Forecast Expenditures
Compelling Case

WESTERN POWER CORPORATION'S JUSTIFICATION OF OPERATION AND CAPITAL EXPENDITURE FORECASTS (RESOURCE CONSTRAINED)

FOR THE SOUTH WEST INTERCONNECTED NETWORKS

Prepared For
Access Arrangement Submission 2005

Foreword

This report provides the detailed justification for Western Power Networks' proposed "resource constrained" capital and operating expenditures for the 3 year regulatory term commencing 1 July 2005.

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.

The resultant **unconstrained** expenditure proposals (for transmission operating and capital and distribution operating and capital) were then reviewed from the perspective of current and assessed future resourcing capabilities of the Network business, utilizing the available range of internal and external resources, to produce practically achievable **resource constrained** expenditure levels which are significantly less than the original **unconstrained** proposals.

This assessment of the resource constrained expenditure needs was, by necessity, completed prior to the end of the 2004/05 financial year in order to facilitate the final stages of preparation of the proposed Access Arrangement for submission to the ERA by August 2005.

This report therefore provides useful background information and explanation in support of Western Power's expenditure forecasts. However, the required expenditures identified in this report generally exceed those presented in the main text of the AAI, as the latter take further account of financing and pricing issues.

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Executive Summary

Western Power Networks'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 Networks is changing to meet the current and future requirements of customers and stakeholders.

Western Power Networks 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 Networks 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 Networks as an efficient/low cost provider.

Western Power Networks 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 Networks 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 Networks' reliability does not currently meet the legislated targets as set by the Energy Safety Directorate. Western Power Networks has developed a detailed program to restore network reliability to these minimum levels. In addition, Western Power Networks is working to better understand the customer's needs to ensure that the reliability outcomes are matched with customer needs and expectations.

- Safety, Health, Environment and deregulation – Western Power Networks maintains a close working relationship with all industry regulators including the safety and environmental bodies. In consultation with these bodies, Western Power Networks 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 Networks 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 Networks 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 Networks. Whilst the growth of the Western Australia 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 Networks' ability to undertake all the investments needed.

On this basis, Western Power Networks has undertaken a detailed review of resource availability over the forecast period and has determined a realistic, deliverable expenditure plan. This deliverable work plan is significantly less than that which Western Power Networks would otherwise like to deliver during the regulatory period and a number of important projects have consequently been deferred.

The following tables summarise the resultant forecast expenditures;

Figure 1 – Western Power Networks Forecast Capital Expenditures
(Resource Constrained)

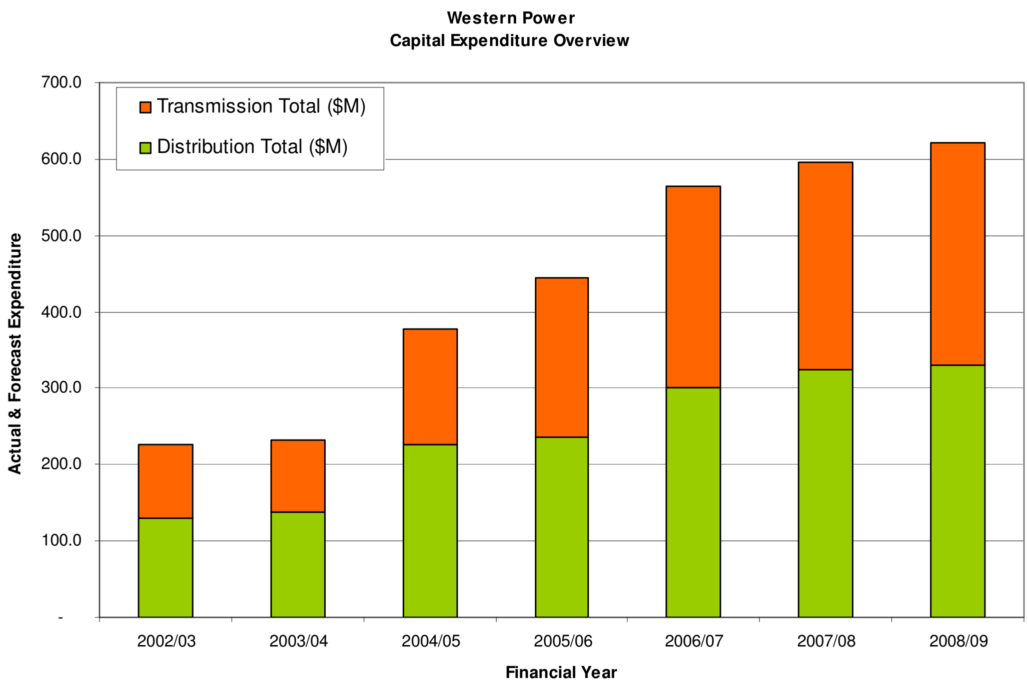
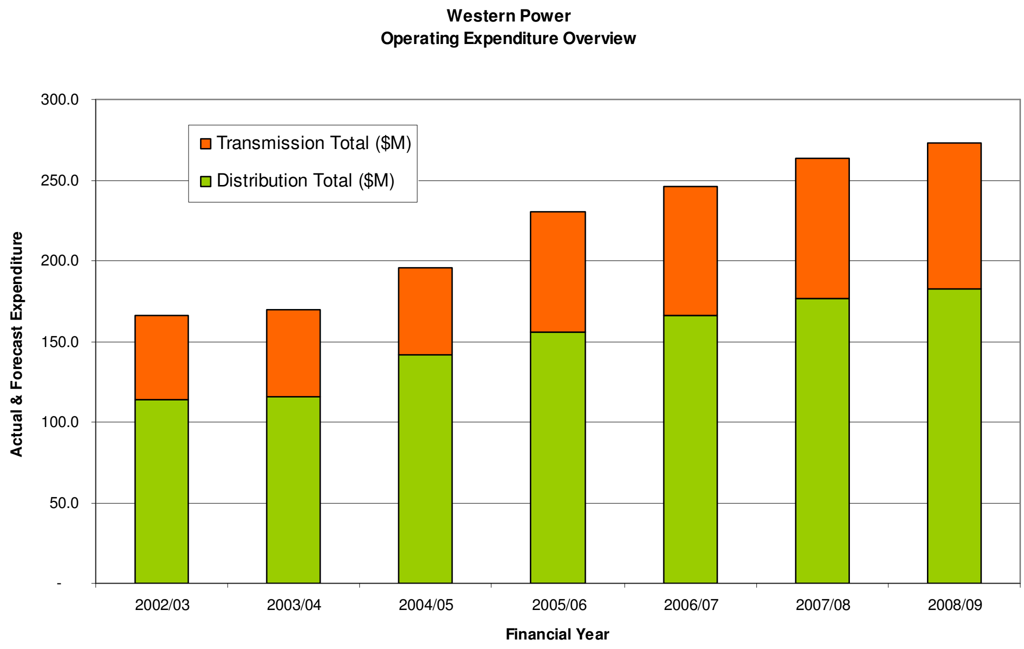


Figure 2 – Western Power Networks Forecast Operating Expenditures (Resource Constrained)



NOTE: The information contained in the subsequent sections of this report is a detailed assessment and justification of the unconstrained expenditure needs of the business required to meet all ideal business performance outcomes from the perspective of service standards and prudent management of network assets.

1. Introduction

With the establishment of the Economic Regulation Authority (ERA), Western Power Networks is required to submit an Access Arrangement by the end of August 2005. 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 investment requirements have that been compiled for the new Regulatory regime from July 2006 to June 2009, represent a significant increase on current expenditure levels. This increase is due to the need to meet the declared service standards that apply to Western Power Networks including the obligation to connect new generators and loads, reliability, safety, environmental and market reform.

The base expenditures for Western Power Networks are remaining essentially unchanged compared with historical levels. This paper therefore focuses on the additional obligations that are driving the need for increased expenditures.

Business Responsibilities

Western Power Networks 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 the networks services for all participants on an equitable and transparent basis.

The Western Power Networks' 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 Networks must balance the requirements to operate commercially and meet regulatory, Government and community expectations for reliability of supply.

Regulatory Requirements

The regulatory regime requires Networks, as a ring-fenced provider of network access, to propose an Access Arrangement to the ERA by the end of August 2005. This Access Arrangement defines the network revenue projections and tariffs, the service standards to be met by Networks and the capital and operating investment expenditures required to meet these standards over the regulatory period. The ERA has a further six to twelve months to respond to the proposed AA and define the AA (including performance standards and expenditure) that will operate for the financial years 2006/07 through to the end of 2008/09.

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

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

National Comparators

Western Power Networks 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 Networks 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;

- The Western Power Network 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 Networks would be challenged to be cost competitive with other Australia 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 Networks as a better than average performer.

A summary of the above studies is provided below.

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 Networks expenditures across both the transmission and distribution networks.

Note: The information provide by Benchmark Economics is based on data available in the public domain.

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 Networks, 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 in Western Australian 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.

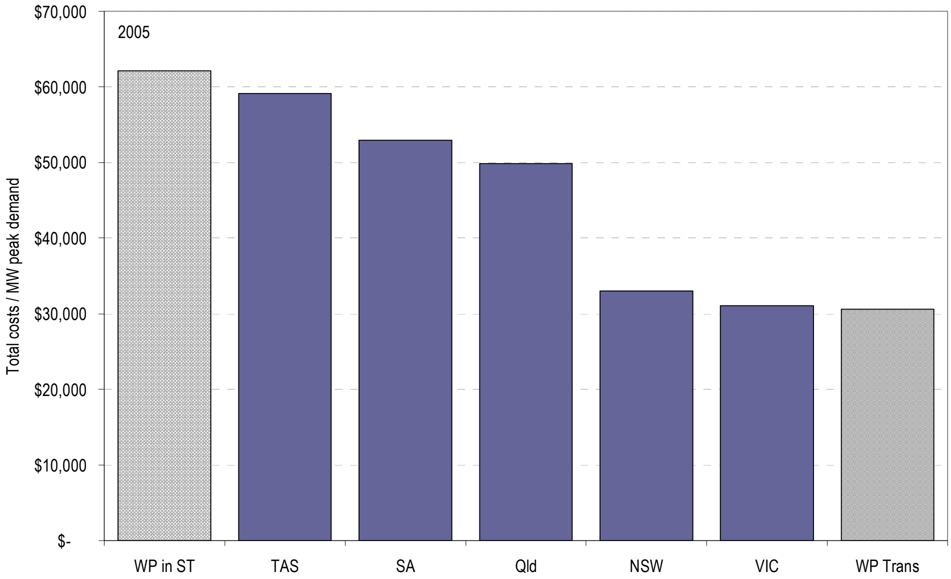
Figure 3 - Transmission networks in the study: scale and key operating conditions

	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.

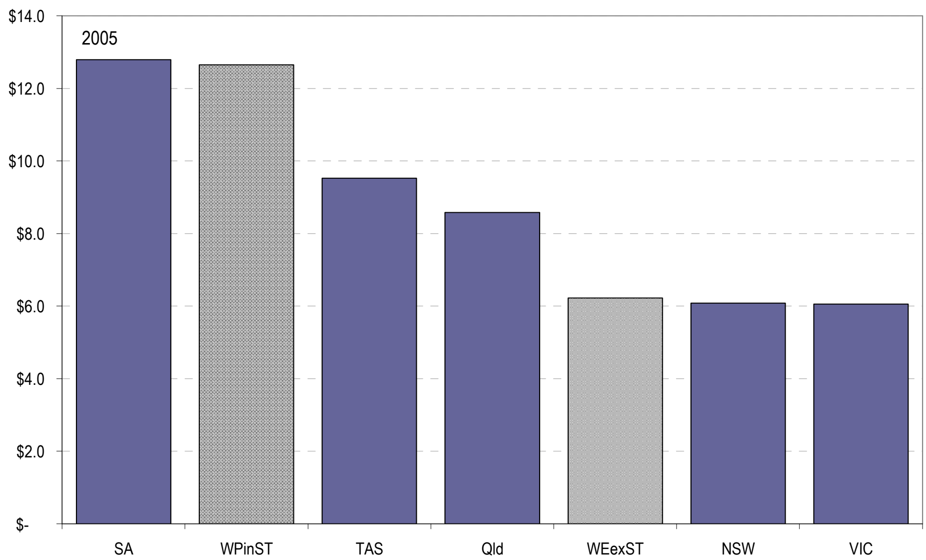
Average costs for the transmission networks, measured as total revenue/peak demand MW, are depicted in the following figure. The transmission network of Western Power exhibits the lowest average costs for the sample. Notably, even the cost of the combined transmission and sub-transmission networks is 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

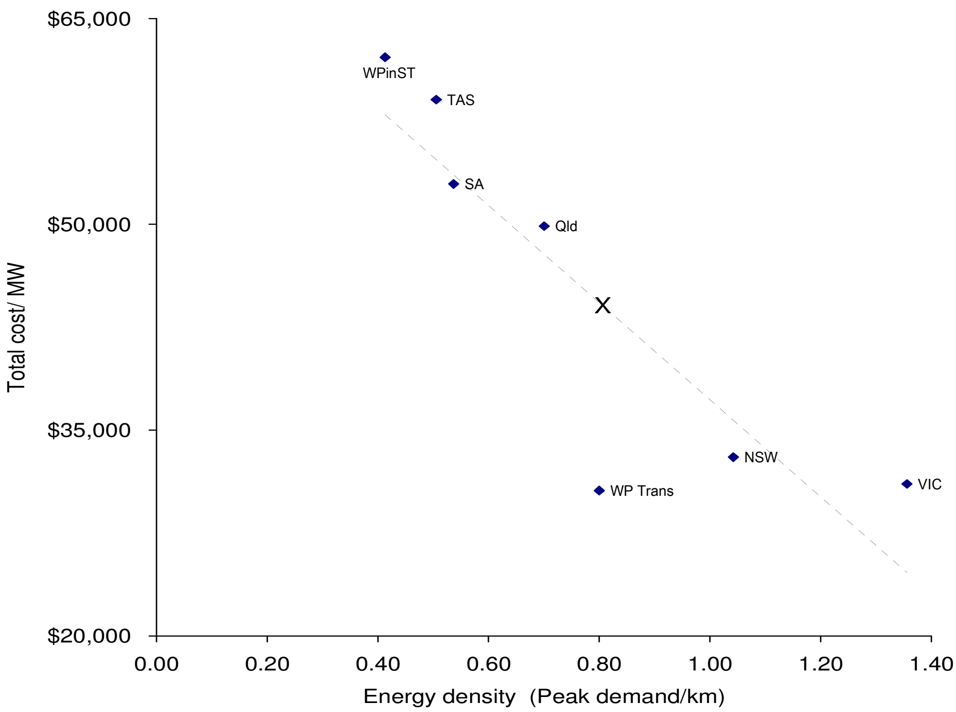


To assess the influence that operating conditions may have on Western Power's cost outcomes, the following section examines the link between energy density and load factor on total network cost.

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

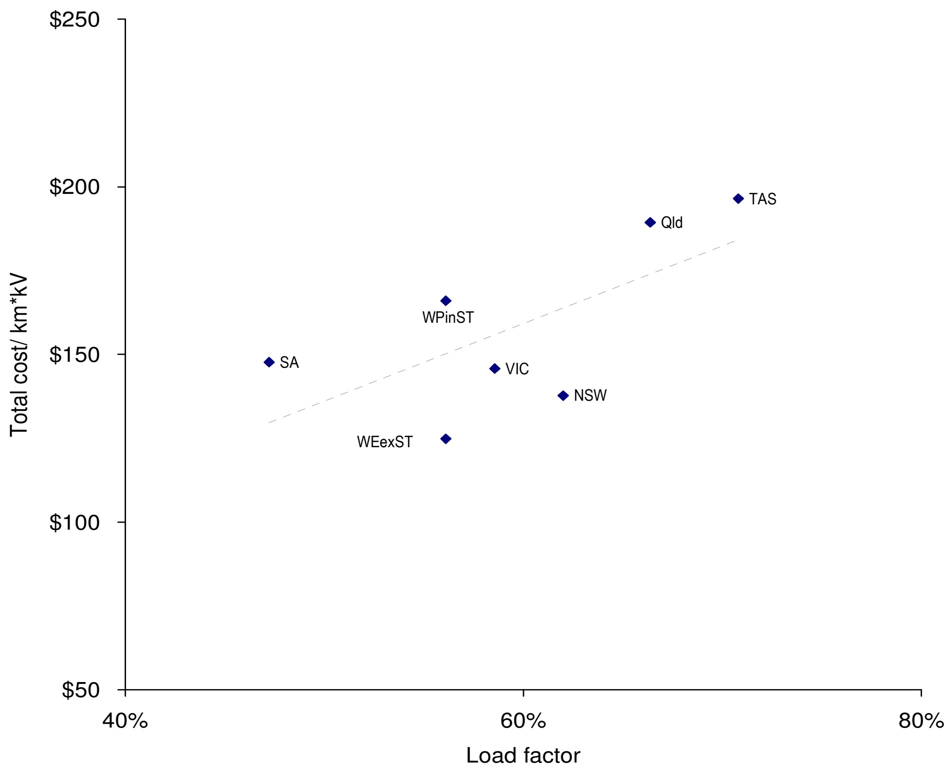
Average capacity costs = -35401 + 72620, R2 75%

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 above chart 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 pr km*kV= -231.47x + 20.297, R2 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 smooth out the variability 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)

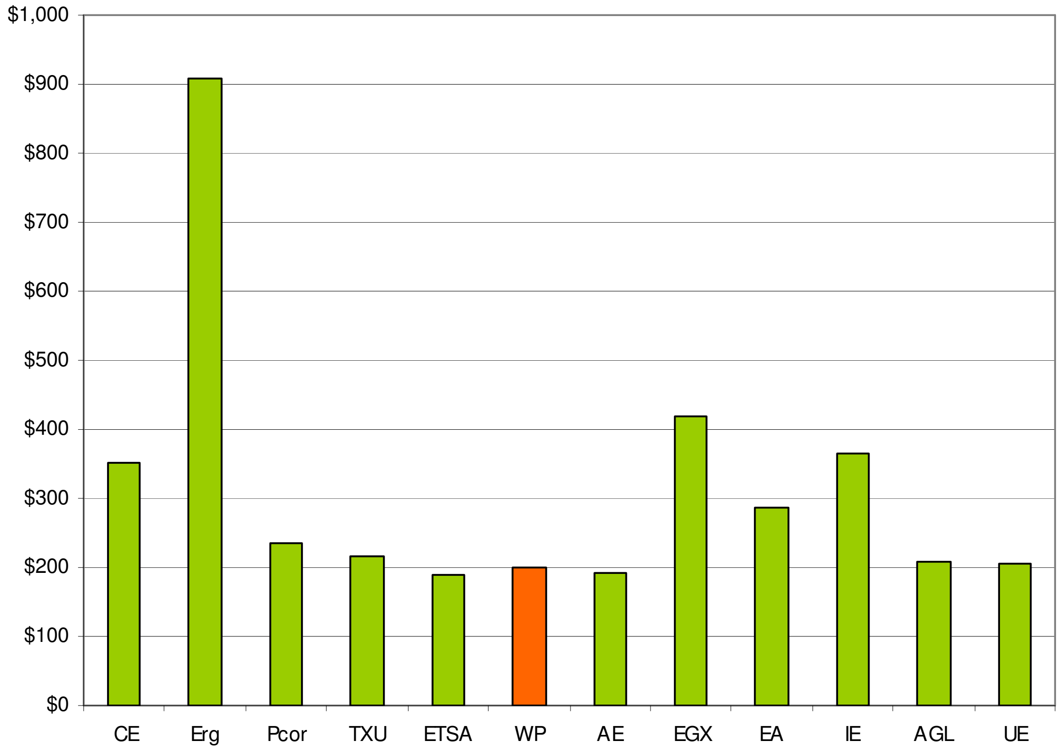
The PB Associates analysis utilised regulatory expenditures for the majority of Australian Distribution networks adjusted to a common base. Western Power Networks appears as a best performer in many of the measures and above average in almost all.

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

Expenditure per Customer

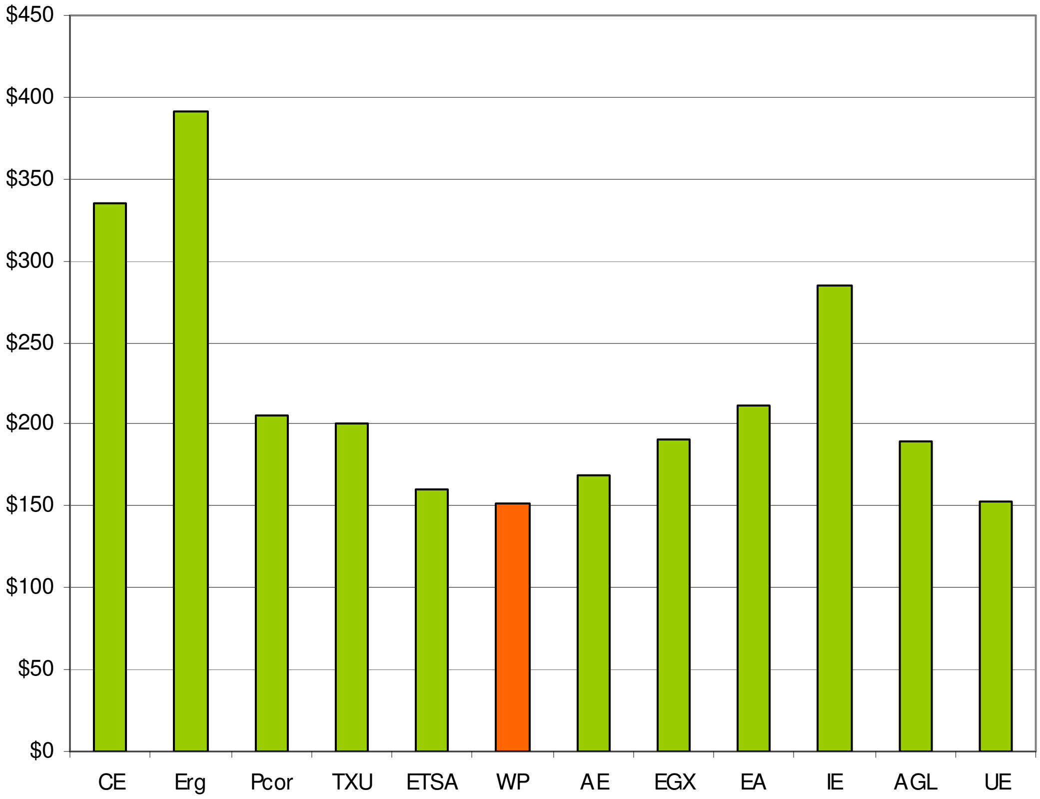
The expenditure per customer measure provides an indication of the average annual expenditure per network customer[2]. In general, it would be expected that the cost per customer would increase for predominantly rural networks. The length of line and therefore number of assets required to service a rural customer is generally greater than that of the average urban customer.

Figure 8 - Total Capital Expenditure per Customer



[2] 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.

Figure 9 - Total Operating Expenditure per Customer



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[3] 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.

[3] With the exception of Aurora Energy in Tasmania

Figure 10 - Total Capital Expenditure per kVA

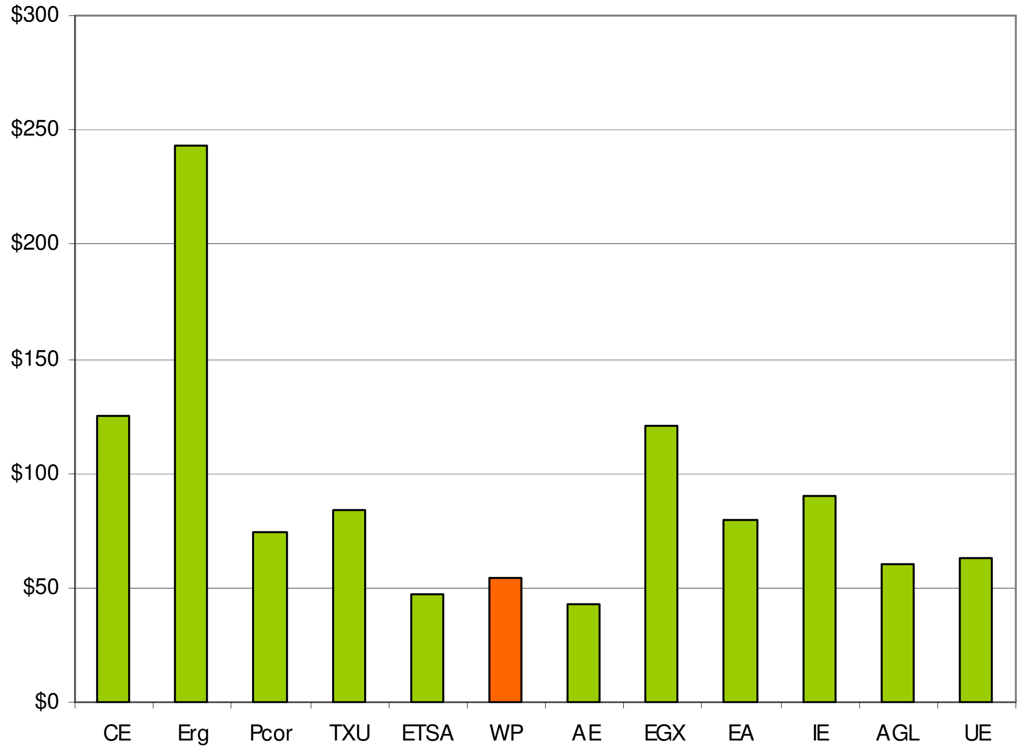
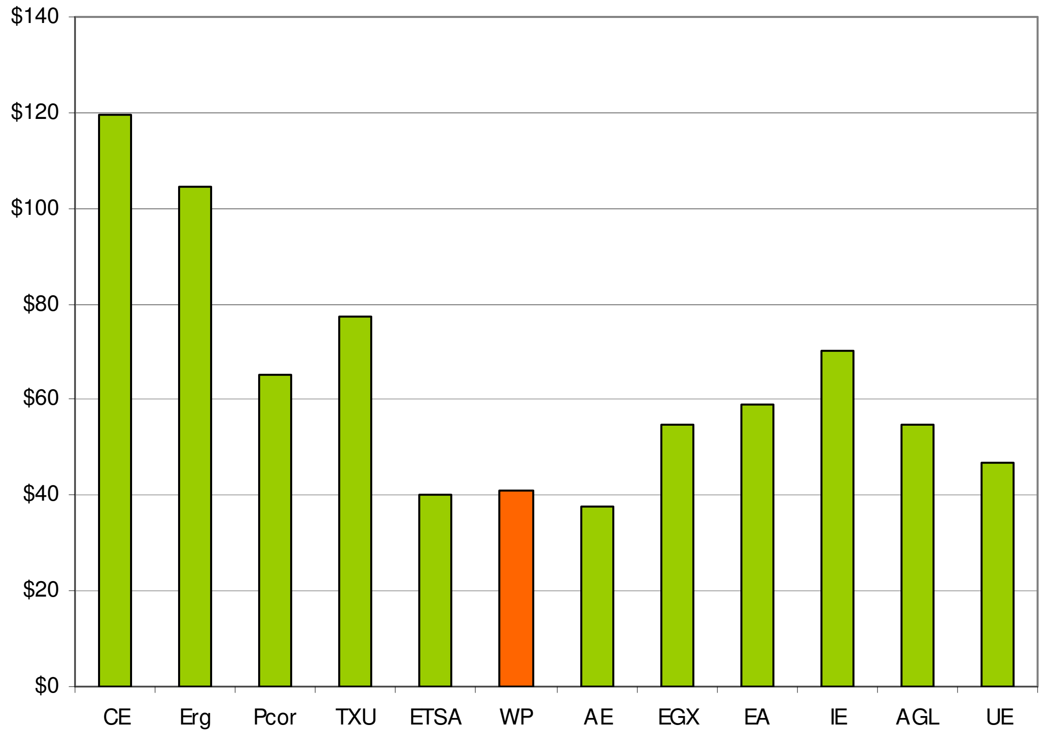


Figure 11 - Total Operating Expenditure per kVA



<u>Expenditure per km (of distribution network)</u>

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

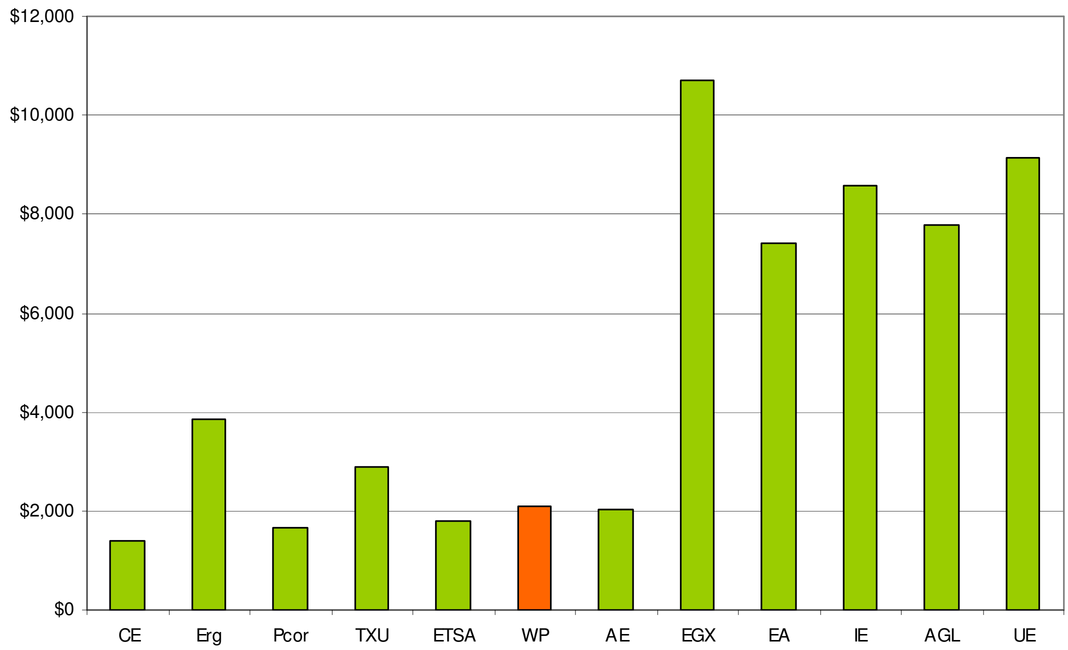
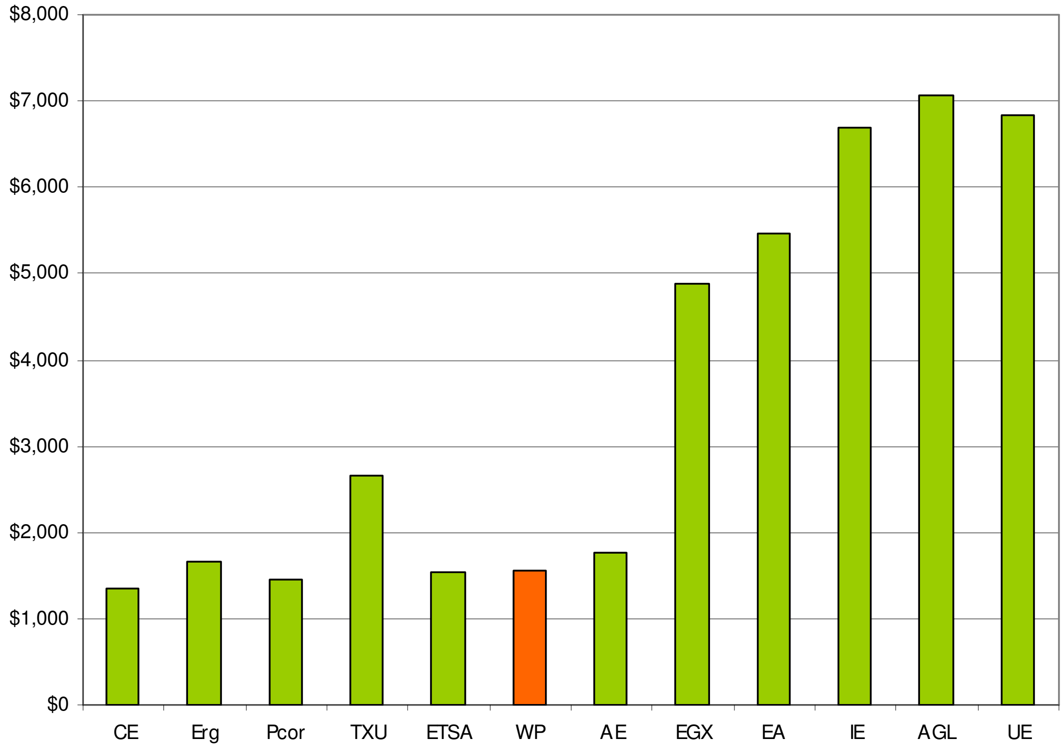


Figure 13 - Total Operating Expenditure per km of Line



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

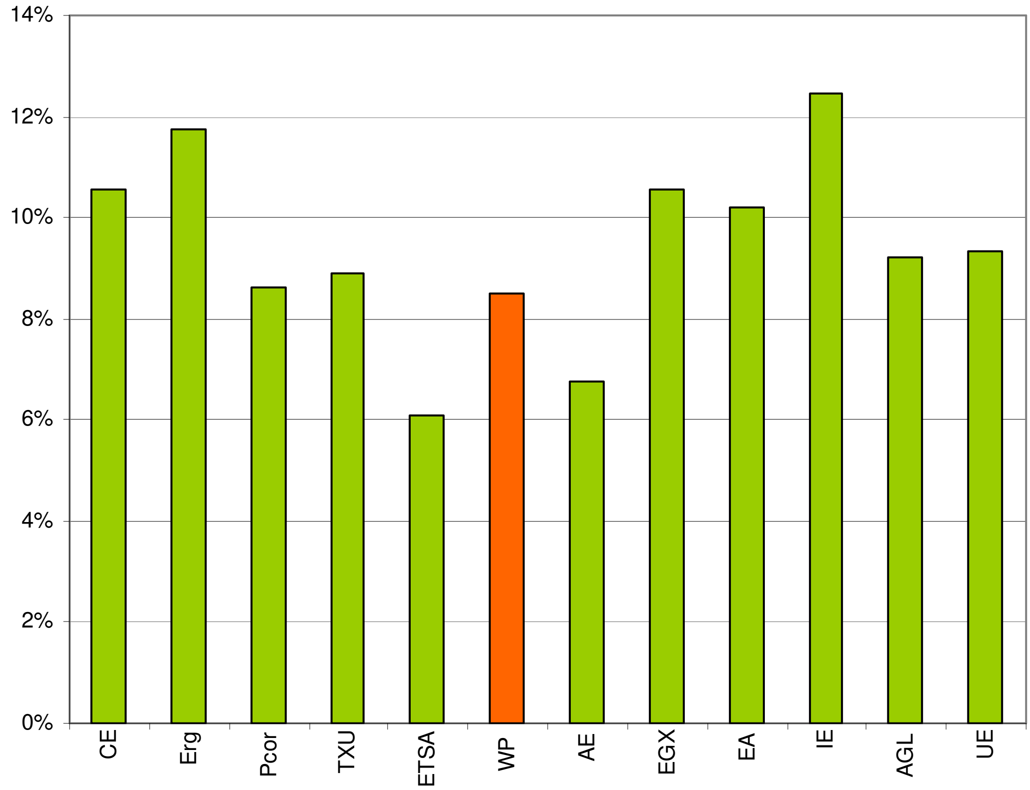
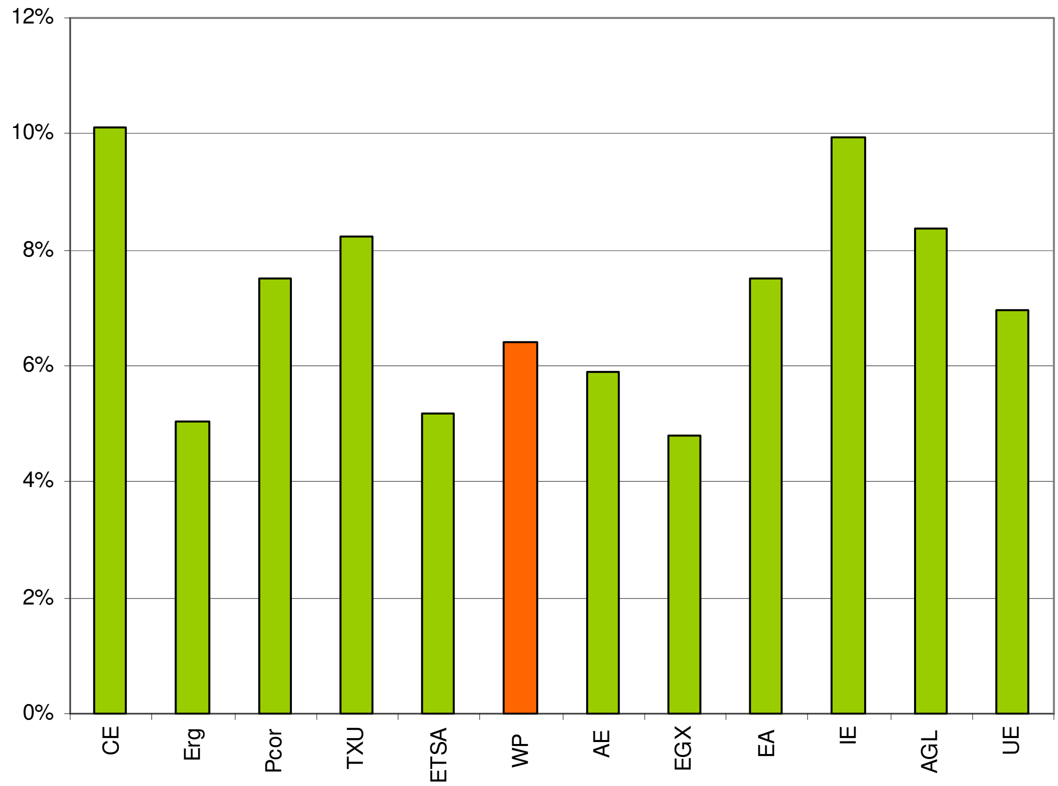


Figure 15 - Total Operating Expenditure per RAB



Meyrick & Associates Benchmarking

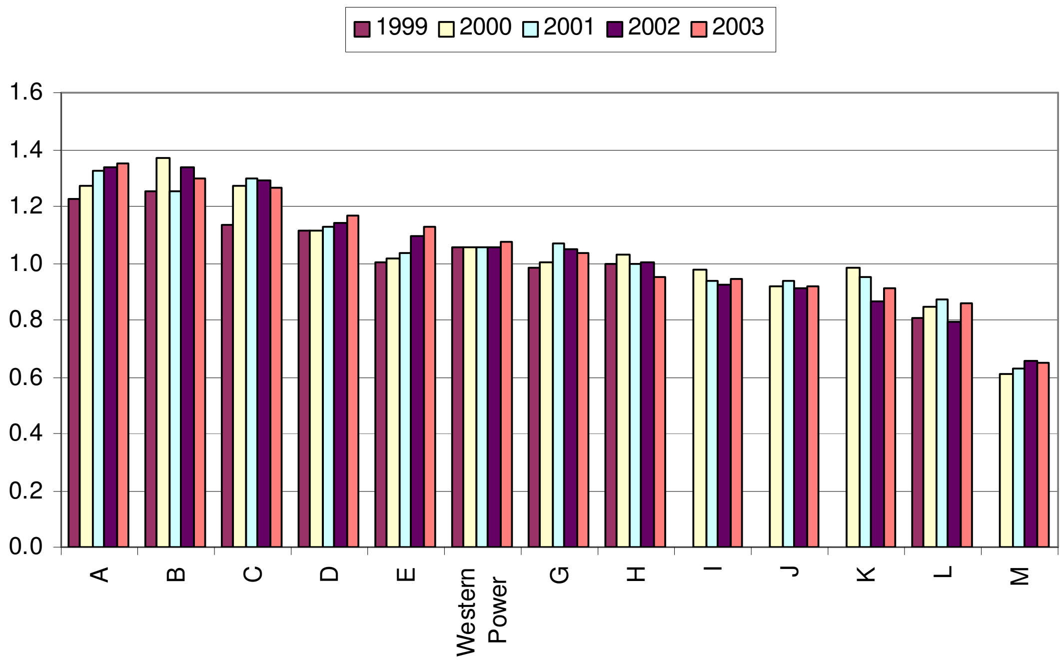
The Meyrick & Associates report reviews the performance of Western Power's distribution operations over the period 1999–2003 compared to 12 other Australian electricity distribution networks[4].

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.

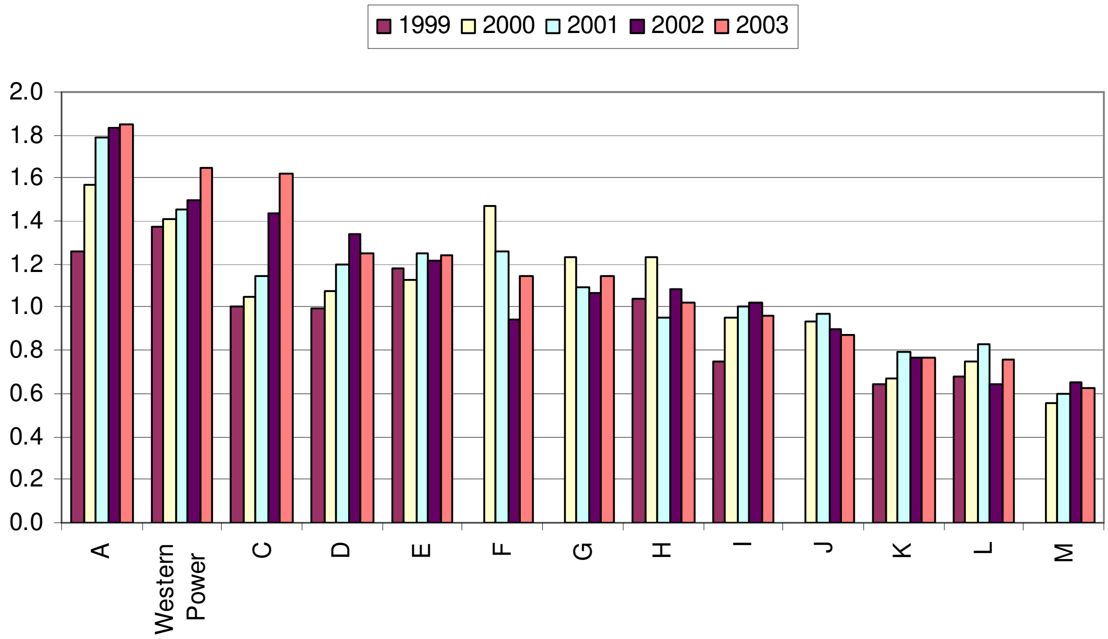
Figure 16 - Multilateral total factor productivity indexes, 1999–2003



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

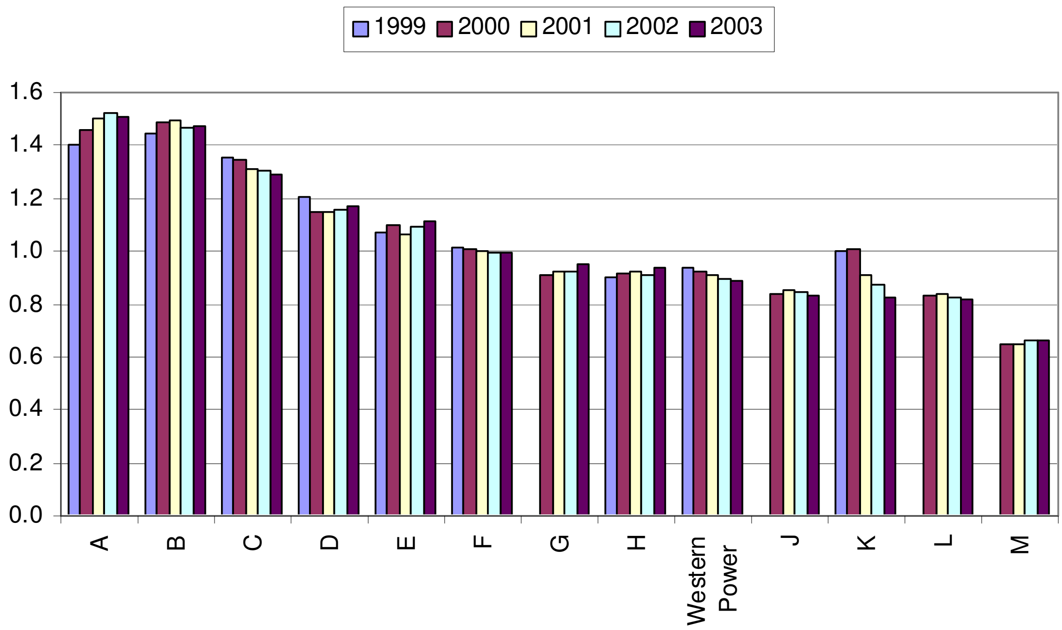
On operating and maintenance expenditure (opex) partial productivity (the total output index from the TFP analysis divided by the quantity of opex) Western Power ranks second best out of the 13 included networks. It had a steady increase in its opex partial productivity over the 5 year period, with an 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.

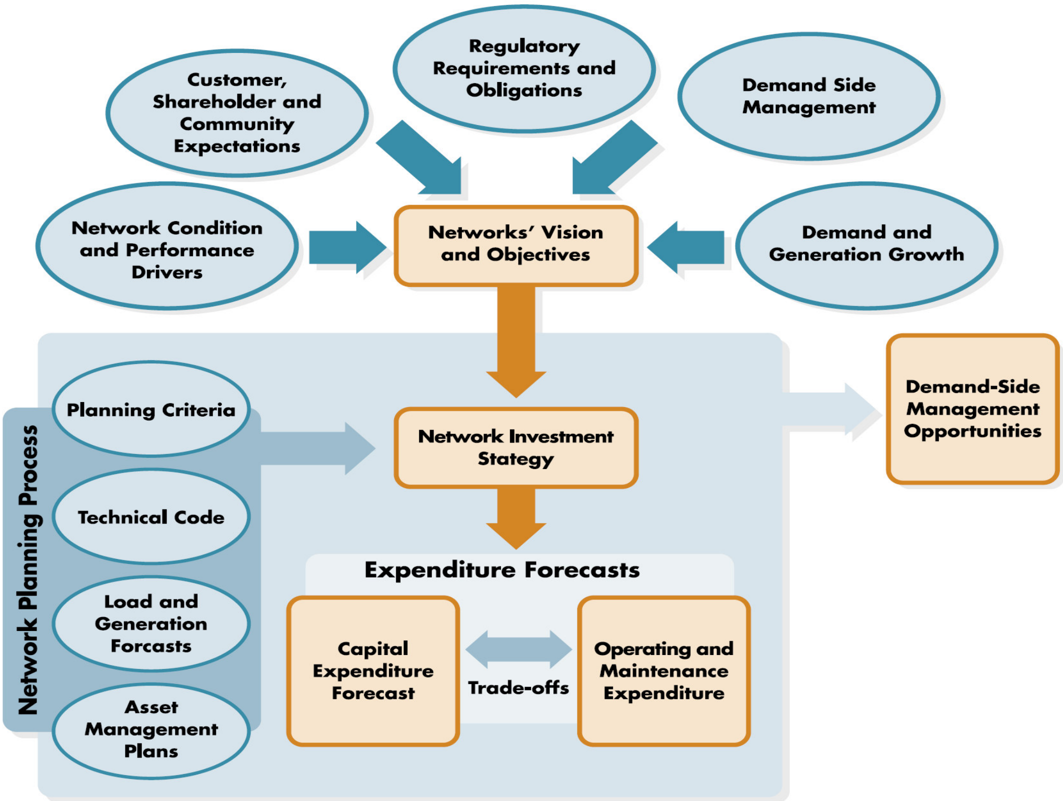
Figure 18 - Capital partial productivity indexes, 1999–2003



2. Systems, Processes and Procedures

The modern electricity business is required to operate in a complex multi-dimensional environment. The days of the electrical engineer determining what is best for the consumer and the owner are long gone.

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 Networks undertakes its planning and network development activities in line with a number of legislative requirements including the Electricity Access Code 2004. The code together with the Electricity (Supply Standards and System Safety Regulations 2001 define technical, customer access and public/network safety requirements. Western Power Networks 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. At the present time, Western Power Networks is preparing for the separation of the network from the Generation and Retail arms. 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 Networks operates.

In recognition of the fluid operating environment, Western Power Networks 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 Networks has implemented the use of the “asset mission” document to integrate the operations of the various network business units. Western Power Networks 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. In time, these processes will be influenced by the commercial incentives and service standards to be established under the new networks access regulatory arrangements.

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 Networks' 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 Networks applies a risk management approach when determining its network development options. Applying the network investment criteria in the Technical Rules, Networks' 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) [5] and the Regulatory Test[6].

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 example 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 WPC undertake to produce the forecast in the application.

The planning processes applied by Western Power Networks 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 Networks is confident that the investments proposed in this assess 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 and $15million for transmission). This test is in place to ensure sufficient consultation and evaluation has been performed prior to the augmentation being undertaken. The 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.

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

It is important to note that the regulatory test does not need to have been applied for major augmentations proposed within this application. As with the NFIT test, the relevance for this application is whether or not it is reasonable that the major augmentations would pass the regulatory test based upon the best available knowledge at this time. Obviously, the implementation of the regulatory test, and specifically the consultation process involved, may result in alternative projects being proposed – albeit noting that it can not be assumed here that these alternatives will materially change the revenue requirement[7]. However, based upon the available knowledge of the most likely market development, and the robust planning processes applied by WPC in determining the most likely network augmentations, it is considered reasonable to assume these projects (or an alternative of a similar revenue requirement) will pass the regulatory test during this regulatory period.

[7] For example, a generation or demand side alternative may require support payments that result in no net difference in revenue requirements.

3. Expenditure Drivers

Western Power Networks 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, Environment and Deregulation
- Constrained Expenditures (Historically)

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? In each case identified above, the works are required as a direct response to an external event and Western Power Networks has no choice but to undertake the works identified.

(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 Networks 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 Networks 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 Networks 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 Networks 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 Networks is required to provide connection to new generation plant under the terms of the Access Code.

Network Reliability

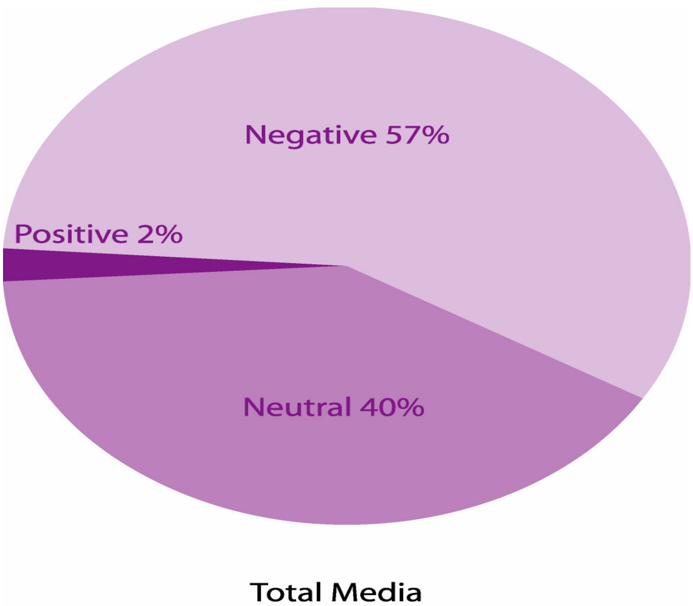
Western Power Network's reliability targets are legislated by the Energy Safety Regulator via the *Electricity (Supply Standards & Safety System Safety) Regulations 2001.*

Based on June 2004 performance figures, Western Power Networks is presently performing above (worse than) the Energy Safety SAIDI target[8].

Western Power Networks has also 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[9] 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

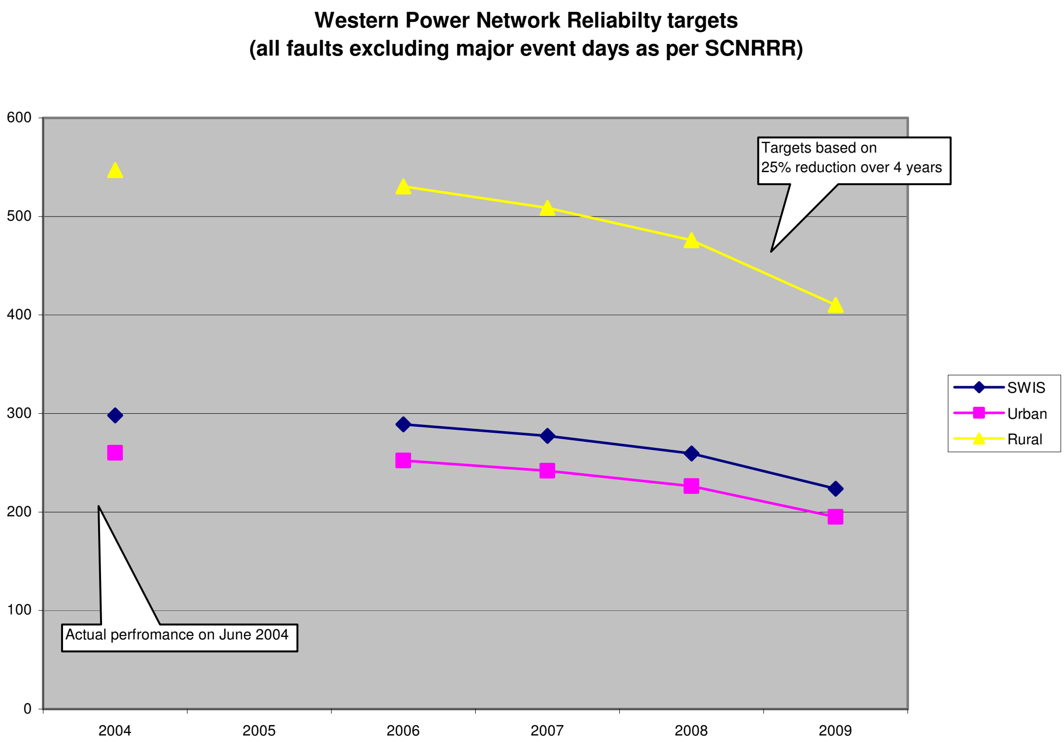


Western Power Networks considers that the current reliability performance of the network is not acceptable to its customers and stakeholders and is proposing to move to the target SAIDI figure over two regulatory periods. The following chart highlights the significant reliability improvement program that Western Power Networks 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 Adjusting for differences in definition between Energy Safety definitions and Australian reporting standards for SAIDI.

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

Figure 20 - Western Power Networks Reliability Targets (SAIDI)



Safety and environmental drivers

Safety and environmental considerations are already well embedded in Western Power Networks systems and processes. However, a number of new requirements have recently, or are about to, be imposed upon Western Power Network. These requirements are additional to the current Western Power Networks 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
- River Crossing Safety

Safety, Health, Environment and Deregulation - Market reform

Western Power Networks 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 Networks in the Information Technology area, although structural changes will impact all areas of the business.

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

- **Standalone business systems** - Configuration of the corporate systems adopted by Networks 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 Networks 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.

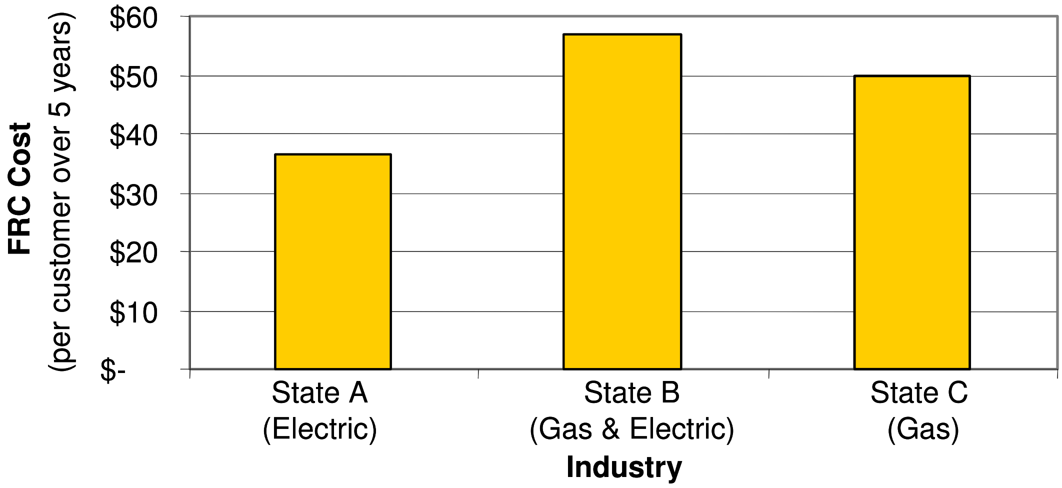
Significant market reform expenditures have been incurred in all states that have implemented retail competition in the electricity and gas markets. The vast majority of these expenditures have been incurred in the IT business groups due to the need to radically alter systems to meet the new working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

The system changes identified by Western Power Networks 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



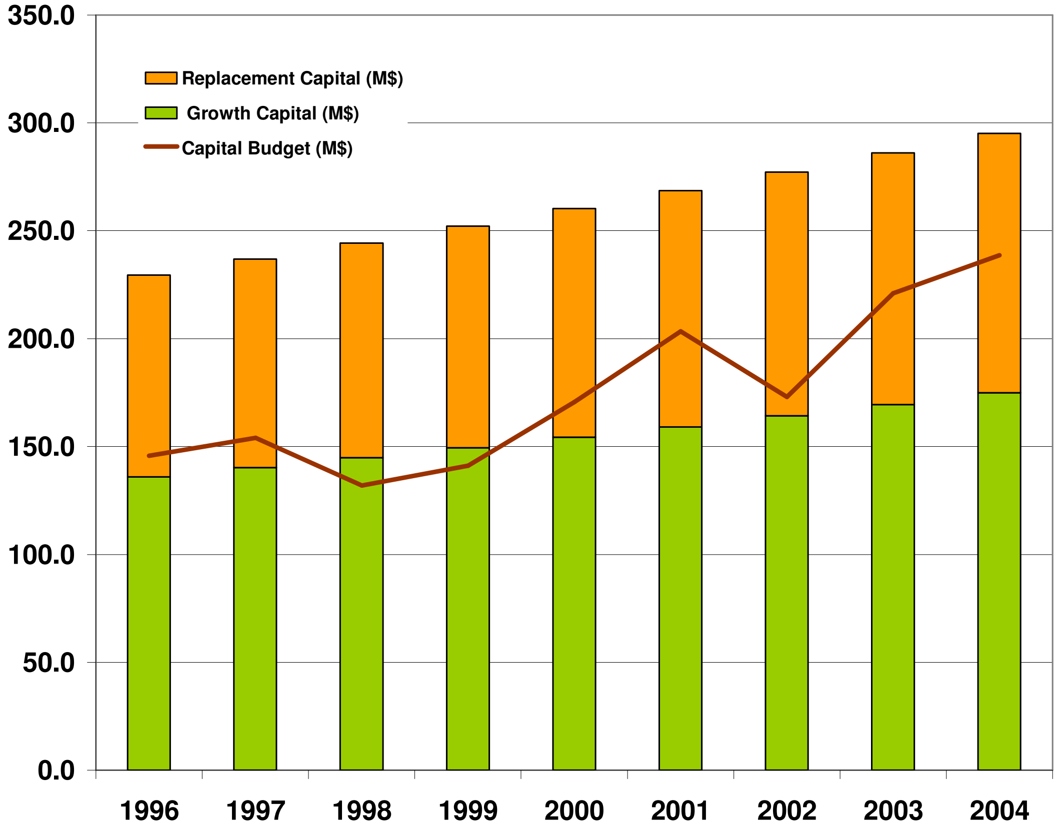
The projected Western Power Networks expenditures associated with market reforms include instances of both disaggregation and competition reforms, whereas recent expenditures in other states primarily relate to competition reforms. On this basis, the Western Power Networks expenditure of less than $50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

Constrained Expenditures and Backlog

The following graph presents historical data for the ten years from 1995/96, the year in which Western Power 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 Networks 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 following chart clearly highlights that the capital budget has remained at a level that has barely allowed Western Power Networks 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 Networks has identified $40 million of backlog in the transmission network and $12 million of backlog in the Distribution area. Under the current budget expenditures this backlog is continuing to grow.

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 Networks is now approaching a period where greater numbers of assets will require replacement than in any time in its history.

At present Western Power Networks 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 resulting in an increasing utilisation of the substations. As more substations are now approach the planning limits, it is becoming increasingly difficult to 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[10] 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 Networks NCR assigned substations have N-1 spare capacity.

An independent review commissioned by Western Power Networks has determined that the NCR criteria as applied by Western Power Networks 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.

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

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

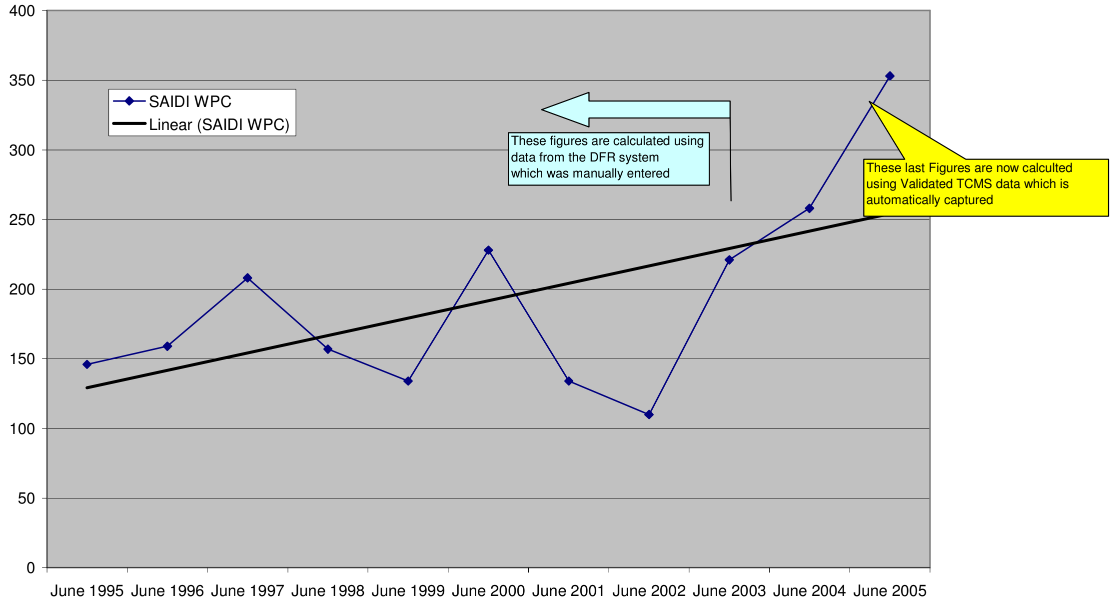
4. Customer Outcomes

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 Networks reliability indicates a trend of worsening performance[11].

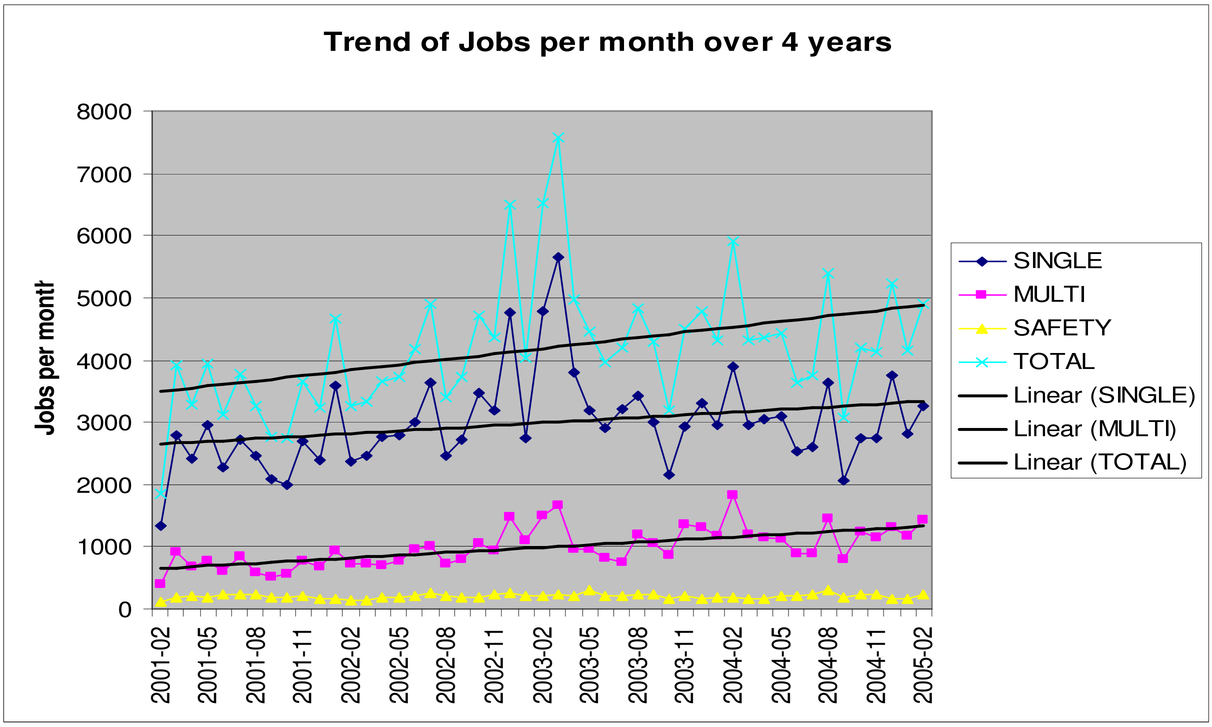
Figure 23 - Western Power Networks SAIDI



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

[11] Note: The SAIDI numbers provided in Figure 23 are sourced from the Western Power Networks DFR system. These numbers are therefore not directly comparable to the Western Power Networks target SAIDI.

Figure 24 - Fault Jobs Trends



The principle 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 Networks;

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 Networks 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.

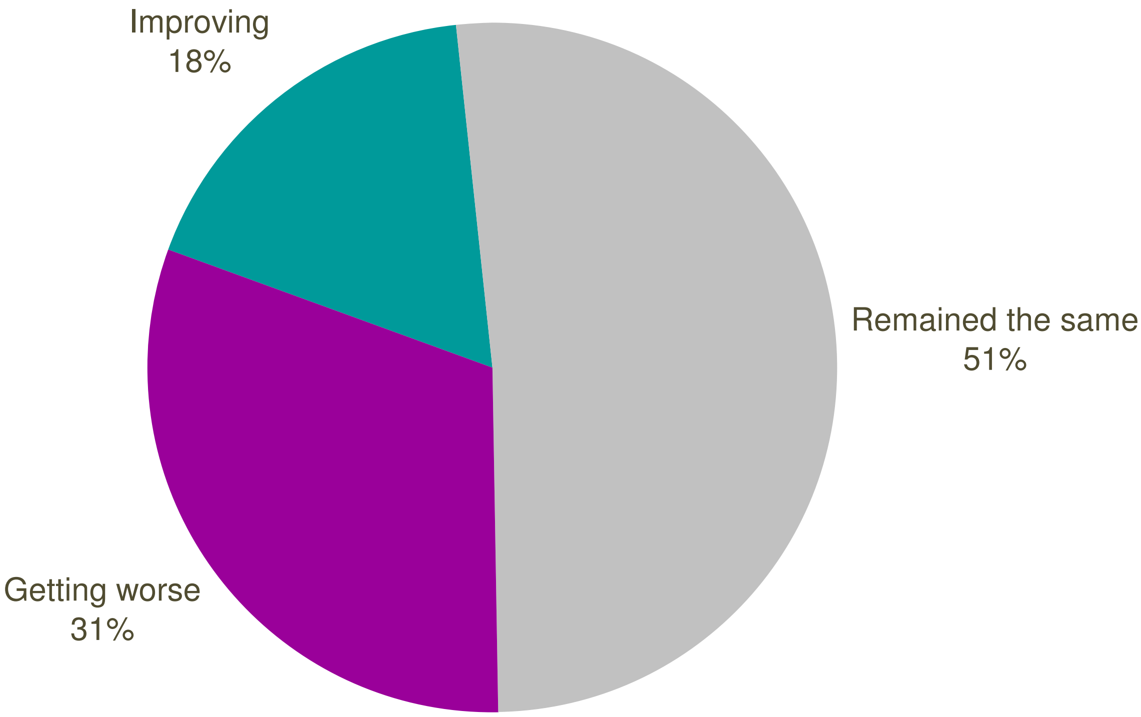
A recent survey of Western Power customers identified the consistency and reliability of supply as the overwhelming issue of importance to them.[12] Over 85% of customers identified "Consistency/reliability of supply" as the principle issue facing Western Power Networks (refer to Figure 25). When surveyed 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 (eg, customer service, good maintenance and power surges)	5
Don't know	2

[12] Market Equity Customer Survey – April 2005

Figure 26 - Customer Perceptions of Quality of Supply



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

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 (eg, forward planning, bush fires)	6
Don't know	5

Western Power Networks 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

The Electricity (Supply Standards and System Safety) Regulations 2001 sets supply reliability standards that Western Power Networks must use best endeavours to meet. Schedule 1, part 8 of these regulations require Western Power Networks to achieve certain targets for outage duration and frequency. These targets equate to a figure of 160 minutes per year (off supply) for the average SWIS customer[13].

Western Power Networks management has set a target reliability improvement of 25% across the SWIS. The improvement will be implemented in stages over the next 4 years (commencing during 2005/2006). This is based on reasonable endeavours and would not include in the targets one in ten year events. This is measured using the SCNRRR[14] definition and IEEE 1366 Guide for Electric Power Distribution Reliability Indices for major event days known as the Beta method[15].

A 25% improvement in reliability is a significant step, and it is acknowledged by Western Power Networks that the 160 minutes target will only be achieved over two regulatory periods.

[13] The target of 160 minutes is set based on a number of exclusions made by Energy Safety Directorate regulations – where the event is beyond the control of Western Power.
[14] Steering Committee for National Regulatory Reporting Requirements.
[15] Beta method is used to identify major event days which are to be excluded from the minimum service standards as per SCNRRR.

5. Corporate Allocations & Ring-fencing

The Network business is ring fenced from other Western Power business operations to enable identification of costs and regulated network activities in line with the industry restructure requirements. The ring fencing arrangements enable the preparation of financial statements that underpin the revenue requirements of the Network. Western Power is keenly aware of the importance to maintain rigour, consistency, transparency and accuracy in the preparation of these accounts and has therefore established guidelines for the allocation and assignment of costs between ring fenced segments. In particular, the ring fencing guidelines provide for an appropriate allocation of shared corporate costs between segments of Western Power Corporation. Preparation of the ring fenced accounts for Western Power Networks is facilitated by the general ledger structure that separates Transmission, Distribution, Generation and Retail as individual businesses.

In allocating shared corporate costs Western Power Networks has established a management accounting system that vests shared asset ownership with business units where practical and assigns costs on the basis of usage. Examples of this include costs for IT, Fleet and Logistics.

The remaining shared corporate costs include:

- Governance & Audit
    - General Counsel
- Company Secretary
    - Internal Audit
- Finance, Risk Mgt & Service Delivery
    - Group Accounting & Tax
    - Treasury
    - Claims Mgt
    - IKM
    - Risk Management
    - Corporate Projects
    - SWIS Power Procurement
    - Technology Group:
        - Business as Usual
        - IT&T Corporate Strategic Plan
- Finance Management
- Head Office Refurbishment
- Human Resources & Org Development
    - HR Strategy
    - HR Consulting

- Stakeholder Mgt, Communications & PR
- Strategy Reform & Strategic Projects
    - Environment
    - Strategy
- Board / Executive
    - Executive
    - Board
- Corporate Costs
    - Rates & Taxes, FBT & Audit Fees
        - Reform Costs per June 2003 Cabinet decision

These costs are allocated across the businesses (including network) generally on the basis of full time equivalent employees (FTEs). The following extracts from Western Power's Corporate Allocations policy document December 2001 reflect the principles behind the proportional allocation of each corporate cost component.

CP1100 Corporate Allocations Treasury

These costs are allocated to the business units based on the business units' percentage of debt as a percentage of Western Power Network's total debt.

The costs allocated comprise the operating costs for the Strategic Services Treasury Branch.

CP1200 Corporate Allocations Employee Services

These costs are allocated to the business units based on the number of employees in the business unit as a percentage of Western Power Network's total number of employees.

The costs allocated comprise the operating costs for the Human Resources Branches of the Corporation (including Management, Administration Branch, Employee Services Branch, Consulting Branch, Counselling & Rehabilitation Branch, MLI, and PICG Consulting).

CP1300 Corporate Allocations Occupancy

These costs are allocated to the business units based on the Head Office floor space occupied by the business unit as a percentage of total Head Office floor space.

The costs allocated comprise the costs for the Properties and Head Office Building Branch, Motor Vehicle Pool and Finance Cadets.

CP1500 Corporation Allocations Rates & Taxes

These costs are allocated to the business units based on the land holdings of the business unit as a percentage of Western Power Network's total land holdings.

The costs allocated comprise the annual local authority council rate equivalents and land tax payments.

CP1600 Corporate Allocations Other

These costs are allocated to the business units based on the business unit's annual labour and materials budget in the Strategic Development Plan (SDP) as a percentage of Western Power Network's total SDP labour and materials budget.

The costs allocated comprise the operating costs for Executive Management; General Counsel; Internal Audit; Strategic Services Division (excluding Treasury and HR); Commercial Services Division including Accounting Services, Logistics, Fleet and Business Information Technology; and Corporate depreciation. Any corporate revenues, for example computer hire charges are deducted from corporate expenditure before allocation.

EX4000 Insurance

These costs are allocated to the business units based on the business units' annual insurance budget in the Strategic Development Plan (SDP) as a percentage of Western Power Network's total SDP insurance budget.

Network Allocations of Corporate Costs

Based on the methodologies described above, Western Power has established the following corporate allocation figures for each year of the period.

Figure 28 - Corporate Cost Allocations to Distribution ($M)

	2003	2004	2005	2006	2007	2008	2009
DISTRIBUTION							
Treasury Branch	$0.47	$0.50	$0.57	$0.60	$0.63	$0.66	$0.69
Employee Srv	$0.21	$0.22	$0.24	$0.25	$0.26	$0.27	$0.29
Rates & Taxes	$0.83	$0.39	$0.46	$0.48	$0.50	$0.53	$0.56
Other	$5.20	$6.31	$7.81	$8.16	$8.57	$8.99	$9.44
Total Distribution Corporate Allocations	$6.71	$7.43	$9.08	$9.48	$9.96	$10.46	$10.98
Escalators				1.045	1.050	1.050	1.050

Figure 29 - Corporate Cost Allocations to Transmission ($M)

	2003	2004	2005	2006	2007	2008	2009
TRANSMISSION							
Treasury Branch	$0.35	$0.37	$0.40	$0.41	$0.43	$0.46	$0.48
Employee Srv	$0.10	$0.10	$0.11	$0.11	$0.12	$0.13	$0.13
Rates & Taxes	$1.60	$1.61	$1.78	$1.86	$1.95	$2.05	$2.15
Other	$1.92	$4.47	$2.87	$3.00	$3.15	$3.31	$3.47
Total Transmission Corporate Allocations	$3.96	$6.54	$5.15	$5.39	$5.66	$5.94	$6.24
Escalators				1.045	1.050	1.050	1.050

The tables show that corporate cost allocations have increased significantly between 2003 and 2005 for both Distribution and Transmission. The increases reflect the considerable investigations and analysis required to facilitate consideration of market reforms and industry restructuring initiatives. These costs were incurred firstly in relation to market reform issues which were attributable mainly to the transmission business areas of control and market management. More recently the costs have been incurred in relation to industry restructure issues which have then been assigned generally in line with employee numbers.

Western Power Networks is projecting corporate costs to escalate in future years in line with general factors, predominantly labour. Western Power recognises that implicit in this assumption is that the costs relating to market reform and industry restructure are captured within the projections. This raises the issue that should the network business be more formally separated from generation and retail operations there will be a requirement to establish independent corporate resources, particularly in relation to financial and human resource management.

Western Power Networks is currently investigating the impacts of business separation to determine the levels of corporate costs that might be incurred. The corporate allocations shown in the above table are based on simple projections of actual costs and therefore do not include additional specific costs of business separation. They do include some costs relating to market reform, however these would not provide fully for such reorganisation.

Insurance Cost Allocations

Western Power Networks currently acquires insurances through its corporate operations that cover all aspects of the business, including generation, networks, retail and other ancillary operations. Western Power Networks believes that this approach has allowed the business to gain reduced premiums through the diversification of business risks. The insurance premiums are then allocated to the various business segments based on the specific nature of the policies or on more general bases where the costs cannot be accurately assigned. The allocated insurance costs proposed by Western Power Networks for the distribution and transmission network businesses are shown below.

Figure 30 - Insurance Cost Allocations ($M)

	2003	2004	2005	2006	2007	2008	2009
Distribution	3.50	5.99	8.44	8.96	9.62	10.39	11.29
Transmission	0.71	1.40	1.78	2.81	3.02	3.26	3.54
Total	**4.21**	**7.39**	**10.23**	**11.77**	**12.64**	**13.65**	**14.83**

The table shows substantial increases in insurance costs over the past 2 years which are then projected to escalate further over the regulatory period. Increases occurring in 2004 and 2005 reflect the difficult climate for utility insurances following 9/11 and the general tightening of policy availability and conditions. The continued increases reflect the expected industry trends for insurance premiums following careful analysis of the market. Western Power Networks is currently in the process of obtaining quotes for insurance coverage that relate specifically to the networks. This will provide a clearer indication of the levels of premiums for which the network businesses are responsible and which are likely to apply following disaggregation of business segments. Nevertheless, the projected premiums are based on reasonable apportioning of costs between segments derived from claims histories and business risks.

Network Support and Finance and Administration

Finance and Administration includes all staff carrying out finance and accounting functions as well as general administrative staff. Network Support includes the engineering and administrative staff carrying out the planning, design, regulatory strategy, maintenance management and construction and maintenance functions.

Costs for these areas are projected to increase in line with the resources required to support the substantial additional maintenance and capital programs proposed by Western Power over the regulatory period. Comparison of these expenditures over time, separate from other Corporate Costs is not entirely appropriate due to some variations in cost categorisations following reorganisation of accounts and personnel. The following section therefore provides an analysis of corporate costs.

The organisational structure of Western Power Networks is constantly changing and evolving and as a result there have been movements of staff and costs between the Corporate Allocations and Network Support categories over the years. In order to consider a consistent grouping of expenditures, the Corporate Allocations and Network Support categories have been aggregated for the purposes of the chart and analysis in this section.

Forecast corporate expenditures for the transmission and distribution networks are outlined in the table and chart below.

Figure 31 – Corporate and Support Expenditure

	Historical Data			Interim		Review Period		
($million)	**01/02**	**02/03**	**03/04**	**04/05**	**05/06**	**06/07**	**07/08**	**08/09**
Transmission Support	-	17.21	16.41	15.17	20.28	22.19	24.05	25.01
Distribution Support	-	22.22	26.22	26.54	26.78	28.24	29.75	31.41

Figure 32 - Transmission Corporate and Support Expenditure

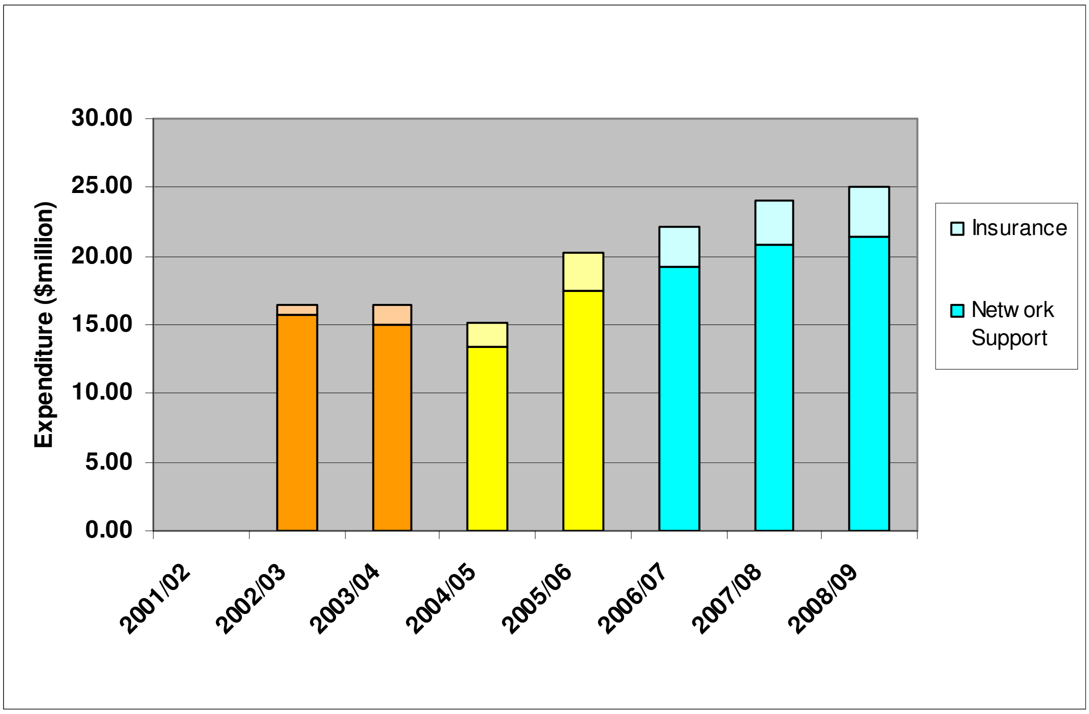
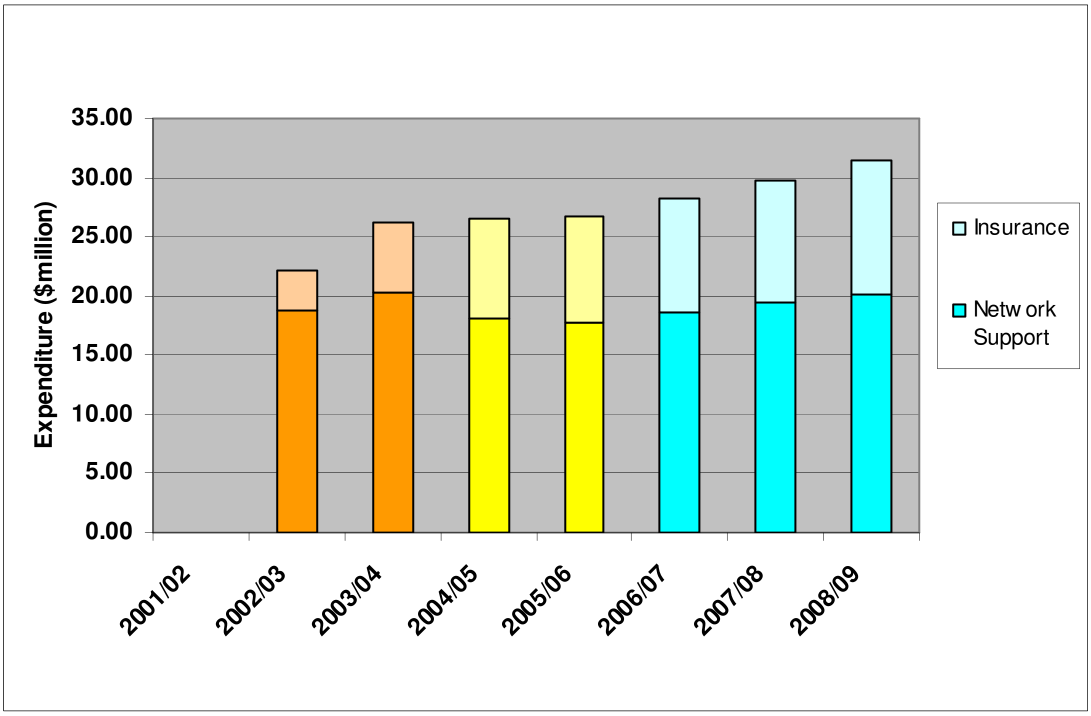


Figure 33 - Distribution Support Operating Expenditure



Corporate Allocations and Network Support costs have been grouped together to give a more consistent view of expenditures over time and the insurance costs are shown separately in the chart due to the unique factors driving these costs.

As the chart shows, Network Support costs have fallen slightly over the past few years, but are projected to rise during the regulatory period. The increases are directly related to the increasing number of Western Power Networks staff. During the last three years actual staff numbers in the Western Power Networks business unit have increased from approximately 1550 to around 2000 full time equivalent (FTE) staff[16] and are forecast to continue increasing to a total of approximately 2200 by the end of the regulatory period. Total staff numbers are increasing for three main reasons:

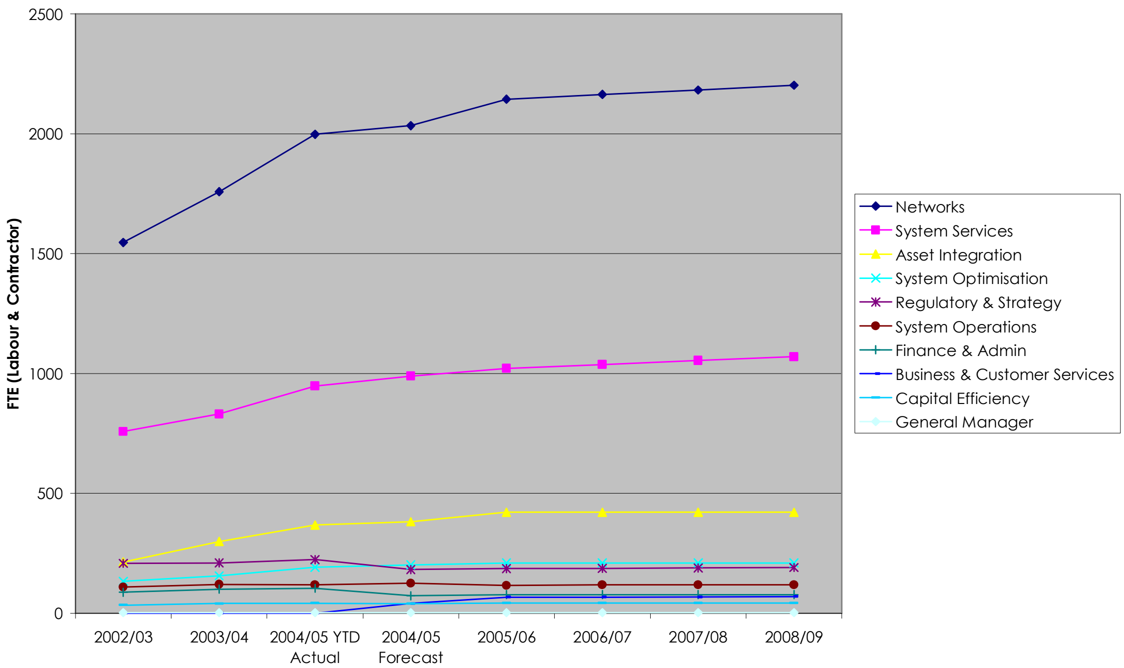
- To manage and implement the increased capital and maintenance spend programmes, for example additional staff are being employed in the areas of Field Services, Design, Capital Planning and Maintenance Planning.

- To manage additional regulatory obligations, for example the preparation of the Access Code, implementation of the meter verification program, safety issues such as bushfire mitigation etc.

- Disaggregation issues requiring transfer of staff from the Western Power Corporate area and other units to the Network Business Unit e.g. transfer of metering and meter reading functions to the network business unit.

The following table shows the historical and forecast changes in Western Power Networks staff numbers for the period 2002/03 to 2008/09.

Figure 34 - Western Power Networks Staff Numbers by Function



With overall staff numbers increasing there is a corresponding need for increases in Corporate and Support staff and therefore operating costs. The increases in support staff have lagged behind the increase in overall staff numbers. However, the increases

[16] Some adjustments have been made to historical staff numbers to provide a consistent view and eliminate effects of changes in the Western Power Networks organisation structure.

in support costs over the regulatory period are proportional to the increases in staff numbers.

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 public information is 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 industry figures.

Figure 35 - Corporate Cost Allocations Rates

Electricity Distribution[17]	
Energy Australia (2003)	26.70%
Country Energy (2003)	49.35%

Gas distribution (2000)[18]	
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% 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.

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

Figure 36 - Corporate Costs and Overhead Proportion

Distribution	2003	2004	2005	2006	2007	2008	2009
Total Corporate Costs	22.22	26.22	26.54	25.53	28.24	29.75	31.41
Total Operating and Maintenance Costs	101.28	104.20	126.38	166.01	166.56	171.10	177.68
Corporate Overhead Rate	21.94%	25.16%	21.00%	15.38%	16.96%	17.39%	17.68%

As the table above shows, Western Power's Network distribution corporate overhead costs are projected to remain well under 20% over the regulatory period. These levels compare favourably with those presented by IPART and indicate that Western Power's Network corporate cost allocations are efficient by comparison.

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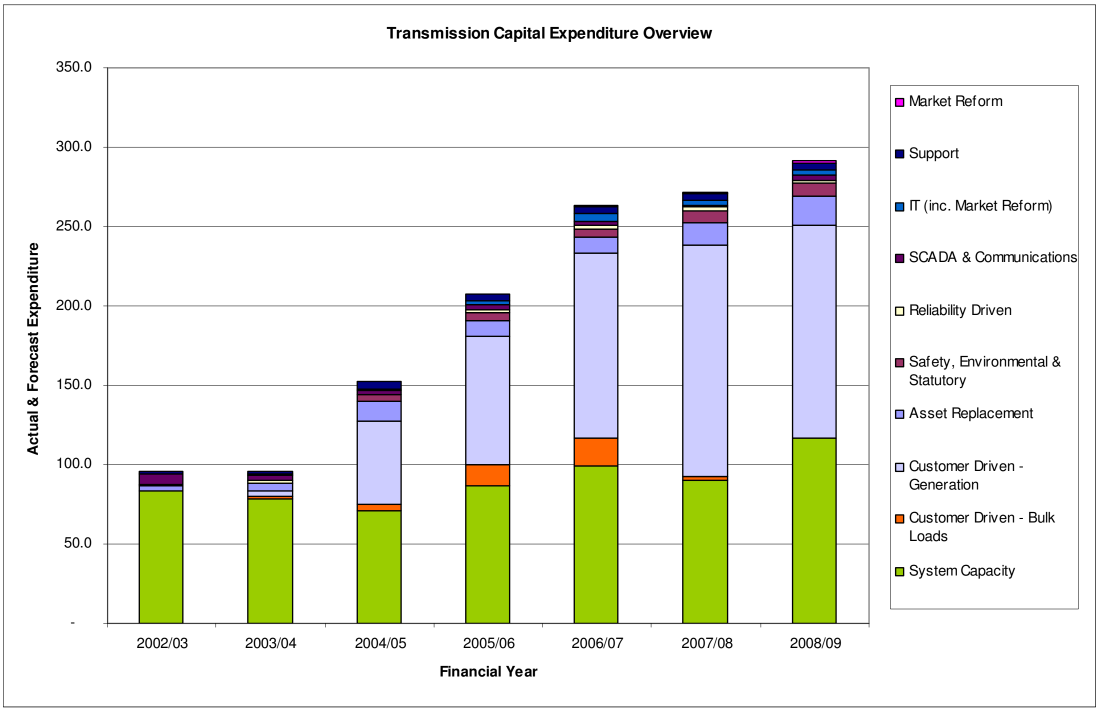
17 Electricity distribution figures extracted from regulatory accounting information available on the IPART and QCA websites.

18 Gas ratios quoted in IPART 1999 Draft Gas Access Decision for AGLGN.

Transmission Forecast Capital Expenditure

At first glance, it appears that Western Power Networks is proposing a dramatic increase in overall transmission capital expenditure. However, if you exclude the work that Western Power Networks is required to undertake to connect new generation, there is very little change in overall expenditures.

Figure 37 - Transmission Capital Expenditure (Resource Constrained)



Western Power Networks is proposing to increase expenditure by almost 100% for the regulatory period. 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.

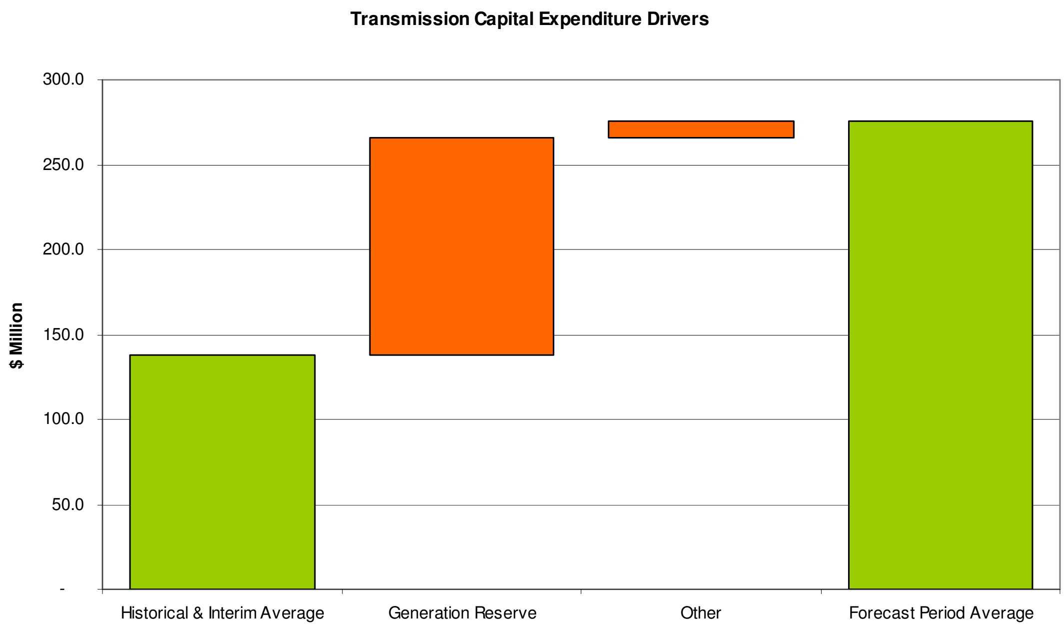
The drivers for change are;

1. Generation and bulk load connections
2. Zone substation Normal Cyclic rating “wind back”
3. Line capacity and undergrounding
4. Asset Replacement
5. Safety, Environmental & Statutory

Summary of Cost Drivers

The impact of Driver 1 (generation connections) averages out to an additional $128 million per annum for the 3 year regulatory period. The overall impact of the remaining drivers is relatively small in comparison and equates to approximately $10 million per annum.

Figure 38 – Transmission Capital Expenditure Drivers



As noted in the executive summary of this report, Western Power Networks has undertaken a detailed review of resource availability over the forecast period and has determined a realistic, deliverable expenditure plan. This deliverable work plan is significantly less than that which Western Power Networks would otherwise deliver during the regulatory period and a number of important projects have consequently been deferred.

However, the information and analysis contained in the subsequent sections of this chapter is based on the unconstrained level of expenditure identified as necessary to satisfy the key business drivers.

Generation Reserve

These works include both the connection costs of new generation and associated upgrades and augmentations of the shared network required by the connection of the new generation capacity to allow a reliable system operation.

The high volume of future generation related works appears completely at variance with recent historical expenditures in this area. However, generation construction activity is a relatively cyclic phenomenon, triggered when utilization of existing assets becomes high.

Figure 39 – Transmission Customer Driven - Generation Capital expenditure

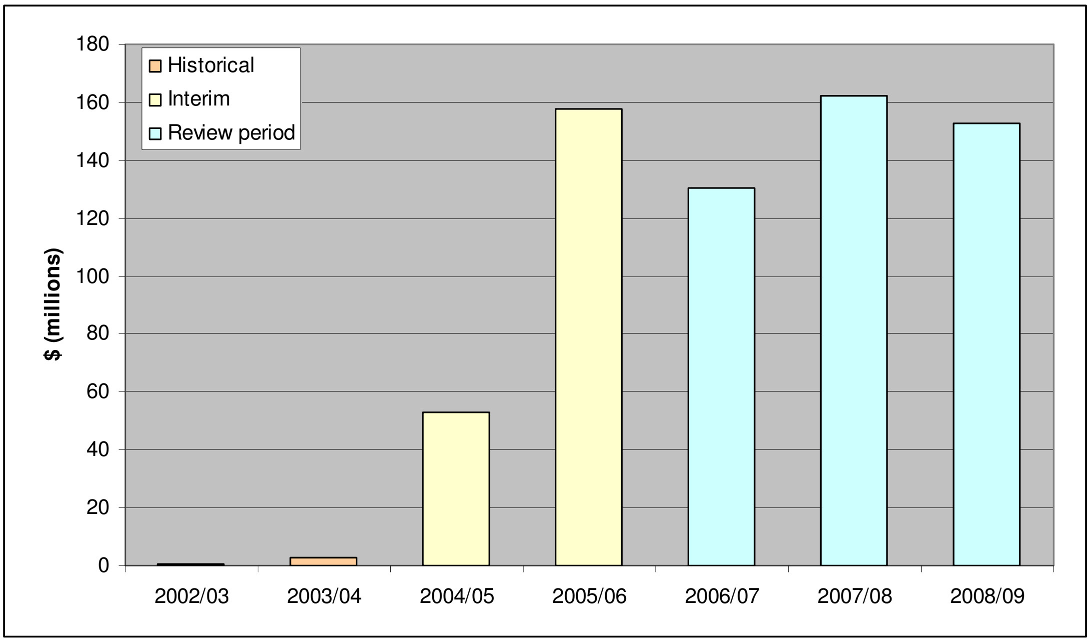


Figure 39 clearly shows a significant increase from recent historical levels. It is important to note, that this does not reflect the longer term historical trend. Historically, investment in generation connections has been lumpy driven by both major connections and available capacity in the shared network. The last major project driven by generation connections was the SHO-ST 91 330 kV transmission line, which was constructed in 1999.

The present supply/demand balance on the SWIS and the transmission system under-pinning 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. The bulk transmission network that underpins this generation capacity, allowing the reliable supply from the generation to the load centres, will also require significant level of network investment to allow the system to accommodate the increased 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[19]. 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.

[19] 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..

The existing reserve margin is 304 MW, plus a further 30 MW of regulating reserve i.e. 334 MW total. Future changes to the reserve margin will be subject to further determination by the IMO.

In addition, there are also plans to retire certain old and inefficient generating plant, namely:

- 2008: Muja A/B is approx. 40 years old with sent-out capacity of 202MW (confirmed project in the GSR)
- 2009: Kwinana A/B is approx. 35 years old with sent-out capacity of 388MW

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

- 2005: Kemerton 260 MW
- 2005: Alinta 1 150 MW
- 2005 Walkaway Windfarm 90 MW (note: intermittent capacity)
- 2006 Alinta 2 150MW

Based upon existing and committed generation capacity, the forecast in peak demand, and the above issue, the system is forecast to be below its minimum reserve margins by 2007/08. Detailed information on this is provided in the Western Power Networks Generation Status Review.

Preparation of generation scenario

In order for Western Power Networks 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 Networks cannot control the location, timing, size etc. of new generation plant connecting to its network. To this end, Western Power Networks are 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 Networks has produced a generation scenario based upon its knowledge of the announced projects and high probability locations[20]. 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:

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

- precedence was given to generation proposals contained in the 2004 GSR or well developed proposals that have been made since publication of the 2004 GSR;

- 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 Networks consider 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 40 below lists the generation connections, on top of 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.

Figure 40 - Assumed generation connections & decommissioning [21]

Generation Connection	Target Date	MW
Emu Downs Windfarm	Nov 2006	80
Albany Windfarm Stage 2	**Nov 2006**	**14**
Alinta 2 (Pinjara)	**Nov 2006**	**140**
Alinta 1 & 2 Wagerup	**Nov 2007**	**280**
Worsley	**Nov 2007**	**120**
Bluewaters 1	**Nov 2008**	**200**
Collie 2 (PPP2)	**Nov 2008**	**300**
Kwinana A/B	Nov 2008	-388
Bluewaters 2	**Nov 2009**	**200**
Cockburn 2	Nov 2011	240

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. As such, although specific actual

[21] Projects in bold indicate a South West location.

generation projects may change from those assumed, particularly in the later years of the scenario, Western Power Networks considers that the level of connection costs, and the nature and scale of the shared network augmentations is more certain.

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 Networks to produce the capital expenditure in this category is discussed in more detail in the Western Power Networks document – Development of Generation Scenarios for use in Network Reinforcement Plans[22].

Planning studies

The process adopted by Western Power Networks to produce the bulk transmission system augmentation forecast is very much based around Western Power Network's normal planning cycle. This is described in the Transmission and Distribution Annual Planning Report (APR) which is a public document produced by Western Power Network. 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[23]. This analysis is via power system modelling of the bulk transmission system. A range of options to alleviate the network violations are considered. These options are 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[24]. 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 issue and

[22] DMS# 2193620v1

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

[24] DMS# 1934690v2A

related Western Power Networks reports. They also summarise the main driver, planning criteria, options considered, and scope and cost of the preferred option.

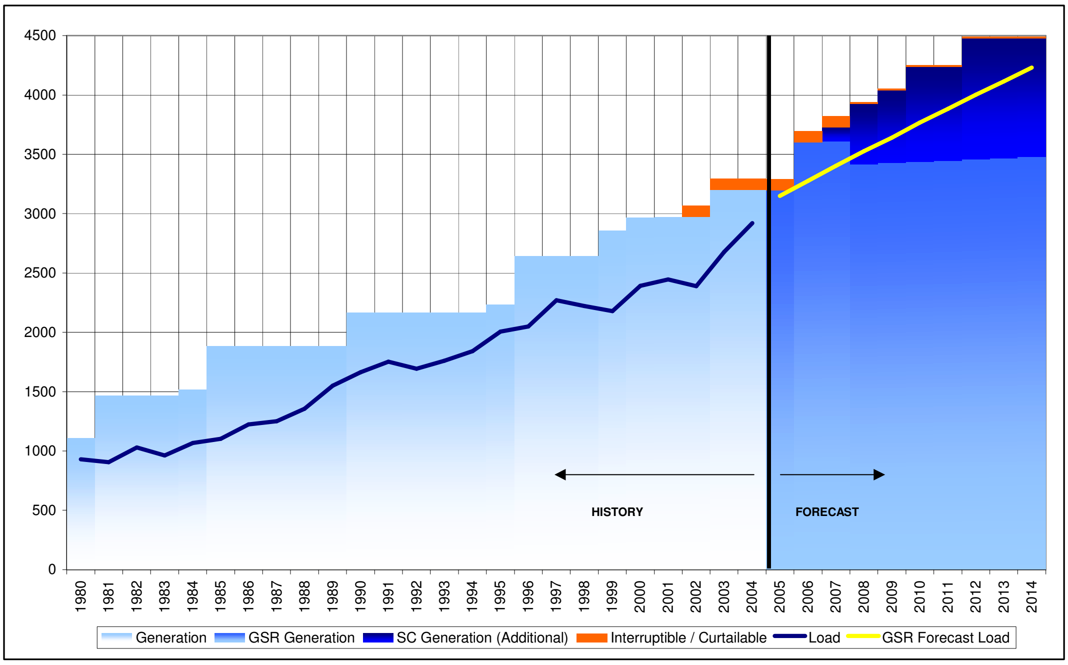
The shallow connection based works of the generation connection is determined based upon known scoped connection projects and assuming similar connection scopes for the assumed projects in the later years of the scenario.

Key factors driving increasing needs

Figure 41 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 41. The impact of these multiple smaller connections is total connection costs higher than recent historical levels.

Figure 41 - 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 42 (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 was in 1999, and prior to this 1990.

Figure 42 - Historical generation connections and associated network reinforcements

Pinjar A/B	1990	193MW	NT-PJR 81 & 82 double circuit transmission line
Pinjar C	1996	202MW	
Collie	1999	304MW	SHO-ST 91 330kV transmission line
SWJV	2000	111MW	
Cockburn 1	2003	229MW	

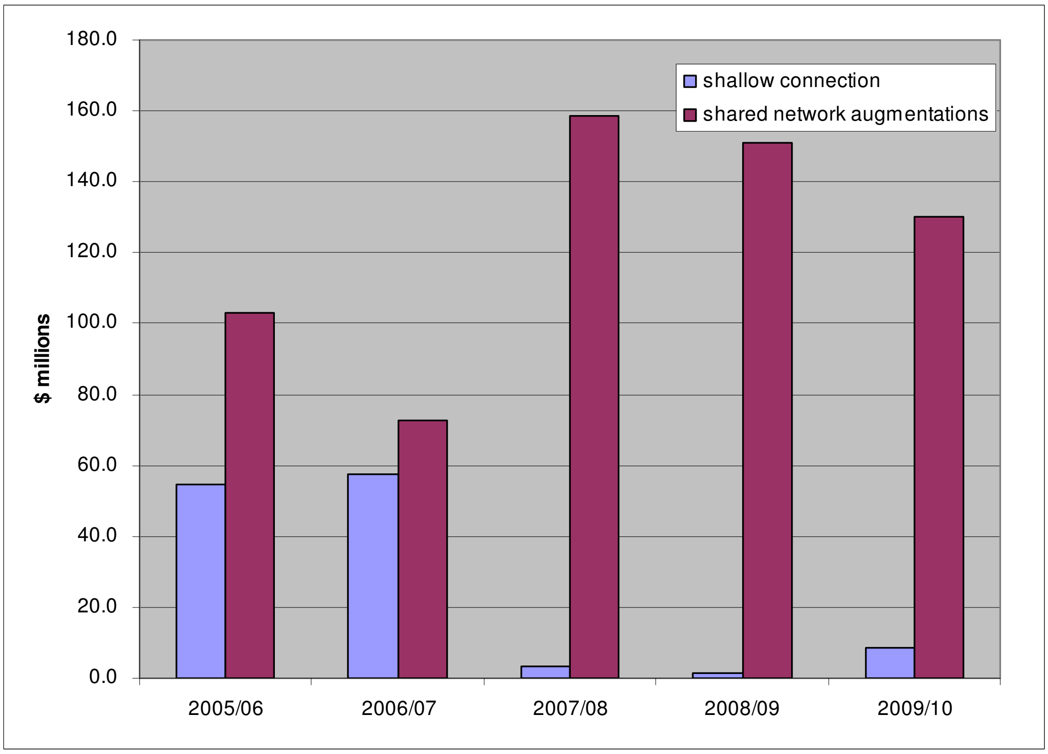
The most likely location for new generation is in the South West for the reasons discussed above. Projections prepared by Western Power Networks indicate that this may well result in approximately 1000 MW of additional generation capacity in the South West by around 2010.

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

Discussion of forecast build-up

The transmission customer driven generation connection capital expenditure forecast is build up from 71 individual projects. 9 of these projects relate to shallow connection works, and 62 projects relate to shared network augmentations. Figure 43 shows the breakdown of shared network augmentation capital expenditure to shallow generation connection capital expenditure. This shows the network augmentations work to be the significant portion of the capital expenditure forecast.

Figure 43 - Shared network to generation connection breakdown



There are ten shared network projects that would be defined as major projects in the Access Code and as such would be subject to the regulatory test. Figure 44 summarises these projects and the costs to be incurred during the regulatory term, noting that a significant proportion of the capital expenditure forecast for these major projects is in the final year of the period.

Figure 44 - Summary of major projects

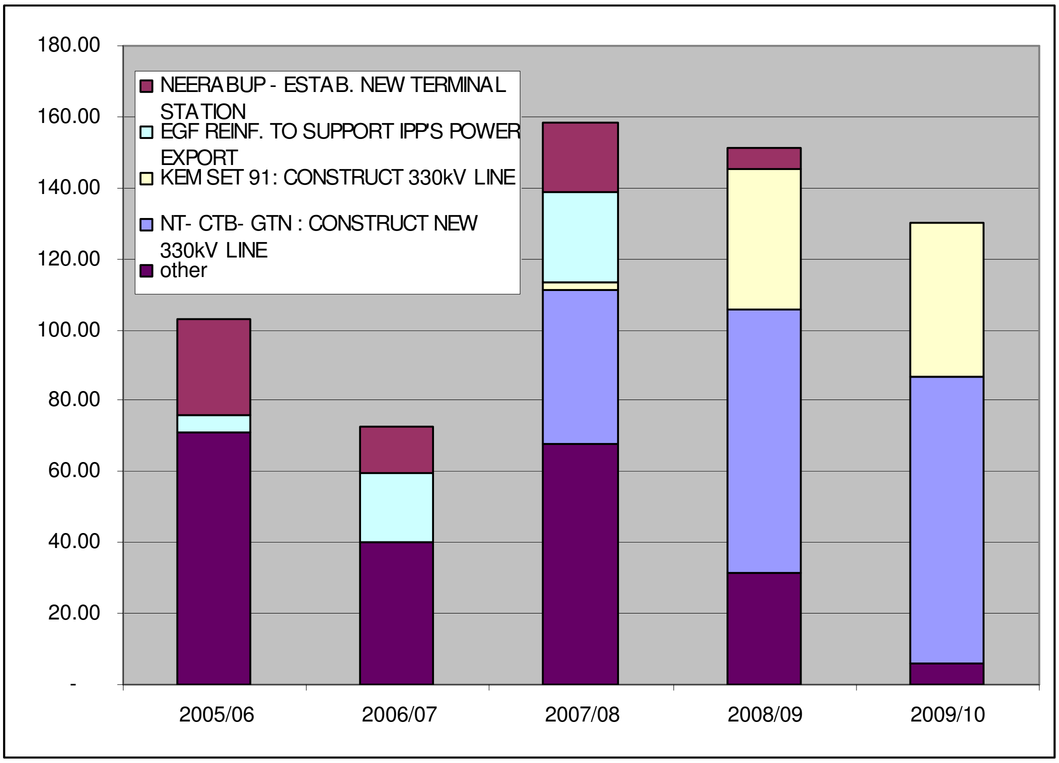
Project	Total
PJR - WNO : CONSTRUCT NEW 132KV LINE	$19
EGF REINF. TO SUPPORT IPP'S POWER EXPORT	$50
NEERABUP - ESTAB. NEW TERMINAL STATION	$40
NORTHERN TERMINAL: INSTALL 200 MVAr SVC	$25
KENWICK LINK: ESTABLISH 330kV/132kV TRAN	$22
S/E TERM : CUT- IN MU-NT 91 & KW - NT 91	$25
KEM SET 91: CONSTRUCT 330kV LINE	$86
SHO-KEM 91 STRINGING 2ND SIDE ON 330 kV	$16
NT- CTB- GTN : CONSTRUCT NEW 330kV LINE	$198

Of these ten projects, the following four projects are very significant in terms of the total capital expenditure requirement:

- NT- CTB- GTN :construct new 330kV line
- KEM SET 91: construct new 330kV line
- NEERABUP – Establishment, and land and easement purchase
- EGF reinforcement to support IPP power exports in region

Figure 45 below shows the total shared network capital expenditure broken down into these four projects with all other projects in the "other" category. This chart shows that the large capital expenditure requirement in the last two years is very much driven by two projects: NT- CTB- GTN : construct new 330kV line; and KEM SET 91: construct new 330kV line.

Figure 45 - Shared network project breakdown



Customer Driven - Bulk Loads

The capital expenditure in this template 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 46 – Transmission – Customer Driven Bulk Loads - Capital expenditure

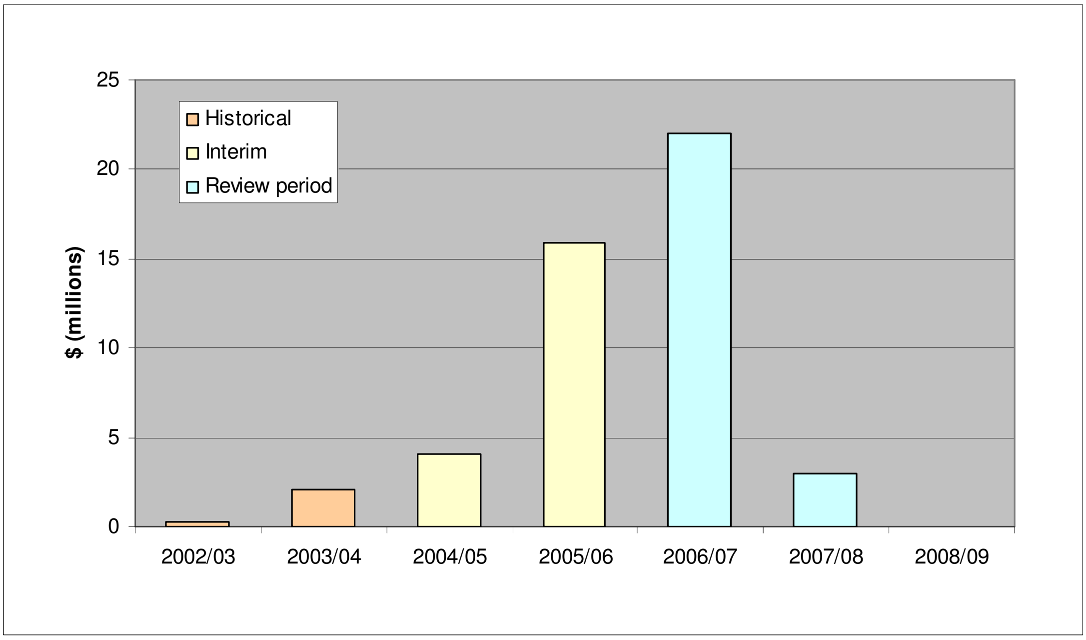


Figure 46 shows an increasing capital expenditure need from recent historical levels, with capital expenditure dropping off in the later years of the review period. Bulk load connection capital expenditure is invariably lumpy as it is driven by connections of a small number of individual bulk loads to the transmission system.

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

- Southern Suburbs Railway (approved) – June 2006.
- Westonia Gold Mine – June 2006.
- Kwinana Desalination Plant (approved) – October 2006.
- Iluka Cataby Mine – January 2007.
- Simcoa Third Furnace – June 2007 (could be end of 2006).
- Boddington Gold Mine – November 2007 (scope & timing unclear).

It should be 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 $100M may be required.

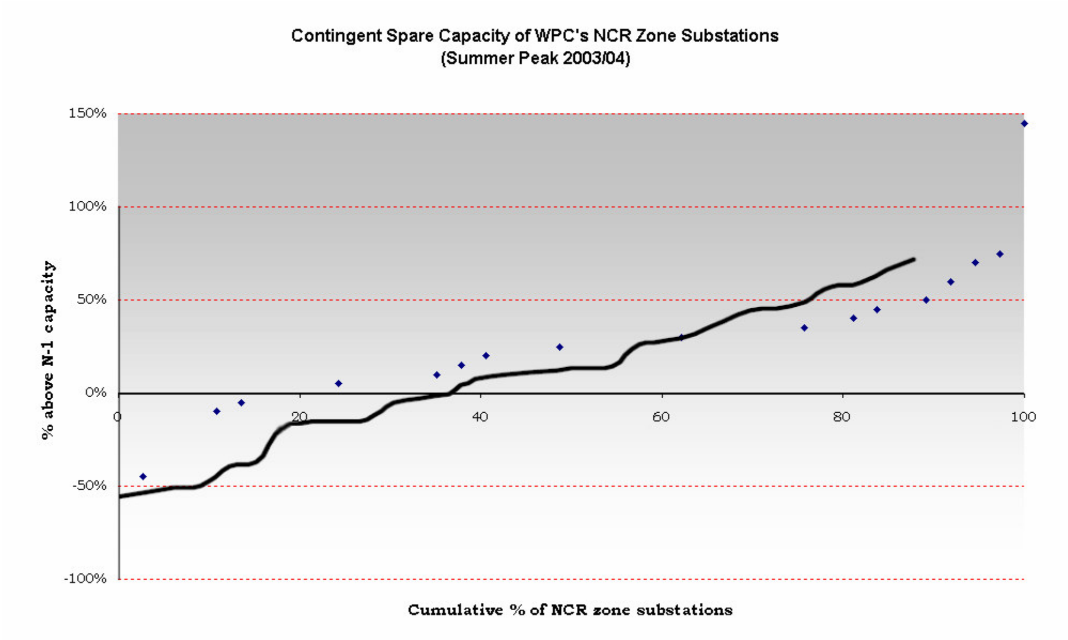
Zone substation Normal Cyclic rating “wind back”

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. The average peak utilisation on NCR rated substations is approaching 80%, compared against a Queensland average utilisation of 76% and the Australian Average utilisation of 56%.

Figure 47 shows a comparison of the Queensland substation utilisation (solid line) with the Western Power Networks 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 Networks NCR assigned substations have N-1 spare capacity.

Figure 47 - Contingent spare capacity of existing substations



Following the finding of the Queensland Independent Panel report[25] on capital investment planning practices in Queensland, particularly relating to substation planning practices and high utilisation levels in Queensland, Western Power Networks 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 Networks 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 Networks has conducted a further investigation into the prudency of the existing NCR criterion. This review is documented in the Western Power Networks document, Review of the NCR Criterion – A Re-examination of the Risks of Load Shedding and Transformer Loading Levels. This review examined a number of options with respect to the existing NCR policy. The recommendation of this review was to reduce the NCR criteria from 90% to 75% of the NCR.

This revised NCR criteria is defined within the proposed Technical Rules. The adoption of this 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 Networks plan is to wind back to the new proposed criteria over a ten year period. This increase in expenditure should be balanced by the ability to maintain the performance of the sub-transmission system as peak demand grows.

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[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

Line capacity and undergrounding

Over the last decade, the maximum operating temperature of many of Western Power Network's critical lines has been raised from $65^{O}C$ 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 Networks 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.

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

Asset Replacement

Asset replacement relates to the replacement of existing assets with a modern equivalent.

Figure 48 – Transmission – Asset Replacement- Capital expenditure

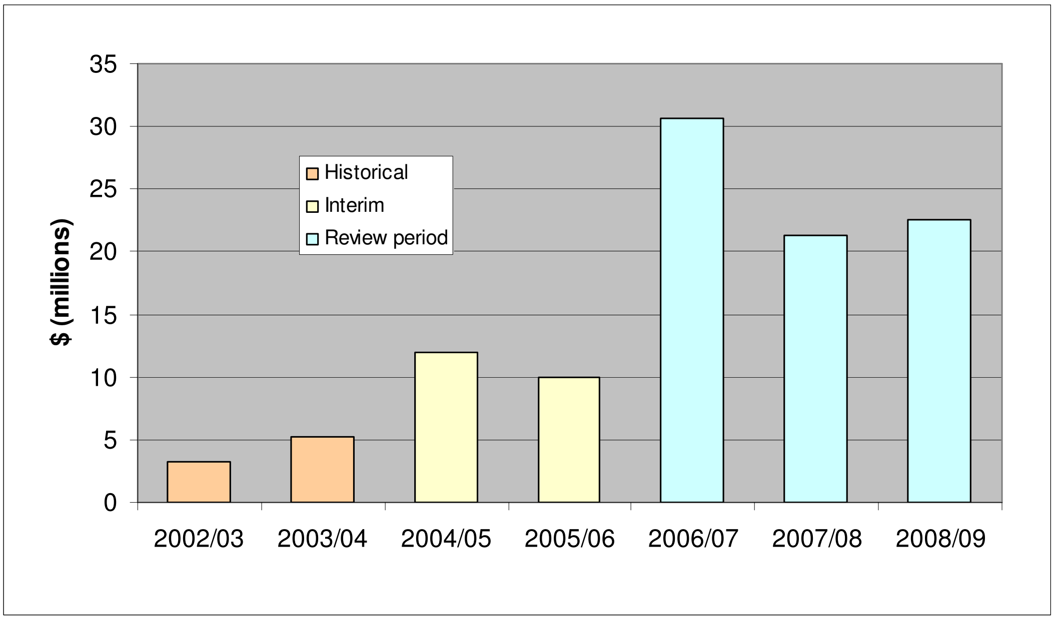


Figure 48 clearly shows a forecast increase from recent historical levels. The gross replacement cost of the SWIS transmission network is calculated to be $2.86 billion.

Maintaining replacement expenditure at recent historical levels would indicate an average asset life in the order of 300 years. The typical transmission asset life 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

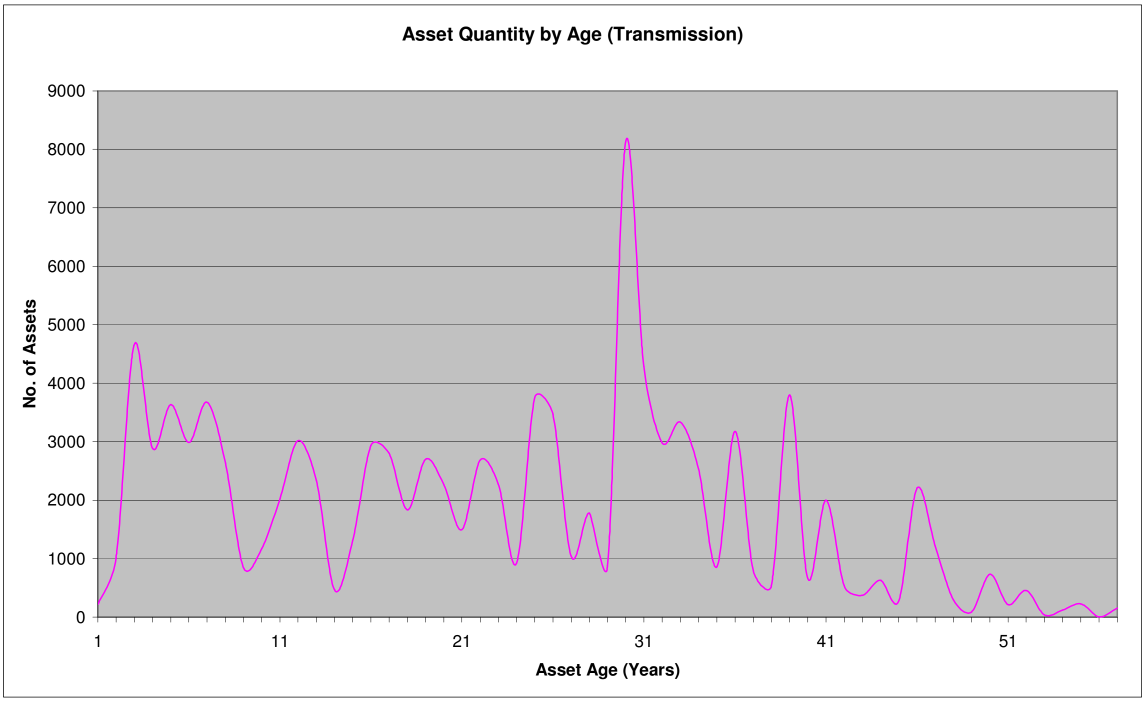
There are two main factors driving the need for an increase in expenditure:

- the underlying age profile which has a predicted wave of replacement needs due to the historical installation dates; and
- the level of backlog of overdue assets that are remaining in service on the network that should be reduced from existing high levels.

The advancing age of the network means within the next 10 to 15 years, Western Power Networks will need to replace much greater volumes of asset than have been required in the last ten years.

Figure 49 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, this clearly shows that Western Power Networks are entering a period of increasing need for asset replacement.

Figure 49 - Transmission asset age profile



In addition to the network aging effect, the recent low levels of asset replacement have been exacerbated by budgetary constraints 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. This not only results in increasing levels of assets at risk of in-service failure, and the associated possibility of higher emergency replacement costs on failure, but also higher maintenance costs on 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 asset overdue for replacement increases, the risk[27] of loss of supply increases also. At a transmission level, due to the much greater scale of loss of supply, it can be the economic risk costs of this loss of supply to customers that can be the significant factor in driving the need for scheduled replacement.

Western Power Networks does not consider the existing level of asset overdue for replacement to be prudent. The overarching philosophy of this application to the regulator is to improve network performance and reduce the existing levels of risk Western Power Networks current operate to. The Western Power Networks 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 Networks introduced the Transmission Investment Planning Database (TIPD). This database holds information on every transmission asset in the Western Power Networks SWIS and can be used to forecast capital expenditure.

The basis of the methodology Western Power Networks has applied to determine its asset replacement capital expenditure is detailed in the SWIS Transmission Network Asset Management Plan (TNAMP)[28].

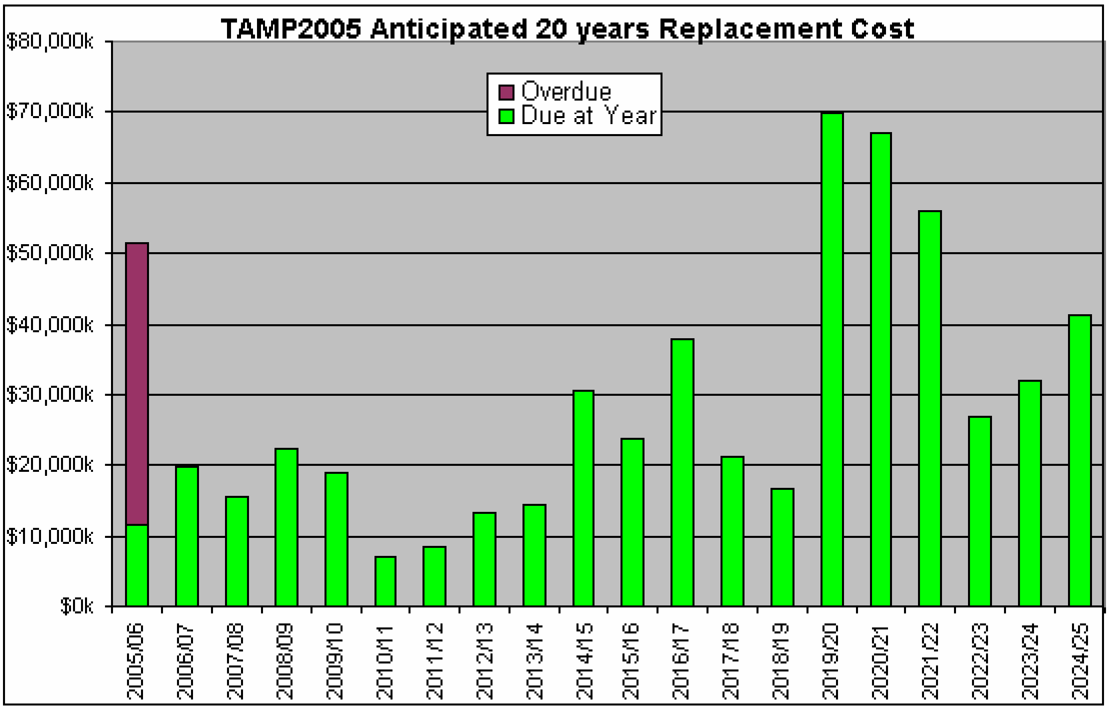
All assets are assigned an expected life by asset type[29], based upon the actual age of the asset a provisional remaining life can be defined. For primary substation plant, this remaining life is further adjusted based upon known historical defects within an asset population. Condition information from 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 Networks maintain paper files detailing the analysis of these assets[30].

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

Figure 50 below shows the 20 year asset replacement forecast based upon the Western Power Networks methodology. This graph clearly indicates the predicted rising trend in replacement needs due to the historical installation profile of transmission assets. This indicates in excess of a ten fold increase over the next 20 years in asset replacement needs from recent historical levels ($3 to $5 million). The red bar in the first year indicates the level of assets considered being overdue for replacement, this equates to approximately $40 million. Western Power Networks is proposing to reduce the level of overdue asset during the review period to 3/5 of the existing level.

Figure 50 - Transmission asset replacement forecast.



Discussion of forecast build-up

The Western Power Networks forecast has been developed in three main categories, namely primary and 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 51 and Figure 52 (below) 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 51 - Primary (non 66 kV) asset breakdown.

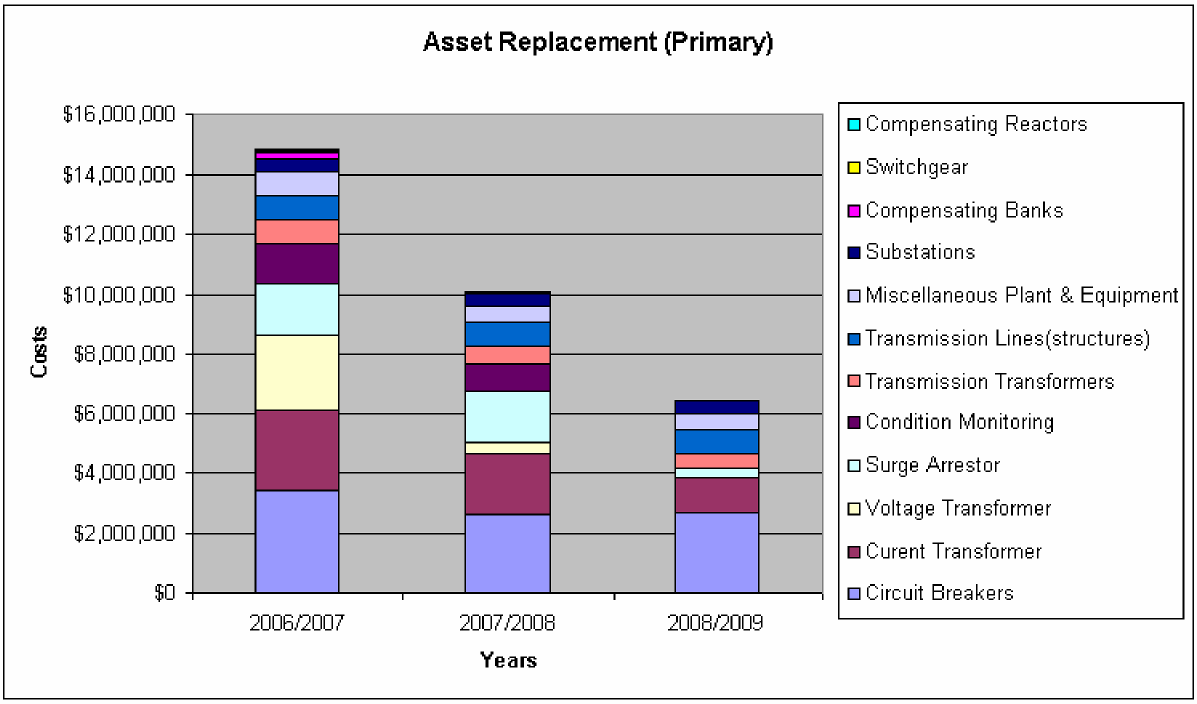
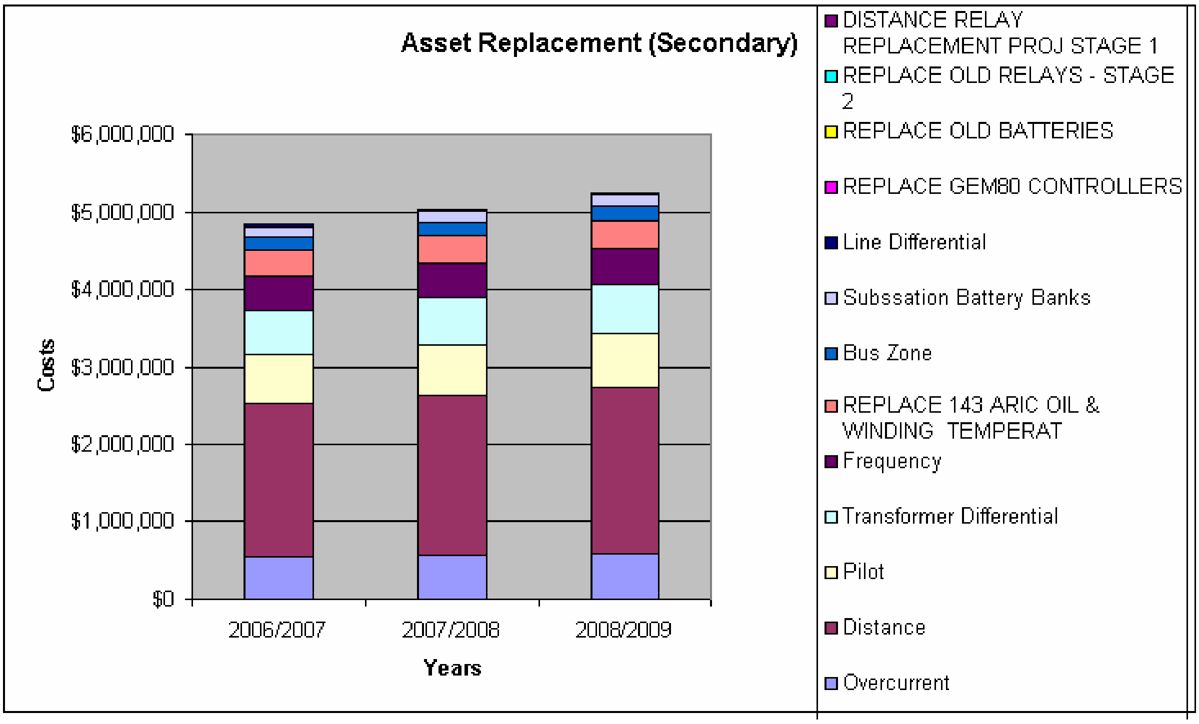


Figure 52 - Secondary (non 66 kV) asset breakdown



The Western Power Networks 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 $19.8million in asset replacement over a 5 year period.

Figure 53 and Figure 54 (below) show a breakdown of asset capital expenditure during the review period for the 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 transformers, transmission line structures, and overcurrent relays.

Figure 53 - 66 kV Primary

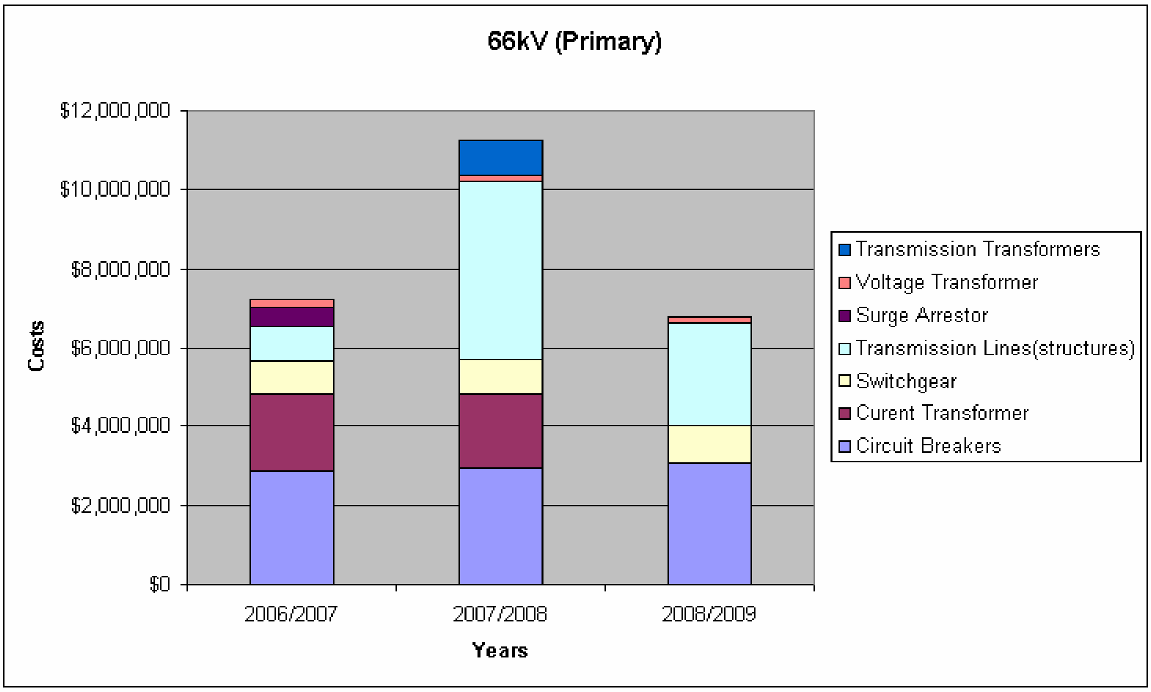
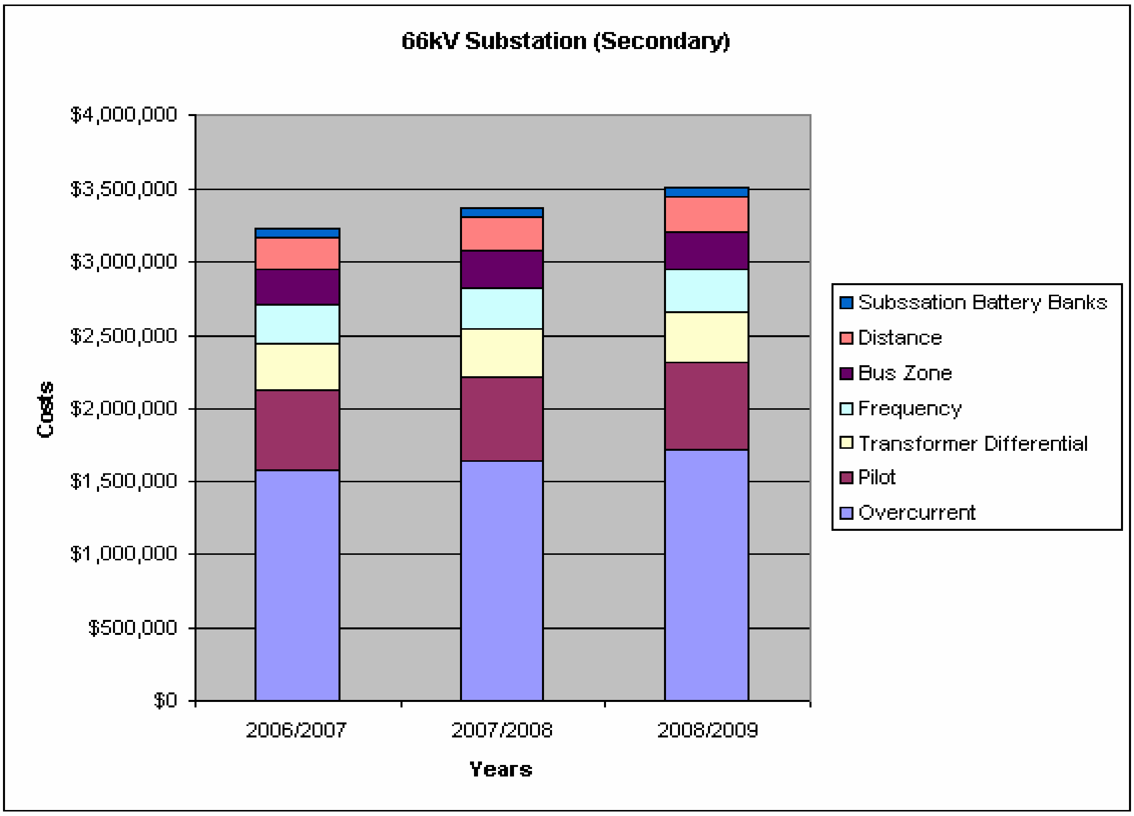


Figure 54 - 66 kV secondary



Safety, Environmental & Statutory

The capital expenditure in this expenditure category relates to meeting external obligations including technical and safety requirements. The following graph provides a graphical representation of this expenditure.

Figure 55 – Transmission – Safety, Environmental & Statutory- Capital expenditure

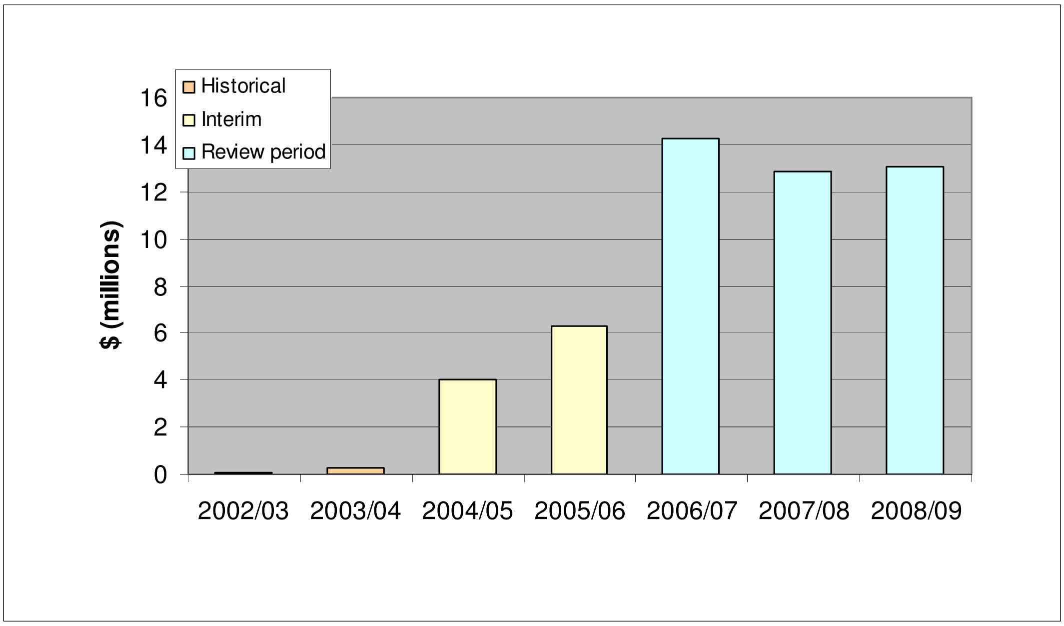


Figure 55 clearly shows a significant increase from recent historical levels. This increase is very much driven by specific needs due to *new* safety, environmental and regulatory requirements that will need to be met in the coming period.

These specific projects and programmes are discussed in more detail in the section below.

Programme breakdown

The majority of capital expenditure in the Safety, Environmental and Statutory template category is due to health and safety related projects on the primary assets (see Figure 56). Figure 57 shows the project level breakdown. This shows the major portion of this capital expenditure to be related to 5 specific projects:

1. Substation fencing and security upgrades;
2. Transmission line river crossing;
3. Replacement of 216 22 kV bus disconnectors;
4. Transmission substation safety upgrades; and
5. Transformer neutral earthing resistors.

Figure 56 - Safety, Environmental and Statutory (primary)

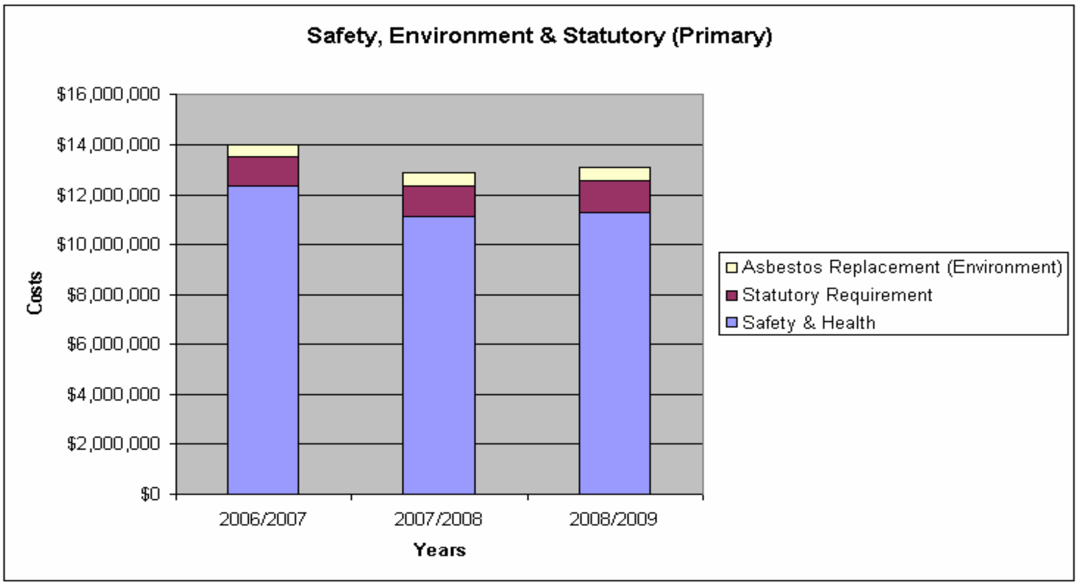
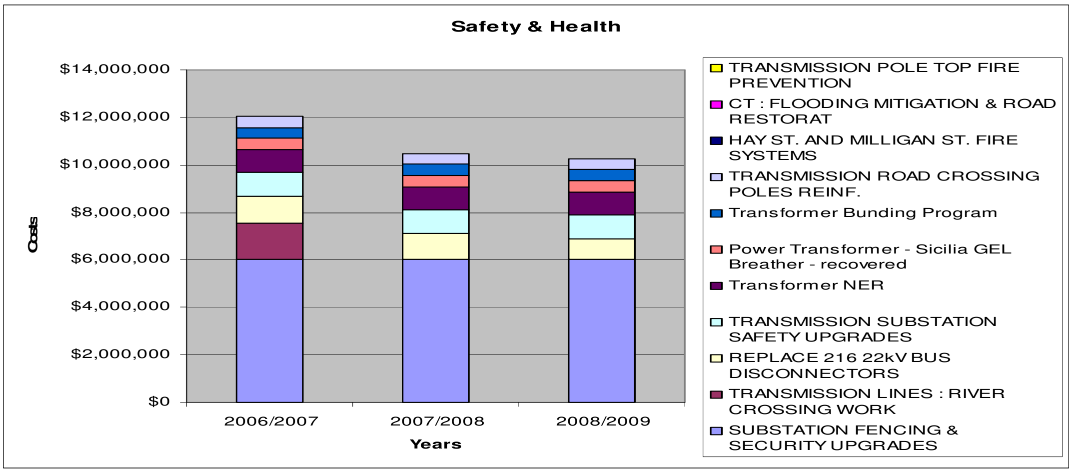


Figure 57 - Safety related project breakdown

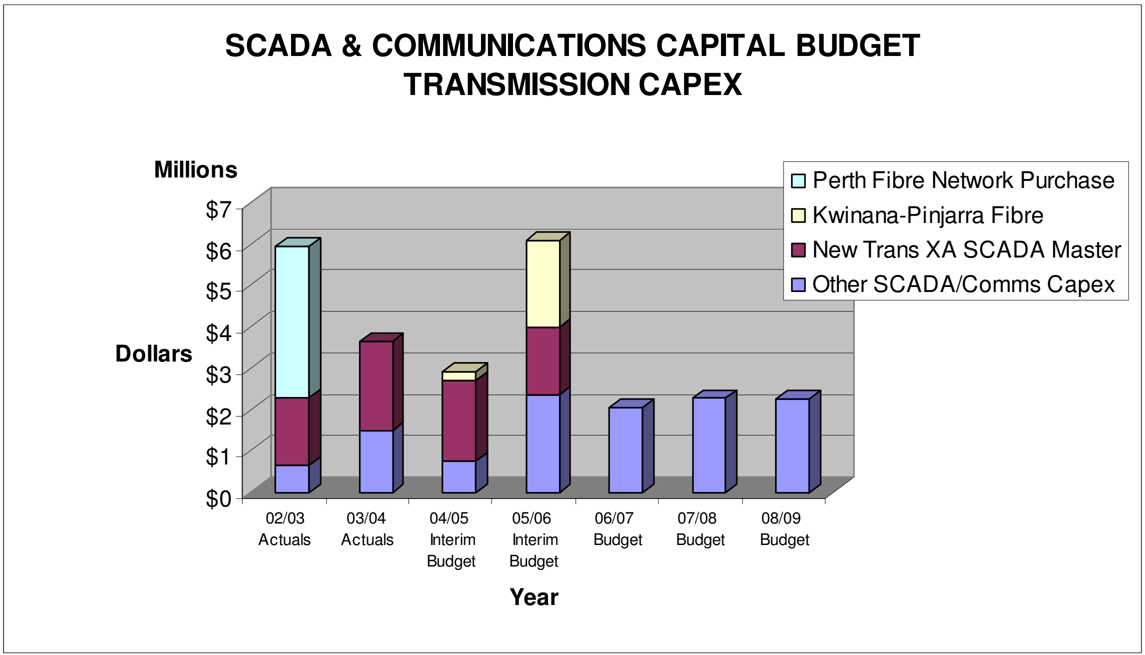


Scada & Communications

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 58 – 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 Networks 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 Networks via competitive tendering processes.

Information Technology

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

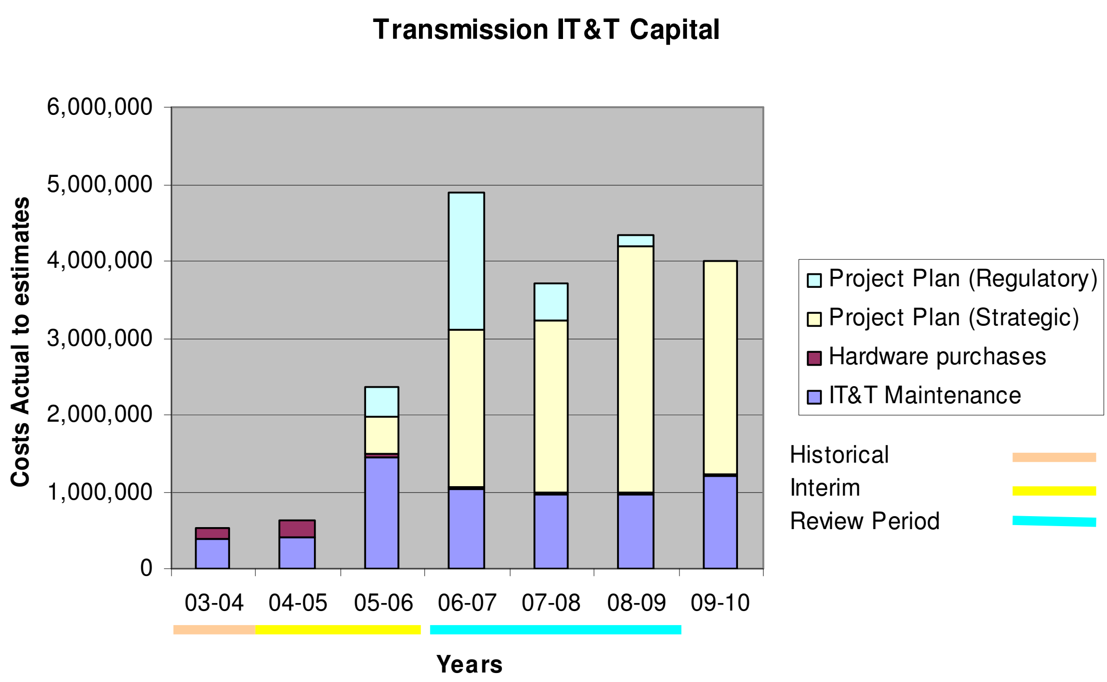
Detailed market design[31] suggests that System Management needs to be ring-fenced and is expected to have significant Information Technology reform costs to meet wholesale market needs. Western Power Networks has made no allowance for the ring fencing of System Management as the rules for ring fencing are not yet clear.

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

- **Regulatory Project Plan** - Expenditure associated with market reform projects,
- **Strategic project Plan -** Replacement of existing Information Technology systems as they approach or have passed the end of their economical and useful life, and
- **Maintenance and Hardware Purchases** - A return to sustainable maintenance levels following a period of historically constrained expenditure.

The following figure provides a breakdown of the relative contributions of the above drivers to the overall transmission capital expenditure forecasts.

Figure 59 - Information Technology Transmission Capital Expenditure



31 KEMA Consulting 4th November 2003

Regulatory Project Plan

A number of reform projects are associated with the implementation of government directives to establish Western Power Networks as a separate corporation and facilitate competition and open access in line with federal COAG directives.

1. **Interface to the Interim Market & Transitional Provisions** – Works 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.

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

Strategic Project Plan

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 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.

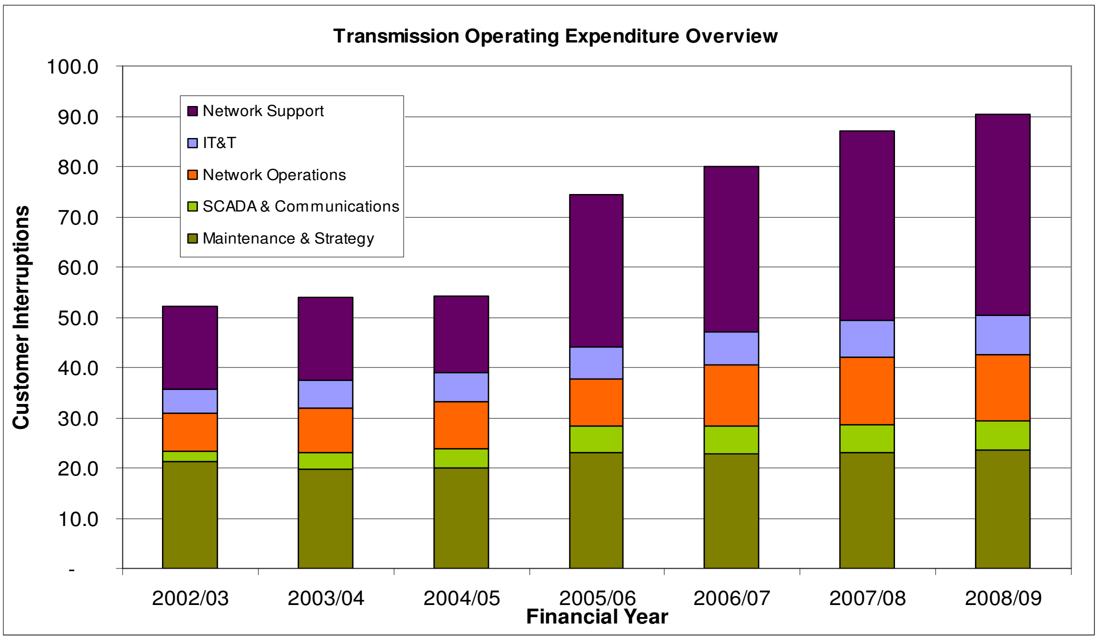
Maintenance and Hardware Purchases

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.

7. Transmission Forecast Operating Expenditure

Figure 60 - Transmission Operating Expenditure (Resource Constrained)



Expenditure Category –Transmission Operating Expenditure)

Western Power Networks is proposing to increase transmission operating expenditures by 46% during the regulatory period. 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 preventative 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 Network as an independent business segment

of Western Power;

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 Networks has undertaken a detailed review of resource availability over the forecast period and has determined a realistic, deliverable expenditure plan. This deliverable work plan is significantly less than that which Western Power Networks would otherwise deliver during the regulatory period and a number of important projects have consequently been deferred.

However, the information and analysis contained in the subsequent sections of this chapter is based on the unconstrained level of expenditure identified as necessary to satisfy the key business drivers.

Network Maintenance

Network maintenance costs are reported under five key groupings of:

- Preventative Routine
- Preventative 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.

Transmission network maintenance costs are projected in line with the following table.

Figure 61 – Projected Transmission Maintenance Expenditures ($M)[32]

	2003	2004	2005	2006	2007	2008	2009
Network Maintenance							
Preventative Routine	2.54	3.84	2.82	3.97	4.07	4.18	4.30
Preventative Condition	5.90	5.85	6.83	6.60	6.67	6.85	7.00
Corrective Deferred	7.77	6.62	6.90	9.17	8.93	9.18	9.39
Corrective Emergency	3.09	2.88	2.35	2.08	2.19	1.97	1.93
Maintenance/Strategy	2.02	0.63	1.14	1.03	1.04	0.97	0.94
Total Maintenance	21.32	19.81	23.52	22.86	22.90	23.15	23.56

32 Note that these figures include street lighting maintenance.

The above table shows overall increases in projected maintenance of $2.24m by 2009 from levels experienced in 2003. This represents approximately 10.5% or an average of around 1.75% pa. In real terms, therefore, transmission maintenance costs have fallen over the period. The key nominal increases in costs occur in preventative maintenance and maintenance strategy, which together account for $4.5m of the increase. This is largely offset by anticipated reductions in corrective maintenance which are expected decrease by $2.25m over the period as a result of strategically targeted preventative maintenance programs.

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

- Reduced corrective maintenance costs (supply restoration)
- Less 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 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 62 - 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 Network's substation asset quantities are shown in the following table.

Figure 63 -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 Network. The remaining 22,000 structures consist of a range of largely steel and concrete arrangements.

Transmission Outages

Preventative 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 Networks 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 Preventative Routine programs proposed are listed below:

Substation Primary Plant Maintenance

This activity includes maintenance of switchgear, disconnectors, transformers and other associated transmission primary pant 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 Networks 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.

Preventative 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 Networks 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 Preventative Routine and Preventative Condition maintenance projections is shown in the following table.

Figure 64 – Projected Preventative Maintenance Expenditures ($M)

	2003	2004	2005	2006	2007	2008	2009
Preventative Routine	5.90	5.85	6.83	6.60	6.67	6.85	7.00
Preventative Condition	7.77	6.62	6.90	9.17	8.93	9.18	9.39
Total Preventative	13.67	12.47	13.72	15.78	15.60	16.03	16.39
% Change		-8.76%	10.06%	14.95%	-1.14%	2.80%	2.23%

The above table shows substantial overall decreases in preventative maintenance between 2003 and 2004, followed by significant increases proposed for 2005 and 2006. These proposed expenditures are intended to establish a consistent program for preventative maintenance over the regulatory period which places appropriate importance on maintaining preventative programs to preserve and maximise the operational lives of network assets. The proposed increases in 2005 and 2006 reflect the implementation of the new preventative 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 61, historical levels of corrective deferred expenditures reduced between 2003 and 2005 and are projected to further decrease in 2006.

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 preventative maintenance. Western Power Networks is projecting for Corrective Deferred expenditures to return to levels in line with escalated 2003 expenditures in 2007. Projections over the regulatory period then remain relatively stable.

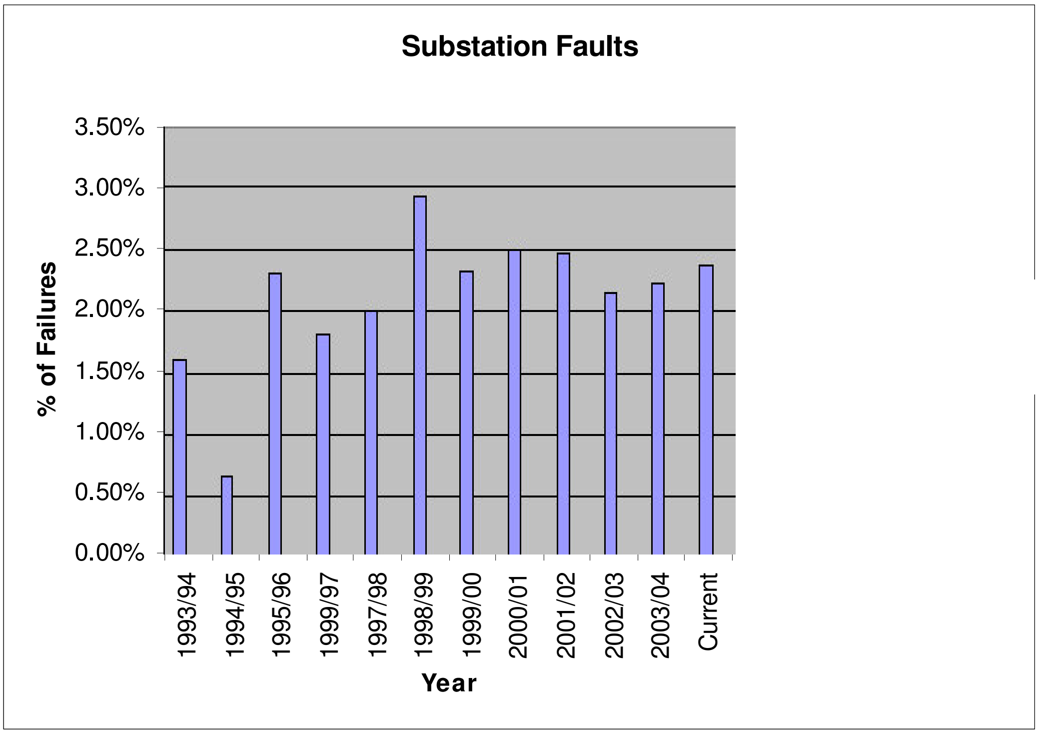
Corrective Emergency

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 to the public and personnel, prevent further damage to equipment or degradation of system performance and to return supply to customers.

Western Power Networks is projecting for expenditures on Corrective Emergency to reduce by $1.16m between 2003 and 2009. These reductions are premised on increases in preventative 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 Networks has investigated the causes of emergency maintenance costs where possible and has identified key areas where preventative 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 Networks is now in the process of identifying the corrective maintenance costs associated with these outages to enable preventative 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.

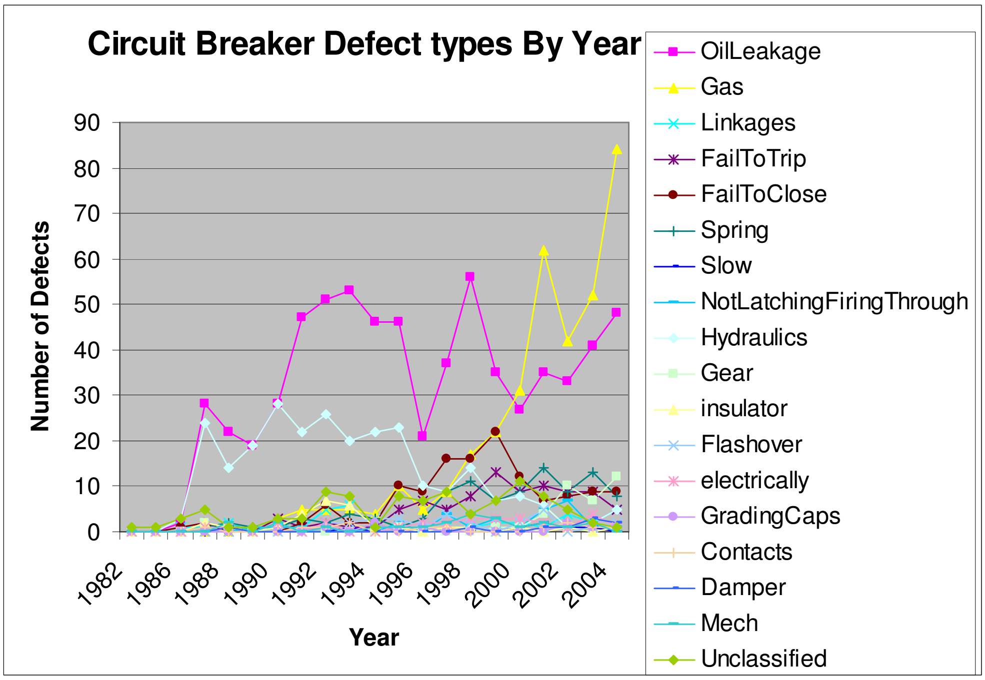
Figure 65 – Historical Records of Substation Faults



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 66 - Historical Records of Circuit Breaker Defects



The above figure 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 Networks 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 are shown in the following table.

Figure 67 - Historical and Projected Corrective Maintenance Expenditures ($M)

	2003	2004	2005	2006	2007	2008	2009
Corrective Deferred	3.09	2.88	2.35	2.08	2.19	1.97	1.93
Corrective Emergency	2.02	0.63	1.14	1.03	1.04	0.97	0.94
Total Corrective	5.11	3.50	3.49	3.11	3.24	2.94	2.87
% Change		-31.49%	-0.36%	-10.85%	4.06%	-9.26%	-2.47%

As the above table shows, corrective maintenance levels in 2009 are below actual 2003 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

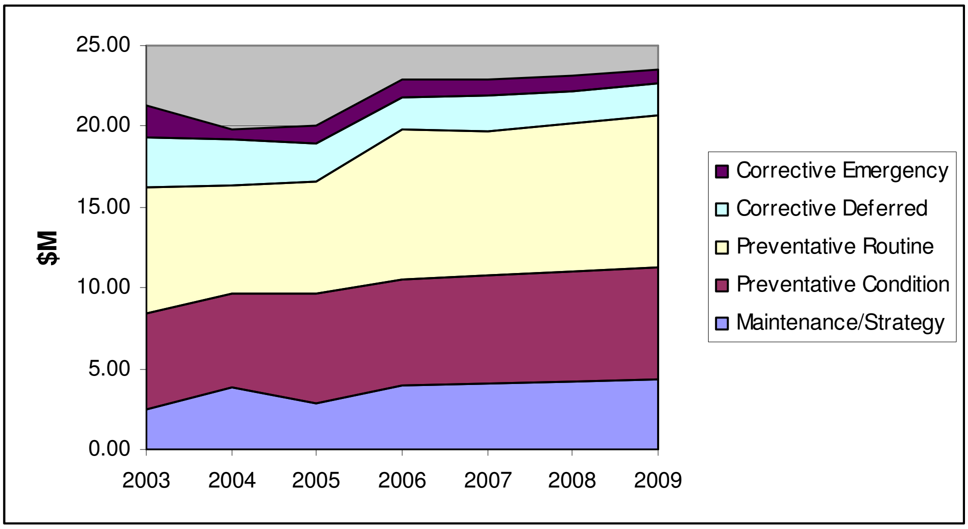
This cost area is a relatively new initiative for Western Power Network. Theses costs relate to the management of asset strategy development as well as short duration specific projects or asset evaluations which are targeted to assess opportunities for improving the management of assets through strategic initiatives.

The expenditures shown in Figure 61 indicate that Western Power Networks is projecting to increase costs in this area by 70% over the period. This increase is premised in a similar fashion to preventative 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 preventative maintenance expenditures and the anticipated performance and cost benefits which have been proposed, Western Power is confident that these costs are soundly justified.

Summary of Transmission Maintenance Costs

The transmission maintenance expenditures proposed by Western Power Networks are summarised in the following chart.

Figure 68 – Summary of Proposed Transmission Maintenance Expenditures



As the above chart shows, overall maintenance costs are expected to increase from 2003 levels by approximately $2.24m (10.5%). This is attributable to increases in preventative maintenance which are anticipated to deliver benefits of improved reliability and safety, as well as achieve compliance with regulatory requirements and optimise the long term service potential of the assets.

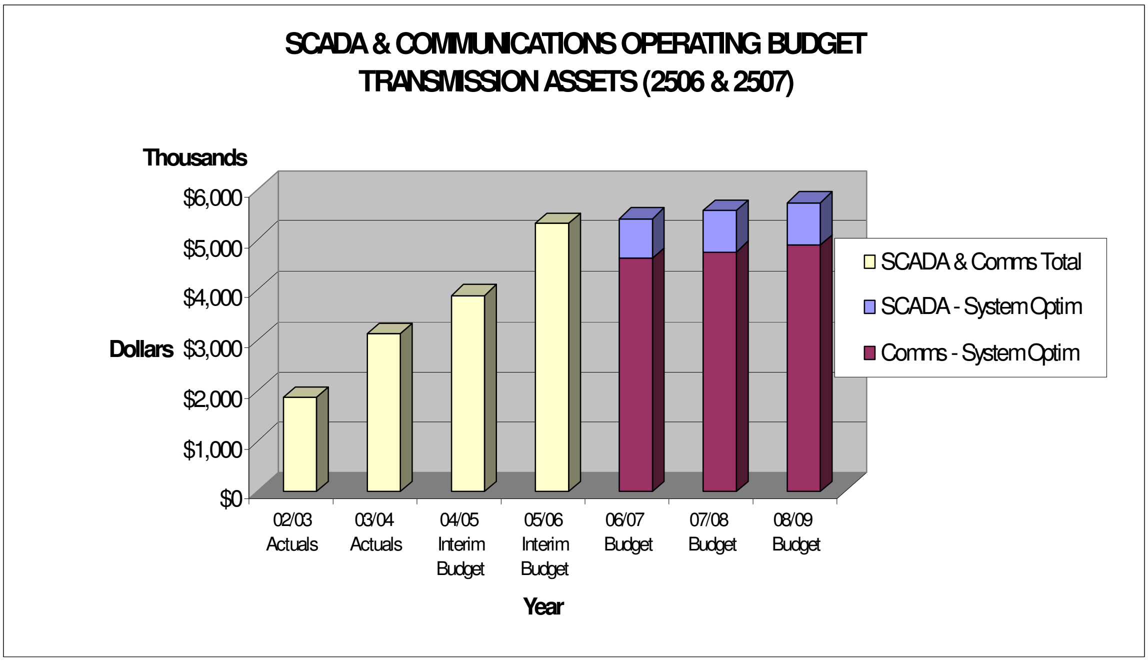
A summary of the increases in maintenance costs and the associated drivers for these increases is provided below.

Scada & Communications

The SCADA and Communication Systems Strategic Asset Management Plan 2005/2006 was recently reviewed by an independent consultant and Western Power Networks 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 Network'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 a steady increase in operating expenditures between 2004/05 and 2005/06. 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 69 - SCADA & Communications Expenditure

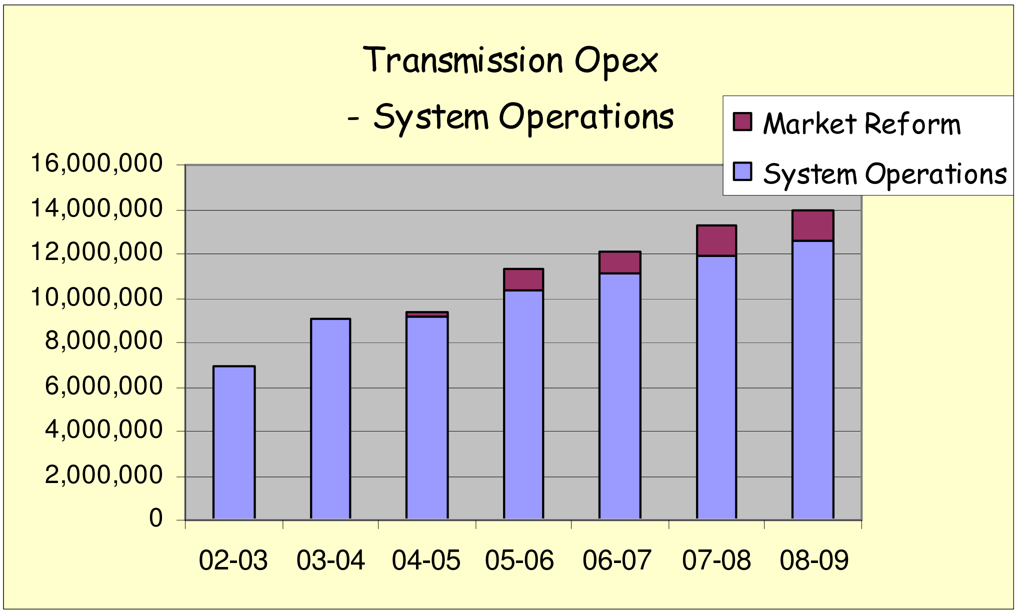


Network Operations

The System Operations group provides control, switching, operations planning and monitoring for the Western Power Networks 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. Western Power Networks is also proposing the implementation of additional SCADA assets further to a government initiative.

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 market reforms. The system operations expenditures are categorised into "business as usual" and "market reform" as per the following chart.

Figure 70 – System Operations Transmission Operating Expenditure



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

- a projected increase in labour costs and material costs – 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 05/06, 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

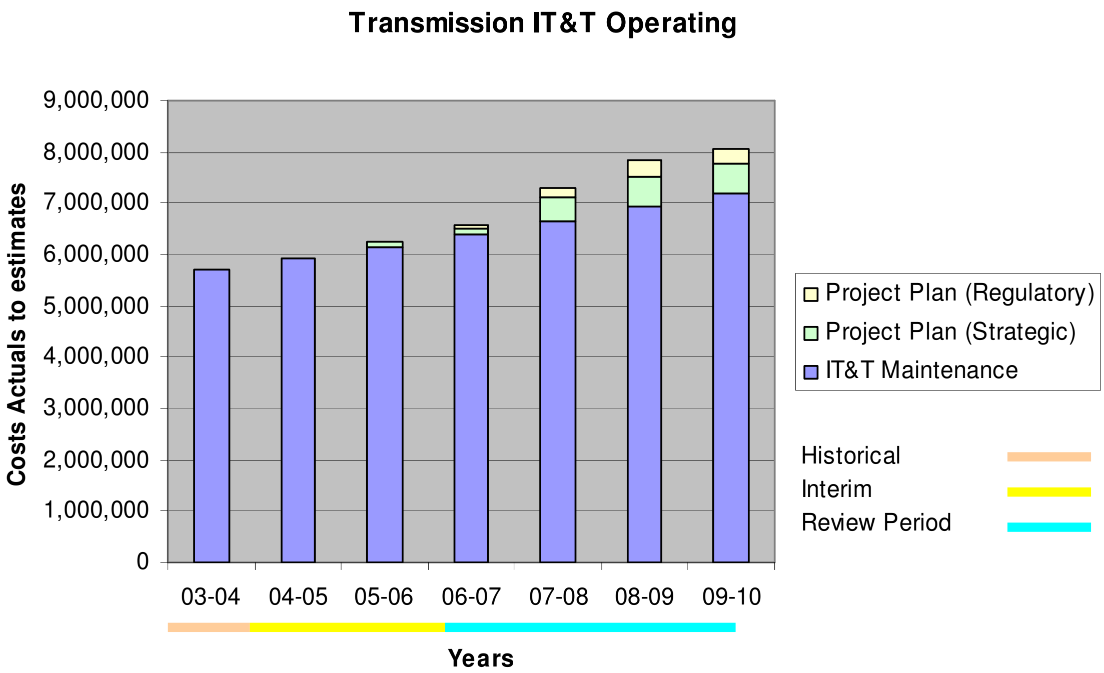
It is noted that the Information Technology group is not responsible for the control system (eg. SCADA) or the Telecommunications network supporting the control system.

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

The Western Power Networks Personal Computer (PC) fleet is leased and the associated expenditures are therefore captured as operating expenditures.

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

Figure 71 - Information Technology Transmission Operating Expenditure



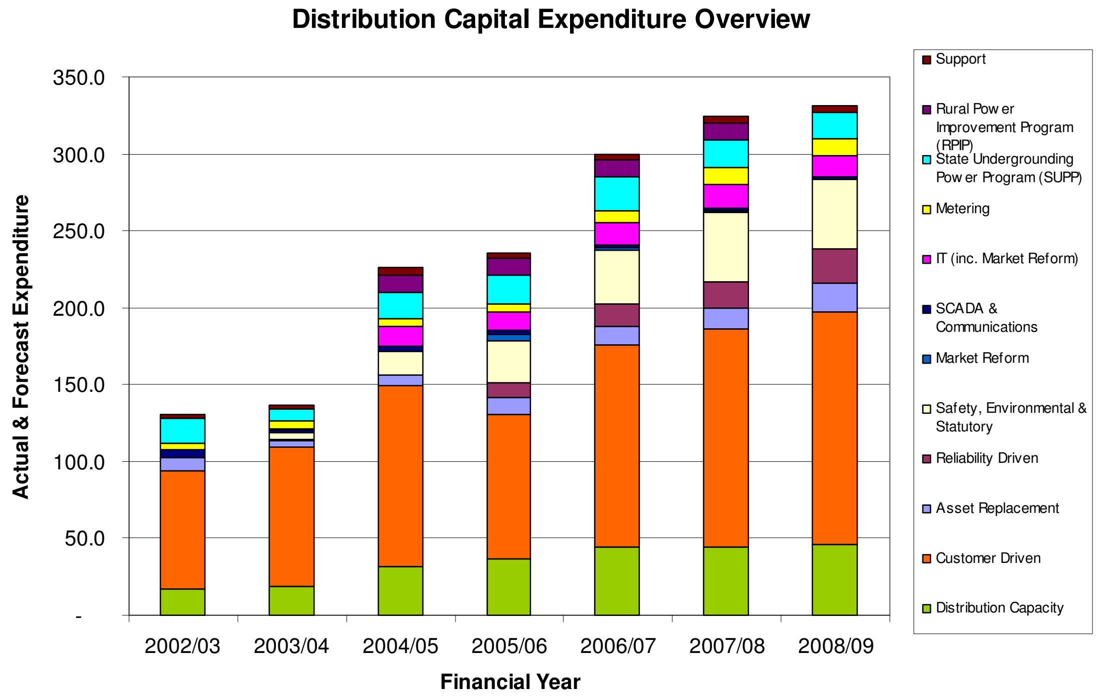
Base IT&T maintenance is projected to grow at 4% per annum for the forecast period. This projection includes adjustments for labour and material inflation. This compares favourably with projections of employee numbers which are estimated to increase 8.28% from 04/05 to 08/09.

The proposed expenditures associated with the regulatory and strategic project plans (Figure 71 above) are based on individual project plans. These project plans provide detailed justifications and documentation supporting the overall IT expenditure levels.

8. Distribution Forecast Capital Expenditure

The following charts provide the historical and projected expenditures for the Western Power Networks distribution business.

Figure 72 - Distribution Capital Expenditure (Resource Constrained)



Western Power Networks is proposing to increase average distribution capital expenditure by 74% over the regulatory period. 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 Networks. This resulting increase in distribution capital expenditure is referred to as the "resource constrained" capital expenditures. The increase in overall distribution capital expenditure is in response to a number of key drivers that are already or will impact the Network business over the next 3-5 years.

The drivers that have resulted in Western Power Networks having to increase expenditures over the regulatory period on distribution capital expenditure 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 interim and 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 Networks made in January 2005, to target a 25% improvement in SAIDI and SAIFI (all faults statistics) across the SWIS – over the next 4 years. This target represents the first step in meeting the Energy Safety Directorates’ (ESD) target.

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 and SAIFI have been acknowledged and identified.

The projects included in this category have been primarily designed to achieve reductions in SAIDI and SAIFI 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.

Driver 3 – Asset Condition

Western Power’s distribution assets have a weighted average remaining life of 56% in 2005. In order to ensure a continued safe and reliable operating environment assets at the end of their service life need to be replaced with modern equivalent 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 has been populated with Western Power’s distribution asset data and the replacement capital expenditures determined by the model have been used as the basis of the projected expenditures in the Asset Replacement category in 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 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 historical $121M to a "resource constrained" expenditure of $185M per annum, an increase of approximately 153%.

2. **Reliability**. The average capital expenditure over the regulatory period will increase from an historical $2M to a "resource constrained" expenditure of $18M per annum, an increase of 900%.

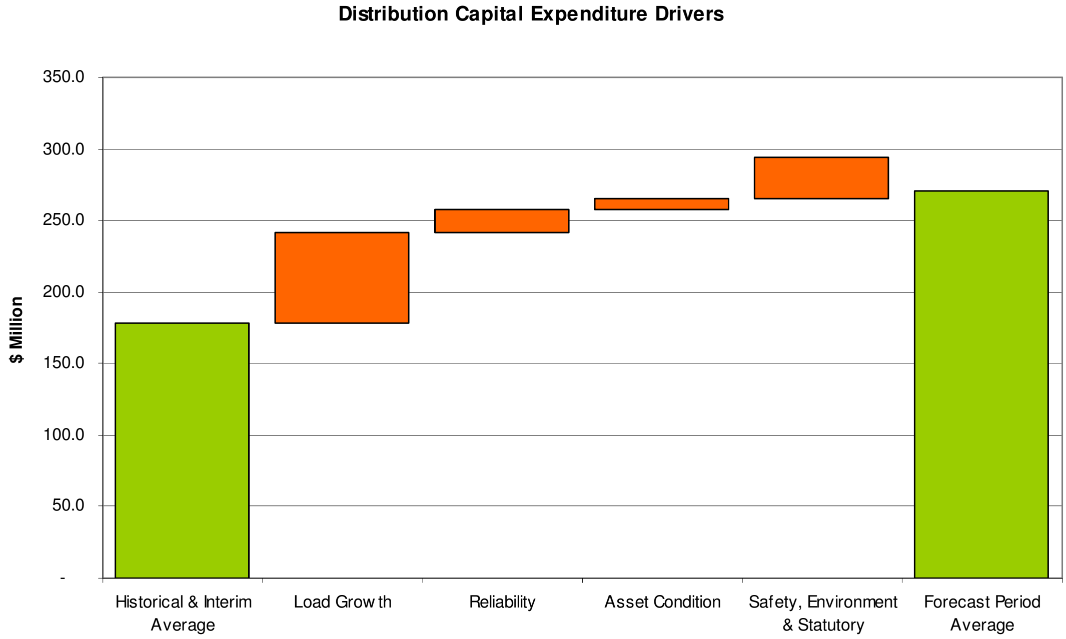
3. **Asset Condition**. The average capital expenditure over the regulatory period will increase from an historical $8M to a "resource constrained" expenditure of $15M per annum, an increase of approximately 188%.

4. **Safety, Environment and Statutory**. The average capital expenditure over the regulatory period will increase from an historical $12M to a "resource constrained" expenditure of $41M per annum, an increase of approximately 342%.

As can be seen from the following chart, the summation of the driver impacts is greater than the proposed forecast expenditure. The reason for the difference is that the forecast expenditures have been reduced to recognise the assessed constraints in future resource availability.

However, the information and analysis contained in the subsequent sections of this chapter is based on the unconstrained level of expenditure identified as necessary to satisfy the key business drivers.

Figure 73 – Distribution Capital Expenditure Drivers



Load Growth

The average expenditure over the regulatory period will increase from an historical $121M to a "resource constrained" expenditure of $185M per annum, an increase of approximately 153%. The average "unconstrained " projected distribution capital expenditure, as detailed below, over the Regulatory Period was $239M per annum, and hence the resource constrained levels of expenditure are considered very prudent.

There are two significant components of distribution capital expenditure associated with load growth. The direct works associated with connecting new customers to the network 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.

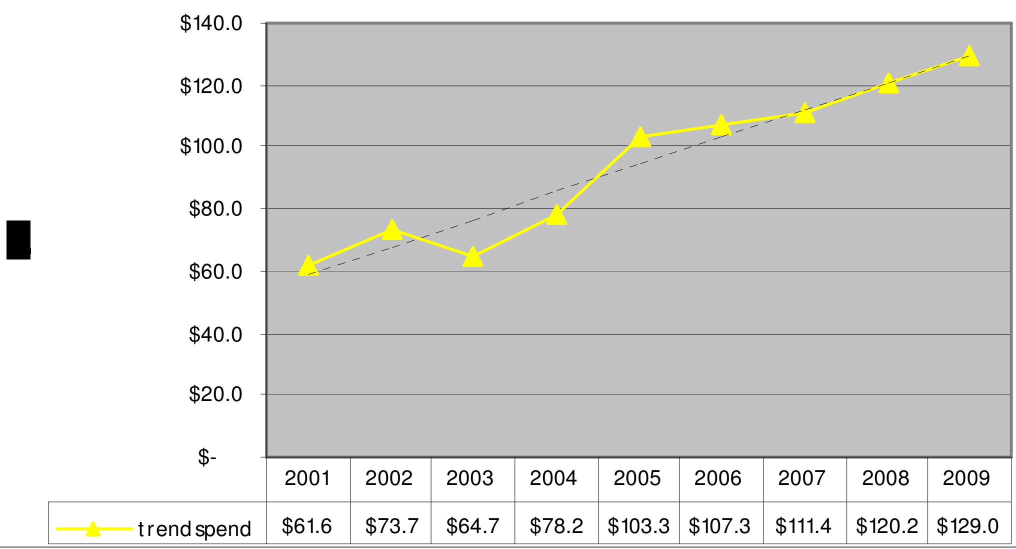
The two components responsible for the increase in projected expenditures on customer driven works are the increasing number and costs of customer connections, and changes to the standards and policies affecting the design requirements for connection assets. Western Australia is currently experiencing a period of high growth which is being reflected in a continued growth in the quantity of new underground residential subdivisions (URD) being commissioned and a sustained growth in number of commercial and industrial connections. Western Power has used historical data to determine the forecast projected expenditures on a business as usual basis over the regulatory period.

In addition Western Power has found it necessary to revise design policies and standards including the electrical design standards applicable to new customer connection 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.

Other design policies and standards changes include the 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 maim switches (RMU), changes to street light designs, increased approval costs, fire proof construction in fire risk areas, and the need to source wood poles outside Western Australia.

The underlying expenditure trend has been determined by using linear regression analysis and historical expenditure data to predict future expenditures as detailed in the following chart. The projected expenditures over the three year regulatory period are $111.4M, $120.2M, and $129.0M respectively.

Figure 2.0 Trend Forecast Spend



The individual design changes which have been added to the base line trend are as follows:

Transformer Noise Abatement.

This design change is in response to an EPA requirement for substations in residential areas to have low ambient noise emissions. To satisfy the EPA requirement Western Power Networks will have to construct masonry or other similar noise deadening screen walls around kiosk substations in residential areas. Western Power Networks has allowed $0.8M / annum for these works.

Increased ADMD Design Criteria.

Western Power Networks has carried out a detailed investigation into current ADMDs in a range of demographic areas within the SWIS and also reviewed experiences in other Australian States. The recommendations from this report have been adopted, resulting in Western Power Networks using a formula to predict design ADMD based on lot price and lot/dwelling size. For example the formula provides an ADMD of 4.5kVA for a medium sized house on a medium priced lot and 7.2kVA for a high priced lot.

The application of this formula to new URD designs should avoid likely future overloading of distribution transformers and LV circuits which are extremely difficult and hence expensive to retrospectively augment. Western Power Networks has estimated that the impact of this design change will incur additional expenditures of $19.1M / annum

Increased Minimum Design Load Industrial / Commercial Lots.

Western Power Networks currently uses a standard rate of 200kVA per ha as the design load for industrial and commercial subdivisions. This approach produces unrealistically low design loads for small lots.

Customers who eventually develop these smaller lots still have air conditioning requirements and in many instances their load requirements are no longer in proportion to the lot size. Western Power Networks propose to continue to utilise this standard rate of 200kVA per ha but to also impose a minimum load requirement irrespective of lot size of 110kVA.

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. Western Power Networks has estimated that the implementation of this design change will incur additional expenditures of $5.2M / annum, as the new minimum load would affect approximately 70% of all industrial and commercial subdivisions.

Street Light Changes.

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 has been incorporated into this capital expenditure category. This move is driven by coronial inquiry recommendations, motorists and pedestrian security expectations

In addition local councils are demanding more control over the visual landscape in 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 Networks has now included a range of more decorative luminaries to cater for this need and developed new streetlighting tariffs for these fittings.

These luminaries will be used at road upgrades, roundabouts and street beautification projects. Western Power Networks has estimated that the additional capital expenditures associated with design change are $1.8M / year.

Work Approvals.

Western Power Networks now incurs additional costs to obtain the necessary approvals prior to commencing construction relating to Native Title, EPA studies and Die Back Studies which affects work in urban fringe and country areas. Council charges also affect all projects.

Western Power Networks has estimated that obtaining the necessary approvals for future works will incur additional costs of $4.8M / year. These studies and approvals are an integral part of carrying out a distribution business and hence form an integral part of the total costs associated with these works.

Fireproof Construction.

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.

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

Wood Pole Replacements.

Western Power has been forced, due to a lack of availability of Jarrah poles, to source wood poles from the eastern states and overseas. However the pole suppliers have advised that the cost of these poles will rise by 100%

Western Power Networks has allowed an additional $3.7M for sourcing wood poles from these areas.

Reduced Number of Customers on HV and LV Spur lines.

These two design changes relate primarily to improving supply reliability. The HV design changes involve the installation of interconnectors between HV spurs involving more switchgear and cables and also limiting the number of customers on HV spur lines to 860. Each of these projects has been estimated at approximately $80,000

The LV design changes involve the installation of additional Uni Pillars in LV underground circuits so isolated LV circuits can be back-fed after faults have been identified. The installation of a Uni Pillar every fourth pillar to facilitate switching or the connection of remote generation has been estimated at $100

Western Power Networks has estimated that incorporation of these deign changes would incur additional capital expenditure of $5.4M / Annum

Replacement of Overhead services with UG Pole to Pillar (P2P).

The provision of underground service connections for all new installation 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 proposal also includes making it mandatory to install underground services when upgrading existing residential, commercial and industrial services in metropolitan Perth.

Western Power Networks has estimated that adoption of this proposal will incur additional capital expenditures of $8.0M / annum.

DCRM of Switchgear and Transformers.

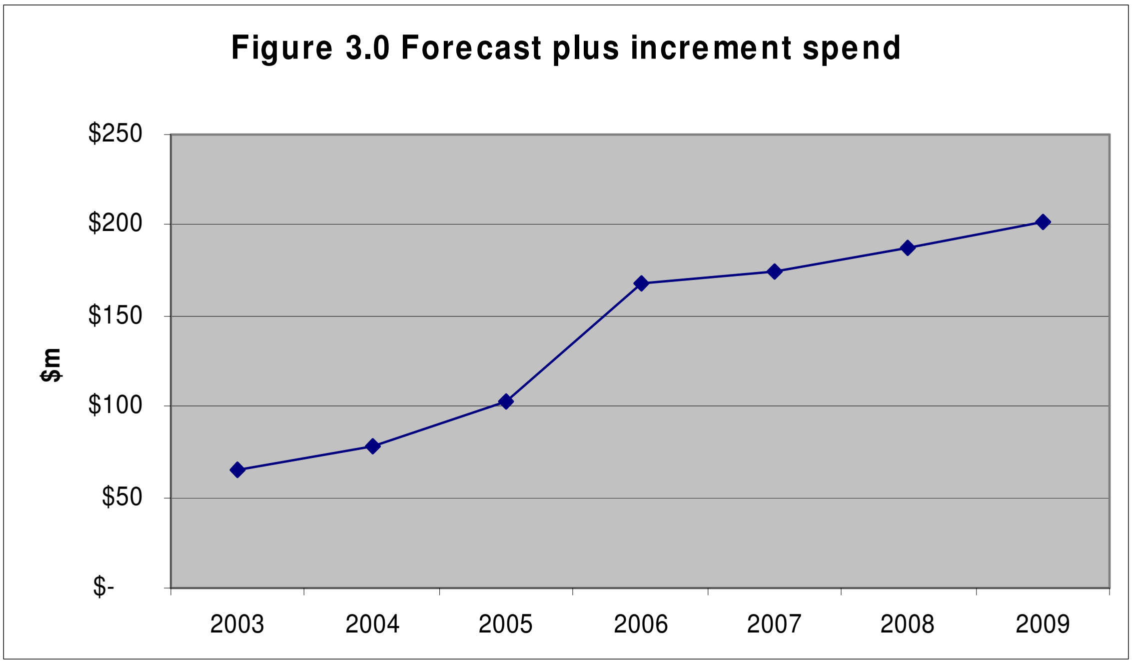
This proposal essentially is designed to improve supply reliability and consists of the remote supervision and operation of switchgear and transformers in suburban Perth.

The project involves the installation of distribution remote control and monitoring equipment at the time of installation. The anticipated cost for RMUs DCRM is $26,000 and for transformer installations $20,000

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

The chart below details the total projected "unconstrained" capital expenditures for both the underlying trend expenditure and the expenditures associated with the additional design changes for direct customer connection works.

Figure 74 – Forecast Total Customer Driven Spend



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 Networks 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.

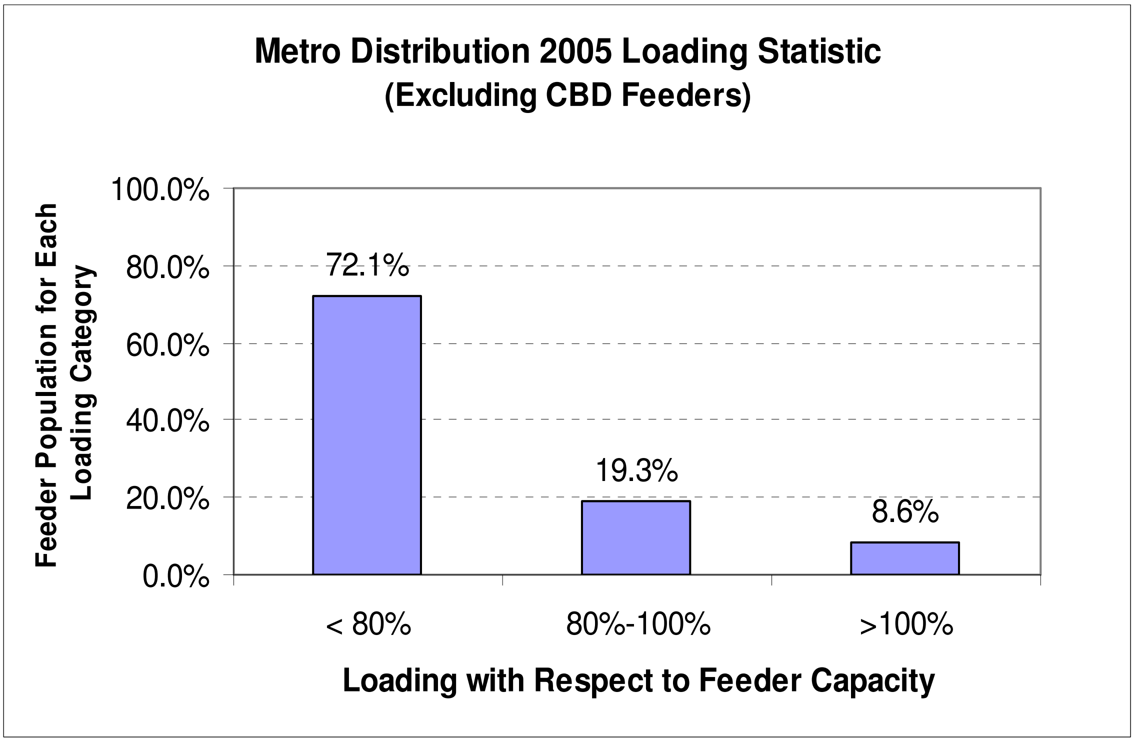
- The need to integrate (over 4 year period) 13 new greenfields zone substations into the distribution network and 5 new replacement zone substations requiring conversion of distribution feeder voltage from 6kV to 11kV or 22kV. Each new greenfield zone substation requires an additional three or four 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 75 - Metropolitan Distribution Feeder Loading



Western Power Networks 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 Networks 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 Networks plans to replace 180 distribution transformers in 2005/06 at an estimated expenditure of $4.7M and a further 228 distribution transformers over the control period (128 units in 2006/07, 50 units in 2007/08 and a further 50 units in 2008/09) at an estimated cost of $9M over the three year control period.

LV circuit monitoring by Western Power Networks when changing overloaded transformers has indicated that 50% of the low voltage circuits connected to these overloaded transformers are also overloaded and require rectification. 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 Networks 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 $16,000 has been allowed for the rectification of each residential LV circuit and $32,000 for the rectification of each commercial LV circuit. The proposed spend on removal of LV circuit overloads is $2.24M in 2006/07, $4.8M in 2007/08 and $4.8M in 2008/09.

Historical, interim and "unconstrained" projected expenditures (nominal dollars) for distribution capacity related expenditures, i.e. works associated with augmenting the existing network are as follows:

Figure 76 - Distribution Capacity Related Expenditure

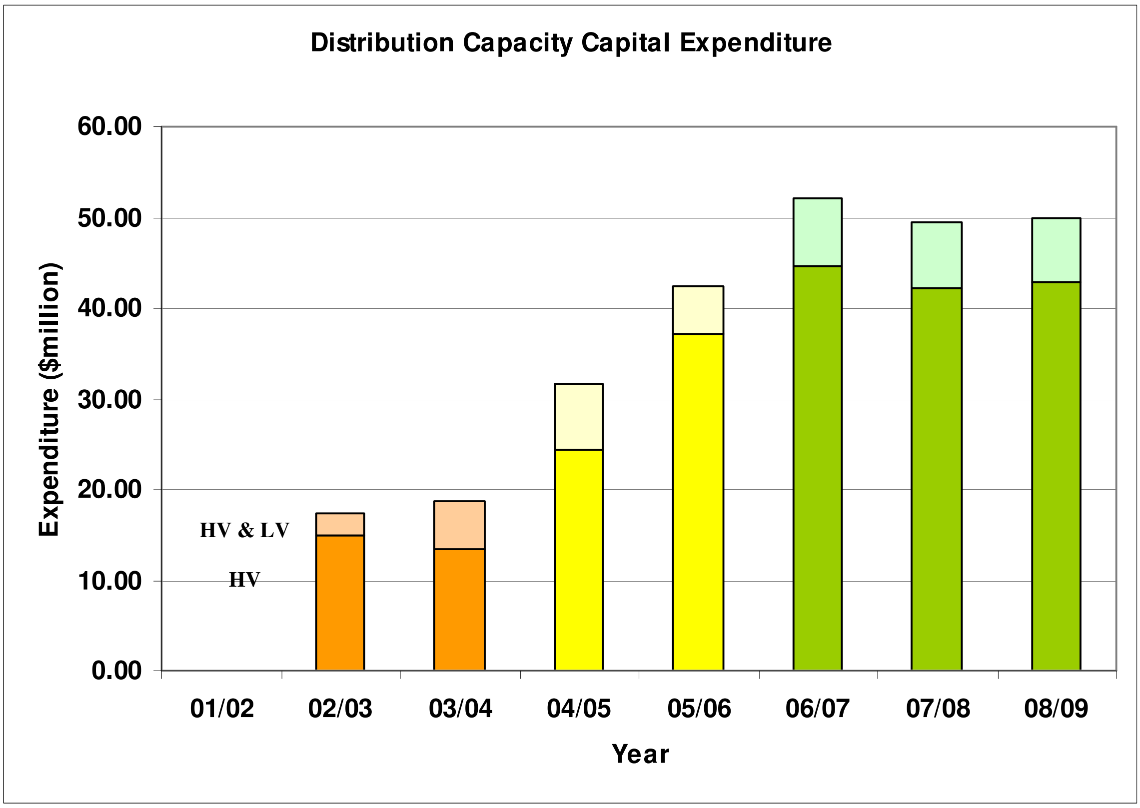
Distribution Capacity	Historical Data			Interim		Review Period		
($million)	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09
Capital Expenditure	-	17.30	18.68	31.71	43.84	51.89	50.09	50.98

This data is illustrated graphically below highlighting 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 Networks 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.

Figure 77 - Distribution Capacity Related Expenditure



Hence the total "unconstrained" forecast demand related distribution capital expenditures over the Regulatory Period are $226M in 2006/07, $238M in 2007/08, and $253M in 2008/09.

Reliability

The average capital expenditure over the regulatory period will increase from an historical $2M to a "resource constrained" expenditure of $18M per annum, an increase of 900%. To place this proposed level of distribution capital expenditure into context the average "unconstrained " projected distribution capital expenditure, as detailed below, is $20M per annum, and hence the resource constrained levels of expenditure are considered very prudent.

Western Power's network performance based on all faults statistics[33] as at June 2004, is detailed in the chart below.

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

Figure 78 - Western Power Networks Performance Figures – June 2004

Region	SAIFI	SAIDI	CAIDI
Urban	3.61	260	72
Rural	4.43	547	124
SWIS	**3.70**	**298**	**81**

In January 2005, Western Power Networks management set a target of 25% improvement on SAIDI and SAIFI across the SWIS – over the next 4 years (commencing during 2005/2006). This target represents the first step in meeting the Energy Safety Directorate's target.

These targets represent a total improvement of 75 SAIDI minutes across the SWIS. The SAIDI targets over the next four years are:

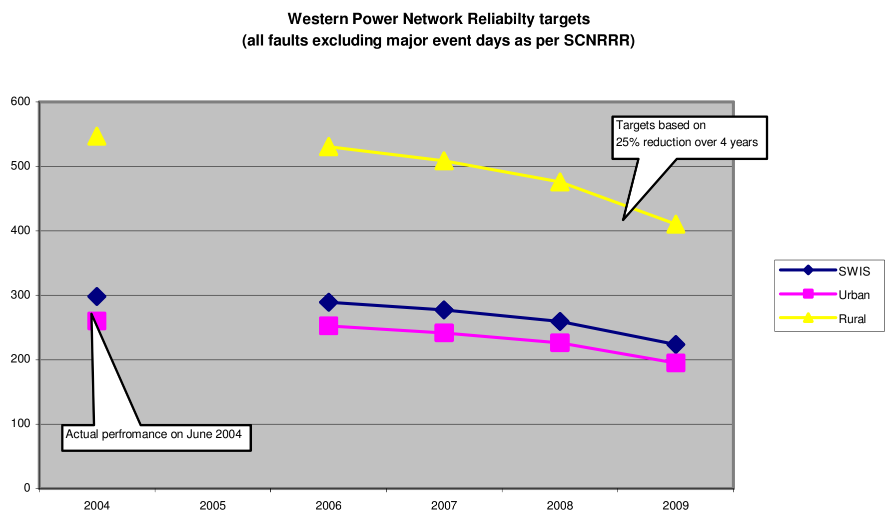
Figure 79 - Western Power Networks Performance Targets[34] (Regulatory Period)

	SWIS	Urban	Rural
June 2006	289	252	531
June 2007	277	242	509
June 2008	259	226	476
June 2009	224	195	410

The planned reductions in SAIDI over the Review Period are shown graphically below:

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

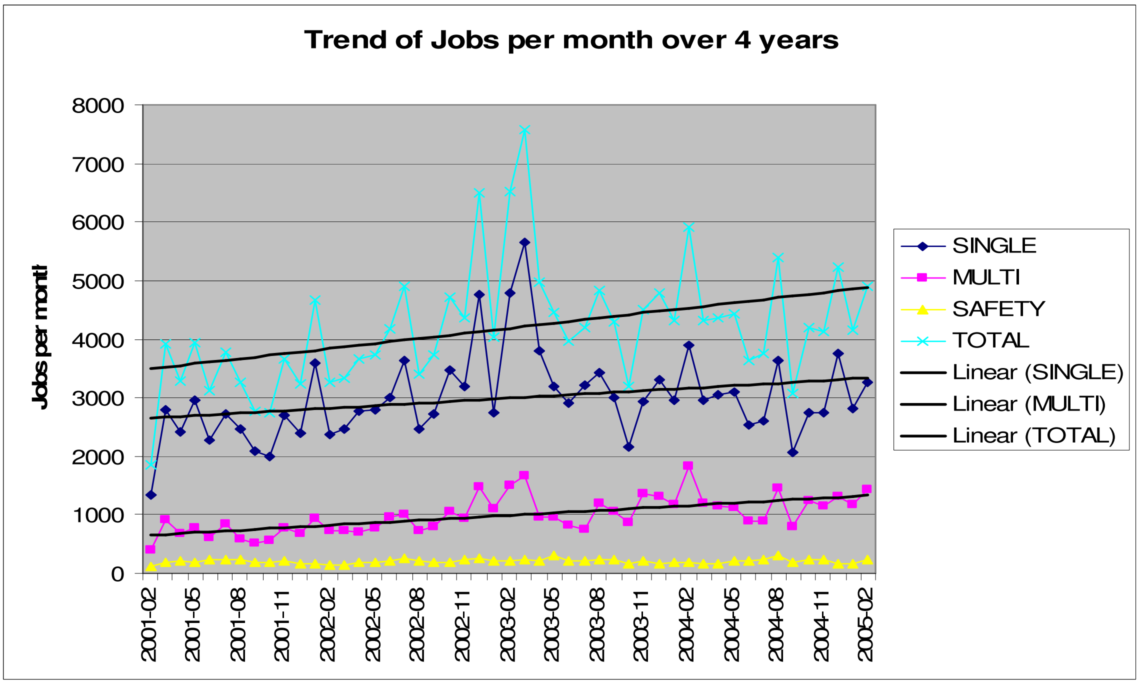
Figure 80 - Western Power Networks SAIDI Targets



Western Power Networks Management adopted the targeted 25% reduction in SAIDI because substantial evidence exists that the current levels of Network Reliability are unacceptable to customers. Western Power Networks 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.

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

Figure 81 - Western Power Networks 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%.

In addition, Networks has carried out a customer survey that indicates that 49% of customers do not feel favourably towards Western Power Network. 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 Network's response to their outage.

In order to achieve the target improvements described above Western Power Networks has reviewed all the capital and operating projects in the Access Arrangement Submission and identified those 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 additional reliability enhancing projects required to be incorporated in order to achieve the desired outcome.

The combined effect of the SAIDI impacts of both the Indirect Effect Strategies and the reliability enhancement projects (Direct Strategies) would achieve an outcome greater that the proposed 25% reduction in SAIDI over the review period. However, the fact that resource constraints will result in Western Power Networks delivering a less than optimum capital works program will reduce the number of capital projects and result in a lower reduction of SAIDI minutes. This outcome will not be quantified until the final capital works program has been determined and the impact of the included projects assessed.

The Direct Strategies that have been included in the Access Arrangement Submission in order to achieve the desired 25% improvement in SAIDI and SAIFI across the SWIS over the regulatory period as 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 Network'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 Networks has estimated that Phase I will cost $467,000 pa.

It is expected that the pilot program will reduce system SAIDI by 2 minutes 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 21 SAIDI minutes over the next 4 years.

Phase 2 will include the rollout of 1,000 Line Fault Indicators (LFI) over the next four years at an estimated cost of $1.5M, the installation of 100 remote controlled pole top switches (PTS) per annum over the net four years at an estimated cost of $1,17M, and the installation of 20 additional reclosers per annum over the next 4 years at an estimated cost of $0.9M pa.

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 $15.7M pa and result in a 49 minute improvement in SAIDI over 4 years.

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 4 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 4 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 Networks is predicting that they will remain at approximately the same levels over the review period, namely $5M 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		
	06/07	07/08	08/09
Cost per annum ($million)	20.6	19.8	19.8
SAIDI minutes improvement	28.7	25.5	22.9

Asset Condition

The average capital expenditure over the regulatory period will increase from an historical $8M to a “resource constrained” expenditure of $15M per annum, an increase of approximately 188%.– Unconstrained capital expenditure on distribution asset replacement as forecast by PB Associates model were $48M per annum and hence resource constrained expenditures of $15M per annum are considered more than justified.

The age, condition and risk associated with failure of the non run to failure (RTF) distribution assets triggers replacement capital expenditures on distribution infrastructure. Run to failure assets are replaced upon failure and the replacement costs expensed. In order to determine the magnitude and timing of this replacement asset expenditure Western Power engaged PB Associates to develop an age, condition and risk distribution asset replacement model. This model has been populated with Western Power’s asset data including asset quantities, age profiles, and with modern equivalent replacement costs.

The model has been used to predict distribution asset replacement expenditures over the regulatory period and also the weighted average remaining life of these assets. The model has indicated that 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 $2.86 billion and an ODV $1.7 billion. Recommended asset replacement expenditures of, on average, $42.26M per annum infer that the assts have a service life of between 50 and 100 years and therefore do not appear unreasonable.

The model incorporates the current backlog of assets identified for replacement in the MIMS data base and has predicted total asset replacement expenditures over the regulatory period of $143.77m as detailed in the summary chart below. The model has also predicted that these levels of investment will not arrest the decline in weighted average asset age, with the weighted average remaining life decreasing from 54% to 52% over the regulatory period.

Distribution Asset Replacement Model							
	Group	**Deferred**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**TOTAL**
	ID	**2005**	**2005**	**2006**	**2007**	**2008**	**REVIEW**
TOTAL CAPEX Requirement $ m		39.574	51.077	42.069	48.060	56.084	PERIOD
Average Expenditure over 20 year period			105.622	105.622	105.622	105.622	
Weighted Average Remaining Life			0.551	0.539	0.526	0.516	
WARL (Using Standard Asset Lives)			0.551	0.539	0.526	0.516	
AUTO	1		0.000	0.007	0.007	0.007	0.020
HVOH	2		1.899	0.449	0.366	0.489	1.303
HVUG	3		0.000	0.037	0.044	0.069	0.150
LVOH	4	0.017	4.235	6.859	8.450	10.174	25.483
LVUG	5		0.036	0.146	0.187	0.169	0.502
DIHV	6		0.020	0.000	0.006	0.014	0.020
DOF	7		3.114	4.005	3.117	5.979	13.101
DSTR	8		1.221	0.624	0.916	0.598	2.138
FLTI	9		0.000	0.000	0.001	0.000	0.002
FSDO	10		0.153	0.173	0.234	0.370	0.777
FSDU	11		23.587	15.002	14.820	14.742	44.563
FSSW	12		0.271	0.288	0.194	0.256	0.738
HVTM	13		0.473	0.406	0.459	0.383	1.249
LVDF	14		2.243	0.772	0.840	1.032	2.644
PAUS	15		0.000	0.001	0.001	0.007	0.009
PTSD	16		1.386	3.678	1.931	6.504	12.113
PWOD	17	3.838	10.051	5.831	12.951	11.817	30.599
REAC	18		0.000	0.000	0.000	0.000	0.000
RECL	19		0.019	0.013	0.008	0.013	0.034
SBST	20		0.000	0.008	0.001	0.004	0.013
SD	21		0.235	0.278	0.133	0.329	0.739
SECT	22		0.000	0.000	0.003	0.002	0.006
SWDC	23		0.104	0.058	0.053	0.043	0.154
RTF	24		0.000	0.000	0.000	0.000	0.000
POLE REIN	25	2.247	2.004	0.993	3.340	3.084	7.417
				39.628	48.060	56.084	143.77

As the following chart clearly demonstrates there has been substantial underinvestment in the replacement of distribution assets. Western Power has identified additional aged assets that it would like to replace over the coming regulatory period.

Figure 83 – Asset Replacement Capital Expenditure

Distribution	Historical Data			Interim		Review Period		
CAPITAL EXPENDITURE	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
Asset Replacement	-	8.22	4.00	6.60	3.84	39.63	48.06	56.08

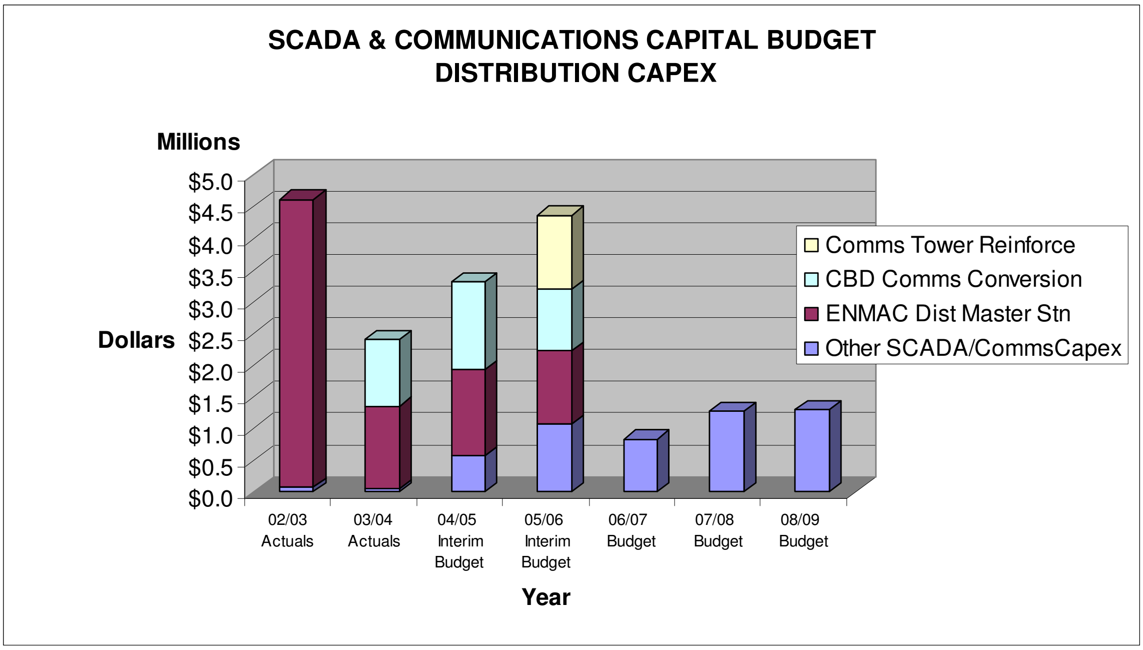
Scada & Communications

The Western Power Networks 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 compliments 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 - $.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 Networks 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 Networks IT expenditures include all capital Information Technology projects and all capital purchases for printers, PDA's software etc. The Western Power Networks Personal Computer (PC) fleet is leased and the associated expenditures therefore appear as operating expenditures.

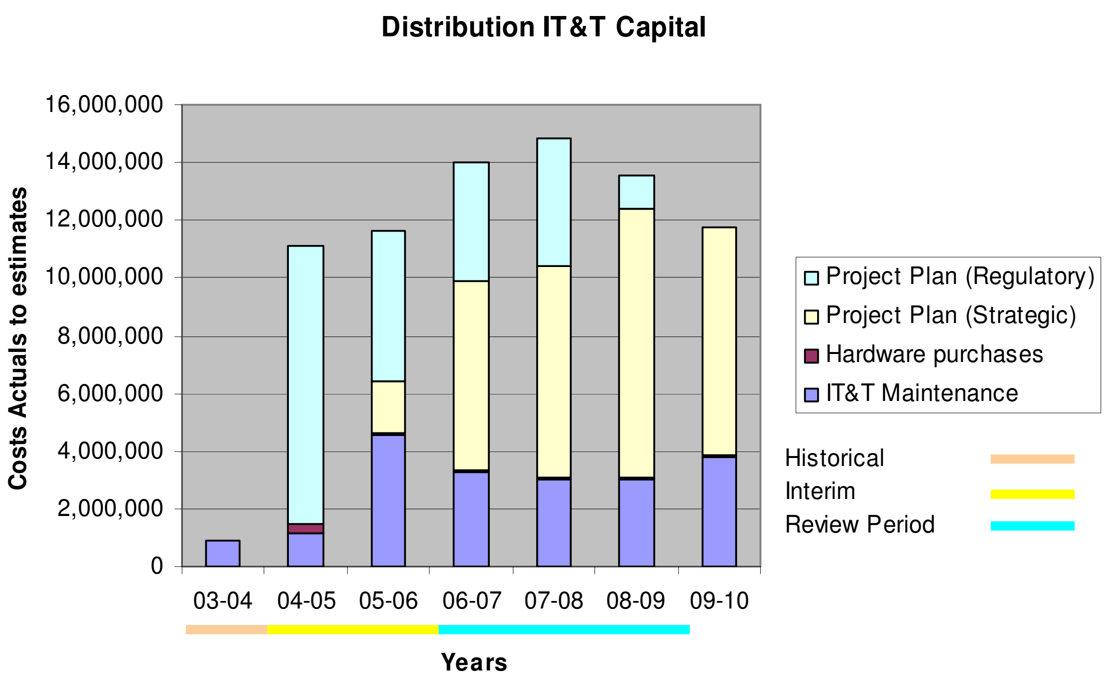
Detailed market design[35] suggests that System Management needs to be ring-fenced and is expected to have significant Information Technology reform costs to meet wholesale market needs. Western Power Networks has made no allowance for the ring fencing of System Management as the rules for ring fencing are not yet clear.

The IT forecast expenditures are required to increase based on a number of key drivers;

- **Regulatory Project Plan** - Expenditure associated with market reform projects,
- **Strategic project Plan -** Replacement of existing Information Technology systems as they approach or have passed the end of their economical and useful life, and
- **Maintenance and Hardware Purchases -** A return to sustainable maintenance levels following a period of constrained expenditure.

The following figure provides a breakdown of the relative contributions of the above drivers to the overall capital expenditure forecasts.

Figure 85 - Information Technology Distribution Capital Expenditure



35 KEMA Consulting 4th November 2003

Regulatory Project Plan

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

The proposed Western Power Networks 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 Networks and the Regulator.

3. **Standalone business systems** - Configuration of the corporate systems adopted by Networks 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 Networks 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 Networks relating to market reform are consistent with meeting the government reforms.

The projected Western Power Networks expenditures associated with market reforms include both disaggregation and competition reforms. On this basis, the Western Power Networks 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[36], 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.

36 The Graphical Information System (GIS) is in excess of 20 years old.

The proposed Western Power Networks 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 Networks 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.

Safety, Environment and Statutory

The average capital expenditure on safety, environment and statutory capital works over the regulatory period will increase from an historical $12M to a "resource constrained" expenditure of $41M per annum, an increase of approximately 342%. The unconstrained projected expenditures on these capital works was on average $54M per annum and hence the resource constrained projected expenditures are considered to be clearly justified.

The unconstrained expenditures are detailed below and also include the capital cost of ensuring metering compliance.

Figure 86 – Safety, Environmental & Statutory Expenditure

Distribution CAPITAL EXPENDITURE	Historical Data			Interim		Review Period		
	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
Safety, Environmental & Statutory	-	0.01	4.26	15.30	26.43	40.68	43.84	46.91

Western Power Networks have 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 twisty connections. In 2003/2004 a pro-active pilot test program commenced to gather data on the condition of these assets.

In September 2003 the Systems Services Branch released an interim branch instruction. This instruction detailed the inspection and replacement requirements for Overhead Service Cables and the termination hardware (updated in December 2003). The following summarises the branch instruction:

All new or upgraded overhead service cables must be replaced with Cross Linked Polyethylene (XLPE) service cable and terminated using the approved wedge type clamp.

All Polyvinyl Covered (PVC) overhead service cables disconnected from the customer’s point of attachment must be replaced with Cross Linked Polyethylene (XLPE) service cable and terminated using the approved wedge type clamp.

A survey of overhead customer service connections by meter readers commenced in late February 2004, which will identify the extent of some of the key issues within the SWIS distribution network. The survey will be a SWIS-wide inspection and will cover some of the key issues which can be identified visually.

Capital approval was given in early March 2004 based on the expected results from the meters survey of overhead customer service connections. Several replacement options were considered including undergrounding the overhead services, however Western Power has 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 $45,520,921

Conductive Metal Streetlight Poles

A number of electric streetlight 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 luminare 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 $9,180.805

Distribution Conductive Power Poles Step and Touch Potential Mitigation

This 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 $3,003,532

Streetlight Switch Wires

There have been 2 fatalities in the last 10 years and 2 potentially fatal electric shock incidents in the past 4 years to the public 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 meters of old small-gauge copper switch wires for controlling streetlights in the SWIS that has been corroding and is at risk of failing. When it does, it 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 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 replacement of corroded small gauge streetlight switch wires is $2,203,681.

URD Cable Pits

There are 5711 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 Networks 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 $2,494,461.

Henley Cable Boxes

There has 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 would be 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 $9,721,329.

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 (eg. 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 2000 barriers at current cost of approximately $250 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 $520,700.

Pole Top Switch (PTS) Earthing Mats

Five years ago a Western Power Networks operator received a near fatal electric shock. Temporary measures have been taken 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 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 installation of earthing mats underneath PTS operating handles is $7,553,197.

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 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 installation of the shielding is $1,953,783.

Wrapped Copper LV Neutral Service Connections

Typically there are a number of potentially fatal electric shock incidents per year directly attributed to faulty wrapped neutral connections. They are usually caused by open circuit or high resistance overhead neutral connections. It’s estimated that about 200,000 connections need to be bypassed or replaced.

The removal of this safety issue is an outcome agreed with the ESD and clearly required under the provisions of the Electricity (Supply Standards & System Safety) Regulation 2001.

The total projected expenditure over the regulatory period for the replacement of this type of service is $5,068.992.

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 removal 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 $2,309,350.

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 $25000 and $5000 per day under Section 51 of EP Act or fines of $5000 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 $6,590,605.

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 $444,840.

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 a desire of both the West 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 $33,630,807

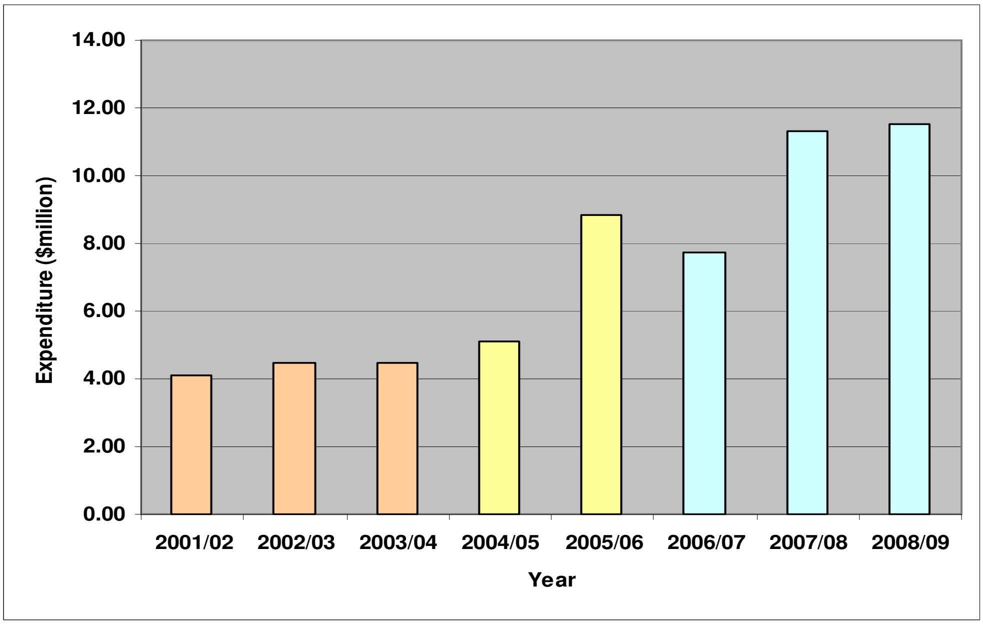
Metering

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 87 - Metering Capital Expenditure

	Historical Data			Interim		Review Period		
($million)	**01/02**	**02/03**	**03/04**	**04/05**	**05/06**	**06/07**	**07/08**	**08/09**
Metering	$4.12	$4.48	$4.50	$5.08	$8.82	$7.75	$11.30	$11.52

Figure 88 - Metering Capital Expenditure



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 Networks 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 89 – New Connections Volume

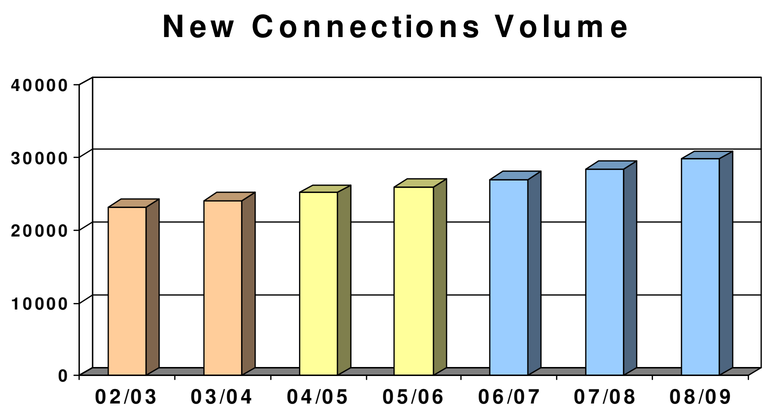
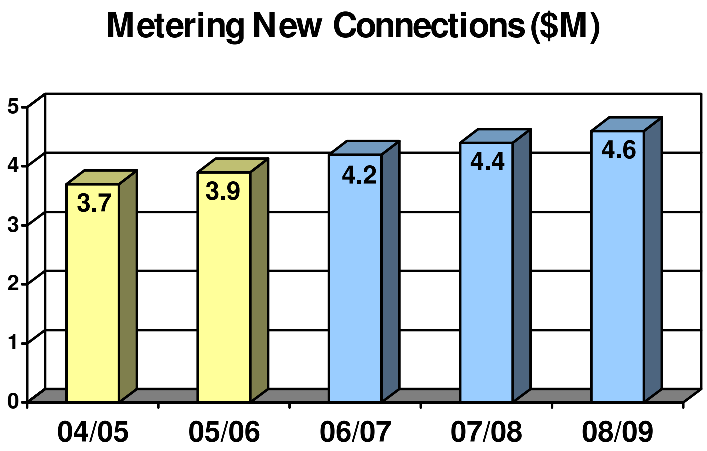


Figure 90 – Metering New Connections



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 Networks has assumed that a similar number of 3 phase meters will require replacement. A forecast of approximately $16.5 million has been made for the replacement of 3 phase meters and this replacement program will be spread over a 3 year period commencing in 2007/08. 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 Networks have 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.

Special Programs

Rural Power Improvement Program (RPIP)

The Rural Power Improvement Program (RPIP) is a targeted 4-year, $48 million capital expenditure program. The broad objective of the program is to enhance power supplies in country areas. Selected projects are 50% funded by the Office of Energy (OoE) and 50% by Western Power Network. The program commenced in 2004/05 and is scheduled to be completed in 2007/08.

Figure 91 - RPIP Capital Expenditure

	Historical Data			Interim		Review Period		
($million)	**01/02**	**02/03**	**03/04**	**04/05**	**05/06**	**06/07**	**07/08**	**08/09**
RPIP	-	-	-	11.00	13.00	12.00	12.00	12.00

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.

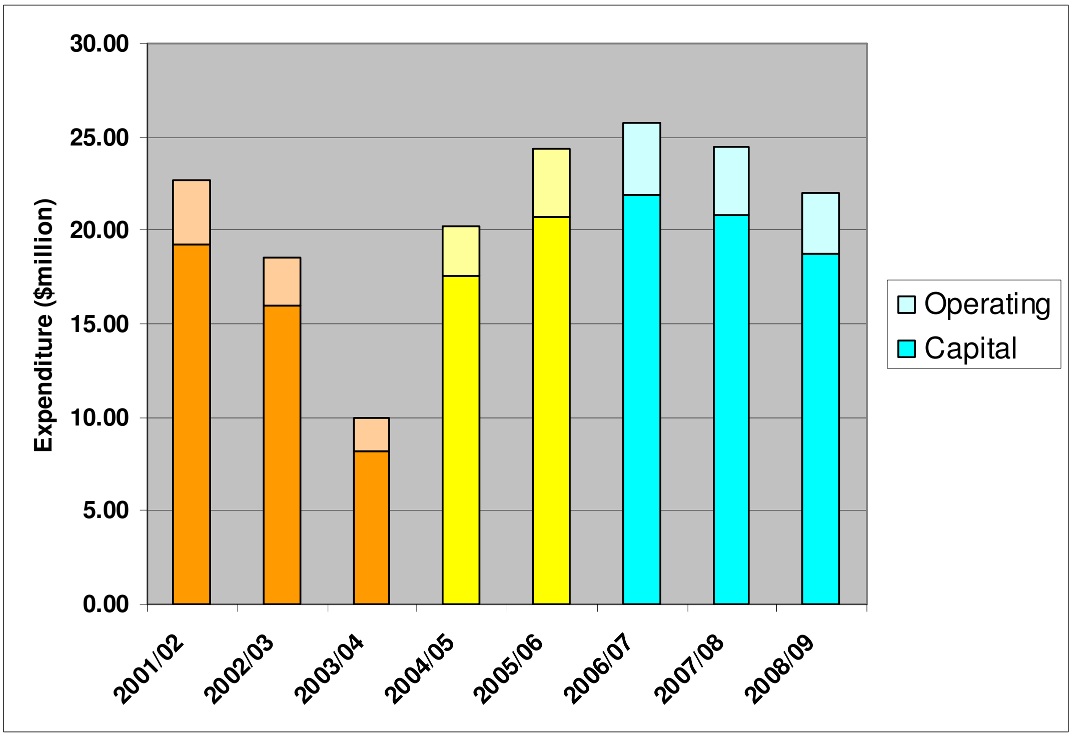
State Underground Power Program (SUPP)

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 budget (including capital and operating expenditure) is $20 million per annum.

Figure 92 – SUPP Capital & Operating Expenditure

	Historical Data			Interim		Review Period		
($million)	**01/02**	**02/03**	**03/04**	**04/05**	**05/06**	**06/07**	**07/08**	**08/09**
SUPP Capex	19.251	15.990	8.173	17.562	20.697	21.894	20.839	18.712
SUPP Opex	3.419	2.596	1.771	2.700	3.644	3.855	3.669	3.295
SUPP TOTAL	**22.670**	**18.586**	**9.944**	**20.914**	**24.340**	**25.750**	**24.510**	**22.010**

Figure 93 - SUPP Capital and Operating Expenditure



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 Networks 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 capital component of the expenditure relates to the underground cable installation whilst the operating expenditure component relates to provision of underground services to connect individual properties.

The recently re-elected government has committed to a continuation of SUPP with election promises including a continuation of current funding levels.

The Round 4 selection process will commence in 2005 with projects expected to commence in 2007. Western Power Networks expects that the level of expenditure required in Round 4 will be in the order of $24 million per annum in order to achieve the stated target of 50% undergrounding by 2010.

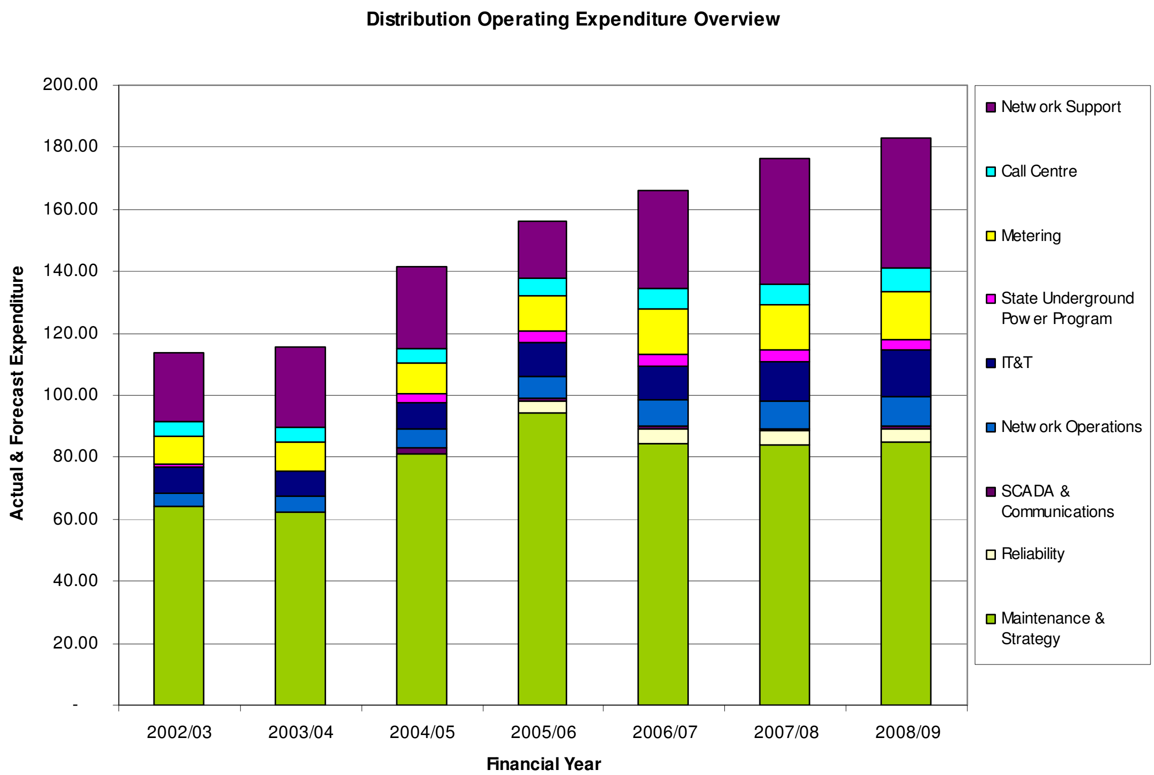
The selection criterion for round 4 projects is currently under discussion and is expected to be based on the following items:

- 50% for power system improvement criteria (reliability, capacity, power quality);
- 20% for general suitability, amenity improvement;
- 20% for value for money based on expected project cost and number of residences;
- 5% for LGA funding credibility;
- 5% for community support survey results.

The application, evaluation and selection process of the SUPP applications is rigorous, and there is keen competition for the limited funding available.

9. Distribution Forecast Operating Expenditure

Figure 94 - Distribution Operating Expenditure (Resource Constrained)



Western Power Networks is proposing to increase distribution operating expenditures by 33% for the regulatory period. 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 preventative 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 Network as an independent business segment of Western Power;
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 Networks has undertaken a detailed review of resource availability over the forecast period and has determined a realistic, deliverable expenditure plan. This deliverable work plan is significantly less than that which Western Power Networks would otherwise deliver during the regulatory period and a number of important projects have consequently been deferred.

However, the information and analysis contained in the subsequent sections of this chapter is based on the unconstrained level of expenditure identified as necessary to satisfy the key business drivers.

Network Maintenance

Network maintenance costs are reported under five key groupings of:

- Preventative Routine
- Preventative 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 in line with the following table.

Figure 95 - Historical and Projected Maintenance Expenditures ($m)

	2003	2004	2005	2006	2007	2008	2009
Maintenance/Strategy	3.01	3.56	3.77	5.87	6.50	6.56	6.62
Preventative Condition	8.58	8.92	14.02	19.14	15.23	15.80	16.28
Preventative Routine	8.89	9.30	17.75	25.60	26.48	27.51	28.49
Corrective Deferred	13.20	13.31	15.81	15.51	12.43	11.67	11.39
Corrective Emergency	30.62	27.03	29.96	28.43	23.88	22.44	21.92
Total Maintenance	**64.29**	**62.12**	**97.64**	**94.56**	**84.53**	**83.98**	**84.70**

The above table shows that Western Power is proposing overall increases in maintenance expenditures over historical levels. These increases are required in order to achieve 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 in 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.

Preventive Routine

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.

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

However, 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 preventative 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 table shows how inspection levels are projected to increase in line with levels specified in the Missions for key maintenance areas. The table also shows how unit costs for these inspections have changed relative to historical levels. Unit rates used to cost inspections have been based on agreed contract rates where appropriate and on historical levels using 2003/04 figures for internally provided services. “Baseline” figures represent preventative routine maintenance requirements relating to the actual volume of assets and do not include any additional maintenance relating backlogs.

Figure 96 - Historical and Baseline Preventative Routine Maintenance

Works Code	2004 Jobs Completed	2004 Actual Cost	2004 Rate	Baseline Annual QTY	Baseline Annual Cost	Baseline Rate
K1K0 Pole Base Inspection & Treatment	86,685	2,206,651	25.46	177,229	5,150,000	29.06
K1K1 Line Insulator Washing Note 1	182	1,990	10.93	0	0	0
K1K2 Insulator Siliconing	2,939	436,165	148.41	24,000	3,600,000	150
K1K3 Pole Top Inspect & Line Patrols	128,191	763,792	5.96		4,950,000	
K1K4 Vegetation Inspect	93,069	1,889,781	20.31		3,940,000	8.82
K1K5 Fuse Pole Inspect Note 2	5,815	110,895	19.07	20,000	2,624,881	131.24
K1K6 OH Switchgear Inspect	1,903	361,918	190.18	3,076	302,746	98.42
K1K8 G/mounted Switchgear/Substation Inspections	1,899	124,636	65.63	10,245	3,400,000	331.87
K1K9 OLD Ground mounted Substn Inspect Note 3	1,663	327,104	196.69	0	0	0
K1KB UG System Inspect	71	1,315	18.51	0	0	0
K1LO Bulk Globe Replacement	39,734	1,491,700	37.54	48,024	1,750,000	36.44

Note 1: this routine maintenance has changed to Insulator Siliconing for longer term benefits.
Note 2: Fuse Pole Clearing Maintenance has all been combined in Preventive Routine Fuse Pole Inspection.
Note 3: this is now obsolete and has been incorporated with K1K8 G/mounted Switchgear/Substation Inspections.

Western Power has increased the volumes of inspections and as a result the overall costs of preventative 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.

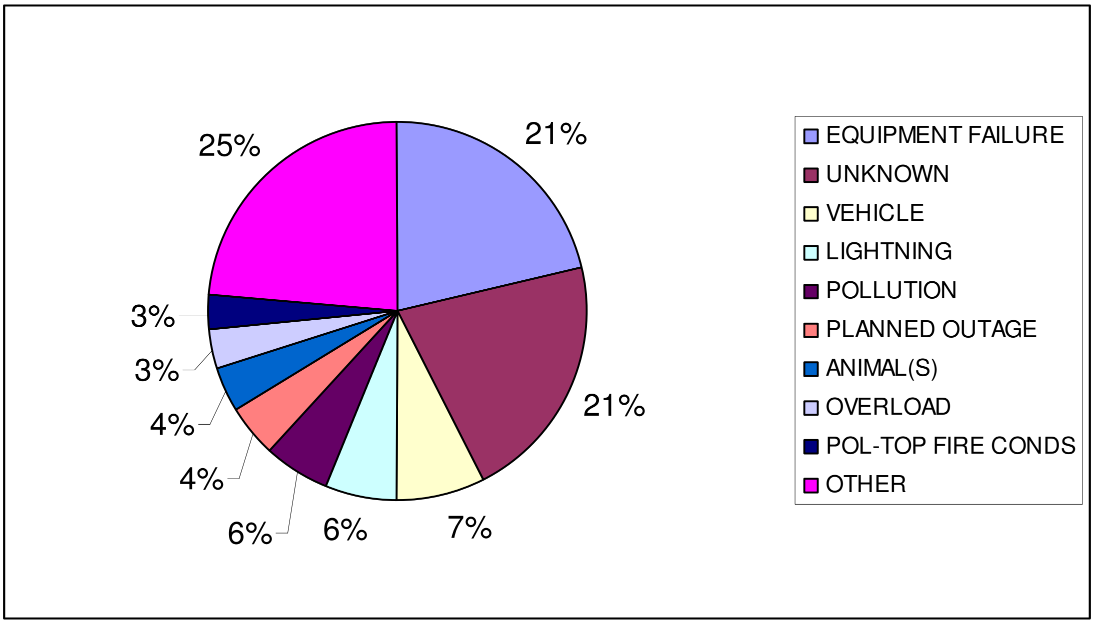
A dissection of the key causes of supply interruptions indicates that vegetation management and pole inspections could also reduce these incidents and therefore impact on both reliability and corrective maintenance costs, whilst also reducing the risks of bush fires and public safety incidents. As a result of these changes, the overall costs of preventive routine increase from $9.3m in 2004 to $25.6m in 2006.

Figure 97 - Baseline and Projected Preventative Routine Maintenance Costs

Works Code	Inspection Cycle (Years)	Annual Baseline Cost	2006	2007	2008	2009
K1K0 Pole Base Inspection & Treatment (all except Metal>5km from coast))	4	4,710,819	5,812,581	4,882,697	5,073,262	5,222,723
K1K0 Pole Base Inspection & Treatment (Metal >5Km from coast)	8	470,329	580,329	487,489	506,515	521,438
K1K2 Insulator Siliconing	1	3,600,000	3,600,000	3,731,350	3,876,979	3,991,197
K1K3 Pole Top Inspect & Line Patrols (except line patrol part)	1	23,320	25,407	704,802	754,044	933,291
K1K3 Pole Top Inspect & Line Patrols (Line Patrols part)	4	4,922,617	5,363,050	5,156,181	5,350,248	5,518,281
K1K4 Vegetation Inspect (except LFR/MFR zones))	1	3,284,410	1,904,017	1,973,487	2,050,510	2,110,919
K1K4 Vegetation Inspect (LFR/MFR zones)	3	655,986	380,284	394,159	409,543	421,608
K1K5 Fuse Pole Inspect	1	613,893	2,624,881	2,720,652	2,826,836	2,910,116
K1K6 OH Switchgear Inspect (recl insp)	1	285,791	261,908	296,222	307,783	316,852
K1K6 OH Switchgear Inspect (Sect Insp)	3	16,954	15,537	17,573	18,259	18,797
K1K7 Misc OH (OH Service Connections inspections)	4	626,000	349,270	750,000	770,000	790,000
K1K8 G/mounted Switchgear/Substation Inspections (except RMUl)	1	1,148,850	2,805,255	3,356,053	3,478,756	3,585,753
K1K8 G/mounted Switchgear/Substation Inspections (RMU)	4	2,244,849	166,416	199,091	206,370	212,718
K1LO Bulk Globe Replacement	4	1,746,520	1,713,228	1,810,243	1,880,895	1,936,307
Total K1 Prev Routine		**24,350,339**	**25,602,164**	**26,480,000**	**27,510,000**	**28,490,000**

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

Figure 98 – 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 preventative maintenance.

In addition to achieving network performance improvements, much of the proposed additional inspections are required to achieve regulatory compliance. In particular, wood pole inspection requirements designate a 4 year inspection cycle. In 2004 Western Power Networks only achieved inspections of 86,685 poles - approximately 14% of the wood pole population. Western Power is targeting to achieve 25% or approximately 177,000 pole inspections per annum. As shown in Figure 96 this will require an additional $3 million per annum. These inspection cycles are consistent with those of other Australian electricity distribution businesses.

Increases in pole top inspections are also required to achieve regulatory compliance. Costs for these inspections are projected to increase from $0.8 million to $5.0 million per annum; an increase of $4.2m for regulatory compliance. Western Power has commenced using aerial inspections to achieve its inspection cycles.

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 preventative routine expenditures, preventative 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.

The following tables show the individual work categories and the historical and projected volumes and costs. Unit rates used to cost these works have been based on agreed contract rates where appropriate or on historical rates using 2003/04 figures for internally provided services.

Figure 99 - 2003/04 Unit Rates for Preventative Condition Maintenance

Works Code	2004 Jobs Completed	2004 Actual Cost	2004 Rate
K2KE Pole Maintenance	2,907	1,395,160	479.93
K2KF Line Easement Vegetation Maint	14,207	5,333,417	375.41
K2KG Fuse Pole Clearing	14,737	422,087	28.64
K2KH OH Switchgear Maint	3,085	541,895	175.65
K2KI Groundmounted Switchgear Maint	516	372,096	721.12
K2KJ Substn Maint	1,448	428,675	296.05
K2KK Earthing Maint	476	97,810	205.48
K2NH UG System Maint	3	2,741	913.67
K2NK Street Light Maintenance	38	18,392	484.00
K2NS Minor Asset Replacement	197	175,964	893.22

Backlog

The lower levels of funding for preventative 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 preventative 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 preventative maintenance and has commenced work to assess the risks of outstanding preventative maintenance and determine criteria for initiating this maintenance in the most cost effective manner.

Figure 100 - Backlog Program for Preventative Condition Maintenance

Works Code	Current Backlog	2/3 of Backlog	Annual backlog catch up over 4 years
K2KE Pole Maintenance	6,118,278	4,078,852	1,019,713
K2KF Line Easement Vegetation Maint	980,842	653,895	163,474
K2KH OH Switchgear Maint	1,898,545	1,265,697	316,424
K2KI Groundmounted Switchgear Maint	270,746	180,497	45,124
K2KJ Substn Maint	337,089	224,726	56,182
K2KK Earthing Maint	2,862,306	1,908,204	477,051
K2NH UG System Maint	18,293	12,195	3,049
K2NK Street Light Maintenance	8,143	5,429	1,357
K2NS Minor Asset Replacement	762,878	508,586	127,146
Total K2 Prev 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 in the above table, 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 101 - Baseline and Projected Expenditure for Preventative Condition Maintenance

Works Code	Annual Baseline Cost	Backlog Catch up	Total annual cost	2006	2007	2008	2009
K2KE Pole Maintenance	3,150,000	1,019,713	4,169,713	5,609,595	4,911,953	5,081,792	5,236,912
K2KF Line Easement Vegetation Maint	12,060,562	163,474	12,224,035	9,867,113	7,211,516	7,492,972	7,713,719
K2KH OH Switchgear Maint	125,090	316,424	441,514	465,300	467,331	485,153	502,045
K2KI Groundmounted Switchgear Maint	181,305	45,124	226,429	214,821	241,937	251,391	260,971
K2KJ Substn Maint	848,358	56,182	904,539	889,022	940,633	977,293	1,006,948
K2KK Earthing Maint	785,417	477,051	1,262,468	1,262,468	1,323,341	1,373,775	1,417,765
K2NH UG System Maint	0	3,049	3,049	0	0	0	0
K2VI Investigative/Triggered Maint	0	0	0	499,836	0	0	0
K2NK Street Light Maintenance	0	1,357	1,357	0	0	0	0
K2NS Minor Asset Replacement	0	127,146	127,146	336,256	133,533	138,535	142,985
Total K2 Prev Condition	**17,150,731**	**2,209,520**	**19,360,250**	**19,144,411**	**15,230,244**	**15,800,911**	**16,281,344**

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

Figure 102 - Projected Preventative Maintenance Expenditures

	Total annual cost	2006	2007	2008	2009
Total K1 Prev Routine	17,745,530	25,602,164	26,480,000	27,510,000	28,490,000
Total K2 Prev Condition	14,021,055	19,144,411	15,230,245	15,800,912	16,281,344
Total Preventative Maintenance	**31,766,585**	**44,746,575**	**41,710,245**	**43,310,912**	**44,771,344**

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 preventative maintenance expenditures should then reduce by around $2.2m in following years. There has been no allowance made for addressing backlogs of Preventative 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 the following table.

Figure 103 - Historical Corrective Deferred Maintenance Expenditures ($M)

Works Code	2003	2004
KN - N Asset Damage - Known Perpetrator	1.40	0.98
KO - N Environmental Cleanup	0.12	0.25
KP - N Minor Defects	0.33	0.47
KQ - N Pq Audit	0.00	0.00
KR - N Pq Investigation	1.55	1.58
KS - N Emerg Follow-Up/Correct Maint Oh	3.64	3.09
KT - N Emerg Follow-Up/Correct Maint Ug	1.74	1.86
KU - N Tvi Investigation	0.25	0.15
KV - N Tvi Repair	0.26	0.47
KW - N Perth One Call	0.18	0.31
KX - N Data Correction	0.47	0.31
KY - N Data Maint	0.06	0.18
L2 - N Graffiti Cleanup	0.07	0.13
N7 - N Soii	0.48	0.70
N8 - N Emerg Follow-Up Asset Replace	0.77	0.64
N9 - N Car Versus Pole	1.06	1.03
UW - N Asset Damage - Known Perpetrator	0.01	0.71
VG - N Vandalism	-	-
K3 Total (excluding metering and chargeable works)	**12.38**	**12.86**

As previously discussed, past budgetary constraints in preventative maintenance programs have resulted in some additional corrective expenditures. As a result of the proposed increases in preventative 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 preventative 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 104 - Historical Corrective Emergency Maintenance Expenditures ($M)

Work Description	2003	2004
KZ - N Primary Response Assistance	11.47	8.46
L3 - N Primary Response Group	6.24	8.02
L4 - N Streetlight	3.83	3.69
L5 - N Storms	7.88	5.78
L6 - N Truck Items & Minor Consumables	1.25	1.08
K4 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 Networks 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 Networks is now in the process of identifying the corrective maintenance costs associated with these outages to enable preventative 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 Networks 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. The adhesion 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 Networks 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;
- 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 Networks in detecting sagging or deteriorating conductors, long bays or poor condition pole tops in order for preventative 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.

Summary of Corrective Maintenance

Based on the introduction of these preventative maintenance programs Western Power has targeted to reduce corrective emergency maintenance to $21.9m by 2009, with the majority of the reduction occurring in 2007. This represents an $8.7m or 20% reduction over the period. The accelerated benefits relate to the targeting of preventative maintenance programs to those areas with the greatest impact in the initial years (2005 and 2006).

Maintenance Strategy

These costs reflect a relatively new initiative of Western Power Network. 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 105 - Historical and Projected Maintenance Strategy Expenditures ($M)

	2003	2004	2005	2006	2007	2008	2009
Maintenance Strategy	3.01	3.56	3.77	5.87	6.50	6.56	6.62

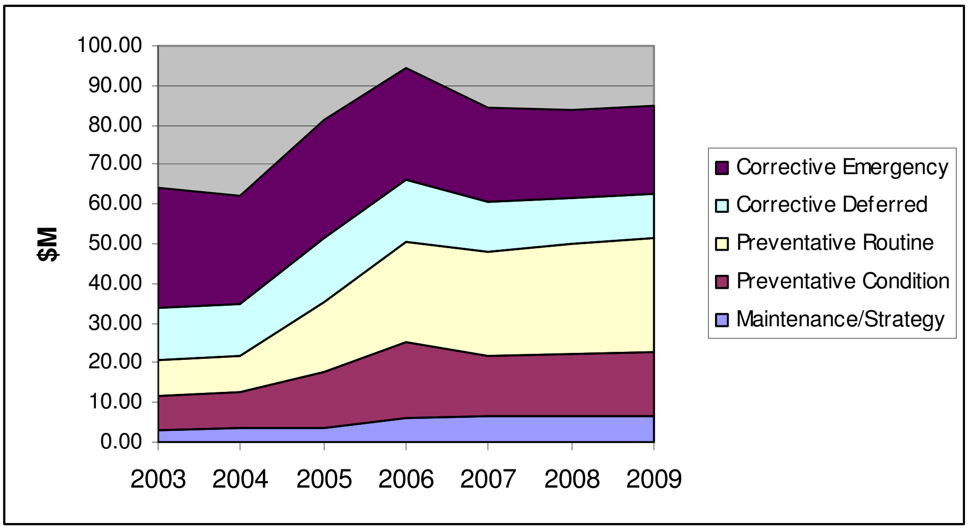
Western Power Networks has developed this category to provide a conduit for strategic consideration of asset maintenance and improving the overall efficiency and effectiveness of asset maintenance programs. As such, Western Power Networks is expecting benefits of these expenditures to manifest in terms 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 preventative 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 and that this area of expenditure

Summary of Distribution Maintenance Costs

The distribution maintenance expenditures proposed by Western Power Networks are summarised in the following chart.

Figure 106 – Dissection of Distribution Maintenance Expenditures



As the above chart shows, overall maintenance costs are expected to increase from 2003 levels by approximately $20.4m (32%). This is attributable to the substantial increases in preventative maintenance which are anticipated to deliver benefits of improved reliability and safety, as well as achieve compliance with regulatory requirements. A summary of the estimated net increases in maintenance costs and the associated drivers for these increases is provided below.

Regulatory Compliance	$9m
Safety	$4m
Maintenance Backlog Reduction	$2m
Reliability and Network Performance Improvement	$6m
Total net maintenance cost increase	**$21m**

These figures are estimated based on specific maintenance programs and the associated offsetting net benefits for each principle cost driver.

Scada & Communications

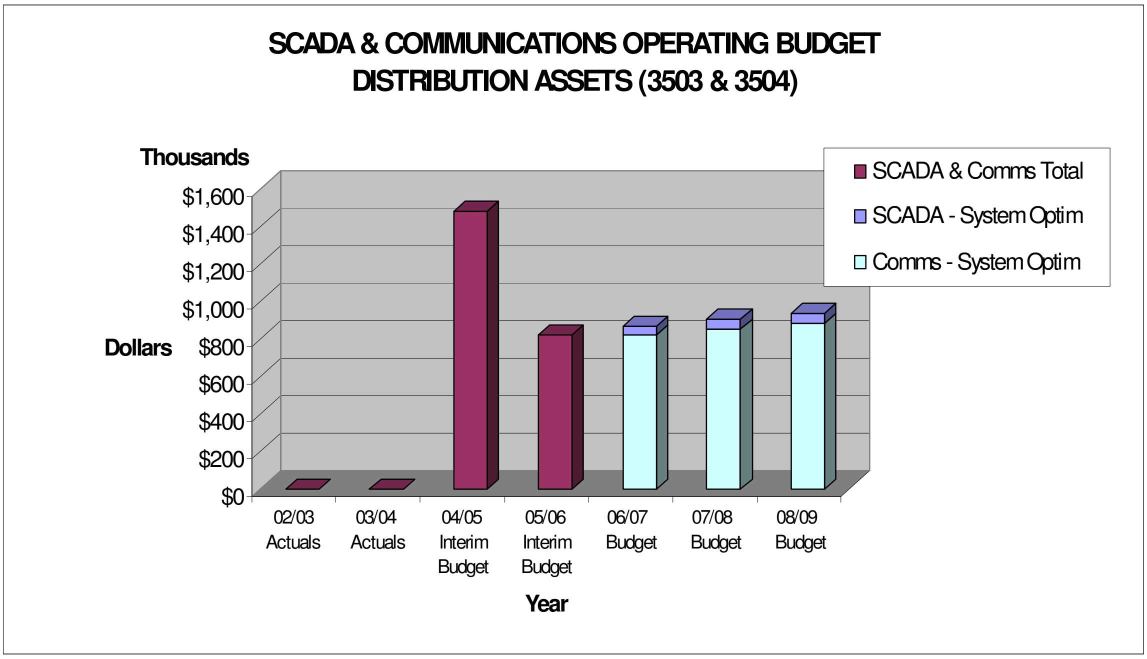
The Western Power Networks SCADA and Communications group provides Strategic Planning, Communications Network Design and Optimisation, Maintenance & Operations, Radio Communication Licenses for the Western Power Transmission and Distribution network.

Projected operating costs for Distribution SCADA and Communications over the review period includes 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 05/06 and expenditure will increase only marginally from this point.

Western Power Networks projected expenditures for Distribution SCADA and Communications operating expenditures are detailed in the chart below. 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 107 - 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.

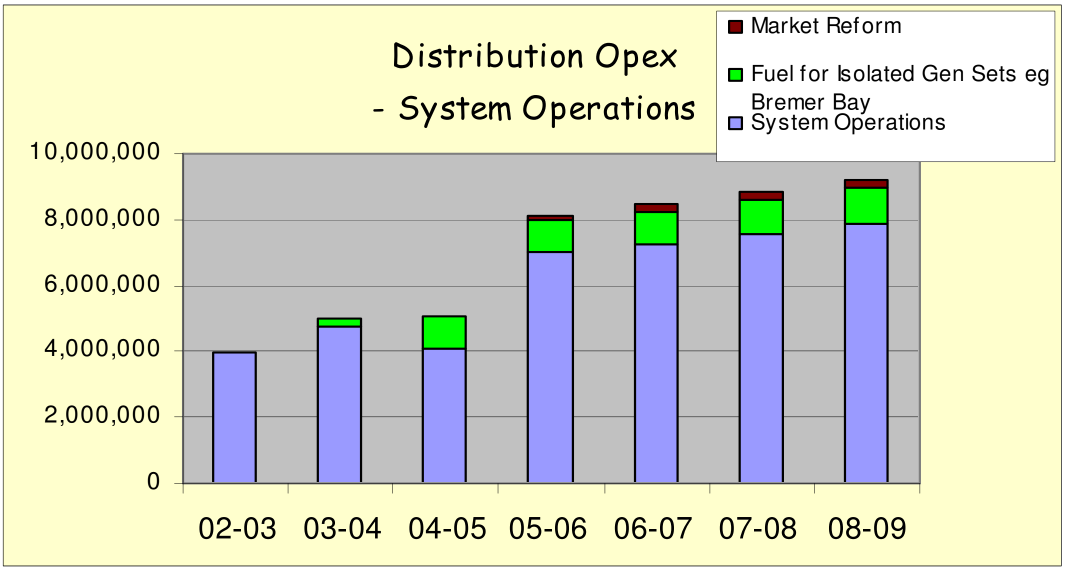
Network Operations

The System Operations group provides control, switching, operations planning and monitoring for the Western Power Networks transmission and distribution networks. These expenditures do not include the telecommunications side of IT&T or SCADA.

Government mandated reforms will also 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 Networks is also proposing the implementation of additional SCADA assets further to a government initiative.

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. The system operations expenditures are categorised into “business as usual”, “Fuel Costs” and “market reform” as per the following chart.

Figure 108 – System Operations Distribution Operating Expenditure



Fuel costs associated with Bremer Bay have been included in the Network Operating expense.

The operating expenditure for System Operations (Distribution component) remains steady until 05/06 whereby an increase in staff numbers is required in order to accommodate the decisions to centralise switching programme writing and to control the country network. This centralisation is in line with national trends designed to improve network operations safety.

The business as usual activities are also impacted by a projected increase in labour costs and material costs – 4% and 1% respectively.

There is expected to be a small increase in staff due to market reform within the distribution operations. These staff will be dealing with compliance and statistical reporting to meet the codes. The market reform costs have been assessed based on identified labour resource requirements as follows;

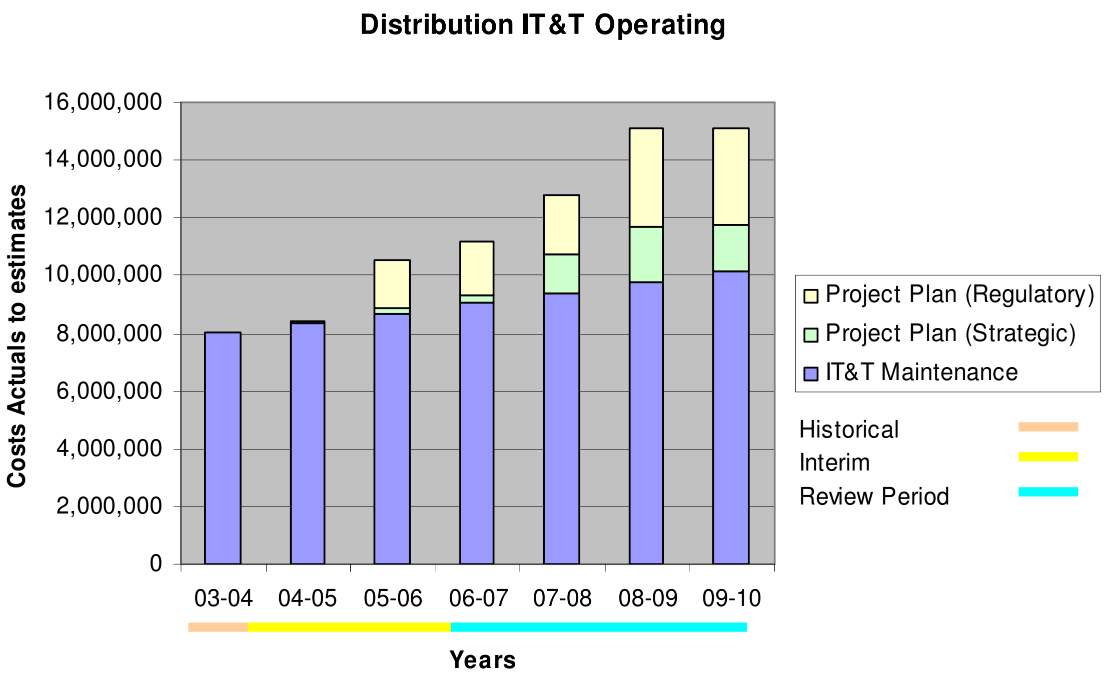
- Market Reform
    - 2005/06 : 1
    - 2006/07 to 2008/09 : 2

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

Information Technology

The Western Power Networks Personal Computer (PC) fleet is leased and the associated expenditures are therefore captured as operating expenditures. The general trend for Western Power Networks Information Technology operating expenditure is increasing as highlighted in the following figure.

Figure 109 - Information Technology Distribution Operating Expenditure



Base IT&T maintenance is projected by Western Power Networks to grow at 4% per annum for the forecast period. The Western Power Networks projection includes adjustments for labour and material inflation. This compares favourably with projections of employee numbers which are estimated to increase 8.28% from 04/05 to 08/09.

The proposed expenditures associated with the regulatory and strategic project plans (above) 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

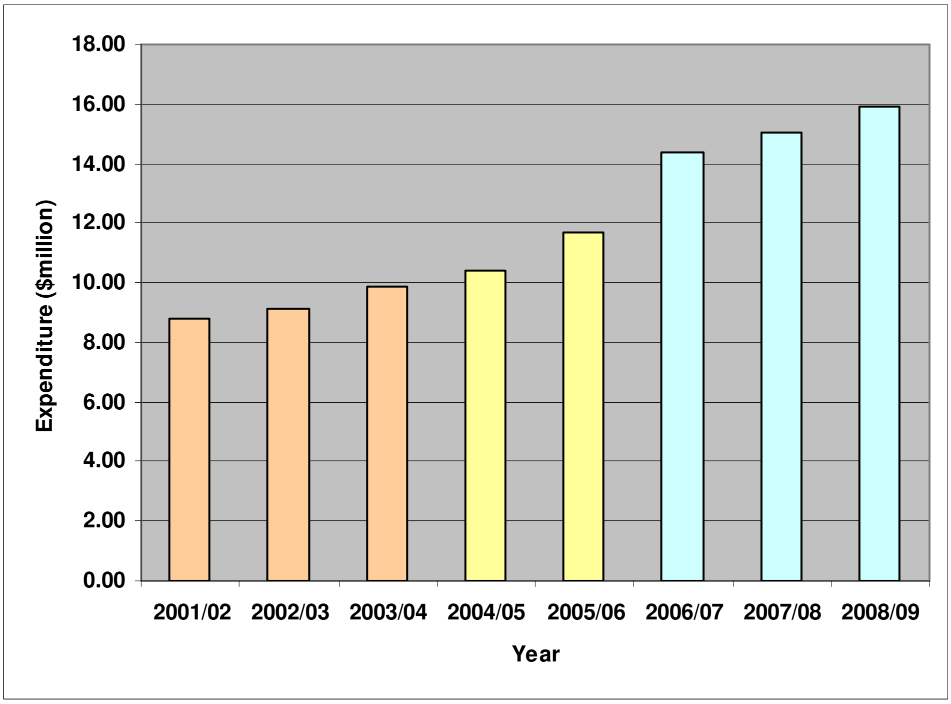
Metering Services operating expenditure includes all expenditures relating to the provision of the following meter and connection related services:

- Regulatory Inspections Services;
- Metering Provision including field maintenance and laboratory activities; and
- Data Management including administration and meter reading, and
- Meter Reading.

Figure 110 – Metering Maintenance Base Case Operating Expenditure

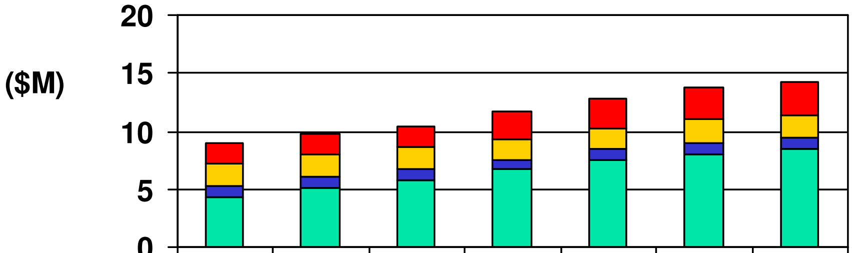
	Historical Data			Interim		Review Period		
($million)	**01/02**	**02/03**	**03/04**	**04/05**	**05/06**	**06/07**	**07/08**	**08/09**
Metering Services	8.81	9.15	9.85	10.44	11.69	14.35	15.07	15.89

Figure 111 - Metering Services 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 Networks has been nominated as the meter provider and meter reading agent, and there is currently no competition for these services in Western Australia.

Figure 112 - 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 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 Networks 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 Networks participated in the PACE 2002 benchmarking study which showed Western Power Networks compared favourably with other meter service providers.

Call Centre Operating Costs

Currently the Network call centre function is handled by the Retail Group 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 Retail call centre facility as soon as practicable after July 2005. The Network Business Unit intends to enter into a service level agreement with Western Power Retail 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 Network Business Unit 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 Networks 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 Retail call centre and include allowances for call volume growth and margin inclusion (from 06/07).

Figure 113 - Call Centre Expenditures – Business as Usual

	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	6.56	6.86	7.20

These business as usual projected expenditures are based on the following projected call volumes and unit rates in the following table

Figure 114 - Call Volumes and Unit Rates

	Actual	F/Cast	F/Cast
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 Networks management set a target of 25% improvement on SAIDI and SAIFI 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, which also details the likely staged reduction in projected call volumes if the project is successfully implemented.

Figure 115 - 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 116 - 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