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1 September 2006

Paula Rebstock
Chair
Commerce Commission
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Dear Ms Rebstock

Unison's Settlement Proposal

I am pleased to attach a settlement proposal from the Unison Board in respect of the post-breach inquiry.

In summary the settlement proposal is that Unison will voluntarily amend its tariffs, effective 1 October 2006, to a level that would result in compliance with the threshold price path come the 31 March 2007 assessment date, had those tariffs been applied from 1 April 2006. As those tariffs will only apply from 1 October 2006, Unison is likely to breach the threshold, at the 31 March 2007 assessment date, by approximately $450,000.

The settlement proposal reflects a rebalancing of charges between regions and customer groups based on a cost of supply model. The cost of supply model is underpinned by pricing principles consistent with the industry agreed model pricing principles. This rebalancing will also be implemented on 1 October 2006.

To achieve these outcomes Unison needs to secure agreement from retailers to permit tariff changes outside the terms of Unison's Use of System Agreements, i.e.: frequency of changes and required notice periods. This agreement has not yet been obtained.

The settlement proposal reflects the in principle positions expressed in correspondence to the Commission dated 24 July 2006 and 18 August 2006. The settlement proposal also reiterates the general concerns expressed in that correspondence in respect of the regulatory framework. While the Unison Board considers that it has little option but to make this proposal in order to reach a settlement and, thereby, manage the risk of control being imposed on the business by the Commission, it looks forward to working constructively through the forthcoming engagement as part of the regulatory threshold reset process pending in 2009 to address many of these concerns.

In the meantime, Unison is committed to maintaining the level of effort and expenditure directed at maintaining network performance and to maintaining the standard of asset management practices and philosophy. Unison undertakes to achieve the targeted level of renewals expenditure, within the overall projected level of capital expenditure, over the period of the settlement.

Yours sincerely

p.p.

Brian Martin
Chairman

Settlement Proposal

31 August 2006

[Public Version]

…we're always working for you

Contents

1. Introduction

This document describes and summarises Unison Networks Limited's ("Unison") settlement proposal to the Commerce Commission ("the Commission") in respect of the current post-breach investigation.

Without Prejudice
Unison provides this settlement proposal and the material supporting this offer without prejudice to its position in respect of the ongoing post breach investigation and without prejudice to its position in respect of the appeal of the High Court decision *Unison Networks Limited vs Commerce Commission* (Wellington Registry CIV 2005 485 960, Wild J, 28 November 2005). The settlement proposal is subject to the outcome of the Court of Appeal proceedings.

Material Change
In the event of a material change in the regulatory landscape (for example, but not limited to, the Commission's consideration of the Government Policy Statement dated 7 August 2006) Unison may seek an amendment to any terms agreed with the Commission as part of this settlement. It is understood that such an approach would need to be supported by relevant evidence of the change and its likely impact.

Reservation of Unison's Position
Unison has previously expressed reservations regarding a number of aspects of the Commission's Targeted Control Regime and the associated assessment framework. We continue to hold these reservations as we believe the threshold regime and the conclusions drawn by the Commission in respect of matters such as the weighted average cost of capital determination approach and parameter selection, the treatment of the depreciation taxation shield arising on acquisition of networks, the use of optimised deprival valuation and the treatment of asset revaluations introduce strong disincentives for lines businesses to achieve efficiencies through industry consolidation and to undertake much needed investment in critical infrastructure.

These reservations notwithstanding, Unison's directors consider that they have little option but to make this proposal in order to reach a settlement and thereby manage the risk of control being imposed on the business by the Commission. In taking this step, the directors recognise the benefit of reaching a conclusion to the investigation and control processes in order to allow the business to more fully focus on the provision of service to its customers. The directors also recognise that further engagement with the Commission is necessary to address the concerns recorded above and that this engagement will be forthcoming as part of the regulatory threshold reset process pending in 2009. The directors look forward to working constructively through this engagement in seeking a more workable regulatory environment.

Structure of this document

- o A summary of the settlement proposal is included in section 2.
- o Section 3 provides a brief background of Unison's threshold breaches and the post breach inquiry process to date.
- o The proposal to resolve the outstanding threshold breaches is explained in more detail in section 4.
- o The impact of the settlement proposal on regional and customer group outcomes is covered in summary in section 5. Detailed descriptions of Unison's Cost of Supply Model and the cost allocations to regions and customer groups are provided in Appendix A.
- o Section 6 addresses Unison's quality threshold breaches.
- o Section 7 summarises Unison's proposed capital expenditure and the Company's commitment to meeting its renewal expenditure targets. Further detail of the capital plan is provided in Appendix B.
- o The settlement proposal is analysed in terms of satisfaction of the relevant purpose in the Commerce Act in section 8.

2. Summary of the Proposal

Unison's revised settlement proposal consists of the following key elements:

1. Subject to the ability to secure agreement from retailers to permit tariff changes outside the terms of Unison's use of system agreements, Unison will voluntarily amend its tariffs, effective 1 October 2006, to a level that would result in compliance with the threshold price path come the 31 March 2007 assessment date, had those tariffs been applied from 1 April 2006. Unison seeks the Commission's assistance to work with retailers to ensure this price change does not inhibit a regular tariff review effective 1 April 2007 and that the contractual period for notice of tariff changes is waived.

2. Unison's subsequent tariff reviews (effective 1 April 2007 and 1 April 2008) will be determined to maintain compliance with the threshold price path through to the end of the current regulatory period.

3. On a regional basis, the tariff change will reflect cost allocations between the regions that result in a consistent rate of return from each regional network.

4. Unison will also rebalance tariffs between customer groups to better deliver cost reflective prices. This rebalancing will reflect the allocation of costs in Unison's current Cost of Supply Model.

5. Unison's quality thresholds are 152.7 for SAIDI and 2.39 for SAIFI. Unison seeks agreement that the information examined in the course of achieving this settlement adequately addresses the past quality breaches by Unison. The settlement should address and resolve Unison's quality breaches on the basis that Unison has applied and continues to apply sound asset management practices. Unison believes that its quality thresholds were been set too low, probably as a result of inadequate data quality and completeness over the course of the five year benchmark period. It seems probable, therefore, that Unison may continue to breach the quality thresholds. However, Unison is committed to maintaining the level of effort and expenditure directed at maintaining network performance and to maintaining the standard of asset management practices and philosophy as observed by Parsons Brinkerhoff in their review of Unison on behalf of the Commission as part of the post breach inquiry process.

6. Unison is scheduled to spend $48.3 million on renewals (in nominal terms) over the three years from 1 April 2006 to 31 March 2009. These expenditure targets represent a further increase in expenditure levels over the level of previous years. Unison undertakes to achieve the targeted level of renewals expenditure, within the overall projected level of capital expenditure. Unison will report annually, in its Asset Management Plan, on the cumulative renewals spend against the forecast included within the settlement proposal.

7. The settlement arrangement ends on 31 March 2009.

Sections 4, 5, 6, 7 and 8 of this report explain the basis of the settlement proposal.

3. Background

Unison is the fourth largest electricity distribution business in New Zealand and supplies consumers in the Hawke's Bay, Taupo and Rotorua regions. The company is 100% owned by the Hawke's Bay Power Consumers' Trust, which holds the shares on behalf of the consumers connected to Unison's network in Hawke's Bay.

Consequent on the introduction of the price and quality thresholds as part of the Targeted Control Regime established by the Commission pursuant to Part 4A of the Commerce Act, Unison has breached the price path thresholds at the first, second and third assessment dates. These breaches arise from a price increase on the Hawke's Bay network in April 2002 and a price increase across all of its network areas in March 2004.

Unison has also breached the price path at the fourth assessment date, albeit that Unison has not increased prices since March 2004. Due to the cumulative nature of these assessments, Unison will also breach the price thresholds the next assessment date (31 March 2007), notwithstanding that Unison reduced its prices in Rotorua/Taupo on 1 April 2006 and is proposing further price reductions as part of this settlement proposal. Nonetheless, the extent of Unison's breaches has been diminishing over time.

Unison has also breached the SAIDI criterion of the quality threshold at the second and third assessment dates and the SAIFI criterion at the third assessment date. Unison has also breached the SAIFI criterion at the fourth assessment date.

Following an inquiry in respect of Unison's breaches the Commission indicated, in December 2004, that it considered there were grounds to proceed to an intention to declare control. In February 2005, Unison made an Administrative Settlement Offer ("the initial ASO") to the Commission and the Commission deferred its decision on whether to publish an intention to declare control, pending an opportunity to evaluate the initial ASO.

Having considered the initial ASO and other information provided by Unison, the Commission published its intention to make a declaration of control of Unison's electricity distribution services on 9 September 2005.

As an interim measure, and a gesture of good faith, Unison has reversed its most recent (March 2004) distribution price rises as they affected the Taupo and Rotorua areas, effective from the first of April 2006. As a result, the Commerce Commission has delayed its decision on whether to place the company's electricity distribution services under control, giving Unison time to prepare a revised ASO for the Commission.

4. Proposal to Resolve the Outstanding Breaches

4.1 Context of Proposal

Unison's directors are concerned that any settlement must preserve the Company's ability to undertake necessary investment in the network. Decisions on investments must be made by directors within the requirements of Directors duties under the Company's Act to act in the best interests of shareholders. In essence this requires that directors ensure the business and any investments to perpetuate or expand the business do not destroy shareholder value and that the business generates sufficient cash to be able to pay its debts as they fall due.

It is acknowledged that a business has three primary sources of cash: equity capital, debt capital and operating cash flow. In considering the cash requirements of the business, Unison observes that its ability to raise additional equity funding is constrained, at least in the short term, by the current ownership structure. As debt providers have regard to the Company's leverage, this limitation potentially constrains the Company's access to further debt capital.

In any case, a control or settlement outcome that has a materially adverse impact on the financial position and financial performance of the business, in particular operating cash flow and a reasonable rate of return, would also have the effect of further diminishing the ability of the Company to raise additional (debt or equity) capital to fund its operation.

Unison's directors have considered the cash flow requirements of the business to ensure that sufficient cash is available to meet the ongoing needs of the business over the settlement period. In particular, the level of capital expenditure required by the business over the period to 31 March 2009 is discussed in section 7 and more fully in Appendix B. As part of this settlement offer, Unison undertakes to achieve the targeted level of renewals expenditure, within the overall projected level of capital expenditure. The level of renewals expenditure necessary to maintain the level of quality and reliability of network services will be identified in the Asset Management Plan each year, as will the performance against those spend targets.

4.2 Voluntary Undertaking to Amend Tariffs

In developing this settlement offer Unison has engaged with the Commission (and interested parties) through:

- the post breach investigation process (stage I)
- the Notice of Intention to Declare Control
- the submission, conference and cross submission processes, and
- subsequent discussions with the Commission.

Taking account of the information and views provided through these processes Unison is committing to voluntarily amend its tariffs to a level that would result in compliance with the threshold price path come the 31 March 2007 assessment date, had those tariffs been applied from 1 April 2006.[1]

This tariff schedule change will be effective from 1 October 2006, subject to obtaining retailers' agreement to this change.

The majority of Unison's use of system agreements with retailers limit Unison to changing prices only once in any twelve month period, subject to the exceptions of changes in transmission charges and changes required by law or changes in regulatory levies. As the proposed change will be either a unilateral and voluntary change by Unison or a result of an administrative settlement between Unison and the Commission, this will not satisfy the exception for changes required under law. In effecting this settlement Unison does not wish to compromise its ability to reset prices at 1 April 2007 and subsequently at 1 April 2008. Accordingly, Unison will seek retailers' agreement to this change and we request the Commission's assistance in this matter.

Under the use of systems agreements Unison is also required to provide up to 60 days notice to retailers of tariff changes. Implementing the proposed tariff schedule changes will also be conditional upon retailers agreeing a shorter notice period.

4.3 Revenue Levels for 2007, 2008 and 2009

The revenue outcome of the change to tariff schedules committed to for 2006/07 (notional annualised revenue) and forecast for 2007/08 and 2008/09 is reflected in the tables 1 to 4 below:

Allowable Notional Revenue under CPI -X price path		
Term	**Description**	**$000**
X	X Factor	0%
R_{2004}	Maximum Revenue at 31 March 2004 that would not have caused a breach under the Initial Notice	45,968
$(1+\Delta CPI_{2005})$	Average change in Consumer Price Index over 2004	1.0229
$(1\text{-}X)$	1-X Factor	1.00
R_{2005}	Allowable Notional Revenue under the CPI-X Price Path for the year ended 31 March 2005	47,021
$(1+\Delta CPI_{2006})$	Average change in Consumer Price Index over 2005	1.0304
$(1\text{-}X)$	1-X Factor	1.00
R_{2006}	Allowable Notional Revenue	48,449

[1] In particular, the test for regulation 5(1)(a), ie $NR_{2006}/R_{2006} \leq 1$

	under the CPI-X Price Path for the year ended 31 March 2006	
$(1+\Delta CPI_{2007})$	Average change in Consumer Price Index over 2006	1.035
$(1-X)$	1-X Factor	1.00
R_{2007}	Allowable Notional Revenue under the CPI-X Price Path for the year ended 31 March 2007	50,144

Table 1: Forecast Allowable Notional Revenue under CPI-x to 31 March 2007

Forecast Notional Revenue includes transmission and other pass though costs. Transmission costs are based on Unison's expected costs for the year. The transmission charge increase introduced by Transpower with effect from 1 April 2007 is included in the transmission costs as Unison's policy is to recover this charge from consumers. Any difference between the amount recovered from consumers in respect of transmission charges and the actual amount of transmission charges paid to Transpower, for the period from 1 April 2006 and up to resolution of the Commission's post-breach investigation in respect of Transpower, will be refunded to consumers in accordance with the requirements set out for lines companies by the Commission.[2] Unison believes that the approach outlined above resolves the primary concerns over forecasting transmission costs for the purposes of this settlement proposal.

The assumed rate of increase in the Consumer Price Index for the year to 31 March 2007 is 3.5%.

Forecast Notional Revenue for the year ending 31 March 2007		
Term	**Description**	**$000**
$NR_{2006}=\Sigma P_{i,2006}Q_i-K_{2006}$	Notional Revenue for the year ending 31 March 2007	50,144
K_{2006}	Forecast Transmission Charges for the year ending 31 March 2007	24,047
	Forecast Rates for year ending 31 March 2007	70
	Forecast Electricity Commission Levies for the year ending 31 March 2007	179
$\Sigma P_{i,2006}Q_i$	Prices at 31 March 2007 multiplied by 31 March 2003 Base Quantities	74,441

Table 2: Forecast Notional Revenue for 2006/07

2 Paula Rebstock letter to distributors; "Reversal of Transpower's 1 April 2006 price increase"; 11 April 2006

Forecast Total Compliant Revenue for the year ending 31 March 2007		
Term	**Description**	**$000**
$\Sigma P_{i,2006}Q_{2006}$	Prices at 31 March 2007 multiplied by 2006/07 Quantities	83,382

Table 3: Forecast Total Compliant Revenue for 2006/07

Unison's subsequent tariff reviews (effective 1 April 2007 and 1 April 2008) will be determined to maintain compliance with the threshold price path through to the end of the current regulatory period. The current forecasts of compliant notional revenue for 2007/08 and 2008/09, assuming CPI of 2.5% for 2007 and 2008, are shown in the following table:

Forecast Notional Revenue and Total Complaint revenue for 2007/08 and 2008/09			
Term	**Description**	**2007/08 *(x=8)* $000**	**2008/09 *(x=9)* $000**
$NR_{200x}=\Sigma P_{i,200x}Q_i-K_{200x}$	Notional Revenue for the year ending 31 March	51,398	52,683
K_{200x}	Forecast Pass Through Costs for the year ending 31 March	24,936	26,060
$\Sigma P_{i,200x}Q_i$	Prices at 31 March multiplied by 31 March 2003 Base Quantities	76,584	78,993
$\Sigma P_{i,200x}Q_{200x}$	Prices at 31 March multiplied by 200x Quantities	86,979	90,921

Table 4: Forecast Notional Revenue and Total Compliant Revenue for 2007/08 and 2008/09

This analysis is completed in respect of the regulated lines business only. Non-regulated activities include:

- Generation activities;
- Management services provided to other lines businesses, as these are non-conveyance services;
- Disconnection and reconnection work because Use of System Agreements across Unison's distribution network allow for suitably trained and authorised service providers to undertake disconnection and reconnection services on behalf of retailers;
- Instantaneous reserves as this income is derived as a result of a competitive tendering process and forms non-conveyance services not directly related to the provision of electricity distribution;
- Fault-related recoveries, as these are recoveries of costs not related to the conveyance of electricity; and

- Miscellaneous other revenue, for example interest, rent, profit on sale of assets. These are non-conveyance services.

4.4 Compliance at next assessment date (31 March 2007)

Price Thresholds 5(1) a and b

The effect of implementing this tariff schedule change will not avoid Unison breaching the price thresholds at the 31 March 2007 assessment date. The breach at that date will be due to the level of the tariffs predating the 1 October 2006 change and is an outcome that is now out of the Company's control. Unison is likely to breach the threshold, for this reason, by approximately $450,000.

Unison's threshold breach at 31 March 2007 may also reflect the impact of Transpower's current transmission charge rebates, depending on whether Transpower's dispute with the Commission is resolved by the assessment date, ie the extent to which Unison has recovered transmission costs from consumers in excess of the charges levied by Transpower. In accordance with the Commission's instruction, Unison is holding any over recovery to be passed onto consumers, if necessary, when the Commission's price breach investigation into Transpower is resolved.[3]

Quality Thresholds 6(1) a and b

The Company has also advised the Commission that, as a result of the severe storm events that affected our regions in June, the quality thresholds are also likely to be breached as at 31 March 2007. Unison is preparing information to provide to the Commission to substantiate that these storm events represent extreme events and should be discounted when the Commission reviews quality compliance for the period.

In section 6 Unison observes that the quality thresholds have not been met for any rolling 12 month in the past three years. It is believed that this is due to the thresholds having been set too low, probably as a result of inadequate data quality and completeness over the course of the five year benchmark period. It seems probable, therefore, that Unison may continue to breach the quality thresholds. However, Unison is committed to maintaining the level of effort and expenditure directed at maintaining network performance and to maintaining the standard of asset management practices and philosophy as observed by Parsons Brinkerhoff in their review of Unison on behalf of the Commission as part of the post breach inquiry process. As noted in that review, the level of direct maintenance and capital expenditure on the network is significantly higher than that for the five year period from 1999 to 2003 and for prior periods.

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[3] Paula Rebstock letter to distributors; "Reversal of Transpower's 1 April 2006 price increase"; 11 April 2006

5. Regional and Customer Group Impacts

The Commission's concerns that the profitability levels derived in respect of the acquired network areas of Rotorua and Taupo were in excess of those being achieved in the Hawke's Bay area have been considered in Unison's settlement proposal.

> *"This analysis … has revealed that the estimated* [returns on investment] *on Taupo and Rotorua assets for 2003/04 were significantly higher than the* [return on investment] *on Hawke's Bay assets"*[4]

In response, Unison has reviewed its pricing methodology.

In the analysis that follows, Unison has treated Rotorua and Taupo as a single region rather then two separate regions. The reasons for this approach are:

- Unison's development plans which include strengthening of the electrical contiguity of the two network areas
- To facilitate rationalisation of tariff structures and implementation of the Cost of Supply Model where assets are shared or potentially shared between the network areas
- To reflect the common reliance on Siemens' outsourced services in the two network areas
- The Transpower line which feeds electricity between Taupo and Ohaaki results in consumption from some Rotorua customers in the Ohaaki region contributing in part to the transmission costs in the Taupo region. The amount that the Rotorua customers contribute to the transmission costs in Taupo is not readily determined.

5.1 Cost of Supply Model

Unison has developed a Cost of Supply Model that underpins its setting of tariffs allocates costs between regions, asset groups and customer groups. The Cost of Supply Model is based on cost reflective pricing principles. These costs are then converted into a tariff structure to recover the costs from consumers via Unison's relationship with the electricity retailers. The pricing methodology, Cost of Supply Model and the allocation of costs to regions and customer groups are discussed in more detail in Appendix A.

As with any allocation methodology there are likely to be imperfections in the allocations incorporated in the Cost of Supply Model. The Cost of Supply Model is likely to change over time as cost drivers are reviewed and better information is gathered or becomes available. This may result in further rebalancing between regions or customer categories in the future. This is a normal part of continual improvement to Unison's pricing structures.

[4] Intention to Declare Control of Unison Networks Limited; Commerce Commission; 9 September 2005; paragraph 221

5.2 Regional Impacts

Table 5 shows the breakdown of costs by region, as determined in the Cost of Supply Model.

Region	Transmission $000	Maintenance and Operating $000	Network Depreciation $000	Cash Tax & Interest Tax Shield $000	Net after Tax Return $000	Regulatory Asset Base[5] $000	Real Rate of Return %
Rotorua/ Taupo	11,378	9,096	6,882	1,790	6,618	144,290	**4.6%**
Hawke's Bay	12,669	12,329	10,181	2,649	9,790	213,445	**4.6%**
Total Unison	**24,047**	**21,425**	**17,063**	**4,439**	**16,408**	**357,735**	**4.6%**

Table 5: Allocation of Costs for 2006/07 to Regions

The Real Rate of Return identified in this proposal (tables 5, and 7.1 – 7.3) reflects relevant inputs for the purposes of Unison's cost allocations. This differs from the inputs that the Commerce Commission would employ in determining the regulatory rate of return. These differences are identified below:

- The Cost of Supply Model produces a consistent real rate of return on the regulatory assets base from each region. The rates of return shown in table 5 are expressed as real rates of return because they do not include the notional return that may result from the annualised increase in the value of the system fixed assets as a result of successive asset valuations using the ODV methodology.

- The rates of return are also net of capital contribution income. Capital contributions are not part of the cost allocation process undertaken in the Costs of Supply Model.

- The Cost of Supply Model allocates the Company's accounting depreciation values. The Commerce Commission's methodology for determining rate of return uses ODV depreciation. As the ODV depreciation is approximately $4 million lower than the accounting depreciation.

[5] The regulatory asset base is determined from the 2004 ODV, adjusted by $12 million to reflect a more appropriate application of ODV Handbook multipliers, plus additions at cost, plus annual revaluations at CPI, less depreciation. This is in accordance with the Commission's preferred approach for asset value roll forward. The regulatory asset base has been allocated between the regions based on the relative split of the ODV Unison had undertaken as at 31 March 2006 as this provides a more accurate basis for allocating costs between the regions.

The regional allocation of costs from the Cost of Supply Model is compared with the allocation of revenue for the year, forecast based on the current pricing methodology in table 6. The average change in charges per customer is shown in table 6. Unison notes that reliance on regional averages across a broad range of customers can be misleading. As indicated in tables 8 and 9 some customer groups will see increases notwithstanding that the overall movement in each region is a reduction.

	Rotorua/Taupo $000	Hawke's Bay $000	Total $000
Current forecast	36,406	47,670	**84,076**
Proposed	35,764	47,618	**83,382**
Change	(642)	(53)	**(694)**
ICPs (forecast as at 31/3/07)	45,237	60,503	**105,740**
Average change/customer[6]	**$14 reduction**	**$1 reduction**	**$7 reduction**

Table 6: Impact of Applying Cost of Supply Model at a regional level

Table 6 reflects annualised figures for the 2006/07 year.

5.3 Customer Group Impacts

The allocation of costs to customer groups is summarised in tables 7.1 and 7.2 for each region and table 7.3 in total.

Rotorua/ Taupo	Transmission $000	Maintenance and Operating $000	Network Depreciation $000	Cash Tax & Interest Tax Shield $000	Net after Tax Return $000	Regulatory Asset Base[5] $000	Real Rate of Return %
Unmetered	100	61	90	24	87	1,896	**4.6%**
Mass market	5,193	6,550	3,639	947	3,500	76,299	**4.6%**
Small Commercial	3,090	1,766	2,166	563	2,082	45,403	**4.6%**
Large Commercial	1,708	513	745	194	716	15,617	**4.6%**
Industrial	1,287	205	242	63	233	5,076	**4.6%**
Total	**11,378**	**9,096**	**6,882**	**1,790**	**6,618**	**144,290**	**4.6%**

Table 7.1: Allocation of 2006/07 costs to customer groups for Rotorua/Taupo

6 The reduction in charges to Taupo and Rotorua consumers implemented from 1 April 2006 as part of the interim undertaking resulted in an average $46 per customer fall in charges in Taupo and a $40 per customer fall in charges in Rotorua.

Hawke's Bay	Transmission $000	Maintenance and Operating $000	Network Depreciation $000	Cash Tax & Interest Tax Shield $000	Net after Tax Return $000	Regulatory Asset Base[5] $000	Real Rate of Return %
Unmetered	160	147	183	48	176	3,846	**4.6%**
Mass market	6,480	9,563	6,067	1,578	5,834	127,192	**4.6%**
Small Commercial	1,555	1,039	1,456	379	1,400	30,529	**4.6%**
Large Commercial	2,995	1,072	1,670	435	1,606	35,020	**4.6%**
Industrial	1,479	509	804	209	773	16,858	**4.6%**
Total	**12,669**	**12,329**	**10,181**	**2,649**	**9,790**	**213,445**	**4.6%**

Table 7.2: Allocation of 2006/07 costs to customer groups for Hawke's Bay

Unison (Total)	Transmission $000	Maintenance and Operating $000	Network Depreciation $000	Cash Tax & Interest Tax Shield $000	Net after Tax Return $000	Regulatory Asset Base[5] $000	Real Rate of Return %
Unmetered	260	208	274	72	263	5,741	**4.6%**
Mass market	11,673	16,113	9,706	2,525	9,333	203,491	**4.6%**
Small Commercial	4,645	2,805	3,622	942	3,483	75,932	**4.6%**
Large Commercial	4,703	1,585	2,415	628	2,323	50,637	**4.6%**
Industrial	2,766	714	1,046	272	1,006	21,934	**4.6%**
Total	**24,047**	**21,425**	**17,063**	**4,439**	**16,408**	**357,735**	**4.6%**

Table 7.3: Allocation of 2006/07 costs to customer groups for Unison in total

The customer group allocation of costs from the Cost of Supply Model compares with the allocation of revenue for the 2006/07 year, forecast based on the current pricing methodology:

	Rotorua/Taupo			Hawke's Bay			Total Unison		
	Old method $000	New method $000	Change $000	Old method $000	New method $000	Change $000	Old method $000	New method $000	Change $000
Unmetered	354	362	9	880	715	(166)	1,234	1,077	(157)
Mass market	19,484	19,829	345	31,403	29,522	(1,881)	50,887	49,350	(1536)
Small Commercial	9,400	9,667	268	4,620	5,829	1,209	14,020	15,497	1477
Large Commercial	5,139	3,876	(1263)	6,993	7,778	785	12,132	11,654	(478)
Industrial	2,030	2,030	0	3,774	3,774	0	5,804	5,804	0
Total	**36,406**	**35,764**	**(642)**	**47,670**	**47,618**	**(53)**	**84,076**	**83,382**	**(694)**

Table 8: Impact of cost reflective prices by customer group

Table 8 reflects annualised figures for the 2006/07 year.

The average impact of the change in charges between the old allocation methodology and the new allocation methodology combined with the threshold complaint revenue for 2006/07 is expressed in table 9. This table shows the impact by region and by customer group. The impact on Mass Market customers is best assessed in terms of $/ICP while for other customer groups the average cents/kWh is a better indicator of the impact.

	Rotorua/Taupo			Hawke's Bay			Total Unison		
	Change $000	$/ICP	c/kWh	Change $000	$/ICP	c/kWh	Change $000	$/ICP	c/kWh
Unmetered	9		0.2	(166)		(1.8)	(157)		(1.1)
Mass market	345	9	0.1	(1,881)	(33)	(0.4)	(1,536)	(16)	(0.2)
Small Commercial [7]	268		0.2	1,209		1.1	1,477		0.6
Large Commercial [8]	(1,263)		(0.9)	785		0.4	(478)		(0.1)
Industrial	0		0.0	0		0.0	0		0.0

Table 9: Average impact of cost reflective prices by region and customer group

7 As a result of changes to tariff categories, a small number of customers will move between the small commercial and large commercial groups in Rotorua/Taupo.

6. Quality

Unison's performance against the quality thresholds is summarised in table 10 below.

Assessment Date	SAIDI	SAIDI Breach	SAIFI	SAIFI Breach
Thresholds	*152.7*	*n/a*	*2.39*	*n/a*
31/3/04	201.6	48.9	2.39	-
31/3/05	155.3	2.6	3.21	0.82
31/3/06	132.1	n/a	2.82	0.43

Table 10: Performance against SAIDI and SAIFI Thresholds

In respect of the assessment period ended 31 March 2004, Unison submitted that extreme weather events in February 2004 caused 52 minutes of SAIDI and 0.39 times in SAIFI. Unison has also submitted that a further 19 minutes of SAIDI in respect of the assessment period ended 31 March 2005 were caused by extreme weather events on 18 October 2004.

Unison's performance has consistently been worse than the quality thresholds, despite progressively higher asset spend. As explained in the report in Appendix B, Unison believes that the thresholds have been set too low. This is most likely due to the poor quality data, in varying degrees, for the Hawke's Bay and Rotorua/Taupo regions in the periods prior to 2003. This view is supported by the LECG report included as Appendix 4 to the report in Appendix B. The average SAIDI and SAIFI performance of the network over the three complete years following acquisition of the Rotorua and Taupo network areas is shown in the following table:

	Current Threshold Levels	Average Network Performance over the period 2004 to 2006
SAIDI	152.7	163.6
SAIFI	2.39	2.81

Table 11: Average SAIDI and SAIFI Performance

Notwithstanding the poor outcomes relative to the current quality thresholds, Unison's maintenance practices and expenditure has continued at, or been extended from, the levels prevailing prior to the introduction of the targeted control regime. It, therefore, cannot be said that Unison's poor quality performance (where this has occurred) is the result of Unison continuing or descending into bad practice in maintaining its network. Unison's performance in this regard has been reviewed by Parsons Brinkerhoff on behalf of the Commission. Accordingly, Unison seeks agreement that the information examined in the course of achieving this settlement adequately addresses the past quality breaches by Unison and that the settlement addresses and resolves all Unison's quality breaches to date on the basis that Unison has applied and continues to apply sound asset management practices.

Unison does not intend to invest to specifically to bring quality within the quality threshold levels because it is doubtful that these levels reflect the previous quality experienced by consumers and to target these levels of performance is likely to result in inefficient expenditure and would be inconsistent with consumers' expressed preference not to pay more for better quality. However, Unison is committed to maintaining the level of effort and expenditure directed at maintaining network performance and to maintaining the standard of asset management practices and philosophy as observed by Parsons Brinkerhoff in their review of Unison on behalf of the Commission as part of the post breach inquiry process. As noted in that review, the level of direct maintenance and capital expenditure on the network is significantly higher than that for the five year period from 1999 to 2003 and for prior periods.

Unison's further comments on performance against the quality thresholds are summarised below. Unison's approach to network performance has focussed on three key aspects:
1. Identify the main causes of faults on the network;
2. Improve the management of causes that are under our control; and
3. Manage the impact of faults on Unison's customers.

6.1 The management of causes that, within reason, are under Unison's control

The controllability of the causes of faults affecting SAIDI and SAIFI varies significantly. As an example, "Planned Maintenance" is, to a high degree, under Unison's control, whereas "External Influence" (such as motor accident or vandalism) is not. Unison has improved the management of the controllable component of fault causes as follows:

- **Equipment failure**
  Unison's asset renewal strategy is a key component of managing asset failure. Unison has developed and implemented strategies for the efficient renewal of all assets. This includes strategies for the repair, refurbishment or replacement of assets. Asset management strategies are based on a total life cycle cost approach, which includes the impact on customers if asset failure could result in an outage.

  A key component of the asset management strategy is Unison's inspection programme. The inspection programme forms a large part of the condition monitoring of assets, which help to identify and prioritise renewal work. Field inspections have been accelerated by making use of aerial surveys, which use aerial photography to help identify defects on assets.

  Unison has increased the asset renewal budget compared to previous years. A major focus of the increased expenditure is to proactively replace poor performing 11kV cables, as identified in the 2005 AMP. While these activities increase customer outages in the short term while Unison performs the installations, they are essential projects to ensure long term sustainable performance of the network.

Renewals activity also includes an increased rate of replacement of certain types of 11kV switchgear which have proved to be increasingly unreliable. Customer outages resulting from these activities are also necessary, but will improve long term performance of the network.

- **Animal contact**
  Unison cannot totally prevent birds and possums from ending up in its lines and other assets. However, Unison has continued down the track of altering the design of existing assets to make it more difficult for such animals to make contact with the assets. This includes projects to change copper lines to aluminium, which helps to prevent ducks from flying into the lines, conversion of high risk lines to delta construction and the installation of "Bird Be Gone" devices, which prevent birds from perching on poles.

- **Environmental**
  A key aspect of Unison's approach to managing this cause category has been the review of design standards. This initiative has only started in 2005/06 and will continue for a few years due to the magnitude of the task. It involves the evaluation of existing design standards to determine whether they are suitable for the operational environment. As a result of this initiative, Unison has identified the need to install more surge arrestors on our lines, which will limit the impact of lightning on our assets and customers.

- **Planned maintenance**
  The impact of planned maintenance on Unison's customers is minimised by the use of live line techniques and by using portable generation as a stand-by supply, where feasible. This proactive approach comes at a considerable cost, but assists in keeping the inconvenience to customers, as a result of our asset renewal programme, to a minimum.

- **Vegetation**
  Unison's strategy for vegetation control, as developed in the past year, will result in a "first cut" for the whole network over a period of three years. This has resulted in a considerable increase to operational costs, but also contributed to the excellent SAIDI result.

- **External influence**
  This cause is not within Unison's control. Motor accidents as a cause are a major contributor to SAIFI results. In an attempt to manage this trend Unison is investigating the feasibility of using "day time" reflectors on poles and changing the design of poles used in exposed locations.

6.2 Manage the impact of faults on Unison's customers

As stated before, different fault causes have different degrees of controllability. However, Unison can manage the impact of faults on customers. This is achieved by limiting the number of customers impacted by a single event through reconfiguring the network, and by restoring the network more rapidly through automation. The degree to which these two strategies are successful depends on the historical approach to the development of the network. During 2005/06 Unison has initiated several projects to reconfigure and automate the network, especially in the Taupo and Rotorua regions.

In addition to the specific strategies discussed, Unison does the following to ensure its asset management approach supports the delivery of appropriate network performance to customers:

- Unison actively monitors network performance with regular meetings to review outages on a fortnightly basis. These meetings are attended by representatives from the wider business and cover the investigation of the failures, review of response times to outages, suitability of operational restoration procedures and options to improve network configuration to minimise recurrence and support improvements in future restoration.

- Network performance is a standard agenda item for the monthly meetings with contractors on Unison’s network

- Regular reviews are undertaken by external experts to ensure Unison has adopted sound asset management practices. A recent review by Dellwind (Australia) confirmed that Unison’s practices are aligned with world best practice. Unison’s asset management approach has also received positive feedback from the Commerce Commission’s reviewers (Parsons Brinkerhoff).

Unison is cognisant that quality can be a lagging indicator of expenditure on the network. Unison is also aware that we have only monitored the performance of all of the network areas for a relatively short period of time; and as a result there is a real risk of a statistical variation arising from random events in the future. Despite these concerns, Unison is confident that the strategies put in place in 2005/06, and reflected in the 2006 Asset Management Plan (AMP), will have a positive influence on SAIDI and SAIFI in future reporting periods.

7. Capital Expenditure

The proposed level of capital expenditure is discussed in detail in sections 3 to 8 of the paper on Unison's Asset Management Approach appended to this document as Appendix B.[8] The attached report identifies the cost drivers underpinning the expenditure levels in each class of capital expenditure, as reflected in Unison's 2006 AMP.

In summary, the capital expenditure projections over the settlement period are shown in the following table:

Network CAPEX	Real 2006 $million[9]		
	2006/7	**2007/8**	**2008/9**
Customer driven	$6.2	$6.2	$6.2
Network augmentation	$5.6	$6.3	$5.3
Asset Renewals	$13.8	$15.8	$17.5
UG Conversion	$1.5	$1.5	$1.5
Total CAPEX	**$27.1**	**$29.8**	**$30.5**

Table 12: Capital Expenditure Forecast – per 2006 AMP
(based on 2006 view of Unison's replacement costs)

These expenditure targets represent a further increase in expenditure levels over the level of previous years. While the reasons for the increase in expenditure levels are explained in the document in Appendix B, Unison has had difficulty in achieving its expenditure targets in recent years. This is due to the difficulty increasing both internal and contractor capability to process and complete the level of work that is now required on the network. Considerable effort has been put into developing these capabilities and Unison intends to continue this development throughout the settlement period.

Section 11 of the document in Appendix B describes the progress Unison is currently making in rolling out the 2006/07 capital expenditure plan.

As part of this settlement offer, Unison undertakes to achieve the targeted level of renewals expenditure, within the overall projected level of capital expenditure. The level of renewals expenditure necessary to maintain the level of quality and reliability of network services will be identified in the Asset Management Plan each year, as will the performance against those spend targets.

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8 "Unison's Asset Management Approach, Practices and Outcomes"; 29 May 2006; compiled by Unison's General Manager Network.

9 These costs are included in Unison's financial model having been converted into nominal terms.

8. Satisfying the Purpose of the Act

The terms of the settlement proposal are consistent with the purpose of subpart 1 of Part 4A of the Commerce Act. In particular:

Suppliers:

(a) are limited in their ability to extract excessive profits.

Adherence to the threshold price path over the balance of the regulatory period through to 31 March 2009 limits Unison's ability to extract excessive profits.

Unison has undertaken a rebalancing of revenues, and therefore profits, between regions as part of its interim undertaking to the Commission (implemented on 1 April 2006). Unison also has undertaken, as part of this settlement proposal, to further rebalance returns between regions and customer groups by amending its tariff structure to align with the Company's cost reflective cost of supply modelling.

(b) face strong incentives to improve efficiency and provide services at a quality that reflects consumer demands.

The Commission has indicated that it will retain the current quality thresholds that apply to Unison. Accordingly, Unison is incentivised to continue to strive to achieve these levels of quality.

The amount of asset expenditure (capital and maintenance) underpinning the settlement proposal has been, and will be, subject to review and confirmation by engineers appointed by the Commission to confirm these expenditures are appropriate and necessary to maintain quality and meet customer demand. Unison has also specifically undertaken to report to the Commission on spend against its renewals budget to ensure activity to maintain the capability of the assets is occurring as proposed in the settlement proposal.

(c) share the benefits of efficiency gains with consumers, including through lower prices.

In complying with the threshold price path, Unison is subject to the same incentives to improve efficiency and the same sharing of benefits of efficiency gains with consumers over the settlement period as would have been the case had the threshold breaches not occurred.

APPENDIX A

Price Methodology and Cost of Supply Model

A.1 Price Methodology

Unison's pricing methodology was developed using the following steps;

- Establish an agreed set of **Pricing Principles**. These should drive critical decisions in methodology design and cost allocation.
- Determine the **Revenue Requirement**, identifying the costs to be allocated/recovered through the tariffs
- Determine the **Allocation of Costs** to:
    - Identify those costs that are specific to each **Zone/Region**, and those assets that are non-region specific
    - Identify those costs that are specific to particular **Asset Groups**, to ensure costs are allocated to the customer groups that utilise those assets
    - Identify cost drivers to allocate costs to **Consumer Groups** in a manner that satisfies the pricing principles and to determine the share of revenue/costs to be recovered from each customer group

The revenue allocated to each customer group will then be allocated to individual customers by way of a **Tariff Methodology** and the resulting **Tariff Schedule**.

A.1.1 Pricing Principles

Pricing principles form the basis for the Cost of Supply Model to allocate costs between regions and customer groups (as discussed below) and the tariff schedules that are intended to recover the necessary revenue from customers overall and send appropriate signals to users of the distribution service. Unison's pricing principles are largely drawn from the model principles developed by the industry and currently with the Electricity Commission for final adoption as an industry model.[10] Unison has the following pricing principles (interpretive comments are shown in italics):

- Prices should encourage efficient investment and technology innovation in the provision of distribution services; *ie*
    - *not to encourage over investment in distribution network assets*
    - *encourage least long-term cost solutions to network investment, whether that is investment by Unison or third parties*
    - *foster identification and development of innovative solutions to network investment needs*
- Prices should not create inefficient barriers to entry in the market for distribution services; *ie*
    - *should not price to prevent competition for distribution services*

[10] "Model Approaches to Distribution Pricing"; Pricing Approaches Working Group

- Prices should not unjustifiably discriminate between Retailers/consumers of the Distributor; *ie*
  - *need to consider the impact of the pricing methodology on different retailers (eg incumbent versus others) and different customer groups*
  - *any differential treatment or outcomes under the pricing methodology must be justifiable*
- Prices should encourage the efficient use of distribution services; *ie*
  - *not encourage inefficient bypass of distribution network assets*
  - *prices should fall between the incremental cost of providing the specified service and the stand alone cost of providing the specified service*
  - *encourage management (flattening) of coincident load peaks within sub networks*
- Prices should, so far as it is efficient to do so, relate to the level of service delivered and reflect the cost structures and risks of delivering the services, and be easily understood; *ie*
  - *reflect relative services required or received*
  - *be cost reflective and should recover all the efficient costs incurred*
  - *reflect risk of providing service to different customers/customer groups*
  - *avoid undue complexity in meeting these requirements*
- Changes to pricing methodology (and the rationale for them) should follow consultation with interested parties, and be widely publicised, transparent, predictable and readily verifiable;
- Prices should satisfy legal and regulatory requirements, *ie including*
  - *low fixed user tariff requirements*
  - *rural price increase requirements*

A.1.2 Setting the Revenue Requirement

The revenue to be recovered through the tariff schedule is the total of all the costs of the line business, including the cost of capital. Under Unison's settlement undertaking, the overall line service revenue for the year to 31 March 2007 is specified in table 3 of the settlement proposal document as the "Forecast Total Compliant Revenue for 2006/07".

A.2 Cost of Supply Model

A.2.1 Allocation of Costs

Unison has developed a Cost of Supply Model that underpins its setting of tariffs allocates costs between regions, asset groups and customer groups. The Cost of Supply Model is based on cost reflective pricing principles. These costs are then converted into a tariff structure to recover the costs from consumers via Unison's relationship with the electricity retailers. The allocation of costs to regions and customer groups requires the identification of relevant cost drivers and the identification of appropriate bases of cost allocation. This is then implemented through the Cost of Supply Model.

A.2.2 Regional Allocation for 2006/07 (Annualised)

The allocation process identifies those costs that are regional (ie costs can be allocated to regions on a rational basis) and those costs that are not region specific. Under the pricing methodology regional costs are split into:

- Load specific
- Customer specific
- Asset specific

Some costs are specifically incurred on a regional basis. Other regional specific costs are allocated to regions on the basis of a cost driver such as relative system length, relative MW, relative GWh, or relative ODV. Costs that are not region specific are indirect or overhead type costs. In general, these costs are allocated to customer groups (and therefore also to regions) based on relative number of ICPs.

Costs are allocated using the following regional bases:

Allocation Base	Rotorua/Taupo	Hawke's Bay	Total
ICPs number	44,944	59,634	104,578
ICPs %	43%	57%	100%
Asset Value $million	144	213	358
Asset Value (%)	40%	60%	100%
Line Length km	3,819	5,498	9,317
Line Length %	41%	59%	100%
Coincident Peak Demand MW	134	185	319
Coincident Peak Demand %	42%	58%	100%
Consumption GWh (ICP metered)	707	899	1,606
Consumption %	44%	56%	100%

Table A.1: Cost Allocation Bases – as at 31 March 2006

The costs reflected in the cost of supply model are characterised in a number of different ways to meet disclosure requirements and to facilitate sensible cost allocations. For summary disclosure purposes costs are classified as:

- Transmission charges
- Maintenance and operating costs (including non-network depreciation)
- Network depreciation charges
- Tax and interest tax shield costs[11]
- Net returns after tax

Where sensible costs within these broad classifications are allocated on a similar basis, however in some instances it is more sensible to allocate some of the costs

[11] The interest tax shield is an adjustment to the overall tax charge to reflect the benefit (reduction in tax charge) as a result of using borrowed funds. Because the Return reflects returns to both lenders and equity providers and because the Returns are expressed in after tax terms, the interest tax shield is effectively a transfer of a portion of the interest costs from the Returns to the Tax classification.

within these classifications (particularly maintenance and operating) using different cost drivers. The following sections explain these cost allocations.

The costs in tables A.2 and A.3 are allocated directly to regions, ie these costs are incurred in respect of a single region or the incidence of the costs incurred by each region is directly identifiable (eg from the invoice). Because these costs are incurred specifically on a regional basis, this is the most appropriate method of allocating cost to regions in the Cost of Supply Model.

Transmission costs are classified as load specific and are allocated to the regions as direct costs (e.g.: transmission costs are billed for grid connection points that are located in and serve specific regions).

Cost Item	Rotorua/Taupo $000	Hawke's Bay $000	Total $000
Transmission	11,378	12,669	24,047

Table A.2: Allocation of Transmission Costs

Some maintenance and operations costs are classified as asset specific costs.

Some of these costs are allocated to regions directly because the costs are incurred and recorded in respect of the Hawke's Bay region and it is necessary to recognise this to avoid these costs being allocated to any of the other regions.

Cost Item	Rotorua/Taupo $000	Hawke's Bay $000	Total $000
Local body rates	63	52	115
Unison's procurement function	-	(264)	(264)
First response costs	480	362	842
Hawke's Bay service group costs	-	72	72
Hawke's Bay service group vehicle depreciation	-	151	151
Hawke's Bay design, drawing and project delivery costs	-	230	230
Total Maintenance and operations costs allocated directly	**543**	**604**	**1,147**

Table A.3: Allocation of direct maintenance and operations costs

The maintenance and operations costs in table A.4 are allocated to regions based on line length. Both line length and asset value are indicators of the number of assets in each region, and therefore are associated with the amount of maintenance and network control activity relating to each region.

Depreciated asset value is considered unsatisfactory as a cost driver as it reflects an inverse relationship with the likely extent of maintenance resulting from asset age and has no special relationship with storm driven maintenance work or the effort required in controlling the network.

Asset replacement value is a better indicator of the relativity of physical assets in each region, however, like depreciated value, it does not have a particularly strong relationship with storm driven maintenance or the effort required in controlling the network.

Line length is the preferred driver for these costs as it has a relationship to both the value of assets in each region and also the configuration and therefore exposure to storm related maintenance. For example, the Rotorua and Taupo networks have relatively lower asset values than the Hawke's Bay but because of their relatively radial, unmeshed nature and exposure to vegetation and storm damage are relatively more vulnerable.

Cost Item	Rotorua/Taupo $000	Hawke's Bay $000	Total $000
Planned and reactive maintenance costs	2,731	3,932	6,663
Network control costs	394	567	960
Total Maintenance and operations costs allocated based on line length	**3,125**	**4,498**	**7,623**

Table A.4: Allocation of maintenance and operations costs driven by line length

The costs in table A5 relate to the cost of servicing customers with specific needs, eg industrial and large commercial customers. The incidence of such customers in each region is best represented by the relative coincident maximum demand in each region.

Cost Item	Rotorua/Taupo $000	Hawke's Bay $000	Total $000
Customer servicing costs	545	753	1,297
Total Maintenance and operations costs allocated based on coincident maximum demand	**545**	**753**	**1,297**

Table A.5: Allocation of maintenance and operations costs driven by maximum demand

The remaining maintenance and operations costs (table A.6) are not specific to any region and are classified as non-regional, overhead type costs. These costs are unlikely to be influenced by differences in the amount (eg line length) or value of assets in each region. These costs are allocated based on ICPs so individual network users contribute a similar amount to these overhead costs regardless of which region they are in.

Overhead costs include:

- o Asset management and planning costs
- o Non-capitalised new connection costs
- o Legal and human resources costs
- o Finance and accounting costs
- o Administration and head office costs

Cost Item	Rotorua/Taupo $000	Hawke's Bay $000	Total $000
Overhead costs	4,802	6,371	11,173
Total Maintenance and operations costs allocated based on ICPs	**4,802**	**6,371**	**11,173**

Table A.6: Allocation of non-regional maintenance and operations costs

The costs in the table below relate to Electricity Commission levies. These costs are mostly levied on the basis of consumption.

Cost Item	Rotorua/Taupo $000	Hawke's Bay $000	Total $000
Electricity Commission levies	81	104	185
Total Maintenance and operations costs allocated based on MWh	**81**	**104**	**185**

Table A.7: Allocation of Electricity Commission levies

The remaining costs in the Cost of Supply Model represent the return of capital (ie depreciation) and the return on capital (ie interest costs and returns to shareholders). Because tax is a deduction from the return available to shareholders it is allocated on the same basis as the return to shareholders. An additional item, interest tax shield, is also included with the actual tax paid by the business because the rate of return is generally measured after tax but independent of leverage – accordingly, an adjustment needs to be made to remove the effect interest deductibility has on the tax actually payable by the business. These costs are classified as asset specific costs.

Table A.8, A.9 and A.10 shows these costs, allocated on the basis of ODV (depreciated asset value). In respect of depreciation, there is a fairly obvious relationship between the relative depreciated asset value in each region and the share of the depreciation expense that should be allocated to that region. In addition, because the tax and rate of return items are assessed relative to the amount of capital invested in each region, this is most appropriately represented by the ODV of the assets in each region.

Cost Item	Rotorua/Taupo $000	Hawke's Bay $000	Total $000
Depreciation charge	6,882	10,181	17,063

Table A.8: Allocation of depreciation charges

Cost Item	Rotorua/Taupo $000	Hawke's Bay $000	Total $000
Cash tax and interest tax shield	1,790	2,648	4,439

Table A.9: Allocation of tax and interest tax shield costs

Cost Item	Rotorua/Taupo $000	Hawke's Bay $000	Total $000
Net return after tax	6,618	9,790	16,408

Table A.10: Allocation of net return after tax

Components of operating and maintenance costs are allocated to regions using a number of different drivers. These allocations are summarised in table A.11.

Cost Item	Rotorua/Taupo $000	Hawke's Bay $000	Total $000
Maintenance and operations costs allocated directly	543	604	1,147
Maintenance and operations costs allocated based on line length	3,125	4,498	7,623
Maintenance and operations costs allocated based on coincident maximum demand	545	753	1,297
Maintenance and operations costs allocated based on ICPs	4,802	6,371	11,173
Maintenance and operations costs allocated based on GWh	81	104	185
Total maintenance and operations costs	**9,096**	**12,329**	**21,425**

Table A.11: Summary allocation of maintenance and operations costs

(Summary of Tables A.3, A.4, A.5, A.6, A.7)

A.2.1.1 Regional Rates of Return

Table A.12 shows the breakdown of costs by region, as determined in the Cost of Supply Model.

Region	Transmission $000	Maintenance and Operating $000	Network Depreciation $000	Cash Tax & Interest Tax Shield $000	Net after Tax Return $000	Regulatory Asset Base[12] $000	Real Rate of Return %
Rotorua/ Taupo	11,378	9,096	6,882	1,790	6,618	144,290	**4.6%**
Hawke's Bay	12,669	12,329	10,181	2,649	9,790	213,445	**4.6%**
Total Unison	**24,047**	**21,425**	**17,063**	**4,439**	**16,408**	**357,735**	**4.6%**

Table A.12: Allocation of Costs to Regions

(Summary of Tables A.2, A.8, A.9, A.10, A.11)

The Real Rate of Return identified in this proposal (tables A.12, and A.7.1 – A.7.3) reflects relevant inputs for the purposes of Unison's cost allocations. This differs from the inputs that the Commerce Commission would employ in determining the regulatory rate of return. These differences are identified below:

- The Cost of Supply Model produces a consistent real rate of return on the regulatory assets base from each region. The rates of return shown in table A.12 are expressed as real rates of return because they do not include the notional return that may result from the annualised increase in the value of the system fixed assets as a result of successive asset valuations using the ODV methodology.

- The rates of return are also net of capital contribution income. Capital contributions are not part of the cost allocation process undertaken in the Costs of Supply Model.

- The Cost of Supply Model allocates the Company's accounting depreciation values. The Commerce Commission's methodology for determining rate of return uses ODV depreciation. As the ODV depreciation is approximately $4 million lower than the accounting depreciation.

12 The regulatory asset base is determined from the 2004 ODV, adjusted by $12 million to reflect a more appropriate application of ODV Handbook multipliers, plus additions at cost, plus annual revaluations at CPI, less depreciation. This is in accordance with the Commission's preferred approach for asset value roll forward. The regulatory asset base has been allocated between the regions based on the relative split of the ODV Unison had undertaken as at 31 March 2006 as this provides a more accurate basis for allocating costs between the regions.

A.2.1.2 Summary of Regional Revenue Changes

The regional allocation of costs from the Cost of Supply Model compares with the allocation of revenue for the 2006/07 year, forecast based on the current pricing methodology. The average change in charges per customer is shown in the table below. Unison notes that reliance on regional averages across a broad range of customers can be misleading. As indicated in tables A.38 and A.39 some customer groups will see increases notwithstanding that the overall movement in each region is a reduction.

	Rotorua/Taupo $000	Hawke's Bay $000	Total $000
Current forecast	36,406	47,670	**84,076**
Proposed	35,764	47,618	**83,382**
Change	(642)	(52)	**(694)**
ICPs (forecast as at 31/3/07)	45,237	60,503	**105,740**
Average change/customer[13,14]	**$14 reduction**	**$1 reduction**	**$7 reduction**

Table A.13: Impact of Applying Cost of Supply Model at a regional level

Table A.13 reflects annualised figures for the 2006/07 year.

A.2.2 Customer Group Allocations for 2006/07 (Annualised)

Having allocated costs where appropriate to regions, costs are then allocated to customer groups.

Unison allocates its costs to the following customer groups:

- Unmetered
- Mass Market
- Small Commercial
- Large Commercial
- Industrial

In summary, the costs allocated on a regional basis are allocated to the five customer groups using the cost drivers shown in table A.14.

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[13] The reduction in charges to Taupo and Rotorua consumers implemented from 1 April 2006 as part of the interim undertaking resulted in an average $46 per customer fall in charges in Taupo and a $40 per customer fall in charges in Rotorua.

[14] It is noted that reliance upon average movements can be misleading, given the potential for rebalancing between customer groups as Unison moves to more cost reflective charges.

Cost	Allocation Driver to Customer Groups
Non-region Specific	ICP
Load Specific	Customer group's share of regional coincident peak demand (kW) or kWh
Asset Specific	First to Asset groups, based on ODRC, then to Customer groups by share of aggregate coincident peak demand

Table A.14: Allocation drivers for cost categories

These allocations are described in more detail below.

A.2.2.1 Non-region Specific Costs

As described above, non-region specific (indirect or overhead) costs are allocated to customer groups based on the relative number of ICPs in each group. Table A.15 shows the ICP statistics relating to each consumer group.

ICP numbers	Rotorua / Taupo		Hawke's Bay	
	# ICPs	%	# ICPs	%
Unmetered	73	0.2%	415	0.7%
Mass Market	40,519	90.2%	56,984	95.6%
Small Commercial	4,183	9.3%	1,912	3.2%
Large Commercial	167	0.4%	306	0.5%
Industrial	2	0.0%	17	0.0%
Total ICP numbers	44,944	100%	59,634	100%

Table A.15: ICP statistics for allocating non-region specific costs

The table below shows these non-region specific costs allocated into consumer groups.

Non-Regional Specific Costs	Rotorua / Taupo $000	Hawke's Bay $000	Total $000
Unmetered	8	44	52
Mass Market	4,329	6,088	10,417
Small Commercial	447	204	651
Large Commercial	18	33	51
Industrial	0	2	2
Total	**4,802**	**6,371**	**11,173**

Table A.16: Non-region specific costs allocated to consumer groups

A.2.2.2 Load Specific Costs

Load specific costs (ie transmission charges, commercial, customer relations and Electricity Commission levies) are allocated to customer groups based on load related drivers. Transmission charges, commercial and customer relations costs are allocated to customer groups based on the customer groups' relative share of aggregate coincident peak demand. This is because the coincident peak demand drives the amount of capacity Unison requires at Transpower grid exit points (the connection service) in each of its regions and also drives the level of Transpower charges for the transmission interconnection service. Electricity Commission levies are allocated based on consumption because that is the major determinant of the charge by the Electricity Commission to Unison. Table A.17 shows the coincident peak demand statistics relating to each consumer group, and tables A.18 and A.19 show the transmission, commercial and customer relations costs allocated to each consumer group.

Coincident Demand	Rotorua/Taupo		Hawke's Bay	
	kW	%	kW	%
Unmetered	1,176	0.9%	2,342	1.3%
Mass Market	61,120	45.6%	94,668	51.1%
Small Commercial	36,371	27.2%	22,723	12.3%
Large Commercial	20,103	15.0%	43,755	23.6%
Industrial	15,148	11.3%	21,600	11.7%
Total Aggregate Coincident Maximum Demand	**133,918**	**100%**	**185,088**	**100%**

Table A.17: Coincident Maximum Demand statistics for allocating load specific costs

Transmission Costs	Rotorua/ Taupo $000	Hawke's Bay $000	Total $000
Unmetered	100	160	260
Mass Market	5,193	6,480	11,673
Small Commercial	3,090	1,555	4,645
Large Commercial	1,708	2,995	4,703
Industrial	1,287	1,479	2,766
Total	**11,378**	**12,669**	**24,047**

Table A.18: Transmission costs allocated to consumer group by share of Coincident Maximum Demand

Consumer Servicing Costs	Rotorua/ Taupo $000	Hawke's Bay $000	Total $000
Unmetered	5	10	14
Mass Market	249	385	634
Small Commercial	148	92	240
Large Commercial	82	178	260
Industrial	62	88	149
Total	**545**	**753**	**1,297**

Table A.19: Consumer Servicing costs allocated to consumer group by share of Coincident Maximum Demand

As noted above, Electricity Commission levies are charged to Unison primarily based on the company's kWh distributed. Therefore it is appropriate to allocate these costs to consumer groups based on their share of total consumption. Table A.20 shows the consumption statistics relating to each consumer group, and table A.21 shows the costs allocated to each consumer group.

kWh by customer group	Rotorua / Taupo		Hawke's Bay	
	kWh	%	kWh	%
Unmetered	4,614,249	0.7%	9,471,743	1.1%
Mass Market	289,126,019	40.9%	431,072,557	48.0%
Small Commercial	146,249,960	20.7%	107,099,535	11.9%
Large Commercial	143,736,153	20.3%	209,559,460	23.3%
Industrial	123,579,863	17.5%	141,796,016	15.8%
Total consumption	707,306,244	100%	898,999,311	100%

Table A.20: Consumption statistics for allocating consumption specific costs

Electricity Commission levies	Rotorua / Taupo $000	Hawke's Bay $000	Total $000
Unmetered	1	1	2
Mass Market	33	50	83
Small Commercial	17	12	29
Large Commercial	17	24	41
Industrial	14	16	31
Total	**81**	**104**	**185**

Table A.21: EC Levies allocated to consumer group by share of MWh

A.2.2.3 Asset Specific Costs

Asset specific costs relate to assets employed. These costs include maintenance and operations costs (not allocated elsewhere), depreciation, tax and net return costs. The asset specific costs are split up into four groups based on the broad asset classes of:

- Consumer Specific (industrial customers)
- High voltage assets after removing assets relating specifically to industrial customers (33kV and 11kV network assets)
- Low voltage (400 volt network assets)
- Street lighting assets

It is necessary to allocate costs to asset groups first, and then allocated these costs to consumer groups by their coincident demand on these assets. This split is to ensure customer groups are allocated only costs for the assets they use. For example, costs associated with the low voltage (400 volt) network are charged to the unmetered, mass market and small commercial customer groups because the large commercial and industrial groups generally do not utilise the low voltage network. The costs of the high voltage network (11kV and 33kV) are allocated between all customer groups because all customers rely on the service provided by these assets to connect and distribute electricity drawn from the national grid and the various grid exit points in the network.

Asset specific costs are split into the four asset categories based on relative asset Optimised Depreciated Replacement Cost (ODRC). The asset values of the four asset categories are summarised in table A.22.[15]

Asset Class	Rotorua/Taupo		Hawke's Bay	
	$000	%	$000	%
Customer Specific (Industrials)	5,076	4%	16,858	8%
High Voltage	92,266	64%	130,849	61%
Low Voltage	46,520	32%	65,039	30%
Street Lighting	428	0%	699	0%
Total Assets	**144,290**	**100%**	**213,445**	**100%**

Table A.22: Split of 2006 ODRC between asset categories

The costs for each asset category are allocated to the customer groups based on the group's share of the coincident peak demand related to those asset classes. The tables below show how the asset classes are allocated to customer groups, based on utilisation, and how the coincident demand of each consumer group determines the relative share of the asset related costs allocated to each customer group.

Customer specific assets related to high voltage assets and are identified only for the Industrial customer group.

Coincident Demand on Customer Specific assets	Rotorua/Taupo		Hawke's Bay	
	kW	%	kW	%
Unmetered	-	0.0%	-	0.0%
Mass Market	-	0.0%	-	0.0%
Small Commercial	-	0.0%	-	0.0%
Large Commercial	-	0.0%	-	0.0%
Industrial	15,148	100.0%	21,600	100.0%
Total Assets	**15,148**	**100%**	**21,600**	**100%**

Table A.23.1: Coincident demand by consumer group relating to customer specific assets

15 The asset values in table A.22 reflect the ODV valuation undertaken as at 31 March 2006. This value allocation is used as it more accurately reflects the relative weighting of this driver between regions and customer groups than the 2004 ODV.

The remaining high voltage assets costs are allocated to all groups other than industrials as they all rely on the high voltage network.

Coincident Demand on assets relating to High Voltage assets	Rotorua/Taupo		Hawke's Bay	
	kW	%	kW	%
Unmetered	1,176	1.0%	2,342	1.4%
Mass Market	61,120	51.5%	94,668	57.9%
Small Commercial	36,371	30.6%	22,723	13.9%
Large Commercial	20,103	16.9%	43,755	26.8%
Industrial	-	0.0%	-	0.0%
Total Assets	**118,770**	**100%**	**163,488**	**100%**

Table A.23.2: Coincident demand by consumer group relating specifically to the high voltage assets

Low voltage assets are utilised by the Unmetered, Mass Market and Small Commercial customer groups. Large Commercial and Industrial customers generally connect to the 11kV network and do not utilise the low voltage network.

Coincident Demand on assets relating to Low Voltage assets	Rotorua/Taupo		Hawke's Bay	
	kW	%	kW	%
Unmetered	1,176	1.2%	2,342	2.0%
Mass Market	61,120	61.9%	94,668	79.1%
Small Commercial	36,371	36.9%	22,723	19.0%
Large Commercial	-	0.0%	-	0.0%
Industrial	-	0.0%	-	0.0%
Total Assets	**98,667**	**100%**	**119,733**	**100%**

Table A.23.3: Coincident demand by consumer group relating specifically to the low voltage assets

The street lighting assets are specific to the Unmetered customer group.

Coincident Demand on assets relating to street lighting assets	Rotorua/Taupo		Hawke's Bay	
	kW	%	kW	%
Unmetered	1,176	100.0%	2,342	100.0%
Mass Market	-	0.0%	-	0.0%
Small Commercial	-	0.0%	-	0.0%
Large Commercial	-	0.0%	-	0.0%
Industrial	-	0.0%	-	0.0%
Total Assets	**1,176**	**100%**	**2,342**	**100%**

Table A.23.4: Coincident demand by consumer group relating specifically to the street lighting assets

Asset Specific maintenance and Operating costs

Table A.24 below shows the allocation of maintenance and operating costs to asset classes, based on relative ODRC values per table A.22 above.

Maintenance and Operating Costs	Rotorua / Taupo $000	Hawke's Bay $000	Total $000
Consumer Specific (industrials)	129	403	532
High Voltage Assets	2,345	3,128	5,473
Low Voltage Assets	1,183	1,555	2,737
Street lighting Assets	11	17	28
Total	**3,668**	**5,102**	**8,770**

Table A.24: Maintenance and Operating costs allocated to asset class by share of ODRC

Each asset class's costs are then allocated to each consumer groups, based on relative coincident maximum demand, per tables A.23.1 to A.23.4.

Maintenance and Operating Costs of Consumer Specific Assets	Rotorua / Taupo $000	Hawke's Bay $000	Total $000
Unmetered	0	0	0
Mass Market	0	0	0
Small Commercial	0	0	0
Large Commercial	0	0	0
Industrial	129	403	532
Total	**129**	**403**	**532**

Table A.25.1: Maintenance and Operating for consumer specific assets allocated by share of Coincident Maximum Demand on these assets

Maintenance and Operating Costs of High Voltage Assets	Rotorua / Taupo $000	Hawke's Bay $000	Total $000
Unmetered	23	45	68
Mass Market	1,207	1,811	3,018
Small Commercial	718	435	1,153
Large Commercial	397	837	1,234
Industrial	0	0	0
Total	**2,345**	**3,128**	**5,473**

Table A.25.2: Maintenance and Operating for high voltage assets allocated by share of Coincident Maximum Demand on these assets

Maintenance and Operating Costs of Low Voltage Assets	Rotorua / Taupo $000	Hawke's Bay $000	Total $000
Unmetered	14	30	45
Mass Market	733	1,229	1,962
Small Commercial	436	295	731
Large Commercial	0	0	0
Industrial	0	0	0
Total	**1,183**	**1,555**	**2,737**

Table A.25.3: Maintenance and Operating for low voltage assets allocated by share of Coincident Maximum Demand on these assets

Maintenance and Operating Costs of Street Lighting Assets	Rotorua / Taupo $000	Hawke's Bay $000	Total $000
Unmetered	11	17	28
Mass Market	0	0	0
Small Commercial	0	0	0
Large Commercial	0	0	0
Industrial	0	0	0
Total	**11**	**17**	**28**

Table A.25.4: Maintenance and Operating for street lighting assets allocated by share of Coincident Maximum Demand on these assets

Table A.26 summarises the total asset specific maintenance and operation costs for each consumer group.

Summary of Asset Specific Maintenance and Operating Costs per consumer group	Rotorua / Taupo $000	Hawke's Bay $000	Total $000
Unmetered	48	92	140
Mass Market	1,940	3,040	4,980
Small Commercial	1,154	730	1,884
Large Commercial	397	837	1,234
Industrial	129	403	532
Total	**3,668**	**5,102**	**8,770**

Table A.26: Total Asset Specific Maintenance and Operating costs allocated to consumer groups (Summary of tables A.25.1 – A.25.4)

Depreciation

Table A.27 below shows the allocation of depreciation charges to asset classes, based on relative ODRC values per table A.22 above.

Depreciation Costs	Rotorua / Taupo $000	Hawke's Bay $000	Total $000
Consumer Specific (industrials)	242	804	1,046
High Voltage Assets	4,401	6,241	10,642
Low Voltage Assets	2,219	3,102	5,321
Street lighting Assets	20	33	54
Total	**6,882**	**10,181**	**17,063**

Table A.27: Depreciation costs allocated to asset class by share of ODRC

Each asset class's costs are then allocated to each consumer groups, based on relative coincident maximum demand, per tables A.23.1 to A.23.4.

Depreciation Costs of Consumer Specific Assets	Rotorua / Taupo $000	Hawke's Bay $000	Total $000
Unmetered	0	0	0
Mass Market	0	0	0
Small Commercial	0	0	0
Large Commercial	0	0	0
Industrial	242	804	1,046
Total	**242**	**804**	**1,046**

Table A.28.1: Depreciation for consumer specific assets allocated by share of Coincident Maximum Demand on these assets

Depreciation Costs of High Voltage Assets	Rotorua / Taupo $000	Hawke's Bay $000	Total $000
Unmetered	44	89	133
Mass Market	2,265	3,614	5,879
Small Commercial	1,348	867	2,215
Large Commercial	745	1,670	2,415
Industrial	0	0	0
Total	**4,401**	**6,241**	**10,642**

Table A.28.2: Depreciation for high voltage assets allocated by share of Coincident Maximum Demand on these assets

Depreciation Costs of Low Voltage Assets	Rotorua / Taupo $000	Hawke's Bay $000	Total $000
Unmetered	26	61	87
Mass Market	1,375	2,453	3,827
Small Commercial	818	589	1,407
Large Commercial	0	0	0
Industrial	0	0	0
Total	**2,219**	**3,102**	**5,321**

Table A.28.3: Depreciation for low voltage assets allocated by share of Coincident Maximum Demand on these assets

Depreciation Costs of Street Lighting Assets	Rotorua / Taupo $000	Hawke's Bay $000	Total $000
Unmetered	20	33	54
Mass Market	0	0	0
Small Commercial	0	0	0
Large Commercial	0	0	0
Industrial	0	0	0
Total	**20**	**33**	**54**

Table A.28.4: Depreciation for street lighting assets allocated by share of Coincident Maximum Demand on these assets

Table A.29 summarises the total depreciation charges for each consumer group.

Summary Depreciation Costs per consumer group	Rotorua / Taupo $000	Hawke's Bay $000	Total $000
Unmetered	90	183	274
Mass Market	3,639	6,067	9,706
Small Commercial	2,166	1,456	3,622
Large Commercial	745	1,670	2,415
Industrial	242	804	1,046
Total	**6,882**	**10,181**	**17,063**

Table A.29: Total depreciation costs allocated to consumer groups

(Summary of tables A.28.1 – A.28.4)

Cash tax and interest tax shield

Table A.30 below shows the allocation of tax and interest tax shield costs to asset classes, based on relative ODRC values per table A.22 above.

Cash Tax and Interest Tax Shield Costs	**Rotorua/ Taupo $000**	**Hawke's Bay $000**	**Total $000**
Consumer Specific (industrials)	63	209	272
High Voltage Assets	1,145	1,623	2,768
Low Voltage Assets	577	807	1,384
Street lighting Assets	5	9	14
Total	**1,790**	**2,648**	**4,439**

Table A.30: Cash tax and interest tax shield costs allocated to asset class by share of ODRC

Each asset class's costs are then allocated to each consumer groups, based on relative coincident maximum demand, per tables A.23.1 to A.23.4.

Cash Tax and Interest Tax Shield Costs on consumer specific assets	**Rotorua/ Taupo $000**	**Hawke's Bay $000**	**Total $000**
Unmetered	0	0	0
Mass Market	0	0	0
Small Commercial	0	0	0
Large Commercial	0	0	0
Industrial	63	209	272
Total	**63**	**209**	**272**

Table A.31.1: Cash tax and interest tax shield for consumer specific assets allocated by share of Coincident Maximum Demand on these assets

Cash Tax and Interest Tax Shield Costs on High Voltage assets	**Rotorua/ Taupo $000**	**Hawke's Bay $000**	**Total $000**
Unmetered	11	23	35
Mass Market	589	940	1,529
Small Commercial	351	226	576
Large Commercial	194	435	628
Industrial	0	0	0
Total	**1,145**	**1,623**	**2,768**

Table A.31.2: Cash tax and interest tax shield for high voltage assets allocated by share of Coincident Maximum Demand on these assets

Cash Tax and Interest Tax Shield Costs on Low Voltage assets	Rotorua/ Taupo $000	Hawke's Bay $000	Total $000
Unmetered	7	16	23
Mass Market	358	638	996
Small Commercial	213	153	366
Large Commercial	0	0	0
Industrial	0	0	0
Total	**577**	**807**	**1,384**

Table A.31.3: Cash tax and interest tax shield for low voltage assets allocated by share of Coincident Maximum Demand on these assets

Cash Tax and Interest Tax Shield Costs on Street Lighting assets	Rotorua/ Taupo $000	Hawke's Bay $000	Total $000
Unmetered	5	9	14
Mass Market	0	0	0
Small Commercial	0	0	0
Large Commercial	0	0	0
Industrial	0	0	0
Total	**5**	**9**	**14**

Table A.31.4: Cash tax and interest tax shield for street lighting assets allocated by share of Coincident Maximum Demand on these assets

Table A.32 summarises the total tax and interest tax shield costs for each consumer group.

Summary Cash Tax and Interest Tax Shield Costs per consumer group	Rotorua/ Taupo $000	Hawke's Bay $000	Total $000
Unmetered	24	48	71
Mass Market	947	1,578	2,525
Small Commercial	563	379	942
Large Commercial	194	435	628
Industrial	63	209	272
Total	**1,790**	**2,648**	**4,439**

Table A.32: Total cash tax and interest tax shield costs allocated to consumer groups (Summary of tables A.31.1 – A.31.4)

Net Returns after Tax

Table A.33 below shows the allocation of net returns after tax to asset classes, based on relative ODRC values per table A.22 above.

Net Return after Tax	**Rotorua / Taupo $000**	**Hawke's Bay $000**	**Total $000**
Consumer Specific (industrials)	233	773	1,006
High Voltage Assets	4,232	6,002	10,233
Low Voltage Assets	2,134	2,983	5,117
Street lighting Assets	20	32	52
Total	**6,618**	**9,790**	**16,408**

Table A.33: Net return after tax allocated to asset class by share of ODRC

Each asset class's costs are then allocated to each consumer groups, based on relative coincident maximum demand, per tables A.23.1 to A.23.4.

Net Return after Tax on consumer specific assets	**Rotorua / Taupo $000**	**Hawke's Bay $000**	**Total $000**
Unmetered	0	0	0
Mass Market	0	0	0
Small Commercial	0	0	0
Large Commercial	0	0	0
Industrial	233	773	1,006
Total	**233**	**773**	**1,006**

Table A.34.1: Net return after tax for consumer specific assets allocated by share of Coincident Maximum Demand on these assets

Net Return after Tax on High Voltage assets	**Rotorua / Taupo $000**	**Hawke's Bay $000**	**Total $000**
Unmetered	42	86	128
Mass Market	2,178	3,475	5,653
Small Commercial	1,296	834	2,130
Large Commercial	716	1,606	2,323
Industrial	0	0	0
Total	**4,232**	**6,002**	**10,233**

Table A.34.2: Net return after tax for high voltage assets allocated by share of Coincident Maximum Demand on these assets

Net Return after Tax on Low Voltage assets	**Rotorua / Taupo $000**	**Hawke's Bay $000**	**Total $000**
Unmetered	25	58	84
Mass Market	1,322	2,359	3,680
Small Commercial	787	566	1,353
Large Commercial	0	0	0
Industrial	0	0	0
Total	**2,134**	**2,983**	**5,117**

Table A.34.3: Net return after tax for low voltage assets allocated by share of Coincident Maximum Demand on these assets

Net Return after Tax on Street Lighting assets	**Rotorua / Taupo $000**	**Hawke's Bay $000**	**Total $000**
Unmetered	20	32	52
Mass Market	0	0	0
Small Commercial	0	0	0
Large Commercial	0	0	0
Industrial	0	0	0
Total	**20**	**32**	**52**

Table A.34.4: Net return after tax for street lighting assets allocated by share of Coincident Maximum Demand on these assets

Table A.35 summarises the total net returns after tax for each consumer group.

Summary Net Return after Tax on use of assets	**Rotorua / Taupo $000**	**Hawke's Bay $000**	**Total $000**
Unmetered	87	176	263
Mass Market	3,500	5,834	9,333
Small Commercial	2,082	1,400	3,483
Large Commercial	716	1,606	2,323
Industrial	233	773	1,006
Total	**6,618**	**9,790**	**16,408**

Table A.35: Total net returns after tax allocated to consumer groups

(Summary of tables A.34.1 – A.34.4)

A.2.2.4 Summary of maintenance and operating cost allocations to customer groups

To assist with understanding tables A.37.1 and A.37.2, below, the allocations of maintenance and operating costs are summarised, by region, in tables A.36.1 and A.36.2.

Rotorua / Taupo	Non Region Specific (ICPs)	Load Related (CMD)	Load Related (kWh)	Asset Related	Total
	$(000)	$(000)	$(000)	$(000)	$(000)
Unmetered	5	1	48	8	61
Mass Market	249	33	1,940	4,329	6,550
Small Commercial	148	17	1,154	447	1,766
Large Commercial	82	17	397	18	513
Industrial	62	14	129	0	205
Total	**545**	**81**	**3,668**	**4,802**	**9,096**

Table A.36.1: Allocations of maintenance and operations costs to Rotorua / Taupo

(Summary of tables A.16, A.19, A.21, A.26)

Hawke's Bay	Non Region Specific (ICPs)	Load Related (CMD)	Load Related (kWh)	Asset Related	Total
	$(000)	$(000)	$(000)	$(000)	$(000)
Unmetered	10	1	92	44	147
Mass Market	385	50	3,040	6,088	9,563
Small Commercial	92	12	730	204	1,039
Large Commercial	178	24	837	33	1,072
Industrial	88	16	403	2	509
Total	**753**	**104**	**5,102**	**6,371**	**12,329**

Table A.36.2: Allocations of maintenance and operations costs to Hawke's Bay

(Summary of tables A.16, A.19, A.21, A.26)

A.2.2.5 Summary of Customer Group Allocations

The allocation of costs to customer groups is summarised in tables A.37.1 and A.37.2 for each region and table A.37.3 in total.

Rotorua / Taupo	Transmission $000	Maintenance and Operating $000	Network Depreciation $000	Cash Tax & Interest Tax Shield $000	Net after Tax Return $000	Regulatory Asset Base[16] $000	Real Rate of Return %
Unmetered	100	61	90	24	87	1,896	**4.6%**
Mass market	5,193	6,550	3,639	947	3,500	76,299	**4.6%**
Small Commercial	3,090	1,766	2,166	563	2,082	45,403	**4.6%**
Large Commercial	1,708	513	745	194	716	15,617	**4.6%**
Industrial	1,287	205	242	63	233	5,076	**4.6%**
Total	**11,378**	**9,096**	**6,882**	**1,790**	**6,618**	**144,290**	**4.6%**

Table A.37.1: Allocation of 2006/07 costs to customer groups for Rotorua/Taupo

(Summary of tables A.18, A.36.1, A.29, A.32, A.35)

Hawke's Bay	Transmission $000	Maintenance and Operating $000	Network Depreciation $000	Cash Tax & Interest Tax Shield $000	Net after Tax Return $000	Regulatory Asset Base[16] $000	Real Rate of Return %
Unmetered	160	147	183	48	176	3,846	**4.6%**
Mass market	6,480	9,563	6,067	1,578	5,834	127,192	**4.6%**
Small Commercial	1,555	1,039	1,456	379	1,400	30,529	**4.6%**
Large Commercial	2,995	1,072	1,670	435	1,606	35,020	**4.6%**
Industrial	1,479	509	804	209	773	16,858	**4.6%**
Total	**12,669**	**12,329**	**10,181**	**2,649**	**9,790**	**213,445**	**4.6%**

Table A.37.2: Allocation of 2006/07 costs to customer groups for Hawke's Bay

(Summary of tables A.18, A.36.2, A.29, A.32, A.35)

[16] The regulatory asset base is determined from the 2004 ODV, adjusted by $12 million to reflect a more appropriate application of ODV Handbook multipliers, plus additions at cost, plus annual revaluations at CPI, less depreciation. This is in accordance with the Commission's preferred approach for asset value roll forward. The regulatory asset base has been allocated between the regions based on the relative split of the ODV Unison had undertaken as at 31 March 2006 as this provides a more accurate basis for allocating costs between the regions.

Unison (Total)	Transmission $000	Maintenance and Operating $000	Network Depreciation $000	Cash Tax & Interest Tax Shield $000	Net after Tax Return $000	Regulatory Asset Base[16] $000	Real Rate of Return %
Unmetered	260	208	274	72	263	5,741	**4.6%**
Mass market	11,673	16,113	9,706	2,525	9,333	203,491	**4.6%**
Small Commercial	4,645	2,805	3,622	942	3,483	75,932	**4.6%**
Large Commercial	4,703	1,585	2,415	628	2,323	50,637	**4.6%**
Industrial	2,766	714	1,046	272	1,006	21,934	**4.6%**
Total	**24,047**	**21,425**	**17,063**	**4,439**	**16,408**	**357,735**	**4.6%**

Table A.37.3: Allocation of 2006/07 costs to customer groups for Unison in total (Summary of tables A.37.1-37.2)

The customer group allocation of costs from the Cost of Supply Model compares with the allocation of revenue for the 2006/07 year, forecast based on the current pricing methodology:

	Rotorua/Taupo			Hawke's Bay			Total Unison		
	Old method $000	New method $000	Change $000	Old method $000	New method $000	Change $000	Old method $000	New method $000	Change $000
Unmetered	354	362	9	880	715	(166)	1,234	1,077	(157)
Mass market	19,484	19,829	345	31,403	29,522	(1,881)	50,887	49,350	(1536)
Small Commercial	9,400	9,667	268	4,620	5,829	1,209	14,020	15,497	1477
Large Commercial	5,139	3,876	(1263)	6,993	7,778	785	12,132	11,654	(478)
Industrial	2,030	2,030	0	3,774	3,774	0	5,804	5,804	0
Total	**36,406**	**35,764**	**(642)**	**47,670**	**47,618**	**(53)**	**84,076**	**83,382**	**(694)**

Table A.38: Impact of cost reflective prices by customer group

Table A.38 reflects annualised figures for the 2006/07 year.

The average impact of the change in charges between the old allocation methodology and the new allocation methodology combined with the threshold complaint revenue for 2006/07 is expressed in table A.39. This table shows the impact by region and by customer group. The impact on Mass Market customers is best assessed in terms of $/ICP while for other customer groups the average cents/kWh is a better indicator of the impact.

	Rotorua/Taupo			Hawke's Bay			Total Unison		
	Change $000	$/ICP	c/kWh	Change $000	$/ICP	c/kWh	Change $000	$/ICP	c/kWh
Unmetered	9		0.2	(166)		(1.8)	(157)		(1.1)
Mass market	345	9	0.1	(1,881)	(33)	(0.4)	(1,536)	(16)	(0.2)
Small Commercial [17]	268		0.2	1,209		1.1	1,477		0.6
Large Commercial [8]	(1,263)		(0.9)	785		0.4	(478)		(0.1)
Industrial	0		0.0	0		0.0	0		0.0

Table A.39: Average impact of cost reflective prices by region and customer group

[17] As a result of changes to tariff categories, a small number of customers will move between the small commercial and large commercial groups in Rotorua/Taupo.

Unison's Asset Management Approach, Practices and Outcomes

Report submitted to the Commerce Commission in support of Unison's Settlement Proposal

29 May 2006

…we're always working for you

Contents

1.0 Report Overview

Unison's capital and maintenance expenditure forecasts are a direct result of the asset management practices and philosophies of the Company. This report discusses the drivers, processes and outcomes pertaining to the Company's asset management approach.

The report provides the expenditure forecasts that result from this approach. These forecasts span a ten year period consistent with the planning period for the regulatory Asset Management Plan ("AMP"). This is indicative of the long term nature of the distribution network assets and service expectations, which are underpinned by longer term asset management strategies within the business. The forecasts are analysed from a project specific and bottom up perspective, as well as from a strategic perspective, to ensure there is a good alignment between strategy and practice.

The report clarifies the cost basis for all expenditure forecasts. Unison recently (March 2006) completed a review of Company specific replacements costs. This was done from a FRS-3 and ODV perspective. These replacement costs were signed off by SKM and PwC.

The report also highlights Unison's concern that the current regulatory thresholds for SAIDI and SAIFI are potentially driving inefficient investment, and proposes an alternative methodology to calculate regulatory thresholds for the Company.

2.0 Structure of the Report

This report discusses the following key areas of Unison's asset management approach in detail:

- Asset renewals;
- Network augmentation;
- Customer initiated work;
- Underground conversion; and
- Network Maintenance (operating expenditure).

The preamble explains the evolution of Unison's asset management approach over the past years and specifically focuses on developments and changes to the AMPs since 2004. It also provides a summary of the forecasted expenditure for the next ten years.

The basis for all asset related expenditure forecasts is discussed in Section 4. The business drivers for each area, the management process and the expenditure forecasts that result are highlighted in Sections 5 to 9. The existing regulatory quality thresholds are reviewed in Section 10.

In some cases, supporting information is provided in appendices in an attempt to keep the main body of the report as concise as possible.

Unison has made extensive use of external experts' input to ensure that the principles driving the AMP align with world best practice, and that the outcomes are prudent and accurate. Where appropriate, the experts' input has been quoted and supporting documentation provided.

3.0 Preamble

Unison's asset management philosophies and methodologies have changed considerably over the past few years:

- These have developed from an asset centric approach to an approach that is customer centric and that will increasingly strive to deliver appropriate and agreed customer service levels.

- An approach that focused on short term cost savings has developed to an approach that is based on total life cycle costs and sustainability.

- New smart technologies are being employed to enable decisions supported by knowledge based information systems.

- Where appropriate, alignment with world best practice has been sought.

Unison's asset management practices and resultant expenditure forecasts have evolved as a result of these developments:

- Structured field inspection programmes, supported by extensive investment in smart technology, such as thermal scan cameras and aerial surveys, has led to considerable improvements in the integrity and completeness of field asset and assessed condition data.

- The improvement in the quality and quantity of field data has resulted in increased demands being placed on Unison's information systems. In response Unison has invested extensively in information systems to improve integration between financial, asset and GIS information systems.

- In turn, this had led to improvements in capital investment forecasting, such as improved forecasting of renewal needs and fine tuning of maintenance practices to maximise asset utilisation.

These changes have been progressively incorporated into Unison's published AMPs:

- The 2004 AMP saw an improvement in the methodology used to forecast renewals, but data capture was still incomplete for all assets in Unison's networks. An improved financial reporting system (SAP) was also implemented during this time to better monitor Unison's replacement costs, so that future AMPs could better balance the actual level of costs faced by the business and the standard costs incorporated in the ODV Handbook for valuation purposes. The expenditure forecasts, published in the 2004 AMP, are shown in Table 1a.

- The 2005 AMP benefited from further improvement to network asset data, and an improved understanding of asset performance. This has allowed sufficient data to be captured to confirm current practices are delivering life extensions to some asset classes. It has also led to targeted capital and operating expenditure investment on certain underperforming assets (e.g. Magnafix RMUs, 1970s XLPE cable). However, renewals forecasting was based on the 2004 ODV Handbook values as data was still accumulating in SAP. The expenditure forecasts, published in the 2005 AMP, are shown in Table 1b.

- In 2006 Unison has seen the benefit of the SAP investment realised with a detailed understanding of renewal costs incurred by Unison, both in underpinning the FRS-3 2006 revaluation, and incorporation into the 2006 AMP forecasts. Another year of improvement in the capture of field data and improved integration between GIS and asset systems has also occurred. In addition, further refinement in the long term modelling of asset renewal requirements has been incorporated with the work performed by LeverEdge, allowing better consideration of planned/reactive cost trade-offs. Modelling of constraints, such as limited contracting resource, has then been overlaid forcing not only prioritisation of work within the envelope of feasibly achievable asset spend, but also further development of strategies to expand the contractor market in Unison's areas of operation. Considerable external review has also occurred in this period, allowing further refinement to Unison's asset management practices. The network related expenditure forecasts that will be used for the 2006 AMP, and that are based on the improved understanding of costs, are shown in Table 2.

A key aspect of the changes is the fact that it is mostly cost related. The impact of changes in the asset management strategies and philosophies are likely to emerge only slowly given the nature of the information gathering process and the assets themselves.

Unison's asset management philosophies, and resultant AMPs, have been reviewed on behalf of the Commerce Commission by Parsons Brinkerhoff Associates ("PBA") from a disclosure compliance perspective. They have also been reviewed by Stephen Blanch (Dellwind, Australia) in respect of the high level philosophy and practice. In general, the feedback from these reviews has been very positive and has confirmed that Unison's asset management approach aligns well with world best practice. [1]

[1] High level review of Unison's asset management philosophies. Examination of planning processes and related network performance and capital and maintenance expenditure for Long Term System Sustainability as outlined in the AMP; October 2005; Stephen Blanch.

	2004 AMP - Real 2004 RC ($000)										
Network CAPEX	**2004/5**	**2005/6**	**2006/7**	**2007/8**	**2008/9**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**10 year average**
Customer driven	$4,115	$4,184	$4,243	$4,298	$4,371	$4,446	$4,521	$4,598	$4,676	$4,756	$4,421
Network augmentation	$4,259	$6,738	$5,941	$3,434	$3,221	$2,420	$3,065	$2,384	$1,972	$1,921	$3,535
Asset Renewals	$6,076	$8,503	$11,078	$11,465	$11,533	$9,793	$5,966	$6,230	$7,148	$7,818	$8,561
UG Conversion	$3,057	$2,985	$3,028	$2,334	$2,334	$2,334	$2,334	$2,334	$2,334	$2,334	$2,541
Total CAPEX	**$17,507**	**$22,411**	**$24,291**	**$21,530**	**$21,459**	**$18,993**	**$15,885**	**$15,545**	**$16,129**	**$16,829**	**$19,058**
	2004 AMP - Real 2004 Costs ($000)										
Network Maintenance	**2004/5**	**2005/6**	**2006/7**	**2007/8**	**2008/9**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**10 year average**
Maintenance	$5,484	$5,169	$5,126	$4,842	$4,811	$4,831	$4,872	$4,904	$4,941	$4,981	$4,996
Siemens first response	$330	$330	$330	$330	$330	$330	$330	$330	$330	$330	$330
Total Maintenance	**$5,814**	**$5,499**	**$5,456**	**$5,172**	**$5,141**	**$5,161**	**$5,202**	**$5,234**	**$5,271**	**$5,311**	**$5,326**

Table 1a: Forward looking expenditure 2004 AMP

	2005 AMP - Real 2005 RC ($000)										
Network CAPEX	**2005/6**	**2006/7**	**2007/8**	**2008/9**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**10 year average**
Customer driven	$4,320	$4,380	$4,436	$4,512	$4,588	$4,665	$4,745	$4,825	$4,906	$4,990	$4,637
Network augmentation	$6,547	$3,068	$2,653	$3,256	$2,123	$3,415	$3,231	$3,460	$2,366	$1,950	$3,207
Asset Renewals	$8,567	$11,285	$11,599	$10,880	$9,003	$6,783	$6,439	$6,243	$6,637	$5,965	$8,310
UG Conversion	$4,322	$4,154	$4,132	$3,449	$3,448	$3,448	$3,448	$3,448	$3,448	$3,448	$3,675
Total CAPEX	**$23,756**	**$22,887**	**$22,821**	**$22,096**	**$19,162**	**$18,011**	**$17,863**	**$17,975**	**$17,358**	**$16,353**	**$19,828**
	2005 AMP - Real 2005 Costs ($000)										
Network Maintenance	**2005/6**	**2006/7**	**2007/8**	**2008/9**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**10 year average**
Maintenance	$5,749	$5,817	$5,659	$5,620	$5,607	$5,505	$5,509	$5,516	$5,527	$5,442	$5,595
Siemens first response	$330	$330	$330	$330	$330	$330	$330	$330	$330	$330	$330
Total Maintenance	**$6,079**	**$6,167**	**$5,989**	**$5,950**	**$5,937**	**$5,835**	**$5,839**	**$5,846**	**$5,857**	**$5,772**	**$5,925**

Table 1b: Forward looking expenditure 2005 AMP (based on 2004 ODV Handbook replacement costs)

	2006 AMP – Real 2006 RC ($000)										
Network CAPEX	**2006/7**	**2007/8**	**2008/9**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**10 year average**
Customer driven	$6,200	$6,200	$6,200	$6,200	$6,200	$6,200	$6,200	$6,200	$6,200	$6,200	$6,200
Network augmentation	$5,600	$6,273	$5,286	$5,186	$4,700	$4,153	$4,274	$4,335	$4,396	$4,517	$4,872
Asset Renewals	$13,800	$15,800	$17,500	$18,500	$18,500	$18,500	$18,500	$18,500	$18,500	$18,500	$17,660
UG Conversion	$1,500	$1,500	$1,500	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$3,950
Total CAPEX	**$27,100**	**$29,773**	**$30,486**	**$34,886**	**$34,400**	**$33,853**	**$33,974**	**$34,035**	**$34,096**	**$34,217**	**$32,682**
	2006 AMP - Real 2006 Costs ($000)										
Network Maintenance	**2006/7**	**2007/8**	**2008/9**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**10 year average**
Maintenance	$6,778	$6,914	$7,052	$7,193	$7,337	$7,483	$7,633	$7,786	$7,942	$8,100	$7,422
Siemens first response	$480	$480	$480	$480	$480	$480	$480	$480	$480	$480	$480
Total Maintenance	**$7,258**	**$7,394**	**$7,532**	**$7,673**	**$7,817**	**$7,963**	**$8,113**	**$8,266**	**$8,422**	**$8,580**	**$7,902**

Table 2: Forward looking expenditure as at May 2006 (based on 2006 view of Unison's replacement costs)

4.0 Replacement Costs

This section of the report discusses the cost basis for all expenditure forecasts used throughout subsequent parts of the report.

In March 2006 Unison completed a review of company specific replacement costs. This was done from a FRS-3 and ODV perspective. These replacement costs were signed off by SKM and PwC.[2]

The FRS-3 replacement costs have been used as the basis for all 2006 based expenditure forecasts in this report.

The following sections describe the methodologies used to derive the FRS-3 and ODV based replacement costs, and concludes with a table summarising the differences between the two approaches.

Unison's approach throughout this report has been to use FRS-3 based replacement costs to forecast asset renewal related expenditure (see Table 2), and ODV based replacement costs to forecast network augmentation related expenditure (see Table 2).

In addition to the audit and review by PwC and SKM, Unison appointed Wilson Cook & Co Limited ("WC&C") to provide an expert opinion on the methodology used, and the appropriateness of the resultant FRS-3 and ODV based replacement costs attached as Appendix 1.[3] WC&C concluded that the methodology used is appropriate, but caution that the scale assumptions (applicable to the FRS-3 and ODV methodologies) may not always apply to the projects undertaken by Unison, which implies that an upwards adjustment might be necessary when estimating project specific costs.

4.1 Replacement Costs Based on FRS-3 Principles

The assets have been classified in a manner that is generally consistent with the requirements of the Commerce Commission's "Handbook for Optimised Deprival Valuation of System Fixed Assets of Electrical Lines Businesses" (ODV Handbook) dated 30 August 2004. This approach was adopted on the basis that the ODV Handbook classification is relatively sensible and is generally regarded as an industry standard.

Replacement Costs

Unison has primarily used two approaches to establish asset replacement costs as follows:

1. **Historical project evidence**: in this case Unison collated evidence from their internal records in order to determine appropriate replacement costs. The evidence was generally based on data extracted from Unison's SAP. This approach was applied to assets for which Unison has significant historical project evidence. PwC has provided the Commerce Commission with analysis of Unison's

[2] Unison Networks Limited - Valuation of Electricity System Fixed Assets for Financial Reporting Purposes as at 31 March 2006; May 2006; PwC; Appendix D.

[3] Briefing for Unison Board – ODV Valuation of Fixed Assets for Settlement Purposes; 9 May 2006; Wilson Cook & Co.

project costs relative to those of several other Electricity Lines Businesses (ELBs).[4] Acknowledging the limitations of the PwC study due to the unavoidably small sample size, this survey shows that Unison's project costs are in line with those of other comparable ELBs.

2. **Asset cost breakdowns**: in this case Unison built up the asset replacement costs based on actual material purchase costs coupled with engineering estimates of (i) design, (ii) installation and commissioning, (iii) transport and plant, and (iv) administration and project management. This approach has been applied to assets for which Unison does not have significant project evidence. An example is that of overhead lines assets which are being refurbished on a piecemeal basis (pole & cross-arm replacements). While Unison does not have project evidence suitable to support entire overhead line replacement costs, it does have sufficient evidence of the individual cost elements, based on external and market related quotes for materials, labour rates etc, to accurately estimate replacement costs.

Both costing methods have been used on the fundamental principle that forecast costs should reflect those that Unison will actually face given the asset replacements it expects to undertake. For example, in the underground cable context this typically involves replacing cable lengths of roughly 200-1,000 metres. In the case of discrete asset elements (i.e.: distribution substations or switchgear) the replacement costs have been assessed on the basis of single elements, given that Unison is faced with having to replace these assets on an individual basis (as opposed to bulk replacement).

4.2 Replacement Costs Based on ODV Principles

The basis of the ODV exercise has been to adjust the FRS-3 DRC replacement costs described above. The adjustments made were required to translate the FRS-3 DRC replacement costs to comply with the framework and intent of the Commerce Commission's ODV Handbook.

The ODV Handbook assumes a hypothetical operating environment and requires that the replacement cost of assets should be:

"commensurate with a significant scale of construction rather than piecemeal additions. As a guide, replacement costs … should be on the basis that each complete substation, circuit or feeder is constructed as a single project."

In order to establish a set of ODV replacement costs Unison adjusted the asset replacement costs established for FRS-3 DRC valuation to reflect the larger scale requirements of the ODV Handbook. In addition, costs associated with maintaining customer supply and disposal of existing assets were removed. The replacement costs established are those costs of modern equivalent assets of the same service potential that would be installed on, or about, valuation date and include installation, excavation, reinstatement, testing, commissioning, design, construction, supervision and project management costs.

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4 "Optimised Deprival Valuations in the Context of a Post Breach Inquiry for Unison Networks Limited – Final Report"; 21 October 2005; PwC.

4.3 Replacement Costs Summary

Table 3 summarises the outcomes of the two different approaches for determining replacement costs.

Valuation Methodology	Total Replacement Costs ($000)
FRS-3	799,737
ODV	732,438

Table 3: Unison replacement costs as at 31 March 2006

5.0 Renewals

5.1 Drivers

Renewals refer to the replacement of assets that have reached the end of their economic life. The key driver for Unison's asset renewal strategy is to optimise asset life cycle costs. This is achieved by ensuring that assets are renewed subject to balancing the following criteria:

- Health and safety;
- Statutory obligations (e.g.: environmental compliance);
- Optimised trade-off between maintenance costs and cost of renewal;
- Operational efficiencies;
- Achieving customer service levels;
- Impact on the market as a result of an asset failure; and
- Appropriate risk analysis.

The asset life cycle treatment plan that results from this strategy is covered in detail in the disclosed 2005 AMP.[5]

As a general principle, and in line with the objective of implementing life cycle cost minimisation, an asset will be replaced when:

- it ceases to be suitable for the intended purpose, which includes reliability considerations; or

- it becomes unsafe; or

- the present value of the cost of its replacement plus the cost of removing or de-commissioning it, less the scrap value recovered, if any, becomes less than the present value of its future maintenance; or

- its replacement or refurbishment forms part of the least cost development of the network.

Key enablers of Unison's renewal strategy are:

- Establishment of a framework for ensuring that the best and most efficient use is made of all network assets employed.

- Continuing efforts to develop a consistent and optimal approach to analysis and decision-making across all of Unison's operating regions.

- The ongoing development of asset information systems. This includes systems such as SAP, Smallworld GIS and EMS WASP (a system that is used by large international utilities such as Country Energy in Australia).

- Unison is also in the process of evolving more electronic data capture into field activities with the use of PDAs and hand-held GPS units.

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[5] Unison Networks Limited disclosed AMP 2005; Section 4.

5.2 Process

The key process related aspects pertaining to this strategy are the need for asset information and asset condition information. Unison makes extensive use of smart, cost effective technology such as thermal scan cameras, low impact condition testing equipment (tan delta cable test sets) and aerial surveys to undertake condition assessment and monitoring on a regular basis.

The key driver for selecting individual assets for replacement is Unison's condition assessment programmes included in the operating expenditure forecasts. These activities report and identify each asset that has deteriorated to a point that requires replacing, and all these assets are then reviewed and ranked by priority after reviewing safety, customer disruption, network configuration and other drivers. After reviewing the local configuration around the highest risk assets, projects are then issued for renewal. Provisional sums are also held during the year to allow urgent replacements.

The Ground Mount Inspections (GMIs) are the key driver to identify replacement of RMUs and ground mount transformers. Where it is deemed uneconomic or impractical to repair an asset, it is flagged for consideration to replace. Other drivers also lead to renewals, such as replacement of neighbouring assets. Where connected assets are close to end of life, consideration is also given to including these in the project scope if economic or operational benefits are sufficient to justify this.

Replacement of overhead assets is primarily piecemeal in nature, driven by condition assessments from feeder inspections of pole and conductor state. Conductors of particular type/age/location criteria are also sampled for more detailed condition assessment where the likelihood to deterioration is considered to be of potential concern.

Zone Substation assets are also closely monitored by various techniques to determine rate of deterioration and most economic time for replacement.

It is much harder to determine the condition of cable assets but Unison has invested considerable effort in this area to improve its asset management techniques. Historical industry practice has been to replace cables after a certain number of faults have occurred on a cable, but this does little to support good customer service. Unison has been developing its technical competencies over the past year to enable condition assessment of cables to be performed on key network sections to allow planned replacements before failure occurs. This has been driven by the cable failure rate experienced in the Hawke's Bay region which is 2.5 times above New Zealand and international norms.

Consequently, Unison is the first ELB in Australasia to develop a comprehensive condition assessment programme on cables by procuring tan delta testing equipment. This equipment allows Unison to identify dielectrics suffering from water treeing and programme their replacement before failure and customer disruption occurs.

As this technology is very new and complex, development of the required technical skills is expected to take 1-2 years.

5.3 Asset Renewal Expenditure Forecasts

5.3.1 Bottom-up view

The asset renewal process discussed in section 5.2 forms the basis of forecasting the bottom-up, project driven renewal capital expenditure. This forecast feeds into the annual budgeting process, which is ultimately signed off by the Board.

The 2006/07 budget for asset renewals, signed off by the Board, is shown in Table 4. Table 4 also indicates the actual expenditure for 2005/06.

Category	2006/07 Budget $m	2005/06 Actuals $m
UG Conversion	1.5	3.7
Asset Renewals	13.8	7.5
Network Augmentation	5.6	4.9
Customer Projects	6.2	10.3
Total Network Capital Expenditure	**27.0**	**26.4**
Total Network Maintenance Expenditure	**7.3**	**7.3**

Table 4: Approved 2006/07 Budget

Table 4 reflects a significant increase for renewals in 2006/07 when compared to 2005/06. A key driver of the higher expenditure is the replacement of unreliable XLPE cables; and the higher costs associated with the constrained contractor market.

It is important to note that the approved budget is a constrained budget due to the lack of contracting resources currently available in the region. As a result we have deferred some cable replacement projects, while we work with contractors to increase their capacity in Unison's regions.

Section 5.3.2 identifies an increased level of renewal capital expenditure over future years. Unison has staged the required increase in renewal capital expenditure to match a corresponding mobilisation of contracting resources over the next three years.

5.3.2 Long term view

The long term expenditure forecasts for asset renewals are provided in Table 2 of this report. There is a significant increase compared to Unison's view in 2005 (see Table 1b). However, as stated above, this is mainly driven by our improved understanding of the cost of performing these types of activities on our network.

Unison, along with several other ELBs, have identified an increasing need for asset replacements due to the ageing of their respective networks.[6,7] Further analysis by LeverEdge, as part of Unison's submission in response to the Notice of Intention to Declare Control, estimated the long term level of renewals expenditure having regard to the age and condition of the Company's assets.

6 Examples are PowerCo and PowerNet.
7 "Threshold Compliance Statement Supporting Paper for the First Assessment Date"; October 2003; Unison Networks Limited.

This section briefly summarises key principles underpinning the methodology that has been used to estimate the efficient level of renewal capital investment required for longer term sustainable network operation and service delivery, as reflected in Table 2 for the asset renewal category. This is based on the same methodology used previously by LeverEdge, but has been updated to reflect the latest version of the asset register and replacement costs (see Table 3). Supporting report and details have been documented separately.[8]

Summary of Principles

The driver of investment level is that assets will be preventively replaced only if the benefit:cost ratio of such replacement exceeds 1, based on of the estimated economic value of mitigating the risk of failure. The decision as to whether an asset should be replaced, and when, is based on risk management principles.

A key premise of this methodology is that the total cost of reactive replacement of an asset (after failure) is more than the cost of preventive replacement. If the total cost of reactive replacement (to the Company and the market) were exactly the same as for preventive replacement, the most efficient deployment of capital would be to simply run assets to failure and then replace them. However, this is not the case.

The **total cost of reactive replacement** can be considered to be comprised of:

- The basic cost of replacement equivalent to the preventive cost;
- A cost premium relating to the nature of reactive work, e.g.:
  - disruption of planned work, with resulting resource inefficiencies
  - unavailability of components, often requiring more expensive urgent deliveries (if high inventory levels are maintained to avoid costly urgent deliveries, higher costs are incurred anyhow);
- A cost premium relating to quality-of-supply deterioration, e.g.: increases in SAIDI/SAIFI associated with ageing and failing assets; and
- A cost premium accounting for consequential losses, e.g.: cost of non-supply to the Company, as well as losses incurred by other parties.

The total cost of reactive replacement is taken to be 1.5x the cost of preventive replacement in the modelling that supports the estimated investment requirements.

If the total cost of reactive replacement is more than the cost of preventive replacement, then it would be prudent to replace assets when the discounted present value of the benefits of replacement equal the present value of preventive replacement[9]. The diagrams in Figure 1, read from top to bottom, summarise the logic of arriving at a value for the benefits of preventive replacement.

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[8] Report on Efficient Investment of Renewal Capital, prepared for Unison Networks Limited, 21 October 2005.
Efficient Investment of Renewal Capital, for presentation at Commerce Commission Conference, 5 December 2005.
Cross-Submission for Submission to The Commerce Commission: Efficient Investment of Renewal Capital, prepared for Unison Networks Limited, 21 December 2005.
Note on Efficient Investment of Renewal Capital, prepared for Unison Networks Limited, 27 April 2006.

[9] It should be noted that concepts alluded to here would typically be based on continuous probability distributions (e.g.: probability of failure vs. time for a particular asset type), which would enable the calculation of a distribution of expected value for life expectancy. In the present analysis, absent the required distribution parameters (typically Weibull parameters), point estimates are used for life expectancies.

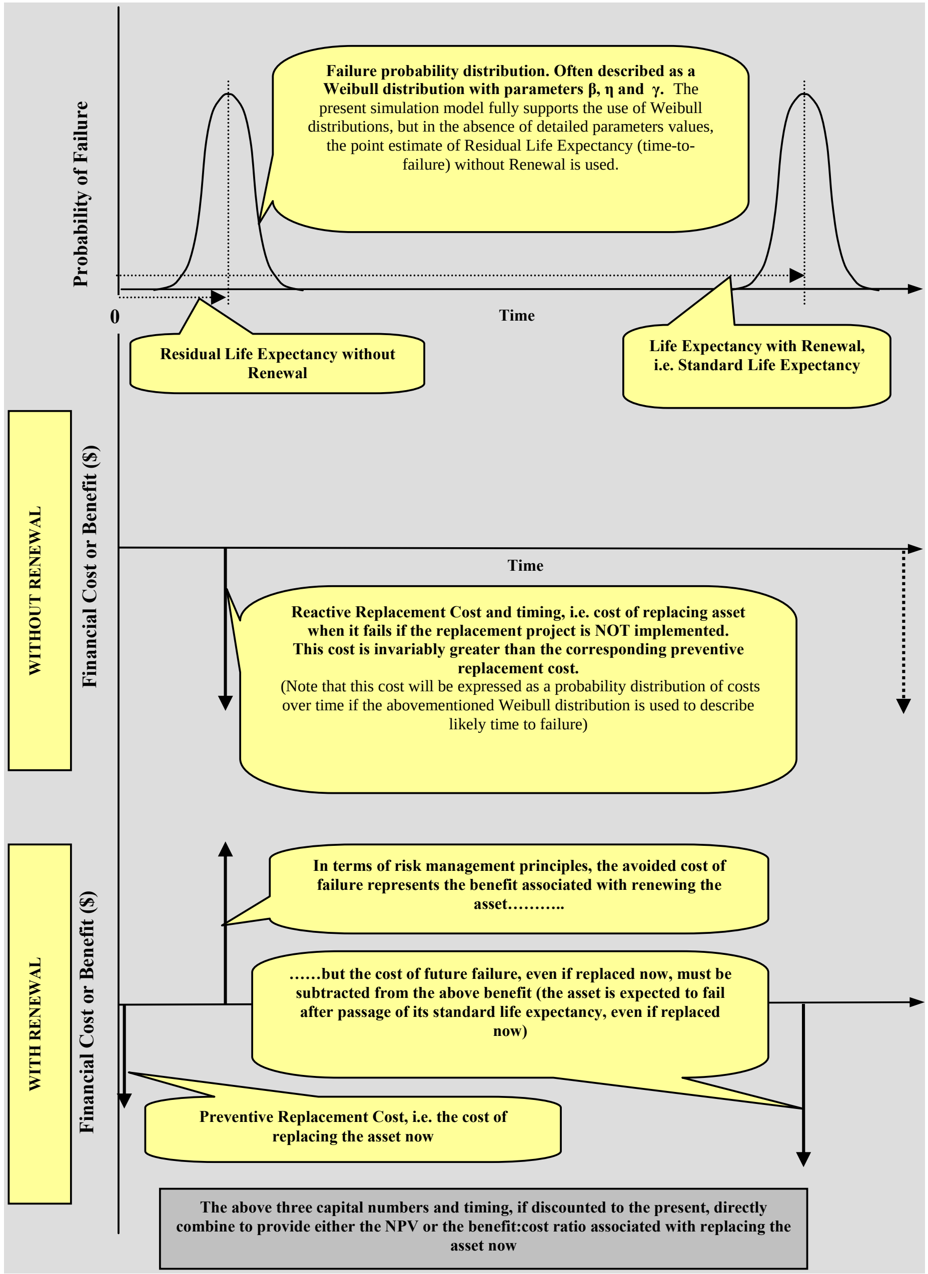

Figure 1: Logic for Estimating Benefits of Preventive Replacement

In Figure 1, when the renewal investment analysis is conducted (i.e.: at time = 0), a given asset can be expected to fail when it reaches its residual life expectancy (RLE). The latter number is derived from the asset register, as the difference between the asset's standard life (SL), and its present age. If it is replaced now, it can be expected to fail again at time = SL years. The above asset could be replaced preventively now, at the preventive replacement cost. The benefit of such replacement is the avoided cost of failing – simply the present value of the cost of failure, which in our case is taken as 1.5x the cost of preventive replacement. However, because the replaced asset is again expected to fail when it reaches its standard life, the present value of the cost of failure at that time needs to be deducted from the above benefit to yield the net benefit of preventive replacement.

The benefit:cost ratio of preventive replacement is simply the above benefit divided by the preventive cost value, as shown in the following text box:

Let:

RP_{Ratio} = Reactive:Preventive replacement cost ratio
PRC = Preventive replacement cost
RLE = Residual life expectancy at time of preventive replacement, yr
SLE = Standard life expectancy, yr
Discount rate = 5.8% (real)

Then:
Benefit:Cost ratio = $[RP_{Ratio} \times PRC \times \{1/(1.058)^{\wedge}RLE - 1/(1.058)^{\wedge}SLE\}]/PRC$

Estimate of Investment Requirements

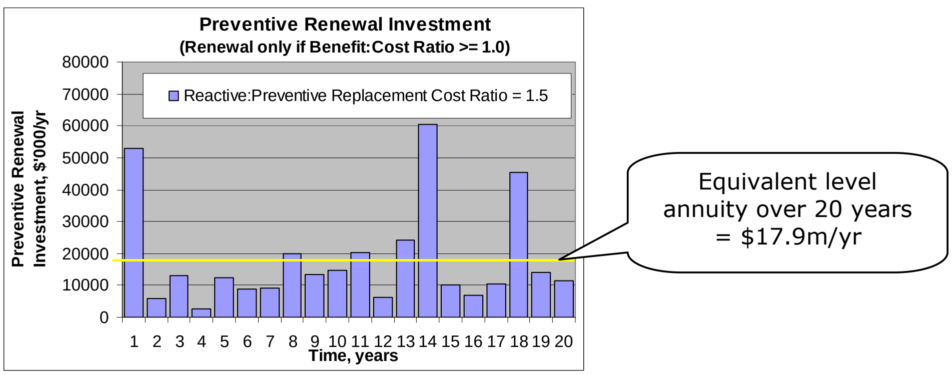

Figure 2: Annuity Approach to Estimating Renewal Investment Required over 20 Years (Reference Case)

Figure 2 shows the sequence of renewal investments required over 20 years, for renewal every year of all assets with benefit:cost ratio ≥ 1. The resulting investment pattern is irregular, but can be converted to an equivalent level annuity over 20 years. If the reactive-to-preventive replacement cost ratio is taken to be 1.5, then this equivalent level annuity is $17.9m/yr (this is the renewal investment required assuming there are sufficient contracting resources in the market to do the work).

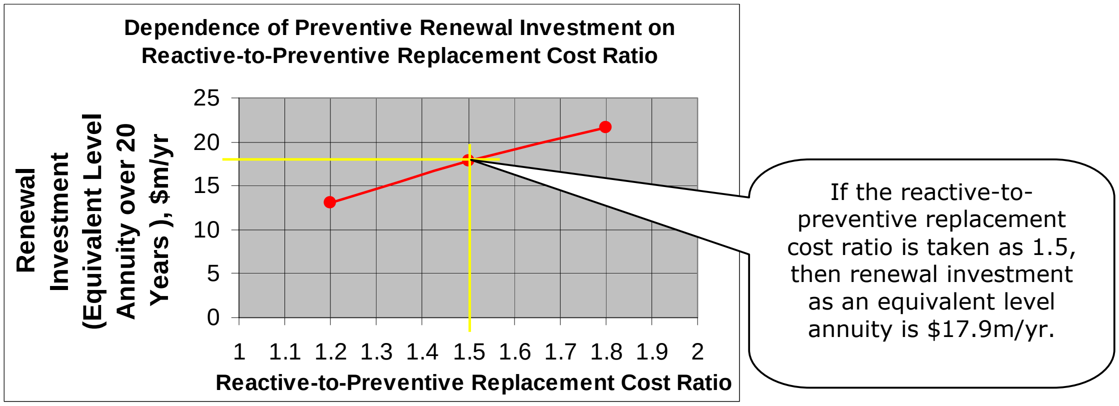

Figure 3: Summary of Dependence of Renewal Investment on Reactive-to-Preventive Replacement Cost Ratio

Figure 3 shows the dependence of renewal investment, as an equivalent level annuity, on the selected ratio of reactive-to-preventive replacement costs.

Summary of Investment Requirements

- The driver of investment level is that assets will be preventively replaced only if the benefit:cost ratio of such replacement exceeds 1, based on an attribution of economic value to the mitigation of the risk of failure. The decision as to whether an asset should be replaced, and when, is based on risk management principles.

- A key premise of this methodology is that the total cost of reactive replacement of an asset (after failure) is more than the cost of preventive replacement. If the total cost of reactive replacement (to the Company and the market) were exactly the same as for preventive replacement, the most efficient deployment of capital would be to simply run assets to failure and then replace them. However, this is not the case.

- The efficient renewal investment for an assumed range of reactive-to-preventive replacement cost of 1.5x to 1.6x, is $17.9m/yr to $19.1m/yr (expressed as equivalent level annuities).

- If a specific renewal investment scenario is followed comprising $13.8m, $15.8m and $17.5m respectively in years 1 to 3, driven by a lack of contracting resources in the market, then a level annuity of about $19.5m/yr needs to be invested during years 4 to 20 (thus compensating for the lower initial investments).

Framework to Interpret Proposed Investment Requirements

The following framework, with hypothetical upper and lower boundaries, may help to interpret the proposed investment requirements.

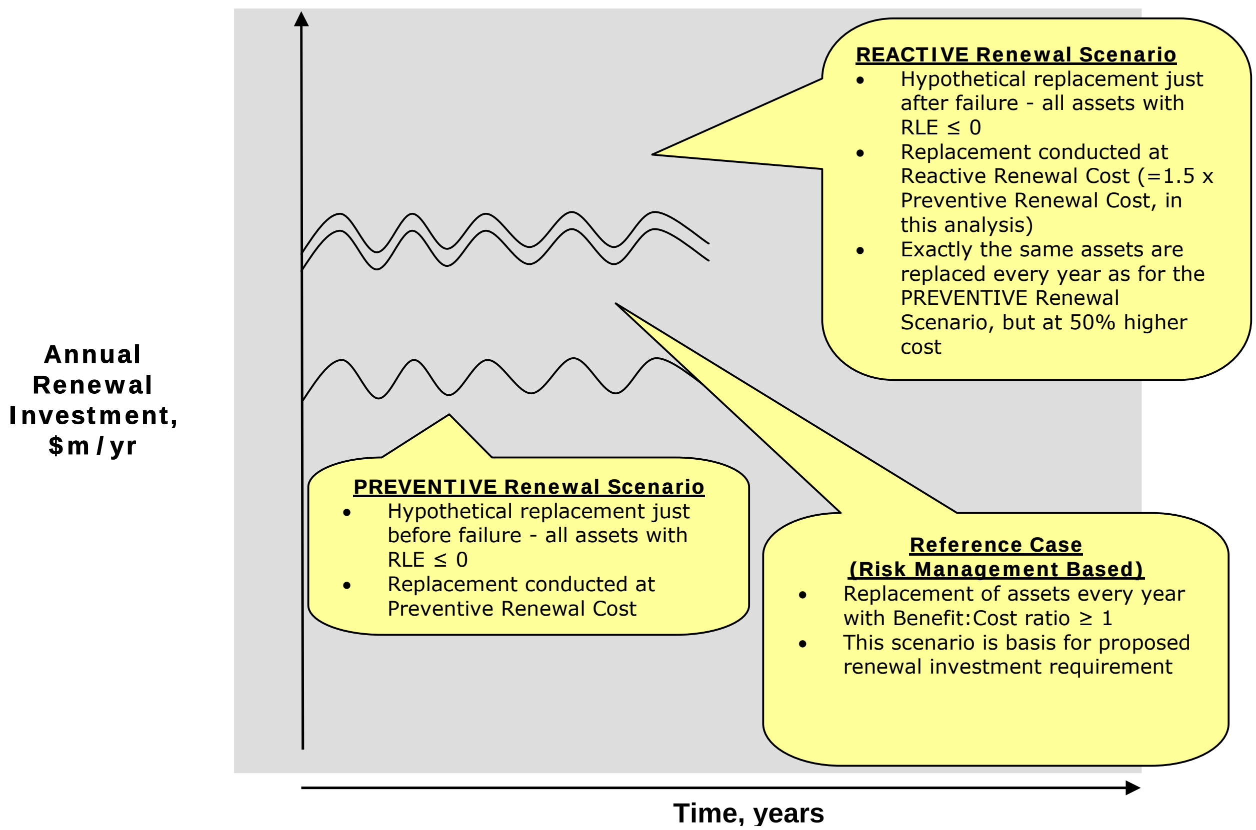

Figure 4: Framework to Interpret Proposed Investment Requirements

Figure 5 below shows the Reference Case being interposed between the hypothetical 'preventive' and 'reactive' scenarios respectively, in terms of total renewal investment over 20 years.

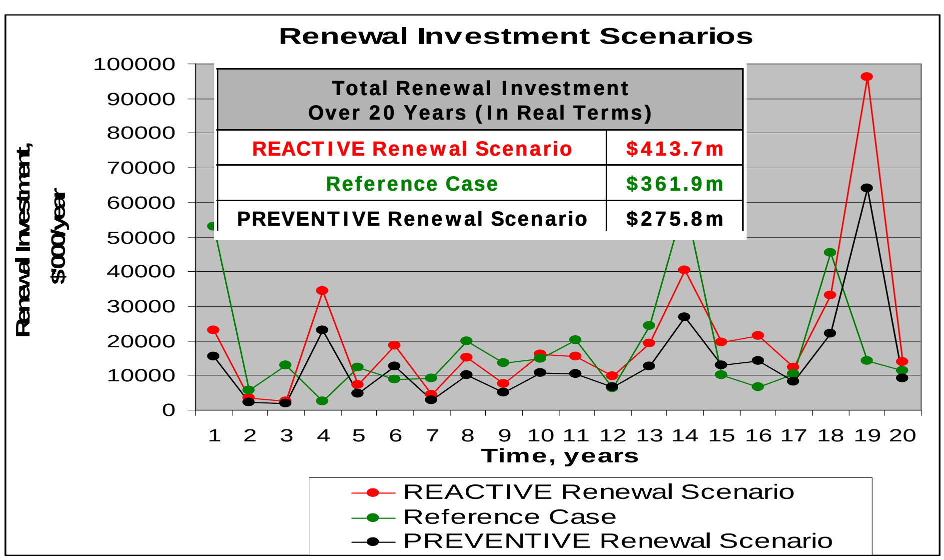

Figure 5: Actual Output Data Based on Unison Asset Register and Presented in Terms of Framework shown in Figure 4

6.0 Augmentation

6.1 Drivers

Augmentation relates to capital expenditure on the backbone of the network to ensure appropriate quality and reliability of supply standards are maintained and meet the forecasted load growth in a sustainable manner.

The strategy that drives this category is based on maintaining the right balance between network security, network reliability and risk management to ultimately deliver appropriate service levels to our customers. It covers the following activities:

- Investments in network **security** to support customer demand on the network. The network needs to have sufficient capability to support the forecasted load during normal, peak and contingency scenarios.

- Investment in network **reliability** to support customer service levels. This includes availability, reliability, restoration and power quality.

- Investment in network **compliance** projects. This relates to investment to ensure compliance of existing network components to regulations. Non-compliance is a result of industry practice changes, network growth and asset deterioration with age (compliance accounts for approximately 5% of the total augmentation activity).

There is a high degree of inherent uncertainty in this category of expenditure:

- The load forecast is based on assumptions regarding customer driven developments, customer behaviour and expectations. Unison’s current load forecast is attached as Appendix 2.

- The current expenditure forecast is based on Unison’s view on how compliant we are in meeting target service levels, since we do not have the systems in place to measure compliance (Unison’s target service levels, as published in the 2005 AMP, are shown in Table 4). Unison is using SAIDI, SAIFI and CAIDI, coupled with power quality monitoring of feeders and specific consumer sites, as the basis for measuring compliance against service levels (a major driver for 2006 is to develop metrics and systems for the service level measures). Unison is, in consultation with customers, also in the process of reviewing the appropriateness of these service levels.

- Unison’s network capability is still being established at this time. Systems are being rolled out to perform asset ratings, but this will take another year or so to come to fruition.

- Compliance requirements can change with time, which results in more uncertainty.

Service Measures	Target Service Level	Policy
RELIABILITY		
Restoration of supply: Unplanned Service Interruptions.	Urban - restore supply within 3 hours of notification of an urban unplanned service interruption; Rural - restore supply within 6 hours of notification of a rural unplanned service interruption; and Remote Rural - restore supply within 12 hours of notification of a remote rural unplanned service interruption.	Service area: Urban – Up to 6 km from city boundary; Rural – 7 – 25km from urban boundary; and Remote Rural – greater than 25km from urban boundary.
Frequency of Service Interruptions and short interruptions.	Urban: No more than 4 per annum recorded by Unison or reported by the customer; Rural: No more than 10 per annum recorded by Unison or reported by the customer; and Remote Rural: No more than 20 per annum recorded by Unison or reported by the customer.	Includes cessation of supply to a consumer of greater than 1 minute to the extent advised by the customer, but excludes subsequent interruptions that relate to an intermittent system fault.
INVESTIGATIONS OF POWER QUALITY AND SERVICE INTERRUPTIONS		
Power quality or service interruption investigations.	Respond within 7 working days of receiving notification. Unison will remedy any problems under its control in a timely manner, in accordance with good industry practice.	Power quality investigations include, but are not limited to momentary voltage fluctuations, flicker, harmonics, voltage imbalance and sags.
ENVIRONMENTAL STANDARDS		
Environmental emergency or disasters	Zero environmental related issues on the network. All significant site hazards identified and removed.	Various network standards

Table 5: Customer Service Levels

6.2 Augmentation Process

The augmentation process can be described as the process to match the network capability to load and service level requirements. If there is a mismatch, then the most cost efficient solution is developed and implemented.

The key steps in this process are:

I. **Establish network loading**

Instantaneous 33kV and 11kV feeder loads are collected in real time via the SCADA system and recorded in the 'PI' database. This PI data is then grouped to give half-hourly average loading information for 33kV and 11kV feeder and 33/11kV transformers for the last year. These are then graphed to determine the sustained maximum demand. One-off peaks due to temporary load transfer are ignored.

II. Perform long term load forecasts

Short-term information from developers gives known load increase areas in the short term – generally with a 2-5 year horizon. Longer term population, industrial and commercial growth information is available via city and district council long-term development plans. These are combined with historical business and population growth information to give an overall load forecast prediction for each feeder, which is aggregated to zone substation and grid exit point level. The load forecast is based on a normal year, and does not account for out of the ordinary temperature fluctuations or adverse weather events.

III. Establish equipment ratings

Equipment ratings are derived from a number of databases, GIS, WASP, substation drawings and protection records. Currently continuous ratings are used. The exception to this is zone substation power transformers where a short-term emergency overload limit of 120% has been assumed. There is an ongoing project to more closely study actual equipment ratings given local conditions rather than assigning limits on a network-wide basis.

IV. Match the load and the network capability

The forecast loads and equipment rating data is entered into the network modelling software ‘PSS/Adept’. Load-flow analysis is run for present and future loads to ensure that equipment current and voltage ratings are met throughout the planning period. Subtransmission contingency analysis is performed to ensure that substations continue to meet the required security standard as load grows. Where this is not the case, an augmentation project is initiated.

V. Match the customer service levels and network response

Once we have identified that we are not meeting customer service levels, or we identify unacceptable network performance (SAIDI, SAIFI) we investigate various options such as network configuration changes, automation and the management of external factors such as vegetation, motor accidents and bird strikes. These investigations result in augmentation projects that feed into the budget.

VI. Identify areas of non compliance

There are a number of potential areas that require compliance related augmentation to remain compliant as load grows. This includes:

a. To provide customers with a supply voltage within the limits prescribed by the electricity regulations.
b. To upgrade Unison’s Single Wire Earth Return (SWER) system to ensure we remain compliant with regulatory load limits for this type of reticulation.
c. Ongoing reviews of our protection systems to ensure that protection systems provide adequate safety to the general public and Unison personnel.

6.3 Augmentation Expenditure Forecasts

6.3.1 Bottom-up view

The augmentation process discussed in 6.2 identifies areas where the system reinforcement is potentially required. This provides a list of probable projects, based on assumptions around load growth and the likelihood of the developments actually going ahead within the timeframes specified. Some projects and, therefore, their budgets, may be subject to change depending on actual timeframes, final solutions adopted and phasing of new developments. The projects that are generated as a result of this process are then analysed and investigated to determine, amongst others, the following:

- The most efficient solution based on technical robustness, customer needs, future proofing and cost;
- The solution that provides the best strategic fit with the long term development plan;
- Project timeframe; and
- Potential for economically viable deferral options (probability weighted risk analyses plays an important role in this).

Once this optimisation process has been completed, the prioritised project list, complete with costs, forms the Development Plan.

This plan forms the basis of forecasting the bottom-up, project driven augmentation capital expenditure requirements. This forecast feeds into the annual budgeting process, which is ultimately signed off by the Board. This plan covers a five year window, but only projects expected to go ahead in the next financial year go into the budget.

The 2006/07 budget for network augmentation, signed off by the Board, is shown in Table 6. Table 6 also indicates the actual expenditure for 2005/06.

Category	**2006/07 Budget $m**	**2005/06 Actuals $m**
UG Conversion	1.5	3.7
Asset Renewals	13.8	7.5
Network Augmentation	5.6	4.9
Customer Projects	6.2	10.3
Total Network Capital Expenditure	**27.0**	**26.4**
Total Network Maintenance Expenditure	**7.3**	**7.3**

Table 6: Approved 2006/07 Budget

The 2006/07 budget is supported by the Development Plan for 2006/07, which is provided in Appendix 3. The inherent uncertainties in this process mean that the Development Plan has to be flexible to allow for changes as a result of better information, changes to the base case assumptions and costs. The budget includes a provisional sum to cater for new developments, or changes to known developments, during the budget period.

The 2006/07 Development Plan is a "live plan". Additional detail pertaining to this plan is currently under review by Unison. Due to insufficient planning resources a significant amount of development and verification work is continuing on this plan.

In addition to addressing security enhancements, the 2006/07 augmentation plan reflects the targeted drive to improve network reliability by installing network automation and network sectionalising equipment.

A provisional allowance has been made for compliance related projects. A key focus for 2006/07 is to ensure that the Single Wire Earth Return (SWER) circuits in operation in the Taupo network are compliant with regulations.

The 2006/07 budget also caters for the design and planning of future projects with long lead times.

6.3.2 Long term view

The accuracy of the augmentation plan diminishes the further out into the future it is predicted. The reason for this is that uncertainties around the probability of loads eventuating as per the load forecast increases with time.

The 2005 AMP states that Unison needs to spend, on average, $3.4m per annum for the next ten years on augmentation (see Table 1b).

This number has been revised, based on our current understanding of costs, to $4.9m (see Table 2) for the next ten years.

The methodology used to derive this number is as follows:[10]

Step 1:
Determine the historical costs of establishing the high voltage, backbone network. Unison used the 2006 ODV replacement costs, less the costs of the other assets that are not part of the high voltage network, as a proxy for this.

Step 2:
Determine the installed high voltage capacity (MVA). This is 654MVA, based on ONAF ratings obtained from Unison's GIS

Step 3:
Calculate the cost to establish one MVA of installed capacity, which is used as a proxy for marginal growth on the network. This calculation is shown as follows:

[10] This approach was supported by Stephen Blanch in his report, "Assessment of Prudent Reinforcement Capital Expenditure"; October 2005.

	ODV 2006 $000
Replacement costs (Table 3)	732,438
Less LV & General Assets:	
Distribution Transformer Value	125,999
LV Lines, LV Cables, Pedestals	176283
Streetlights, Hot water pilots	29340
Other non system assets	
Control Room	1592
Total HV assets in RC	399,223
Installed HV Capacity in MVA	654.1
$1000/MVA for HV assets	**610**

- The $399m total replacement cost reflects the costs to establish the capacity of the high voltage network, which (as per Table 7) is approximately $0.61m/MVA installed capacity, based on the 2006 ODV replacement costs.

- This approach assumes that we will be able to expand the network at the cost reflected by the 2006 ODV.

- It also assumes that the inherent security and reliability of the network, as a result of historical practices, is suitable for the future and thus excludes specific initiatives aimed at improving network security or reliability.

- This includes compliance projects to date, but excludes any future compliance related expenditure.

Step 4:
Determine the marginal, annual growth for the next ten years, based on Unison's long term load forecast[11] (see Table 7).

[11] The long term load forecasts are included in Appendix 2.

Year	Projected Peak Demand (MVA)			Marginal Peak Demand Growth (MVA)
	Rotorua & Taupo	Hawkes Bay	Total Peak Demand	
2005	143.3	184.5	327.8	-
2006	146	188.4	334.4	6.6
2007	151	192.4	343.4	9
2008	155	196.6	351.6	8.2
2009	159	200.8	359.8	8.2
2010	162	205.2	367.2	7.4
2011	164	209.7	373.7	6.5
2012	166	214.4	380.4	6.7
2013	168	219.2	387.2	6.8
2014	170	224.1	394.1	6.9
2015	172	229.2	401.2	7.1

Table 7: Marginal Peak Demand Growth

Step 5:
Calculate the annual augmentation capital requirement:

Augmentation capital required = Cost to establish a marginal MVA x Marginal MVA + Compliance related costs

Step 6:
Translate this to the ten year capital expenditure plan for augmentation capital expenditure. The outcome of this calculation, for the next ten years, is reflected in Table 2.

- This approach results in an average expected expenditure of $4.9m per annum for the next ten years, since the average marginal growth, based on Table 7, is approximately 7.4MVA per year; and compliance related expenditure is on average $330k per annum.[12]

- The year on year forecasts vary slightly, based on Table 7. This approach results in a reasonable smoothed expenditure profile, but this expenditure will be lumpier in practice.

[12] $0.61/MVA installed capacity x 7.4MVA per year + $330k per annum = $4.9m per annum.

7.0 Customer Driven

7.1 Drivers

Customer driven expenditure is driven by new subdivision, infill connections, customer supply upgrades and requests from land owners and other authorities for assets to be changed or moved.

7.2 Customer Driven Process

Projects in this category are initiated as a result of a request from a customer, a developer or the regional councils.

7.3 Customer Driven Expenditure Forecasts

7.3.1 Bottom-up view

The 2006/07 budget for customer driven expenditure, signed off by the Board, is shown in Table 8. Table 8 also indicates the actual expenditure for 2005/06.

The budget reflects a decrease in activity when compared to the 2005/06 forecast, which is based our assessment of the likelihood of a slow down in the development of subdivisions.

Category	2006/07 Budget $m	2005/06 Actuals $m
UG Conversion	1.5	3.7
Asset Renewals	13.8	7.5
Network Augmentation	5.6	4.9
Customer Projects	6.2	10.3
Total Network Capital Expenditure	**27.0**	**26.4**
Total Network Maintenance Expenditure	**7.3**	**7.3**

Table 8: Approved 2006/07 Budget

7.3.2 Long term view

This category is very difficult to predict, since it depends on external and economy related factors. In recent years this budget varied between $4.5m and $10.3m. Table 2 reflects Unison's expectation for the next ten years, which is based on our 2006/07 view.

8.0 Underground Conversion (OHUG)

8.1 Drivers

OHUG refers to the undergrounding of overhead assets. In Hawke's Bay the decision has been made, in conjunction with the Hawke's Bay Power Consumers' Trust, to underground urban residential areas in recognition of consumer amenity value.

8.2 OHUG Process

A programme has been initiated to underground all the existing urban residential areas in Hastings and Napier over the next 10 to 15 years. This programme is prioritised based on condition assessments of the overhead lines, exposure of overhead lines to external factors such as motor accidents and agreements with local councils' to ensure work is completed in conjunction with their civil works.

In Rotorua the Rotorua Energy Charitable Trust (RECT) contribute to the underground conversion of specific areas to enhance aesthetics.

8.3 OHUG Expenditure Forecasts

8.3.1 Bottom-up view

The 2006/07 budget for OHUG expenditure, signed off by the Board, is shown in Table 9. Table 9 also indicates the actual expenditure for 2005/06.

Category	2006/07 Budget $m	2005/06 Actuals $m
UG Conversion	1.5	3.7
Asset Renewals	13.8	7.5
Network Augmentation	5.6	4.9
Customer Projects	6.2	10.3
Total Network Capital Expenditure	**27.0**	**26.4**
Total Network Maintenance Expenditure	**7.3**	**7.3**

Table 9: Approved 2006/07 Budget

The budget reflects a decrease in activity when compared to the 2005/06 forecast, which is a reflection of the resource constraints in the contracting market. In addition, the RECT has indicated that they do not foresee any projects for the 2006/07 financial year.

The projects planned for 2006/07 are mainly driven by asset condition, exposure to third parties (e.g.: car vs. pole incidents) and financial benefits obtained through participation with local councils' civil projects.

8.3.2 Long term view

Table 2 reflects Unison's long term view of this category. We expect to increase OHUG expenditure in three years' time, once we have established the necessary contracting resources in the region.

The increased activity corresponds with the current understanding with the Hawke's Bay Power Consumers' Trust.

9.0 Operational Expenditure

9.1 Drivers

Operational expenditure refers to the maintenance costs Unison incurs to keep the existing asset base in a safe and serviceable condition, to ensure reliable operation and achieve a reasonable service life for the asset.

A range of factors are taken into account when determining the most suitable approach to maintenance for each asset type. The cost of repair versus cost of renewal, planned maintenance costs versus predicted reactive repair costs, likelihood and consequence of failure, safety and compliance, are but some of the considerations that shape each of the categories below.

In producing the maintenance plan, Unison considers the total life cycle costs of assets. The maintenance plan is therefore integrated with, and independent on, the strategies driving the asset renewal plan. Assumptions inherent in the renewal plan, such as life expectancy and replacement costs, are therefore indirect drivers of the maintenance plan.

9.2 Process

Maintenance policies are driven by safety, regulatory and operational drivers, as well as attempting to optimise the trade-off between maintenance and the cost of renewals. For this reason Unison continually monitors and compares the maintenance plans against the level of faults and asset failures occurring on the network. Maintenance (and renewal) plans are then tweaked were necessary to react to changes in asset performance or external influences such as weather patterns.

Two examples of changes resulting from this continual review can be seen in the 2005 year where inspection activities found unsatisfactory numbers of LV assets with defective security, so the plan was accelerated by $100k to ensure public safety was maintained. Climate and rainfall conditions led to vegetation growth rates during 2005 that were exceeding mitigation measures in place for the year. The increase in fault rates and condition reports led to Board approval of an increase (by 25%, $250k) in vegetation spend to ensure customer service is maintained.

Reactive (repair) costs and asset failures are also closely monitored by asset category, as these are strong indicators of the effectiveness of planned maintenance activities and allow good estimation of the possible benefits/consequences of increasing/reducing maintenance levels. The maintenance process for each maintenance activity is covered in detail in various internal Unison documents, which were made available to PBA during their recent visit to Unison.

9.3 Operational Expenditure Forecasts

9.3.1 Bottom-up view

During 2005, Unison developed a methodology to model the impact of maintenance activities (and some key capital expenditure activities) on network SAIFI at feeder level. While still in the first iteration, the model has been extremely powerful in assessing what is required in the coming year to ensure thresholds are not breached.

The ability to model performance against investment and activity levels is a significant step forward in Unison's asset management practices.

From this modelling it was concluded that, while current practices and investment at the 2005/06 level are delivering sustainable improvements at very low costs, the rate of improvement is not sufficient to ensure threshold compliance will be achieved in 2006/07. This has driven an extensive review of practices to determine which activities can be accelerated to achieve the coming year's targets (note that the influence of weather on reactive costs for overhead assets is impossible to accurately predict, since the modelling only allows for a normal weather year).

As a result, changes to maintenance activities have been significant for overhead line assets, an area that contributes a significant portion of customer interruptions. This relates to both vegetation management and maintenance of the poles and lines themselves.

The 2006/07 budget for network operational expenditure, signed off by the Board, is shown in Table 10.

	2006/07 OPEX Budget ($000)		
	Planned Maint	**Reactive Maint**	**Total Maint**
Overhead Lines	1,865	752	2,617
Underground Cables	185	410	595
Zone Substations			
Zone Transformers	80	3	83
Circuit Breakers	149	15	164
Other Substation Equipment & Buildings	270	13	283
Distribution Transformers and Regulators	730	84	814
Distribution Switchgear	123	14	137
Load Control Plant	51	10	62
Miscellaneous Distribution Equipment	215	92	308
Vegetation	1,250	-	1,250
SCADA Control & Communications	137	113	250
	5,055	**1,508**	**6,563**
Power Quality	100	-	100
Council Rates & Electricity	115	-	115
Siemens first response		**480**	**480**
	5,270	**1,988**	**7,258**

Table 10: 2006/07 Operating Expenditure Plan

The operating expenditure forecast for 2006/07 is 13% higher than the 2005 AMP forecast as reflected in Table 1b. The higher forecast is a result the following:

- An increase in the maintenance activities for Overhead Line assets, an area that contributes a significant portion of customer interruptions. This relates to both vegetation management and maintenance of the poles and lines themselves.

- Cost increases experienced by contractors working on Unison's network.

Unison's operating expenditure is budgeted at $7.3m for 2006/07, or 2.4% of the Total Fixed Asset Value as contained in the 2005/06 Information Disclosure, which compares very favourably with other ELBs, e.g.:

Vector	2.8% for 2005/06
Powerco	3.2% for 2005/06

9.3.2 Long term view

It is expected that this level of operating expenditure is sustainable in the medium term with no significant changes expected other than CPI adjustments and a 2% increase to reflect the natural growth rate of the network per year, as reflected in Table 2.

Maintenance plans are likely to have different drivers in subsequent years, but the overall operating expenditure investment is expected to move between categories rather than change in total value.

Key risks that could potentially change this view going forward, but that are not quantifiable at this stage, are:

- The potential for compliance driven maintenance expenditure for LV assets to be understated; and
- Ongoing negotiations with contractors resulting in increases in contracting rates.

Unison's operating expenditure plan has been reviewed by Dellwind, who confirmed that it aligned well with world best practice.

10.0 Network Reliability

As stated earlier, Unison currently uses SAIDI and SAIFI as customer service level driven reliability indicators, while implementing measurement systems for the target customer service levels quoted in the 2005 AMP.

The regulatory thresholds have been adopted as the target levels for SAIDI and SAIFI. As a result, investment in reliability initiatives is driven by, amongst others, compliance to the regulatory thresholds. Unison therefore wants to ensure that the regulatory threshold is correct.[13]

Unison introduced the concept of the network signature in 2005. The network signature is determined by factors such as the network's inherent design methodology, historical maintenance practices and the type of customers connected. Network performance is one way of describing the network signature.

Under this definition, it is generally very costly to change the network signature, since it involves capital expenditure to fundamentally change the way the network has been designed and operated.

We support the approach to base the regulatory threshold on five years of data in principle, which is another way of defining the network signature. However, in Unison's case this is problematic, because of the following:

- The calculation of the quality threshold requires SAIDI and SAIFI information relating to periods when Unison did not own the Rotorua and Taupo distribution networks as these were acquired from UnitedNetworks Limited (UNL) on 1 November 2002.

- Although historical outage data on these networks relating to periods prior to acquisition exists, it is not reliable. The reason for this is that it had to be extracted (using various assumptions) from data provided for the Eastern Region of UNL, which included the Tauranga and Coromandel areas.

- Similar problems were encountered with sourcing historical customer numbers.

- The data for Unison is also incomplete and the disclosure information is based on assumptions, i.e.: pro rata to cover periods of missing data.

Unison has highlighted these problems in its threshold compliance statements and the auditors of the threshold compliance statements have qualified their audit opinions as a result. Unison has come to the view that the regulatory thresholds are too stringent, based on the understanding we have developed for the performance of the combined regions since the acquisition, i.e.: our current understanding of our network's signature. The graphs in Figures 6 and 7 support this view.

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[13] Other drivers for network reliability related investment are the reconfiguration and automation of feeders performing poorly, thus affecting the quality of supply delivered to customers on those feeders.

Figure 6 shows that SAIFI, based on the combined actual data for Hawke's Bay, Taupo and Rotorua, has not met the regulatory threshold over the last three years.

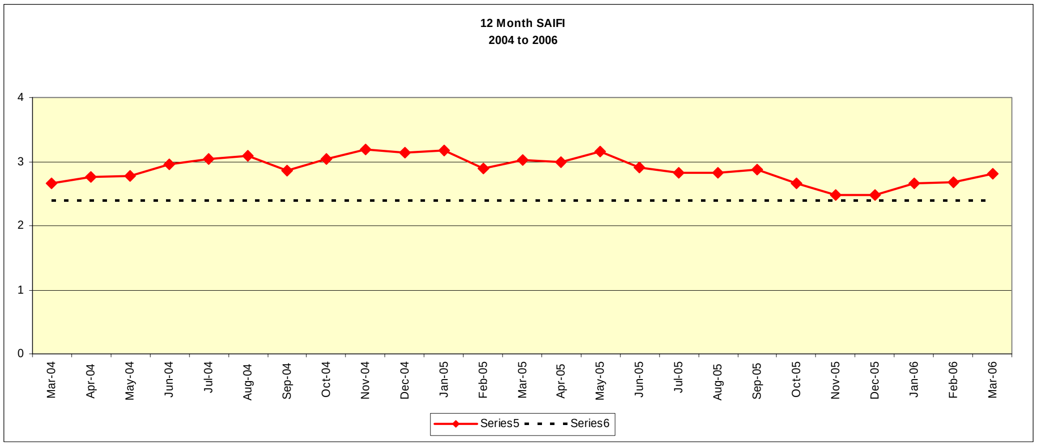


Figure 6: SAIFI Trend for the past three years (rolling twelve months)

Figure 7 shows that SAIDI has met the regulatory threshold since June 2005, but this has been as a result of a very aggressive expenditure plan that targeted external influences such as vegetation. Furthermore, the period covered by this data represents a period of average weather conditions, which means that there is insufficient headroom to cater for the probable impact of adverse weather events.

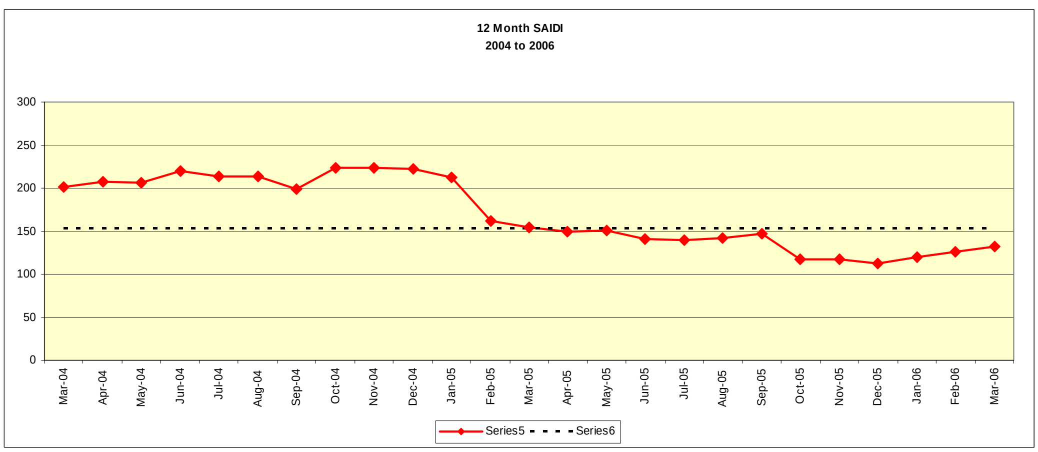


Figure 7: SAIDI Trend for the past three years (rolling twelve months)

This implies that huge investment is potentially required to fundamentally improve the network signature to the levels supported by the current threshold. This also implies improving the reliability experienced by customers to levels they have not been experiencing historically. Unison does not believe that this is prudent, since our customers are not indicating to us that they are willing to pay for improved network reliability.

Unison sees the administrative settlement process as an ideal opportunity to reset the regulatory thresholds, since more appropriate thresholds will more closely represent the network's signature, which will assist in driving efficient investment practices.

The proposal is to base the thresholds on the period for which Unison has accurate and reliable outage data. This implies excluding data prior to 31 March 2003 from the threshold calculation. Table 11 shows the data set that we propose is used for calculating a more appropriate threshold, since it ignores the years for which Unison used assumed data in the current threshold calculation. The data set is based on SAIDI and SAIFI values reported by Unison under the information disclosure regime for 2004 and 2005 (the 2006 values are yet to be reported).

Year ending	**2004**	**2005**	**2006**
SAIDI disclosed by Unison[14]	201.6	155.3	133.8
SAIFI disclosed by Unison[15]	2.39	3.21	2.82

Table 11: Disclosure Data

Table 12 sets out the SAIDI and SAIFI threshold levels that result from using this approach. The current Unison thresholds levels are included for comparison purposes.

	Recommended Threshold Levels[16]	**Current Threshold Levels**
SAIDI	163.6	152.7
SAIFI	2.81	2.39

Table 12: Recommended Thresholds

This approach is supported by LECG. Their recommendation report, in support of the Unison proposal, is included as Appendix 4.

In summary, Unison believes that changing the thresholds to the levels proposed will more accurately reflect the network signature. However, we are also aware that we have only monitored the performance of the three combined regions for a relative short period of time; and as a result there is a real risk of a statistical variation arising from random events in the future.

14 As disclosed in our Threshold Compliance Statement for the Assessment Period ending 31 March 2005 and the second Assessment Period ending 31 March 2004. We have not yet disclosed the 2006 SAIDI performance, but will be disclosing the number indicated.

15 As disclosed in our Threshold Compliance Statement for the Assessment Period ending 31 March 2005 and the second Assessment Period ending 31 March 2004. We have not yet disclosed the 2006 SAIFI performance but will disclose the number indicated.

16 The average of the value shown in Table 11.

11.0 Execution of the Plan

Unison has a well established method of execution of planned maintenance activities. Annual plans are developed and issued to regional contractors at the start of the financial year so contractors can schedule resources and commit to agreed completion plans/timelines. Actual physical progress is reported against plans by each contractor in monthly reports and financial progress is closely tracked by Unison each month. Financial tracking is very detailed, being performed by region, by asset type and by maintenance activity - into more than 200 reporting elements, allowing detailed understanding of the plan execution, during the whole financial year.

Execution of the capital expenditure plan is tracked in a similar manner with all stages from initial design through to final commissioning monitored against target timelines. To ensure adequate lead times are available to design and install all projects issued within the financial year, over 90% (in value) of 2006/07 planned capital expenditure projects have already been issued to Unison's Service Delivery team for design/construction at the time of writing.

As a further measure of progress, at this point in the year (end of April) approximately 25% of the total capital expenditure has been issued to contractors, i.e.: issued for pricing, is out on tender, or is in the process of being constructed.

12.0 Conclusion

Unison is confident that the expenditure forecast shown in Table 2 is an accurate representation of the capital required to ensure we meet customer expectations in the short and long term. It is based on solid, prudent and smart engineering principles, satisfies the drivers of the Company and will ultimately ensure the sustainability of the network.

The engineering and costing principles driving this expenditure have been supported by experts from PwC, SKM, Wilson Cook & Co, Dellwind and LeverEdge. LECG have provided expert input into the consideration of the quality thresholds.

The expenditure forecast represents a stretch for Unison, since internal and external resources have to be put in place to ensure that we deliver, not only the total expenditure, but the expenditure in the appropriate categories.

Appendix B1 – Expert review of Unison's methodology to establish Replacement Costs

Wilson Cook & Co

Engineering and Management Consultants
Advisers and Valuers

Reply to: Auckland Office
Our ref: 0606
Email: jeffrey.wilson@wilsoncook.co.nz

9 May, 2006

Mr André Botha
General Manager, Network
Unison Networks Limited
PO Box 555
HASTINGS

Dear André,

BRIEFING FOR UNISON BOARD – ODV VALUATION OF SYSTEM FIXED ASSETS FOR SETTLEMENT PURPOSES

In response to your request, we provide a briefing for the Board on our assessment of the ODV valuation that the company has prepared for settlement purposes, pending the completion of our report. For the Board's information, we have also included our terms of reference and a brief statement of the background to the matter.

Terms of Reference

Our terms of reference were to:

(a) Receive the supporting evidence available and consider its suitability in relation to the selection of appropriate lives, replacement costs and multipliers for the proposed ODV valuation for settlement purposes;
(b) review the robustness of the assumptions made to derive asset replacement costs and lives in cases where the Handbook's standard replacement costs and lives are not proposed for use;
(c) review the robustness of the assumptions made to derive multipliers in cases where the Handbook's standard multipliers are not considered to have sufficient range to cover Unison's circumstances or where additional multipliers are required to deal with identifiable factors;

(d) express a view on the compliance of the resulting valuation with deprival valuation principles;
(e) consider such other factors as in our opinion are relevant when providing Unison with the opinion requested; and
(f) express a view on the appropriateness of the resulting valuation for use for settlement purposes;

We were asked to take into particular account:

- the need to ensure that the valuation complies with deprival valuation principles and is consistent with the principle of efficiency that underpins the Commission's targeted control regime for the electricity lines businesses;
- the need to ensure that the valuation reflects reasonable and efficient costs of an electricity lines business working in Unison's circumstances; and
- the need to ensure that the valuation reflects Unison's true costs of replacement and thus that it is appropriate for use in the present phase of the targeted control regime (viz: for settlement).

We were not required to (and did not) review or audit the accuracy of the asset register or the calculations used to derive the valuation as that work has been carried out by Unison's other professional advisers.

Nor were we required to (and we did not) review or audit the determination of life extensions, multiplier applications, optimisations or economic values determined and agreed with Unison's valuers at the time of preparation of the company's 2004 ODV valuation for regulatory purposes.

The Valuation

Since October 2005, Unison has concluded a comprehensive review of its system fixed asset replacement costs, asset lives and cost multipliers and has documented the evidence that it has compiled in support of departures from the industry standards given in the Handbook and used in its 2004 valuation. The material is comprehensive and well presented. It was produced and checked systematically by Unison and was then reviewed, audited and accepted by SKM as reasonable for use in the valuation.

It includes evidence on asset lives, replacement costs and the adequacy of the multipliers used in the 2004 valuation; reports by SKM of the field visits it made to check the accuracy of the asset register (the corrections found necessary in the database appeared to us to be minor but have been incorporated); copies of relevant correspondence between Unison and it suppliers, SKM and other consultants in which data and assumptions relating to the analyses are discussed and agreed; and source data for the valuation of easements, stores and miscellaneous special items such as the quantity of underground cable that runs up poles and is therefore not included in the company's two-dimensional geographic information system (GIS) database.

Supporting Expert Opinion

Unison's proposed asset life extensions are supported in the material cases by evidence from recognised experts in the fields concerned. The main instances were reports on asset lives or condition from: General Cable New Zealand Limited on certain 11 kV XLPE cable condition; Hastings consulting engineering practice, LHT Limited, on concrete substation buildings; Wellington consulting practice, Linetech Consulting Limited, on the life of concrete poles; suppliers' quotations (supplementing Unison's own project cost data) in respect of the replacement costs of various asset categories; and various items of evidence in support of the cost multipliers applied and the extent of their coverage.

SKM's Review and Conclusions

SKM were engaged by Unison through PwC to review and approve the technical assumptions made by Unison. A statement summarising the derivation of lives, replacement costs and, where applicable, multipliers, was prepared by Unison for each asset category and signed by SKM, after agreed modifications had been incorporated in the calculations, in confirmation of SKM's view that the assumptions were reasonable and appropriate.

The Valuation

Unison then calculated the valuation for settlement purposes. It uses the 2004 ODV valuation as its basis with adjustments to reflect the evidence referred to above as well as the usual adjustments for additions and deletions from the asset base since 2004 and for a further period of depreciation.

There are several material changes in replacement costs, asset lives and multipliers in the proposed valuation v. those in the Handbook and used in the 2004 valuation and we summarise them in our assessment below.

Cost Indexation

Cost indexation has not been proposed as the standard replacement cost of each asset category has been determined from project evidence spanning between one and two years' duration and that evidence is considered more robust than indexation. We support that view.

Optimisation and Economic Testing

It is not proposed to review the optimisation of economic value calculations made in the 2004 valuation, as neither has a material impact.

Our Assessment of Material Changes

Asset Lives

The material changes in asset lives from 2004 are:

(a) 11 kV XLPE cables installed in the 1970s: further work to identify the affected areas has resulted in a reduction of the deductions made in 2004;
(b) concrete (substation) buildings: life extended to 100 years, other than in the case of Arawa Street substation, based on expert evidence;
(c) concrete poles: life extended from 60 to 80 years based on expert evidence;
(d) disconnectors: life extension from 35 to 40 years based on the fact that 28% of the assets in this category already exceed the standard Handbook life of 35 years but are serviceable;
(e) load control plant: life extension from 20 years to 30 based on service experience.

The evidence appears to be suitably robust and the assumptions reasonable and appropriate.

The adoption of a longer life for concrete poles results in a material uplift in the valuation as the life of overhead lines as a whole is imputed from the life of their supports (concrete poles in this case). This is notwithstanding the fact that the lives of other components that make up the lines are not expected to match the extended lives of the poles. It is thus implicitly assumed that the replacement of other line components over time will be expensed. We were satisfied with this adjustment on that basis.

Replacement Costs

The replacement cost of all asset categories has been reviewed by Unison, based on evidence adduced from the cost of representative, completed, project costs. The evidence appears to be suitably robust.

Of importance, and after discussion with PwC, SKM and ourselves, allowance has been made for an appropriate measure of ‘scale’ in the construction costs used, particularly in project management costs.

In their final form, the assumptions made appear reasonable and appropriate.

The impact is a significant uplift in replacement costs. This reflects the fact that the replacement costs of the seven asset categories that account for two-thirds of the ODRC value (and thus of the ODV as well, as optimisation and EV impacts are immaterial) have risen by between 1.4 times and 1.5 times their 2004 cost, including the effects of extended areas of application of the multipliers for rugged and rocky terrain and of small increases in quantity. The asset categories concerned are 11 kV lines and cables, distribution substations and low voltage XLPE cables.

Conclusion

Having considered the evidence presented to us for review, our view (which we will confirm in our report) is that:

(a) the assumptions made in the valuation are appropriate and are based on robust evidence;
(b) the resulting valuation is consistent with deprival valuation principles and reflects the reasonable and efficient costs of an electricity lines business working inUnison’s circumstances;

(c) departures from the prescriptive costs and lives of the Handbook reflect Unison's actual circumstances, do not have the effect of contravening (b) above and are identified and explained in the company's documentation to our satisfaction; and

(d) subject, obviously, to the view of the Commission, the valuation can be considered appropriate for use for settlement purposes.

Whilst, however, the valuation is suitable in our view for the intended purpose, the replacement costs assumed in it may not be suitable for use in the company's capital expenditure projections without modification as they reflect an element of 'scale' that will not apply to all works undertaken. A review of the company's capital expenditure projections was outside the scope of our work but the projections should be checked to ensure that appropriate cost assumptions have been made in each case, taking account of scale where appropriate and selecting other costs where not.

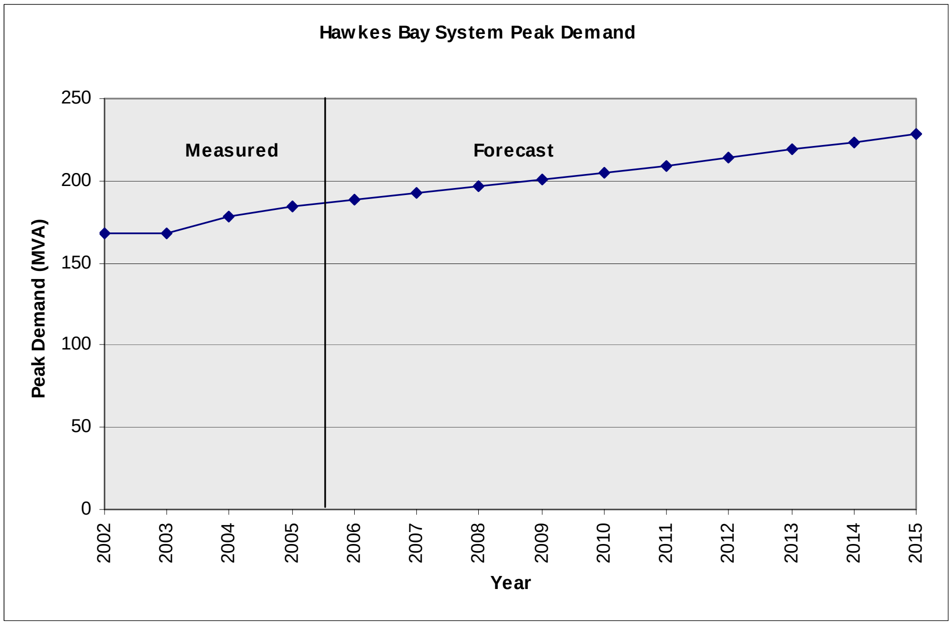
Yours faithfully,

Wilson Cook & Co Limited

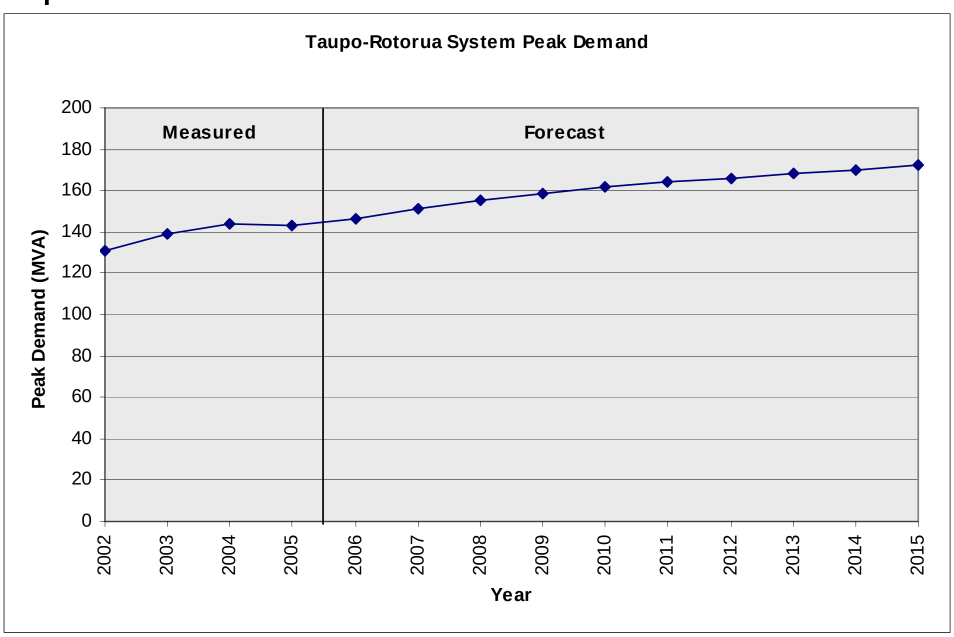
Appendix B2 – Load forecasts

The load forecast for the network is illustrated by the following graphs:

Graph 1



Graph 2



Appendix B3 – Development Plan

Area	Project	Justification	2006	2007	2008	2009	2010	2011
	Merlot Drive Tie Cable	Increase 11kV transfer capacity from Tamatea to Church Rd	$ 35,000					
	Esk Substation Security Project	Provision for mobile regulator to provide partial n-1 security to Esk substation	$ 55,000					
	New Feeder (Phillips) Waitangi Rd	Provision of required capacity to support load growth due to subdivisions	$ 250,000					
	Tutira Automation	Provision of partial n-1 capacity to Tutira substation	$ 3,000					
	Burness Feeder Conductor Upgrade	Provision of required capacity to support load growth due to subdivisions	$ 102,000					
	VC 93 Hill Rd	Increase capacity to meet load growth	$ 10,000					
	Remote Automation Pohukura Feeder	Improve reliability of Pohukura feeder	$ 9,000					
	Automation Tangoio Feeder	Improve reliability of Tangoio feeder	$ 26,340					
	Tamatea Substation Reconfiguration	Security upgrade to Tamatea substation	$ 60,000					
	Awatoto Substation re Insulation	Reduction in pollution related faults Awatoto substation	$ 30,000					
	Automation Valley Feeder	Improve reliability of Valley feeder	$ 40,000					
	Automation Rissington feeder	Improve reliability of Rissington feeder	$ 20,000					
	Automation Tangoio feeder	Improve reliability of Tangoio feeder	$ 26,000					
	NCC 33kV cable marking	Comply with council request	$ 8,900					
	Sub 3630 Upgrade		$ 40,000					
	Purchase of second generator step-up t	Provide extra capacity during line/transformer outages		$ 50,000				
	Tamatea transformer upgrade	Load already exceeds 120% of n-1 capacity. Upgrade could be deferred by load shifting with new feeder out of Marewa. **Defer.**						
	Napier subtransmission reconfiguration	Provide for 33kV capacity into city on loss of double circuit 33kV line. Also reduces SAIDI due to faults on North Tie and momentary interruption events to Napier CBD and port.					$ 504,570	
	Marewa new 11kV feeder	into Tamatea area. Allows deferral of substation upgrade at Tamatea, and better utilisation of transformer capacity at Marewa and Tannery Rd.			$ 75,009			
	Tamatea new 11kV feeder	Supply load growth in Lagoon Farm residential development		$ 287,650				
	Niven feeder conductor upgrade	Provide additional load transfer capacity between Tamatea and Marewa		$ 8,250				
	Taradale B 11kV cable upgrade	Maintain n-1 capacity for feeder		$ 95,656				
	Protection Upgrade Church Rd	Is required to allow full use of existing subtransmission line capacity into Napier, and to correct existing discrimination problems.		$ 77,000				
	Provision for complicance projects		$ 62,500	$ 200,000	$ 75,000	$ 50,000	$ 50,000	$ 50,000
	Provision for subdivision driven augmentation		$ 75,000	$ 175,000	$ 162,500	$ 175,000	$ 112,500	$ 152,250
	Provision for reactive capacity upgrades		$ 50,000	$ 150,000	$ 110,000	$ 170,000	$ 75,000	$ 175,000
	Provision for reactive voltage support upgrades		$ 56,750	$ 168,250	$ 75,000	$ 112,250	$ 50,000	$ 125,000
Napier	**Napier Total**		**$ 959,490**	**$ 1,211,806**	**$ 497,509**	**$ 507,250**	**$ 792,070**	**$ 502,250**

Area	Project	Justification	2006	2007	2008	2009	2010	2011
	LV Conductor Upgrade, Okere Falls	Increase capacity to meet load growth	$ 60,000					
	LV Underground Supply to Transit Traffi	Increase capacity to meet load growth	$ 25,000					
	Install 33kV Circuit, Wairekei - Fernleaf	Design for future subtransmission security enhancement project	$ 10,000					
	Remote Automation - Tarukenga	Provision of n-1 capacity to Tarukenga substation	$ 110,000					
	Remote Automation - Rainbow	Provision of partial n-1 capacity to Rainbow substation	$ 50,000					
	Automation of Arawa-Owhata feeder ties	Provide n-1 security of supply to Owhata and Arawa substations	$ 40,000					
	ABS Installation on Identified Rotorua Su	Reliability improvements to Rotorua overhead feeders	$ 75,000					
	Install Recloser on Kaharoa Feeder	Increase reliability of Kaharoa feeder	$ 40,000					
	Install New Recloser on Dalbeth Feeder	Increase reliability of Dalbeth feeder	$ 40,000					
	Reporoa Fdr - Install 2 Reclosers & Relo	Increase reliability of Reparoa feeder	$ 115,000					
	Relocate S6036 & Install New Recloser	Increase reliability of Tarawera feeder	$ 60,000					
	Okere Automation	Increase reliability of Okere feeder	$ 92,000					
	Air Condition Arawa Substation Switch R	Reduce heat related failures of zone substation equipment	$ 10,000					
	White Rd SWER Upgrade	Reduce load below 8A limit	$ 25,000					
	Install LV Rd xing pole	Meet minimum height regulations	$ 2,300					
	Arawa substation T1 & T2 Foundation &	Reduce risk of oil spill	$ 90,000					
	Purchase of mobile voltage-regulator for	Provide extra capacity during line/transformer outages - Rotorua			$ 200,000			
	Northwest Rotorua Substation	All substations in Rotorua area are highly loaded. Feeder capacity to CBD and industrial areas is nearing limits. Arawa substation is at 144% of n-1`rating, can not be easily upgraded due to 33kV cable and 11kV switchboard constraints. Rotorua 11kV GXP is at 157% of n-1 and is well outside of security standard. Transpower load forecast for Rotorua GXP is to reach 37MVA (93% or substation ONAN rating) by 2011.		$ 300,000			$ 2,143,792	$ 2,143,792
	New GXP or 33kV line n-1 to Rainbow/Fernleaf	Rainbow/Fernleaf substations are on single 33kV line, Fernleaf is approx 37km line length from GXP. Combined load is 9.8MVA, largely industrial. According to security standard should have 100% restoration within 1 hour. Subject to commercial negotiation with customer and Trustpower.		$ 1,005,460	$ 1,005,460			
	Rotorua feeder conductor upgrades	Support industrial load growth.		$ 82,500				
	Arawa overload protection	Transformer exceeds 120% of n-1 capacity and is above 11kV switchboard limit. Prevents damage to equipment during n-1 events, until extra substation capacity built.		$ 16,500				
	Provision for complicance projects		$ 62,500	$ 200,000	$ 75,000	$ 50,000	$ 50,000	$ 50,000
	Provision for subdivision driven augmentation		$ 75,000	$ 175,000	$ 162,500	$ 175,000	$ 112,500	$ 152,250
	Provision for reactive capacity upgrades		$ 50,000	$ 150,000	$ 110,000	$ 170,000	$ 75,000	$ 175,000
	Provision for reactive voltage support upgrades		$ 56,750	$ 168,250	$ 75,000	$ 112,250	$ 50,000	$ 125,000
Rotorua	**Rotorua Total**		**$ 1,088,550**	**$ 2,097,710**	**$ 1,627,960**	**$ 507,250**	**$ 2,431,292**	**$ 2,646,042**

Area	Project	Justification	2006	2007	2008	2009	2010	2011
	Extend Taupo North Feeder to Suply Acacia Bay Area	Improve security to Acacia Bay area	$ 60,000					
	Upgrade Sub T267	Increase capacity to meet load growth	$ 7,500					
	Upgrade Sub T133	Increase capacity to meet load growth	$ 5,500					
	Install 33kV CB's at Runanga	Close 33kV bus to meet security requirements for Runanga	$ 40,000					
	New 33kV Substation at Kinloch (stage 1)	Design for future substation to meet load growth	$ 250,000					
	New 33kV Substation at Kinloch (stage 1)	Design for future substation to meet load growth	$ 250,000					
	Relocate Richmond Feeder	Connect Richmond feeder to spare vacuum circuit breaker to improve fault restoration times	$ 10,000					
	Replace Sub T456 with a ground mount	Reduce outages due to overhead transformer vehicle impacts	$ 45,000					
	Replace Sub T713 with a ground mount	Reduce outages due to overhead transformer vehicle impacts	$ 45,000					
	Upgrade Poihipi Rd Regulator	Improve capacity to Kinloch area	$ 7,000					
	Capacity Upgrade - Ben Lomond	Provide capacity for load growth at Acacia Bay & Kinloch	$ 340,000					
	Install a Recloser at ABS SP121	Increase reliability of Acacia Bay feeder	$ 35,000					
	Automation of Ben Lomond Feeder	Increase reliability of Ben Lomond feeder	$ 200,000					
	Acacia Bay Upgrade	Increase capacity to Acacia Bay, Nukuhau and Kinloch	$ 400,000					
	Lochinver/Rangitaiki Swer Line Upgrade	Comply with 8A SWER limit	$ 120,000					
	Centennial Drv relocate CB317 Fletchers T1	Increase security to major industrial customers	$ 40,000					
	Scada Indication Disconnectors	Improve fault response time, Taupo South substation	$ 12,000					
	Runanga Substation Security Fence	Increase site security	$ 50,000					
	Centennial Drive Landscape Frontage	Comply with district council requirements	$ 10,000					
	Rangitaiki Swer Line Upgrade (design)	Meet 8A regulatory requirement	$ 2,000					
	Palmer Mill Rd SWER Line Upgrade	Meet 8A regulatory requirement	$ 100,000					
	Build new 33kV line to Kinloch site and run at 11kV	Provides required capacity to Kinloch in short term, i.e. at least 5 years		$ 576,912				
	Build new Kinloch substation	Can be deferred by 11kV solutions, at this stage construct line and run at 11kV. Load growth has not occurred at rate originally						
	Rainbow - SH5 feeder tie	Allows extra load 11kV backup capacity between Runanga and Taupo South		$ 136,550				
	2nd 33kV line to Taupo South	Provides n-1 capacity to Taupo South - can **defer** with 11kV load transfer upgrade.						
	Centennial Drive 33/11kV transformer	Supply industrial growth in Crown Rd area. Backup capacity for n-1 at Runanga. **Not necessary** if take new feeder from Fletchers site.						
	Voltage regulator Wharewaka feeder	Provide voltage support during 33kV line outages to Taupo South		$ 116,160				
	Voltage Regulator Waikato feeder	Solves existing voltage problem			$ 116,160			
	Voltage Regulator Acacia Bay feeder	Solves existing voltage problem, defers construction of Acacia Bay substation, provides backup capacity once Kinloch in place		$ 116,160				
	Runanga overload protection	Protects supply to CBD in case of transformer trip without overloading network plant.			$ 16,500			
	New feeder from Fletchers substation.	Allows extra load 11kV backup capacity to Taupo South and Runanga. Subject to commercial negotiation.			$ 185,460			
	Runanga substation switchboard renewa	Is below rating for transformer n-1 event, 11kV feeder protection is limiting feeder capacity. **Renewal.**						
	Provision for complicance projects		$ 62,500	$ 200,000	$ 75,000	$ 50,000	$ 50,000	$ 50,000
	Provision for subdivision driven augmentation		$ 75,000	$ 175,000	$ 162,500	$ 175,000	$ 112,500	$ 152,250
	Provision for reactive capacity upgrades		$ 50,000	$ 150,000	$ 110,000	$ 170,000	$ 75,000	$ 175,000
	Provision for reactive voltage support upgrades		$ 56,750	$ 168,250	$ 75,000	$ 112,250	$ 50,000	$ 125,000
Taupo	**Taupo Total**		**$ 2,273,250**	**$ 1,639,032**	**$ 740,620**	**$ 507,250**	**$ 287,500**	**$ 502,250**

Area	Project	Justification	2006	2007	2008	2009	2010	2011
	New RMS Flaxmere Village	Increase security to commercial customers	$ 39,891					
	Henderson Rd Conductor Upgrade	Increase 11kV backup capacity to Flaxmere substation	$ 45,000					
	Mahora Zone Sub Fast Load Trasfer for	Increase 11kV backup capacity to Mahora substation	$ 72,000					
	Upgrade 11kV Cable, Clive Feeder	Increase capacity to meet load growth	$ 440,000					
	Install RMS Complete OHUG (Te Mata	Increase 11kV transfer capacity between Havelock and Arataki substations	$ 80,000					
	Maraekakaho Sub Security	Upgrade 11kV conductors to provide partial n-1 security to Maraekakaho substation	$ 100,000					
	Install Recloser V2	Improve reliability of Poukawa feeder	$ 18,000					
	Patoka Automation	Increase reliability to Patoka substation	$ 39,875					
	Purchase of mobile voltage-regulator for	Provide extra capacity during line/transformer outages - Hawkes Bay	$ 200,000					
	Camberley Transformer upgrade	Can **defer** if upgrade Flaxmere						
	Fernhill second transformer	Single bank site will exceed ONAN rating in 2007.				$ 821,354		
	Flaxmere upgrade transformers and incoming cables	Site exceeds 120% of n-1 capacity, spare capacity at surrounding substations is limited, load growth expected.				$ 1,556,919		
	New transformer and 33kV circuit breaker at Windsor	Load will grow significantly if transfer load from Hastings. Windsor has spare feeder capacity and is closer to load growth areas than Hastings.			$ 859,854			
	Hastings transformer upgrade	Load is exceeding n-1 rating of site. Upgrade will be difficult due to site access, and growth is limited by 11kV switchboard, 33kV cable and 11kV feeder constraints. Future load growth is on northern side of city so upgrade Windsor instead. **Defer**.						
	Havelock transformer upgrade	Load already exceeds 120% of n-1 rating. Can **defer** by load transfer to Arataki.						
	Arataki T1 upgrade	Site will exceed 120% of n-1 rating if load is transferred from Havelock. Residential load growth is expected.				$ 778,460		
	Mahora T1 upgrade	Existing load exceeds 120% of n-1 rating. Industrial subdivisions in area within next 5 years.			$ 774,054			
	Maraekakaho transformer upgrade	Load growth will exceed rating of voltage regulators. Growth doesn't reach limit until 2011, so can **defer**.						
	Tomoana transformer upgrade	2006 new RMU to tie to Mahora will allow **deferral** - at least 5MVA of load transfer exists, and is doubtful whether forecast industrial load growth will actually eventuate within next 5 years.						
	Hastings 33kV cable replacement and circuit breaker	Existing cable is limited in capacity, so will not allow future upgrade of transformers. Existing security to substation does not meet security standard. New cable will allow no-break security to both Hastings and Windsor. Can **defer** if transfer load from Hastings to Windsor, as Hastings load will then be below SLT1 requirement.						
	New 33kV cable Irongate - Camberley	Existing security constraint - insufficient capacity to provide 33kV n-1 capacity to either Irongate or Flaxmere due to cable size limits. Will allow conversion of Irongate and Camberley to no-break n-1, and allow remote transfer and increased reliability to Flaxmere.					$ 902,066	
	Install 33kV line ABS at Irongate	Allows restoration of supply to Irongate on loss of pole between Irongate and SH2.		$ 40,000				
	Hastings 11kV switchboard and incomin	Switchboard and incoming cables under-rated. Can defer by load transfer to Windsor. Is due for **renewal**.						
	Camberley Feeder tie automation	Allows deferral of upgrade of Camberley transformers			$ 66,000			
	Fernhill feeder tie automation	Allows deferral of upgrade of Fernhill transformer		$ 66,000				
	Nottingly feeder upgrade	Supply increased load due to residential subdivisions		$ 55,000				
	Completion of coastal upgrade project	Increased reliability to Waimarama feeder, allows for future load increase due to initial stages of Ocean Beach development.		$ 470,448				
	Simla-Te Mata Tie	Allows more load transfer from Havelock to Arataki substations, defers transformer upgrade at Havelock.			$ 119,273			
	Railway feeder upgrade	To allow for forecast load increase			$ 84,467			
	Queen feeder upgrade	To allow for forecast load increase			$ 93,715			
	Provision for complicance projects		$ 62,500	$ 200,000	$ 75,000	$ 50,000	$ 50,000	$ 50,000
	Provision for subdivision driven augmentation		$ 75,000	$ 175,000	$ 162,500	$ 175,000	$ 112,500	$ 152,250
	Provision for reactive capacity upgrades & automation		$ 50,000	$ 150,000	$ 110,000	$ 170,000	$ 75,000	$ 175,000
	Provision for reactive voltage support upgrades		$ 56,750	$ 168,250	$ 75,000	$ 112,250	$ 50,000	$ 125,000
Hastings	**Hastings total**		**$ 1,279,016**	**$ 1,324,698**	**$ 2,419,861**	**$ 3,663,983**	**$ 1,189,566**	**$ 502,250**

Recommended SAIDI & SAIFI levels for the Quality Thresholds of Unison Networks Ltd

To Unison Networks Ltd

Stuart Shepherd & Mischa Mutavdzic

29 May 2006

LECG Limited

www.lecg.com

About LECG

LECG is a global expert services firm with highly credentialed experts and professional staff conducting economic and financial analysis to inform legislative, judicial, regulatory and business decision–makers. LECG provides independent expert testimony, original authoritative studies and strategic advice to clients in both the public and the private sector. LECG experts are renowned academics, former senior government officials, experienced industry leaders and seasoned consultants.

Our experts and professional staff have specialised knowledge in regulation, economics, financial and statistical theories and analysis, as well as in-depth knowledge of specific markets and industries. LECG's business model enables our highly credentialed, independent, and capable individuals, both inside and outside the firm, to work together to understand and explain complex business and organisational behaviour.

Since 1994, our experts and professional staff have worked on over 6,200 assignments for over 3,500 clients in over 30 countries. LECG is listed on the NASDAQ Stock Exchange and has approximately 900 experts and professional staff worldwide.

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Table of Contents

1 Introduction

Unison Networks Ltd (Unison) requested we:

- Identify the historical SAIDI and SAIFI levels of its electricity networks by reference to its Faults Database.
- Recommend an approach to setting SAIDI and SAIFI levels for Unison's quality thresholds in the context of its proposed administrative settlement with the Commerce Commission (Commission).
- Identify the SAIDI and SAIFI threshold levels which would result from the recommended approach.

1.1 Context

Unison is preparing material for a potential administrative settlement with the Commerce Commission subsequent to breaches of its "thresholds" set under Part 4A of the Commerce Act. These thresholds set maximum expected prices that an electricity distribution business may charge, and minimum expected service quality levels it must deliver, or face the prospect of an investigation by the Commission and possible control of its electricity distribution service under Part V of the Commerce Act.

This report focuses on the SAIDI and SAIFI measures of the quality thresholds only. It:

- Discusses the method used to set the quality thresholds and documents Unison's historical SAIDI and SAIFI performance, as disclosed under the information disclosure regime and as identified by us using Unison's Faults Database.
- Recommends an approach to setting Unison's quality thresholds going forward and identifies the SAIDI and SAIFI threshold levels that would result from using our recommended approach.

2 Quality thresholds and Unison's historical performance

2.1 Method used to set quality threshold levels

The Commission's method for setting quality thresholds for electricity distribution businesses, as set out in clause 6 of the Gazette Notice[1] , can be summarised as follows:

[1] This Gazette Notice is titled " Commerce Act (Electricity Distribution Thresholds) Notice 2004", 31 March 2004.

- The quality thresholds incorporate a measure of SAIDI, SAIFI and customer communication. This report focuses on the SAIDI and SAIFI measures only.
- The SAIDI and SAIFI measures relate to Class B and C interruptions only, which are planned and unplanned interruptions respectively that originate within the works of the disclosing entity.[2]
- The SAIDI and SAIFI threshold level for each distribution business for the years ending 31 March 2004 onward (but expected to be reset in five years) are determined by taking the arithmetic average of the SAIDI and SAIFI levels reported by that business for the five years from 1998/99 - 2002/03.
- A threshold breach occurs if the SAIDI or SAIFI level for any year is greater than the threshold level for that business.
- There is provision for adjustment of the threshold level if the total customer numbers or system length changes by 10% or more, or if there is a transfer of assets between the distribution business and Transpower.
- If, because of a lack of information, it is not practicable to determine whether a business has complied with the thresholds, the business will be regarded to have complied with the thresholds if it demonstrates beyond reasonable doubt that the substance of the thresholds has been complied with.

2.2 Unison's historical performance

Unison has owned and operated its Hawkes Bay electricity network for many years, but purchased its Rotorua and Taupo networks from UnitedNeworks Ltd in November 2002. The current customer numbers on each network are approximately 60,000 for Hawkes Bay and 45,000 for Rotorua & Taupo.[3]

The latter two networks were operated by UnitedNetworks as an integrated business with its other electricity networks in Wellington, Tauranga and Waitemata prior to their sale to Unison in November 2002. Unison does not have reliable service performance information for the Rotorua and Taupo networks prior to the purchase date (this is discussed below).

To calculate the threshold levels that apply from the 2003/04 year onward, Unison was required to estimate the SAIDI and SAIFI levels for previous years as if the purchase had occurred on 31 March 1998 (i.e. the 5-year SAIDI and SAIFI averages needed to be calculated as if Unison had owned all its current networks for the 5-year period). Table 1 below provides the SAIDI and SAIFI values used in that calculation, as well as the values disclosed by Unison over the same period with respect to its Hawkes Bay network only.

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[2] See clause 6 of the Gazette Notice and Schedule 1 of the Electricity Information Disclosure Requirements issued 31 March 2004 (consolidating all amendments to 1 April 2006), by the Commerce Commission.

[3] These numbers were based on values extracted from Unison's WASP database as at 20 April 2006 and includes only consumers with an ICP status of Energised or De-energised.

Financial Year ending	1999	2000	2001	2002	2003	Threshold value[4]
SAIDI used for calculating threshold[5]	175.49	148.36	186.38	120.60	132.68	152.7
SAIDI disclosed for Hawke's Bay[6]	162.4	103.99	140.03	100.76	N/a	N/ a
SAIFI used for calculating threshold[7]	2.48	2.11	2.89	2.24	2.23	2.39
SAIFI disclosed for Hawke's Bay[8]	2.38	1.48	2.75	2.14	N/a	N/a

Table 1. SAIDI and SAIFI values for Financial Years ending 1999 to 2003.

Unison has advised us that it does not have reliable data to verify the historic SAIDI and SAIFI values used to calculate the threshold levels. This is consistent with the qualified audit opinions expressed by PricewaterhouseCoopers (PwC) in Unison's Threshold Compliance Statement for the Second Assessment Date, 31 March 2004, and the Assessment Period ending 31 March 2005. PwC made the following statements regarding their limited ability to verify the calculation of Unison's threshold values:

- Outage records are not available for the entire period that was required to set the threshold levels.

- Prior to the implementation of a fault management system in 1999 control over the completeness and accuracy of outage records was limited.

- Interconnection point (ICP) records for the Rotorua and Taupo networks are not available for periods prior to their acquisition by Unison Networks Limited in 2002 and therefore control over the completeness and accuracy of ICP data

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[4] Calculated as the 5-year arithmetic average.

[5] As published on page 25 of Unison Networks Limited Threshold Compliance Statement for the Assessment Period ending 31 March 2005.

[6] Values taken from Hawke's Bay Network Limited 2001 and 2002 Information Disclosure.

[7] As published on page 32 of Unison Networks Limited Threshold Compliance Statement for the Assessment Period ending 31 March 2005.

[8] Values taken from Hawke's Bay Network Limited 2001 and 2002 Information Disclosure.

included in the SAIDI and SAIFI calculations is limited throughout the required period.

We attempted to review data relating to the SAIDI and SAIFI calculations for the period used to set the current thresholds. However, our observations were similar to those expressed in PwC's audit reports. In instances where data were available we found they were unreliable, incomplete or based on questionable assumptions.

Unison has advised us that its Faults Database, from which it calculates its SAIDI and SAIFI values, is reliable from 1 April 2003 onward, for all its networks. Using this database[9], we calculated Unison's SAIDI and SAIFI values for the 2004, 2005 and 2006 years, as set out in Table 2. Table 2 also includes for comparison purposes the SAIDI and SAIFI values reported by Unison under the information disclosure regime for 2004 and 2005 (the 2006 values are yet to be reported).

Year ending	2004	2005	2006	Average[10]
SAIDI derived from Faults Database	200.9	154.4	133.8	163.0
SAIDI disclosed by Unison[11]	201.6	155.3	133.8	163.6
SAIFI derived from Faults Database	2.66	3.03	2.82	2.84
SAIFI disclosed by Unison[12]	2.39	3.21	2.82	2.81

Table 2. Comparison of SAIDI and SAIFI values disclosed by Unison and those calculated based on data obtained from the Faults Database for periods 2004 to 2006

[9] We did not audit the Faults Database.

[10] Determined using the arithmetic average of 2004, 2005 and 2006.

[11] As disclosed in Unison Networks Limited Threshold Compliance Statement for the Second Assessment Period ending 31 March 2004 and the Assessment Period ending 31 March 2005. As Unison has not yet disclosed its 2006 SAIDI performance we have used the SAIDI number we derived from the Faults Database for 2006 when deriving an average for the three years.

[12] As disclosed in Unison Networks Limited Threshold Compliance Statement for the Second Assessment Period ending 31 March 2004 and the Assessment Period ending 31 March 2005. As Unison has not yet disclosed its 2006 SAIFI performance and we have used the SAIFI number we derived from the Faults Database for 2006 when deriving an average for the three years.

We have not been able to explain the differences between previously disclosed values for financial years ending 2004 and 2005 and those we obtained from the Faults Database, as the data and modelling assumptions used to derive the disclosed values for the respective periods were not adequately recorded. However, these discrepancies are relatively small.

Thus we consider the situation is as follows:

- The SAIDI and SAIFI data underlying the threshold levels currently applying to Unison could not be verified by the auditors and similarly we were unable to verify them, due to the absence of reliable data for the Rotorua and Taupo networks over the period 1998/99 – 2002/03.

- The SAIDI and SAIFI values disclosed by Unison for 2004 and 2005 differ slightly from those that we calculated using Unison's Faults Database. However, the records are not available to identify and explain those differences.

3 Recommended approach to re-setting quality threshold levels

It appears the objective of the method used by the Commission to set the SAIDI and SAIFI threshold levels is to obtain an average value for each service measure for an extended period (i.e. five years) leading up to the period over which the thresholds apply. These threshold values are unique to each distribution business.

To replicate this approach as close as practicable in the case of Unison, for periods commencing 1 April 2006, we recommend the following:

- That the SAIDI and SAIFI values for the last three years be used, rather than the last five years. This approach would recognise that the values up to 31 March 2003 and prior cannot be verified as a reliable reflection of the service quality delivered by the combined Hawkes Bay, Rotorua and Taupo networks which Unison has operated since November 2002.

- That the values disclosed by Unison for 2004 and 2005, plus those we derived for 2006 from Unison's Faults Database, be used to derive an average value for SAIDI and SAIFI over this three year period (we note the three year average for these values is very similar to the average of the values we derived for all three years, see Table 2 above).

Table 3 sets out the SAIDI and SAIFI threshold levels that would result from using our recommended approach. The current Unison thresholds levels are included for comparison purposes.

	Recommended Threshold Levels	Current Threshold Levels
SAIDI	163.6	152.7
SAIFI	2.81	2.39

Table 3 – Recommended and current threshold levels