2006 Electricity Distribution Price-Service Offering

United Energy Distribution
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Executive Summary

Purpose and Scope of this Submission

United Energy Distribution Pty Ltd (UED) is one of five electricity distribution businesses operating under licence within the State of Victoria, with assets totalling approximately $2.0 billion. UED's network provides services to some 600,000 end-use customers in Melbourne's southern and eastern suburbs, with its area of operation confined to geographically defined boundaries set out in the Distribution Licence.

This submission sets out UED's formal response to the 2006 Electricity Distribution Price Review (EDPR) and has been prepared in accordance with the guidelines issued by the Essential Services Commission (the Commission). The submission provides details of UED's price-service package for the regulatory period 1 January 2006 to 31 December 2010, including detailed information on future service level benchmarks and proposed reductions in distribution charges.

At the outset of this submission, it is important to note that the Commission's approach to regulation continues to focus primarily on the "cost of service". UED has consistently argued that "cost of service" and "building block" regulation is too heavily focused on driving costs out of the businesses, without recognising the longer-term detrimental impact of such an approach on innovation, dynamic efficiency and customer service.

An alternative to the cost of service regulatory approach is required, to facilitate greater commercial negotiation, and to encourage dynamic efficiency and the maximisation of welfare over the longer term. One credible alternative that has already been established successfully (in the airports sector) is price monitoring. A price monitoring approach would provide a better means of strengthening the incentives for distributors to deliver services that meet customers' needs in an efficient manner over the long term.

UED also takes this opportunity to draw the Commission's attention to the Productivity Commission reviews, other independent reviews[1]; decisions made by the Court[2]; and appeal decisions made by the Australian Competition Tribunal[3], which all emphasise the need for regulators to recognise the limitations of the "building block" methodology.

In the light of these recent reviews and decisions, UED believes that the Commission should foster long-term customer benefits by encouraging investment and dynamic efficiency, and reducing the emphasis on short-term price reductions. In UED's view, a non-intrusive, pragmatic use of the building block approach, recognising its limitations and risks, together with the Commission's focus on incentive mechanisms, as outlined in the 2001 Determination, is appropriate for this EDPR.

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1 Council of Australia Governments Energy Market Review Panel, Towards a Truly National and Efficient Energy Market: Final Report [Parer Report], 20 December 2002.

2 *Re Dr Ken Michael AM; Ex parte Epic Energy (WA) Nominees Pty Ltd* [2002] WASCA 231.

3 See for example, Application by GasNet Australia (Operations) Pty Ltd [2003] ACompT 6; Application by East Australian Pipeline Limited [2004] ACompT 8; and Application by Epic Energy South Australia Pty Ltd [2003] ACompT 5.

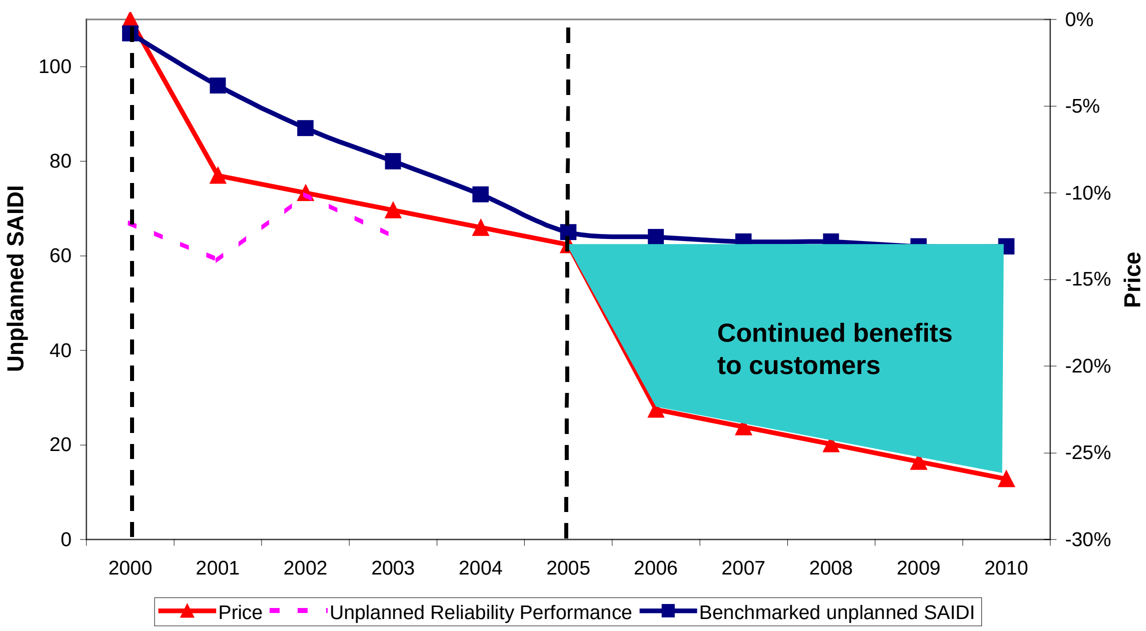
UED's Price-Service Offering for this Review

UED proposes a package of measures over the forthcoming period that, if accepted by the Commission, will:

- deliver further modest improvements in service performance by aiming to reduce unplanned interruptions to supply;
- result in undergrounding of assets, with consequential benefits in terms of improved public safety;
- see the creation of a fund aimed at funding institutions and or individuals with research into technological improvements in the energy industry;
- support the implementation of the interval metering rollout program;
- implement an industry skilling and training program, to ensure that appropriate skills and knowledge are retained and developed within the industry over the longer term; and
- deliver further price reductions in real terms for each year in the 2006-2010 period.

The company's price-service offering for the forthcoming regulatory period is depicted in Figure 1 below. The actual price and service outcomes delivered over the 2001-2005 regulatory period are also shown for comparative purposes.

Figure ES 1 – Price and Service Outcomes, 2001-2010



UED's price-service offering for the 2006-2010 regulatory period builds on and consolidates the substantial service improvements and price reductions already delivered by the company over the 2001-2005 period. Clearly, customers have benefited, and will continue to benefit substantially though improved services and lower prices over these two regulatory periods. On the basis of our past performance and our planned future performance, we consider that our price-service offering for the 2005-2010 regulatory period represents very good value for money for our customers.

Table 1 below summarises alternative proposed real percentage reductions in average prices over the 2006-2010 regulatory period.

Table ES 1 – Average Price Reduction Proposed over the 2006-2010 Regulatory Period

	2006	2007	2008	2009	2010
Step Price Reduction	9.5%	1.0%	1.0%	1.0%	1.0%
Smoothed Reduction	4.4%	4.4%	4.4%	4.4%	4.4%

In addition to proposing a continuation of a scheme similar to the present service incentive ("S-factor") scheme, UED is also proposing to extend the guaranteed service level (GSL) scheme in the forthcoming regulatory period. The GSL scheme provides the company with clear financial incentives to address persistent service problems, and also provides individual customers with some compensation in the event that defined service commitments are not achieved. This provides further assurance to customers that UED continues to be focussed on service delivery.

It should be noted that UED's price-service offering also includes the likely costs of complying with UED's regulatory and safety obligations under its Electricity Safety Management Scheme (ESMS). In terms of safety, new and replacement assets are installed to meet the latest regulatory standards, with other non-compliant assets being upgraded as work programs present opportunities. UED believes that its existing practices are sufficient to meet the requirements of the Office of the Chief Electrical Inspector (OCEI). However, if it transpires that additional expenditure is required to achieve "literal compliance" with the safety standards, significant changes to the price-service offering will need to be made. UED is continuing to work with the OCEI and Government to ensure that workable and practical approaches to achieving compliance are adopted.

Customer Outcomes – Past and Future Service Levels

Since 1997, UED's capital and maintenance programs have focused on improving the level of supply reliability to customers. Over that period, the company has delivered significant benefits to customers, in terms of improved service standards. In addition, UED's performance has bettered each of the network reliability benchmarks set by the Commission in the 2001 Determination.

UED estimates that the service performance improvements it has achieved – compared to the regulatory benchmarks – have delivered a net benefit to customers worth approximately $36 million in aggregate to date, after taking account of the increased revenue earned by UED under the S-factor scheme. Customers have clearly benefited from the service performance improvements achieved by the company to date.

During the forthcoming regulatory period, UED plans to continue to focus on maintaining the present high levels of service, and to deliver further improvements where it is feasible and economic to do so. UED proposes a package of measures over the forthcoming period which will deliver further modest improvements in service performance by focusing on the worst performing assets and momentary interruptions to supply. Specifically, the company's efforts will focus on:

- improving performance in areas of worst performing feeders;
- improving the quality of power delivered to customers; and
- reducing the number of interruptions that customers experience (through consultation, customers have identified frequency of interruption as the highest priority item for reliability improvement).

UED's analysis indicates that given the present high level of reliability performance, and the costs incurred by the company in achieving performance improvements over recent years, there is very limited scope for further substantial reliability improvements to be delivered cost-effectively. However, UED is proposing two initiatives which it believes complement its commitment to safety, the industry initiative to reduce energy demand and efficiency:

- Firstly, UED proposes to pro-actively work with road authorities and local government to use undergrounding techniques to minimise the risk to public safety arising from the location of electricity distribution assets in identified hazardous locations. As part of this initiative, UED plans to incorporate in its works program (new construction, augmentation and replacement) a step to review, as part of any project, the location of assets with a view to minimising the number of assets located above ground within the road reserve area. This initiative, if accepted by the Commission, will deliver substantial benefits to the community, in terms of improved public safety.
- Secondly, UED is proposing to establish a Technology Development Fund with the purpose of providing practical and financial support to groups and institutions to undertake research and development activities which would facilitate improvements in reliability, power quality and service performance. Programs could include component development (eg service breakaway devices), and continuing research into demand management and alternative energy opportunities and undergrounding technology and techniques.

UED supports arrangements that provide assurance to all stakeholders that UED's total revenue would be adjusted to permit the company to recover only the costs of works actually completed under this program. In this regard, UED believes that it should not be subjected to any additional reward or penalty through these initiatives and believes the funds associated with these initiatives should be excluded from the Efficiency Carryover Mechanism.

Interval Meters

Interval meters provide the opportunity to measure the real time consumption of electricity in predetermined time periods and to use the information obtained to set end-use pricing to mirror wholesale market price movements, and thus more accurately reflect the real cost of supply. To date interval metering has mainly been used for customers consuming greater than 160 MWh per year and for those customers who have chosen to enter the contestable retail market with a contestable meter provider.

The Commission's decision to implement an interval metering strategy as proposed for the Victorian market is considered to be at the forefront of industry practice, not only in Australia but internationally, particularly in terms of the volume of metering installations and data quantities involved. As such it presents particular risks and uncertainties for Distributors. In particular, whereas UED manages the risks involved with its normal business operations, UED has no choice but to supply interval meters in accordance with the Commission's timetable. This creates risks that are beyond UED's control.

Interval metering is a relatively new business, certainly on the scale proposed by the mandatory rollout program. The market for the supply of meters on this scale is immature. It is impossible for UED to predict with any certainty all the risks and costs associated with this mandated move to interval meters over the next five years.

Given this high level of uncertainty, UED has been unable to obtain reliable data on costs. Interval meter suppliers have only provided indicative costs. Prospective suppliers have been careful to expressly refer to the fact that prices provided so far are 'indicative' only. It is not clear how the actual costs that will prevail during the regulatory period will compare to these indicative costs.

UED does not know how the Commission intends to use the indicative cost data supplied in relation to interval metering in calculating UED's allowed revenue. While the Commission has proposed a mechanism for quarantining the metering efficiency carryover, it is not clear precisely how the 'M' factor will be applied and whether it will be used to compensate UED for the risks associated with such cost uncertainties.

UED considers that the Commission's consultation process to date in relation to the mandated interval meter rollout, has not allowed a complete examination of these commercial issues associated with the rollout to occur. UED looks forward to discussing these issues with the Commission at the earliest possible opportunity. If the Commission considers its obligations under the rules of procedural fairness require it to deal with the issue through an open consultation process UED welcomes such transparency.

Capital Expenditure Benchmarks

UED's capital expenditure plans are produced through the company's asset management planning processes. One of the main purposes of asset management planning is to ensure an optimal balancing of capital and recurrent expenditure, so that maintenance, replacement and augmentation of the electricity distribution network proceeds in a manner that delivers the required level of services at the lowest possible life cycle cost. UED has developed capital expenditure benchmarks for the forthcoming regulatory period that reflect sound asset management principles and practice.

The Commission states that its approach in assessing forecasts of capital expenditure is to use historic expenditure and trends in the different capital expenditure components as a starting point. In this regard, UED notes that:

- it would be an error for the Commission to expect that capital expenditure in the future period would match history;

- however, the Commission expects that variations in the forecasts from historical trends should be able to be explained with reference to various cost drivers; and
- the Commission also considers that it is appropriate to place the onus on distributors to justify to the Commission and the distributors' customers the benefits of any variation in past expenditure patterns.

UED's capital expenditure benchmarks have been developed in accordance with the Commission's requirements as set out in its Guidance Paper[4]. In particular, UED has used a capital expenditure model developed by PB Power (which applies cost drivers to estimate network capital expenditure) as a basis for validating and substantiating its benchmarks.

The model is based on historical and forecast information, thereby providing the explanatory link between actual and benchmark capital expenditure that the Commission wants to explore. The model can be calibrated with input assumptions that reflect the *actual* network cost drivers[5] that existed over the 2001-2005 regulatory period and it can produce a revised benchmark of capital expenditure for the period that is reasonably consistent with the company's actual level of expenditure. This provides substantiation of the model's capability to both explain past investment patterns, and to predict future investment requirements.

It is also noted that in calibrating the model to produce benchmarks of future expenditure requirements, UED has incorporated the positive impacts of the innovations and efficiency gains it achieved in the 2001-2005 regulatory period. These efficiency gains include:

- the use of innovative approaches to achieve improvements in the network power factor, and hence the realisation of additional capacity from the existing asset base;
- the adoption of probabilistic planning, to facilitate more efficient utilisation of the existing network's capacity;
- the establishment and implementation of a Distribution Management System (DMS);
- the economic deferral of some asset replacement works, through innovative plant life extension programs; and
- the adoption of innovative approaches to improving quality of supply at costs well below those typically incurred in the industry.

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4 Essential Services Commission, Electricity Distribution Price Review 2006 - Final Framework and Approach: Guidance Paper, Page 62

5 The relevant drivers include factors such as remaining asset lives (adjusted for the asset life extension initiatives implemented by the company over the 2001-2005 period), actual load growth, actual network utilisation and the higher utilisation threshold for reinforcement investment which is implied by the application of probabilistic network planning.

Weighted Average Cost of Capital (WACC)

The cost of capital is a critical element of the "building block" formulation that is used to derive an estimate of a regulated utility's total revenue requirement. There is a significant degree of imprecision and subjectivity involved in the estimation of the cost of capital, and there is certainly no one objectively determinable "correct" estimate of the cost of capital. It is universally recognised however, that very large costs to society as a whole would arise if regulators set the WACC at a level that is insufficient to encourage on-going investment in infrastructure over the long term.

UED's view is that the Commission's assessment of the WACC should take full account of:

- the potential cost of regulatory error (as described in the Productivity Commission's recent reviews);
- the uncertainties associated with estimating the WACC and its constituent parameters; and
- the need to ensure that in practice, investors are adequately remunerated for all risks (including the regulatory and commercial risks, as required by the Government's proposed modifications to the national access regime) involved in the provision of infrastructure.

On the basis of KPMG's advice, UED estimates its real "vanilla" WACC to be 6.7%. The return on the Regulated Asset Base has been calculated for each year of the 2006-2010 regulatory period, by applying the real vanilla WACC to an average of opening and closing asset values for the year.

Operating Expenditure Benchmarks

Operating expenditure comprises both operating and maintenance costs where:

- 'Maintenance' includes those works associated with the maintenance and repair of regulated business assets; and
- 'Operating' includes those functions associated with operating an asset or item of equipment, or those functions that support the business operations.

Operating expenditure is considered by the Commission to be a recurrent expense, which may reduce over time as genuine efficiency gains are achieved, subject to changes in the scope of operating activity and the volume and quality of outputs produced. Given this view of operating expenditure, and the incentive properties of the regulatory framework, there is no benefit or purpose in establishing operating expenditure requirements on a detailed "bottom-up" basis. Therefore, the Commission's approach is to base future operating expenditure benchmarks on each company's actual reported costs, plus an adjustment for scope changes.

UED has identified a number of scope changes for the forthcoming regulatory. The scope changes have been characterised by UED as follows:

- any change of cost associated with a change in, or change in reasonable interpretation of a Regulation and or law. These can include changes to Regulations by other government authorities and changes in Regulations initiated by the Commission and or the National Electricity Market governance agencies; and

- Any sustained cost change not included in UED's cost base which the Commission uses as a starting point for establishing future benchmarks, and which falls outside of normal cyclical variations in costs associated with cyclical variations in operating conditions.

An important area of concern for UED relates to the possible inclusion by the Commission of an "efficiency factor" in relation to operating expenditure benchmarks. In this regards, UED notes that clause 5.10 of the Tariff Order[6] requires the Commission, amongst other things, to have regard to the need to ensure a *fair sharing* of the benefits achieved through efficiency gains between customers and the distributors.

In the 2001 Determination, the Office argued that a 70:30 sharing ratio in favour of customers satisfied this requirement for the fair sharing of efficiency gains. In UED's view, 50:50 would be much more consistent with common application of the concept of *fair sharing*. Moreover, UED we notes that if the Commission anticipates *future* efficiency gains in setting operating expenditure benchmarks, customers will in effect enjoy even more than 70% of the benefits. In fact, such an ex ante setting of efficiency gains delivers an immediate gain of 100% of that forecast gain to customers and could result in customers receiving more than 100% of any future gain. In terms of what is allowed under the Tariff Order, this is neither a "fair sharing" nor is it an outcome derived from a gain actually "achieved". For this reason alone, UED challenges the inclusion of any future efficiency gain, which is speculative and unrealised, in setting the operating expenditure benchmarks in the next regulatory period.

Tariffs

The Commission has stated[7] that distribution tariffs should lie between the following lower and upper bounds, respectively:

- tariffs for each customer should generate revenue in excess of the avoidable cost to service the customer; and

- tariffs for each customer should generate revenue less than the cost of providing the service on a stand-alone basis to the customer.

UED has conducted tariff modelling, which demonstrates the company's compliance with this requirement.

UED is committed to the progressive introduction of interval meters across all customer segments in the medium term, and will assess the tariff design implications of the interval meter rollout as more accurate half-hourly load data for all customers becomes available.

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6 Victorian Electricity Supply Industry Tariff Order.

7 Essential Services Commission, Final Framework and Approach: Volume 1, Guidance Paper June 2004, page 97.

It is expected that while there may be some relatively minor refinements to existing tariffs. At this stage however, UED is not contemplating significant tariff changes during the 2006-2010 regulatory period.

UED's proposed distribution and network tariffs (including transmission charges) for calendar year 2006 are set out in the templates that accompany this submission. The precise level of these tariffs will depend on the Commission's revenue determination, and therefore the tariffs presented in the templates are indicative only.

Demand Forecasts

UED commissioned National Institute of Economic and Industry Research (NIEIR) to provide independent demand forecasts. Demand forecasts are relevant for estimating the expenditure benchmarks described earlier, and the revenue that will be earned from UED's proposed tariffs.

NIEIR employed its state and regional industry based economic projection models with electricity consumption data for the UED distribution region. Forecasts of regional electricity demands are developed within NIEIR's regional economic model of the Victorian economy.

Under the baseline scenario, NIEIR forecast that UED region's gross regional product is expected to grow by 2.9 per cent in average terms between 2004 and 2014. Population is expected to rise by an average rate of 0.3 per cent between 2004 and 2014. NIEIR estimate that UED's average electricity sales will grow by 1.3 per cent per annum between 2006-2010. These forecasts have been reflected in this price submission.

Concluding Comments

In summary, this submission provides a detailed description of the challenges facing the business as it looks forward to the next regulatory period and beyond. In broad terms, UED must maintain its focus on customer service, including a continuation of the improvements in service and cost efficiency already obtained. In addition, the forthcoming regulatory period will bring new challenges and risks – such as those associated with the rollout of interval meters. There are also the more traditional, but no less challenging, issues of compliance with regulatory and safety obligations, against a backdrop of an ageing asset profile.

Despite these risks and challenges, UED's price-service offering promises service performance that builds on and consolidates the substantial service improvements already achieved. Service incentive schemes (the S-factor and GSLs) are also proposed to provide a financial imperative on service delivery. Importantly, UED also proposes substantial reductions in prices in addition to those already provided. Overall, the price-service offering represents very good value for money for our customers, and should be accepted by the Commission.

1 Introduction

1.1 Purpose

Clause 12 of the Electricity Industry Act and clauses 32 and 33 of the Essential Services Act 2001 confer on the Commission the power to regulate prescribed prices in respect of prescribed goods and services including charges for connection to, and the use of, any distribution system. In September 2000, the Commission's predecessor, the Office, established the price controls currently applying to distribution network tariffs for the 2001-2005 regulatory period. These current price controls are due to expire on 31 December 2005 and a new set of price controls will be required for the next regulatory period, commencing 1 January 2006.

In March 2004 the Commission commenced a consultative process on key issues and information requirements which it considered would 'enable it to make a well informed and balanced judgement in determining price controls and related matters'[8]. The Commission saw a key feature of the consultation process as:

> "an opportunity [for distributors] to lay out a plan for consideration by the Commission and stakeholders on how investment in their distribution networks should be undertaken to meet customer demands and technical and safety requirements, and how the costs of this investment will be recovered through the distribution tariffs they charge customers for using the network"[9]

in the form of consolidated price-service proposals.

This submission sets out UED's formal response to the 2006 EDPR and has been prepared in accordance with the Guidance Paper issued by the Commission.

1.2 United Energy Distribution

Formed in 1994 following the disaggregation and privatisation of the Victorian electricity supply industry, UED is one of five electricity distribution businesses operating under licence within the State of Victoria, with assets totalling approximately $2.0 billion. UED's network provides services to some 600,000 end-use customers in Melbourne's southern and eastern suburbs, with its area of operation confined to geographically defined boundaries set out in the Distribution Licence.

UED is a wholly owned subsidiary of UED Holdings Pty Limited (UEDH). UEDH is 66% owned by Diversified Utilities and Energy Trust (DUET), with the remaining 34% owned by Alinta Limited (Alinta). Both DUET and Alinta are Australian companies listed on the Australian Stock Exchange.

8 Essential Services Commission, 23 February 2004, Open letter to stakeholders.

9 Essential Service Commission, June 2004, 'Final Framework and Approach: Volume 1, Guidance Paper, page 8.

UED has sought to establish itself as a leader in providing utility network services. It has established a reputation for innovation and leadership through sound business planning and practices. These practices include the engagement of independent contractors to provide management, operating, maintenance and other services to enable UED to efficiently and effectively meet its responsibilities as a distribution network operator and service provider as described in this submission .

UED currently has responsibilities under jurisdictional and national legislation as:

- a distribution system operator, responsible for network security and stability; and
- a network service provider, responsible for network planning, and for providing and facilitating customer connection and transfer administration for the competitive retail market.

UED has no retail or generation business interests.

UED continues to make a positive contribution to the wealth and well-being of its customers and the community in which it operates. UED's overarching objectives to provide services to customers in an efficient manner and in accordance with customers' needs and preferences, whilst meeting investors' requirements for a commercial return on the substantial capital invested in the business. UED seeks to achieve these objectives, by building on the positive reputation for service delivery, innovation and community support that it has established in both the industry and the community in general.

1.3 Structure of Submission

The structure of this submission is as follows:

- Chapter 2 describes UED's price-service offering for the forthcoming regulatory period.
- Chapter 3 describes an overview of the Regulatory Framework, judicial decisions and reports that UED consider are relevant in assessing this submission.
- Chapter 4 provides a description of the customer outcomes and service standards that UED has achieved over the 2001-2005 regulatory period, and the customer outcomes and service standards it plans to achieve over the 2006-2010 period.
- Chapter 5 provides details of the efficiency gains achieved over the current regulatory period.
- Chapter 6 sets out UED's expenditure benchmarks for metering and discusses the proposed approach to implementing the Commission's July 2004 Determination in relation to the mandatory rollout of interval metering.
- Chapter 7 details capital expenditure requirements that UED considers to be prudent and efficient.
- Chapter 8 provides information relevant to the "rolling forward" of the regulatory asset base value.
- Chapter 9 summarises UED's cost of capital requirements. Further supporting information can be found in Appendix A – KPMG Cost of Capital

- Chapter 10 details UED's operating and maintenance requirements, including scope changes for the 2006-2010 period.
- Chapter 11 summarises the efficiency carryover mechanism, proposed adjustments to the benchmarks, and UED's calculation of the allowance for a carryover amount to be included in its revenue requirement.
- Chapter 12 summarises UED's total revenue requirement for the 2006-2010 period.
- Chapter 13 provides details on UED's tariffs and tariff strategy.
- Chapter 14 provides an overview of energy volume and demand forecasts on UED's distribution network.
- Chapter 15 discusses compliance issues relating to technical regulations administered by the Office of the Chief Electrical Inspector.

1.4 Contact Details

The contact officer for further details in relation to this submission is:

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2 Price – Service Offering

2.1 Introduction and Overview

The purpose of this chapter is to summarise UED's price-service offering for the forthcoming regulatory period. As noted in the Commission's Guidance Paper, the price-service package provides distributors with an opportunity to lay out an investment plan for meeting customer requirements and the technical and safety requirements, and to describe the resulting prices. The detail of these investment plans, and the resulting prices are provided in subsequent chapters of this submission.

At the outset of this submission, it is important to note that the Commission's approach to regulation continues to focus primarily on the "cost of service". UED has consistently argued that "cost of service" and "building block" regulation is focused too much on driving costs out of the businesses, without recognising the longer term detrimental impact of such an approach on innovation, dynamic efficiency and customer service.

An alternative to the "cost of service" regulatory approach is required to facilitate greater commercial negotiation, and to encourage dynamic efficiency and the maximisation of welfare over the longer term. One credible alternative that has already been established successfully (in the airports sector) is "price monitoring". A "price monitoring" approach would provide a means of strengthening the incentives for distributors to deliver services that meet customers' needs in an efficient manner over the long term, whilst minimising the direct and indirect costs associated with more intrusive forms of regulation such as the "building block" approach.

Notwithstanding UED's views on this matter - which the Company will continue to advocate – UED has tried to develop a genuine customer focused and innovative price-service package, within the Commission's building block framework. Accordingly UED has applied the building block methodology as per the Guidance Paper together with the efficiency carryover mechanism which was detailed in the 2001 Determination.

In this price-service offering UED has focused not just on a cost and investment plan, but sought to develop a full price-service package that seeks to deliver better outcomes for customers. This includes initiatives to meet service obligations generally set at the 2005 reliability targets, together with some improvements in customer service as outlined in Chapter 4 of this submission. These service improvements, including undergrounding assets to address public safety concerns and community amenity, are in addition to the substantial price reductions and improvements in service reliability already delivered to customers over the current regulatory period.

It is noteworthy that UED offers to deliver these service improvements alongside further reductions in distribution charges. Inevitably, "cost of service" regulation cannot continue to deliver these types of outcomes indefinitely. In this price review, the Commission must find the right balance between short term cost outcomes and fostering efficient long-term service levels. In UED's view, the Commission's statutory obligation to protect the *long-term* interests of Victorian customers requires the Commission to consider the negative effects of continued cost-cutting. Chapter 3 of this submission presents a more detailed discussion on the Commission's statutory obligations, and the implications of recent regulatory developments in Australia for this forthcoming review.

The remainder of this chapter is structured as follows:

- Section 2.2 recaps on the outcomes delivered by UED under the price-service offering which applied in the 2001-2005 regulatory period;
- Section 2.3 summarises the price-service package that UED is offering to provide during the forthcoming regulatory period; and
- Section 2.4 provides concluding comments.

2.2 Outcomes Delivered During the 2001-2005 Regulatory Period

In the lead-up to the 2001 Determination, UED proposed three alternative price-service offerings, which represented different trade-offs between price levels and service standards. UED's preferred package (the Customer Value Proposal) was designed following extensive consultation with customers. The offering aimed to optimise customer service standards in a socially responsive and sustainable manner.

The 2001 Determination established the price-service package that UED was required to deliver over the 2001-2005 regulatory period. In many respects, UED has delivered outcomes that exceed the price-service package established by the 2001 Determination. In particular, during the current (2001-2005) regulatory period, UED has delivered substantial improvements in service compared to the benchmarks set by the Commission. These improvements have been achieved by:

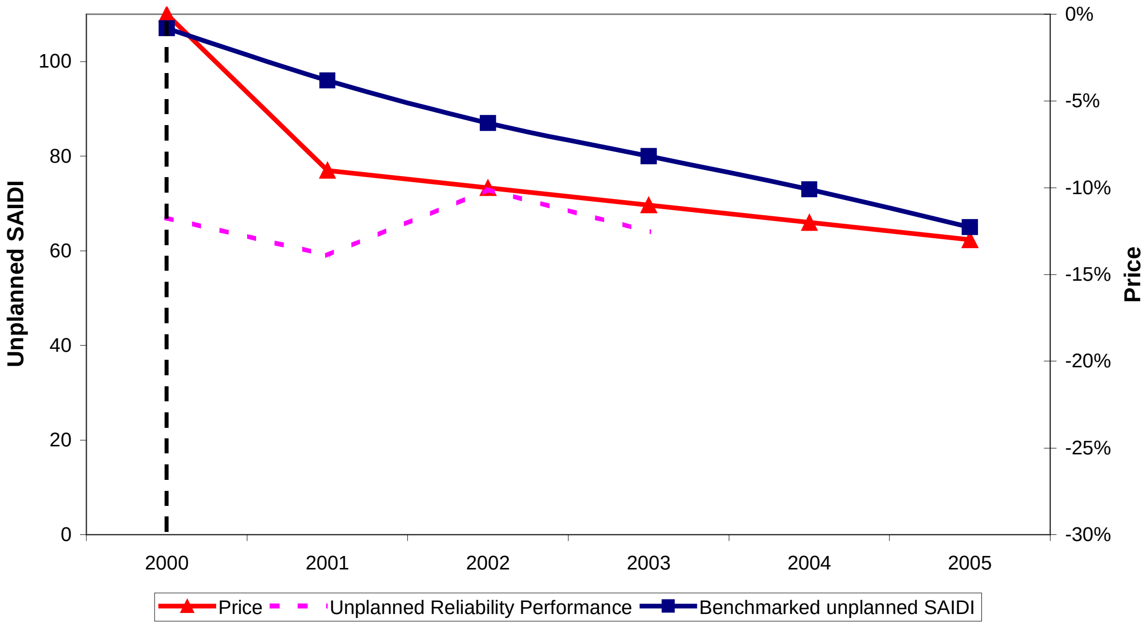
- effective identification of under-performing assets in the worst performing areas, and efficient upgrading of those assets;
- improving procedures and work practices to achieve faster repair and response times;
- optimising the amount of work on live powerlines and improving works planning processes to minimise planned shutdowns;
- monitoring power quality across the network to pro-actively identify any issues that may require rectification; and
- introducing new technologies to reduce the impact of electricity outages.

All of these initiatives have been successful in delivering improvements in customer service. The objective at all times is to improve the reliability of supply to customers by:

- reducing the number of long-duration power cuts caused by faults;
- minimising the time taken to find faults; and
- minimising the time taken to restore supply once the fault cause is found.

As noted earlier, and as shown in Figure 2.1 below, the improvements in service performance over the current regulatory period have been achieved along with reductions in distribution charges. UED's customers have therefore benefited through improved service standards and lower prices.

Figure 2.1: Price-Service Performance 2000-2005



Furthermore, UED has achieved greater than expected cost efficiencies, and these will be passed on to customers through lower future charges. The cost efficiency initiatives achieved by UED include:

- improvements in network power factor, leading to more efficient utilisation of existing network capacity;
- adoption of probabilistic planning, facilitating more efficient utilisation of existing network capacity;
- implementation of a distribution management system to facilitate improved efficiency in network operation and planning;
- economic deferral of demand-related capital projects;
- asset life extension programs that contribute to an overall reduction in the total life cycle cost of various asset classes; and
- enhanced delivery of network performance (quality of supply) capital expenditure.

These efficiencies are described in further detail in Chapter 5 of this submission.

2.3 Price-Service Offering for 2006-2010

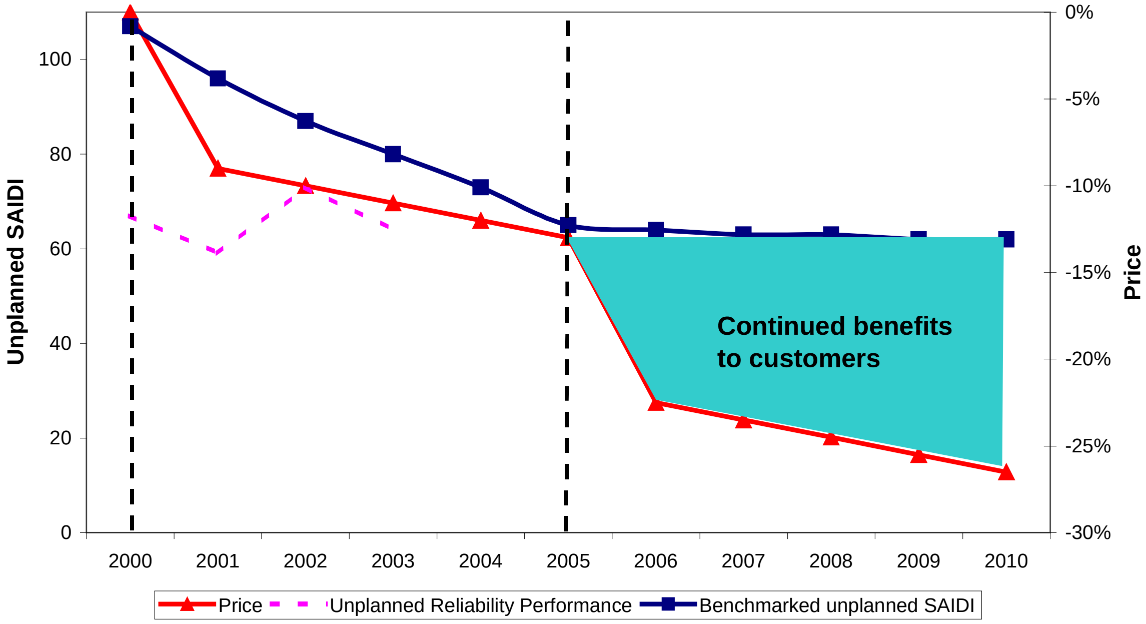
In the forthcoming regulatory period, UED has proposed capital and operating expenditure benchmarks which take account of the better performance and lower costs achieved in the current regulatory period, and which also provide appropriately for customer and network requirements in the forthcoming period. Inevitably, the scope for further service improvements and cost efficiencies diminish with each year. The practical limitation on delivering further improvements in service levels is described in more detail in Chapter 4 of this submission.

Nevertheless, UED proposes a package of measures over the forthcoming period which, will:

- Maintain UED's already high standards of service and deliver further modest improvements in service performance by focusing on the worst performing assets and by aiming to reduce interruptions to supply;
- result in undergrounding of assets, with consequential benefits in terms of improved public safety;
- enable UED to comply with all applicable regulatory obligations;
- implement an industry skilling and training program, to ensure that appropriate skills and knowledge are retained and developed within the industry over the longer term; and
- deliver further price reductions in real terms for each year in the 2006-2010 period.

The company's price-service offering for the forthcoming regulatory period is depicted in the diagram below. The actual price and service outcomes delivered over the 2001-2005 regulatory period are also shown for comparative purposes.

Figure 2.2: Proposed Price-Service Offering 2006-2010



UED's price-service offering for the 2006-2010 regulatory period builds on and consolidates the substantial service improvements and price reductions already delivered by the company over the 2001-2005 period. Clearly, customers have, and will continue to benefit substantially though improved services and lower prices over these two regulatory periods. On the basis of UED's past performance and planned future performance, UED considers that its price-service offering for the 2006-2010 regulatory period represents very good value for money for our customers.

Table 2.1 below summarises alternative proposed real percentage reductions in average prices. It does not include the effect of metering and associated systems.

Table 2.1: Average Price Reduction Proposed Over the 2006-2010 Regulatory Period

	2006	2007	2008	2009	2010
Step Price Reduction	9.5%	1.0%	1.0%	1.0%	1.0%
Smoothed Reduction	4.4%	4.4%	4.4%	4.4%	4.4%

UED offers the continuation of the S-factor scheme, with some modification. (These modifications include: incorporating the Momentary Average Interruption Frequency Index (MAIFI) parameter in the formula, deleting planned SAIDI from the formula, and a re-balancing of weighting factors.) UED is also proposing to extend the guaranteed service level (GSL) scheme in the forthcoming regulatory period. The GSL scheme provides the company with clear financial incentives to address persistent service problems, and also provides customers with some compensation in the event that defined service commitments are not achieved. The S-factor scheme and the GSL scheme will provide further assurance to customers that UED continues to be focussed on service delivery.

UED's approach to the price-service offering in this regulatory period differs from the three alternative packages that UED presented at the commencement of the 2001 price review. In this price-service offering, UED has presented a single option which reflects an integrated and internally consistent mix of investment, service delivery and price, having regard to customer feedback and management imperatives in seeking to deliver reliable network services now and into the future. As a price-service package, it is important to consider the submission as a whole, rather than seeking to cherry-pick the "best" aspects of the offer. The link between the scope of the offer and the cost of delivering it as represented ultimately in the Total Revenue Requirement must be recognised. For example, it is simply not possible to enjoy the *benefits* of existing or improved service levels included within the offer without also meeting the *cost* of substantial new investment. The investment program is discussed in more detail in Chapter 7 of this submission.

2.4 Concluding Comments

UED's price-service offering presents an attractive mix of service delivery improvements alongside price reductions. UED considers that its price-service offering for the forthcoming regulatory period represents value for money for it's customers. This offering follows a regulatory period where the company has already delivered service improvements beyond those required by the Commission, whilst also delivering reductions in prices.

In the longer term, further reductions in costs will inevitably lead to a deterioration in UED's service focus as the business looks to cost reductions rather than customer-orientated innovations. For this reason, UED continues to support a regulatory model that looks beyond cost of service and building blocks, and instead embraces innovation. In Chapter 3 of this submission, UED looks closer at the recent regulatory changes which lend support to UED's view that the Commission should avoid focusing narrowly on estimating the minimum costs of service delivery.

3 Regulatory Framework

3.1 Introduction and Overview

The purpose of this chapter is to provide UED's perspective on the regulatory framework under which UED and the Commission operate. In this context, it is important to recognise that the regulatory framework is not static. In fact, there have been a number of regulatory developments since the 2001 Determination.

In particular, the Commission replaced the Office of the Regulator-General, and new statutory objectives now apply to the Commission's work. Recent independent reviews of regulation and regulatory decisions (notably by the Productivity Commission, the Western Australian Supreme Court and the Australian Competition Tribunal) have identified some deficiencies, and areas in which regulatory decision-making can be made more effective. These reviews have important implications for the future direction and conduct of regulators, and for the Commission's forthcoming 2006 Determination.

UED believes that in its decision-making during this price review, the Commission is required to have regard to the findings of these independent reviews and Court and Tribunal decisions.

UED recognises that these regulatory developments should be kept in perspective. In particular, there is no doubt that the Commission's incentive regime has delivered some positive outcomes. UED's performance with regard to costs and service levels demonstrates that the company has responded to the incentives put in place by the Office in the 2001 Determination. Nevertheless, there are important lessons for the Commission arising from these regulatory developments, which must be reflected in the forthcoming 2006 Determination.

This chapter is structured as follows:

- Section 3.2 provides a brief description of the Commission's statutory objectives and matters to which the Commission must have regard;
- Section 3.3 describes the recent regulatory developments, particularly focusing on the Productivity Commission's independent review of the regulatory arrangements;
- Section 3.4 provides concluding comments in relation to the recent regulatory developments.
- Section 3.5 provides concluding comments on the Regulatory Framework.

3.2 The Commission's Statutory Objectives and Matters to which the Commission must have Regard

The Commission has outlined the objectives it is required to apply in assessing the distributors' price-service proposals, as part of the preliminary price review process. The Guidance Paper states:

> "In finalising its framework and approach the Commission's primary concern has been to apply the legal and regulatory framework that guides its decisions in a balanced and reasonable manner. In short, its legal and regulatory framework consists of the Essential Services Commission Act 2001, the Electricity Industry Act 2000 and the remaining clauses of the Victorian Electricity Supply Industry Tariff Order (specifically clauses 1, 5.7, 5.9, 5.10, 6.1 and 6.4)."[10]

In the Commission's Framework and Approach Consultation Paper No. 1 (Consultation Paper 1), the Commission also notes that it will have regard to the objectives and principles set out in clauses 6.10.2 and 6.10.3 of the National Electricity Code (NEC) to the extent that these are consistent with the legal framework described above.

In Consultation Paper 1 the Commission states:

> "The primary objective of the Commission is to protect the long-term interests of Victorian consumers with regard to the price, quality and reliability of essential services."[11]

The Commission notes that in seeking to achieve its primary objective, it must have regard to the following facilitating objectives:

- to facilitate efficiency in regulated industries and the incentive for efficient long term investment;
- to facilitate the financial viability of regulated industries;
- to ensure that the misuse of monopoly power or non-transitory market power is prevented;
- to facilitate effective competition and promote competitive market conduct;
- to ensure that regulatory decision making has regard to the relevant health, safety, environmental and social legislation applying to the regulated industry;
- to ensure that users and customers (including low-income or vulnerable customers) benefit from the gains from competition and efficiency; and
- to promote consistency in regulation between States and on a national basis.

The Commission also refers to the requirement, under Clause 5.10 of the Tariff Order, to utilise price based regulation adopting a CPI-X approach, and not rate of return regulation. It also refers to other elements of clause 5.10, which require it to have regard for the need to:

- provide each distributor with incentives to operate efficiently;
- ensure a fair sharing of the benefits achieved through efficiency gains between customers and the distributors;

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10 Essential Service Commission, *EDPR 2006 Final Framework and Approach: Volume 1, Guidance Paper*, June 2004, page 8.

11 Essential Service Commission, *EDPR 2006 Consultation Paper No. 1: Framework and Approach*, March 2004, page 5.

- ensure appropriate incentives for capital expenditure and maintenance in the distributors' distribution systems; and
- have regard to the levels of executive remuneration in each distributor by reference to any relevant interstate and international benchmarks for such remuneration.

UED notes that section 33(2) of the Essential Services Commission Act 2001 ("ESCA") requires the Commission, in making a price determination, "to adopt an approach and methodology which the Commission considers will best meet the objectives specified in the ESCA and in the Electricity Industry Act 2000".

As the Commission has stated, its primary objective under section 8(1) of the ESCA is to protect the long-term interests of Victorian customers with regard to the price, quality and reliability of essential services."[12]

UED submits the Commission must have particular regard to the fact that this objective directs the Commission to the long term interests of customers, not only with regard to price, but also with regard to quality and reliability. UED notes the Commission has endorsed this objective as a matter of regulatory principle in the context of the Productivity Commission Review of the Gas Access Regime, which as a regime for price regulation is analogous for these purposes, in saying:

> "The ESC agrees with the Draft Report that the overall objective of the Gas Access Regime must be to foster long-run economic efficiency…".[13]

In meeting its primary objective the Commission is required to construe the meaning of long term interests of customers, not only with regard to price, but also with regard to quality and reliability. It is required to adopt an approach and methodology that best meets this objective. It is UED's submission that the Commission must, as a matter of law, have regard to the outcomes of recent independent reviews of regulation and regulatory decisions to determine the best approach and methodology that protects the long term interests of customers.

UED recognises the legal framework in which the Commission operates. UED has developed this submission with the Commission's statutory objectives in mind. UED shares the goal of protecting the long-term interests of Victorian customers by delivering the services that customers want at prices that reflect best practice performance.

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12 Essential Services Commission, *EDPR 2006 Consultation Paper No. 1: Framework and Approach*, March 2004, page 5.

13 Essential Services Commission, Submission to the Draft Report of the Productivity Commission Review of the Gas Access Regime, 7 April 2004, page 4

3.3 Recent Regulatory Developments

A number of recent events have provided greater clarity on how the objectives of regulation should be interpreted, and thus how regulation should be applied. While most of these recent developments have occurred within the context of the gas industry, it is important to recognise their relevance for this review and the requirement under the ESCA for the Commission to have regard to them. In particular, there are important lessons relating to the question of how regulators should best discharge their statutory duties.

This submission does not examine all of these developments in detail. It examines the two specific independent Government-sponsored reviews that are particularly relevant to this EDPR and draws upon the salient features of the Western Australian Supreme Court decision of *Re Dr Ken Michael AM; Ex parte Epic Energy (WA) Nominees Pty Ltd* [2002] WASCA 231 (the "Epic Decision").

The two reviews are the Productivity Commission's:

- Review of the National Access Regime[14] (and the Government's Response[15]); and
- Review of the Gas Access Regime.[16]

It is important to emphasise that these reviews have been conducted by the Productivity Commission, which is an independent adviser to the Australian Government on microeconomic policy and regulation. The findings and recommendations of the Productivity Commission are therefore not biased by commercial or other interests.

Each of the Productivity Commission's reviews are discussed briefly in turn below, prior to a short commentary on the key elements of the Epic Decision.

3.3.1 Review of the National Access Regime

The Productivity Commission's Review of the National Access Regime emphasised the risk of "regulatory error", and noted that the potential costs associated with too little infrastructure investment are far greater than those associated with too much investment. In short, there is asymmetry in the consequences of regulatory pricing errors:

> "Given that precision is not possible, access arrangements should encourage regulators to lean more towards facilitating investment than short term consumption of services when setting terms and conditions …
>
> [and] given the asymmetry in the costs of under- and over-compensation of facility owners, together with the informational uncertainties facing regulators, there is a strong in principle case to 'err' on the side of investors".

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[14] Productivity Commission, Review of the National Access Regime: Inquiry Report, 28 September 2001.

[15] Government Response to the Productivity Commission Review of the National Access Regime, released 17 September 2002.

[16] Productivity Commission, Review of the Gas Access Regime, 11 June 2004.

It is in this vein that the Productivity Commission provided a clear warning to regulators against an excessive focus on the removal of so-called “monopoly rents” from the revenue streams of facility owners, quoting a submission to the review by NECG, which stated:

> “In using their discretion, regulators effectively face a choice between (i) erring on the side of lower access prices and seeking to ensure they remove any potential for monopoly rents and the consequent allocative inefficiencies from the system; or (ii) allowing higher access prices so as to ensure that sufficient incentives for efficient investment are retained, with the consequent productive and dynamic efficiencies such investment engenders.
>
> There are strong economic reasons in many regulated industries to place particular emphasis on ensuring the incentives are maintained for efficient investment and for continued productivity increases. The dynamic and productive efficiency costs associated with distorted incentives and with slower growth in productivity are almost always likely to outweigh any allocative efficiency losses associated with above-cost pricing. (sub. 39, p. 16)”

As a result the Productivity Commission’s review highlighted the need to modify implementation of the regime and made 33 recommendations to improve its operation. In particular it identified as a:

> “…threshold issue, the need for the application of the regime to give proper regard to investment issues” and “the need to provide appropriate incentives for investment”[17]

3.3.2 The Review of the Gas Access Regime

More recently, the Productivity Commission argued in its Review of the Gas Access Regime that:

> “…Based on the Commission’s assessment (of both costs and benefits), including taking into account input from interested parties, it is reasonable to conclude that there are problems with the current regime. These mainly arise from the considerable costs the regime imposes and its real potential to distort investment and inhibit innovation.”[18]
>
> “Regulators seek a large amount of detailed information from service providers and users. They also commission or undertake a substantial amount of research. In this way, service providers and regulators can incur large costs. Principally, regulators require the information to satisfy themselves that they have discharged their responsibilities in relation to approving and determining reference tariffs, in accordance with the flexible and highly discretionary framework set out in the regime. The outcome is the intrusive and meticulous use of the ‘building block’ cost method and incentive regulation framework to set reference tariffs with a false sense of precision.”[19]

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17 Productivity Commission, Review of the National Access Regime: Inquiry Report, 28 September 2001, p. xxii.

18 Productivity Commission, Review of the Gas Access Regime, 11 June 2004, page XXVII.

19 ibid., page XXVIII.

3.3.3 The Epic Decision and Commentary

In the Epic Decision the Court made a number of comments which have been the subject of considerable discussion and debate in recent years. UED does not wish to dwell upon the Court's views regarding "workable competition" but instead draws upon and adopts the commentary of Dr Darryl Biggar, which formed part of the submission of the Australian Consumer and Competition Council (ACCC) to the Productivity Commission's Review of the Gas Access Regime.[20]

In effect, Dr Biggar took the view that the benefit from the Court's decision lay not so much in its determination that section 8(1)(b) of the National Gas Code should be interpreted as requiring the Commission to replicate the outcomes of a workably competitive market but in the emphasis that the Court places on certain outcomes of a competitive market that it would like to see.

UED supports the view that the case establishes outcomes for which a regulator should strive when required to "replicate the outcome of a competitive market" and notes that clause 6.1.1(b)(3) of the National Electricity Code records that the key principles of that chapter include an intention "to regulate the non-competitive market for network services in a way which seeks the same outcomes as those achieved in competitive markets". UED submits the Commission has committed to have regard to this principle as one which is consistent with the Victorian legal framework. In any event, UED believes the Epic Decision establishes the outcomes for which a regulator should strive when meeting an objective relating to the long term interests of customers.

Dr Biggar made the comment that the Court took the opportunity to emphasise certain outcomes of a workably competitive market that it would like to see replicated and noted the "strong implication that these are the outcomes which the Commission should seek to replicate". Quoting the Epic Decision at paragraph 128, these outcomes he noted as[21]:

> "(a) First, workable competition is a dynamic process: 'A workably competitive market is not a fixed and immutable condition with any absolute or precise qualities, but a process which involves rivalrous market behaviour. … As such, a workably competitive market will react over time and according to the nature and degree of various forces that are happening within the market.'
>
> (b) Second, there may be temporary departures from static equilibrium conditions: 'There may well be a degree of tolerance of changing pressures or unusual circumstances before there is a market reaction. The expert evidence and writings tendered in evidence suggest that a workably competitive market may well tolerate a degree of market power, even over a prolonged period.'
>
> (c) Third, efficiency does not necessarily attain 'theoretically ideal [static] efficiency': 'The underlying theory and expectation of economists, however, is that with workable competition market forces will increase efficiency beyond that which could be achieved in a non-competitive market, although not necessarily achieving theoretically ideal [static] efficiency.'

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20 ACCC, Submission to the Productivity Commission Review of the Gas Access Regime, 15 September 2003, attachment 1

21 ibid, page 111.

Dr Biggar then discussed the third of these outcomes concluding that:

> "[The] primary force of the Court's argument is that the regulator should not place undue weight on static concepts of efficiency. Instead, according to the Court, the regulator should place due weight on the dynamic efficiency outcomes of competitive markets – the incentives to take risks, to exploit opportunities and to innovate. This could lead to temporary (or even prolonged) deviations from some narrow notions of efficiency, but to the greater good of efficiency overall."[22]

Dr Biggar went on:

> "Finally, the Court seems to acknowledge that a workably competitive market must be sustainable in the long run: 'The expert evidence … suggested a growing awareness of the long term disadvantages of striking the balance [between the interests of consumers in obtaining low prices and the service provider in receiving high prices] with too great an emphasis on the interest of consumers in securing lower prices, and without due regard to the interest of the service provider in recovering both higher prices and its investment'."[23]

3.4 Conclusions on Recent Regulatory Developments

These Productivity Commission reviews, other independent reviews[24]; decisions by the Court[25]; and appeal decisions by the Australian Competition Tribunal[26] all emphasise the need for regulators to recognise the limitations of the "building block" methodology.

In the context of considering future regulatory approaches, the Commission too has recognised these limitations. The Commission has said:

> "…while the building block model has been effective in the past, the ESC is concerned that it may not be the best regulatory approach going forward. In particular, the problem of information asymmetries remain pronounced under the building blocks model. Even if the efficiency of past expenditures is "revealed," the method still requires forecasts of efficient capital and operating expenditures during the price control period. Projecting future costs is an information-intensive and inherently uncertain process that is fraught with risk. On the one hand, there is the risk of overcompensating regulated businesses, thereby leading to excessive prices and profits, distorted infrastructure investment and misallocated resources in upstream and downstream markets. On the other hand, there is a risk of providing inadequate prices and revenues for regulated businesses, undermining their financial viability and incentive and capacity to invest."[27]

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22 ibid, page 112.

23 ibid, page 113.

24 Council of Australia Governments Energy Market Review Panel, Towards a Truly National and Efficient Energy Market: Final Report [Parer Report], 20 December 2002.

25 *Re Dr Ken Michael AM; Ex parte Epic Energy (WA) Nominees Pty Ltd* [2002] WASCA 231.

26 See for example, Application by GasNet Australia (Operations) Pty Ltd [2003] ACompT 6; Application by East Australian Pipeline Limited [2004] ACompT 8; and Application by Epic Energy South Australia Pty ltd [2003] ACompT 5.

27 Essential Services Commission, Submission to the Draft Report of the Productivity Commission Review of the Gas Access Regime, 7 April 2004, page 14.

There is now a significant body of authoritative and independent opinion that demonstrates the importance of avoiding regulatory error, and the risks to regulated infrastructure investment - and thus the long term interests of customers - that might arise from those errors.

The Commission must exercise broad judgements in this EDPR to balance, broadly speaking, the interests of shareholders and customers, on a long term prospective basis. It has been recognised that in making those judgements "…different minds, acting reasonably, can be expected to make different choices within a range of possible choices which nonetheless remain consistent with the [regulatory principles].[28]".

Faced with this difficult task and the trade offs it involves between regulatory endeavour and regulatory cost and error, the developments discussed above counsel against striving for an outcome with "absolute or precise qualities" and the need to accept that a "workably competitive market may well tolerate a degree of market power". There is a strong case for regulators' decisions to err in favour of encouraging more, rather than less infrastructure investment.

3.5 Conclusions on Regulatory Framework

In the exercise of regulatory discretion where a broad range of outcomes are reasonable, the goal is not a solution represented by absolute or precise qualities. In this context, recognition of the need to foster long term customer benefits through investment and dynamic efficiency, perhaps involving less emphasis on short term price reductions, is encouraged. A non-intrusive, pragmatic use of the building block approach, recognising its limitations and risks (including the need to concentrate on the long term), together with the Commission's focus on incentive mechanisms, as outlined in the 2001 Determination, is appropriate for this EDPR.

UED supports such a conclusion based upon its view of the current development of regulatory best practice. In doing so it does not waver from the broader view it holds that best regulatory practice in the future will foster an environment in which regulated businesses are free to offer a range of price/service offerings tailored to the wishes of customers, in the context of a light handed regulatory framework founded upon productivity based regulation.

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28 Application by GasNet Australia (Operations) Pty Ltd [2003] ACompT 6, paragraph 29.

4 Customer Outcomes – Past and Future Service Levels

4.1 Introduction and Overview

This chapter provides an overview of the customer service outcomes delivered by UED over the 2001-2005 regulatory period, and the outcomes that the company is planning to deliver over the forthcoming regulatory period.

Since 1997, UED's capital and maintenance programs have focused on improving the level of supply reliability to customers. Since then, the company has delivered significant benefits to customers in terms of improved service standards. In addition, UED's performance has bettered each of the network reliability benchmarks set by the Commission in the 2001 Determination.

UED estimates that the service performance improvements it has achieved – compared to the regulatory benchmarks – have delivered cost-savings to customers worth approximately $36 million to date. Customers have clearly benefited from the service performance improvements achieved by the company.

During the forthcoming regulatory period, UED plans to continue to focus on maintaining the present high levels of service, and to deliver further improvements where it is feasible and economic to do so. UED proposes a package of measures over the forthcoming period which will deliver further modest improvements in average service performance by focusing on the worst performing assets and by aiming to reduce interruptions to supply. Specifically, the company's efforts will focus on:

- improving performance in areas of worst performing feeders;
- improving the quality of power delivered to customers; and
- reducing the number of interruptions that customers experience (through consultation, customers have identified frequency of interruption as the highest priority item for reliability improvement).

Analysis suggests that, given the current configuration of UED's network, the scope for further significant improvements in performance (as measured in "customer minutes off supply" through the reliability index SAIDI) is limited. This reflects the incidence of increasing incremental costs associated with achieving further reductions in SAIDI.

In regard to the S-factor scheme, while acknowledging the concern of some customers and the Commission with respect to momentary interruptions, UED is concerned that any change to the scheme should not increase its complexity, or the level of risk to distributors. UED would support a change to the formula to include the Momentary Average Interruption Frequency Index (MAIFI) parameter, subject to the deletion of planned SAIDI and a re-balancing of the weighting factors.

In the Guidance Paper[29], the Commission has suggested the inclusion of a service measure based on call centre performance. UED does not support the inclusion of such a parameter in either the S-factor or GSL scheme at this time as it believes current call centre performance to be adequate and the cost-benefit of improvements would be difficult to quantify. UED would support the maintenance of a watching brief on call centre performance over the coming period as part of the Commission's proposed additional reporting requirements.

The remainder of this chapter is structured as follows:

- Section 4.2 presents an overview of the network performance delivered by UED over the 2001-2005 regulatory period.
- Section 4.3 sets out the service level targets that UED plans to achieve during the 2006-2010 regulatory period.
- Sections 4.4 and 4.5 set out UED's proposed service incentive arrangements (that is, the S-factor and GSL schemes) to apply during the forthcoming regulatory period.
- Section 4.6 presents UED's proposals regarding undergrounding of distribution assets.
- Section 4.7 sets out UED's proposal for the establishment of a technology development fund.
- Section 4.8 discusses issues relating to the determination of customers' willingness to pay (WTP) for service improvements.

4.2 Network Performance Improvements Achieved

Reliability of supply refers to maintaining continuity of supply to customers, and is generally considered by customers as the most important characteristic of electricity network performance. As part of the 2001 Determination, the Office established performance targets for distributors for the following reliability measures:

- System Average Interruption Frequency Index (SAIFI) - the total number of planned or unplanned distribution customer interruptions, divided by the total number of connected distribution customers averaged over the calendar year, excluding momentary interruptions (less than one minute duration).
- Customer Average Interruption Duration Index (CAIDI) - the sum of the duration of each unplanned distribution customers (in minutes), divided by the total number of unplanned distribution customer interruptions in that year, excluding momentary interruptions (less than one minute duration).
- System Average Interruption Duration Index (SAIDI) - the sum of the duration of each planned or unplanned distribution customer interruption (in minutes), divided by the total number of connected distribution customers averaged over the calendar year.

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29 Essential Services Commission, Guidance Paper page 46

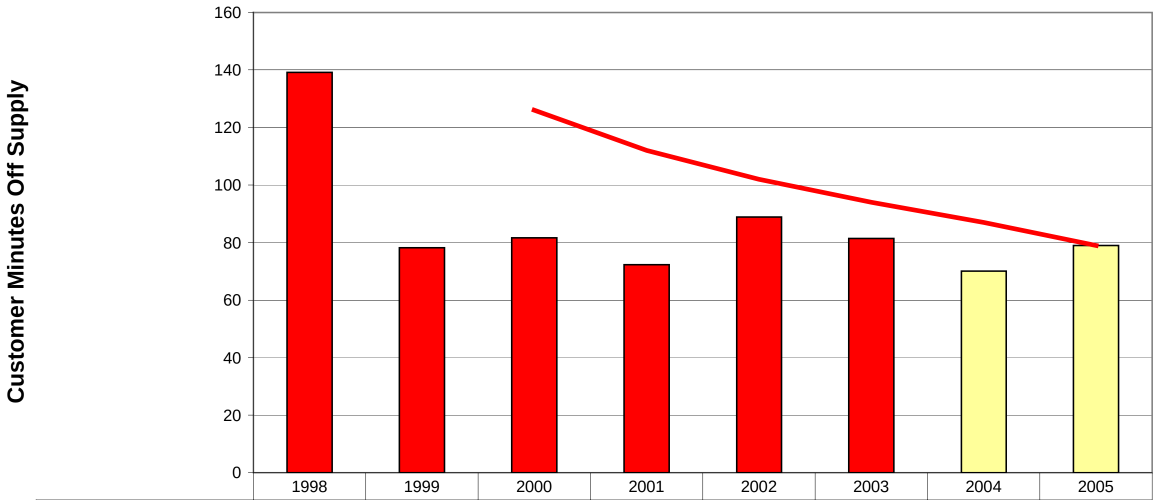
- Momentary Average Interruption Frequency (MAIFI) - the total number of momentary distribution customer interruptions (less than one minute), divided by the total number of connected distribution customers averaged over the calendar year.

In the 2001 Determination, UED committed to a 37% improvement in electricity reliability from 2000-2005, the most ambitious program of all of the Victorian Distributors and achieved this improvement from a competitive starting benchmark. Moreover, UED's goal was to better the benchmarks adopted by the Commission to ensure superior customer service delivery during this period.

UED's performance against each of these measures is detailed in below.

Figure 4.1 below shows UED's actual reliability performance (measured in terms of minutes off supply per customer, or SAIDI) against the regulatory benchmark since 1998.

Figure 4.1: Actual and Regulatory Benchmark Minutes off Supply per Customer



	1998	1999	2000	2001	2002	2003	2004	2005
UED SAIDI	139	78	82	72	89	81		
Internal SAIDI Estimate							70	79
Reg SAIDI benchmark			126	112	102	94	87	79

Figure 4.1 above shows that over the 2001-2005 regulatory period, UED delivered a level of reliability (as measured by SAIDI) that was substantially better than that required by the performance benchmarks set in the 2001 Determination with the 2003 performance being on par with the 2005 targets.

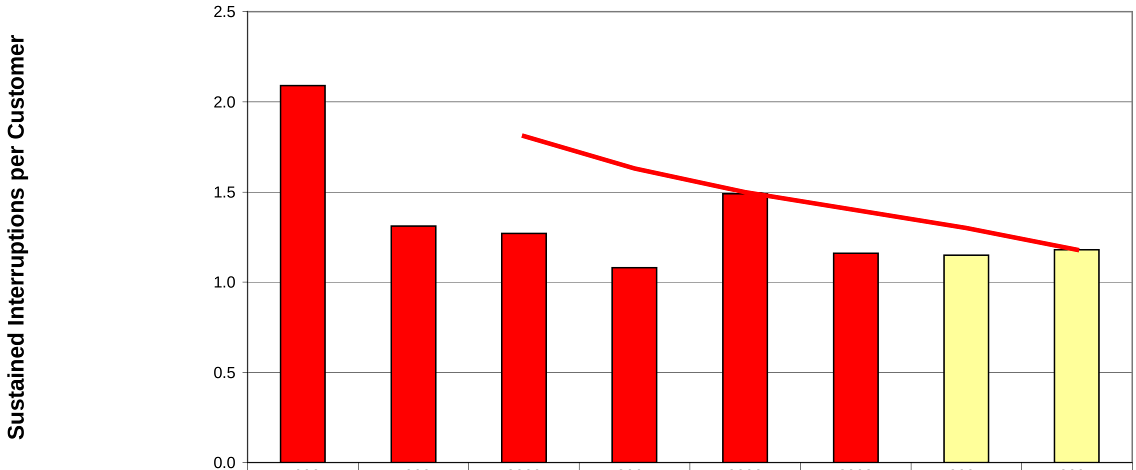
UED estimates that the performance improvements achieved by the company over the period have delivered benefits to customers worth approximately $45 million to date compared with the Commission's benchmarks.[30] After netting off the additional revenue earned by the company under the S-factor scheme (estimated to be $9 million over the

[30] The reductions in the level of customer minutes off supply (compared to the regulatory benchmark) in each year equates to a reduction in unserved energy of 1500 MWh. Valuing this reduction in unserved energy at the marginal cost of unserved energy to consumers (approximately $30,000 per MWh) implies a saving to customers of $45 million to date.

2001-2004 period), customers are better off by $36 million as a result of the improvements delivered by UED.

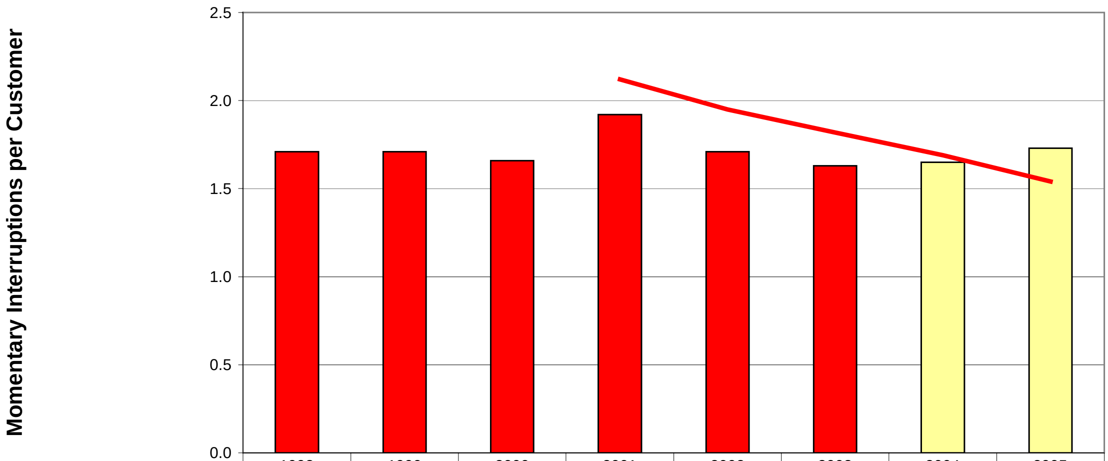
Figure 4.2 and Figure 4.3 below shows UED's actual performance against the regulatory benchmarks for SAIFI and MAIFI established at the 2001 Determination has also been superior, with the 2003 performance being on par with the 2005 benchmarks.

Figure 4.2: Actual Performance and Regulatory Benchmarks for SAIFI



	1998	1999	2000	2001	2002	2003	2004	2005
UED SAIFI	2.09	1.31	1.27	1.08	1.49	1.16		
Internal SAIFI Estimate							1.15	1.18
Reg SAIFI benchmark			1.81	1.63	1.5	1.4	1.3	1.18

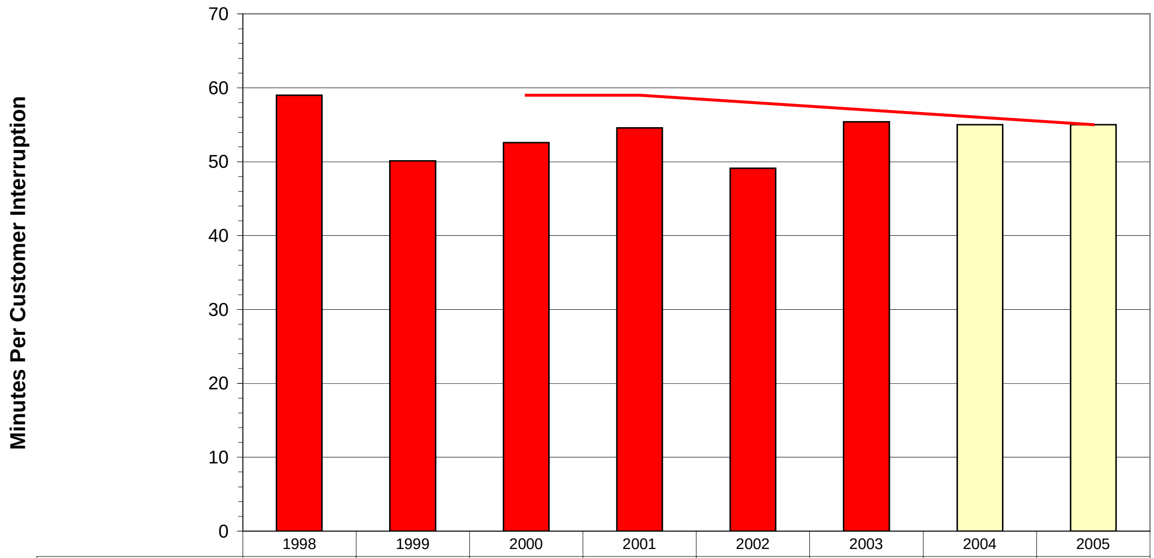
Figure 4.3: Actual Performance and Regulatory Benchmarks for MAIFI



	1998	1999	2000	2001	2002	2003	2004	2005
UED MAIFI	1.71	1.71	1.66	1.92	1.71	1.63		
Internal MAIFI Estimate							1.65	1.73
Reg MAIFI benchmark				2.12	1.95	1.82	1.69	1.54

Figure 4.4 shows that UED's performance against the CAIDI benchmarks established at the 2001 Determination has been superior with the 2003 performance being on par with the 2005 benchmark.

Figure 4.4: Actual Performance and Regulatory Benchmarks for CAIDI



	1998	1999	2000	2001	2002	2003	2004	2005
UED CAIDI	59	50	53	55	49	55		
Internal CAIDI Estimate							55	55
Reg CAIDI benchmark			59	59	58	57	56	55

A program of performance improvement initiatives undertaken since 1997 has been the prime driver of the dramatic improvement in reliability performance over this period. These initiatives focused not just on reducing the time customers are without electricity but also on reducing the number of interruptions that customers experience. They focused on:

- targeting major fault causes to reduce the frequency of customer interruptions;
- upgrading assets in the worst performing areas;
- improving procedures and work practices to achieve faster repair and response times;
- optimising the amount of work on live powerlines and improving works planning processes to minimise planned shutdowns;
- monitoring power quality across the network to pro-actively identify any issues that may require rectification; and
- introducing new technologies to reduce the impact of electricity outages.

All of these initiatives have been successful in delivering improvements in customer service. The objective of UED at all times has been to improve the reliability of supply to customers by:

- reducing the number of long-duration power cuts caused by faults;

- minimising the time taken to find faults; and
- minimising the time taken to restore supply once the fault cause is found.

A substantial investment in programs such as possum and bird proofing, pole fire mitigation work, the deployment of Automatic Circuit Reclosers and fault indicators and the limited remote control of field devices have all driven improvements in SAIFI and SAIDI over the 2001-2005 regulatory period. In fact, these programs have driven a 60% improvement in SAIDI from 205 customer minutes off supply in 1997 to 81 minutes in 2003 and a 66% improvement in SAIFI over the same timeframe.

4.3 Proposed Performance for 2006-2010

On page 38 of its Guidance Paper, the Commission sets out its proposed approach to establishing target service levels for the 2006-2010 regulatory period as follows:

> "Given that the Commission intends to continue to use average reliability measures and that there is no evidence that average performance levels need significant improvement, the Commission considers that it is appropriate to adopt the 2005 targets as the targets for the 2006-010 regulatory period. Where a distributor can demonstrate to the Commission that its customers value an alternative level of reliability, then this information should be provided to support a consistent target. In such cases, the distributor will be required to provide details (including costs) of the projects that will be undertaken to meet this alternative level of reliability and the supporting information demonstrating that customers do value this improvement in reliability."

UED concurs that there is no evidence that its average performance levels require significant improvement. Indeed, as previously noted, UED has already achieved substantial improvements in service performance. It is important to note that average performance, as measured by SAIDI, is a combination of both planned and unplanned interruptions. The 2005 Commission benchmark for these measures is 80 minutes comprising of 15 planned and 65 unplanned customer minutes off supply respectively. In this offering, UED is proposing to improve only the unplanned component (ie 65 minutes) and improve that benchmark to 62 minutes.

Based on the benchmark level of capital expenditure and UED's obligation to safety, it is anticipated that this benchmark will increase from 15 to 30 customer minutes off supply.

UED's analysis indicates that given the present high level of reliability performance, and the costs incurred by the company in achieving performance improvements over recent years, there is very limited scope for further substantial reliability improvements to be delivered cost-effectively. In the coming regulatory period, UED therefore proposes to undertake a relatively modest level of incremental expenditure on reliability improvements, principally focussed on:

- improving performance in areas of worst performing feeders;
- improving the quality of power delivered to customers; and
- undertaking continued analysis to identify emerging trends and opportunities within the network to achieve cost-effective improvements in reliability.

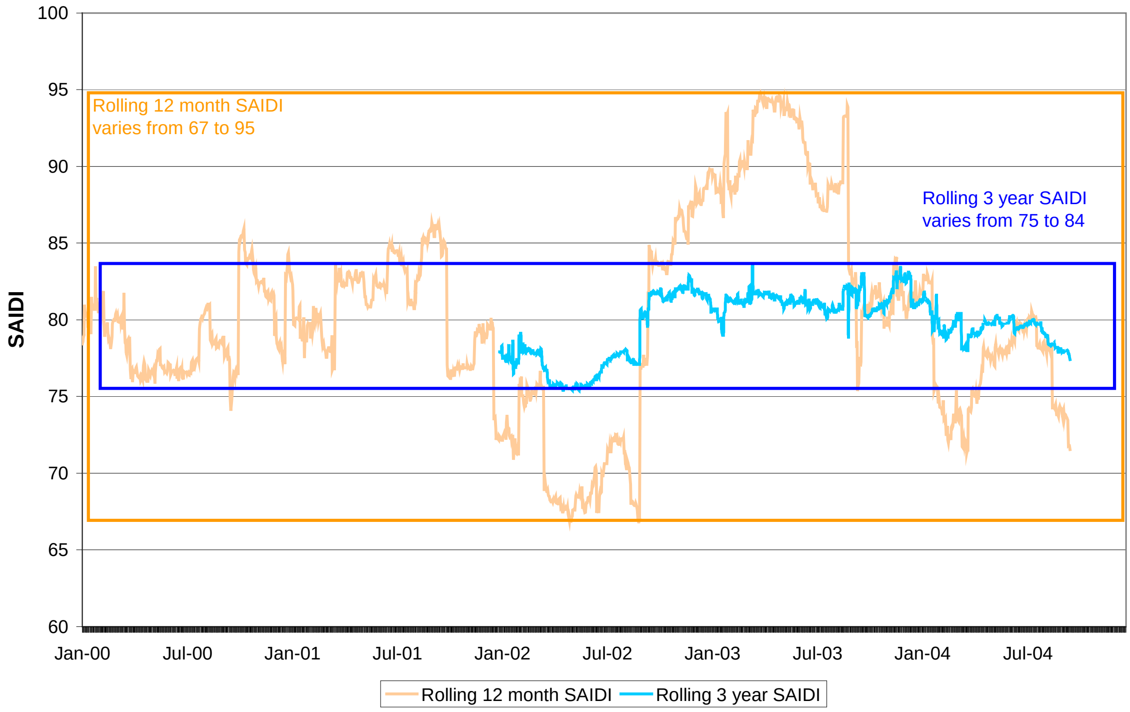
It is expected that these initiatives will deliver a small improvement in average reliability performance of unplanned minutes off supply over the coming regulatory review period.

Figure 4.5 below shows that, although the annual performance has varied from 72 minutes off supply to 89 minutes off supply over the past few years, the variability on a rolling 12 month performance (plotted daily) has varied even more dramatically from 67 minutes to 95 minutes over the same period.

This analysis highlights the impact that storms, periods of good weather and other extraneous events have on the network performance. A similar result is true on a rolling 2 year basis also with major incidents causing “jumps” in performance trends.

However if we plot a rolling 3 year SAIDI over the period since the end of 2001, we see below a much smoother chart with only a relatively small variability in performance from 75 minutes to 84 minutes. Even with the large investment that UED has made into this area in the past few years, the best performance during this period was during the middle of 2002, not more recently in 2004.

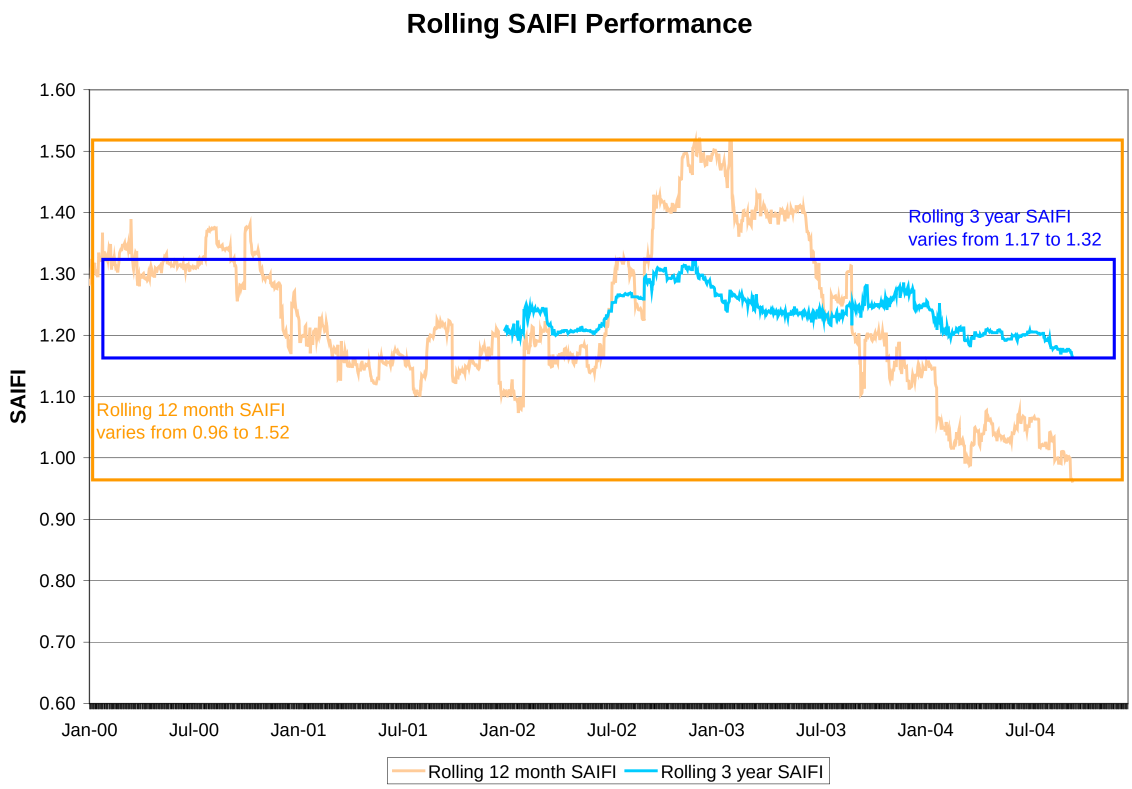
Figure 4.5: Actual SAIDI Performance (rolling)



Measuring SAIDI performance on a longer term (three year rolling average) basis indicates that:

- network reliability has essentially reached a “plateau” at approximately 80 customer minutes off supply; and
- variability in annual SAIDI performance (as reported in the Commission’s annual comparative performance report) will reflect the impact of external factors such as storms, periods of good weather or major events, rather than the underlying performance of the network or the impact of factors within the company’s control.

Figure 4.6: Actual SAIFI Performance (rolling)



Similarly, measuring recent SAIFI performance on a longer term (three year rolling average) basis indicates that network reliability as measured through customer interruptions has essentially reached a "plateau" at approximately 1.2 sustained interruptions per customer.

Figure 4.7 and Figure 4.8 below indicate the distribution of the normalised figures of the time based charts above over the last 3 years. They show that the three year rolling SAIFI averages 1.237 customer interruptions and SAIDI presently averages 79.8 minutes per customer when measured on a three year rolling average. These figures are within 5% of the 2005 targets and lend support to the Commission's proposal that generally the 2005 reliability targets should be adopted as the starting benchmarks for the 2006-2010 regulatory period. As already noted, UED supports the Commission's proposal.

Figure 4.7: Distribution of SAIFI Since 2000

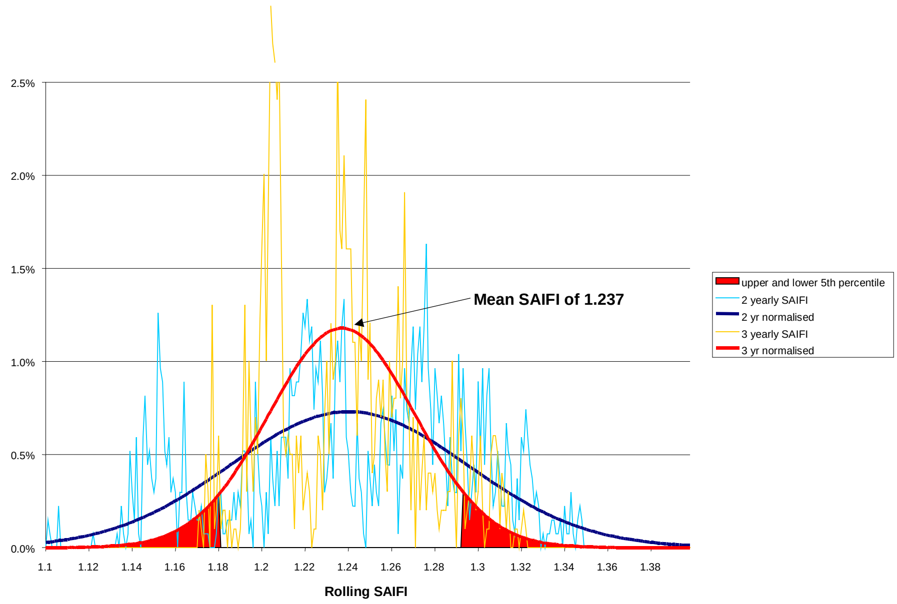
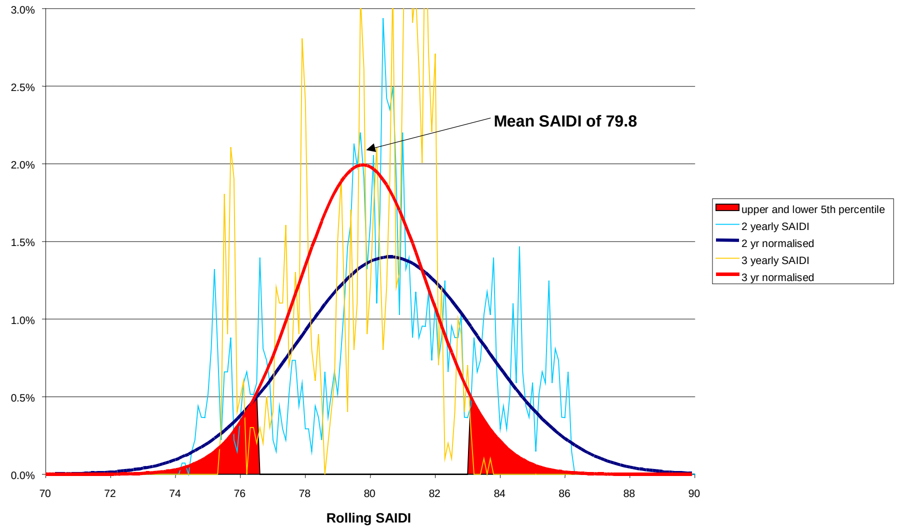


Figure 4.8: Distribution of SAIDI Since 2000



In developing proposed reliability benchmarks for the 2006-2010 regulatory period, a further consideration is required of the impact that an increasing capital works program will have on customers, in terms of planned interruptions. UED's recent performance indicates that since the expansion of 'live line' practices in recent years, there is now minimal scope for further improvements in work practices to achieve further reductions in planned interruptions to customers. Future planned interruptions are expected to be driven far more by the increasing asset replacement and demand based capital workload than any potential improvements in work practices. Based on the past three years, planned customer minutes off supply vary by just under one minute for every $2.5 million spent on the network for non-customer initiated works. An increasing workload over the 2006-2010 regulatory period will necessitate an increased number of planned shutdowns to deliver that program. Future planned SAIDI forecasts are based on this strong correlation between workload and planned shutdowns.

The benchmarks in Table 4.1 below are based on the starting point of the 2005 benchmarks and considering the proposed investment in both Reliability and Quality Improved and Reliability and Quality Maintained expenditure detailed in Section 7.7 and 7.8 of this submission.

Table 4.1: Proposed Reliability Benchmarks 2006-2010

	Existing B/Marks	Proposed Benchmarks				
	2005[31]	2006	2007	2008	2009	2010
SAIFI	1.21	1.20	1.19	1.18	1.17	1.16
MAIFI	1.55	1.72[32]	1.71	1.70	1.70	1.69
SAIDI Accidental	65	64	63	63	62	62
SAIDI planned	14	25	25	25	26	32

Note: UED is proposing to remove planned SAIDI from the S-factor scheme. As detailed elsewhere, evidence suggests that customers value momentary interruptions greater than planned interruptions. The increase in this measure reflects the increased level of work and safety requirements in this regulatory period.

4.4 Performance Incentives: S-factor Scheme

As part of the 2001 Determination, the Office implemented a financial incentive mechanism, which rewarded (penalised) distributors for positive (negative) variations in average performance compared to the regulatory benchmarks. The scheme comprised two components:

- an S-factor mechanism based on reliability levels with the scheme given effect through a change (positive or negative) to average tariff levels; and
- a GSL scheme delivering a direct benefit to customers affected by poor service levels.

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31 The 2005 targets have been modified from the original 2001-2005 Determination based on a change of inputs to the network wide targets in the ratio between customers classified as Urban and Short Rural over the period.

32 Refer Section 4.4.3 regarding proposed target setting for MAIFI

At the time, the Office stated that the scheme was implemented to:

> "…provide genuine incentives to the distributors to achieve and out-perform their reliability targets. The Office also considers that the schemes should not seek to compensate customers for the costs, or loss of value, associated with supply interruptions."[33]

The S-factor mechanism is used to adjust the overall price control formula for the gap between targeted and actual performance in SAIFI, CAIDI and planned SAIDI based on a nominal marginal cost of service improvement established by the Commission as part of the 2001 Determination. UED believes that the S-factor mechanism has been a driver in focussing business decisions relating to reliability expenditure to optimise the level of benefits delivered. In EDPR Service Incentive Arrangements (Consultation Paper 2), on page 6, the Commission stated that generally "the current financial incentive arrangements have performed well" and that as part of the 2006 EDPR, it "is looking to refine the existing arrangements, rather than overhaul the entire system."

UED generally agrees with the Commission's view and proposed approach. However, there are a number of issues that UED considers need to be addressed and resolved as part of the forthcoming price Determination. These are discussed below.

4.4.1 Complexity in the Process of Exclusion Events from the Financial Incentive Calculations

UED has made three applications to the Commission for exclusions under the current scheme, two of which related to upstream events (connection asset failures) and were approved, while the third related to a rare event (storm damage) and was rejected. UED considers the management of the current scheme to be complex and difficult to administer, particularly in the area of exclusion for 'rare' events. The current exclusion approach is time consuming and resource intensive for both the Commission and Distributors. A key area of concern is the definition of rare events which currently is too subjective and UED considers a more objective definition is needed.

In a paper[34] submitted to the Summer Power Meeting held in Chicago in 2002, James D Bouford, Manager of Distribution Performance at National Grid, Northborough, MA, USA, suggests that reliability indices should measure the ability of the system to address the level of disturbances for which it was planned, designed and constructed and is maintained and operated. Bouford further suggests that abnormal [rare] events which exceed reasonable design and operational limits 'seriously impact on a utility's operational ability to provide reasonable customer service and must be removed from the calculation of reliability indices, and must be reviewed individually'.

Abnormal events require different processes and resourcing by a utility.

The Bouford approach enables short and longer term reliability performance, within design and operational conditions, to be analysed without the distortion of abnormal events. It also

33 Office of the Regulator General, Electricity Distribution Price Determination, Determination 2001-2005 Volume 1: Statement of Purpose and reasons, September 2000, page 21

34 James D. Bouford, 'The Need to Segment Abnormal Events from the Calculation of Reliability Indices', March 15, 2002.

enables the business and the Commission to monitor the adequacy of the level of response to abnormal events.

A paper[35] by D.A. Kowalewski to the same meeting discusses three alternative methodologies to identifying events where the impact on the reliability of electricity services to customers is so severe as to dominate reliability statistics and therefore real design and operational performance. These methodologies are:

- The Institute of Electrical and Electronics Engineers (IEEE) approach: a method where 'A major event … impacts at least 10% of customers in an operating area in a 24 hour period'.
- The Bootstrap method: a method where major event days are defined as those where SAIDI per day is greater than the worst days per year when comparing to prior years.
- The 3-beta method: a method using 5 years of data – the natural logarithms of SAIDI per day are calculated to convert to a log normal distribution. Identification of major events is computed using three standard deviations above the mean.

UED has applied two of these methodologies to its reliability performance data for the past 4 years. The results are set out in the figures below.

Figure 4.9: Major Events (IEEE Method)

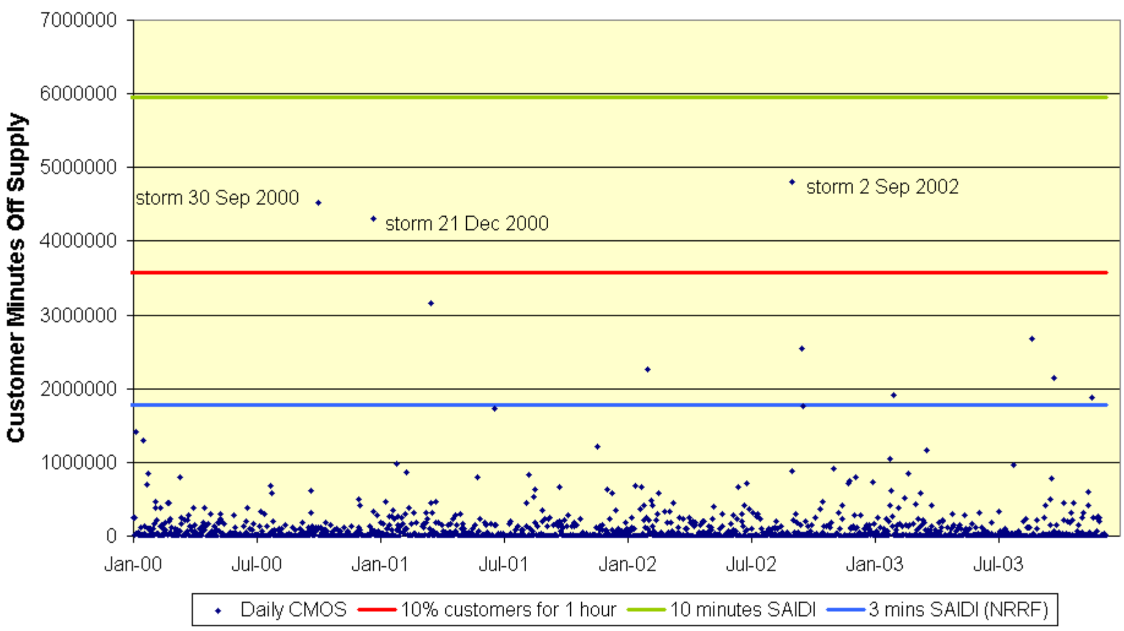


Figure 4.9 above and Figure 4.10 below indicates that a more objective threshold could be used to set exclusion criteria such as 10% of customers affected or 10% of customers off supply for 1 hour.

35 D.A.Kowalewski, 'A Comparable Method for Benchmarking the Reliability Performance of Electric Utilities', 2002.

Figure 4.10: Daily Interruptions Impacting More than 10% (IEEE Method)

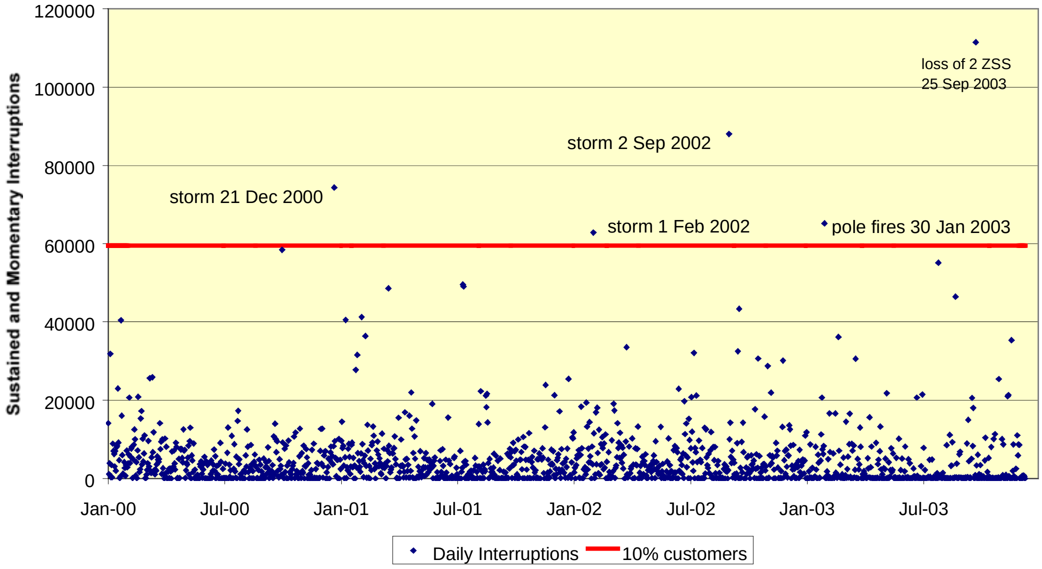
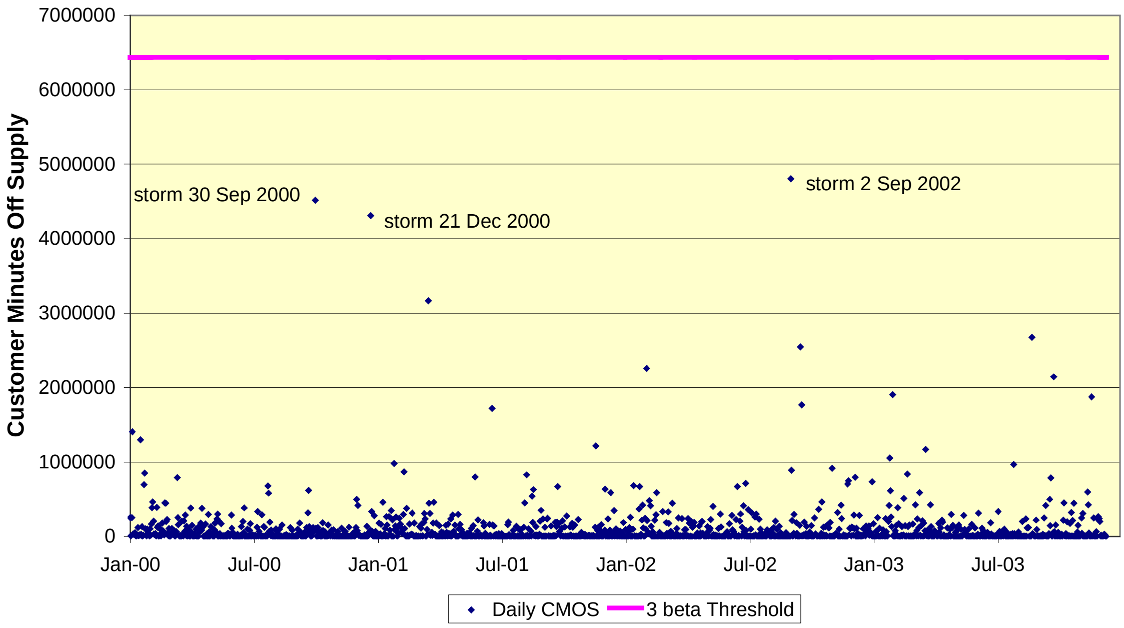


Figure 4.11 the 3 beta chart below, while not specifically giving a 1 in 5 year event threshold, also indicates that a more objective threshold could be used to set exclusion criteria.

Figure 4.11: 3 Beta Method



UED proposes that the existing incentive scheme be modified to limit exclusion to upstream events (including embedded generation) over which the distributor has limited control and that a cap be applied either to overall annual performance, or to the impact of individual incidents. UED believes that an approach that relies on objective measures would be simpler to implement and less costly to administer.

In the capacity augmentation of transmission connection assets, the Commission has encouraged the Distributors to consider embedded generations as alternative to traditional network solutions. Feedback from embedded generation proponents indicate that while they are keen to enter into network support agreements with UED, the penalty associated with the S-factor scheme, in the event of generation failure to support the network when support is required, is too great to be commercially viable. UED is of the opinion that if an embedded generator displaces or defers the need for a transmission connection asset augmentation, then they should be treated the same as transmission connection assets as far as S-factor calculation is concerned. That is, failure of generation should be treated as an upstream event and be excluded from the calculation of S-factor and GSL payments.

UED recognises that a cap could be applied either to overall annual performance, or to the impact of individual incidents. This could be in the form of a cap on revenue, minutes off supply or the number of customers affected. This could be weighted differently against the customer sectors (eg CBD, Urban, Rural) with each Distributor having a weighted average cap. Such an approach would deliver a more realistic representation of design and operational performance within ‘normal’ conditions.

UED proposes that a cap on customers affected by individual incidents at 10% of customers (for total momentary and sustained interruptions) be adopted rather than a SAIDI-based cap (which would wrongly exclude poor fault response times) or a fixed customer number such as 50,000 customers (which would not be equitable across all distributors). This cap would match similar international standards and would be consistent with a relatively infrequent occurrence based on UED’s recent figures.

Depending on the detailed design of the cap, it would be appropriate to implement symmetrical capping arrangements that would limit the amount of additional revenue that a distributor could earn for achieving performance improvements.

UED considers achieving the Commission’s objectives will be enhanced by refining the S-factor scheme as discussed and looks forward to working with the Commission in the detailed design and development of a refined S-factor scheme, to address these issues.

4.4.2 Asymmetry of Risk and Reward

Across Victoria, average customer minutes off supply for all Distributors has improved over the period 1995-2002, with a significant levelling out of the rate of improvement over the last 4 years. For UED, customers have experienced an improvement from 205 minutes customer minutes off supply in 1997, to 81 minutes off supply in 2003.

UED’s analysis suggests that there is very limited scope for achieving further substantial performance improvements, in terms of minutes off supply, in a cost-effective manner. Conversely, any reduction in funding to manage reliability performance will have a negative impact on reliability levels.

UED believes that the “downside risk” to its revenues under the S-factor scheme is substantially higher than the potential “upside” available through marginal improvements in reliability. In this sense, the potential revenue outcomes under the scheme are not symmetrical.

In this context, the S-factor may, in practice, become a scheme in which there is little or no financial benefit available to the distributor. In these circumstances, the ‘rewards/penalties’ incentive mechanism would degenerate into a ‘penalty’ system over which UED will have little effective control. The asymmetric properties of the S-factor scheme reinforce the need, noted above, for UED’s financial exposure under the scheme to be capped or limited.

4.4.3 Move to MAIFI

MAIFI measures the average number of momentary interruptions per customer per year, where a momentary interruption is considered to be an interruption of less than one minute duration. While now reported as a performance measure, when the financial incentive scheme was devised, MAIFI was considered for inclusion but not included due to a lack of historical information.

In considering MAIFI, UED believes that it is necessary to recognise the relationship between momentary and sustained interruptions. Since 1995, UED has expended considerable effort in reducing the number and duration of interruptions occurring on its network. Through technology improvements such as automatic circuit reclosers and remote control devices, many sustained interruptions have been reduced to momentary interruptions, with most customers benefiting due to the faster restoration of supply.

The impact of interruptions to customers, whether momentary or sustained, will vary between customer classes and between customers within a class. For many customers, momentary interruptions may be an inconvenience with relatively low cost impacts - ie inconvenience associated with resetting clocks, videos and other electronic based systems and devices. However for other customers, such as continuous process industries, the impact of even momentary interruptions can be catastrophic with process lines plugging, etc. In such cases the cost impact may be significant.

UED understands that momentary interruptions impact on customers and that it is appropriate to consider the use of MAIFI as a component of the financial incentive formula. While UED supported the inclusion of MAIFI in 1999, as discussed in Section 4.4.1 above, the company would be concerned if the addition of a new component created further complexity in the S-factor scheme and its calculations.

UED suggests that MAIFI be included and planned SAIDI be deleted from the formula. This is because planned shutdowns affect less than 5% of customers each year, few complaints are received when the current four-day notice period for planned interruptions is adhered to and UED is proposing to make the four-day notice for planned shutdowns more onerous by making a GSL payment for not providing this notice. The Commission’s comparative performance reports indicate that for UED, approximately 4-5% of customers experience a planned interruption per year (1 every 22 years on average), so it would be reasonable to argue that less emphasis should be placed on planned interruptions in any performance incentive scheme.

Moreover, UED manages its network having regard to reliability GSLs which focus the company on reducing the number of interruptions to customers each year. Hence, there is a driver on the company to minimise repeat shutdowns in a local area. Given the increased limitation on the options available to undertake work, and the fact that few complaints are received when the current four day notice period for planned interruptions is adhered to, UED proposes that planned SAIDI be removed from the S-factor formula and MAIFI be included.

UED also supports varying the definition of a momentary interruption from less than one minute to less than three minutes duration. This would align with definitions applied in other countries[36] while allowing UED greater scope to pursue practical technical and operational solutions to minimise both momentary and short duration incidents. An increase from one to three minutes duration is unlikely to impact most customers.

Further, any move to include MAIFI in the incentive scheme in future would need to consider the relative weightings of components to ensure that there are no perverse incentives which might discourage the turning of a sustained outage into a momentary outage. UED believes that weighting information similar to that set out on page 33 of Consultation Paper 2 (ie a 10:1 ratio between sustained and momentary outages) should be used to determine the relative weightings.

UED proposes that MAIFI be included and appropriate performance target for 2006 should be based on an average of the past 4 years performance (1.73), with other reliability criteria being based on "normalised" performance levels which would give UED a MAIFI target of 1.72 by the end of 2006.

4.4.4 Call Centre Performance

In the Guidance Paper[37], the Commission has suggested the inclusion of a service measure based on call centre performance. UED considers current arrangements for telephone enquires and call centre performance monitoring appropriate, and does not support the inclusion of call centre performance in the incentive scheme at this time. Further, inclusion of such a parameter would impose additional complexity, resourcing and data requirements on an already difficult and resource-intensive process, for little improvement in actual service delivery to customers or the incentive to improve for distributors.

UED would support the maintenance of a watching brief over the course of the next price review period to monitor performance and collate relevant data, to facilitate the introduction of new measures if this is found to be necessary in the future.

4.4.5 Incentive Rates For Each Measure

As noted above, the Commission has stated that generally "the current financial incentive arrangements have performed well". UED agrees that the incentive scheme and the weightings of the measures established in the 2001 Determination have optimised the level of benefits delivered. As there is very limited scope for further substantial reliability improvements to be delivered cost-effectively and UED is only proposing to undertake a relatively modest level of incremental expenditure on reliability improvements in the coming regulatory period, UED sees no reason to modify the existing incentive rates for the individual measures. This includes the move from CAIDI to SAIDI proposed by the Commission which UED considers can be weighted based on the previous CAIDI weighting without affecting the balance of the scheme.

UED believes that any variation could add to the complexity, volatility, risk and workload associated with administering the S-factor scheme. UED does not support increasing the

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36 Notably many areas of the USA and CENELEC European standard EN50160

37 Page 46.

number, or changing the relativity of formula components without a full analysis of the risk, cost effectiveness and benefit.

4.5 Performance Incentives - Guaranteed Service Levels

The GSL component of the incentive arrangements provides a payment to individual customers where actual performance is below a defined threshold. The purpose of the GSL scheme is to provide additional incentives to the distributor to improve service to specific customers who receive sub-standard levels of service. The scheme provides an incentive to the company to address localised service delivery problems, and provides some compensation to poorly served individual customers, even if UED's overall level of reliability performance meets the benchmarks established in the 2001 Determination. The GSL scheme therefore complements the S-factor scheme.

In Consultation Paper 2 the Commission canvassed a number of issues relating to the operation and make-up of the GSL scheme. In its submission dated 10 May 2004, UED responded in detail to the issues raised by the Commission in Consultation Paper 2 and does not propose to repeat those discussions as part of this submission. UED considers that any change to the principles underlying the GSL scheme would need to be considered in terms of the long term objective of the incentive arrangements as a whole.

4.5.1 Current GSLs

UED currently makes a GSL payment to a customer with an annual consumption of less than 160MWh where GSL thresholds and payment levels are summarised in Table 4.2 below:

Table 4.2: Existing GSLs

GSLs	Payment
The customer experiences an interruption of duration greater than 12 hours	$80
UED is more than 15 minutes late for an appointment	$20
UED does not repair a public light it is responsible for maintaining within 2 business days of being notified by the occupier of the immediately neighbouring residence or business	$10
The customer experiences more than 9 interruptions in a year (urban customer) or 15 interruptions in a year (rural customer)	$80
UED does not supply electricity to a customer's supply address on the day agreed with the customer. Where no date is agreed, the standard connection time is 20 business days. Payments are subject to Electricity Distribution Code clauses 2.3.1 and 2.6.1.	$50 per day $250 cap

4.5.2 Proposed GSLs

While UED considers that performance under the current GSL Scheme has been satisfactory, it proposes a number of changes to threshold and payment levels as well as additional GSLs for the 2006-2010 regulatory period.

The full range of GSLs proposed are listed below:

Table 4.3:Proposed GSLs

GSLs	Payment
Existing GSL – Carried forward to new period	
The customer experiences an interruption of duration greater than 12 hours	$80
UED is more than 15 minutes late for an appointment	$20
UED does not repair a public light it is responsible for maintaining within 2 business days of being notified by the occupier of the immediately neighbouring residence or business	$10
Existing GSL – Changed Obligation	
The customer experiences more than 7 (previously 9) sustained interruptions in a year (urban customer) or 13 (previously 15) sustained interruptions in a year (rural customer)	$80
UED does not supply electricity (normally 20 days) to a customer's supply address on the day agreed with the customer. Where no date is agreed, the standard connection time is 15 (previously 20) business days. Payments are subject to Electricity Distribution Code clauses 2.3.1 and 2.6.1.	$50 per day $250 cap
Proposed new GSL	
If UED has a planned interruption for which 4 days notice is not given	$20

The proposed introduction of the GSLs and amendment of a number of existing GSLs as detailed in the table above, does not impose any additional costs in relation to systems and or processes. The number and amount of payments will increase marginally, and the additional are included as a scope change in Chapter 10.

On page 48 of the Guidance Paper, the Commission proposed that GSL payments should be made available to all customers. UED does not support this position and proposes to continue to limit the payment of GSLs to customers with an annual consumption of less than 160MWh. UED believes that by concentrating its efforts on poor performing feeders and reducing the level of momentary interruptions, the benefit delivered to larger customers through achieving such improvements will outweigh any financial benefit that might be delivered through a GSL payment.

4.6 Undergrounding

4.6.1 Introduction

While there has been a transition to underground reticulation in new urban residential subdivisions in recent years, the majority of electricity networks throughout Australia are of overhead construction. Even where new underground reticulation networks are installed, existing and new high voltage networks feeding such networks are built above ground due to the difficulties of higher installation or retro-fitting costs and a lack of available space for underground systems within and adjacent to road reserves.

4.6.2 Key Drivers for Undergrounding

The key drivers for undergrounding existing and future reticulation assets are perceived to be:

- improvements in public safety;
- enhancement of the visual amenity; and
- improvements in system reliability and performance;

For the purposes of this submission, discussion is limited to voltage levels of 22kV and below, as the costs and technical issues associated with undergrounding sub-transmission assets above 22kV would require separate consideration.

4.6.2.1 Public Safety

Consistent with UED's regulation obligations, its current approach to undergrounding is based on achieving its regulatory obligations and supporting local government and other authorities to achieve improvements to public safety and visual amenity. Customer initiated requests for undergrounding are considered on an individual basis and UED's charges for all undergrounding projects are developed in accordance with Electricity Industry Guideline No 14.

While undergrounding to achieve an enhancement to visual amenity may have a level of community WTP in areas of significance, the level of that support would appear to dissipate as the individual customer's use of, or relative location to such an area falls away. Similarly, as KPMG found in its analysis of customer preferences on behalf of Essential Services Commission of South Australia, (ESCOSA) "*customers expressed a willingness to pay for undergrounding in their streets or suburb, but were less willing to pay for undergrounding in other areas.*"

UED recognises the community's desire for maintenance of, and improvements to reliability and service performance, public safety and visual amenity, albeit that the WTP of the community for maintained or improved levels varies across different community sectors. In addition to its current approach to undergrounding, UED proposes to implement additional programs which, while primarily focussed on public safety, may deliver some marginal reliability, service performance and visual amenity benefit at the same time.

4.6.2.2 Reliability - System Performance

Undergrounding of assets in particular locations may deliver improvements in reliability or system performance due to a reduction in incidents relating to contact with trees, vehicle collisions into poles and storm and tempest damage. As previously discussed, various surveys have suggested that there is a level of customer WTP where such benefits are seen to deliver service improvements.

Any undergrounding program based on service performance would require significant funding. Given the high levels of service reliability and system performance being achieved by Victorian Distributors generally, UED does not believe that the levels of improvement likely to be achieved through undergrounding could be justified solely on the basis of improved reliability of supply. For instance:

- the cost of undergrounding HV assets to improve SAIDI averages around $5 million per 1 customer minute off supply. This cost is an order of magnitude higher than that of existing reliability improvement programs undertaken by UED; and
- indicative analysis suggests that the financial rewards available to UED (under the present S-factor and GSL scheme) as a result of undergrounding HV assets would be around 2% of the total cost. Even valuing the benefits at the customer's marginal value of supply reliability, the cost of undergrounding would be substantially in excess of the reliability benefit.

Undergrounding of assets reduces the number of faults on the network but increases the fault duration. UMS benchmarking studies involving UED, and the federal report on putting cables underground[38] both indicate that underground networks are 3 times more reliable than overhead networks, however CAIDI performance deteriorates by between 50% and 600%. UED's assessment is that a 50% deterioration in CAIDI can be expected.

4.6.2.3 Program - Risk Minimisation at Hazardous Locations

UED proposes to pro actively work with road and other authorities and local government to use undergrounding techniques to minimise the risk to public safety arising from the location of electricity distribution assets in identified hazardous locations. UED proposes to undertake projects up to the value of $2m per annum during the 2006-2010 price review period. UED has consulted with VicRoads during the consultation process and received strong endorsements for the proposed program.

While UED makes no admission of liability, it is proposing a pilot scheme in the 2006-2010 regulatory period to determine whether the undergrounding or relocation of assets in areas of high accident zones has an effect on the road toll. UED is proposing to include $10m over the next five years to undertake this program. VicRoads have estimated a total community cost of approximately $50 million per annum for collisions involving roadside objects.

UED also suggests that arrangements could be put in place to provide assurance to all stakeholders that UED's total revenue would be adjusted to permit the company to recover only the costs of works actually completed under this program. A co-operative working

[38] Bureau of Transport and Communication Economics, Putting Cables Underground, 1997

committee would be established with representatives from VicRoads and UED to administer the funding and ensure that funds are directed to those areas with the highest risk.

4.7 Other Initiatives

Consistent with fostering dynamic efficiency UED is offering to include an annual fund of $5 million for developing initiatives for the improvement of the electricity network reliability and power quality and for service performance improvements. This includes pilot projects for:

4.7.1 Technology Development Fund

UED is proposing to establish a Technology Development Fund with the purpose of providing practical and financial support to groups and institutions to undertake research and development activities which would facilitate improvements in reliability, power quality and service performance. Programs could include component development (eg service breakaway devices), and continuing research into demand management and alternative energy opportunities and undergrounding technology and techniques.

Demand side management: pursue low cost solutions to reduce peak demand for specific customer groups. UED believes this is complementary with the intent of the interval meter program, to reduce peak usage.

Undergrounding: develop innovative undergrounding solutions to support UED's program to minimise the number of distribution poles in road reserves refer Section 4.7.2.

Environmental: the trialing of alternate technologies to reduce the impact on the environment. This may include reducing noise emissions from transformers, minimise leaks in gas switches, reduced energy loss transformers and funding of specific groups for technology research of assets specific to UED.

Power quality improvement: the trialing of new technologies such as early warning systems for pole fire detection, power system harmonics trend monitoring and mitigation, and voltage sag characterisation with the intent of delivering improved power quality.

4.7.2 Program – Minimise Number of Poles in Road Reserves

The Victorian Government has recently enacted the Road Management Act 2004 which established a coordinated management system that would promote safe and efficient road networks at State and local levels and the responsible use of road reserves for other legitimate purposes. As a respondent to, and in support of the intent of the Act to improve public safety, UED proposes to implement a policy to use undergrounding techniques to minimise the number of distribution poles in road reserves.

Under this program, UED would review its works program (new construction, augmentation and replacement) with a view to minimising the number of assets located above ground within the road reserve area. UED would work pro-actively with other authorities to implement this policy as part of its programmed road project activities.

4.7.3 Other Initiatives - Funding

UED supports arrangements that provide assurance to all stakeholders that UED's total revenue would be adjusted to permit the company to recover only the costs of works actually completed under this program. In this regard, UED believes that it should not be subjected to any additional reward or penalty through these initiatives and believes the funds associated with these initiatives should be excluded from the Efficiency Carry-over Mechanism.

4.8 Customer Willingness to Pay

Delivery of a regulated price-service offering challenges both the Commission and the service provider to identify the quality of service required by customers and the price at which the service provider is able and willing to deliver that service at the desired quality. In economic terms, the level of quality of service occurs where the cost of supplying additional service quality is equal to the marginal customer benefit.

In the electricity distribution sector, many of the services delivered such as reliability, connection and fault response are delivered on a regulated basis and to similar standards (allowing for regional differences) across the jurisdiction. Common standards, the relatively high level of service currently delivered relative to industry best practice, and the lack of any real 'competitive market' data make identifying customer preferences difficult without undertaking detailed, targeted research on the customers being considered.

Moreover, the research that has been undertaken suggests that unless the customer has a poor experience of the service, it is likely that in most instances customers will not have considered or formed an opinion as to their service preference. For instance, in a presentation to the KPMG Regulators Conference 2003, KPMG discussed WTP for reliability performance in electricity, and concluded from its research that

> "…there appears to be a large proportion of consumers that are satisfied with their existing level of performance. Mostly these consumers have "good" service and do not value improvements in performance.
>
> Conversely there are some consumers who experience very poor reliability of supply. These consumers do value an improvement in supply."[39]

In Consultation Paper 2[40], the Commission referred to studies within Australia on WTP and while acknowledging the limitations of the studies, the Commission set out a number of conclusions which are summarised below:

- WTP for service reliability varies substantially across customer types, being substantially greater for commercial and industrial customers than for residential;
- the cost or 'negative value' of an interruption to a customer has a fixed component and a variable component;
- consumers value customer service as well as reliability; and
- current incentive payments to distributors for reliability improvements may not match the value of the improvement to different customer classes.

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39 KPMG, February 2003, "Using strategic market research to inform policy decisions"

40 Essential Services Commission, April 2004, "Service Incentive Arrangements – Consultation Paper No. 2", page 38

While accepting that customer WTP may vary substantially across customer types, as argued in our response to Consultation Paper 2[41], UED believes that WTP varies substantially within customer types and that the quantification of the fixed and or variable cost component of an interruption will also vary between and within customer types. A customer's WTP to avoid an interruption will be influenced by:

- The impact of the interruption (momentary or sustained loss of supply) on the operation - loss of product or sales or just deferral;
- The financial significance of the interruption - loss and or additional maintenance or production costs; and
- the timing of the interruption – many customers are generally only marginally affected by interruptions that occur out of hours.

Research[42] undertaken by KPMG on behalf of ESCOSA, considered customers' WTP for improvements to a number of service attributes including reliability and quality of supply, customer service (including the ability to detect interruptions and respond to enquires) and undergrounding. The results of this study demonstrated how WTP for a particular attribute varies by customer type (residential, small business, large business) and by network type (CBD, metro, rural and remote). Similar research[43] undertaken by Accent Marketing and Research on behalf of the Office of Gas and Electricity Markets (Ofgem), also shows significant variations in customer WTP based on customer and network type.

Finally, it is noted that the surveys and estimates of the marginal cost of supply interruptions to customers can provide a proxy for WTP. For instance, VENCorp has commissioned research into customer interruption costs, and the "Value of Customer Reliability".[44] This estimate of the value of supply reliability to customers forms the basis for the economic evaluation of network investment decisions.

Given the current configuration of the UED distribution network, the high cost particularly for UED of delivering marginal performance improvements and the variability in scope, approach and outcomes of current research into customer WTP, UED does not believe there is a sound basis on which to vary the current approach to evaluating reliability improvements or rewarding and or penalising UED's performance.

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41 UED, May 2004, "Submission to Essential Services Commission Service Incentive Arrangements, Consultation Paper 2", page 5.

42 KPMG, Feb 2003, Consumer Preference for Electricity Services, page 12

43 Accent Marketing & research, June 2004, Consumer Expectations of DNOs and WTP for Improvement in Service, page 52

44 Assessment of the Value of Customer Reliability (VCR) Final Report

5 Efficiency Gains Achieved

5.1 Introduction and Overview

The purpose of this chapter is to provide an overview of the expenditure-related efficiency gains achieved by UED during the 2001-2005 regulatory period.

A key feature of the incentive based regulatory regime established by the 2001 Determination is the incorporation of arrangements that encourage distributors to achieve and reveal efficient costs in the course of a regulatory period. UED considers that these incentive arrangements have been effective in encouraging the company to achieve cost reductions over the course of the 2001-2005 regulatory period. This chapter provides examples of the efficiency gains that UED has delivered, and also describes the ways in which customers will benefit, over the course of the forthcoming regulatory period - and beyond – from the innovations and efficiency gains achieved by UED management over the 2001-2005 regulatory period.

Chapter 4 of this submission noted that over the 2001-2005 regulatory period, UED delivered a level of reliability that was substantially better than that required by the performance benchmarks set in the 2001 Determination. (The performance improvements achieved by the company estimated to have delivered net benefits to customers worth approximately $36 million to date.) UED considers that this outcome demonstrates that the cost reductions achieved by the company over the 2001-2005 regulatory period have not come at the expense of service standards. UED therefore considers that the incentive arrangements, along with other regulatory mechanisms have been effective in:

- providing safeguards against degradation of overall (or average) service levels by regulated companies that might otherwise pursue cost reductions at the expense of service quality; and
- providing an effective discipline on the distributors to meet or exceed their target levels of performance.

It is also noted that any detrimental impact on future service performance as a result of actions taken or not taken during the current regulatory period, will be caught by S-factor penalties in the forthcoming regulatory period. This contingent cost is borne by UED's shareholders, rather than customers, and provides a further safeguard that the company is focused appropriately on medium- and long-term service performance.

As noted in detail in Chapter 11 Efficiency Carryover, the expenditure benchmarks established in the 2001 Determination provide a basis for determining the efficiency carryover incentive payment to be incorporated into the company's revenue allowance for the 2006-2010 regulatory period. In comparing the actual level of expenditure to the regulatory benchmarks, it is important to reiterate the following key principles that appeared on page xxi of the 2001 Determination[45]:

[45] Office of the Regulator General, *Electricity Distribution Price Determination 2001-2005, Volume I: Statement of Purpose and Reasons*, September 2000.

> "Importantly, these [expenditure] benchmarks do not represent amounts that the distributors are required to spend, or to direct to particular activities. They are free to determine their own expenditure priorities in the light of emerging market and commercial circumstances and to pursue innovations and efficiencies that enable them to outperform the revenue benchmarks and service targets. The incentive-based price cap approach used in this determination means that the distributors will retain, without any retrospective adjustment, the benefits of any gains made by spending less than the amounts estimated by these benchmarks. In addition, these benchmarks provide a reference point to measure any such gains and to determine the amount that may be retained by the distributors during the 2006-2010 regulatory period as an incentive payment."

The remainder of this chapter:

- explains the cost-savings and efficiency gains achieved by the company over the 2001-2005 regulatory period: and
- describes the ways in which customers will, in the future, benefit from these innovations and efficiency gains.

Accordingly, this chapter is structured as follows:

- Section 5.2 describes the actions taken by UED to achieve improvements in the network power factor, and hence to realise additional capacity from the existing asset base.
- Section 5.3 outlines the benefits achieved by UED through the adoption of probabilistic planning.
- Section 5.4 describes the benefits delivered though UED's implementation of the Distribution Management System (DMS).
- Section 5.5 provides an overview of the initiatives taken by the company to economically defer demand-related capital projects.
- Section 5.6 provides an overview of the initiatives taken by UED to economically defer some asset replacement works.
- Section 5.7 describes how UED has been able to adopt innovative approaches to improving quality of supply at costs well below those typically incurred in the industry.
- Section 5.8 provides an overall summary and concluding comments.

5.2 Improvement in Network Power Factor Achieved

Over the course of the current regulatory period, UED has implemented an extensive program involving the installation of pole-top capacitors in its high voltage overhead distribution system. By the end of 2003, 471 three-phase units of pole-top capacitors, with a total reactive capacity of 397 MVAr, had been commissioned into service. In addition, a total of 330 MVAr of capacitors are in service at zone substations.

UED introduced kVA based tariffs to large, high voltage and low voltage customers in 1998. Many of the customers on kVA tariffs have since installed power factor correction capacitors within their own installations and at their own cost (thus avoiding the need for UED to invest in some power factor correction projects).

The installation of capacitors by UED has significantly improved network power factors. As a result of this, additional capacity has been released in distribution lines, zone substations and sub-transmission lines, enabling the economic deferral of the need for some capacity augmentation work. In the forthcoming regulatory period, the improved power factor is used to convert load growth (MW) into capacity (MVA) requirement. The benefit of improved power factor is therefore passed to customers in the form of reduced capacity augmentation requirement.

A comparison of network power factors used in the establishment of the regulatory benchmarks for 2001-2005, and the power factors achieved to date is shown in Table 5.1 below:

Table 5.1: Power Factor Forecast used to set Expenditure Benchmarks Compared to Actual Power Factor

Year	Power Factor Assumed in Expenditure Benchmarks	Actual Power Factor
2001	0.916	0.93
2002	0.921	0.962
2003	0.922	0.962
2004	0.920	0.965*
2005	0.918	0.965*

* **Note**: 2004 and 2005 figures are estimates.

In many parts of the high voltage distribution system, the power factors at demand peaks are near unity. This demonstrates the effectiveness of UED's initiatives to improve power factor, and indicates that only very limited scope remains for using pole-top capacitors to defer further demand-related augmentation during the forthcoming regulatory period.

5.3 Probabilistic Planning has Produced a Better Economic Outcome

The demand-related capital benchmark estimated by PB Power and adopted as the basis for the regulatory expenditure benchmark reflects the application of a modified deterministic (N-1) planning standard[46]. When this deterministic planning approach is applied to develop capital expenditure forecasts, it is assumed that an augmentation (e.g. the addition of a new zone transformer) is required whenever demand has exceeded the planning threshold.

Such assumptions enable a reasonable indicative estimate to be made of likely future capital expenditure requirements. However, UED undertakes more detailed economic analysis of capital expenditure programs and projects prior to committing expenditure.

[46] Whilst strictly speaking, the criterion applied in the 2001 Determination time was a modified (N-1) standard, it did embody a fixed capacity utilisation threshold as the trigger for augmentation, compared to the threshold applied by UED after its adoption of a probabilistic planning approach. For brevity, the modified (N-1) standard is referred to throughout this submission as simply "(N-1)".

Instead of applying a simple deterministic (N-1) investment criterion, UED evaluates the risks to supply reliability that are associated with different levels of network capacity and capital investment. Under the probabilistic planning approach applied by UED, the total cost of network service to customers (taking into account the expected cost of supply interruptions to customers) may be minimised if, under extreme conditions, the network is planned on the basis of being loaded beyond its (N-1) capability, and the associated risk of non supply during a critical circuit outage at times of peak demand is managed by a combination of:

- appropriate allocation of short-time ratings to network elements to enable momentary overload while load reduction is carried out;
- the utilisation of spare capacity elsewhere in the network, that allows load to be transferred away from the critically loaded station;
- the use of technologies such as DMS for the detection of system overloads and remote control to effect rapid load transfer or reduction; and
- procurement of a mobile transformer, and preparation of highly loaded stations to enable the rapid installation of the mobile transformer in the event of a critical outage.

The application of a probabilistic planning approach, supplemented with detailed contingency planning has facilitated the increased asset utilisation achieved by UED over the 2001-2005 regulatory period. This approach, which is consistent with that applied by VENCorp in its planning of the transmission network has facilitated the economic deferral of demand related augmentation works, whilst enabling UED to maintain a high standard of service to customers. Details of UED's application of probabilistic planning to the augmentation of transmission connection assets and distribution assets have been made available to the public via the annual Transmission Connection Planning Report and Distribution System Planning Report.

As noted in Chapter 7, UED has continued to apply a probabilistic approach in the development of its forecasts of demand-related capital expenditure for the next regulatory period. The use of the probabilistic planning approach, plus other initiatives as outlined in Section 5.2 to 5.5, have resulted in economic deferral of demand related capital projects, and increased asset utilisation. UED's forecast demand expenditure requirement for the forthcoming regulatory period has been determined based on maintaining this high level of asset utilisation, and in this way the economic benefits of deferral has been passed to customers. Refer to Chapter 7 for more details of how the demand-related expenditure is determined for the forthcoming regulatory period.

5.4 Distribution Management System

In 2001, UED commenced the phased implementation of an advanced DMS over its electrical network. The core of the DMS is a remote monitoring and control system which allows real-time monitoring of the loadings at various parts of the distribution network. Detailed loading data are also stored in historical archive (in 5-minute resolution blocks), and are now used to facilitate more effective network planning. The availability of more detailed and accurate network loading data enables the application of less conservative planning margins, and the probabilistic planning approach described above. This, in turn, has facilitated increased asset utilisation, and the economic deferral of some augmentation projects.

The benefits associated with the on-going application of the DMS in network planning and operation have been taken into account in the development of UED's capital benchmarks for the 2006-2010 regulatory period (as set out in Chapter 7 of this submission.) Thus, the benefits of cost-savings associated with the application of the DMS will be transferred to customers over the course of the forthcoming regulatory period.

5.5 Economic Deferral of Demand-Related Capital Projects

UED initiated and implemented a number of measures to economically defer the need for major demand related capital expenditure during the 2001-2005 regulatory period. These included:

- reconstruction of highly loaded 66 kV and 22 kV subtransmission lines to operate at higher temperatures, rather than replacing the under-rated conductors with larger size conductors; and
- installation of 65 inter-zone substation remote-controlled load transfer schemes using remote-controlled gas switches and remote-controlled automatic circuit reclosers. In conjunction with the adoption of short term ratings, the scheme helped to defer a number of major projects while enhancing the reliability of high voltage distribution feeders.

These initiatives have led to an overall reduction in the total life cycle costs of providing reliable network services. Limited scope remains for further deferral of works using such initiatives over the forthcoming regulatory period.

5.6 Economic Deferral of Asset Replacement and Life Extension Programs

Action taken by UED over the course of the 2001-2005 regulatory period has facilitated the extension of the effective economic lives of some asset categories. This action has delivered cost savings in the 2001-2005 regulatory period, and will continue to do so in future periods (through the deferral of asset replacement and renewals expenditure that would otherwise have been programmed to occur). These benefits have been incorporated into the forecasts of replacement and renewals expenditure for the 2006-2010 regulatory period. Thus, the benefits of cost-savings associated with the life extension initiatives pursued by UED in the 2001-2005 regulatory period will be transferred to customers over the course of the forthcoming regulatory period.

5.6.1 Pole Life Extension Program

Pole condemnation rates have consistently fallen since 1997 despite an ageing pole population. UED attribute this improvement, and therefore the expenditure savings achieved in the 2001-2005 regulatory period to better pole inspection techniques as well as the preventive maintenance and chemical treatments introduced in the past few years as detailed below:

- *Preservative Treatment of Distribution Poles*: Poles are on average about 12 metres long but the most vulnerable part of each wood pole is the metre that resides just below and above ground level. Careful treatment of this wood with internal and external wood preservative (depending on the type of wood) is carried out to extend the life of each pole and the assets attached to it.

- *Polesaver Rods*: All wooden poles are treated with Preschem Polesaver rods in conjunction with each inspection cycle. Treatment commences when the pole is 5 years old, with a second treatment at 10 years of age, and then continues at each inspection cycle (with inspection commencing at 15 years of age). Polesaver rods are placed in existing treatment holes and provide a 3 to 5 year protection period against all forms of wood rot, as well as deterring termites from attacking the treated wood.

- *Bioguard Pole Bandages*: Bioguard bandage is a remedial treatment against external rot. It is wrapped onto the external surface of wood poles at and under ground level, at the time of pole inspection, as the earth around the pole must be excavated to a minimum depth of 300 mm. A number of pole species are susceptible to attack by external rot, including CCA Poles.

This work has extended pole lives by an estimated 8 years compared with the lives assumed in the asset replacement expenditure benchmarks established in the 2001 Determination. UED's benchmarks of reliability and quality maintained expenditure for the 2006-2010 regulatory period take into account the positive impacts of UED's pole life extension program on the company's future asset replacement expenditure requirements. In this way, the benefits of the program will be realised by customers – through lower costs - over the forthcoming regulatory period.

5.6.2 Zone Substation Transformer, Tapchanger, Switchgear and Busbar Refurbishment

During the 2001-2005 regulatory period, UED undertook a program of refurbishment of Zone Substation transformers, tapchangers, switchgear and busbars to economically defer large increments of asset replacement expenditure. An overview of the approach undertaken by UED is provided below:

- ***Transformers***: In UED's zone substation transformer population there are 17 units aged over 50 years, and 74 units over 30 years old. Many of these transformers will have to be replaced over the next two decades or so. To minimise the high cost of transformer replacement, a refurbishment management plan has been developed to extend the life of zone substation transformers. The company's goal is to minimise the total present-valued life cycle cost of network service by deferring expenditure whilst still maintain reliability of the distribution system. The refurbishment of transformers postpones the replacement date of the plant, however, at some point it will not be possible to continue to defer replacement and maintain adequate levels of plant reliability.

  UED's present strategy is aimed at cost-effectively maximising the useful life of transformers by drying-out insulation and re-blocking winding assemblies.

  This work has improved the condition of transformers by 5% "good" in the PB Power model compared with the condition assumed in the asset replacement expenditure benchmarks established in the 2001 Determination.

- ***Tapchangers***: A program of refurbishment as recommended by a Reliability Centred Maintenance study was developed for tapchangers during the course of the 2001-2005 regulatory period. This program is aimed at minimising total life cycle costs, and has led to cost savings – through deferral of replacement expenditure – in the 2001-2005 regulatory period.

  This work has improved the condition of tapchangers by 5% “good” in the PB Power model compared with the condition assumed in the asset replacement expenditure benchmarks established in the 2001 Determination.

- ***Circuit Breakers***: Life extension refurbishment programs have been developed to address specific problems that have been identified in the course of the 2001-2005 regulatory period. At present a refurbishment program is being implemented for bushings fitted to 22 kV Email 345GC type outdoor circuit breakers and Siemens 3AF circuit breakers. This program has been in progress for several years, and the company plans to refurbish all bushings of circuit breakers of this type. This program is aimed at minimising total life cycle costs, and has led to cost savings – through deferral of replacement expenditure – in the 2001-2005 regulatory period.

  This work has improved the percentage of good condition circuit breakers by approximately 35 % compared with the levels assumed in the asset replacement expenditure benchmarks established in the 2001 Determination.

- ***Busbars***: A refurbishment program has been put in place to extend the lives of a number of indoor switchboards which are due for replacement based on age. This program involves stripping all the switchboard fixed HV components, drying any wet paper based insulating components and re-insulating with modern insulating materials. This program is aimed at minimising total life cycle costs, and has led to cost savings – through deferral of replacement expenditure – in the 2001-2005 regulatory period.

  This work has extended busbar lives by an estimated 10 years compared with the lives assumed in the asset replacement expenditure benchmarks established in the 2001 Determination.

In the case of these four categories of plant items, UED has achieved substantial reductions in total life cycle costs through its refurbishment initiatives. UED’s forecasts of asset replacement and renewals expenditure for the forthcoming regulatory period take into account the positive impacts of the company’s refurbishment initiatives on the future asset replacement expenditure requirements. In this way, the benefits of these initiatives will be realised by customers – through lower costs - over the forthcoming regulatory period.

5.6.3 Overhead Conductor Replacement Deferral

In 2001, UED engaged a materials scientist to inspect copper conductors in the Mornington area to assess their condition. The report indicated the conductors were in reasonable condition for their age and no major planned replacements were necessary for 5 years. A few specific sections were identified as being in need of replacement, given localised geographic and environmental conditions. A similar assessment of conductor condition is due to be undertaken again in late 2004.

The more detailed assessment of conductor condition has enabled UED to economically defer some conductor replacement capital expenditure in the 2001-2005 regulatory period. Since this review, other areas which have been subjected to secondary damage following faults have been studied and a detailed strategy has been put in place to replace copper conductors on these feeders. However, the extent of replacement capital expenditure required under this detailed strategy is less than that predicted by the PB Power model for the 2001 Determination.

5.7 Network Performance (Quality of Supply) Capital Expenditure

At the time of the 2001 Determination, UED's forecasts of capital expenditure included the costs of works aimed at improving quality of supply. Following consultation with customers, UED determined that short-term voltage dips, caused by network faults, were the power quality issue of highest concern to customers employing sensitive electrical equipment. Consequently, UED's capital expenditure forecasts at the 2001 Determination included a provision for the costs of installing an average of 2 zone substation Neutral Earthing Resistors (NERs) per year. The average cost of each NER installation project is around $500,000.

UED subsequently trialed the installation of NERs and found them to be effective in mitigating voltage dips when the fault nature was single-phase-to-ground. However, in 2002 UED developed an alternative technology which offered better voltage dip performance at a fraction of the NER project cost. The technology is called "Automatic Open Bus-tie Scheme", and it offers voltage dip performance improvement for all types of network faults (not just phase-to-ground type faults) in parts of the distribution network where the fault levels are high, for example, those parts supplied by zone substations with three zone transformers. An additional advantage of this technology is that the average cost of an "Automatic Open Bus-tie Scheme" is less expensive than the alternative NER installation.

During the 2001-2005 regulatory period, some NER projects were completed in accordance with the company's original plans, however some of the planned NER installations have been substituted with "Automatic Open Bus-Tie" projects. The company's development of this innovative approach[47] to improving quality of supply has enabled it to exceed its minimum benchmark level of network performance at a substantially lower cost than that provided in the regulatory capital expenditure benchmark.

It is now also company practice to install NERs at the time of major demand based upgrades such as installation of a third transformer or at the time of construction of a new zone substation.

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[47] UED published a paper on its "automatic open bus-tie scheme" at the *Distribution 2003* conference in Adelaide last year. The project has attracted wide interest from Australian utilities.

5.8 Conclusions

As already noted in this submission, the 2001 Determination established an incentive based regulatory regime in which:

- regardless of the expenditure benchmarks used to establish their price controls, the distributors are free to determine their own expenditure priorities in the light of emerging market and commercial circumstances;
- distributors are encouraged (through the prospect of financial rewards) to pursue innovations and efficiencies that enable them to outperform the expenditure benchmarks and service targets; and
- most importantly, regulated companies are held accountable through a variety of mechanisms (including the S-factor, and Distribution Code provisions) for the outcomes that they deliver, should these fail to accord with minimum required standards and customers' reasonable expectations.

Over the 2001-2005 regulatory period, UED has achieved cost savings whilst substantially improving service standards.

The results achieved by UED - in terms of reduced costs and improved service standards relative to benchmarks - demonstrate that the incentive-based regime established in the 2001 Determination has delivered benefits. The innovations and cost savings achieved in the 2001-2005 regulatory period have been taken into account by UED in the development of its benchmarks of efficient capital and operating expenditure for the forthcoming period, as set out in Chapters 7 and 10 of this submission. Thus, the benefits of cost-savings associated with innovations and efficiency gains achieved by UED during the 2001-2005 regulatory period will be transferred to customers over the forthcoming regulatory period, in accordance with the intent of the incentive based regulatory regime established in the 2001 Determination.

6 Metering

6.1 Introduction and Overview

This chapter presents UED's expenditure benchmarks associated with metering in accordance with the Commission's requirements as set out in its Guidance Paper. This chapter addresses UED's assumptions associated with the mandated program of interval meters, together with UED's requirements for those meters not affected by the interval meter program.

The remainder of this Chapter is structured as follows:

- Section 6.2 summarises the Commission's final decision on the mandatory interval meter Program;
- Section 6.3 discusses issues associated with the interval meter rollout process and the additional risks found by UED;
- Section 6.4 summarises the assumptions underlying UED's approach to the interval metering program;
- Section 6.5 details the assumptions applied by UED for the purpose of establishing benchmark metering installation costs for the forthcoming period;
- Section 6.6 details the assumptions applied by UED for the purpose of establishing benchmark Information Technology and metering data management costs associated with metering for the forthcoming period;
- Section 6.7 summarises UED's "M" factor position; and
- Section 6.8 provides the number of meters forecast to be installed in the 2006-2010 period.

6.2 Commission's Decision on Interval Meter Program

Interval meters provide the opportunity to measure the real time consumption of electricity in predetermined time periods and to use the information obtained to set end-use pricing to mirror wholesale market movements and thus more accurately reflect the real cost of supply. To date interval metering has mainly been used for customers consuming greater than 160 MWh/year and for those customers who have chosen to enter the contestable retail market with a contestable meter provider.

It is anticipated that the availability of interval data at a customer level would enable Distributors to better manage demand on existing assets over time. Future network investment decisions that deliver customer needs in the most cost effective and efficient manner can be based on actual customer behaviour, stemming from revised tariff structures in place due to the availability of interval metering and interval metered data.

To support and improve the competitiveness and efficiency of the electricity market in Victoria, in its Final Decision of July 2004, the Commission has determined that it is necessary to mandate a rollout of interval meters to Victorian customers on the following basis[48]:

Table 6.1: Commission's Final Decision on a Mandatory Interval Meter Rollout

Consumption Band	Metering Installation	Typical Customer	Interval meter rollout Decision		Interval Meter Cost Recovery Approach
			Meter Changeover	New and Replacement	
Business greater than 160 MWh/year (first tier customers only)	All meters (three phase, CT connect; three-phase, direct connected)	Large office, Large Restaurant or Industrial Plant	To be completed by 2008	Mandated from 2006	Regulated excluded service
Business and Residential Less than 160 MWh/year And greater than 20 MWh/year	Three phase, CT connected; three phase, direct connect; two phase	Medium Office, café or Large Residential Customer	To be completed by 2011	Mandated from 2006	Regulated Prescribed service (separate metering charge)
	Single phase, offpeak; time of use	Residential, Shop or small Office, Usually with Electric hot water	To be completed by 2011	Mandated from 2006	Regulated Prescribed service (separate metering charge)
Business and Residential Less than 20 MWh/year	Three phase, CT connected; three phase, direct connect; two phase	Small office Or café or Large Residential Customer	To be completed by 2013	Mandated from 2006	Regulated Prescribed Service (separate Metering charge)
	Single phase, offpeak; time of use	Residential, Shop or small Office, Usually with Electric hot water	To be completed by 2013	Mandated from 2006	Regulated Prescribed Service (separate metering charge)
Business and residential— all consumption	Single phase, non offpeak	Residential, Shop or small office without electric hot water	Meter changeover not required	Mandated from 2008	Regulated prescribed service (separate Metering charge)

The Commission justified its decision:

> "on the basis that the benefits to customers would exceed the costs[49]".

UED has concerns as to the timing of a mandated rollout, the basis on which some benefits have been calculated and the risks to UED as a result of this mandated program. The path for cost recovery of any rollout (including stranded assets) and the need to allow tariffs to be

48 Essential Services Commission, July 2004, 'Mandatory Rollout of Interval Meters for Electricity Customers – Final Decision', page25, Table 2.

49 ibid, page 2

amended to take advantage of the new technology and information available also require careful consideration.

Despite these concerns UED is planning to move forward based on the Commission concluding comment on page 3 of the final Decision that:

> 'This is the Commission's **final** [emphasis added] decision on this matter.'

6.3 Issues Associated with the Interval Meter Roll-out Process

The Commission has mandated a rollout of interval metering with which UED must comply. This creates a significant difference between UED's interval metering operations and UED's other operations. Whereas UED exercises a discretion and has control over the management of its distribution business generally, its control of the provision of metering has been removed by regulatory direction.

The mandatory nature of interval metering is significant and should be borne in mind by the Commission during the review process. Whereas UED manages the risks involved with its normal business operations, UED has no choice but to supply interval meters in accordance with the Commission's timetable. This creates risks beyond UED's control.

Interval metering is a fairly new business, certainly on the scale proposed by the mandatory rollout. The market for the supply of meters on this scale is immature. It is impossible for UED to predict with any certainty all the risks and costs associated with this mandated move to interval meters over the next five years.

For instance, UED has identified several asset stranding risks:

- replacement of existing basic meters before the end of their useful life;
- stranding of the interval (meter or data) technology based on customer/retailer request;
- stranding due to lack of robustness in new technology or the ability of the technology to meet current accuracy requirements over the expected asset life;
- stranding due to changes in the technical metering requirements and accuracy standards, for instance following a review of the Metrology Procedure or as a result of Trade Measurement Victoria imposing stricter accuracy requirements; and
- stranding due to a changed regulatory decision, for example:
  - the new national regulator may review previous regulatory decisions based on more current information or a re-interpretation of the net public benefit;
  - meter contestability may be reconsidered as part of the implementation of a revised Chapter 7 of the NEC and a revised National Metrology Procedure; and
  - the contestability consumption threshold may be lowered over time, resulting in stranded metering assets.

A number of these risks were raised during the interval meter consultation process but, in UED's view, were not adequately addressed in the Commission's Final decision on the mandatory rollout of interval meters.

The Commission did not provide any additional certainty on these issues in the Final Framework and Approach Guidance Paper to this review:

> "The Commission continues to be of the view that the existing accumulation meters should remain in the regulatory asset base and financing costs for these assets should be recovered through DUOS charges………This approach is consistent with the Commissions view that assets should not be stranded, particularly where the investment was undertaken in good faith. Continuing to recover these assets through the regulated asset base, at the same rate as previously recovered, is least distortionary, provides sufficient certainty to the distributors and minimises the impact on customers" (page 134).

Based on these statements by the Commission, UED consider these risks are best dealt with on the same basis as the initial asset stranding and hence UED reiterates its previous position that these costs should be recovered via Distribution Use of System (DUOS).

During the consultation process, the Commission stated that the customer would not be expected to continue to pay for a DUOS based meter in addition to paying for a contestably provided meter, yet the initial meter was provided by UED according to regulatory requirements. Based on this logic it would appear that, if the risks identified above occurred, the distributor who has funded the rollout may have difficulties recovering stranded costs. The scale of this rollout and the extension of contestability in metering services to first tier customers may only serve to compound these risks.

Another issue which contributes to the high level of risk and uncertainty is the Commission's proposed tariff basket control formula for the interval meter rollout, the 'M' factor. This is discussed in more detail in Section 6.7.

While the Commission has proposed this mechanism for quarantining the metering efficiency carryover, it is not clear precisely how the 'M' factor will be applied and whether it will be used to compensate UED for the risks associated with cost uncertainties.

UED is examining the most efficient way to meet its regulatory obligations in the context of the risks and uncertainties noted. For instance, UED is considering the option of leasing, rather than purchasing, interval meters. In this way, UED may be able to manage the considerable interval metering risks more efficiently until it becomes clear how the newly created interval meter market mandated by the Commission will develop. This leasing option is a new strategy which UED has only recently started to consider.

UED is keen to meet the process and timetable set by the Commission for this EDPR as best it can. Therefore, UED has attempted to gather data on interval metering for the purposes of this submission. However, given the considerable risks involved and the prevailing high level of uncertainty, UED has been unable to obtain reliable data on costs. Interval meter suppliers have only provided indicative costs. It is not clear how the actual costs that will prevail during the regulatory period will compare to these indicative costs.

Thus the costs data provided in Table 6.2 and Table 6.3 below is an estimate only and should be treated as such by the Commission. This estimated data has been provided in good faith, in order to assist the Commission with its preparation of the key issues paper that it intends to release in November.

UED looks forward to discussing the interval metering issue with the Commission at the earliest opportunity. As a clearer picture of UED's preferred delivery strategy and likely costs emerges, UED will need to inform the Commission for the purposes of this review process. UED would like to discuss how this can be best managed. If the Commission considers its obligations under the rules of procedural fairness require it to deal with the issue through an open consultation process, UED welcomes such transparency.

6.4 Assumptions Underlying UED's Approach

UED's approach in this submission is predicated on the following conditions:

- there will be no material change to timing and general approach to the rollout process as set out in the July 2004 Commission Final Decision;
- full cost recovery is available, including recovery for any assets stranded as a result of the mandatory rollout decision or later technology stranding or contestability decisions;
- UED will have systems and processes in place which provide the necessary scale and functionality required for the commencement of the rollout process. Systems and processes should be scalable to meet future needs;
- any expenditure incurred in establishing systems and processes or in procuring metering and related assets that become redundant as a result of a change to the 2004 Final Decision will be recoverable; and
- the impact of other programs, such as meter testing and any outcomes from that program, will not impact detrimentally on UED under the 'M' factor proposed as part of the rollout process. The 'M' factor should only apply to the rollout portion and not new and replacement. The 'M' factor should not apply to >160 customers given the involvement of the 1st Tier retailer. The 1st Tier retailer will decide if they use UED or a contestable meter provider to install interval metering, and consequently UED has no control over installation deadlines.

The following 'technical' assumptions apply:

  – benchmarks will be based on installation of metering which allows the customer to retain existing retail and distribution tariffs. For example single phase electric hot water customers will have a 2 element, 2 channel interval meter installed;
  – distributors will be able to offer cost reflective tariffs, within any relevant tariff constraints;
  – distributor costs associated with difficult sites will be smeared across the customer base, however costs involving modification of the customer's installation will remain to that customer's account; and
  – interval meters once installed are intended to be read as interval meters from time of installation.

- UED has maintained its current testing of meter obligations in this submission. UED has not allowed for any increase of expenditure for testing and more significantly a large increase in capital expenditure for more onerous testing obligations.

Table 6.2 below provides a summary of the capital benchmarks with metering and systems that support UED's metering processes.

Table 6.2: Capital Benchmarks – Metering

(Real $m at June 2004)

	Year Ending 31 December				
	2006	2007	2008	2009	2010
Rollout					
>160	0.2	0.2	-	-	-
20-160	0.9	0.9	3.1	3.1	3.1
<20	-	-	15.6	15.6	15.6
Sub Total	**1.1**	**1.1**	**18.7**	**18.7**	**18.7**
Faults	-	-	-	-	-
>160	-	-	-	-	-
20-160	0.1	0.1	0.1	0.1	0.1
<20	0.1	0.1	0.1	0.1	0.2
Family Failures	1.5	6.6	20.6	-	1.8
Sub Total	**1.7**	**6.8**	**20.8**	**0.2**	**2.1**
New Installations					
20-160	2.4	2.4	2.5	2.5	2.5
<20	2.0	2.0	2.4	2.4	2.4
Sub Total	**4.4**	**4.4**	**4.9**	**4.9**	**4.9**
Total Meter Costs	**7.2**	**12.3**	**44.4**	**23.8**	**25.7**
Total Information Technology	**17.8**	**2.0**	**0.8**	**0.8**	**0.8**
Other Equipment	0.5	0.2	0.1	0.1	0.1
TOTAL BENCHMARK	**25.5**	**14.5**	**45.3**	**24.7**	**26.6**

Table 6.3 below provides a summary of the operating and maintenance benchmarks for each year of the forthcoming regulatory period associated with metering.

Table 6.3: Operating & Maintenance Benchmarks - Metering

(Real $m at June 2004)

	Year Ending 31 December				
	2006	**2007**	**2008**	**2009**	**2010**
Standard Metering Maintenance	0.5	0.5	0.4	0.3	0.3
Interval Metering Maintenance	0.1	0.1	0.2	0.4	0.4
Meter Reading – Basic	2.1	2.1	1.8	1.7	1.5
Meter Reading – Interval	0.1	0.1	0.7	0.9	1.3
IT	1.2	3.0	3.1	2.9	3.0
Back Office	4.6	4.2	8.6	6.9	7.5
Total	**8.6**	**10.0**	**14.8**	**13.1**	**14.0**

6.5 Metering Installation

Having considered various metering alternatives and the likely needs of the business and customers, UED's proposed approach to single phase and multiphase new and replacement metering installations is set out below. UED believes that by adopting this approach it is providing the best opportunity for customer choice, that is either maintaining their existing retail and distribution tariffs or moving to a new tariff(s). UED's approach can be summarised as:

6.5.1 Meter Installation

- All single phase electric hot water customers will have a two element, two channel interval meter installed with load control capability.
- Where a single phase customer with electric hot water has recorded zero consumption on the hot water meter for a period of approximately one year they will be excluded from the mandated rollout. These sites will be treated as "single phase, non offpeak" and will be replaced when a failure occurs from 2008.
- Multiphase domestic customers with load control capability (storage heating and or electric hot water) will have multiple interval meters installed on a one for one basis when replacing existing basic meters. Interval meters will have load control capability.
- Multiphase interval meter load control requires a customer contactor. Where such a device does not already exist, UED will provide the initial contactor however ongoing responsibility for maintenance will rest with the customer. This cost will be smeared into the charge for this category of customer.
- All interval meters will include a port to enable remote reading if a communications device is fitted at a later time.

- All basic two phase meters will be replaced by three phase interval meters.
- Installations for above 160 MWh per year customers will only be completed on confirmation from the host retailer.
- Where possible UED's interval meter rollout program will interface with the outputs of meter sample testing undertaken as part of UED's asset and maintenance strategy for metering to ensure a prudent and efficient approach is adopted.

6.5.2 Meter Asset Cost

- New and replacement single phase metering installations will be costed on the basis of a two element, two channel meter with load control capability or single element, single channel with load control capability or single element, single channel with out load control capability based on either the existing installation configuration for replacement or the retail/network tariff requirements for new installations.
- New and replacement multiphase metering installations will be costed on the basis of three phase interval meters with load control capability where the existing installation configuration requires it. The majority of multiphase sites will require a three phase interval meter without load control.
- In some sites, 50 Amp time switches will need to be replaced with contactors when the meter and time switch are replaced. Costs will be smeared into the charge for this category of customer. UED will supply the initial contactor(s) and the customer will be responsible for ongoing maintenance and replacement.
- UED will continue to supply Low Voltage Current Transformers (LVCT) for all sites (1st and 2nd tier). The 2nd tier retailer taking on the Responsible Person role would be responsible for accuracy of the metering installation and UED would supply replacement LVCTs when requested. LVCT meters would only be supplied for >160 customers upon retailer request.
- UED will not supply new or replacement High Voltage Metering Transformers (HVMT). This is the customer's financial responsibility and the Responsible Person should facilitate any new or replacement HVMTs. Most new installations are supplied by the HV customer as part of their HV switchboard design.

6.5.3 Meter Installation Benchmarks

- UED proposes to meet its interval meter rollout and meter replacement responsibilities using external contractors. A specific list of National Meter Identifier (NMI)'s will be provided to the installation contractor to be completed over a specified period. The detailed rollout schedule will be left to contractors to manage while avoiding scheduled reading dates by minus two week and plus one week. Relevant data will be provided to the Retailers to advise of forthcoming meter exchanges.
- Activities considered part of metering installation costs include planning, appointments, site work, complex work (asbestos board removal, wiring changes, price on application problems etc.) and updating of new meter details into systems.

- All benchmarks are based on work carried out in normal business hours. Any after hours appointment costs will be met by individual customers.
- Installation benchmarks do not include data commissioning.
- Given the demand for skilled resources at the time of the rollout process, a premium for labour costs has been included.
- An allowance has also been included to provide information in the customer notice of supply outage to explain the operation of the new interval meter, eg. how to read, explain interval data, boost button, flashing Light Emitting Diode rather than spinning disc.

6.6 Information Technology (IT) and Metering Data Management

6.6.1 Meter Register IT Benchmarks

The rollout of interval meters by 2012 for UED has significant implications for UED IT systems. This requires the current interval metering IT solution to be replaced or upgraded in 2006 or early 2007 as the current systems cannot support this increase in interval meters and the associated increased data. For the purpose of this submission UED has costed a replacement of systems as this is considered to be the least risk, least cost approach.

The current UED architecture was designed mainly for basic meters and is nearing the end of its life. It consists of a highly customised six year old basic meter management, billing and customer care system, MV-90 for receipt and first level validation of interval meter reads, an interval meter data store (IMS), a standing data repository (SDR) and an application to extract the interval meter data and format it for delivery to the electricity market (Extracts Manager). IMS, SDR and Extracts Manager were internally developed to meet Full Retail Contestability requirements and the low volume of interval meters envisaged at that time, these systems are not readily scalable.

Currently UED receives approximately 7600 (UED read data channels from approximately 5,600 interval meters) plus a further 5200 (external MDA data channels from 3,200 interval meters) channels of interval meter data. Significant manual data management occurs to enable UED to manage the storage of that data, the provision of that data to the market and the aggregation of that data for billing. The interval meter rollout requires this architecture to be upgraded or replaced due to scaling issues (the number of channels will rise from 5075 to 595,000 and the current system is only estimated to be able to scale to 20,000).

Three options have been analysed to understand the costs the interval meter rollout will impose on UED:

- Option One - Enhance existing systems;
- Option Two - Outsource MDP functions to a third party; and
- Option Three - Replace existing systems with a vendor interval metering solution.

For the purpose of this submission, UED has chosen Option Three as the least cost technical solution, based on UED's internal analysis of the current billing and meter management systems. The current systems are passed their technical lives and in some cases are no longer supported by the system vendor. UED believes that the systems would require replacement in the next regulatory period even without an interval meter program.

Option three requires UED to appoint a vendor to provide a software solution that involves the replacement of IMS, SDR, Extracts Manager and CISPlus with a integrated vendor software package as well as in-house development for system integration and the implementation of the enterprise version of a meter reading system. Discussions have been held with a number of vendors who are confident of being capable of providing a full solution to UED. This option is considered to be the least risk and least cost as some risk and cost can be passed to the vendor under a fixed price agreement and both vendors have recently successfully implemented their products around the world including Australia.

6.6.2 Meter Reading Costs

- UED's approach to meter reading costs is predicated on the assumption that interval data will be collected from the time the meter is installed. To do otherwise will cause complications and errors in the programming of the meter's local display to represent existing retail and distribution tariffs. UED will program the display for total consumption.
- Additional costs for meter reading will be incurred due to the longer time taken to read meters and upload data and the need to re-sequence reading routes.
- Handheld reading equipment and associated probes will need to be upgraded and or replaced.

6.6.3 Back Office Systems

The implementation of an interval meter rollout will impact significantly on the back office processes associated with service, data and revenue billing management.

6.6.3.1 Service Management

Increased interaction with, and impacts on, service performance and consequently costs can be expected due to:

- the higher volume of service orders required to upload meter details into CISPlus systems;
- an increase in validation and data commissioning requirements in order to ensure correct billing between retailers and distributors;
- increased error correction of data uploads and downloads associated with meter exchanges and new connections, particularly in the initial stages, given the greater volumes of data involved and the need to train additional staff in new systems and procedures; and
- additional enquiries, and possible Energy and Water Ombudsman (Victoria) (EWOV) involvement, as customers deal with new meters, bill formats, etc, and seek to enhance their understanding of the changes.

6.6.3.2 Data Management

Increased costs can be expected in the management of meter reading data due to:

- the increased complexity in validation processes for interval as compared to basic meter reading data. This is more resource intensive and will only be able to be curbed once more automated systems can be implemented;
- in addition to the higher initial meter cost, reading costs will also increase as more time will be required at each meter location, particularly where 180 or 200 days of data is to be downloaded;
- changed processing practices such as the management of second read estimates;
- increased data volumes will stress all interfaces, batch processes, etc.

6.6.3.3 Revenue Billing Management

Revenue billing management is anticipated to be more resource intensive and time consuming and therefore more costly due to:

- the increased complexity of billing and rebilling processes and the likelihood of more complex enquiries relating to bills;
- UED architecture requires the CISPlus system to interface with an interval meter data storage system which increases processing times for cancel and rebilling of interval data as opposed to basic data.

6.7 'M' Factor

The Commission is proposing a tariff basket control formula specifically for the interval meter rollout called the 'M' factor. The commission envisages that this 'M' factor will;

- provide no rewards for interval meters rolled out faster than forecast but would provide a reduction in the allowed revenue based on activity that did not occur, and
- is aimed at rewarding or penalising the distributors for unit cost efficiencies or inefficiencies.

The Commission expects that this adjustment would apply if the cumulative forecast quantity of meters is less than the cumulative actual quantity and would consist of the financing costs (return on and return of capital) of the meters not rolled out. In view of the significance of the meter failure volumes indicated in Table 6.4 this style of approach almost encourages the early replacement of meter families due for testing.

The 'M' factor needs to be considered in light of these uncertainties and asset stranding covered in Section 6.3. Moreover, it will be important for the Commission to ensure that the operation and effect of the 'M' factor is consistent with the incentive properties of the regulatory regime. UED will consider the 'M' factor further with a view to balancing the risks and uncertainties versus the costs of the intrusive regulatory measures being proposed.

6.8 Meter Volumes

UED's approach has been to average the mandated rollout volumes over the number of years envisaged by the Commission in earlier decisions with a view to meeting obligations by the end dates. Where possible meter families which may fail testing are incorporated into the mandated rollout numbers and the failed family volumes depicted below are incremental meter volumes within the rolled out program. UED remains concerned with capability to meet the spike in 2008 and is continuing to review options to smooth this out.

Table 6.4 below details UED's metering requirements for the 2006-2010 period.

Table 6.4: Meter Installations

	No of Units				
Category	**2006**	**2007**	**2008**	**2009**	**2010**
Rollout					
>160	283	283	-	-	-
20-160	1,265	1,263	5,077	5,077	5,077
<20	-	-	32,428	32,428	32,428
Sub Total	**1,548**	**1,546**	**37,505**	**37,505**	**37,505**
Faults					
20-60	129	218	217	217	237
<20	257	333	333	333	513
Subtotal	**386**	**551**	**551**	**551**	**750**
Family Failures	2,286	10,421	84,083	-	7,160
Sub Total	**2,672**	**10,972**	**84,634**	**551**	**7,910**
New Installations					
20 – 160	2,869	2,869	2,869	2,869	2,869
<20	5,566	5,566	5,566	5,566	5,566
Sub Total	**8,435**	**8,435**	**8,435**	**8,435**	**8,435**
TOTAL METERS	**12,655**	**20,953**	**130,574**	**46,491**	**53,850**

6.9 Conclusion

The Commission's decision to implement an interval metering strategy presents particular risks and uncertainties for UED that are beyond UED's control. In particular, it is impossible for UED to predict with any certainty all the costs associated with this mandated move to interval meters over the next five years. While the Commission has proposed a mechanism for quarantining the metering efficiency carryover, it is not clear precisely how the 'M' factor will be applied and whether it will be used to compensate distributors for the risks associated with such cost uncertainties.

Given this high level of uncertainty, UED has been unable to obtain reliable data on costs, and has presented estimates in this submission. UED considers the Commission's consultation process to date in relation to the mandated interval metering rollout has not allowed a complete examination of the commercial issues associated with the rollout. As a consequence UED is not able at this stage to fully present its case in relation to expenditure benchmarks for interval metering. UED looks forward to progressing these issues with the Commission, in an open process if the Commission believes procedural fairness requires it, at the earliest opportunity.

7 Capital Expenditure Benchmarks

7.1 Introduction and Overview

Capital Expenditure includes expenditure on works associated with the construction of new assets, the replacement of network assets and the reinforcement of assets for increased capacity, together with a range of corporate and non-network expenditures. UED's capital expenditure program has been developed to meet the needs of customers and the business in delivering its regulatory obligation and the network service standards detailed in Chapter 4.

The Commission's Guidance Paper comments that, in relation to capital expenditure forecasts, the key issues for the Commission are to ensure that the forecasts provide only for the distributors' regulated distribution activities, reflect an unbiased forecast of the expenditure that would be undertaken by an efficient distributor over the period, and are consistent with the distributors' demand forecasts, service targets and other obligations.

The Commission states that its approach in assessing forecasts of capital expenditure is to use historic expenditure and trends in the different capital expenditure components as a starting point. In this regard, UED notes that:

- It would be an error for the Commission to expect that capital expenditure in the future period would match history;
- however, the Commission expects that variations in the forecasts from historical trends should be able to be explained with reference to various cost drivers; and
- the Commission also considers that it is appropriate to place the onus on distributors to justify to the Commission and the distributors' customers the benefits of any variation from past expenditure patterns.

This chapter presents UED's capital expenditure benchmarks in accordance with the Commission's requirements as set out in the Guidance Paper. In particular, UED has used capital expenditure models developed by PB Power (which apply cost drivers to estimate network capital expenditures) as a basis for validating and substantiating its benchmarks.

These models are based on historical and forecast information, thereby providing the explanatory link between actual and benchmark capital expenditure that the Commission wants to explore. The models can be calibrated with input assumptions that reflect the actual network cost drivers that existed over the 2001-2005 regulatory period[50] and can produce a revised benchmark of capital expenditure for the period that is consistent with the company's actual level of expenditure. This provides substantiation of the models' capability to both explain past investment patterns, and to predict future investment requirements.

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[50] The relevant drivers include factors such as remaining asset lives (adjusted for the asset life extension initiatives implemented by the company over the 2001-2005 period), actual load growth, actual network utilisation and the higher utilisation threshold for reinforcement investment which is implied by the application of probabilistic network planning.

It is also noted that in calibrating the models to produce benchmarks of future expenditure requirements, UED has incorporated the positive impacts of the innovations and efficiency gains it achieved in the 2001–2005 regulatory period. Thus, the company's benchmarks of future capital expenditure incorporate the efficiency improvements that have been achieved in the current regulatory period (as described in Chapter 5).

Table 7.1 below provides a summary of the capital expenditure forecasts for each year of the forthcoming regulatory period. The column headed "reference" lists the section of this chapter that provides an examination of historical trends in the various components of capital expenditure, and a more detailed substantiation of the capital expenditure benchmarks proposed for the forthcoming regulatory period.

Table 7.1: Benchmark Capital Expenditure by Category

(Real $m at June 2004)

Reference		YEAR ENDING 31 DECEMBER				
		2006	2007	2008	2009	2010
S7.4	Reinforcements Demand	24.7	23.9	23.3	21.1	22.7
S7.5	Customer Initiated Capital	26.0	25.2	23.6	22.7	24.3
S7.7	Reliability & Quality Maintained	43.1	42.1	42.1	49.4	62.6
S7.8	Reliability & Quality Improvements	2.5	2.3	2.3	2.3	2.3
S7.9	Environmental, Safety & Legal	15.2	16.8	16.6	23.3	22.6
S7.10	Non-Network General Assets – IT	10.9	9.8	9.5	11.6	8.3
S7.11	Non-Network General Assets – Other	2.8	2.8	2.8	2.8	2.8
	Gross Total	**125.2**	**122.8**	**120.2**	**133.2**	**145.6**
S7.6	Customer Contributions	5.2	5.0	4.7	4.5	4.9
	Net Capital	**120.0**	**117.8**	**115.5**	**128.7**	**140.7**

The remainder of this chapter is structured as follows:

Section 7.2 provides a brief overview of UED's asset management strategy;

Section 7.3 describes the PB Power models, their cost drivers and their outputs; and

Sections 7.4 to 7.11 substantiates UED's capital expenditure benchmarks for the forthcoming regulatory period.

7.2 UED's Asset Management Strategy

7.2.1 Introduction

UED recognises the importance of sound asset management in ensuring the efficient delivery of services that meet customers' needs. Systems planning, maintenance, improvement and asset replacement are vital components of asset management, with effective asset management having a profound impact on customer service and shareholder value.

One of the main purposes of asset management planning is to ensure an optimal balancing of capital and recurrent expenditure, so that maintenance, replacement and augmentation of the electricity distribution network delivers the required level of services at the lowest possible life cycle cost. Electricity distribution is a capital intensive industry, which requires the application of rigorous and efficient capital budgeting and asset management processes to deliver these services.

The company's approach to capital budgeting and asset management recognises the need to:

- Ensure efficient asset management and investment decisions are robust through:
  - producing asset management strategies, plans and budgets consistent with stakeholder requirements;
  - ensuring management review and monitoring of asset management process Key Performance Indicators;
  - reviewing and maintaining key processes; and
  - continual review of asset management strategies and programs, based on the analysis of asset data.
- Ensure efficient works programming so that appropriate resources are allocated efficiently and any resource conflicts are resolved; and
- Ensure efficient works execution through:
  - efficient construction, maintenance and operation of network assets in accordance with the asset strategies, asset management plan and budget;
  - effective management of programs (inspections, vegetation management, etc); and
  - effective capturing, management and diagnosis of asset condition and performance data.

Through its asset management approach, UED seeks to:

- maintain a comprehensive understanding of its assets and its business;
- communicate and justify capital and operating expenditure requirements for internal management purposes;
- ensure the achievement of regulatory and legal compliance;

- achieve best practice performance in costs;
- optimise the life cycle costs of the network assets;
- replace network assets after considering risk and risk mitigation options, and ensure replacement expenditure is not deferred inefficiently;
- manage the network within its ratings and develop the network to meet projected load growth at the lowest life cycle cost, having regard to scale economies;
- undertake investment evaluation and capital budgeting such that the capital expenditure undertaken reflects the customers' value of reliability;
- ensure that network performance is monitored, and capital and maintenance provisions for performance improvements are well targeted and reflect the customers' value of reliability; and
- identify, rank and manage risks.

The remainder of this Section provides further background information on UED's asset management and investment decision processes.

7.2.2 Approach to Efficient Asset Management and Investment Decisions

The key principles of UED's asset management and investment decision making processes revolve around three key factors, as follows:

Customer requirements:	Analysis and understanding of stakeholder requirements is essential. Performance improvement and asset maintenance and replacement programs are driven by analysis of fault/performance/cost data.
Technical requirements:	Capacity planning is based on probabilistic analysis and contingency planning. Scheduled maintenance and replacement programs are based on Reliability Centred Maintenance analysis. Risk analysis is performed to Australian Standard 4360 for significant asset risks.
Economic requirements:	All projects are subject to an appropriate level of economic analysis in accordance with regulatory requirements.

UED employs several integrated business systems to manage the activities on the Network. These range from SAP based works management and costing systems to business cycle preparation of plans and budgets and Automated Mapping/Facility Management (AMFM) based asset information systems.

Future Demand planning considers reliability of supply within a four-way framework of line and component ratings, probabilistic assessment of loss of supply, customer oriented valuation of security of supply and contingency planning. UED has adopted a probabilistic approach to planning which tolerates a small risk of loss of supply in circumstances involving outage of plant items at infrequent times of high network loading. The probabilistic approach balances the costs of investment against the marginal value of network reliability from the customers' perspective. This in turn facilitates the delivery of services to customers at the lowest overall costs and enables efficient and objective allocation of expenditure across the network.

Life Cycle Management planning ensures the balanced, efficient and effective maintenance and replacement of the network assets. It focuses on ensuring effectiveness and efficiency in maintenance and replacement based on Reliability Centred Maintenance analysis, which is tested against internal and external benchmarks and considers issues of safety, cost, risk and reliability.

Levels of service are based on current and forecast reliability and power quality performance and the assessment of targeted and cost effective plans to improve reliability performance.

The improvement of asset management practices by UED is achieved through a commitment to conducting internal and external audits, and comprehensive gap analysis of all facets of asset management activity. Performance indicators are reviewed monthly by all senior management and all significant gaps between actual performance and target performance are analysed objectively so that alternative strategies and improvement plans can be identified. Internal and external benchmarking is used in establishing performance targets.

7.2.3 Approach to Efficient Works Programming

An efficient works program balances resourcing constraints with the needs of the network and customers over a cycle of one to two years. The works program for business case production, project planning, tendering and field construction is based on prioritised budgets. Works on SPI Powernet, subtransmission and distribution assets, capital projects, maintenance and seasonalised works program are aligned with internal budgets and a resource levelling model.

Projects and programs are targeted for completion to deliver the best outcomes for the business and its customers. Drivers for works programming include the timely construction of performance improvement projects to achieve maximum customer value for the initiatives. Asset replacement projects are performed as programmed replacements before failure and demand projects are completed to ensure that sufficient network capacity is in place to meet forecast loads immediately prior to the critical summer loading period.

Therefore, UED's construction works program is focussed on pro-active asset replacement and performance projects in the first half of the year and demand and bushfire mitigation projects in the second half. Major zone substation projects require an 18 month lead-time and therefore are initiated by May of the preceding year.

7.2.4 Efficient Works Execution

Having established efficient investment and asset management plans, the company must execute these plans in the most cost-effective manner to maximise overall value.

The key elements to the efficient procurement and creation of assets include:

- competitive tendering for capital work activities;
- use of approved materials schedules to deliver streamlined purchasing practices; and
- use of larger longer-term contracts for works involving ongoing programs of a repetitive nature such as pole or cross-arm replacement to capture economies of scale where appropriate.

7.2.4.1 Projects to Tender

One of the main drivers of works programming is to package up projects to enable the opportunity to obtain benefits by tendering significant sized projects to be achieved.

Projects that are suitable to be tendered as turn-key projects are identified at conception stage. A detailed scope of works is prepared as the basis for public tender documents. For these projects, the development of business cases is done in parallel with the tendering process so that the prices tendered for the work are used in the final business cases.

7.2.4.2 Approved Materials Schedules

UED has developed and maintains schedules of materials approved for installation on the network with which all contractors must comply as part of its Health, Safety and Environment systems. This ensures that the integrity of the network assets is maintained and that purchasing and stockholding procedures are streamlined.

7.2.4.3 Longer-Term Prime Contracts

UED delivers much of its maintenance and asset inspection driven asset replacement through longer term, competitively tendered contracts. These contracts involve large quantities of relatively simple and repetitive packages of work such as pole and cross-arm replacement, distribution substation upgrades and minor zone substation works.

7.2.5 Forecasting Inputs

UED asset management investment and decision making is based on acquiring and utilising the appropriate level of data and knowledge of the assets and supported by a system of integrated information systems. Decisions are based on a combination of this internally collected data as well as externally provided information.

Demand related assessments are underpinned by new connection and maximum demand forecasts supported by an independent assessment of demand growth by the National Institute of Economic and Industry Research (NIEIR) undertaken in 2004.

Real-time monitoring of the loadings at various parts of the distribution network as well as detailed loading data stored in historical archive (in 5-minute resolution blocks), is available through the DMS. This information is used to assess maximum demand, asset utilisation and power factor values more accurately and this facilitates the determination of risk of non supply which is essential for the probabilistic network planning approach adopted by UED. Thermal rating information is held in the AMFM system which interfaces with the DMS system.

Distribution substation loading and utilisation information is based on the company's Transformer Load Management (TLM) system which links asset information on transformers with customer billing data and connectivity data.

For **non-load related** assessments, the primary source of asset data is the AMFM system and SAP asset management system. These systems contain asset information on age, asset class, voltage, type and quantity.

A plant failure database has been developed on the Intranet for the purpose of recording and analysing component failures. UED's asset condition assessment is based on this database as well as failure rate information extracted from the DMS system and the SAP asset management system.

Asset replacement costs are based on recent contract rates for similar works and reflect the cost of replacing an asset on a modern equivalent basis.

Asset lives are based on an external review undertaken in 2000 by Arthur Andersen adjusted to reflect asset life extension initiatives undertaken by the company over the 2001-2005 regulatory period.

7.3 PB Power's Capital Expenditure Models

UED commissioned PB Power to model the company's historic and future capital expenditure requirements. The models examine demand related and non-demand related capital expenditure. As noted in Section 7.1 the PB Power models are useful tools for addressing the Commission's proposed approach for establishing capital expenditure benchmarks for the forthcoming regulatory period.

For demand-related capital expenditure, the model uses spreadsheet-based techniques in order to study the technical integrity of the UED network and to estimate the capital benchmarks required to augment the network in order to cater for future load growth, whilst maintaining a benchmark level of asset capacity utilisation across the network. A 10-year period ranging from 2004-2013 has been covered in this study. The demand-related capital expenditure has been divided into two main categories, one for load growth due to existing customers, and the other for new customer load growth called Customer Initiated Capital (CIC). Major exclusions in PB Power's assessment of CIC are the costs of the customer service connection and the meter, and the costs for major and minor road public lighting.

The demand inputs to the model are based on the independent forecasts provided to UED by NIEIR. An overview of NIEIR's forecasts for energy, demand and new customer growth is provided in Chapter 14 of this submission.

For non-demand related capital expenditure, the PB Power model utilises the following network-specific information:

- a listing of UED's network asset classes, broken down by voltage and asset type;
- replacement profiles for each asset class along with remaining asset life curves; and
- UED's asset condition assessment so that asset age profiles can be adjusted to reflect their actual condition.

The asset condition assessment provides an opinion as to whether the assets will actually remain in service for a longer or shorter period than the asset life assigned. Assessment of “Good” or “Poor” is given to indicate a longer or shorter than average life.

The model also recognises that age and condition-based replacement does little to prevent all assets in a given class ageing together, in line with the original investment profile. Therefore, a purely age or condition-based replacement strategy could lead to reliability issues if large populations of network assets reach the end of their expected lives at the same time. The PB Power model therefore utilises information on the average remaining life of each individual class of assets to address this issue.

The Weighted Average Remaining Life (WARL) gives an indication of the overall age of the assets in the system. The remaining life is expressed as a percentage of the assigned asset life, and these are weighted according to the value (based on the replacement costs) of each asset. The PB Power model calculates the asset replacement forecast using asset lives and condition assessment figures.

The results from the PB Power models are detailed against each of the capital expenditure categories (where applicable) described in Sections 7.4 to 7.11 below.

7.4 Reinforcements Demand

7.4.1 Overview

Reinforcement demand expenditure represents native growth capital expenditure required to meet growth in demand by existing customers on the network and consists of the following main categories:

- Subtransmission lines;
- Zone substations;
- HV distribution feeders;
- Distribution substation upgrades; and
- LV feeder augmentation.

Table 7.2 shows the actual Reinforcements Demand capital expenditure for the 2001-2005 regulatory period and the benchmark Reinforcements Demand capital expenditure for the forthcoming period.

Table 7.2: Benchmark Capital Expenditure, Reinforcements Demand (Real $m June 2004)

		YEAR ENDING 31 DECEMBER				
	*01-05 Actual /Forecast	2006	2007	2008	2009	2010
Benchmark	16.2	24.7	23.9	23.3	21.1	22.7

* 01-05 Actual is average annual spend.

7.4.2 Methodology

As already noted, UED has adopted a probabilistic approach to planning which tolerates a small risk of loss of supply in circumstances involving outage of plant items at infrequent times of high network loading. This approach contrasts with one which aims to ensure that forecast network loadings can be sustained even with one circuit element out of service (so-called "N-1" planning).

A probabilistic approach enables the incremental costs of investment to be balanced against the incremental benefits (in the form of maintained supply reliability), to identify those investments that maximise net value to customers. Implicit in the use of probabilistic planning is the acceptance of a certain degree of risk, however, when this approach is supplemented with thorough contingency planning (as is the case with UED), it provides the best economic outcome for customers.

The application of a probabilistic planning approach has been one of the main factors driving the increased utilisation of network assets in the current regulatory period and has facilitated the economic deferral of some augmentation projects. In addition, other initiatives such as network power factor improvement, installation of DMS, reconstruction of over head lines to operate at higher temperature, and inter-zone substation load transfer schemes have all contributed to increased asset utilisation. UED will pass on the benefits of the probabilistic planning approach to customers by basing the PB Power, model's forecast of demand-related expenditure on the assumption that the high asset utilisation already achieved will be maintained over the course of the 2006-2010 period.

The application of this approach to network planning and investment decision making delivers benefits in two forms:

- firstly, the approach leads to an increase in the capacity utilisation of existing assets. This, in turn creates a once-off benefit, derived through the deferral of capital expenditure that was otherwise expected to have been required under the application of an (N-1) investment criterion[51]; and

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51 Such a criterion was applied to develop the forecasts of demand related capital for the 2001 Determination. Whilst strictly speaking, the criterion applied at that time was a modified (N-1) standard, it did embody a fixed capacity utilisation threshold as the trigger for augmentation. For brevity, the modified (N-1) standard is referred to throughout this submission as simply "(N-1)".

- secondly, the approach, if consistently applied through time, leads to on-going savings in capital expenditure requirements, relative to the expenditure that would have been required had an (N-1) investment criterion continued to have been applied. This benefit is derived through the maintenance of a higher level of capacity utilisation over time, compared to the (lower) level that would have prevailed under an (N-1) investment criterion. Under the approach adopted by UED in developing its demand-related capital expenditure benchmarks for the forthcoming regulatory period, all of these future benefits will accrue to customers. In other words, UED will pass on the benefits of the probabilistic planning approach to customers by assuming the maintenance of the high asset utilisation already achieved, when using the PB Power demand-related expenditure model to produce expenditure benchmarks for the 2006-2010 period.

These savings in demand related capital expenditure are illustrated in Figure 7.1 below.

Figure 7.1: Demand Capital Efficiencies

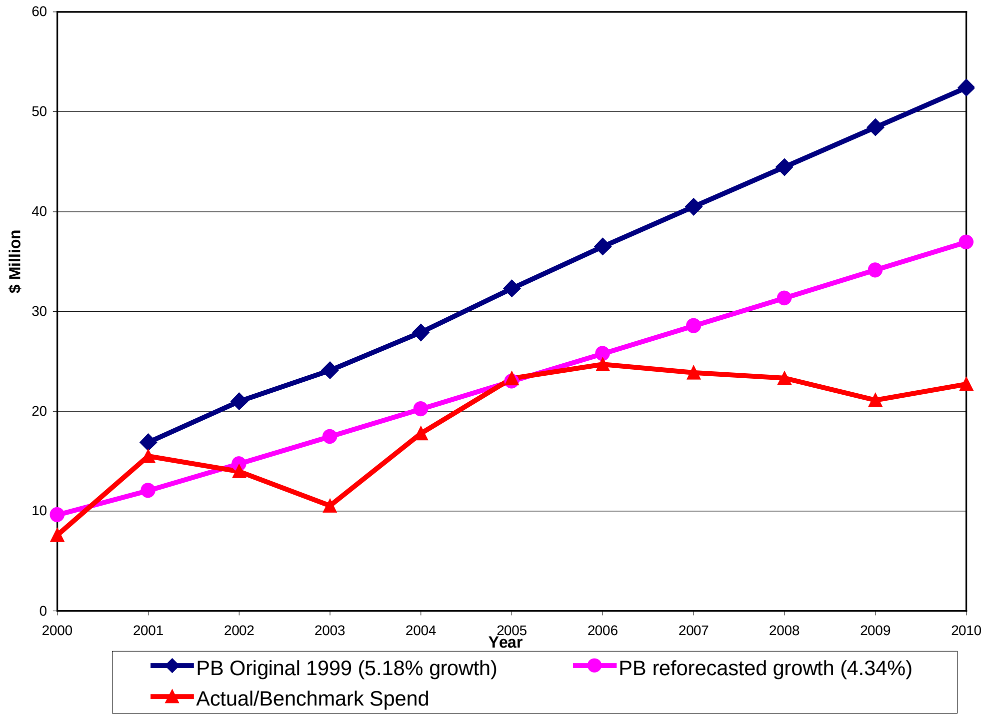


Figure 7.1 shows the level of expenditure predicted by the PB Power model over the ten years from 2000, compared to UED's actual demand-related capital expenditure for the 2001-2005 regulatory period, and its proposed benchmark expenditure for the 2006-2010 period. The line marked "PB Original 1999 (5.15% growth)" depicts the 10 year demand related expenditure forecast made by the model during the 2001 EDPR. The line labelled "PB re-forecasted growth (4.34%)" shows a revised ten year forecast of demand related expenditure from 2000, using input assumptions that reflect actual demand growth over the 2001-2005 regulatory period, and the lower (N-1) capacity utilisation investment trigger. The line labelled "Actual/Benchmark Spend" shows UED's actual expenditure for the 2001-2005 regulatory period and its proposed expenditure benchmark for the coming period.

Figure 7.1 clearly demonstrates the efficiency gains achieved by UED in the area of demand-related capital expenditure.

As discussed in Chapter 5, UED has employed various initiatives in order to achieve a more efficient use of the networks existing capacity, and these initiatives in turn have enabled the deferral of capital expenditure. UED has now achieved amongst the highest network utilisation rates in Australia. A survey by ESAA showed that in 2001 and or 2002, UED's subtransmission and distribution utilisation factors were 17% and 12% higher than the Australian average respectively.

UED now considers that there is very limited scope for achieving further improvements in capacity utilisation without compromising supply reliability. Indeed, given the uncertainty of demand forecasts and the level of capacity utilisation achieved, any further increase in asset utilisation at subtransmission, zone substation and HV feeder levels over the next regulatory period would not be consistent with good asset management practice. In accordance with the intent of the Commission's incentive mechanism, UED has maximised the economic deferral of capital expenditure, and cannot extend this deferral further without compromising reliability. As already noted, UED intends to maintain over the next regulatory period the high level of capacity utilisation already achieved, and in this way, pass on the benefits of increased asset utilisation to customers in the form of lower demand related expenditure, than would be the case were the asset utilisation to be reduced to levels consistent with the 1999 model prediction.

In determining the optimum level of capital expenditure for demand related projects, two approaches were used:

1. "Top-Down" approach using PB Power demand model: This approach attempts to assess the capital expenditure using the projected maximum demand for the overall UED's network and maintain utilisations for various segments (subtransmission, zone substations, HV feeders, etc) at the current high levels. The optimum capital expenditure is assessed by performing a sensitivity analysis as follows.

    – Strict Scenario: This scenario represents the theoretical bare minimum capital expenditure. It reflects the cost of augmenting the network so that the existing levels of load above the planning thresholds are maintained. Additional capacity is only added to match the projected new loads. This scenario is not achievable in practice because the effects of scale economies result in augmentation taking place in "lumpy" increments. In practice, this results in a step increase in capacity, relative to the incremental rate of load growth.

    – *Base Scenario*: (Status quo) This scenario reflects the cost of augmenting the network so that the network utilisation is maintained at present high levels. It takes into account the effects of scale economies and minimum efficient sizes of capacity increments.

    – *Conservative Scenario*: This scenario reflects the cost of augmenting the network so that the network risks are reduced by increasing the capital expenditure for the highly utilised subtransmission, zone substation and feeders and in this way reduce the asset utilisation. This scenario represents a more conservative approach to network planning and is provided as a comparison with the Base Case for demonstrating the economic benefits of continuing with the probabilistic planning approach.

2. "Bottom-Up" in-house approach: Using the projected maximum demand for individual plant items and their utilisation (rather than an average value), this approach attempts to predict the most likely technically acceptable solutions and costs for major projects at subtransmission, zone substation and HV feeder levels. Forecasts of capital expenditure at HV/LV distribution substation level and LV network were assessed using historical expenditure but also taking into consideration present network utilisation and projected growth in customer demand.

As explained in detail below, UED applied the PB Power model Base Scenario to develop its capital expenditure benchmarks for the 2006-2010 regulatory period and verified these benchmarks using internal forecasting.]

7.4.3 Trend Analysis

Table 7.3 below summarises the capital expenditure forecasts obtained using the above approaches. As shown, UED's internal assessment of capital expenditure compares favourably with the PB Power model's forecasts derived using the Base Scenario. The $38 million difference between the expenditure forecasts obtained using the Base Scenario and the Conservative Scenario shown in Table 7.3 also confirms that there is a substantial reduction in projected capital expenditure requirements over the forthcoming period as a result of UED's proposal to maintain high levels of asset utilisation.

Compared with the current period's actual level of expenditure, a significant increase in reinforcement expenditure over the 2006-2010 regulatory period is projected. As already noted, this increase reflects the impacts of:

- lower than expected demand in the 2001-2005 regulatory period (which had the effect of deferring the need for some capacity augmentation);
- the effects of projected demand growth for the 2006-2010 regulatory period; and
- the need to invest in order to maintain a high but prudent and efficient level of capacity utilisation over the period, whilst ensuring that the network remains capable of providing a high level of reliability consistent with the needs and preferences of customers.

Table 7.3: Projected Capital Expenditure at Subtransmission, Zone Substation and HV Feeder Level over the Regulatory Period 2006-2010

(Real $m June 2004)

Scenario	Total* $m
Top-Down (PB Power)	
- Strict	65.6
- Base	114.3
- Conservative	152.0
Bottom-Up	
- UED Internal	115.0

As already noted it is expected that the present level of asset utilisation will be maintained over the 2006-2010 regulatory period, and that customers' expectations regarding supply reliability will be met. The increase in reinforcement expenditure for 2006-2010, compared with current period, is simply a reflection of the fact that significant expenditure is now required, given that the assets are relatively highly utilised, and few low cost deferment options now remain available.

Included also in the expenditure forecast is the cost of constructing an emergency 66 kV tie between Malvern (MTS) and Springvale (SVTS) terminal stations in 2008 ($1.2 million). The tie is required because both MTS and SVTS are radially supplied from Rowville (ROTS) terminal station at 220 kV and VENCorp's latest Annual Planning Review indicates it has no plans to address the supply security issue in the shared transmission network to MTS and SVTS over the next ten years. In the event of a prolonged outage of either 220 kV radial lines, the 66 kV tie will help in restoring customer supply until the affected 220 kV line is brought back in service.

7.5 Customer Initiated Capital

7.5.1 Overview

Capital expenditure required to meet the needs of new customers and customer initiated works is called Customer Initiated Capital (CIC).

UED further divides this CIC capital expenditure into the following categories:

- Large Businesses - new customers requiring a 3-phase supply of more than 10 kVA.
- Dual and Multiple Occupancy - new single-phase domestic customers in dual and or multiple occupancy developments.

- Medium Density Housing - new single-phase domestic customers in URD subdivisions.
- Low Density Housing / Small Businesses - new single-phase rural residential developments and small commercial and or residential developments in low-density areas.
- New Meters, Time Switches and Services - Installation of new single-phase and multi-phase meters including CT connected meters, time switches for electric hot water systems and service installation costs for new residential, commercial and industrial developments. (Costs of meters and time switches are not included in the table above, these are included in the metering Chapter, services however are included in the table).
- Private Electric Lines - Rural pole-to-pit installations and replacement of private electric lines with HV lines and distribution substations.
- Recoverable Works - projects requiring alterations to the existing assets at the request of customers. The works are 100% funded by customers.
- Co-generation / Renewable Energy - connection costs for co-generation schemes and renewable energy projects.
- Reserve Capacity - UED's policy is to assist customers requesting the allocation of reserve (standby) feeder capacity, subject to its availability and the need to reserve spare feeder capacity to cater for general growth.

Table 7.4 below shows the actual Customer Initiated Capital expenditure for the 2001-2005 regulatory period and the benchmark expenditure for the 2006-2010 regulatory period.

Table 7.4: Benchmark Customer Initiated Capital expenditure

(Real $m June 2004)

	YEAR ENDING 31 DECEMBER					
	*01-05 Actual / Forecast	2006	2007	2008	2009	2010
Benchmark	28.4	26.0	25.2	23.6	22.7	24.3

* 01-05 Actual is average annual spend.

7.5.2 Methodology

The PB Power model applies a "Top-Down" approach using NIEIR inputs to predict the number and type of customer growth that is to occur at a much more detailed level. As such, this expenditure is not directly related to existing asset utilisation but growth in customer connections and expected connection costs for specific types of customer connections. The majority of this capital expenditure normally occurs at the LV network and distribution transformer level. However, significant amounts can relate to distribution feeder extensions depending on the development of a region.

The PB Power model does not cater for costs of the customer service connection and the meter, the costs for major and minor road public lighting or the costs of recoverable works. These have been forecast utilising internal asset management techniques and trending based on historical activity.

7.5.3 Trend Analysis

Reduction of customer initiated capital benchmarks for the 2006-2010 period is primarily driven by the exclusion of meters and the anticipated reduction of fully funded capital works (including those works accounted for as '"works in kind"). The benchmarks for meters are dealt with in Chapter 6. The amount included for 'like-for-like' meters is approximately $2.5 million per annum.

7.6 Customer Contributions

7.6.1 Overview

Contributions are received from customers who request new works and augmentation of electrical assets. Levels of contributions are calculated according to Commission guidelines and can vary from fully funded works (ie. 100% contribution), for relocation of assets at the request of a customer (eg. Road widening) to 10-15% for new residential developments.

Table 7.5 below shows the actual customer contributions for the 2001-2005 regulatory period and the benchmark customer contributions for the 2006-2010 regulatory period.

Table 7.5: Benchmark Customer Contributions

(Real $m June 2004)

		YEAR ENDING 31 DECEMBER				
	*01-05 Actual / Forecast	2006	2007	2008	2009	2010
Benchmark	10.0	5.0	5.0	4.7	4.5	4.9

* 01-05 Actual is average annual spend.

7.6.2 Methodology

In establishing a benchmark for customer contributions for the 2006-2010 period UED has applied the following methodology:

- PB Power model outputs for the level of Customer Initiated Capital are used as the basis for developing forecasts; and
- Those works that are fully customer-funded are excluded from the customer contributions benchmarks (and are also excluded from Customer Initiated Capital benchmarks).

7.6.3 Trend Analysis

The benchmark for customer contributions is lower than the amount accounted for in the current period. This is due to the anticipated decline in the level of customer funded projects (eg. Undergrounding Whitehorse Rd project), and the exclusion of those assets accounted for in the current period for "works in-kind".

In addition, following the release by the Commission of Guideline No. 14, the benchmark for customer contributions is expected to decline for projects such as dual or multiple occupancy developments, undergrounding and relocation of assets.

7.7 Reliability & Quality Maintained

7.7.1 Overview

"Reliability & Quality Maintained" capital expenditure encompasses asset enhancement and replacement works to ensure reliability and quality are maintained at the current performance levels.

Since acquiring the network, UED has developed a balanced approach to maintenance and asset replacement strategies, making substantial investments to arrest asset deterioration and to improve service reliability. These customer-focused initiatives have shifted the emphasis from reactive (responding to failure) to pro-active (both preventative and time-based) expenditure with a view to achieving long-term cost minimisation. Benchmarks are based on a combination of both known issues such as poor Dissolved Gas Analysis (DGA) oil tests in some zone substation transformers, as well as anticipated increases in expenditure as the network ages. Forecasts of asset failure rates and modes are derived from either statistical analysis of condition inspection data or documented industry practice. UED uses replacement models based on age and condition to analyse probability distributions of asset failure.

Replacement asset management uses methods that direct replacement on a "just in time" basis. Failure to undertake sufficient preventive replacement will allow the network average age, and hence the component failure rate, to increase to a point where the replacement balance is restored at higher annual cost. Sufficient replacement expenditure needs to be undertaken to control the network failures consistent with a stable average network age (or percentage remaining life). As noted elsewhere in this submission, the anticipated asset lives applied in the development of replacement capital expenditure benchmarks for the 2006-2010 regulatory period reflect the positive impacts of plant refurbishment and life extension initiatives undertaken by UED in the 2001-2005 regulatory period.

Table 7.6 below shows the actual "Reliability & Quality Maintained" capital expenditure for the 2001-2005 regulatory period and the benchmark expenditure for this category for the forthcoming period based on the PB Power model outputs considering age, condition and risk.

Table 7.6: Benchmark, Reliability & Quality Maintained

(Real $m June 2004)

	YEAR ENDING 31 DECEMBER					
	*01-05 Actual / Forecast	2006	2007	2008	2009	2010
Benchmark	24.7	43.1	42.1	42.1	49.4	62.6

* 01-05 Actual is average annual spend.

7.7.2 Methodology

UED engaged the services of PB Power to develop a model to test its in-house forecast of Non-load Related Capital Expenditure. The model includes:

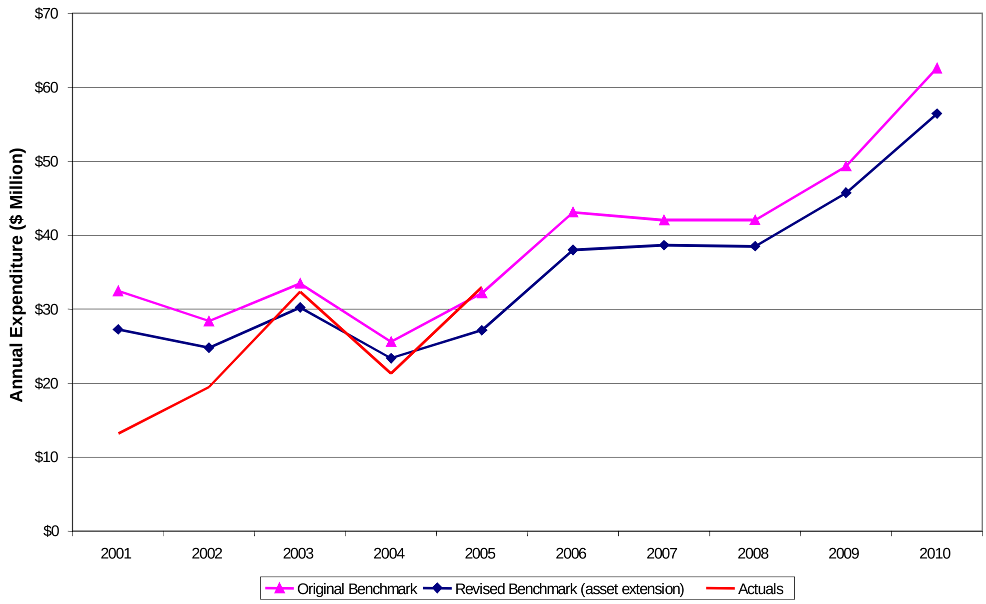
- a listing of network asset classes, broken down by voltage and asset type;
- replacement profiles for each asset class along with remaining asset life curves;
- asset condition assessment to be used to derive alternative asset age profiles in which certain assets in good condition are considered to be younger than their actual age and other assets are either left at their actual age or are considered to be older than their actual age because of poor condition; and
- the asset replacement requirements that result from the use of established minimum remaining life criteria.

Asset replacement costs used in this forecast are the estimated cost of replacing an asset on a modern equivalent basis unless otherwise stated and are considered consistent with the replacement costs used in Victoria.

The PB Power model outputs are determined by age and condition based assessments of assets and therefore does not cater for replacement driven by external causes such as lightning strikes, car incidents, vandalism or work required due to SPI PowerNet projects. Specific risk-based programs such as pole fire mitigation projects or spares inventory increases have been forecast utilising internal asset management techniques and trending based on historical activity.

Figure 7.2 shows that the PB Power model is reasonably accurate in benchmarking reliability and quality maintained expenditure for the 2001-2005 regulatory period when the model is corrected for actual asset replacement criteria.

Figure 7.2: Asset Replacement Efficiencies

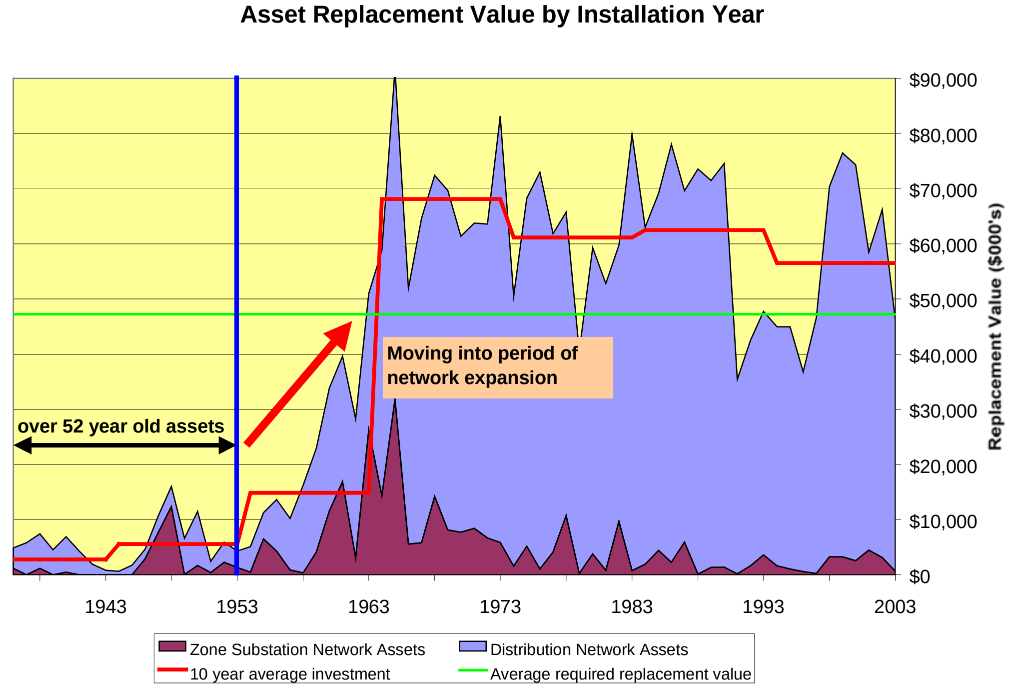


7.7.3 Trend Analysis

As shown in Figure 7.2 the PB Power model reasonably accurately predicts reliability and quality maintained expenditure when adjusted for actual asset profiles utilised by UED. The difference between the line labelled "Original Forecast" and "Revised Forecast (asset extension)" also shows that an increase in capital expenditure would be required had UED not adjusted for actual asset profiles that now exist as a result of its life extension and refurbishment programs.

Figure 7.3 below shows the asset replacement value of UED's assets by installation year. It is noteworthy that the average asset life is 51.8 years. It shows clearly that UED is entering a period in which the requirement for asset replacement expenditure will substantially increase. This increase in replacement expenditure requirements reflects the age profile of the asset population, the large proportion of the assets installed beginning in the early 1960s, and the fact than many of the assets installed at that time are approaching the end of their expected lives. The increase in expenditure is therefore required to ensure that the network age and condition is not permitted to deteriorate to the extent that there is an increased risk of component failures, and a subsequent risk to network reliability over the medium term.

Figure 7.3: Asset Replacement Value of UED's Asset by Installation Year



Some of the significant causes of the increase in benchmark expenditure estimated by the PB Power model from the 2001-2005 regulatory period to the 2006-2010 regulatory period include:

- life extension programs cost-effectively deferring expenditure from 2001-2005 into the next period for pole replacement as well as primary zone substation equipment such as transformers, busbar and circuit breaker replacements;
- a new stream of pole replacement expenditure starting during the next regulatory period, to replace the first of the condemned poles that were staked 20 years ago by the SECV which are now reaching the ends of their lives;
- a new stream of underground cable and LV pillar replacement starting during the next regulatory period, to replace the first of the Undergrounding Residential Development (URD) estates developed in the early 1970's such as Endeavour Hills, Dingley and Glen Waverley which are now coming to the ends of their lives; and
- increases in the replacement of supervisory cable to deliver a 10 year program, which commenced in 2003, to replace most of the aged network together with the associated aged relays.

7.8 Reliability & Quality Improvements

7.8.1 Overview

Reliability & Quality Improvement related capital expenditure encompasses investment aimed at improving customer service standards, particularly in relation to S-factor reliability measures. A description of UED's planned future service levels is provided in Chapter 4 of this submission. In summary, UED's view is that service performance has now reached a plateau and the scope for significant, cost-effective improvements in service performance has diminished. Table 7.7 below, which compares historic and future capital expenditure for reliability and quality improvements, shows a declining trend in capital expenditure.

Table 7.7: Benchmark Reliability & Quality Improvement Expenditure

(Real $m June 2004)

				YEAR ENDING 31 DECEMBER		
	*01-05 Actual / Forecast	2006	2007	2008	2009	2010
Benchmark	5.1	2.5	2.3	2.3	2.3	2.3

* 01-05 Actual is average annual spend.

7.8.2 Methodology

Capital benchmarks in this category are not addressed by the PB Power Model. Benchmarks are established utilising internal asset management techniques which indicate that in the coming regulatory period, only a relatively modest level of incremental expenditure can be justified on reliability improvements, principally focussed on:

- improving performance in areas of worst performing feeders;
- improving the quality of power delivered to customers; and
- undertaking continued analysis to identify emerging trends and opportunities within the network to achieve cost-effective improvements in reliability.

More specifically, this investment will focus predominantly on worst performers, power quality and voltage, rather than on improving customer average performance.

7.8.3 Trend Analysis

It is recognised that recent improvements in performance (as measured in "customer minutes off supply" through the reliability index SAIDI) cannot continue at the same rate into the future. It is believed that SAIDI has reached a plateau and only relatively minor gains are achievable from this point onwards.

Therefore, rather than focus on performance improvements based purely on SAIDI, UED intends to target minor reductions in the frequency of interruption (including momentary interruptions) and to improve performance in the worst performing areas. This focus, together with an increasing concentration on power quality issues through monitoring and improvement of the system performance with respect to voltage sags, is expected to address most customers concerns with the distribution network.

A reduction in proposed expenditure in the 2006-2010 regulatory period compared with the 2001-2005 regulatory period reflects this change in investment focus.

7.9 Environmental, Safety & Legal

7.9.1 Overview

This category of capital expenditure has been defined to include the capital costs incurred by UED's to comply with environmental, safety and legal obligations – both now and over the next regulatory period.

Table 7.8 below shows the actual Environmental, Safety & Legal capital expenditure for the 2001-2005 regulatory period and the benchmark expenditure for this category for the forthcoming 2006-2010 regulatory period.

Table 7.8: Benchmark, Environmental, Safety & Legal

(Real $m June 2004)

		YEAR ENDING 31 DECEMBER				
	*01-05 Actual / Forecast	2006	2007	2008	2009	2010
Operational		2.6	4.2	4.0	2.1	1.4
ESMS		5.6	5.6	5.6	14.2	14.2
Undergrounding		2.0	2.0	2.0	2.0	2.0
Other Initiatives		5.0	5.0	5.0	5.0	5.0
Total Benchmark	**2.5**	**15.2**	**16.8**	**16.6**	**23.3**	**22.6**

* 01-05 Actual is average annual spend.

7.9.2 Methodology

Capital expenditure benchmarks in this category are not estimated by the PB Power Model. UED has Health, Safety, Environment and Quality systems externally certified to AS4801, ISO14001 and ISO9001. Benchmarks are established utilising internal asset management techniques focusing on compliance with these systems in areas of:

- replacing overhead cable with aerial bundled conductor in areas of high bush fire risk areas of high vegetation or overhanging trees;

- construction techniques which are employed to minimise environmental impact when constructing and or maintaining UED assets as well as addressing environmental issues with regard to noise and EMF emissions;
- compliance with appropriate laws and regulations (refer Chapter 15 for further details);
- assessing critical infrastructure to minimise the medium to long term inability to operate; and
- electricity industry research and development.

7.9.3 Trend Analysis

The increase in benchmarks is primarily driven by three factors, these being:

- undergrounding of assets and Technology Development Fund (refer Chapter 4);
- safety related expenditure (refer Chapter15); and
- critical infrastructure protection (CIP)

A summary of the CIP program includes:

- provision of a consistent approach for identifying and prioritising critical infrastructure;
- a consistent assessment and treatment of security risks;
- identifying specific assets that if immobilised, would result in wide spread community impact;
- to identify specific actions and liaison with state emergency response agencies; and
- providing an assurance to the Government and community groups of pro-active preventative measures in respect to critical infrastructure assets.

7.10 Non-Network General Assets – IT

7.10.1 Overview

IT capital expenditure benchmarks for the 2006-2010 period include the costs associated with:

- technology infrastructure such as PC / LAN network and printers;
- billing systems;
- asset management systems;
- financial systems; and
- storage and hardware.

Table 7.9 below shows the actual IT capital expenditure for the 2001-2005 regulatory period and the benchmark expenditure for this category for the 2006-2010 regulatory period.

Table 7.9: Benchmark, IT Capital Expenditure

(Real $m June 2004)

	YEAR ENDING 31 DECEMBER					
	*01-05 Actual / Forecast	2006	2007	2008	2009	2010
Benchmark	11.8	10.9	9.8	9.5	11.6	8.3

- * 01-05 Actual is average annual spend.

7.10.2 Methodology

Capital benchmarks are established using an internal assessment of information technology needs. The replacement or upgrading of systems is focussed on maintaining the existing IT environment, in accordance with good practice IT asset management. The beginning of the forthcoming regulatory period coincides with a planned “technology refresh” by UED. The technology refresh is forecasted in line with UED standards and upgrades of third party products to ensure third party support and thus ensure the maintenance of the company’s IT capability. Examples of technology refresh includes upgrades to operating systems, databases and replacement of hardware to meet increases in processing requirements and storage requirements. It also includes the maintenance of a current fleet of IT equipment in order to avoid additional operational expenditure as a result of higher failures of equipment.

7.10.3 Trend Analysis

The capital benchmarks requirements for UED for 2006-2010 regulatory period is within the average historical spend for the 2001-2005 regulatory period. Expenditure consists of two segments, namely strategic spend and technology refresh spend.

Strategic spend is aimed at assisting in continuous improvement in the UED business and is targeted at improving the management of both structured and unstructured data and in improving the interfaces with UED’s service providers for provision of maintenance and construction services.

7.11 Non-Network General Assets – Other

7.11.1 Overview

Benchmarks in this category include items such as fleet, miscellaneous tools and equipment, furniture and equipment and property alterations.

Table 7.10 below shows the actual expenditure on non-network general assets for the 2001-2005 regulatory period and the forecast (benchmark) expenditure for this category for the forthcoming period.

Table 7.10: Benchmark, Non-Network General Assets

(Real $m at June 2004)

	YEAR ENDING 31 DECEMBER					
	*01-05 Actual / Forecast	2006	2007	2008	2009	2010
Benchmark	2.1	2.8	2.8	2.8	2.8	2.8

* 01-05 Actual is average annual spend.

7.11.2 Methodology

Capital benchmarks are established using an internal assessment of requirements of the items described above and an assessment of historical trends.

7.11.3 Trend Analysis

Benchmarks are consistent with current activity levels.

8 Regulated Asset Base

8.1 Introduction and Overview

The RAB provides the basis on which the value of return on capital (return) and return of capital (depreciation) components of required revenue are calculated. The Office used the roll forward method to update the 'vesting assets valuation' set in 1994, to establish an opening value for the regulatory asset base for the 2001 Determination.

At the time of the 2001 Determination the Office foreshadowed, and the Commission has subsequently confirmed[52] its intention to apply the same methodology for the purposes of this review. UED has calculated the opening value of the RAB for the period commencing 1 January 2006 in accordance with that method.

Adjustments for inflation in accordance with the Commission's methodology set out in Consultation Paper 1, page 30, have been incorporated in the value, while no allowance has been made for stranded or partly stranded assets, again in accordance with Consultation Paper 1.

Table 8.1 below details the calculations for the opening asset value

Table 8.1: Opening Regulatory Asset Base 2006

	$m
Opening Regulatory Asset Base 2001	1,015.2
Inflation adjustment to convert to June 2004	174.1
Adjustment for actual 2000 Capital	20.3
Adjustment for actual 2000 Customer Contributions	4.7
Adjustment for actual 2000 Disposals	(6.1)
Adjusted 2001 Opening Value (June 04)	**1,208.2**
Plus Capital Expenditure 2001-2005	464.0
Minus Customer Contributions 2001-2005	(41.5)
Minus Disposals 2001 – 2005	(1.9)
Minus Regulatory Depreciation 2001-2005	(403.1)
Opening 2006 RAB expressed at June 2004	**1,225.7**

Notes: 2005 values are based on the benchmark values determined for the 2001 Determination.

52 Essential Services Commission, March 2004, "Consultation Paper No.1: Framework and Approach, page 30

The remainder of this Chapter is structured as follows:

Section 8.2 summarises the closing values by each asset category for each year of the forthcoming regulatory period.

Section 8.3 sets out the assumptions applied by UED in calculating depreciation benchmarks.

Section 8.4 details the depreciation benchmarks for each asset category for each year of the forthcoming regulatory period.

8.2 Asset Values for Each Category of Asset

UED has calculated asset values for each category of asset consistent with the methodology outlined in Table 8.1 above. Table 8.2 below provides a summary of the value of the RAB for each year of the 2006 EDPR.

Table 8.2: Value of the Regulated Asset Base

(Real $m June 2004)

	Year Ending 31 December					
Category	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Sub-transmission	204.1	212.3	220.1	227.3	235.7	245.1
Distribution System	768.7	832.1	892.6	948.8	1,012.2	1,087.0
Standard Metering	118.6	98.1	77.7	57.2	45.2	41.5
Public Lighting	16.8	13.0	9.2	5.4	3.3	2.8
SCADA / Network Control	-	-	-	-	-	-
Non Network – IT	92.5	77.1	61.9	44.8	35.7	24.4
Non Network - Other	25.0	24.6	24.0	23.3	22.6	22.1
Total	1,225.7	1,257.2	1,285.5	1,306.8	1,354.7	1,422.9

8.3 Assumptions on Economic Lives of Assets for Depreciation

For the purpose of determining Total Revenue Requirements the economic and average remaining lives of the assets forming UED's Regulated Asset Base are set out in Table 8.3 below. These lives were used in determining depreciation.

Table 8.3: Asset Lives

Category	Economic Life (Years)
Sub Transmission	60
Distribution System	10-50
Standard Metering	15
Public Lighting	15
SCADA / Network Central	NA
Non-Network – IT	5
Non-Network - Other	5-40

8.4 Depreciation

Assets are replaced based on the condition of the asset at any one point of time. Actual asset replacement profiles, have been described in Chapter 7 of this submission and have been used to determine future capital expenditure requirements. The economic lives of asset categories, itemised in Table 8.3 above are based on the return of capital to UED rather than actual asset lives determined by technical factors. In accordance with the lives described in Table 8.3 above, depreciation for each group of assets that form UED's RAB are set out in Table 8.4 below.

Table 8.4: Value of Depreciation

(Real $m June 2004)

	Year Ending 31 December				
Category	2006	2007	2008	2009	2010
Sub-transmission	4.3	4.5	4.7	4.9	5.2
Distribution System	29.8	32.4	34.9	37.5	40.3
Standard Metering	20.5	20.5	20.5	12.1	3.7
Public Lighting	3.8	3.8	3.8	2.1	0.4
SCADA / Network Control	-	-	-	-	-
Non Network – IT	26.4	25.0	26.5	20.7	19.6
Non Network - Other	3.3	3.4	3.5	3.4	3.4
Total	**88.1**	**89.6**	**93.9**	**80.7**	**72.6**

The depreciation forecasts in Table 8.4 have been prepared on the basis that:-

- 50% of capital expenditure that occurs within a year is included in that year and the remaining 50% is included in the following year;
- the cost of each asset category is recovered over the economic life of that asset category; and
- depreciation is calculated on a straight-line basis.

9 Cost of Capital

9.1 Introduction and Overview

This chapter provides an overview of the basis of UED's estimate of the cost of capital.

The cost of capital is a critical element of the "building block" formulation that is used to derive an estimate of a regulated utility's total revenue requirement. There is a significant degree of imprecision and subjectivity involved in the estimation of the cost of capital, and there is certainly no one objectively determinable "correct" estimate of the cost of capital. It is universally recognised however, that very large costs to society as a whole would arise if regulators set the WACC at a level that is insufficient to encourage on-going investment in infrastructure over the long term.

On pages 33 and 34 of its Consultation Paper 1, the Commission states:

> "…having regard to the need to give effect to its statutory objectives to 'protect the long term interests of Victorian consumers' and to 'facilitate incentives for efficient long-term investment' in the electricity industry, the Commission has concluded that the provision of consistency and stability in regulatory decisions is of central importance in attracting new investment into the electricity industry. This is of particular relevance in relation to the method for the estimation of the return on capital."

UED concurs that consistency and stability of regulatory decisions are indeed essential to ensuring the maintenance of incentives for on-going investment in infrastructure. At the same time, as noted above, regulatory judgements regarding the cost of capital must also take full account of:

- the potential cost of regulatory error (as described in the Productivity Commission's recent reviews) and discussed in further detail in Chapter 3 of this submission;
- the uncertainties associated with estimating the WACC and its constituent parameters; and
- the need to ensure that in practice, investors are adequately remunerated for all risks (including the regulatory and commercial risks, as required by the Government's proposed modifications to the national third party regime) involved in the provision of infrastructure.

Under the building block approach, businesses' price-service offerings must make explicit reference to the point estimate of the cost of capital that has been applied in generating the benchmark revenues, which underpin the proposed prices.

To establish the point estimate of the cost of capital that UED has used in its price-service offering, UED engaged KPMG to provide a report on the cost of capital, which sets outs its views on the appropriate range from which a point estimate should be drawn. KPMG's report forms part of this submission and is attached at Appendix A. UED has also reviewed the material in the public domain in regard to:

- uncertainties associated with estimating the cost of capital; and

- asymmetric risks associated with setting the cost of capital too low rather than too high.

UED has taken all of this information into account in informing its view on the appropriate point estimate to apply. Accordingly, UED's price-service proposal uses a real vanilla cost of capital of 6.7%. It is noted that this estimate sits comfortably within the range estimated by KPMG, which is based on WACC parameter value estimates consistent with recent regulatory determinations.

UED believes that this cost of capital is consistent with protecting the long term interests of its customers in regard to the price, reliability and quality of electricity distribution services.

Table 9.1 below lists the parameter values adopted by UED in developing its estimation of this WACC.

Table 9.1: Summary of Parameters used to Estimate the WACC

Parameter	Value	Basis
Real risk-free rate	2.8%	This estimate is based on the average rate in recent times. UED understands that the Commission will apply the 20 day average of the implied yield on a notional ten year indexed linked bond at the time of its decision[53].
Market Risk Premium (MRP)	6% - 8%	UED has used the long term historical average for Australia as the basis for estimating the MRP because it is demonstrably more statistically robust than the other approaches available.
Equity Beta	1.0	The choice of an equity beta of 1.0 reflects consideration of the following factors: • the challenges of beta estimation in general and the guidance from a theory that is not strongly supported by empirical evidence; • the challenges of beta estimation derived from 'empirical' analysis, given the limited information available and the high measurement errors associated with these estimates; • the high degree of volatility observed in current empirical estimates; • the collective outcomes of recent regulatory decisions in Australia in relation to gas and electricity distribution; and • the fact that the equity beta is used to set a rate of return that will apply to UED for a period of five years.
Gearing	60% debt to Total Assets	This estimate is consistent with available market evidence and regulatory precedents in Australia
Debt Margin	151 – 171 basis points	These values represents a range of the costs that would currently be incurred by an efficiently-financed BBB to BBB+ rated, 60% geared electricity distribution business. It includes an allowance for (non-margin) debt-raising costs and the costs of expanded credit spreads that would be incurred in issuing index-linked debt.
The value of imputation credits	30%	This is based on independent empirical evidence of the value of imputation tax credits to the marginal investor in large companies in Australia with substantial foreign investment.
Treatment of diversifiable risks	Expected value cash flows	UED has accounted for diversifiable risks in the cash flows, where possible, in accordance with the method now preferred by the Commission.

53 Regulators in the UK have often not relied solely on existing market rates when setting the real risk free rate or the debt premium. Their approach suggests that questions can be raised about the extent to which the current market yield on government securities provide a reliable estimate of the expected risk free rate. This is another example of the uncertainty associated with estimating the cost of capital. UED will be continuing to analyse this issue over the course of this price review, and the company may seek further detailed discussions with the Commission on this issue, to ensure that the Commission's decision making takes full account of all relevant considerations when the final estimate of WACC is made.

The return on the RAB has been calculated for each year of the 2006-2010 regulatory period, by applying the real after-tax rate of return to an average of opening and closing asset values for the year. These calculations are summarised in Table 9.2.

Table 9.2: Return on Capital

(Real $m June 2004)

	Year Ending 31 December				
	2006	2007	2008	2009	2010
Asset Values					
Opening	1,225.7	1,257.2	1,285.5	1,306.8	1,354.7
Closing	1,257.2	1,285.5	1,306.8	1,354.7	1,422.9
Average	1,241.3	1,271.3	1,296.2	1,330.8	1,388.9
Return on Average Asset Value	**83.2**	**85.2**	**86.8**	**89.2**	**93.1**

This remainder of this chapter is structured as follows:

- Section 9.2 provides a brief overview of the conceptual framework including the Capital Asset Pricing Model (CAPM) applied to estimate the cost of capital. is applied.
- Section 9.3 identifies and discusses the key practical considerations that arise when the CAPM is applied in a regulatory context.
- Section 9.4 provides an overview of the Productivity Commission's assessment of these practical considerations, and the implications for regulatory decisions-making.
- Section 9.5 examines the approaches adopted by other regulators to addressing issues relating to regulatory error and the remuneration of investors for all forms of risk. An overview of the magnitude of errors associated with the estimation of WACC is also provided.
- Section 9.6 describes the approach and assumptions adopted by UED to estimate its cost of tax, for revenue determination purposes, for the 2006-2010 regulatory period.

9.2 Conceptual Framework

The cost of capital is the minimum rate of return required by the marginal investor in a firm (that is, the last investor willing to contribute funds). In other words it represents the minimum return on capital that a firm must expect to earn on its investments to attract new capital and to maintain its value.

The cost of capital of a firm is typically measured by reference to the current cost of raising funds via the various classes of its capital (namely, equity and debt), each weighted by the target proportion of each class of capital to the total market value of capital of the firm. Hence, the cost of capital of a firm is often referred to as a WACC.

In estimating WACC, the CAPM is widely applied to estimate the cost of equity. The CAPM is based on the assumption that an investor in a risky asset requires additional return to be compensated for bearing risk. In simple terms, the CAPM asserts that the required rate of return on a risky asset is a function of the risk free rate of return (Rf) plus a risk premium that reflects the return on a well-diversified portfolio of risky assets over the risk free rate (Rm – Rf), scaled by the "beta" of the risky asset.

In accordance with the proposal set out in the Consultation Paper 1, UED has adopted a real "vanilla" WACC formulation to estimate the cost of capital, which is defined as follows:

Real vanilla WACC = (Real K_e x E/V) + (Real K_d x D/V)

where:

Real K_e represents the real required return on equity and is estimated (in accordance with CAPM principles) as the sum of the real risk free rate of return (RR_f) and a risk premium that reflects the return on a well-diversified portfolio of risky assets over the risk free rate (the market risk premium) scaled by the beta (β_e) of equity, so that:

$K_e = RR_f + \beta_e$ * Market Risk Premium

Real K_d is the real required return on debt and is estimated as the sum of the real risk free rate of return (RR_f) and a debt margin.

E/V and **D/V** represent the weights attached to equity and debt capital in the context of the optimum capital structure of the business.

The use of a real vanilla WACC formulation requires the inclusion of the benchmark cost of tax allowance as a separate cash flow item. Under the approach proposed by the Commission and applied by UED, the allowance for the cost of tax is adjusted for the estimated value of franking credits. Details of the basis of UED's estimate of the value of franking credits are provided in this chapter, while the basis of UED's estimate of the cost of tax allowance is set out in Section 9.6 of this submission.

In simple conceptual terms, estimating the cost of capital may appear to be a straightforward exercise, however, in practice, the application of the CAPM, particularly in a regulatory context, is complicated by a number of factors. The practical issues that arise in the application of the CAPM are discussed in Section 9.3 below.

9.3 Practical Considerations in Applying CAPM in a Regulatory Context

The practical application of the CAPM to estimate the cost of equity in a regulatory context must recognise the following important considerations:

- Whilst various tests of the CAPM have generally lent support to the broad concepts of risk that underpin the model, empirical testing has also shown that the CAPM does not fully explain security pricing and the cost of equity[54].

[54] See, for instance, Richard Roll (1997) "A critique of the asset pricing theory's test", *Journal of Financial Economics, 4*. The Roll critique also highlights the difficulties of testing the theory. Similarly, in its May 2004 *Gas Control Inquiry Draft Report*, the New Zealand Commerce Commission stated: "The

- There are significant information constraints, estimation challenges and uncertainties in applying the CAPM in practice. The potentially detrimental impacts of these challenges and methodological limitations are magnified in a regulatory context, where a substantial proportion of revenues and profitability is dependent on the Commission's estimate of WACC.
- In theory, a number of parameters underpinning the CAPM should reflect forward-looking estimates, which are unobservable in practice.

In UED's view, the most significant practical consideration arising in the application of the CAPM is that estimating the cost of capital *necessarily* involves a very significant degree of uncertainty. This practical reality has been recognised by the Productivity Commission in its final report on its review of the gas access regime, as follows:[55]

> "While the debt costs of a service provider are relatively straightforward to assess, the return required by equity investors is not. The return on equity is typically estimated using the capital asset pricing model (CAPM). This method depends on the measurement of two contentious variables — a service provider's 'beta' (a measure of its risk relative to that of the total market for risky investments) and the market risk premium…
>
> Implementing the WACC/CAPM approach is not a precise science, given the numerous debatable assumptions involved. There is even disagreement on the precise formulas to use, due to different views on how issues such as tax should be treated. Hence, a range of plausible values can be generated for the regulatory rate of return using the WACC/CAPM approach…
>
> This debate highlights the fact that regulatory rates of return are set on the basis of many assumptions. Such assumptions are used because regulation is applied in a world of uncertainty...
>
> There is disagreement among technical experts about how regulatory rates of return (WACC) in Australia compare to those in other countries. This illustrates the inevitable imprecision and subjectivity that occurs when regulators are required to approve reference tariffs…"
>
> Given that the CAPM is a theoretical model based on debatable assumptions, the Commission is concerned that the model has become a de facto requirement under the regime. This situation might have been facilitated by s.8.31 of the Gas Code, which describes the CAPM as a 'well accepted financial model'. The comments of the leading financial experts quoted by Allgas Energy would suggest otherwise. The Commission considers that it needs to be made more explicit that there is no single correct method to calculate a rate of return and there can be a range of plausible values used in applying a method. It is recommended that s.8.31 be reworded to reflect this."

Commission acknowledges that a number of the assumptions underlying the CAPM violate real world conditions".

55 Productivity Commission (2004) *Review of the Gas Access Regime*, Report no. 31, Canberra. pages 297, 299, 302.

For its part, the Commission has also recognised the inherent imprecision and subjectivity involved in estimating WACC[56]:

> "[The] cost (price) of capital cannot be observed in the same manner in which prices for other goods and services may be observed. Neither the regulated entity nor the regulator can either observe or determine the cost of capital. Instead, the risk adjusted price for investment capital must be *estimated* from available capital market data that can be interpreted using models drawn from finance theory and practice.
>
> Given the significance of the return on capital in determining the distributors' forward looking revenue requirements and the degree of statistical imprecision in its estimation, the assessment of cost of capital has generated considerable controversy in the context of regulatory price reviews by the Commission and other utility regulators (both domestic and international)." [Emphasis added]

UED concurs with the Commission's comments. Given the challenges involved in the application of theoretical models, the paucity and uncertainty of the available data, and the impact that regulators' WACC determinations have on incentives for on-going investment, it is clear that:

- a considerable amount of careful judgment and pragmatism is required in selecting appropriate parameter values, and in developing an estimate of the cost of capital; and
- the WACC must be set at a level that takes due account of the estimation error involved, and that minimises the risk of damaging investment incentives.

9.4 Recognising the Practical Constraints in Forming a WACC Estimate

The Commission will be well aware that one of the major themes of the Productivity Commission's recent review of the national access arrangements was the risk of "regulatory error", and the realisation that the potential costs associated with too little infrastructure investment are far greater than those associated with too much investment. The Productivity Commission found that there is asymmetry in the consequences of regulatory errors:

> "Given that precision is not possible, access arrangements should encourage regulators to lean more towards facilitating investment than short term consumption of services when setting terms and conditions …
>
> [and] given the asymmetry in the costs of under- and over-compensation of facility owners, together with the informational uncertainties facing regulators, there is a strong in principle case to 'err' on the side of investors".

It is in this vein that the Productivity Commission provided a clear warning against an excessive focus on the removal of so-called "monopoly rents" from the revenue streams of facility owners, quoting a submission to the review by National Economics Consulting Group Pty Ltd (NECG), which stated:

> "In using their discretion, regulators effectively face a choice between (i) erring on the side of lower access prices and seeking to ensure they remove any potential for

[56] Essential Services Commission, Electricity Distribution Price Review 2006 – Final Framework and Approach: Volume 1, Guidance Paper, Pages 85 and 86.

> monopoly rents and the consequent allocative inefficiencies from the system; or (ii) allowing higher access prices so as to ensure that sufficient incentives for efficient investment are retained, with the consequent productive and dynamic efficiencies such investment engenders.
>
> There are strong economic reasons in many regulated industries to place particular emphasis on ensuring the incentives are maintained for efficient investment and for continued productivity increases. The dynamic and productive efficiency costs associated with distorted incentives and with slower growth in productivity are almost always likely to outweigh any allocative efficiency losses associated with above-cost pricing. (sub. 39, p. 16)"

Given these important considerations, the Productivity Commission's review of the national access regime made 33 recommendations to improve the operation of the regime. The review identified as a "threshold issue":

> "… the need for the application of the regime to give proper regard to investment issues…[and] the need to provide appropriate incentives for investment".[57]

The Productivity Commission's views were supported by the Australian Government's response, which signalled the Government's intention to make changes to the Trade Practices Act which "endorse the thrust" of the Productivity Commission's recommendations.[58] In particular, the Government will modify the regime to require the ACCC to have regard to pricing principles, which specify that that regulated access prices should:

- be set so as to generate expected revenue for a regulated service or services that is **at least sufficient** to meet the efficient costs of providing access to the regulated service or services;
- include a return on investment commensurate with **the regulatory and commercial risks involved.**

The Productivity Commission's recently completed review of the gas access regime also recommended the adoption of an objects clause and pricing principles that are essentially the same as those proposed by the Australian Government for the national access regime. In relation to the issue of regulatory error, regulatory risk and WACC, the Productivity Commission stated:[59]

> "The Commission also considers that there is a potential for *regulatory error* under the regime due to the complex issues involved in determining a reference tariff, including the need to make a subjective judgment about the risk faced by a service provider… In addition, recent appeal decisions suggest that regulators err towards imposing lower returns…
>
> … There is also uncertainty about the values of various parameters a regulator might apply in approving reference tariffs (such as the weighted average cost of capital)…"

57 Productivity Commission (2001), *Review of the National Access Regime: Inquiry Report 28*, p. xxii.

58 Commonwealth Government (2002), *Government Response to Productivity Commission Report on the Review of the National Access Regime: Interim Response*, p. 1.

59 Productivity Commission (2004), *Review of the Gas Access Regime*, Report no. 31, page xxx.

The building block approach necessarily requires that a *point estimate* of the cost of capital be applied in the estimation of total revenue requirements. As already noted, the WACC is probably the most important and uncertain variable in the entire price-service offering. In view of these considerations, the point estimate of the cost of capital used in a price-service offering must take into account:

- the potential cost of getting it “wrong” (as described in the Productivity Commission’s recent reviews);
- the uncertainties associated with estimating the WACC and its constituent parameters; and
- the need to ensure that in practice, investors are adequately remunerated for all risks involved in the provision of infrastructure (including the regulatory and commercial risks, as required by the Government’s proposed modifications to the national access regime).

Section 9.5 below examines the approaches adopted by other regulators to addressing issues relating to regulatory error and the remuneration of investors for all forms of risk. An overview of the magnitude of errors associated with the estimation of WACC is also provided.

9.5 Dealing with Risk and Estimation Error

The New Zealand economic regulator (the Commerce Commission) is presently conducting an inquiry into the possible application of price control to gas network businesses. In its draft report[60], the Commerce Commission assesses forecast company profits (assuming that no price control is in place) against a “benchmark” normal profit (effectively representing the Commission’s estimate of the WACC that would apply under a price control regime), to determine whether there might be net benefits associated with the introduction of price control regulation. The Commerce Commission uses three estimates of WACC (high, mid point and low) in its assessment, by varying the values assumed for the market risk premium and asset beta, as shown in Table 9.3 below.

Table 9.3: NZ Commerce Commission’s MRP and Beta Estimates

	Low	Mid Point	High
Market Risk Premium	6%	7%	8%
Asset Beta	0.4	0.5	0.6

60 New Zealand Commerce Commission (2004) *Gas Control Inquiry Draft Report.*

The Commerce Commission describes its approach to dealing with uncertainty and the potential costs of regulatory error as follows:

> "The Commission proposes assessing profits against all three estimates of WACC given the uncertainty associated with the parameter estimates. The Commission notes concerns about the asymmetric nature of errors in assessing WACC, i.e., underestimation is the more serious error because it may lead to under investment by the regulated firms. These considerations are taken into account in the Commission's judgment as to whether there are likely to be net benefits … from [the introduction of price] control. The Commission also proposes to take the 75th percentile of the WACC range (i.e., the half way point between the High WACC and Mid Point of WACC) in the final report, in order to judge whether there are net benefits [from the introduction of price control]."

It is also worth noting recent Public Utility Commission ("PUC") rulings on return on equity in the USA, which have focused on, among other things, the question of remunerating investors for the carriage of diversifiable risks.

> "On the question of risk, the California PUC also agreed with prior policy that diversifiable risks (those specific to the company) ought not be allowed to inflate the ROE allowance and push rates higher for consumers, since utility companies should be able to mitigate firm-specific risk, such as by assembling a balanced portfolio of investments or supply resources.
>
> Nevertheless, the PUC did not ignore diversifiable risk entirely in its 2002 opinion. Rather, it seemed willing to accept the idea that today's utilities face higher risks than before – warranting higher compensation, all else being equal – even if that higher risk level is to some degree a product of an increase in diversifiable risk.
>
> Thus, in its 2002 generic order, the PUC acknowledged that the utilities it regulated had claimed increases in diversifiable and non-diversifiable business and regulatory risks, but it saw little to gain in the current political climate by attempting to analyse and account separately for each category.
>
> In short, the Commission said investors and the general public now see the electric utility industry as "highly unstable" – buffeted by broad regulatory and business forces.
>
> Given this climate, the PUC dispatched with any need to exclude diversifiable risk from consideration. Instead, it found a net increase in overall utility risks. That increase warranted an ROE award for calender 2003 at the middle to upper-end of the range otherwise found just and reasonable for each utility." [61]

Finally, it is worth quantifying, in broad terms at least, the high level of error associated with estimation of the cost of capital using CAPM and other more sophisticated models. In this regard, SFG Consulting has produced a paper than evaluates the error associated with such estimates.[62] SFG's paper examines a number of issues relating to the estimation of the cost of capital for regulated entities using the CAPM and the leading alternative to the CAPM, the Fama-French three-factor model. SFG states:

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61 Public Utilities Fortnightly, *A Survey of Recent PUC Rulings*, 15 November 2003.

62 SFG Consulting (2003) *Issues in Cost of Capital Estimation.*

"For both model choices the authors [Fama and French] cite that, "large standard errors (in industry costs of equity) are driven primarily by the uncertainty about the true factor risk premiums, with some help from imprecise estimates of period-by-period risk loadings."

Taking the CAPM as our benchmark, the average standard error in the cost of equity resulting from uncertainty in the estimation of the market risk premium alone is at least 3%. The marginal contribution from uncertainty in estimating beta makes the total standard error even greater. The bulk of uncertainty in the cost of equity, however, derives from estimation error in the market risk premium.

Even starting with the highly unlikely assumption that the risk premium is estimated without error, there is sufficient variation in risk loadings (betas) alone to warrant concern. Fama and French (1997) report results that support a 95% confidence interval around the mean cost of equity of more than 3%.

Unfortunately using the three-factor model does not resolve the uncertainty as to the "true" cost of equity. Results that use this model as the asset pricing benchmark tell the same story. Again, uncertainty in risk premiums alone creates standard errors in the costs of equity that exceed 3%. The addition of uncertainty in risk loadings contributes to the size of the standard error. The results of Fama and French (1997) suggest that the average standard error in the cost of equity under the three-factor model to be as high as 3.85%. Of course this would imply practically useless estimates of the cost of equity, with a 95% confidence interval being more than 7.5% either side of the mean. According to the industry results reported above, this supports a "true" cost of equity of somewhere between 2.25% and 17.75% for Energy and between 2.78% and 18.18% for Utilities.

What can we conclude from these results? It is safe to say that neither of the leading alternatives provides any degree of comfort in being able to state precisely and without reservation what the cost of equity actually is. Confidence intervals around the estimated cost of equity are extremely wide whether we use the CAPM or the three-factor model. Moreover, since both models imply considerably different mean returns for both industries examined in the table above, we do not know where the starting point of our cost of equity estimate should be. Furthermore, firm specific estimates would have even greater uncertainty than the industry results that are reported. The merits of the asset pricing approach to cost of equity estimation are perhaps best summed up by Fama and French (1997): "…uncertainty of this magnitude about risk premiums, coupled with the uncertainty about risk loadings, implies woefully imprecise estimates of the cost of equity."

9.6 Cost of Tax

Consistent with the Guidance Paper, UED has segregated it's notional Regulated Tax Asset Base between Pre and Post Ralph tax reforms. Accordingly UED has applied the depreciated profiles appropriate for those groups of assets. For those assets acquired post Ralph tax reforms UED has adopted the following depreciation profiles set out in 9.4 below.

Table 9.4: Tax Depreciation Rates

Expenditure Category	Depreciation Rates
Demand Related	3%
Repairs	100%
Other Replacement	3%
Environmental Safety & beyond	3%
Metering <$1000	37.50%
Metering >$1000	10%
Non-Network IT	40%
Non-Network General	17.65%

A significant factor in the calculation of tax depreciation is the level of capital expenditure, particularly those of a repair nature.

As noted in Chapter 7 the age and condition of UED's assets leads to an increase in benchmark replacement expenditure in order to maintain current service levels. For the purposes of calculating a regulatory tax wedge, this type of expenditure diminishes the value otherwise being returned to the network operator via the taxation regime.

Finally, under the building block approach applied by the Commission, an explicit allowance – or "tax wedge" – is included in the benchmark revenue requirement to represent the forecast taxation costs net of the value of imputation credits. The value of these tax credits, (denoted as gamma, or γ) can be defined as the proportion of actual company tax paid on behalf of the marginal price-setting investor which is really a pre-collection of personal tax. The KPMG report at Appendix A concludes that the existing empirical evidence suggests a value for gamma in the range of 0% to 50%. Based on that analysis, and having regard to the considerations set out in Sections 9.2 to 9.5 above, UED proposes to adopt a value for gamma of 30%.

10 Operating and Maintenance Expenditure Requirements

10.1 Introduction and Overview

Operating expenditure comprises both operating and maintenance costs where:

- 'Maintenance' includes those works associated with the maintenance and repair of regulated business assets; and
- 'Operating' includes those functions associated with operating an asset or item of equipment, or those functions that support the business operations.

In terms of setting expenditure benchmarks, the Commission's approach differs between operating and capital expenditure. In particular, future operating expenditure benchmarks are based on each company's actual reported costs, plus an adjustment for scope changes. The Commission explains the rationale for this approach in the following terms (on page 66 of the Guidance Paper)[63]:

> "As foreshadowed in the 2001-2005 price review, the Commission considers that it can rely on the incentive properties of the CPI-X framework, with an efficiency carryover mechanism, to provide incentives for distributors to achieve efficiencies in operating and maintenance expenditure. The aim of including an efficiency carryover mechanism in the 2001-2005 price review was to provide distributors with a stronger incentive to achieve efficiencies. A corollary of this is that distributors would be expected to reveal their efficient level of costs, because they are directly rewarded for outperforming the expenditure forecasts established at the last price review. Hence, the Commission can infer that reported actual costs are efficient. Where the scope of activities is unchanged, this inferential approach reduces the need for reliance on external benchmarking processes to assess the efficiency of cost forecasts put forward by the distributors."

It follows, therefore, that the operating expenditure information presented in this chapter is less detailed than the capital expenditure information presented in Chapter 7. In particular, operating expenditure is considered by the Commission to be a recurrent expense, which may reduce over time as genuine efficiency gains are achieved, subject to changes in the scope of operating activity and the volume and quality of outputs produced. Given this view of operating expenditure, and the incentive properties of the regulatory framework, there is no benefit or purpose in establishing operating expenditure requirements on a detailed "bottom-up" basis.

Nevertheless, this chapter does provide some information regarding UED's principal operating expenditure activities, and explains how UED is taking measures to ensure that expenditure is allocated in the most efficient manner. The chapter also provides details of future scope changes. These scope changes require the inclusion of additional allowances in the future operating expenditure benchmarks to reflect the increased operating activity or sustained cost increases that will occur in the forthcoming regulatory period.

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63 Essential Services Commission, Electricity Distribution Price Review 2006 Final Framework and Approach: Volume 1, Guidance Paper, June 2004 Pages 66

UED also notes that clause 5.10 of the Tariff Order requires the Commission, amongst other things, to have regard for the need to ensure a *fair sharing* of the benefits achieved through efficiency gains between customers and the distributors. In the 2001 Determination, the Office argued that a 70:30 sharing ratio in favour of customers satisfied this requirement for fair sharing of efficiency gains. In UED's view, 50:50 would be much more consistent with common application of the concept of *fair sharing*.

Moreover, UED notes that if the Commission anticipates *future* efficiency gains in setting operating expenditure benchmarks, customers will in effect enjoy even more than 70% of the benefits. In fact, such an ex ante setting of efficiency gains delivers an immediate gain of 100% of that forecast gain to customers and could result in customers receiving more than 100% of any future gain. In terms of what is allowed under the Tariff Order, this is neither a "fair sharing" nor is it an outcome derived from a gain actually "achieved". For this reason alone, UED challenges the inclusion of any future efficiency gain, which is speculative and unrealised, in setting the operating expenditure benchmarks in the next regulatory period.

Table 10.1 below provides a summary of Operating and Maintenance benchmarks for the forthcoming regulatory period.

Table 10.1: Operating and Maintenance Benchmarks

(Real $m June 2004)

		Year Ending 31 December				
		2006	2007	2008	2009	2010
Actual Expenditure 2004	85.3					
Assumed Efficiency Gains in 2005	(0.6)					
Sub Total	**84.7**					
Opening benchmarks		84.7	-	-	-	-
Metering *		(0.4)				
Incremental Growth *		0.3				
Scope Changes – Regulatory		4.2				
Scope Changes – Sustained		2.4				
Sub Total		**91.2**	**91.2**	**91.2**	**91.2**	**91.2**

*** Note:** These changes are consistent with the Guidance Paper.

The remainder of this Chapter is structured as follows:

Section 10.2 details UED's approach to ensuring that maintenance expenditure is efficiently incurred.

Section 10.3 outlines the approach UED has adopted in establishing benchmark operating and maintenance forecasts for the 2006-2010 period.

Section 10.4 itemises UED's scope changes (adopting 2004 as a base year) due to changes in regulatory compliance obligations and sustained changes in cost drivers.

10.2 Maintenance Approach

UED's maintenance philosophy has evolved through a range of asset management techniques, namely:

- Reactive Maintenance or repair on breakdown;
- Time based preventive maintenance;
- Predictive or condition based maintenance; and
- Reliability Centred Maintenance (RCM).

RCM retains the good features of all previous regimes, but applies them only where they provide the best return in terms of reliability, risk and cost. The RCM process includes consideration of safety, environmental and operational criteria and allows for pragmatic evaluation of risk where quantification is not practicable.

While not all maintenance processes have been formed within the RCM discipline, RCM none-the-less underpins the conceptual maintenance philosophy at UED. UED's maintenance plan is designed to ensure the assets perform their functions over their lifetime with the lowest total maintenance costs and with the least risk.

All maintenance strategies contained within UED's maintenance plan include an asset specific risk analysis where risk is expressed as the product of consequence and likelihood of occurrence. Risks are assessed in terms of public and personnel safety, material loss, customer lost load, environmental safety and public perception.

Maintenance at UED is performed under a three-stage process of:

- Fixing known defects;
- Targeting poor performing assets and high consequence fault types; and
- Monitoring and maintaining on condition.

Systems are in place to monitor and report performance and compliance for each of these processes.

10.2.1 Fixing Known Defects

Fixing known defects is prudent management. Identified defects are repaired on a priority basis. This also extends to repair of circuits where backup exists such as subtransmission circuits, as reduction in circuit availability increases the exposure levels to simultaneous circuit outage.

UED has an internal benchmark performance index that measures outstanding maintenance tasks divided by the total number of planned completions for the period. Weighting factors modify the index in relation to the different contributions of nine maintenance activities. The index target is set in relation to the period between the identifying inspection and the work being undertaken.

By monitoring performance in this way, overdue priority maintenance in 1997 was reduced from 3,870 to under 300 tasks by November 1999. Overdue unserviceable poles have been reduced from 209 to 9. UED's ongoing management of maintenance activities is aimed at ensuring that the level of overdue priority maintenance is kept at this low level.

10.2.2 Targeting Poor Performing Assets and High Consequence Fault Types

Targeting is a key maintenance tool to direct resources in an efficient manner and involves the analysis of faults to determine possible grouping to particular asset types, circuits or regions. UED maintains a list of rogue feeders, to ensure that a database is developed to provide information on the cause of faults, and to ensure that prompt and appropriate action can be taken to attend to faults.

While targeting is essentially reacting to how the network is performing, experience shows that attempting to predict maintenance requirements is not always practical due to the difficulty in measuring or monitoring all the factors that influence fault occurrences from year to year. Also, the maintenance cycle of yearly budgeting and review is invariably shorter than the rate of development of consistent fault trends so network performance targeting may be undertaken by annual analysis of performance data and setting of priorities.

10.2.3 Monitoring and Maintaining on Condition

Monitoring and maintenance on condition programs recognise the limitations of age based preventive replacement and or scheduled maintenance. This arises due to the wide dispersion of equipment condition affected by age, environment and use. Scheduled maintenance or replacement is undertaken only where condition based methods are ineffective or uneconomic and the failure modes are predictable. Such programs include routine lubrication, battery checks and tree cutting.

To facilitate maintenance, UED employs a variety of business systems. These include:

- **Track performance:** supply and cost performance monitoring systems are in place.
- **Monitor faults:** UED uses the DMS system to monitor network faults to direct targeted maintenance as appropriate. Fault activity is reported daily, monthly, six monthly and annually.
- **Works Management System and Maintenance Management System:** UED uses a SAP management system to maintain a database of all work and maintenance needed and planned for the network, including associated costs.
- **Maintenance Strategies:** UED has documented maintenance strategies and policies, that cover all of UED's network assets.
- **Long Term Maintenance and Replacement plan:** this is the set of maintenance and replacement strategies that cover the period to the year 2020.
- **External review:** an external review is part of the production of the Maintenance and Replacement Strategies. Specific reviews have been undertaken for cable, vegetation and transformer maintenance.

10.3 Operating and Maintenance Benchmarks (2006-2010)

Operating costs are those costs that support the operations of UED. They include, but are not limited to, activities such as, finance, corporate office, human resources, information technology, engineering support, etc.

Benchmarks of operating costs are relatively stable throughout the forecast period and are generally not subject to the age and condition of UED's network system.

As noted earlier, UED concurs with the Commission that the incentive properties of the regulatory regime enable an inference to be drawn that reported actual costs are indeed efficient. Accordingly, UED has applied the Commission's approach in developing its forecasts of efficient operating costs for the next regulatory period. Under the Commission's approach:

- the actual operating expenditure in the penultimate year of the regulatory period (year 2004) is adjusted for the implied efficiencies in the 2004 and 2005 expenditure benchmarks set at the previous price review. In UED's case, this adjustment implies a reduction of $0.6 million in actual 2004 expenditure to derive a proxy for efficient operating expenditure for the first year of the 2006-2010 regulatory period; and
- separate additional allowances are included in the expenditure benchmarks for the costs associated with scope changes from one regulatory period to the next.

In response to the Commission's suggestion that distributors should propose a rate of change to the 2006 "starting point" expenditure benchmark, UED has already noted that:

- the Commission's proposal (that price caps should "factor in" as yet unrealised efficiency gains) is inconsistent with the intent and operation of the incentive regime established in the 2001 Determination; and
- the incentive mechanisms established in the 2001 Determination obviate the need for the Commission to estimate future further potential efficiency gains and to factor these assumptions into price caps.

Moreover, the Commission is required under clause 5.10 of the Tariff Order to have regard for the need to ensure a *fair sharing* of the benefits achieved through efficiency gains between customers and the distributors. In the 2001 Determination, the Office argued that a 70:30 sharing ratio in favour of customers satisfied this requirement for fair sharing of efficiency gains. In UED's view, 50:50 would be much more consistent with common application of the concept of *fair sharing*.

Moreover, UED notes that if the Commission anticipates *future* efficiency gains in setting operating expenditure benchmarks, customers will in effect enjoy even more than 70% of the benefits. In fact, such an ex ante setting of efficiency gains delivers an immediate gain of 100% of that forecast gain to customers and could result in customers receiving more than 100% of any future gain. In terms of what is allowed under the Tariff Order, this is neither a "fair sharing" nor is it an outcome derived from a gain actually "achieved". For this reason alone, UED challenges the inclusion of any future efficiency gain, which is speculative and unrealised, in setting the operating expenditure benchmarks in the next regulatory period.

Accordingly, UED has not included forecasts of changes in the "starting point" expenditure benchmark that include prospective efficiency gains.

Costs associated with changes in scope are outlined in Section 10.4. below.

10.4 Scope Changes

For the purposes of this Section, UED has defined a scope change as one of the following two categories:

- any change of cost associated with a change in, or change in reasonable interpretation of a Regulation and or law. These can include changes of Regulations by other government authorities and changes in Regulations initiated by the Commission and or the National Market governance agencies; and
- any sustained cost change not included in UED's cost base from which the Commission uses as a starting point for establishing future benchmarks, and which falls outside of normal cyclical variations in costs associated with cyclical variations in operating conditions.

Table 10.2 below lists each area in which UED considers a scope change has or will occur for the purpose of setting the expenditure benchmarks for the 2006-2010 regulatory period. The cost impacts of the scope change are also listed. The column headed "Section" shows a cross reference to the section of the submission that provides a more detailed explanation of the scope change, and a substantiation of the associated cost impact.

Table 10.2: Scope Changes

Section	Area / Issue	Amount $m pa
Regulatory Change		
S10.4.1	Electrical Safety Regulations	2.8
S10.4.2	Road Management Act	0.5
S10.4.3	Claims - Insurance Companies	0.5
S10.4.4	Embedded Networks	0.2
S10.4.5	GSLs	0.2
S10.4.6	Regulatory Audit	0.1
Sub Total		**4.2**
Sustained Cost Change		
S10.4.7	Claims	0.5
S10.4.8	Allowance for one Small Retailer in Liquidation	0.1
S10.4.9	Labour Rates	0.9
S10.4.10	Skilling for the Future	0.5
S10.4.11	Land Tax	0.4
Sub Total		**2.4**
Total Scope Change		**6.6**

It is noted that the precise nature and impact of some of the regulatory scope changes are not known at this time. In such cases, an alternative to the approach of including an estimate of the cost impact in the expenditure benchmarks now would be to exclude any allowance from the expenditure benchmarks at this time, and instead to provide a cost pass-through provision in the price control arrangements. This pass-through provision would require UED to adjust its prices to reflect changes in costs due to changes in regulatory compliance obligations.

UED expects that the scope of pass through events will be the subject of further consultation by the Commission during the course of this price review in the settlement of the formal price controls.

This approach recently has been consistently adopted by the ACCC in decisions relating to electricity transmission regulation (SPI PowerNet, Electranet, Transend and the draft decision for Transgrid and EnergyAustralia) in allowing a pass-through for a “Service Standards Event”. While the ACCC has noted its concerns about the muting effect that a pass-through mechanism would have on incentives, it recognises that certain events are outside the control of regulated entities. For example, in the SPI PowerNet decision the ACCC provided for a pass-through for a Service Standards Event defined to mean:

"A decision made by the Commission, the Essential Services Commission or any other Authority or any introduction of or amendment to an Applicable Law after the date of the Determination that:

(a) has the effect of:

(i) imposing or varying minimum standards on SPI PowerNet relating to revenue capped transmission services that are more onerous than the minimum standards applicable to SPI PowerNet in respect of revenue capped transmission services at the date of the Determination;

(ii) altering the nature or scope of services that comprise the revenue capped transmission services;

(iii) substantially varying the manner in which SPI PowerNet is required to undertake any activity forming part of revenue capped transmission services from the date of the Determination; or

(iv) increasing SPI PowerNet's risk in providing the revenue capped transmission services, or

(b) results in SPI PowerNet incurring (or being likely to incur) materially higher or lower costs in providing revenue capped transmission services than it would have incurred but for that event."

Similarly, in the Commission's recent decision on the revised gas distribution access arrangement for Multinet and TXU Networks the Commission allowed, as part of the definition of a "Relevant Tax" (a change in which having a material effect on costs is a pass-through event), "costs associated with changes in service standards but only where the Service Provider has been directed, ordered or required as a result of legislation or regulatory arrangements to make such a change in service standards".

10.4.1 Electrical Safety Regulation

The 2001 Determination provided an amount for works associated with changes contained in the 1999 Electricity Safety (Network Assets) Regulation (ESNAR), based on the understanding of the scope of those works at the time. In part that understanding relied on correspondence between the OCEI and the Office which indicated that distributors would be able to seek exemption from the 1999 ESNAR for existing assets where the safety risks were low and any additional conditions set by the OCEI were adequately met.

A survey of assets by UED has indicated a material increase in the scope of works to be undertaken. UED has already commenced this higher volume works program and therefore seeks a scope change estimated at $2.8 million for this additional work.

This amount has been based on UED's ESMS which has been signed by the Minister and is waiting signing by the Governor in Council.

10.4.2 Road Management Act

In early 2004 the Parliament of Victoria enacted the Road Management Act 2004 which in part established a new statutory framework for the management of the road network which facilitates the coordination of the various uses of road reserves for roadways, pathways, infrastructure and similar purposes.

The Act proposes:

- that all works require consent to allow the road authorities to manage this coordination role with exemptions being allowed for some works such as emergencies;
- a Code of Conduct for dealing with management of road and utility infrastructure in road reserves;
- a regulation covering specific works that may be exempt from requirements to obtain consent or give notice; and
- the fees and charges for obtaining consent to undertake works.

While in the past there have been both formal and informal processes in place by which road authorities and utilities have successfully managed works in road reserves, this new level of formality involving formal notifications, permits and requests for exemptions can be expected to impact on work programs, the efficiency of undertaking works and thus the cost.

Anticipated costs associated with the implementation of the Act include:

- establishment of accreditation systems and processes;
- systems and processes associated with consent processes;
- systems and processes associated with notification processes; and
- prescribed fees.

Based on the additional resources needed to meet these requirements, UED believes that an extra three people would be required on an ongoing basis. UED will also be required to pay additional fees outlined in the table below when performing construction and maintenance works.

Based on its current annual work program, UED estimates it would have to obtain 350 to 450 consents per annum for works conducted on the roadway, shoulder or pathway. As most of the minor works are expected to be exempted from the requirement to obtain consent from the relevant coordination road authority, half of the estimated consents would be required for works other than minor works on freeways and arterial roads and the other half for works on municipal or non-arterial roads. Payment for consent as detailed in Table 10.3 is estimated to be $0.2 million per annum.

In addition to these additional ongoing costs, UED estimates that $0.3 million will also be required to establish the necessary systems and processes. These establishment costs are included in UED's forecast of IT capital expenditure.

Table 10.3: Consent Fees (from Regulation-Draft 7)

Type of Roads	Consent Fee			
	Works, other than minor works,		Minor Works	
	Conducted on, or on any part of, the roadway, shoulder or pathway	Not conducted on, or on any part of, the roadway, shoulder or pathway	Conducted on, or on any part of, the roadway, shoulder or pathway	Not conducted on, or on any part of, the roadway, shoulder or pathway
Freeway	45 fee units	32 fee units	25 fee units	10 fee units
Arterial road	45 fee units	25 fee units	11.5 fee units	10 fee units
Municipal road or non arterial State road on which the maximum speed limit for vehicles at any time is more than 50 kilometres per hour	45 fee units	25 fee units	11.5 fee units	5 fee units
Municipal road or non arterial State road on which the maximum speed limit for vehicles is not more than 50 kilometres per hour	20 fee units	5 fee units		

Note: 1 fee Unit[64] = $10.23 from July 2004.

10.4.3 Claims / Insurance Company

UED is required to pay the cost of repairs and or replacement of items that have been damaged due to causes related to the performance and operation of UED's distribution network. These items can range from electrical household items such as TV's, fridges etc, perishable food stuffs for residential customers up to large replacements of electrical motors/equipment used by business customers.

Any claims paid are limited to the item itself and as per the current Commission guideline no claim is paid for consequential loss. For the purposes of this submission UED will continue to interpret the guidelines as it has over the last 3 years and accordingly no allowance has been included for any change of scope in this regard.

UED receives claims from both individuals and insurance companies, however, it only accepts claims made directly from customers. On 28 June 2004, the Commission advised[65] UED that insurance companies have the right to claim compensation for damages due to

64 The fees are expressed as fee units in accordance with the Monetary Units Act 2004.

65 e-mail from Peter Walsh of the Commission, dated 28 June 2004.

voltage surges under the guideline. Following the advice, UED now considers claims made by insurance companies on behalf of a customer.

UED receives approximately 500 requests per year from customers wanting information on voltage variation incidents to support claims made to their insurance company. There may be others who make claims directly to their insurance companies that UED are not aware of. UED has been processing an increased number of claims made directly from insurance companies on behalf of their customers. The majority of these claims are being made by only 2 of the 61 insurance companies registered with the Insurance Council of Australia. Not all of the insurance companies submit claims on UED for payments that they have paid to their customer as a result of damage sustained through possible voltage variations. The average cost of claims using the two insurance companies is approximately $550 per claim. Accordingly, UED estimates a total increase of $0.5 million per annum.

10.4.4 Embedded Networks

Embedded networks occur where non-distribution business assets are connected to the distribution network through a ‘parent’ customer. The management of these installations is a complex and difficult issue given the unclear regulatory rules, regulatory framework and enforcement regime in place.

Customer transfers within embedded networks have proved difficult and extremely complex to negotiate given the number of participants involved and the various interpretations as to the ability of the ‘child’ to have the freedom of retailer choice. The rules and procedures for all facets of service provision need to be considered in terms of all possible variations of embedded networks to ensure a common understanding of the rights and obligations of all parties involved is achieved.

UED is participating in the current consultation on this matter, however, it is concerned with an approach that would impose costs and obligations on a regulated business such as UED and which would make compliance with other parts of the regulatory regime unachievable. The current consultation approach would appear to:

- require distributors to take on full local network service provision responsibilities on a network that the National Electricity Code Administrator (NECA) has agreed can be exempt from any NEC requirements and one which the distributor does not own or receive compensation for servicing;
- contrary to the agreed FRC framework, place responsibility on the distributor for issuing NMIs to children of an embedded network where the local retailer is the parent retailer, due to the fact that the parent retailer has a relationship with the embedded network owner/manager; and
- impose subtractive metering on the Local Network Service Provider (LNSP), yet the distributor may not, and generally does not manage data at the parent meter (usually type 3 or 4).

UED is concerned at the change in obligations on the LNSP and new interpretation of the NEC that the current approach suggests. Moreover, UED is concerned at the high level of risk that such an approach, if accepted, would impose on UED. Further, it is concerned that the approach fails to address all issues associated with this matter (eg, change of voltage from "parent" to "child"). Procedures and rules developed to meet the end-to-end process needs of retailers and distributors need to be developed and implemented.

Accordingly UED have allowed $0.2 million per annum to comply with this changed interpretation of the Regulations.

10.4.5 GSLs

As outlined in Chapter 4, UED is proposing to amend existing GSLs as well as introducing new ones. The estimated cost of these initiatives is expected to be $0.2 million per annum to those customers experiencing levels of service below GSL payment threshold.

10.4.6 Regulatory Audit

Based on licence requirements distributors are required to undertake an operational regulatory audit when requested by the Commission. The Commission has proposed in a paper[66] that they require audits to be undertaken on a regular basis each year. UED estimates the cost of these audits to be $80,000 per annum based on previous audit scope. In the base year (2004) UED is currently undertaking a desk-top audit only, due to the work requirements associated with the 2006 EDPR. The cost of this audit is $10,000 therefore the scope change to be considered is the net increase in costs of $70,000.

10.4.7 Level of 2004 Claims

As indicated elsewhere in this submission, UED has achieved better than benchmark system performance results. These results can be directly related to the amount of claims paid. For example the 2001 SAIDI performance was 72 minutes while claims paid in that year amounted to $1.1 million. In 2002 SAIDI performance was 89 minutes and claims paid were $1.7 million. For 2003, SAIDI performance was 81 minutes and claims paid amounted to $1.7 million.

Current projections of the 2004 SAIDI performance is approximately 70 minutes. Accordingly UED's projections for claims paid is $1.1 million. Based on projected SAIDI performance in the next regulatory period ranging from 80 minutes in 2006 to 75 minutes in 2010, the equivalent claims payments is projected to range from $1.7 million to $1.3 million during the period. Accordingly UED seeks a scope change of $0.5 million per annum which is calculated as the difference between the claims paid in 2004 of $1.0 million and an average claim cost in the next period of $1.5 million per annum.

10.4.8 Allowance for one Small Retailer in Liquidation

The successful implementation of competition in the Victorian retail electricity market has seen a growth in number of retailer participants. Initial participants, dominated by Victorian and other state incumbents, have been joined by a further five new entrant retailers with several more applications under consideration.

New entrants potentially increase the commercial risk for distributors. From UED's perspective, retailer of last resort arrangements are largely unknown and untested. Whilst NEMMCO and the Commission have held paper "walk throughs" of a retailer of last resort

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66 Proposed 3-year Audit Program – Gas & Electricity Distributors – 24 December 2003

event emanating from failure to meet national market settlements or credit support requirements, little has been agreed about the process that would be undertaken if the retailer chose not to pay UED's network and transmission charges. The actions undertaken under this scenario are unlikely to be as swift or as transparent as the NEC process. This regulatory uncertainty, combined with the uncertainty of the immediate post event issues, may mean that the insolvency of small retailer will have a large disruptive impact and potentially could cascade to multiple failures.

UED considers that there are a number of outstanding issues regarding industry participant capability or agreement of process including:

- What happens to transfers in progress away from the old retailer?
- What happens to service requests made by the old retailer in terms of response to whom and payment?
- What agreement is there on the method of the transfer read?
- What notice period is there for distributors and meter data providers to provide additional resources to deal swiftly with these transfers, including all the support resources to make sure transfers, data streams, cancellation of in progress transfers etc?
- How will all the necessary participants be notified of the changes to ensure systems stay aligned?

UED has allowed an estimate of $0.5 million for the 2006-2010 period of a small retailer going into liquidation. This costs includes the cost of the bad debt as well as resources required to transact the necessary market obligations.

10.4.9 Labour Rates

Work by KMPG on behalf of Distributors suggests that there are significant pressures on the Victorian electricity distribution Sectoral Labour Market. This work suggests there will be an average of 4% to 5% increase in average wage rates above inflation.

This increase is driven by:

- demand-side pressures and supply side constraints; and
- historical trends being exacerbated by engineering needs.

The report also concludes that this increase in real wages is net of any productivity improvements that could be expected.

Accordingly UED has allowed $0.9 million per annum as a labour increase for maintenance expenditure.

10.4.10 Skilling for the Future

Resourcing within the electricity sector comprises a specific and highly skilled professional, para-professional and trade based workforce. Over the past decade, as an outcome of restructuring and the drive for efficiency, the level of employment opportunities across the industry has diminished. Trends in the industry to contract based resourcing have seen the emergence of major firms drawing from a common pool to supply resources to the industry, not only in Victoria, but nation wide.

Work by KPMG on behalf of Distributors suggests that skill shortages and an ageing workforce (45% of the electricity sector are over 45 years of age compared to 35% across the Victorian workforce generally) present major risks to the industry going forward as construction and maintenance work programs grow. The Victorian Minister of Energy supported this position when commenting on the energy industry earlier this year, when he stated “skills shortages are a ‘massive’ issue and the ageing workforce is only exacerbating it”[67]. It is also noted that the Ministerial Council on Energy has also listed the issue as a matter for discussion at future meetings[68].

UED recognises the need to have resources available to meet its business needs and has, and will continue, to invest in training and up-skilling of the workforce to ensure that an adequate resource pool available. UED has committed to development of additional professional and trade resources, comprising trainee engineers and line apprentices. The expected cost of this program is $0.5 million per annum.

10.4.11 Land Tax

UED is required to pay land tax levied on properties it owns and leases. For the properties that it leases, contracts are structured so that land tax is a pass through amount to the lessee. During the previous five years it is well documented that property values have increased at a greater rate than inflation. Land tax calculations are based on property values therefore there has been an increasing liability for land tax during this period.

Based on the historic trend of increasing property values it is not unreasonable to assume that land tax payments will grow at a greater rate than inflation. Accordingly UED has calculated that land tax will increase by $0.4 million per annum compared to the 2004 actual cost. This amount is net of any decrease in the rates of land tax applicable from 2005.

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67 Australian Financial Review, “Energy sector is running out of puff: Theophanous”, 27 August 2004.

68 Ministerial Council of Energy, 8th communique, Adelaide, 27th August 2004.

11 Efficiency Carryover

11.1 Introduction and Overview

This chapter describes the application of the efficiency carryover mechanism in relation to the efficiency gains achieved during current 2001-2005 regulatory period.

The efficiency carryover mechanism provides distributors with enhanced incentives to deliver capital and operating cost efficiencies. In the 2001 Determination, the Office described the rationale for the efficiency carryover mechanism in the following terms:

> "…,to ensure that the regulatory framework provides incentives for the distributors to operate efficiently, the Office concluded early in its Price Review consultation process that it would be desirable for distributors to be rewarded for some of their within-period efficiency gains through into the next regulatory period. The principal benefit of such a reward is that by clarifying and strengthening the incentive for distributors to increase their efficiency, the price customers pay for electricity distribution services over the medium term will be lower than otherwise would be the case. It also helps offset the incentive to defer the pursuit of efficiency gains that might otherwise exist in the years immediately before a Price Review.[69]"

UED supports the continuation of the incentive mechanisms developed by the Office in the 2001 Determination, which include measures to safeguard service performance. It is essential that the Commission applies these incentive mechanisms in a manner consistent with the reasonable expectations of customers and shareholders. In this regard, UED concurs with the Office's comments regarding the future operation of the efficiency carryover mechanism:

> "The Office considers that a degree of certainty about the Office's approach to adopting a long-term efficiency carryover mechanism will provide more effective incentives for encouraging the efficient behaviour described above. Whilst the Office cannot now bind the future exercise of statutory powers, it considers that a long-term approach to determining the efficiency carryover (that is, spanning more than one regulatory decision-making period) is consistent with the statutory objectives the Office must meet."[70]

Based on these statements by the Office, and having regard to the need to maintain certainty about incentive arrangements across successive regulatory periods (especially in light of the long life cycles of distribution network assets) UED expects the Commission's forthcoming 2006 Determination to confirm that the existing efficiency carryover mechanism will continue to apply during the 2006-2010 regulatory period.

UED also considers that the 2001 Determination may have created legal obligations on the Commission to now not act otherwise than in accordance with the reliance placed upon it by UED.

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69 Office of the Regulator General, Electricity Distribution Price Determination 2001-2005, Volume: Statement of Purpose and Reasons, September 2000, Page xxiii

70 ibid, page 84.

This chapter is structured as follows:

Section 11.2 explains the adjustments to cost benchmarks to mitigate the effects of demand forecast errors on the measurement of efficiency gains; and

Section 11.3 below shows the calculation of the efficiency carryover mechanism with respect to efficiency gains achieved over the current regulatory period.

11.2 Adjustments for Forecast Errors / "Scope Changes"

The Office's original 2001 Determination was subject to appeal by distributors on a number of issues, including the calculation of the efficiency gains to be carried-over from the previous regulatory period. The basis of the appeal was that the Office calculated "efficiency" from a benchmark cost which assumed a particular level of business activity. In reality, actual business activity exceeded the assumed amount. The Office did not allow for any adjustment in the benchmark costs when assessing each company's efficiency improvement. The Appeal Panel statement of reasons for both the Powercor and AGL Electricity Ltd appeals stated that:

> "The Panel notes that the Office measured efficiency by comparing actual total costs (including operating and maintenance costs, and capital costs) as achieved in 1999 with the benchmark forecasts, for the distribution business, for that year. The Panel recognised that this comparison does not make any allowance for changes in the size or scope of the business from those which were assumed in the benchmark forecast. In the Panel's view this results in a measure which does not reflect efficiency as normally understood, and which creates incentives for the distribution business to perform inefficiently. According to (this) rule of thumb, a cost increase necessitated by an increase in output is treated as a reduction in efficiency. A reduction in the size of the business results in a reduction in costs and thus a measured increase in efficiency, entailing a reward to the business in future years through the efficiency carry over mechanism."[71]

The Commission indicated in the Guidance Paper that it will apply a similar type of adjustment for errors in forecast demand, to reflect the findings of the Appeal Panel. In particular, the Commission has stated that it intends to[72]:

- calculate the carryover amount arising from each year of the 2001-2005 regulatory period, as per the method set out in the 2001 Determination;
- adjust for the impact of any difference (positive or negative) between outturn growth and forecast growth on operating and maintenance expenditure using the same relationship between growth and expenditure that was used in establishing the 2001-2005 operating and maintenance expenditure benchmarks. This will apply only to those components of operating and maintenance expenditure that have a direct relationship to growth (that is, billing and revenue collection, and customer service);

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71 As quoted by the Essential Services Commission 2004, Electricity Distribution Price Review 2006 - Final Framework and Approach: Volume 1, Guidance Paper , Page 73.

72 ibid, pages 75 and 76.

- adjust for the impact of any difference (positive or negative) between outturn growth and forecast growth on capital expenditure using the same relationship between growth and expenditure that was used in establishing the 2001-2005 capital expenditure benchmarks. This adjustment will apply to reinforcement and augmentation capital expenditure, and customer initiated capital expenditure (customer connections).

In providing for adjustment to network reinforcement/augmentation capital expenditure forecasts, the Commission has asked distributors to provide the results obtained by re-running the PB Power models along with supporting explanation of the assumptions they have made about the link between demand growth and capital expenditure on network reinforcement/augmentation.

UED's calculation of the efficiency carryover, detailed in Section 11.3 below, conforms with the Commission's approach to adjustments. However, UED notes as a matter of principle that attempting to precisely adjust all of the cost benchmarks for "scope changes" is fraught with difficulty. Therefore, whilst it is appropriate for the Commission to make adjustments in line with the Appeal Panel's findings, it should avoid a forensic re-examination of the 2001 benchmarks outside the scope of those findings. In UED's view, such a forensic examination is likely to weaken the incentive powers of the regulatory regime, which would be counter to the original purpose of the efficiency carryover mechanism.

11.3 Efficiency Carryover Adjustments to Revenue Requirements

Table 11.1 below details the adjustments to be made to the capital benchmarks when re-running the PB Power model. It is noted that no adjustments are required to the operating and maintenance expenditure benchmarks.

Table 11.1: Efficiency Carryover Adjustments

(Real $m June 2004)

	YEAR ENDING 31 DECEMBER				
	2001	2002	2003	2004	2005
Capital	(1.0)	0.2	0.1	(0.6)	(1.6)
Operating and Maintenance	-	-	-	-	-

The adjustments to the capital expenditure benchmarks are explained in further detail below.

The demand growth rates used in the determination of the regulatory benchmarks for demand-related capital expenditure were based on forecasts provided by the independent consultant, NIEIR, in 1999, for the 2000-2010 period.

The forecasts used by UED in its demand planning are revised annually by NIEIR, to take into account the latest available information. Under these arrangements, the updated forecast obtained in 2000 was used by UED in its demand planning for summer 2001 and or 2002. For each year of the present regulatory period (that is, 2001-2004) the annually revised demand forecasts provided by NIEIR have been lower than the 1999 forecast used in the setting of the regulatory benchmark.

Table 11.2 below shows the difference between the maximum demand forecasts used to set the expenditure benchmark, and the revised maximum demand forecast used in demand planning for each year of the regulatory period.

Table 11.2: Original Demand Forecast Compared to Annually Revised Forecast

Year	Maximum Demand Forecast used to set Expenditure Benchmark (MW)	Maximum Demand Forecast used in UED Demand Planning (MW)
2001	1664	1634
2002	1726	1697
2003	1799	1713
2004	1875	1746
2005	1956	

Various factors have contributed to the revision in demand forecasts, but the mild summers experienced in 2002 and 2003 were the major contributing factors.

12 Total Revenue Requirement

This chapter sets out the approach that has been used to calculate Total Revenue Requirements for the 2006 Determination. The Total Revenue Requirement is a summary of Chapters 5 – 11 and has been calculated below:

TR = AV x WACC + TW + ELM + D + OC

Where

TR = Total Revenue

AV = Asset Value

WACC = After-tax WACC (Real)

TW = Tax Wedge

ECM = Efficiency Carryover mechanism

D = Return of Capital (Depreciation)

OC = Non Capital Costs

Unless otherwise stated all monetary values are expressed in real terms using June 2004 values.

Table 12.1 below provides a summary of the composition of the Total Revenue Requirement for each year of the 2006 Determination, commencing January 2006.

Table 12.1: Total Revenue Requirement 2006 EDPR

(Real $m June 2004)

	Year Ending 31 December				
	2006	2007	2008	2009	2010
Non Capital Costs	83.2	85.2	86.8	89.2	93.1
Return on Capital	88.1	89.7	93.9	80.7	72.5
Depreciation	91.1	91.1	91.2	91.2	91.3
Efficiency Carryover	-	-	-	-	-
Tax Wedge	8.1	9.9	11.9	7.5	3.5
Total Revenue	**270.4**	**275.9**	**283.9**	**268.7**	**260.4**

As is demonstrated by the evidence presented in this submission, UED has identified scope changes for the 2006 Determination and an increase in capital expenditure from the current period. These have been forecast consistent with actual practices employed by UED.

These are all included in the table above and represent UED's forecast of efficient expenditure in for the 2006 Determination.

13 Tariffs

13.1 Introduction

The purpose of this chapter is to provide interested parties and the Commission with a detailed summary of UED's tariff strategy for the forthcoming regulatory period. In doing so, UED intends to satisfy the Commission's requirements as described in its Guidance Paper. In particular, the Commission has retained its previously stated pricing principles, which require that tariffs sit between an avoidable cost "floor" and a stand-alone cost "ceiling". The Commission's Guidance Paper requires distributors to describe the methodologies used to determine standalone and avoidable costs.

The Commission's Guidance Paper noted the recent findings of the Pricing Issues Consultation Group (PICG). The PICG raised concerns on the limited available information on the distributors' tariff strategies – including the potential for tariffs to be re-balanced, the introduction of new tariffs and the redundancy of existing tariffs.

In response to PICG's concerns, the Commission has concluded that the distributors should each produce a Tariff Strategy Report covering the 5 years from 2006, supplemented by an annual report. The Tariff Strategy Report will be published prior to the commencement of the 2006-2010 regulatory period, and distributors will be required to:

- set out their tariff strategy for that regulatory period (including details on the tariffs that the distributors are proposing to charge, as well as a list of excluded services charges and metering charges);
- provide a discussion of their tariff setting policy framework and an explanation of how they have had regard to the Commission's pricing principles;
- explain the basis upon which tariffs were developed including the methodology adopted for developing the structure and level of tariffs, and a description of the methodologies used to determine stand alone and avoidable costs;
- explain the basis on which they have determined the appropriate breakdown between fixed and variable charges;
- indicate the extent to which the tariff structures provide efficient consumption signals to distribution customers;
- indicate the methodology adopted for allocating transmission-related costs to distribution customers through their transmission tariffs;
- provide an estimate of the average annual distribution and transmission charge (in $) for each combination of distribution and transmission tariff; and
- present at least the initial tariffs and a description of how the tariffs and tariff structure are likely to be adjusted over the period including, where new tariffs are to be introduced or old tariffs are to be made redundant.

UED agrees with the Commission that it is important to provide customers with reasonable information on the objectives and rationale for tariff design, and annual changes in tariffs.

The production of the Tariff Strategy Report will provide customers with substantial information regarding the future direction of tariffs and a detailed exposition of each distributor's methodology for setting tariffs.

The focus of this chapter, however, is intended to be more limited and high-level than the Tariff Strategy Report. This chapter provides an overview of the key tariff issues in the context of the price submission. As such, it presents important background information on how tariffs have changed over the current regulatory period as well as UED's proposals for future developments.

In addition, it is important for readers of this submission to understand the relevance of tariff-setting in the context of the Commission's 2006 Determination. In particular, it is important to keep in mind the following matters:

- Distribution tariffs are set so that revenue earned recovers the maximum allowed revenue as determined by the Commission. Tariff design is therefore concerned with "dividing the cake" between customers, rather than determining the "size of the cake".
- For many customers, the principal area of interest is in relation to the structure and level of retail tariffs, rather than the structure of distribution tariffs. Customers can sometimes find distribution tariffs complex and confusing – especially as many customers do not directly pay distribution tariffs.
- A range of alternative tariff structures may satisfy generally accepted principles for setting efficient prices, so it is not possible, therefore, to establish a "perfect" set of tariffs that satisfy all customers.
- Potentially, all customers can benefit if pricing signals are improved so that tariffs are truly "cost reflective". However, "cost of supply" models necessarily rely on cost allocation methods to determine the share of total network costs to be borne by each customer group. Given the practical constraints, it is not possible to determine objectively the "correct" cost allocation. It is only possible, therefore, to make a fairly broad assessment as to whether tariffs are cost reflective and economically efficient.
- In many respects, UED as a stand-alone network business can take an impartial view on tariff design, without favouring one group of customers over another. UED must have regard to providing appropriate price signals – but UED also recognises that considerations relating to equity and "ability to pay" are relevant to tariff-setting decisions.

Together, the issues identified above illustrate why tariff design is likely to be contentious amongst some customer groups. Importantly, however, UED can take an objective approach in setting tariffs, which requires it to weigh the competing objectives and pricing principles dispassionately.

The remainder of this chapter is structured as follows:

- Section 13.2 summarises UED's tariff objectives and principles in the light of the Commission's comments in the Guidance Paper[73];
- Section 13.3 provides an overview of UED's recent tariff initiatives and experience;
- Section 13.4 reports on UED's tariff modelling, including a description of the methodology employed;
- Section 13.5 highlights potential tariff developments over the forthcoming regulatory period, particularly noting the impact of the interval meter rollout;
- Section 13.6 summarises other services provided by UED, and
- Section 13.7 concludes with an overview of UED's distribution tariff proposals.

13.2 UED'S Tariff Objectives and Principles in Setting Tariffs

UED recognises that tariff design must comply with the Commission's regulatory requirements. As noted in Section 13.1, there are two key aspects to regulatory compliance:

- Firstly, tariffs must deliver a revenue stream which does not exceed the maximum allowed revenue as determined by the Commission; and
- Secondly, tariffs must be economically efficient by conforming to the pricing principles established by the Commission.

In relation to the requirements that tariffs should be economically efficient, the Commission has stated[74] that distribution tariffs should lie between the following lower and upper bounds, respectively:

- tariffs for each customer should generate revenue in excess of the avoidable cost to service the customer;
- tariffs for each customer should generate revenue less than the cost of providing the service on a stand-alone basis to the customer.

UED has conducted tariff modelling, described in Section 13.4 below, which demonstrates UED's compliance with this requirement. In addition to setting tariffs to meet its regulatory obligations, UED has also adopted the following principles and objectives for setting tariffs:

- Customer choice. UED aims to provide customers with meaningful choices of tariff options based upon behavioural response and shared benefits.
- Market equity. Having regard to previous price levels and hence relative changes. Further, pricing should apply to all retailers in a neutral manner and should not unreasonably affect the viability of full retail contestability.

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73 Essential Services Commission 2004, Electricity Distribution Price Review 2006 - Final Framework and Approach: Volume 1, Guidance Paper , Page 93

74 ibid, page 97.

- Cost reflectivity. Fixed and shared costs should be allocated amongst customer groups in an equitable way that does not distort pricing signals. Prices should be cost-reflective, and so encourage efficient use of the existing network, and efficient future investment.
- Behavioural elasticity. Seek to utilise rational customer behavioural elasticity, both in terms of usage responses to pricing signals and tariff switching.
- Practicality. Tariff offerings should be as simple as possible, to facilitate ease of understanding by customers, and to minimise tariff implementation and administration costs for UED.
- Environmental considerations. Within the limitations of the scope and context of electricity distribution pricing, UED's tariff policy has regard to opportunities to improve asset utilisation and to accommodate emerging energy technologies, particularly those that may contribute to reducing greenhouse gas emissions.

It is noted that there is a tension between some of these principles. For example, *cost reflectivity*, *equity* and *practicality* may each indicate different types of tariff changes or developments. UED takes account of customer feedback, regulatory requirements and changes in network characteristics in developing its preferred tariffs.

13.3 Recent Tariff Initiatives and Experience

During the period from 1995 to 2000, network price signals were only visible to customers consuming more than 160 MWh per annum. During this period, UED introduced several new tariffs aimed at improving signalling for these larger customers. Specifically, the introduction of kVA demand-based tariffs in 1998 resulted in tangible improvements in network utilisation characteristics.

Further opportunities to develop innovative distribution tariffs arose in 2001, in response to changes in UED's network characteristics, and in response to changing market arrangements. The most significant drivers for change were:

- increasing summer peak demand, as the network's load factor continued to decline (see explanation below);
- retail contestability;
- an increased focus on the environmental impacts of energy usage;
- advances in data-driven technology; and
- changes in the regulatory framework.

Of these drivers for change, the primary driver was the continuing decline in the network's load factor. This decline has resulted in additional distribution network capacity being required to reliably transport similar quantities of total energy to customers. The decline in load factor has been driven principally by an increase in the amount of demand attributable to air conditioning load within UED distribution area, and additional distribution assets have been required to support load only on the hottest summer days. This trend is shown in Figure 13.1.

Figure 13.1: Load Duration Curve

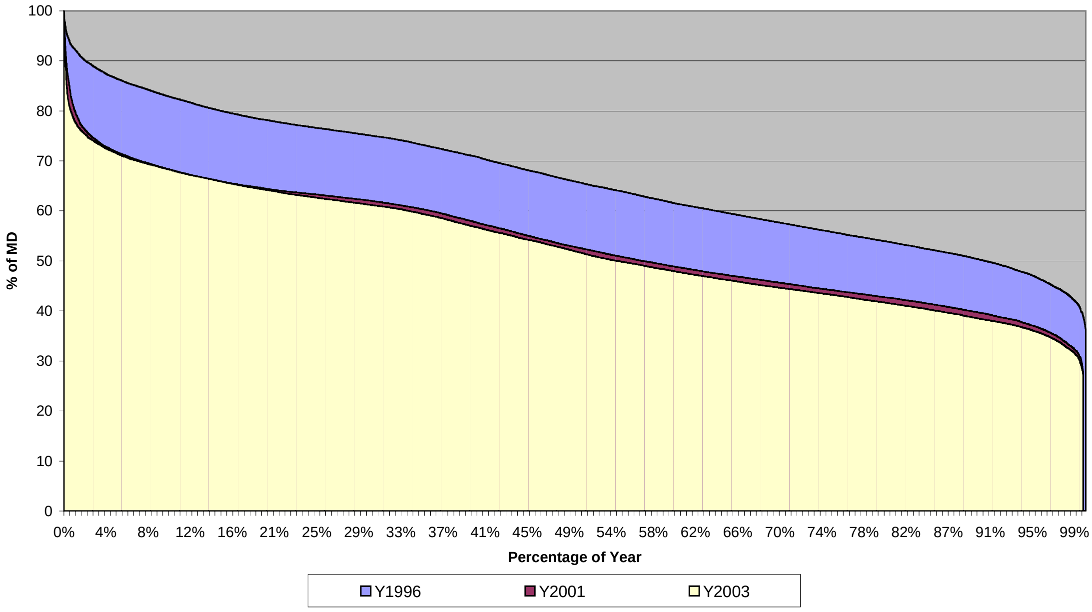

Figure 13.1 shows the Load Duration Curve[75] for the UED network comparing 1996 with 2001 and 2003. Over this period the Load Factor[76] of the network fell. The chart shows the increasing "peakiness" of the load. Further analysis of the data represented in the chart highlights that nearly 30% of the network was utilised for less than 100 hours (in 2003). In addition, the maximum demand on UED's distribution network prior to 1997 was recorded in the winter, however, since then the maximum demand has been recorded in the summer.

In addition to these important changes in network characteristics, UED also wanted to respond positively to calls from customer groups to reduce fixed daily standing charges. In the light of these drivers for change, UED introduced the following tariff initiatives in 2001:

- For all UED customers fixed distribution charges were substantially reduced. For customers using a 'smart' interval meter, fixed distribution charges were completely abolished.
- For small to medium customers, UED introduced the option of a new LV time-of-use (Smart meter) tariff. This tariff utilises interval metering, which measures load every half-hour. Under this tariff, customers have an incentive to avoid usage during peak time on summer workdays. The charge is called the Summer Demand Incentive Charge (SDIC). This tariff has <u>no</u> daily fixed standing charge.

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75 The Load Duration Curve shows each half hour period of demand, expressed as a percentage of the capacity of the network, sorted from the largest (100%) to the smallest.

76 Load Factor is a measure of the utilisation of the network and can be calculated by dividing the shaded area on the chart by the total area.

- For customers with interval meters, the peak/off-peak time zones were re-aligned, which increased the number of hours per year that are classified as off-peak. The new peak/off-peak zones replaced out-of-date time zones that no longer reflected current demand patterns.

- Seasonal components were incorporated into tariffs. This innovation addressed the increasing proportion of temperature-related load, such as air-conditioning in the small to medium sectors, which is an important network cost driver. Accordingly, for all tariffs, two seasons were introduced - summer (November to March inclusive), and non-summer (April to October inclusive). These initiatives, together with the changes to time-of-day zones, encourage customers to shift some of their consumption away from times where costly peak demands are most likely to occur.

- An interruptible tariff was introduced for those large customers who are occasionally willing to have some of their load remotely switched off, or to have stand-by generation started by UED. The purpose of this initiative was to enable more network capacity to be available when it is otherwise highly utilised, by encouraging large customers to delay their usage by a few hours, in doing so, freeing-up capacity for others. Unfortunately, due to limited customer take-up this tariff is now closed.

- UED introduced the HOT variant which was a variant on existing tariffs. The base tariff can be identified by removing the 'HOT' prefix from the Time of Use (TOU) tariffs. The variants and their base tariffs are the same as each other in most respects except that the 'summer demand incentive charge' (SDIC) is nearly double the normal rate in the variants, but only applies is the maximum daily ambient temperature is forecast to reach or exceed 30ºC. The normal SDIC rates apply to all summer workdays, whereas the hot version may only be triggered on between 5 and 20 days per summer. In a given summer month, there is also a chance that no days end up with forecasts over 30ºC, in which case no SDIC charge accrues for that month. Unfortunately, customers have not chosen to move onto this tariff, and therefore UED will be closing this variant in 2005.

- UED introduced Winter Economy Tariff (WET) which was targeted at customers with permanently wired electric panel heaters. Likewise very few customers have chosen this tariff, therefore UED will be closing this tariff in 2005.

- UED introduced the Reverse Cycle air-conditioning kilowatt time of use (RACCkWTOU) which targeted customers with Reverse Cycle air-conditioners. The attractiveness of this tariff is dependent on the customer's willingness and ability to avoid peak summer usage at key times. UED expect the take up of customers moving to this tariff to increase with the mandatory introduction of interval meters.

- UED discontinued the use of 'stepped' energy blocks from its tariffs. The stepped structure proved problematic where scheduled meter readings were not recorded. The benefit of this has been to simplify the data administration.

- UED also reduced the number of tariff offerings by closing a number of tariffs that had proved to be unpopular with customers, or which were based on out-dated metering technology. The streamlining of the tariff offerings has also had the benefit of reducing complexity for customers.

Since 2001, UED has minimised the number of structural changes to its tariffs in order to allow the earlier initiatives to take effect. The changes to the distribution tariffs at the commencement of the current regulatory period demonstrate clearly that UED is prepared to explore innovative pricing mechanisms in order to seek better outcomes for customers and the environment. As noted in Section 13.5 below, UED intends to consider a number of further initiatives in the forthcoming period to further improve the existing tariff offerings.

In some respects the tariff changes in 2001 have not produced the changes in customer behaviour that UED expected at that time.

Interval metering will reveal important information about the actual costs of serving particular customers within a tariff class. Customers will, for the first time, be encouraged to identify opportunities for cost savings by switching to time-of-use network tariffs. In addition, retailers will have an opportunity to deliver savings to customers by exploring alternative network tariff options. UED believes that customers' demand patterns will change in the medium term in response to the sharper price signals that arise from interval metering. UED will monitor these developments closely over the forthcoming regulatory period.

13.4 Tariff Modelling

As noted in Section 13.2, the Commission has stated[77] that distribution tariffs should lie between the following upper and lower bounds:

- tariffs for each customer should generate revenue in excess of the avoidable cost to service the customer; and
- tariffs for each customer should generate revenue less than the cost of providing the service on a stand-alone basis to the customer.

The Commission has not provided any further guidance on how the upper and lower bounds should be assessed. In UED's view, there are a myriad of alternative methodologies that could be applied for estimating upper and lower bounds for network pricing and also for cost allocation to customer groups. Each methodology has its merits and shortcomings.

To demonstrate that tariffs fall between the avoidable cost "floor" and standalone cost "ceiling", UED must first apply a "cost of supply" methodology to assist in setting tariff rates. To reduce the scope of forecasting error, UED has conducted its cost of supply modelling using 2004 data.

UED's cost of supply methodology allocates the 2004 regulated distribution revenue to each tariff. The regulated distribution revenue is treated as the "total costs" of the distribution business. Broadly speaking, tariff rates are set to recover the allocated distribution revenue from that customer group. It is noted, however, that UED has regard to all the pricing principles outlined in Section 13.2 in setting tariff rates. Furthermore, in terms of tariff

77 Essential Services Commission 2004, Electricity Distribution Price Review 2006 - Final Framework and Approach: Volume 1, Guidance Paper , Page 97.

structure, UED has listened to its customers, who have expressed a strong preference for reductions in fixed charges.

The critical issue from a cost of supply modelling perspective is the method by which distribution revenue is allocated across the tariff groups. As network businesses are characterised by relatively high fixed costs and significant asset-sharing between customer groups, there is no unambiguously "correct" method for allocating costs. UED's method of allocation is based on each tariff's relative usage of UED's network assets. The "cost of supply" methodology and data inputs are described briefly below:

1. Load Profile Data:

- Average load patterns for each tariff are derived from historical data such as total or sample tariff interval meter data, SCADA, zone sub, or terminal station interval data.
- Load patterns for each tariff are compared to the system profile, at each asset level. From this data, each tariff's contribution to the maximum demand on the various asset levels of the network is determined.
- Load patterns are also used to determine average tariff parameters such as load factor and power factor.
- In the case of unmetered supplies, a load pattern is assessed from installed equipment inventory, wattage ratings and daylight hours.

2. Asset data:

- UED's network asset database is used to determine the number of asset "levels" and value of the assets employed to serve each tariff.
- The asset "levels" attributed to each tariff is determined in accordance with the following 'asset participation matrix'.

Table 13.1: Asset Participation Matrix

<table>
<tr><th rowspan="3">Tariff name</th><th colspan="6">Asset level</th></tr>
<tr><th>SubTrans</th><th>High V</th><th colspan="3">Low Voltage (LV)</th><th>LV unmetered</th></tr>
<tr><th>SubT</th><th>High V</th><th>Large</th><th>Medium</th><th>Small</th><th>Unmetered</th></tr>
<tr><td>LV Unmetered</td><td colspan="6">LV Unmetered class</td></tr>
<tr><td>LVS1R
LVS2R
LVDed
WET</td><td colspan="5">LV Small class</td><td></td></tr>
<tr><td>LVKWTOU (sml:med)</td><td colspan="4">LVM(cont)</td><td>LVS(cont)</td><td></td></tr>
<tr><td>LVM1R
LVM2R5D
LVM2R7D
RCACTOU</td><td colspan="4">LV Meduim class</td><td></td><td></td></tr>
<tr><td>LVL2R
LVLKWTOU
LVLKWTOU Interuptable (lge)
LVL1R
LVKVATOU (lge)
LVKVATOUInteruptable (lge)</td><td colspan="3">LV Large class</td><td></td><td></td><td></td></tr>
<tr><td>HV-KVA
HV-KVA.Interuptable</td><td colspan="2">HV class</td><td></td><td></td><td></td><td></td></tr>
<tr><td>ST22.KVA</td><td>ST class</td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

UED has extended its "cost of supply" methodology to assess the avoidable and standalone costs.

The avoidable cost model recognises that only a proportion of total costs are avoidable. In particular, the majority of asset-related costs cannot be avoided even if a particular customer group is no longer served. Inevitably, the assessment of which costs are avoidable is a matter of judgement. It should be noted, however, that as the avoidable costs are less than the total costs, UED's cost of supply methodology will always set tariffs at a level that exceeds avoidable costs.

UED's modelling of standalone costs is similarly based on the cost of supply model. The principal differences between the "basic" cost of supply estimates and standalone costs are:

- Standalone networks to serve a particular tariff class will not enjoy the benefit of diversity in peak demand between tariff classes;
- Economies of scale may be lost in supplying a subset of existing customers or tariffs;
- Greater urban congestion may result in the optimised replacement cost exceeding UED's regulated asset value; and
- It is likely that a notional "standalone" competitor to UED may seek a rate of return that exceeds the regulated cost of capital.

These factors indicate that the standalone costs will exceed the cost of supply estimates on which UED bases its tariff design. It is important to recognise that it is difficult to determine the standalone costs with precision – inevitably a judgement must be made. The results of UED's modelling is summarised in Table 13.2 below:

Table 13.2: Comparison of 2004 Tariff Rates with Estimated "Cost Window"

Tariff Group		Lower Bound "Avoidable Cost" (c/kWh)	2004 Avg DUOS (Exc GST) (c/kWh)	Upper Bound "Standalone Cost" (c/kWh)
LV Unmetered		0.16	3.19	6.94
LVS1R	Small	0.28	5.14	10.36
LVS2R*			3.93	
LVDed*			1.53	
WET			4.02	
LVkWTOU			4.41	
lvm1r	Med	0.35	6.88	12.39
lvm2r5d*			6.20	
lvm2r7d*			7.04	
LVL2R*	Large	0.13	5.44	12.39
LVLKWTOU			**	
LVLKWTOU Interruptable (lge)			**	
LVL1R*			4.64	
LVKVATOU (lge)			2.48	
LVKVATOU Interruptable (lge)			**	
HV-KVA	HV	0.06	1.50	2.11
HV-KVA. Interruptable			**	
ST22.KVA*			0.40	
* Tariff closed to new connections and customers not already taking supply under this tariff				
** Omitted due to small number of customers in this tariff class				

13.5 Future Developments

Section 13.4 provided a high-level explanation of UED's tariff modelling. However, it was also noted that UED has a range of objectives and principles which drive tariff design. In this Section, UED consider some of the broader issues that may affect future tariff development.

UED recognises that metering technology will continue to affect tariff design. Specifically, tariff design will be affected by the following metering issues:

- the type and capability of meters on site, e.g. accumulation meters, demand reading capability, number of registers available for reading time of use consumption, half-hourly interval meters etc.;
- meter reading cycle, particularly for accumulation meters in the residential and SME segments, is an issue – for example, seasonal charges that vary each month cannot be introduced when the meters are read only once every three months;
- remote reading capabilities of interval meters may, in theory, provide greater flexibility for retailers in billing and payment arrangements, which in turn could impact distribution revenue collection;
- billing system capability of retailers would also need to be taken into account in any innovative distribution tariff designs; and
- much greater use of TOU tariffs and Interruptible tariffs is possible with interval meter and advanced two-way communications systems between the customer and the utility.

UED will continue to review the effectiveness of its existing tariffs in the light of developments in metering technology. The rollout of interval metering represents an important development in the next regulatory period that is likely to drive future tariff design.

As noted in Section 13.3 UED has been a leader in tariff innovation. UED is committed to the progressive introduction of interval meters across all customer segments in the medium term, and will assess the tariff design implications as more accurate half-hourly load shapes for all customers becomes available.

It is expected that while there may be some refinements to existing tariffs, at this stage, UED is not contemplating significant tariff changes during the 2006-2010 regulatory period. That said, UED will maintain a watching brief on the need for more substantive tariff changes, within the discipline of a well-defined analysis framework, comprising:

- feasibility study;
- business case assessment, including market research;
- stakeholder consultation;
- pilot trial; and
- full implementation.

Possible areas of further study may include:

- premium service tariffs whereby customers get a choice of above code-level supply reliability and services, for a premium on top of the standard tariff. This must be seen in the overall context of customer service as well as relationship strategies;

- an increased number of time-of-day bands, with greater peak / off peak differential, and energy and distribution tariff components peaking at different times; and

- Demand management (DM) programs aimed at different customer classes may be investigated, for example:

  – interruptible tariffs for business customers whereby customers agree to reduce their power consumption for agreed periods at the request of the distributor (likely to be at a time like a hot summer afternoon when the time when the system is heavily stressed), and in return get some compensation payments from the distributor; and

  – DM aggregation program, which involves working with a range of customers and bidding their combined interruptible load in either the wholesale energy or ancillary services market.

13.6 Other Services Provided

UED provides excluded and prescribed services as detailed in the Tariff Order and in accordance with the 2001 Determination. These are listed below in accordance with the requirements of the Guidance Paper. Further services are detailed in Chapter 6 for Metering.

13.6.1 Excluded Services

Per Tariff Order, Clause 5.7

- The transportation of electricity not consumed in the distributor's distribution system (ie inter-network provider distribution).

- Connection to the distribution system.

- Supply installation services (including metering, electric lines or electrical plant) for the specific benefit of any third party (and requested by the third party) and not made available as a normal part of standard service to all customers.

- The relocation of electric lines plant and the carrying out of associated works, (recoverable works).

- Specific services for identified customers.

- Temporary supplies.

- Capital contributions for new works and augmentation.

- Capital contributions for the augmentation of the network in order to receive supply from a co-generator.

- Network services for connection points where customers operate parallel generation requiring a standby supply (All on SECV originated contracts).
- Reserve (duplicate) supply.
- Distribution services and system augmentation required to receive energy from an embedded generator.

In accordance with Electricity Distribution Price Determination Volume II Price Controls, Clause 6.2

- The repair, maintenance, and replacement of street lighting.
- The provision of undergrounding services at the request of a third party.
- The provision of interval metering.
- The collection and processing of meter data.

13.7 Proposed Tariffs

This chapter has explained UED's approach to tariff setting. In summary, UED's existing tariffs satisfy the economic pricing principles established by the Commission. In 2001, UED introduced a number of tariff initiatives, which are now expected to have a greater influence on customer behaviour as interval meters are rolled out. Against this background, UED is not proposing any major changes to the existing tariffs, but will maintain a watching brief as new data from interval meters becomes available.

UED's proposed distribution and network tariffs (including transmission charges) for calendar year 2006 are provided in the accompanying templates. The precise level of these tariffs will depend on the Commission's revenue determination, and therefore the tariffs presented are indicative only.

UED proposes to not make any changes to the current tariffs relating to prescribed and excluded services. Tariffs for public lighting were approved by the Commission effective October 2004 and are therefore current. UED's proposed metering approach are detailed in full in Chapter 6. All remaining Tariffs relating to prescribed and excluded services will be addressed in accordance with Guideline 14.

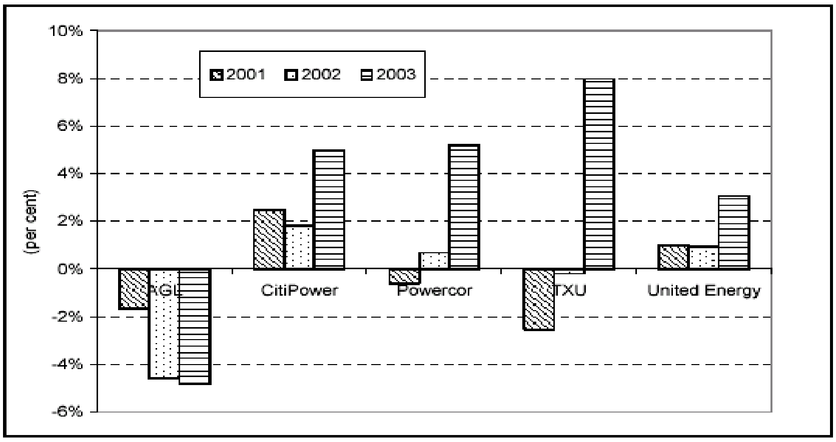
14 Demand

14.1 Introduction

The Commission's Guidance Paper explains that demand forecasts are important in the price review process in two respects. Firstly, future expenditure requirements are driven partly by expected growth in both peak demand and customer numbers. Therefore, the capital expenditure and, to a lesser extent, operating expenditure elements of the building blocks will be affected by demand forecasts. Secondly, the translation of the revenue requirement into a cap on distribution prices also relies on estimates of future quantities to which prices can be applied.

In the 2001 Determination, the Commission adopted demand forecasts following a consultative process that involved distributors, external consultants and customer groups. The Commission has conducted its own analysis of the difference between forecast and actual over the current regulatory period (reproduced below).

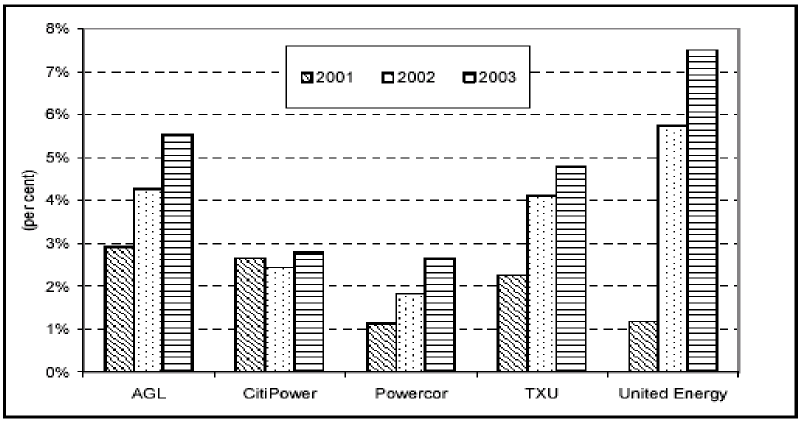
Figure 3.1: Energy consumption, actual versus forecast[a]



[a] Chart shows percentage difference between actual and forecast energy consumption. For example, in 2001, energy consumption experienced by AGL was just under 2 per cent less than was forecast.

Source: Electricity Distribution Comparative Performance Report for the Calendar Year 2001, Electricity Distribution Comparative Performance Report for the Calendar Year 2002, Information submitted by the distributors for the preparation of the upcoming Electricity Distribution Comparative Performance Report for the Calendar Year 2003

Figure 3.2: Customer numbers, actual versus forecast[a]



[a] Chart shows percentage difference between actual and forecast customer numbers. For example, in 2001, the number of customers in AGL's service area was just under 3 per cent more than was forecast.

It must be recognized that forecasting electricity demand and customer numbers is fraught with difficulty. The Commission has rightly identified the unexpected and prolonged housing boom as an important driver of the difference between forecast and actual data. The impact of forecasting errors on company profitability is determined by the form of price control, which encourages tariffs to reflect costs. UED's tariff policy is described in detail in Chapter 13 of this submission.

The Commission's Guidance Paper, explains that distributors will be required to obtain, and provide to the Commission, independent verification that their forecasts, their assumptions, the key input data and forecasting methods are reasonable, and that the forecasting method has been applied appropriately. To meet this requirement, UED has commissioned NIEIR to provide independent demand forecasts.

UED believes that NIEIR has the necessary skills and experience to provide robust, reliable and independent demand forecasts. In particular, UED note that NIEIR has been retained to conduct independent forecast by the other Victorian distribution businesses and VENCorp. This provides further assurance to the Commission that the forecasting approach is consistent across the 5 distributors, and that each forecast is consistent with the aggregate forecast for the State. This is a highly preferred approach as it avoids a situation where distributors each forecast inconsistent “shares” of total state demand, using different methodologies. Such an outcome would have potentially presented the Commission and interested parties with a difficult task in “choosing” between competing approaches.

In addition to forecasting aggregate demand for UED’s network, UED must also provide forecasts for each tariff category. This task is complicated by the prospect of tariff migration – where customers transfer to alternative distribution tariffs in search of lower costs. The rollout of interval meters creates greater potential for tariff migration in the forthcoming regulatory period.

Table 14.1, Table 14.2 and Table 14.3 below provides a high level summary of maximum demand (sum of non-coincident zone substation peak demands), customer numbers and energy volumes for the forthcoming period.

Table 14.1: Maximum Demand (MVA)

	Year Ending 31 December				
	2006	2007	2008	2009	2010
Total	2,120	2,203	2,280	2,355	2,435

Table 14.2: Customer Numbers

	Year Ending 31 December				
	2006	2007	2008	2009	2010
Total	617,221	624,081	630,752	636,511	643,560

Table 14.3: Energy Volumes

	Year Ending 31 December				
	2006	2007	2008	2009	2010
Total	7,595	7,695	7,782	7,879	8,010

The remainder of this chapter is structured as follows:

- Section 14.2 provides an overview of NIEIR's independent forecasts for maximum demand;
- Section 14.3 provides an overview of NIEIRS independent forecasts for energy and customer numbers;
- Section 14.4 discusses the tariff migration issue; and
- Section 14.5 provides a brief summary.

14.2 Overview of NIEIR's Independent Forecasts for Maximum Demand

NIEIR has been engaged to develop forecasts of UED maximum demand (summer and winter) under the base, high and low economic scenarios and two weather probability, the 10 per cent weather probability and the 50 per cent weather probability.

NIEIR employed its state and regional industry based economic projection models for the prediction of economic growth. Forecast of coincident and non-coincident maximum demand is based on a methodology which is consistent with the approach used by NIEIR for VENCorp and NEMMCO (and also Western Power, Powerlink and Energex). The approach involves estimating temperature sensitive load and linking this back to forecasts of air conditioning unit sales which depend upon the building cycle effects, income growth and overall temperature conditions.

Historical electricity loadings across the UED regions have been provided to NIEIR for the estimation of temperature sensitivity of existing loads.

Due to the relatively high penetration of air conditioning in UED's region, maximum demands experienced on the UED network occurred in summer time (where network capacity is at its lowest) and have been found to be very much temperature dependent. To ensure that the network is augmented with sufficient capacity to supply the projected summer load, therefore avoiding the situations which have occurred in Western Australia, NSW and Queensland in recent years where demand outgrew supply capacity, it is prudent for demand reinforcement expenditure to be based on a high economic growth and 10% (1 in 10 years) weather probability. The economic growth and weather scenario chosen is consistent with that approved by the Commission for the current regulatory period.

Maximum demand will grow, on average, at 3.l66 per cent from 2005-2010 under a tenth percentile summer and high economic growth scenario.

14.3 Overview of NIEIR's Independent Forecasts for Energy and Customer Numbers

NIEIR employed its state and regional industry based economic projection models with electricity consumption data for the UED distribution region to forecasts of regional electricity demands.

This model effectively takes NIEIR's state forecast of gross state product (by industry) and disaggregates it into 11 statistical sub-divisions across Victoria and 31 Local Government Areas (LGAs) in Melbourne.

Under the baseline scenario, NIEIR forecast that UED region's gross regional product is expected to grow by 2.9 per cent in average terms between 2004 and 2014. Population is expected to rise by an average rate of 0.3 per cent between 2004 and 2014.

Electricity sales growth averages 1.3 per cent between 2006-2010. Total sales growth in 2004 is forecast to slow to 1.2 per cent, as industrial sales remains flat and residential growth slows. NIEIR sales estimate for 2004 is based on the temperature normalised energy. The strong contribution of temperature to the 2003 calendar year can readily be seen in the growth rates for residential and commercial sales. Both classes rose by over 4 per cent in calendar 2003.

The main movements by class are as follows.

- Residential sales growth slows to 1.9 per cent in 2004, partly reflecting the assumption of normal weather. A downturn in new dwelling construction slows residential sales growth over 2005 and 2006 before a strong recovery in 2007. Residential sales growth reaches 1.8 per cent in 2007 in the UED region. An expected downturn in new dwelling construction slows residential sales growth over 2009 and 2010. Residential sales growth in the UED region is fuelled by customer growth of around 1.0 per cent and continued high penetrations of air-conditioning equipment. Whilst the Victorian Government's 5-star rating will dampen growth, the high penetration of gas in the hot water market suggests many may opt for the solar/gas option.

- Commercial sales in the UED region average 2.2 per cent growth over the 2006-2010 period. Slow growth is forecast for calendar 2004, however, this reflects temperature normalisation of the sales data from 2004 onwards.

- UED industrial sales average 0.3 per cent average annual growth over the 2006-2010 period.

- Traction and public lighting electricity sales are linked to general population growth. Traction is forecast to grow at an average rate of 2.1 per cent between 2003 and 2014 while public lighting is forecast to average 1.8 per cent growth over the same period.

Figure 14.1 and Figure 14.2 below (reproduced from NIEIR's report) summarise the forecast annual growth in electricity sales and customer numbers by class under the base scenario for calendar years to 2014.

Figure 14.1: Electricity Sales by Class – Base Scenario

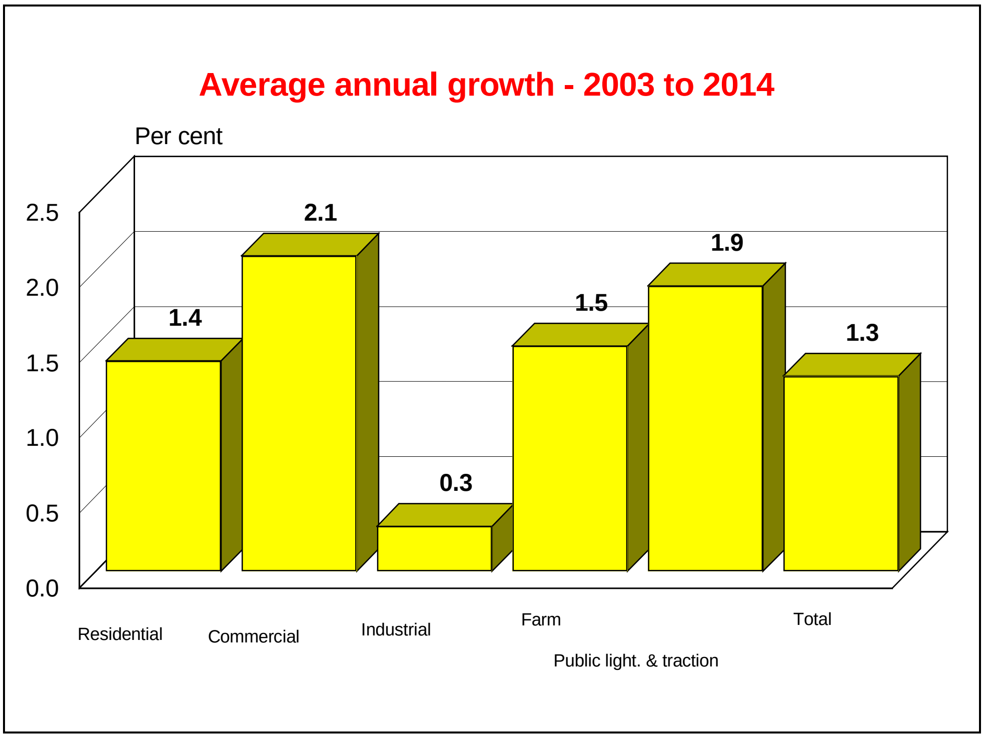
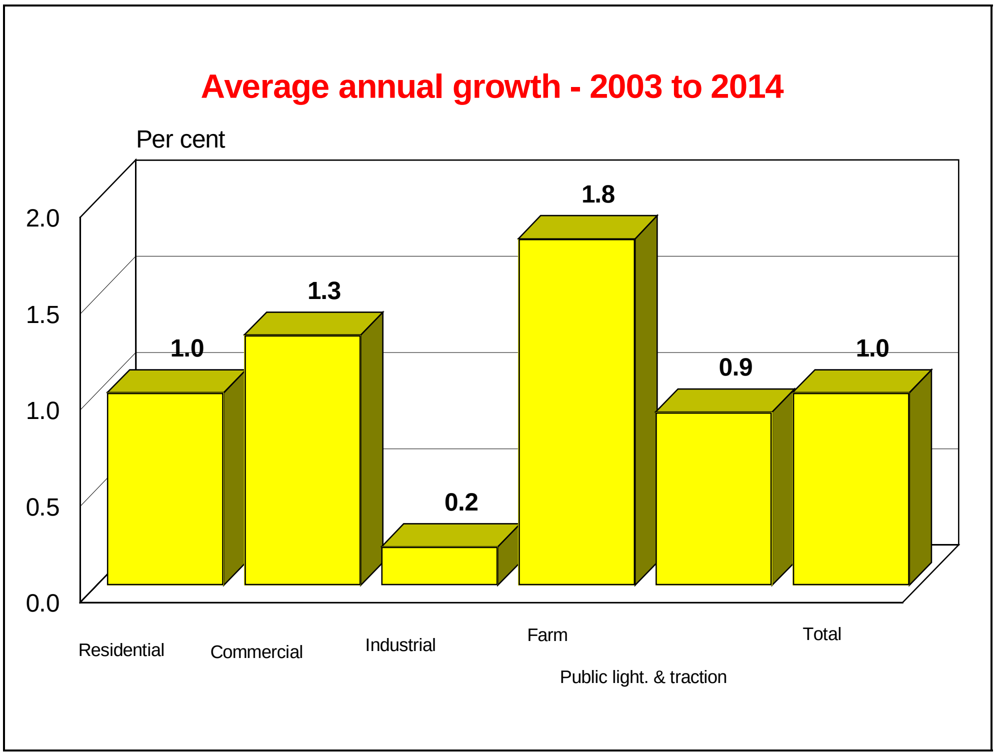


Figure 14.2: Electricity Customers by Class – Base Scenario



14.4 Tariff Migration Issue

Tariff migration occurs when customers transfer from an existing network tariff to an alternative, cheaper tariff. As a matter of principle, UED does not object to tariff migration as it indicates that customers are exercising their choice of tariffs. However, from an equity perspective, it is important that customers and retailers are prevented from exploiting any gaming opportunities, as this may unfairly disadvantage other customers and create an unreasonable administrative burden on UED.

From a forecasting perspective, tariff migration is important because it has an impact on UED's revenue. In the forthcoming regulatory period, there are two key drivers for tariff migration:

- Embedded networks; and
- Interval metering.

In relation to embedded networks, UED faces the risk that existing customers are in future supplied by a "landlord" or "parent" connected at the HV tariff level. The possibility of customers effectively migrating from LV to HV tariffs exposes UED to revenue risk. It also creates substantial uncertainty regarding the process by which "tenants" can subsequently seek alternative retailers, and potentially creates a further administrative burden on UED (as discussed in Section 10.4.11).

It is not easy to estimate the number of embedded networks that may develop over the forthcoming regulatory period, or the precise revenue exposure. The forecasts presented in this submission make no explicit allowance for tariff migration due to embedded networks. However, UED reserves the right to revisit these forecasts over the duration of the review process should further information or data become available that assists in forecasting the extent of the likely migration.

In relation to interval metering, the key driver for tariff migration is that customers may be cheaper to serve on the TOU network tariff. In essence, either the incumbent retailer can seek out these opportunities for cost reductions or, alternatively, competitor retailers will offer low-cost customers more competitive retail prices. The benefit of lower network costs are likely to be significantly outweighed by wholesale energy cost savings. It is highly likely that retailers will be keen to exploit any opportunity to raise retail margins or to increase market share.

The tariff forecasts presented in this submission make an allowance for the migration of customers to TOU tariffs. The key factors in determining the numbers of customers transferring are:

- the rollout program for interval meters;
- the potential benefits to customers of moving to TOU meters;
- retailers' incentives to seek out lower cost customers; and
- the administrative ease with which customers can be transferred.

Some of the key benefits identified in the Commissions Final Decision on[78] interval meter rollout are:

- Provide the capacity and incentive for customers to manage their electricity consumption more efficiently.
- Increase retail price efficiency.
- Provide distributors with the capability and incentive to introduce more efficient pricing to retailers.
- Increase the efficiency of combined wholesale and retail electricity markets.
- Provide distributors with the capability and incentive to manage power quality.
- Lead to improvements in operational network management.
- Increase the accuracy of settlement and ensure equity among customers.

In general, UED expects that retailers will pursue these cost-saving opportunities rigorously. For this reason and those listed above, UED expects significant tariff migration for those customers that are perceived by retailers to be cheaper to serve. UED's assessment of these factors are reflected in the forecasts provided.

14.5 Summary

This chapter has outlined UED's approach to demand forecasting. In summary, UED has used independent forecasters, NIEIR, to develop a robust set of demand forecast in accordance with the Commission guidance paper.

UED has also recognised the forecasting issues arising from tariff migration. In relation to embedded network, UED has not yet made any explicit allowance for this effect in its tariff forecasts. UED, however, reserves the right to revisit these forecasts over the duration of the review process should further information or data become available that assists in forecasting the extent of the likely migration.

In relation to tariff migration as a result of interval meter rollout, UED has reflected this issue in its tariff forecasts. These forecasts may also be subject to change as new or better information becomes available.

78 Essential Services Commission, July 2004, 'Mandatory Rollout of Interval Meters for Electricity Customers – Final Decision', Page 25, Table 2.

15 Electrical Safety Regulations

15.1 Introduction and Overview

The Electricity Safety Act 1998 (ESA) makes provisions for the safety of electricity supply in Victoria. UED is required to comply with the provisions of the ESA and its supporting regulations in the construction, operation and maintenance of its distribution network. Changes to the ESA, in particular supporting regulations relating to supply safety, Electricity Safety Management Schemes (ESMS) and electricity line clearances, have affected UED's ability to comply, not only with respect to new and replacement assets, but also those assets installed prior to the amendments being introduced.

This Chapter discusses issues associated with achieving ***'literal'*** compliance with the Electricity Safety (Network Assets) Regulations 1999 (ESNAR), as introduced in 2000, including the benefits to be derived, costs to customers and the ability of the industry to resource such a compliance program. It also discusses issues associated with the development and approval of an ESMS including the need for compliance with the level of safety determined by the regulations and the ability of the Office of the Chief Electrical Inspector (OCEI) to impose conditions when approving an ESMS.

It should be noted that expenditure benchmarks included in this submission reflects the costs incurred by UED in achieving and maintaining compliance in accordance with UED's ESMS. Nevertheless, if the regulatory compliance issues are not clarified by the time of the 2006 Determination, UED requires an allowance representing the costs outlined in Table 15.1.

The remainder of this Chapter is structured as follows:

- Section 15.2 summarises the relevant safety legislation, and
- Section 15.3 provides UED's approach to the Electrical Safety Management Scheme (ESMS).

15.2 Safety Legislation

15.2.1 Electricity Safety Act 1998

The Electricity Safety Act 1998 (ESA) makes provisions for the safety of electricity supply in Victoria. Part 13 of the ESA provides for the making of regulations in respect of various electricity safety functions while Part 10 of the ESA provides for ESMSs.

15.2.2 Electricity Safety (Network Asset) Regulations 1999

The ESNAR are the principle regulations governing the construction, maintenance and operation of electricity distribution networks within Victoria. The regulations are currently administered by the OCEI. The objectives of the ESNARs are:

(a) to prescribe standards for the design, construction, operation and maintenance of network assets; and

(b) to protect persons from risk, and property from damage, associated with network assets.

The scope of the regulations includes general obligations of the network operator, supply system standards, aerial and underground lines and services, electrical substations, generators, earthing and electrical protection. UED's compliance with the regulations is subject to an annual audit regime by the OCEI.

Amendments to the 1999 Regulations, particularly in the area of clearance heights for service conductors, and the subsequent interpretation of the need for 'literal compliance', has increased the level of compliance obligation and risk for UED.

15.2.2.1 Service Height Clearance

As discussed in various forums and most recently in correspondence to the Commission dated 24 September 2004, UED and other Distributors believe that the 1999 revisions to the ESNAR have rendered a significant number of service installations across the State, installed prior to 2000, non-compliant and thus has increased the risk to each distribution business.

Prior to 1999 the prescribed minimum height for service lines over driveways and other ground traversable by vehicles was 3.9 metres. When the ESNAR's were revised, the minimum height for new service lines was increased to 4.6 metres with effect from 1 January 2000. For various reasons many existing services fail to meet the amended minimum height criteria. Based on the best information available, UED estimates that it has some 290,000 services under height at some part of the service line (145,000 under height over some part of the carriageway, 93,000 over traversable areas and 50,000 over other areas such as at the point of attachment).

15.2.2.2 Other network asset regulatory amendments

While the scope and costs of works associated with service line heights is the most contentious of the network asset regulatory amendments, a number of other amendments to the ESNAR and issues arising under the Electricity Safety (Electric Line Clearance) Regulations (ESELC) require UED to undertake significant works to achieve compliance. A list of these is set out in Table 15.1 below.

15.2.2.3 Progress to Date

The 2001 Determination provided a fund to enable Distributors to undertake a range of compliance related programs including:

- Compliance auditing and increased accident reporting obligations;
- Increased service height clearance for new and replacement service lines over driveways and other ground traversable by vehicles;
- Testing of LV neutrals;
- Pole straightening;
- Marking of underground network assets; and

- Testing of electrical earthing systems and electrical protection equipment.

UED developed and implemented programs to address non-compliance in each of these areas and since 2001 has provided quarterly reports to the OCEI on the status of each program.

In the case of service clearance heights, UED undertook a risk assessment of these services and programs have been completed to replace all identified high risk existing service installations. Work to replace medium and low priority installations is continuing. New and replacement services are installed in accordance with the 1999 ESNAR requirements. Where a service faults, while it may be initially reinstated at its current height in order to restore supply, it is recorded in the maintenance program for early attention.

UED is also working with other Distributors and component manufacturers to develop innovative solutions, such as clean break devices which electrically and mechanically isolate a service, to reduce the level of risk to the public and the network when a service fails or is damaged through contact by vehicle, tree or debris.

15.2.3 Approach Going Forward

While satisfactory progress towards compliance has been achieved in all areas, the issue of service height clearance remains a major concern, particularly in light of the 'literal compliance' discussions.

In the past, UED's approach to achieving compliance with the amended regulations would have been considered appropriate; however the argument for literal compliance in the case of the 1999 ESNAR amendments means this approach can no longer be pursued without significant risk to the business.

The capital expenditure benchmarks included in this submission reflect the cost to UED of continuing the current approach to achieving compliance with the 1999 ESNAR and the ESELC regulations; that is, in the case of services, continuing to replace non-conforming services on a priority basis as discussed above. This approach is consistent with the ESMS lodged with the OCEI by UED in 2003.

Should it be necessary to achieve literal compliance within the period 2006-2010 Table 15.1 below sets out by item the annual cost for each year of the 5 year period. UED considers this alternative approach to be impractical as it is unlikely that the industry would be able to resource such a program and the cost impost on both the industry and customers would be significant.

Irrespective of which approach is adopted, UED believes that a review of the 1999 ESNAR amendments and their interpretation is required to ensure that expected safety benefits are commensurate with the costs incurred by distributors to achieve compliance. UED believes that a significant portion of the work involved in achieving literal compliance with the regulations is unlikely to deliver any real improvement in safety or risk reduction. By way of example, the requirement to install services in areas where high vehicular traffic is negligible is unlikely to deliver any measurable change in the level of safety or risk.

Table 15.1: Summary of Safety Regulations

Safety Regulation	Annual Costs
Inspecting and testing of earths Regulations 27 (2), 23 (2), and 23 (11).	$225,600
Overhead services minimum distance between aerial lines and the ground. Regulation 13(1).	$44,952,862
Minimum substation height above ground Regulation 22(3)	$21,241,832
Poles and towers and other structures must be vertical Regulation 25	$792,200
Other authorities aerial lines minimum distance between aerial lines and the ground Regulation 13 (2).	$253,333
Protective equipment to isolate unsafe situations and conductors Regulation 23 (1,4,11) (breakaway device)	$6,000,000
Code of practice for electric line clearance of 56M trees	$589,000
Total	**$74,054,828**

15.3 Electricity Safety Management Scheme

Section 107 of the ESA allows for the operator of an electrical network to seek to operate under an ESMS considered by the OCEI and approved by the Governor-in-Council. For an ESMS to be approved the OCEI has to be satisfied that it complies with section 107(2) of the Act and the regulations relating to ESMS and that the level of safety to be provided by the ESMS is not less than the level of safety which is required to be provided by the Act and ESNAR.

In 2003, UED applied to the OCEI to operate an ESMS. It provides for:

- an independent validation of the systems and procedures for the design, construction, operation and maintenance of the upstream works;
- applying variations to the ESNAR by seeking exemptions from the OCEI; and
- the implementation of management plans to address areas of non-compliance to the ESNAR.

In areas where compliance to the level required by the ESA or the ESNAR has not been achieved, UED has developed a number of programs which have been agreed to with the OCEI. These plans include:

- overhead Service Heights;
- pole substations;
- Neutral Testing Program; and
- management of shallow cables.

Further, UED is considering the options available to develop management plans, or seek further exemptions in areas such as:

- the use of PE conduit; and
- a targeted Neutral Testing program.

15.3.1 Approach Going Forward

UED supports the ESMS approach to safety management. It believes that in order to give distributors certainty going forward, legislation governing ESMS and the relevant regulations must be clarified to ensure that a distributor operating in compliance with an approved ESMS is deemed to be compliant with relevant regulations.

UNITED ENERGY
Distribution

APPENDIX A

The Weighted Average Cost of Capital
for 2006 Electricity Distribution Price-Service Offering

October 2004