Network Operations call taking arrangements have improved considerably.

The previous arrangement required the Controllers to take fault calls and did not provide a professional service to meet customer expectations and acceptable service standards. The Call Centre service to customers has improved significantly.

The Synergy Call Centre has not been able to take calls 24x7 for various reasons including reform and a restructuring of the Call Centre. There is also some uncertainty on the ERA's position with respect to conflict of interest and Synergy's access to other Retailer's customers for fault call taking. Network Operations continues to cover 88-hours per week of after hours fault calls for Western Power and Horizon. This normally equates to 120-man hours per week and is primarily covered by a roster of approximately 10 contract staff. The hours required in any one particular week may be higher due to escalation for storms and major network disturbances. The additional staff also allow for the potential increased call volumes due to the $80 Extended Outage Penalty Scheme payments.

The cost of this coverage is approximately $300k PA. There is also an increased coordination and administration cost equating to approximately 0.2FTE.

Regulatory and Market Reform changes

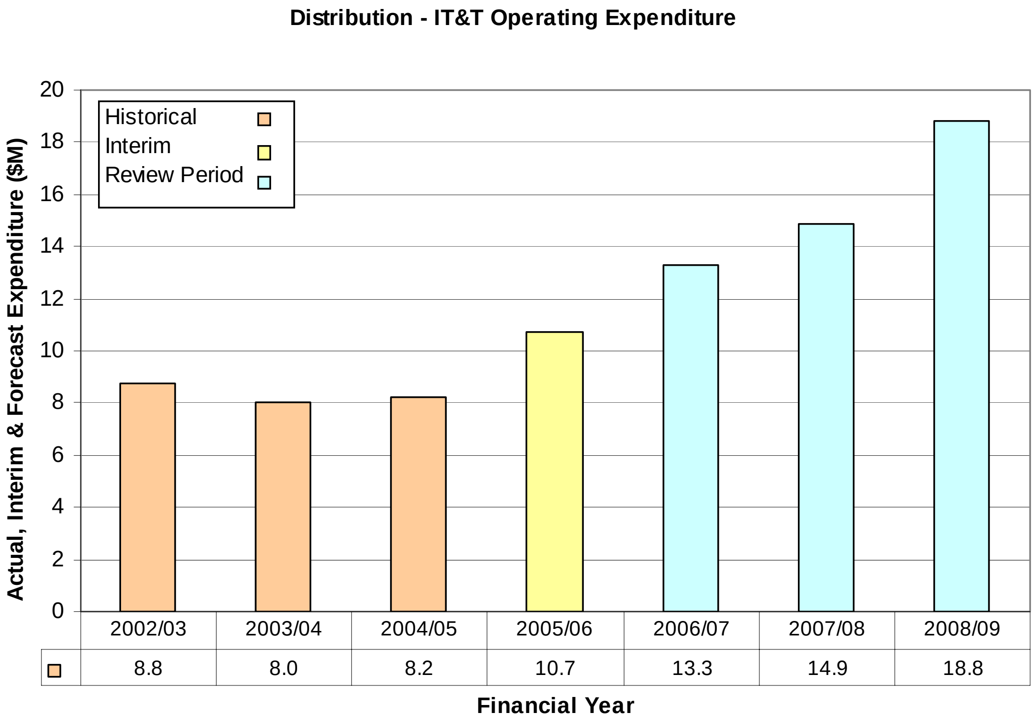
The regulatory changes and market reform changes have created extra work to manage the interfaces between businesses. A particular example is the management of Sensitive Customers for operational purposes such as restoration prioritisation and load shedding stage. The Network Operator must maintain the list of Sensitive Customers and prioritisation based on risk management and not just one dimension such as energy consumption.

To date, this has resulted in 1 new support position for liaison and maintenance of operational database.

Information Technology

The Western Power personal computer (PC) fleet is leased and the associated expenditures are therefore captured as operating expenditures. The general trend for Western Power's Information Technology operating expenditure is increasing as highlighted in the following figure.

Figure 105 - Information Technology Distribution Operating Expenditure



Base IT&T maintenance is projected by Western Power to grow at 4% per annum for the forecast period. The forecast includes adjustments for labour and material inflation and increases in overall employee numbers.

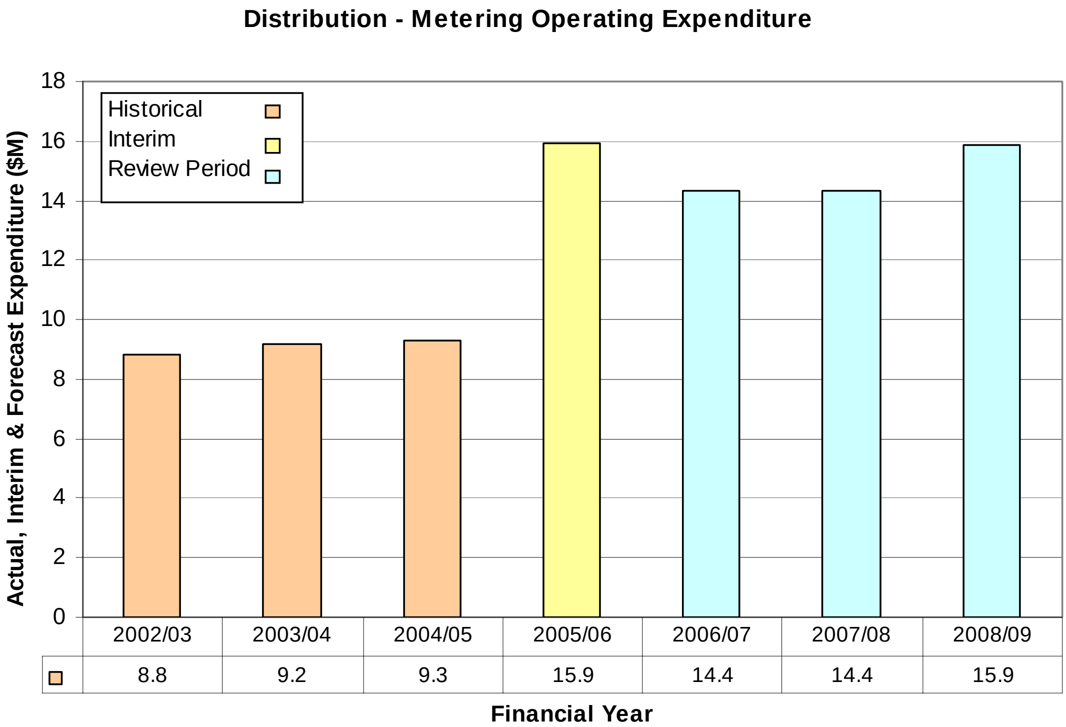
The proposed expenditures associated with the regulatory and strategic project plans are based on individual project plans. The Information Technology operating expenditure increases are well supported by the detailed project plans and are well documented.

Metering

Metering Services operating expenditure includes all expenditures relating to the provision of the following meter and connection related services:

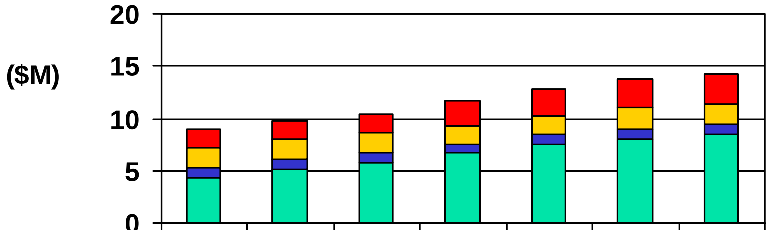
- Regulatory Inspections Services;
- Metering Provision including field maintenance and laboratory activities;
- Data Management including administration and meter reading, and
- Meter Reading.

Figure 106 – Metering Maintenance Base Case Operating Expenditure



The metering services operating expenditure is recurrent in nature and the majority of the expenditure for meter reading and data management is directly related to number of meters in the network. Western Power has been nominated as the meter provider and meter reading agent, and there is currently no competition for these services in Western Australia.

Figure 107 - Metering Services Operating Expenditure Break down



	02/03	03/04	04/05	05/06	06/07	07/08	08/09
Inspection Services	1.615	1.699	1.737	2.38	2.545	2.651	2.77
Meter Provision	1.998	1.963	1.948	1.741	1.843	2.191	1.994
Data Management	0.962	0.965	1.039	0.812	0.895	0.935	0.97
Meter Reading	4.310	5.073	5.719	6.721	7.564	7.989	8.434

Inspection Services covers the regulatory requirement under the Electricity Regulations 1947 to maintain a system of inspections to ensure customer installations are safe for connection and use.

Activities included in this expenditure category include installation inspections, contractor auditing and breach investigations. There is also provision for materials such as protective clothing, equipment and vehicle fleet costs.

The volume of inspections is expected to increase from the current level of 21,000 to 22,000 per annum to approximately 24,000 to 26,000 per annum during the regulatory period. This is in line with projections of customer connection works. Therefore the expenditure forecast for this activity is also increasing compared to current levels. During the regulatory period the forecast expenditure ranges from $2.54 to $2.77 million.

Meter Provision covers the maintenance activities for complex CT metering installations and includes the functional laboratory activities to support the metering plan. An additional allowance of $0.45 million has been included in the Meter Provision forecast to cover 3 additional FTEs plus materials and equipment in anticipation of increased market participation.

Meter Reading and Data Management includes the regular reading of customer meters across the Western Power network as well as the management of the meter data to allow settlement and customer billing. Data Management covers the process of data validation and provision of the consumption and interval data for market participants. Meter Reading covers the process of manual data collection of the consumption and interval data for market participants.

Additional expenditure has been included in the Meter Reading forecast to cover Network Connection Point Surveys; a total of $4.397 million over the 3 year period has been included.

Western Power participated in the PACE 2002 benchmarking study which showed Western Power costs compared favourably with other meter service providers.

Call Centre Operating Costs

Currently the Network call centre function is handled by the Retail Group, now established as the stand alone retail business Synergy, during business hours and outside these times, generally, the Network Operations Control Centre (NOCC) handles all the fault, emergency and routine calls.

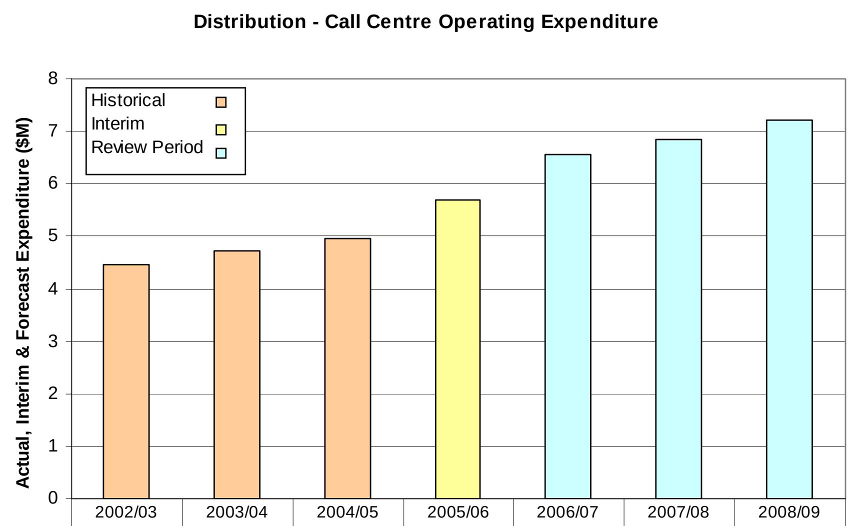
Historically Western Power Retail has not charged Networks for fault call handling. This is a carry-over from when the Call Centre was part of Networks Customer Service business unit. Currently all Network calls received outside existing call centre service hours are taken by operators in the Network Operations Control Centre with the exception of incident escalation where call centre operators are recalled to man the call centre.

It is proposed to manage all fault calls 24-hours/7-days a week from the Synergy call centre facility as soon as practicable after July 2005. Western Power intends to enter into a service level agreement with the Synergy retail business for the provision of these services and initial negotiations on formulating the terms and conditions for this agreement have commenced.

The following table indicates the Western Power historical, interim and projected expenditures over the regulatory period for the delivery of call centre functions, on a business as usual basis. Historically, the only operating costs incurred by Western Power (network business) for this function were the “out of hour’s” operators’ costs of managing calls when the Call Centre was closed - approximately $140,000 per annum.

The projected expenditures, on a business as usual basis, over the review period rise from $6.6M to $7.2M. These expenditures include the 24 hour 7 day management of calls by the Synergy call centre and include allowances for call volume growth and margin inclusion (from 2006/07).

Figure 108 - Call Centre Expenditures – Business as Usual



	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
	4.5	4.7	5.0	5.7	6.6	6.9	7.2

These business as usual projected expenditures are based on the projected call volumes and unit rates shown in the following table

Figure 109 - Call Volumes and Unit Rates

	Actual	Forecast	Forecast
Year	03/04	04/05	05/06
Calls	723k	731k	739k
Cost per Call	$6.34	$6.39	$6.64

In January 2005, Western Power management set a target of 25% improvement on SAIDI across the SWIS – over the next 4 years (commencing during 2005/2006). The 25% reduction in SAIDI is proposed to be introduced in stages, which are detailed in the following chart. If the program is successful it is expected to result in lower fault levels and therefore lower fault call volumes, the projected reduction in call volumes is also shown in Figure 110.

Figure 110 - SAIDI Reduction Strategy Impacts on Call Centre Call Volumes

YEAR	SAIDI PERCENTAGE REDUCTION	CALL VOLUME PRCENTAGE REDUCTION
2006	3%	0%
2007	5.5%	2%
2008	11.5%	4%
2009	25%	8%

If the SAIDI reduction strategy is successfully implemented then call volumes are expected to fall and these reduced call volumes would result in reduced call centre expenditures. The projected expenditures over the regulatory period under these circumstances are detailed in the following chart.

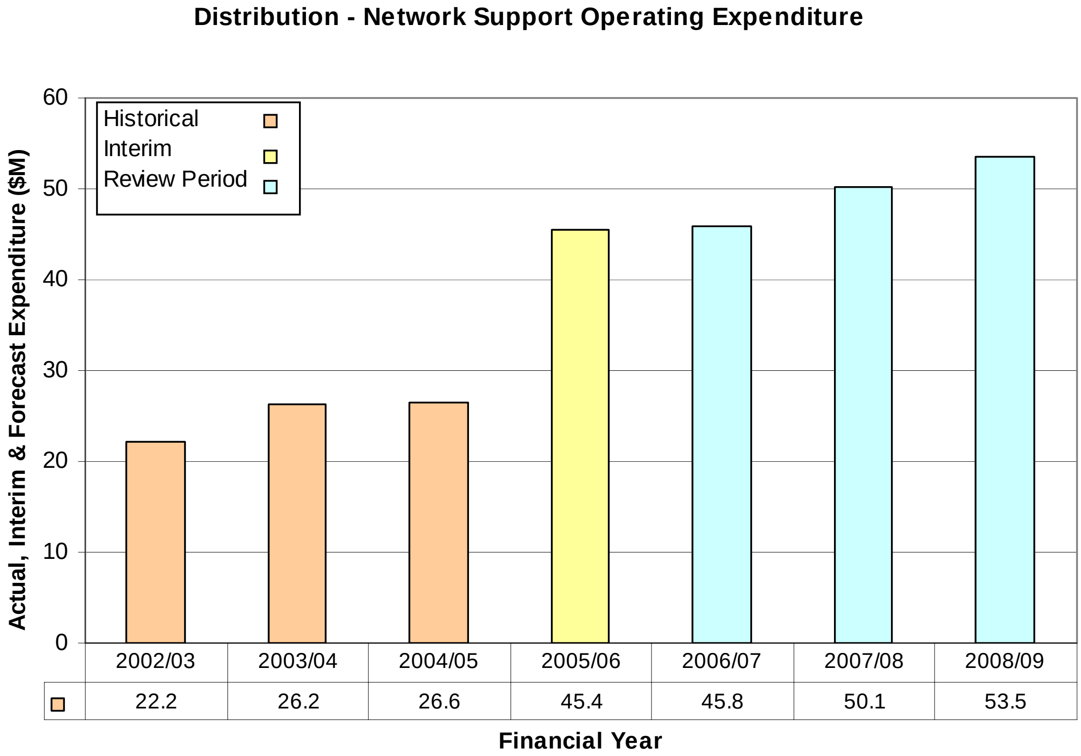
Figure 111 - Call Centre Expenditures incorporating impact of SAIDI Reduction Strategy

	Historical Data			Interim		Review Period		
($million)	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09
Call Centre	-	-	0.14	0.14	5.71	6.47	6.67	6.80

Network Support

Network support functions are conducted to support both the transmission and distribution businesses operated by Western Power. Network Support includes items such as Human Resources, Finance, Strategy and Corporate Affairs, Design and Estimating, Insurance and Rates and Taxes. A full description of the overall expenditure is provided in section 5 Business Support Costs. A summary of the allocation of Network Support costs to the transmission business is shown in Figure 112.

Figure 112 Distribution Network Support Operating costs



	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
	22.2	26.2	26.6	45.4	45.8	50.1	53.5

APPENDIX A

Capital Projects List – Transmission and Distribution